EXHIBIT 11

THE SURETY & FIDELITY ASSOCIATION OF AMERICA

November 7, 2025

Via Electronic Mail occ.hearings@emnrd.nm.gov

Sheila Apodaca, Commission Clerk
New Mexico Oil Conservation Commission
Wendell Chino Building
1220 S. St. Francis Dr.
Santa Fe, NM 87505

RE: Revised Application for Rulemaking from Western Environmental Law Center, Citizens Caring for the Future, Conservation Voters New Mexico Education Fund, Diné C.A.R.E, Earthworks, Naeva, New Mexico Interfaith Power and Light, San Juan Citizens Alliance, and Sierra Club (collectively "Applicants"); Case No. 24683

Dear Clerk Apodaca,

The Surety & Fidelity Association of America ("SFAA")[1] appreciates the opportunity to provide written comments regarding the Applicant's revised application submitted in response to the alternative proposals the Oil Conservation Division submitted on February 12, 2025. SFAA urges the Oil Conservation Commission ("Commission") to reject the amendments proposed explicitly to 19.5.8.9 NMAC-Financial Assurance, notably the addition of a new category of financial assurance for certain operators based on the types of wells they hold.

While SFAA recognizes the need to address the projected oil and gas cleanup liabilities New Mexico faces and appreciates the good intentions behind the proposed amendments to protect the state and its citizens, the additional financial assurance requirements proposed for certain operators are problematic and create adverse selection against smaller operators based on their current portfolios. Additionally, recent market events have already reduced surety appetite and are likely to diminish it further if the proposed amendments are adopted; any remaining appetite will likely be offered on more restrictive terms. Based on SFAA's general understanding of the market, many operators would not qualify for the increased liabilities associated with marginal wells. Therefore, SFAA welcomes the opportunity to engage with the Commission and the industry to find a better solution that benefits all stakeholders while protecting New Mexico's interests.

[1] SFAA is a national trade association of more than 400 insurance companies that write 98 percent of surety and fidelity bonds in the U.S. SFAA is licensed as a rating or advisory organization in all states, and it has been designated by state insurance departments as a statistical agent for the reporting of fidelity and surety experience.

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(202) 463-0600 / www.surety.org

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SFAA THE SURETY & FIDELITY ASSOCIATION OF AMERICA

The proposed amendment to 19.15.8.9 NMAC recommends additional financial assurance requirements beyond the current standards for certain operators, based on the makeup of their portfolios, particularly the percentage of marginal wells they hold. This creates adverse selection against these operators. Furthermore, these wells are in the poorest condition and demand the most significant financial investment for plugging and abandonment, thereby increasing their financial risk. Because this presents more immediate and substantial exposure and, given the nature of the risk, the surety industry would regard these bonds as high-risk obligations, requiring stricter underwriting scrutiny.

As mentioned earlier, the market has recently shrunk further due to adverse developments. If sureties continue issuing these bonds under the proposed changes, they will raise their underwriting standards for operators seeking bonds for these obligations, likely making only the largest operators eligible. As a result, the proposed rules could reduce competition by excluding all but the biggest oil and gas operators from the pool of eligible operators. Small and medium-sized operators might be effectively shut out of this market, as sureties are likely unwilling to issue bonds for them because they often lack enough financial capital to demonstrate their fiscal strength and ability to handle the increased risks to the Commission over time.

For these reasons, SFAA urges the Commission to reject the proposed amendments to 19.15.8.9 NMAC and instead encourages the Commission to work with SFAA and its members to find a better, more effective solution that minimizes impact on current operators in the New Mexico oil and gas industry while safeguarding the state's interests, a shared common goal.

Respectfully submitted,



Julie Alleyne
Senior Vice President & General Counsel
The Surety & Fidelity Association of America
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202.702.8865

Case No. 24683
NMOGA - Exhibit 7

New Mexico state land office seeks higher oil and gas royaltie ag in

INDUSTRY

By **New Mexico Sun**
Nov 5, 2024

The State Land Office in New Mexico is making another attempt to increase oil and gas royalties on leased land. This marks the fourth effort by the agency to push for higher rates in recent years. Greg Bloom, assistant commissioner of mineral resources, presented the proposal during a meeting with the Legislature's Water and Natural Resources Committee.

This initiative follows a failed legislative attempt earlier this year to raise these royalties. In response, State Land Commissioner Stephanie Garcia Richard announced a halt on leasing prime tracts until the Legislature agrees to new terms. This pause remains in effect as the office seeks to update what Bloom described as "antiquated" rates that have not changed since the 1970s.

The proposed increase from 20% to 25% royalty rates aims to generate an additional billion dollars over 25 years. This includes extra funds for both the State Land Office and Legislative Finance Committee, along with $1.5 billion to $2 billion for the Land Grant Permanent Fund by 2050, which supports educational funding.

Currently, nearly all high-value land has been leased out, according to Joey Keefe, spokesperson for the State Land Office. Only about 1% of leaseholders are based in New Mexico; most come from Colorado, Texas, and Oklahoma.

By delaying leases on valuable tracts nominated by private companies for potential development at a 25% royalty rate, the office risks losing immediate bonus payments that can reach millions of dollars. However, Keefe emphasized that Commissioner Garcia Richard is prepared to sacrifice short-term gains for potentially larger long-term benefits for education funding.

Senator Joe Cervantes expressed caution regarding this strategy's potential outcomes. While he acknowledged some logic behind waiting for legislative action and increased rates, he also warned about missing current market opportunities if conditions change.

ORGANIZATIONS IN THIS STORY

Independent Petrolium Association of New Mexico

EXHIBIT 13

Well	API	Title	Vendor	Date	Plugging Dates	Amount	Amount reported to LCS	Purchase Order
North Shugart Queen Unit #11	30-015-05600	North Shugart Queen 11_JB Well Inv 2559.pdf	J&B Well Servicing, LLC	2/29/2020 0:00		$ 50,539.25	$ 42,815.23	52100-0000064138
North Shugart Queen Unit #11	30-015-05600	North Shugart Queen 11.pdf	J&B Well Servicing, LLC	3/2/2020 0:00		$ 750.00		52100-0000064138
North Shugart Queen Unit #10	30-015-05590	North Shugart #10 _ JB Well Inv 2560.pdf	J&B Well Servicing, LLC	2/29/2020 0:00		$ 33,416.60	$ 42,815.23	52100-0000064138
Artesia Metex Unit #80	30-015-21866	Multiple Bond_JB Well Inv. 123030.pdf	J&B Well Servicing, LLC	1/29/2020 0:00		$ 511.00		
Artesia Metex Unit #56	30-015-00987	Multiple Bond_JB Well Inv. 123023.pdf	J&B Well Servicing, LLC	1/29/2020 0:00		$ 522.00		
Cato San Andres Unit #202	30-005-20524	Cato SA 202 _ JB Well Inv 2600.pdf	J&B Well Servicing, LLC	5/28/2020 0:00		$ 734.00		
Cato San Andres Unit #202	30-005-20524	Cato SA 202 _ JB Well Inv 2599.pdf	J&B Well Servicing, LLC	5/28/2020 0:00		$ 40,075.39		52100-0000065848
Cato San Andres Unit #201	30-005-20472	Cato SA 201_JB Well Inv 2597.pdf	J&B Well Servicing, LLC	5/28/2020 0:00		$ 41,044.41		52100-0000065847
Cato San Andres Unit #201	30-005-20472	Cato SA 201 _ JB Well Inv 2598.pdf	J&B Well Servicing, LLC	5/28/2020 0:00		$ 731.28		
Cato San Andres Unit #199	30-005-20957	Cato SA 199 _ JB Well Inv 2596.pdf	J&B Well Servicing, LLC	5/26/2020 0:00		$ 534.26		
Cato San Andres Unit #199	30-005-20957	Cato SA 199 _ JB Well Inv 2595.pdf	J&B Well Servicing, LLC	5/26/2020 0:00		$ 25,770.91		52100-0000065845
Cato San Andres Unit #195	30-005-20272	Cato SA 195 _ JB Well Inv 2607.pdf	J&B Well Servicing, LLC	6/16/2020 0:00		$ 735.00		
Cato San Andres Unit #195	30-005-20272	Cato SA 195 _ JB Well Inv 2602.pdf	J&B Well Servicing, LLC	6/16/2020 0:00		$ 35,701.78		52100-0000065839
Cato San Andres Unit #194	30-005-20546	Cato SA 194_JB Well Inv2593.pdf	J&B Well Servicing, LLC	5/26/2020 0:00		$ 23,527.08		52100-0000065837
Cato San Andres Unit #191	30-005-20526	Cato SA 191 _ JB Well Inv 2592.pdf	J&B Well Servicing, LLC	5/26/2020 0:00		$ 737.58		
Cato San Andres Unit #191	30-005-20526	Cato SA 191 _ JB Well Inv 2591.pdf	J&B Well Servicing, LLC	5/26/2020 0:00		$ 34,325.64		52100-0000065836
Cato San Andres Unit #190	30-005-20544	Cato SA 190_ JB Well Inv 2601.pdf	J&B Well Servicing, LLC	6/16/2020 0:00		$ 35,792.07		52100-0000065834
Cato San Andres Unit #190	30-005-20544	Cato SA 190 _ JB Well Inv 2608.pdf	J&B Well Servicing, LLC	6/16/2020 0:00		$ 642.00		
Cato San Andres Unit #189	30-005-20261	Cato SA 189 _ JB Well Iv 2604.pdf	J&B Well Servicing, LLC	6/16/2020 0:00		$ 34,957.48		52100-0000065833
Cato San Andres Unit #189	30-005-20261	Cato SA 189 _ JB Well Inv 2606.pdf	J&B Well Servicing, LLC	6/16/2020 0:00		$ 725.00		
Cato San Andres Unit #183		Cato SA 183 _ JB Well Inv 2605.pdf	J&B Well Servicing, LLC	6/16/2020 0:00		$ 650.00		
Cato San Andres Unit #183	30-005-20545	Cato SA 183 _ JB Well Inv 2603.pdf	J&B Well Servicing, LLC	6/16/2020 0:00		$ 31,289.61	$ 31,939.61	52100-0000065832
Artesia Metex Unit #68	30-015-27196	Artesia Metex 68 _ JB well Inv 2579.pdf	J&B Well Servicing, LLC	3/31/2020 0:00		$ 20,221.29	$ 20,221.29	52100-0000065266
Artesia Metex Unit #67	30-015-27195	Artesia Metex 67_JB Well Inv 2582.pdf	J&B Well Servicing, LLC	4/6/2020 0:00		$ 18,415.18		52100-0000065265
Artesia Metex Unit #66	30-015-27194	Artesia Metex 66_JB Well Inv 2569.pdf	J&B Well Servicing, LLC	3/12/2020 0:00		$ 21,252.08		52100-0000065264
Artesia Metex Unit #65	30-015-27193	Artesia Metex 65_JB well Inv 2568.pdf	J&B Well Servicing, LLC	3/12/2020 0:00		$ 23,204.73		52100-0000065263
Artesia Metex Unit #64	30-015-27192	Artesia Metex 64 _ JB Well Inv 2578.pdf	J&B Well Servicing, LLC	3/31/2020 0:00		$ 21,298.39	$ 21,298.39	52100-0000065267
Artesia Metex Unit #61	30-015-21874	Artesia Metex 61_JB Well Inv 2567.pdf	J&B Well Servicing, LLC	3/12/2020 0:00		$ 508.98		
Artesia Metex Unit #61	30-015-21874	Artesia Metex 61_JB Well Inv 2566.pdf	J&B Well Servicing, LLC	3/12/2020 0:00		$ 28,446.49		52100-0000065261
Artesia Metex Unit #60	30-015-21866	Artesia Metex 60_JB Well Inv 2580.pdf	J&B Well Servicing, LLC	4/6/2020 0:00		$ 27,077.63		52100-0000065260
Artesia Metex Unit #59	30-015-00949	Artesia Metex 59_ JB Well Inv 2565.pdf	J&B Well Servicing, LLC	3/12/2020 0:00		$ 24,341.91	$ 24,953.39	52100-0000065259
Artesia Metex Unit #58	30-015-00991	Artesia Metex 58 _ JB Well Inv 2575.pdf	J&B Well Servicing, LLC	3/31/2020 0:00		$ 508.98		
Artesia Metex Unit #58	30-015-00991	Artesia Metex 58 _ JB Well Inv 2574.pdf	J&B Well Servicing, LLC	3/31/2020 0:00		$ 24,806.06	$ 29,183.88	52100-0000065258
Artesia Metex Unit #56	30-015-00987	Artesia Metex 56_JB Well Inv 2564.pdf	J&B Well Servicing, LLC	3/12/2020 0:00		$ 520.40		
Artesia Metex Unit #56	30-015-00987	Artesia Metex 56_JB Well Inv 2563.pdf	J&B Well Servicing, LLC	3/12/2020 0:00		$ 26,504.71	$ 29,838.85	52100-0000065256
Artesia Metex Unit #55	30-015-00986	Artesia Metex 55 _ JB Well Inv 2572.pdf	J&B Well Servicing, LLC	3/31/2020 0:00		$ 520.00		
Artesia Metex Unit #55	30-015-00986	Artesia Metex 55 _ JB Well Inv 2571.pdf	J&B Well Servicing, LLC	3/31/2020 0:00		$ 27,024.09	$ 29,838.85	52100-0000065255
Artesia Metex Unit #54	30-015-00956	Artesia Metex 54 _ JB Well Inv 2577.pdf	J&B Well Servicing, LLC	3/31/2020 0:00		$ 508.98		
Artesia Metex Unit #54	30-015-00956	Artesia Metex 54 _ JB Well Inv 2576.pdf	J&B Well Servicing, LLC	3/31/2020 0:00		$ 28,458.84	$ 29,183.88	52100-0000065254
						$ 687,331.08		
					Report to LCS	$ 600,490.40		

EXHIBIT 13

Well	API	Invoice Description	Vendor	Date	Plugging Dates	Amount	Purchase Order
State #002	30-041-20542	State 002_JA_Drake_Well_Service_INV_18891_09-02-21.pdf	Drake Well Service	5/12/2021 0:00	5/6-12/2021	$ 58,373.65	52100-0000068039
State #001	30-041-20445	State 001_JA_Drake_Well_Service_INV_18868_05-13-21.pdf	Drake Well Service	4/30/2021 0:00	4/27-5/6/2021	$ 92,479.26	52100-0000068040
Paye Federal #9	30-005-20501	Paye Fed 9_J_B_Wells_INV_2635_11-30-20.pdf	J&B Well Servicing, LLC	11/24/2020 0:00		$ 47,078.85	52100-0000066965
Paye Federal #9	30-005-20501	Paye Fed 9_J_B_Wells_INV_2634_11-30-20.pdf	J&B Well Servicing, LLC	11/24/2020 0:00		$ 779.00	
Paye Federal #9	30-005-20501	Paye Fed 9_J_B_Wells_INV_2633_11-30-20.pdf	J&B Well Servicing, LLC	11/24/2020 0:00		$ 43,762.72	52100-0000066965
Paye Federal #8	30-005-20500	Paye Fed 8_J_B_Wells_INV_2645_2-9-21.pdf	J&B Well Servicing, LLC	2/6/2021 0:00		$ 779.00	
Paye Federal #8	30-005-20500	Paye Fed 8_J_B_Wells_INV_2644_2-9-21.pdf	J&B Well Servicing, LLC	2/6/2021 0:00		$ 4,592.15	52100-0000066964
Paye Federal #8	30-005-20500	paye Fed 8_J_B_Wells_INV_2643_2-9-21.pdf	J&B Well Servicing, LLC	2/6/2021 0:00		$ 43,670.93	52100-0000066964
Paye Federal #6	30-005-20494	Paye Fed 6_J_B_Wells_INV_2647_2-17-21.pdf	J&B Well Servicing, LLC	2/17/2021 0:00		$ 760.00	
Paye Federal #6	30-005-20494	Paye Fed 6J_B_Wells_INV_2646_2-17-21.pdf	J&B Well Servicing, LLC	2/17/2021 0:00		$ 42,602.85	52100-0000066963
Paye Federal #5	30-005-20493	Paye Fed 5_J_B_Wells_INV_2641_2-1-21.pdf	J&B Well Servicing, LLC	1/29/2021 0:00		$ 779.00	
Paye Federal #5	30-005-20493	Paye Fed 5_ J_B_Wells_INV_2640_2-1-21.pdf	J&B Well Servicing, LLC	1/29/2021 0:00		$ 13,474.46	52100-0000066962
Paye Federal #5	30-005-20493	Paye Fed 5_ J_b_Wells_INV_2639_2-1-21.pdf	J&B Well Servicing, LLC	1/29/2021 0:00		$ 43,736.61	52100-0000066962
Paye Federal #4	30-005-20492	Paye Fed 4_J_B_Wells_INV_2650_2-24-21.pdf	J&B Well Servicing, LLC	2/24/2021 0:00		$ 779.00	
Paye Federal #4	30-005-20492	Paye Fed 4J_B_Wells_INV_2649_2-24-21.pdf	J&B Well Servicing, LLC	2/24/2021 0:00		$ 19,484.80	52100-0000066961
Paye Federal #4	30-005-20492	Paye Fed 4J_B_Wells_INV_2648_2-24-21.pdf	J&B Well Servicing, LLC	2/24/2021 0:00		$ 43,741.09	52100-0000066961
Paye Federal #10	30-005-20502	Paye Fed 10_J_B_Wells_INV_2632_11-10-20.pdf	J&B Well Servicing, LLC	11/9/2020 0:00		$ 779.00	
Paye Federal #10	30-005-20502	Paye Fed 10_J_B_Wells_INV_2631_11-10-20.pdf	J&B Well Servicing, LLC	11/9/2020 0:00		$ 43,720.52	52100-0000066966
Laguna Grande Federal #1	30-015-21636	Luguna Grande 1 _ J__B_Wells_INV_2614_8-31-20.pdf	J&B Well Servicing, LLC	8/31/2020 0:00		$ 50,821.46	52100-0000067164
Laguna Federal #1	30-015-21636	Laguna Fed 1 _ J__B_Wells_INV_2615_8-31-20.pdf	J&B Well Servicing, LLC	8/31/2020 0:00		$ 911.45	
Ingram Federal #6	30-005-20605	Ingram Fed ^_JB_Wells_INV_2630_10-28-20.pdf	J&B Well Servicing, LLC	10/28/2020 0:00		$ 723.00	
Ingram Federal #7	30-005-20639	Ingram Fed 7 _ J__B_Wells_INV_2628_10-21-20.pdf	J&B Well Servicing, LLC	10/19/2020 0:00		$ 723.00	
Ingram Federal #6	30-005-20605	Ingram Fed 6_J_B_Wells_INV_2629_10-28-20.pdf	J&B Well Servicing, LLC	10/28/2020 0:00		$ 40,563.17	52100-0000066967
Ingram Federal #7	30-005-20639	Ingra Fed 7 _ J___B_Wells_INV_2627_10-21-20.pdf	J&B Well Servicing, LLC	10/19/2020 0:00		$ 40,524.24	52100-0000066968
Gulf Federal #3	30-025-20976	Gulf Fed 33 _ J___B_Wells_INV_2622_11-9-20.pdf	J&B Well Servicing, LLC	9/28/2020 0:00		$ 1,528.00	
Gulf Federal #1	30-025-00909	Gulf Fed 31 _ J_B_Wells_INV_2619_11-13-20.pdf	J&B Well Servicing, LLC	9/28/2020 0:00		$ 32,429.65	52100-0000067169
Gulf Federal #3	30-025-20976	Gulf Fed #3_ J___B_Wells_INV_2622_11-9-20.pdf	J&B Well Servicing, LLC	9/28/2020 0:00		$ 1,528.00	
Gulf Federal #3	30-025-20976	Gulf Fed #3 _ J_B_Wells_INV_2621_9-29-20.pdf	J&B Well Servicing, LLC	9/28/2020 0:00		$ 85,758.15	52100-0000067171
Gulf Federal #2	30-025-00910	Gulf Fed #2 _ J__B_Wells_INV_2625_10-05-20.pdf	J&B Well Servicing, LLC	9/30/2020 0:00		$ 32,380.59	52100-0000067170
Gulf Federal #2	30-025-00910	Gulf Fed #1 _ J___B_Wells_INV_2626_10-05-20.pdf	J&B Well Servicing, LLC	9/30/2020 0:00		$ 578.00	
Gulf Federal #1	30-025-00909	Gulf Fed #1 _ J_B_Wells_INV_2620_11-13-20.pdf	J&B Well Servicing, LLC	9/28/2020 0:00		$ 578.00	
Federal 18 #3	30-015-20146	Fed 18 #3 _ J___B_Wells_INV_2624_11-9-20.pdf	J&B Well Servicing, LLC	9/28/2020 0:00		$ 659.00	
Federal 18 #3	30-015-20146	Fed 18 #3 _ J_B_Wells_INV_2623_9-29-20.pdf	J&B Well Servicing, LLC	9/28/2020 0:00		$ 36,846.93	52100-0000067165
Federal 18 #1	30-015-05765	Fed 18 #1 _ J_B_Wells_INV_2618_9-22-20.pdf	J&B Well Servicing, LLC	9/8/2020 0:00		$ 10,518.35	52100-0000067167
Federal 18 #1	30-015-05765	Fed 18 #1 _ J_B_Wells_INV_2617_9-22-20.pdf	J&B Well Servicing, LLC	9/8/2020 0:00		$ 614.00	
Federal 18 #1	30-015-05765	Fed 18 #1 _ JB_Wells_INV_2616_9-22-20.pdf	J&B Well Servicing, LLC	9/8/2020 0:00		$ 34,374.01	52100-0000067167
Cato San Andres #96		Cato SA 96_JA_Drake_Well_Service_INV_18666_3-1-21.pdf	Drake Well Service	2/26/2021 0:00	2/24-26/2021	$ 51,353.46	52100-0000068215
Cato San Andres #95	30-005-20023	Cato SA 95 _JA_Drake_Well_Service_INV_18830_04-27-21.pdf	Drake Well Service	4/13/2021 0:00	4/8-21/2021	$ 120,233.81	52100-0000068323
Cato San Andres #94	30-005-20677	Cato SA 94_JA_Drake_Well_Service_INV_18853_05-03-21.pdf	Drake Well Service	4/24/2021 0:00	4/21-26/2021	$ 55,541.07	52100-0000068324
Cato San Andres #93	30-005-20022	Cato SA 93_JA_Drake_Well_Service_INV_18854_05-05-21.pdf	Drake Well Service	4/24/2021 0:00	4/21-29-2021	$ 49,450.30	52100-0000068326
Cato San Andres #92	30-005-20018	Cato SA 92_JA_Drake_Well_Service_INV_18831_04-27-21.pdf	Drake Well Service	4/13/2021 0:00	4/5-21/2021	$ 65,230.85	52100-0000068327
Cato San Andres #73	30-005-20017	Cato SA 73_JA_Drake_Well_Service_INV_18816_04-14-21.pdf	Drake Well Service	4/8/2021 0:00	3/30-4/7/2021	$ 49,729.03	52100-0000068329
Cato San Andres #72	30-005-20021	Cato SA 72_JA_Drake_Well_Service_INV_18817_04-14-21.pdf	Drake Well Service	4/8/2021 0:00	4/5-8/2021	$ 51,160.07	52100-0000068330
Cato San Andres #71	30-005-20020	Cato SA 71_JA_Drake_Well_Service_INV_18784_04-05-21.pdf	Drake Well Service	4/2/2021 0:00	3/25-4/2/2021	$ 80,235.46	52100-0000068331
Cato San Andres #70	30-005-20019	Cato SA 70JA_Drake_Well_Service_INV_18774_03-31-21.pdf	Drake Well Service	3/30/2021 0:00	3/23-26/2021	$ 43,637.57	52100-0000068332
Cato San Andres #547	30-005-27988	Cato SA 547_JA_Drake_Well_Service_INV_19013_06-24-21.pdf	Drake Well Service	6/22/2021 0:00	6/18-23/2021	$ 40,154.63	52100-0000068678
Cato San Andres #546	30-005-27987	Cato SA 546_JA_Drake_Well_Service_INV_19018_06-24-21.pdf	Drake Well Service	6/24/2021 0:00	6/18-23/2021	$ 42,759.49	52100-0000068679
Cato San Andres #507	30-005-28022	Cato SA 507_JA_Drake_Well_Service_INV_19010_06-21-21.pdf	Drake Well Service	6/18/2021 0:00	6/15-18/2021	$ 52,235.00	52100-0000068680
Cato San Andres #506	30-005-27981	Cato SA 506_JA_Drake_Well_Service_INV_18988_06-17-21.pdf	Drake Well Service	6/16/2021 0:00	6/10-15/2021	$ 39,414.25	52100-0000068681
Cato San Andres #505	30-005-27980	Cato SA 505_JA_Drake_Well_Service_INV_19009_06-21-21.pdf	Drake Well Service	6/18/2021 0:00	6/15-17/2021	$ 38,529.76	52100-0000068682
Cato San Andres #504	30-005-27971	Cato SA 504_JA_Drake_Well_Service_INV_18947_06-17-21.pdf	Drake Well Service	6/2/2021 0:00	6/1-16/2021	$ 34,609.59	52100-0000068683
Cato San Andres #355		Cato SA 355_JA_Drake_Well_Service_INV_18649_2-25-21.pdf	Drake Well Service	2/23/2021 0:00	2/9-20/2021	$ 56,485.02	52100-0000068042
Cato San Andres #124	30-005-20035	Cato SA 124_JA_Drake_Well_Service_INV_18714_03-25-21.pdf	Drake Well Service	3/22/2021 0:00	3/1-23/2021	$ 106,868.86	52100-0000068043
Cato San Andres #123	30-005-20042	Cato SA 123_JA_Drake_Well_Service_INV_18679_03-16-21.pdf	Drake Well Service	3/15/2021 0:00	3/1-12/2021	$ 83,857.43	52100-0000068044
Cato San Andres #122		Cato SA 122_JA_Drake_Well_Service_INV_18218_2-25-21.pdf	Drake Well Service	2/23/2021 0:00	2/4-10/2021	$ 47,959.26	52100-0000068045
Cato San Andres #121	30-005-20041	Cato SA 121_JA_Drake_Well_Service_INV_18658_03-16-21.pdf	Drake Well Service	3/15/2021 0:00	2/4-3/12/2021	$ 109,426.06	52100-0000068046
Cato San Andres #105		Cato SA 105_JA_Drake_Well_Service_INV_18650_3-2-21.pdf	Drake Well Service	2/24/2021 0:00	2/3-26/2021	$ 50,758.82	52100-0000068047
Cato San Andres #104		Cato SA 104_JA_Drake_Well_Service_INV_18220_2-25-21.pdf	Drake Well Service	2/23/2021 0:00	2/2-10/2021	$ 41,971.53	52100-00068049
Cato San Andres #103		Cato SA 103_JA_Drake_Well_Service_INV_18683_3-9-21.pdf	Drake Well Service	3/6/2021 0:00	2/1-3/5/2021	$ 43,239.95	52100-0000068050
Cato San Andres #102		Cato SA 102_JA_Drake_Well_Service_INV_18651_3-2-21.pdf	Drake Well Service	2/24/2021 0:00	2/20-26/2024	$ 57,441.81	52100-0000068216

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Cato San Andres #007	30-005-10536	Cato SA 007_JA_Drake_Well_Service_INV_18935_06-04-21.pdf	Drake Well Service	5/27/2021 0:00	5/24-6/1/2021	$	52,453.53	52100-0000068684
Cato San Andres #006	30-005-20001	Cato SA 006_JA_Drake_Well_Service_INV_18915_05-26-21.pdf	Drake Well Service	5/20/2021 0:00	5/18-21/2021	$	51,733.91	52100-0000068685
Cato San Andres #005	30-005-20271	Cato SA 005_JA_Drake_Well_Service_INV_18909_05-21-21.pdf	Drake Well Service	5/18/2021 0:00	5/12-18/2021	$	62,282.16	52100-0000068686

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Well	API	Invoice Description	Vendor	Date	Plugging Dates	Amount	Purchase Order
Cato San Andres Unit #081	30-005-10572	Cato SA 81 _ JADrake Inv 20226.pdf	Drake Well Service	6/18/2022 0:00	6/3-13/2022	$ 49,154.50	52100-0000071531
Cato San Andres Unit #076	30-005-10566	Cato SA 76 _ JADrake Inv 20282.pdf	Drake Well Service	6/24/2022 0:00	6/15-23/2022	$ 57,194.38	52100-0000071478
Cato San Andres Unit #075	30-005-10562	Cato SA 75 _ JADrake Inv 20290.pdf	Drake Well Service	6/27/2022 0:00	6/23-24/2022	$ 1,284.64	52100-0000071476
Cato San Andres Unit #075	30-005-10562	Cato SA 75 _ JADrake 20283.pdf	Drake Well Service	6/24/2022 0:00	6/20-23/2022	$ 53,779.60	52100-0000071476
Cato San Andres Unit #064	30-005-20028	Cato SA 64 _ JADrake Inv 19434.pdf	Drake Well Service	11/7/2021 0:00	10/20-11/2/2021	$ 76,628.20	52100-0000069505
Cato San Andres Unit #060	30-005-10571	Cato SA 60 _ JADrake Inv 20107.pdf	Drake Well Service	5/23/2022 0:00	5/5-9/2022	$ 52,676.84	52100-0000071197
Cato San Andres Unit #056	30-005-10579	Cato SA 56 _ JADrake Inv 20309.pdf	Drake Well Service	7/8/2022 0:00	6/28-30-2022	$ 60,904.19	52100-0000071472
Cato San Andres Unit #053	30-005-20293	Cato SA 53 _ JADrake Inv 20118.pdf	Drake Well Service	5/26/2022 0:00	5/16-23/2022	$ 73,849.22	52100-0000071383
Cato San Andres Unit #052	30-005-20009	Cato SA 52 _ JADrake Inv 20308.pdf	Drake Well Service	7/8/2022 0:00	6/27-30/2022	$ 40,114.82	52100-0000071469
Cato San Andres Unit #049	30-005-10455	Cato SA 49 _ JADrake Inv 20166.pdf	Drake Well Service	6/8/2022 0:00	5/22-31-2022	$ 68,818.07	52100-0000071378
Cato San Andres Unit #047	30-005-10578	Cato SA 47 _ JADrake Inv 20095.pdf	Drake Well Service	5/22/2022 0:00	5/12-16/2022	$ 72,775.65	52100-0000071193
Cato San Andres Unit #046	30-005-10538	Cato SA 46 _ JADrake Inv 20047.pdf	Drake Well Service	5/5/2022 0:00	4/27-5/2/2022	$ 38,571.76	52100-0000071195
Cato San Andres Unit #044	30-005-20004	Cato SA 44 _ JADrake Inv 19361.pdf	Drake Well Service	10/15/2021 0:00	9/23-11/2/2021	$ 57,871.94	52100-0000069501
Cato San Andres Unit #041	30-005-20047	Cato SA 41 _ JADrake Inv 19299.pdf	Drake Well Service	9/26/2021 0:00	9/7-24/2021	$ 83,979.01	52100-0000069499
Cato San Andres Unit #036	30-005-20065	Cato SA 36 _ JADrake Inv 19992.pdf	Drake Well Service	4/19/2022 0:00	4/13-18/2022	$ 42,438.42	52100-0000069519
Cato San Andres Unit #330	30-005-21166	Cato SA 330 _ JADrake Inv 19568.pdf	Drake Well Service	12/16/2021 0:00	12/8-14/2021	$ 58,704.26	52100-0000069508
Cato San Andres Unit #328	30-005-21164	Cato SA 328 _ JADrake Inv 19609.pdf	Drake Well Service	12/28/2021 0:00	12/14-21-2021	$ 73,923.02	52100-0000069507
Cato San Andres Unit #031	30-005-20170	Cato SA 31 _ JADrake Inv 20043.pdf	Drake Well Service	5/4/2022 0:00	4/18-5/2/2022	$ 74,929.72	52100-0000071198
Cato San Andres Unit #302	30-005-21163	Cato SA 302 _ JADrake Inv 19567.pdf	Drake Well Service	12/15/2021 0:00	12/1-14/2021	$ 75,679.01	52100-0000069506
Cato San Andres Unit #028	30-005-10503	Cato SA 28 _ JAdrake 20165.pdf	Drake Well Service	6/6/2022 0:00	5/22-6/1/2022	$ 69,783.01	52100-0000071377
Cato San Andres Unit #027	30-005-10491	Cato SA 27 _ JADrake Inv 20160.pdf	Drake Well Service	6/6/2022 0:00	5/19-31/2022	$ 84,672.73	52100-0000071376
Cato San Andres Unit #025	30-005-20294	Cato SA 25 _ JADrake Inv 20167.pdf	Drake Well Service	6/8/2022 0:00	5/26-31/2022	$ 51,420.22	52100-0000071388
Cato San Andres Unit #023	30-005-10523	Cato SA 23 _ JADrake Inv 20217.pdf	Drake Well Service	6/15/2022 0:00	5/21-6/7/2022	$ 59,700.30	52100-0000071386
Cato San Andres Unit #021	30-005-20069	Cato SA 21 _ JADrake Inv 20113.pdf	Drake Well Service	5/25/2022 0:00	5/13-23/2022	$ 69,236.00	52100-0000071385
Cato San Andres Unit #010	30-005-20161	Cato SA 10 _ JADrake Inv 19970.pdf	Drake Well Service	4/12/2022 0:00	4/6-11/2022	$ 61,832.71	52100-0000069515
Cato San Andres Unit #050	30-005-29021	Cato SA 050 _ JADrake Inv 20112.pdf	Drake Well Service	5/25/2022 0:00	5/16-23/2022	$ 66,896.20	52100-0000071379
Cato San Andres Unit #003	30-005-20678	Cato SA 003 _ JADrake Inv 19991.pdf	Drake Well Service	4/19/2022 0:00	4/11-18/2022	$ 53,471.80	52100-0000069511

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Cato San Andres Unit #002	30-005-20932	Cato SA 002 _ JADrake Inv 19644.pdf	Drake Well Service	1/13/2022 0:00	1/5-19/2022	$	92,061.04	52100-0000020932
Cato San Andres Unit #089	30-005-10563	Cato SA 89 _ JADrake Inv 20311.pdf	Drake Well Service	7/8/2022 0:00	6/25-30/2022	$	50,455.00	52100-0000071584
Cato San Andres Unit #008	30-005-20160	Cato AA 008 _ JADrake Inv 19993.pdf	Drake Well Service	4/19/2022 0:00	4/13-18/2022	$	50,785.52	52100-0000069513
Cato San Andres Unit #001	30-005-10584	Cato 001 _ JADrake Inv 19643.pdf	Drake Well Service	1/13/2022 0:00	1/6-18/2022	$	73,714.20	52100-0000069509

EXHIBIT 13

Well	API	Invoice Description	Vendor	Invoice Date	Plugging Dates	Amount	Purchase Order
Artesia Metex #043	30-015-02142	Artesia metex 43 _ APlus Inv 1398.pdf	A Plus P&A LLC	6/27/2023 0:00	6/20-28/2023	$ 119,337.31	52100-0000073858
Artesia Metex #042	30-015-02138	Artesia Metex 042 _ APlus Inv 1289.pdf	A Plus P&A LLC	5/18/2023 0:00	5/4-18/2023	$ 266,620.34	52100-0000073858
Artesia Metex #041	30-015-02136	Artesia Metex 41 _ Aplus inv 1371.pdf	A Plus P&A LLC	6/16/2023 0:00	6/13-16/2023	$ 80,024.66	52100-0000073858
Artesia Metex #040	30-015-00954	Artesia Metex 40 _ APlus Inv 1359.pdf	A Plus P&A LLC	6/12/2023 0:00	6/5-28/2023	$ 179,794.00	52100-0000073858
		Multiple _ JADrake Inv 21258.pdf	Drake Well Service	4/11/2023 0:00		$ 94,495.34	52100-00000731110
		Multiple _ Aplus Inv 12515.pdf	A Plus P&A LLC	4/21/2023 0:00		$ 15,753.56	52100-0000072806
Judy #3	30-025-26262	Judy 3 _ APlus Inv 12399.pdf	A Plus P&A LLC	12/2/2022 0:00	11/18/2022-1/12/2023	$ 196,360.35	52100-0000072806
Judy #1	30-025-24641	Judy 1 _ APlus Inv 1067.pdf	A Plus P&A LLC	2/25/2023 0:00	2/15-3/2/2023	$ 130,854.23	52100-0000073064
Lawton State #001	30-025-07119	J_A_Drake_Well_Services_Invoice_21447.pdf	Drake Well Service	6/14/2023 0:00	12/5/2022-1/4/2023	$ 37,904.87	52100-0000073068
Harrison #001	30-025-24609	Harrison 1 _ A plus Inv 1046.pdf	A Plus P&A LLC	2/15/2023 0:00	2/7-3/2/2023	$ 132,569.07	52100-0000073861
Fowler Hair #005	30-025-11107	Fowler hair 5 _ A Plus Inv 12480.pdf	A Plus P&A LLC	1/16/2023 0:00	1/3-3/2/2023	$ 230,534.28	52100-0000072806
Fowler Hair #3	30-025-11105	Fowler Hair 003 _ Aplus Inv 12454.pdf	A Plus P&A LLC	12/30/2023 0:00	12/13/2022-1/13/2023	$ 176,657.80	52100-0000072806
Fowler Hair #1	30-025-11103	Fowler Hair 001 _ A Plus Inv 12419.pdf	A Plus P&A LLC	12/13/2022 0:00	12/2/2022-1/12/2023	$ 170,322.58	52100-0000072806
Foster #1	30-025-07968	Foster #1 _ A plus Inv 12360.pdf	A Plus P&A LLC	11/11/2022 0:00	11/3/2022-1/12/2023	$ 184,806.85	52100-0000072806
Cato San Andres #101	30-005-20010	Cato SA 101 _ JADrake Inv 21529.pdf	Drake Well Service	7/5/2023 0:00	6/14-29/2023	$ 147,885.53	52100-0000073110
Cato San Andres #100	30-005-20007	Cato SA 100 _ JADrake Inv 21554.pdf	Drake Well Service	7/11/2023 0:00	6/14/2023 0:00	$ 3,973.88	52100-0000073110
Cato San Andres #098	30-005-10474	Cato SA 98 _ JADrake Inv 21532.pdf	Drake Well Service	7/6/2023 0:00	6/13-30/2023	$ 99,440.94	52100-0000073110
Cato San Andres #069	30-005-10586	Cato SA 69 _ JADrake Inv 21500.pdf	Drake Well Service	6/26/2023 0:00	6/9-13/2023	$ 106,418.09	52100-0000073110
Cato San Andres #068	30-005-20236	Cato SA 068 _ JADrake Inv 21472.pdf	Drake Well Service	6/20/2023 0:00	5/29-6/15/2023	$ 153,396.09	52100-0000073110
Big Eddy Unit #127	30-015-27635	Big Edd _ APluss Inv 1101.pdf	A Plus P&A LLC	3/8/2023	2/27-3/9/2023	Unknown	52100-0000073010
Artesia Metex #045	30-015-00959	Artesia metex 45 _ APlus Inv 1378.pdf	A Plus P&A LLC	6/20/2023 0:00	6/16-28/2023	$ 132,493.66	52100-0000073858

Handling fees?
Dates of Service after dates of invoices?
Over-payment re mileage for Welder re Metex?

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Well	API	Invoice Description	Vendor	Invoice Date	Plugging Dates	Amount	Purchase Order
Alves A #001	30-2025-06430	Alves A #001 - Drake Inv. 22226	Drake Well Service	3/1/2024	12/16/23 to 1/27/24	$ 454,014.69	52100-0000075938
Alves #004	30-025-36383	Alves #004 - Drake Inv. 22122	Drake Well Service	1/3/2024	12/11/23 to 12/20/23	$144,820.79	52100-0000075938
Alves #002	30-025-06662	Alves #002 - Drake Inv. 22121	Drake Well Service	1/23/2024	12/3/23 to 12/20/23	$194,690.23	2100-0000075938
Alves #003	30-025-24180	Alves #003 - Drake Inv. 22197	Drake Well Service	2/7/2024	11/27/23 to 12/24/23	$214,185.83	52100-0000075938
Artesia Metex Unit #32	30-015-02140	AMU #32 - J&B Well Servicing Inv. 2461	J&G Well Servicing	10/29/2018	Bond	$ 498.87	
Bagley #002	30-025-38192	Bagley #002 - Drake Inv. 22090	Drake Well Service	2/28/2024	11/5/23 to 12/16/23	$ 523,725.26	52100-0000075600
BRC Madera #001	30-015-22372	BRC #001 - Drake Inv. 21793	Drake Well Service	10/21/2023	8/24/23 to 9/20/23	$ 776,110.18	52100-0000075008
Brown 84 #001	30-025-23881	Brown 84 #001 - Drake Inv. 22597	Drake Well Service	6/11/2024	5/25/24 to 6/7/24	$ 276,444.71	52100-0000077042
Brown 84 #002	30-025-25297	Brown 84 #002 - Drake Inv. 22516	Drake Well Service	5/30/2024	5/2/24 to 5/18/24	$ 274,383.81	52100-0000077042
Brown 93 #1	30-025-23975	Brown 93 #1 - Drake Inv. 22586	Drake Well Service	5/31/2024	5/18/2024 to 5/24/24	$ 189,275.69	52100-0000077042
Buckskin Fed #002	30-025-27024	Buckskin #002 - Drake Inv. 22638	Drake Well Service	7/2/2024	5/11/24 to 6/30/24	$ 183,167.86	52100-0000077041
Barkneht #001	30-005-60817	Barkneht #001 - Drake Inv. 21812	Drake Well Service	11/12/2023	9/26/23 to 10/12/23	$ 219,834.41	52100-0000075229
Cato San Andres Unit #097	30-005-10567	Cato SA #097 - Drake Inv. 21760	Drake Well Service	9/28/2023	8/20/23 to 9/2/23	$ 207,466.58	52100-0000075010
Cato San Andres Unit #098	30-005-10474	Cato SA #098 - Drake Inv. 21711	Drake Well Service	8/26/2023	8/12/23 to 8/21/23	$ 210,473.02	2100-0000075010
Cato San Andres #100	30-005-20007	Cato SA #100 - Drake Inv. 21746	Drake Well Service	9/29/2023	8/29/23 to 9/12/23	$ 279,433.00	52100-0000075010
Cato San Andres #119	30-005-20103	Cato SA #119 - Drake Inv. 21741	Drake Well Service	10/9/2023	8/12/23 to 9/20/23	$ 241,297.97	52100-0000075010
Cato San Andres #127	30-005-20071	Cato SA #127 - Drake Inv. 21710	Drake Well Service	9/25/2023	8/12/23 to 8/21/23	$ 164,107.41	52100-0000075010
Cato San Andres #516	30-005-27973	Cato SA #516 - Drake Inv. 21698	Drake Well Service	9/22/2023	8/15/23 to 8/21/23	$ 103,464.72	52100-0000075010
Cato San Andres #520	30-005-28027	Cato SA #520 - Drake Inv. 21863	Drake Well Service	10/25/2023	9/2/23 to 9/12/23	$ 88,628.09	52100-0000073110
Cato San Andres Ut. #531	30-005-27974	Cato SA Ut #531 - Drake Inv. 21740	Drake Well Service	9/27/2023	8/21/23 to 9/2/23	$ 104,186.39	52100-0000075010
Cato San Andres Ut. #532	30-005-27964	Cato SA Ut #532 - Drake Inv. 21748	Drake Well Service	9/27/2023	8/21/23 to 9/2/23	$ 96,065.48	52100-0000075010
Cato San Andres Ut. #533	30-005-27985	Cato SA Ut #533 - Drake Inv. 21743	Drake Well Service	9/28/2023	8/24/23 to 9/2/23	$ 90,943.94	52100-0000073110
Cato San Andres #535	30-005-27983	Cato SA #535 - Drake Inv. 21747	Drake Well Service	9/7/2023	8/27/23 to 9/2/23	$ 121,283.68	52100-0000075010
Cato San Andres #544	30-005-27986	Cato SA #544 - Drake Inv. 21864	Drake Well Service	10/25/2023	9/4/23 to 9/12/23	$ 85,423.13	52100-0000073110
Cato San Andres #545	30-005-27984	Cato SA #545 - Drake Inv. 21865	Drake Well Service	10/25/2023	9/7/23 to 9/12/23	$ 99,512.66	52100-0000075010
Cato San Andres #558	30-005-28010	Cato SA #558 - Drake Inv. 21749	Drake Well Service	10/3/2023	9/9/23 to 9/12/23	$ 79,185.50	52100-0000075010
Cato San Andres #559	30-005-28011	Cato SA #559 - Drake Inv. 21744	Drake Well Service	9/28/2023	9/12/23 to 9/20/23	$ 84,145.22	52100-10000075010
Cato San Andres #560	30-005-28012	Cato SA #560 - Drake Inv. 21745	Drake Well Service	9/28/2023	9/15/23 to 9/20/23	$ 84,151.73	52100-10000075010
Cato San Andres #573	30-005-28016	Cato SA #573 - Drake Inv. 21791	Drake Well Service	10/13/2023	9/19/23 to 9/24/23	$ 73,170.90	52100-0000075010
Cato San Andres #574	30-005-28017	Cato SA #574 - Drake Inv. 21790	Drake Well Service	10/13/2023	9/18/23 to 9/24/23	$ 150,495.66	52100-0000075010
Cato San Andres #586	30-005-29025	Cato SA #586 - Drake Inv. 21792	Drake Well Service	10/12/2023	9/21/23 to 9/24/23	$ 92,162.82	52100-0000075010
Cato San Andres #588	30-005-29027	Cato SA #588 - Drake Inv. 21810	Drake Well Service	10/17/2023	9/23/23 to 10/12/23	$ 145,248.01	52100-0000075010
Cato San Andres #822	30-005-29028	Cato SA #822 - Drake Inv. 21811	Drake Well Service	10/18/2023	9/24/23 to 10/12/23	$ 117,866.01	52100-0000075010
Cato San Andres #827	30-005-29030	Cato SA #827 - Drake Inv. 21789	Drake Well Service	10/13/2023	9/23/23 to 9/24/23	$ 63,667.63	52100-0000075010
Cato San Andres #561	30-005-28029	Cato SA #561 - Drake Inv. 21785	Drake Well Service	10/9/2023	9/16/23 to 9/20/23	$ 108,589.89	52100-0000075010
Cato San Andres #518	30-005-27963	Cato SA #518 - Drake Inv. 21699	Drake Well Service	8/22/2023	8/18/23 to 8/21/23	$ 82,675.45	52100-0000075010
Chaveroo San Andres Ut #4	30-041-20417	Chaveroo SA Ut. #4 - JMR Inv. 2414	JMR Services	6/10/2024	5/24/24 to 6/20/24	$ 161,592.64	52100-0000076993
Chaveroo San Andres Ut #006	30-041-20386	Chaveroo SA Ut. #006 - JMR Inv. 2284	JMR Services	6/11/2024	5/7/24 to 5/23/24	$ 159,524.24	52100-0000076993
Chaveroo San Andres Ut #3	30-041-20483	Chaveroo SA Ut. #3 - JMR Inv. 2426	JMR Services	7/9/2024	6/10/24 to 6/24/24	$ 168,526.06	52100-0000076993
Double L Queen #001D	30-005-60146	Double L Queen #001D - A-Plus Inv. 1705	A-Plus P&A LLC	11/15/2023	10/16/23 to 11/15/23	$ 124,649.73	52100-0000075136
Double L Queen #001K	30-005-60078	Double L Queen #001K - A-Plus Inv. 1864	A-Plus P&A LLC	11/16/2023	11/3/23 to 11/16/23	$ 1,764.10	75136
Double L Queen #002	30-005-60159	Double L Queen #002 - A-Plus Inv. 1717	A-Plus P&A LLC	11/2/2023	10/25/23 to 11/2/23	$ 82,329.64	52100-0000075136
Double L Queen #002G	30-005-60069	Double L Queen #002G - A-Plus Inv. 1672	A-Plus P&A LLC	11/2/2023	10/6/23 to 11/2/23	$ 100,131.59	52100-0000075136
Double L Queen #002P	30-005-20337	Double L Queen #002P - A-Plus Inv. 1590	A-Plus P&A LLC	10/19/2023	9/8/23 to 10/19/23	$ 99,591.77	52100-0000075149
Double L Queen #003G	30-005-60079	Double L Queen #003G - A-Plus Inv. 1862	A-Plus P&A LLC	3/21/2024	11/2/23 to 11/9/23	$ 69,148.62	75149
Double L Queen #003Y	30-005-60153	Double L Queen #003Y - A-Plus Inv. 1701	A-Plus P&A LLC	10/26/2023	10/16/23 to 10/26/23	$ 104,377.24	52100-0000075150
Double L Queen #005Q	30-005-20984	Double L Queen #005Q - A-Plus Inv. 1569	A-Plus P&A LLC	10/11/2023	8/24/23 to 10/11/24	$ 108,995.47	52100-0000075150
Double L Queen #006	30-005-60097	Double L Queen #006 - A-Plus Inv. 1666	A-Plus P&A LLC	10/26/2023	10/5/23 to 10/26/23	$ 121,721.73	52100-0000075150
Double L Queen #007	30-005-60099	Double L Queen #007 - A-Plus Inv. 1716	A-Plus P&A LLC	11/15/2023	10/23/23 to 11/15/23	$ 91,343.31	52100-0000075150
Double L Queen #001H	30-005-60127	Double L Queen #001H - A-Plus Inv. 1858	A-Plus P&A LLC	12/22/2023	11/1/23 to 11/7/23	$ 115,614.62	75136

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Double L Queen Ut #001P	30-005-20332	Double L Queen #001P Ut - A-Plus Inv. 1643	A-Plus P&A LLC	10/18/2023	9/15/23 to 10/18/23	$	120,920.59	52100-0000075136
Double L Queen #001Q	30-005-20327	Double L Queen #001Q - A-Plus Inv. 1603	A-Plus P&A LLC	10/18/2023	9/18/23 to 10/18/23	$	89,618.95	52100-0000075136
Double L Queen #001R	30-005-60117	Double L Queen #001R - A-Plus Inv. 1884	A-Plus P&A LLC	12/12/2023	11/27/23 to 12/12/23	$	115,772.09	52100-0000075136
Double L Queen #001Y	30-005-60084	Double L Queen #001Y - A-Plus Inv. 1882	A-Plus P&A LLC	2/26/2024	11/27/23 to 12/7/23	$	118,708.55	52100-0000075136
Double L Queen #002Q	30-005-20334	Double L Queen #002Q - A-Plus Inv. 1760	A-Plus P&A LLC	2/14/2024	11/14/23 to 12/6/23	$	66,185.54	52100-0000075149
Double L Queen #002X	30-005-60093	Double L Queen #002X - A-Plus Inv. 1801	A-Plus P&A LLC	1/30/2024	12/5/23 to 12/12/23	$	89,502.61	52100-0000073858
Double L Queen #002Z	30-005-60151	Double L Queen #002Z - A-Plus Inv. 1759	A-Plus P&A LLC	12/7/2023	11/14/23 to 12/7/23	$	66,862.97	52100-0000075149
Double L Queen #003	30-005-60161	Double L Queen #003 - A-Plus Inv. 1860	A-Plus P&A LLC	3/21/2024	10/30/23 to 11/14/23	$	69,279.31	75149
Double L Queen #003L	30-005-20346	Double L Queen #003L - A-Plus Inv. 1872	A-Plus P&A LLC	12/13/2023	11/8/23 to 12/6/23	$	102,103.87	75149
Double L Queen #003Q	30-005-20338	Double L Queen #003Q - A-Plus Inv. 1865	A-Plus P&A LLC	3/21/2024	11/9/23 to 11/16/23	$	90,128.62	75149
Double L Queen #004	30-005-60164	Double L Queen #004 - A-Plus Inv. 1640	A-Plus P&A LLC	2/12/2024	9/25/23 to 10/25/23	$	135,947.96	52100-0000075150
Double L Queen #004Q	30-005-20339	Double L Queen #004Q - A-Plus Inv. 6589	A-Plus P&A LLC	10/5/2023	8/25/23 to 10/5/23	$	326,128.34	52100-0000075150
Double L Queen #004G	30-005-60080	Double L Queen #004G - A-Plus Inv. 1546	A-Plus P&A LLC	2/12/2024	8/17/23 to 9/18/23	$	108,724.33	52100-0000075150
Double L Queen #005Q	30-005-60174	Double L Queen #005Q - A-Plus Inv. 1639	A-Plus P&A LLC	2/14/2024	9/26/23 to 10/25/23	$	135,977.60	52100-0000075150
Elizabeth #001	30-005-60610	Elizabeth #001 - Drake Inv. 21813	Drake Well Service	10/18/2023	9/29/23 to 10/12/23	$	132,401.98	52100-0000075229
Elizabeth #002	30-005-60705	Elizabeth #002 - Drake Inv. 21814	Drake Well Service	10/19/2023	9/28/23 to 10/12/23	$	199,555.14	52100-0000073012
Elizabeth #003	30-005-60744	Elizabeth #003 - Drake Inv. 21880	Drake Well Service	10/25/2023	10/3/23 to 10/12/23	$	196,668.94	52100-0000075229
Elizabeth #004	30-005-60747	Elizabeth #004 - Drake Inv. 21815	Drake Well Service	10/19/2023	10/7/23 to 10/12/23	$	92,842.93	52100-0000075229
Elizabeth C #005	30-005-62861	Elizabeth C #005 - Drake Inv. 21901	Drake Well Service	10/27/2023	10/10/23 to 10/23/23	$	164,026.38	52100-0000075229
Graves #001	30-005-60327	Graves #001 - Drake Inv. 21917	Drake Well Service	11/11/2023	10/10/23 to 10/23/23	$	174,233.85	52100-0000075229
INBE 12 #001	30-025-38082	INBE 12 #001 - Drake Inv. 22028	Drake Well Service	12/14/2023	10/18/23 to 11/17/23	$	474,439.27	52100-0000075600
INBE 13 #001	30-025-37840	INBE 13 #001 - Drake Inv. 22087	Drake Well Service	12/22/2023	10/21/23 to 11/17/23	$	414,032.31	52100-0000075600
Indian #002		Indian #002 - Aztec Inv. 2024-00868	Aztec Well Servicing Co.	6/30/2024	6/27/2024	$	107,681.62	
JP Collier #001	30-025-00996	JP Collier #001 - Drake Inv. 22107	Drake Well Service	2/27/2024	11/5/23 to 12/16/23	$	476,334.72	52100-0000075600
JP Collier #004Y	30-025-22133	JP Collier #004Y - Drake Inv. 22110	Drake Well Service	1/4/2024	11/27/23 to 12/16/2023	$	513,954.99	52100-0000075600
Lansford #001	30-025-27211	Lansford #001 - Drake Inv. 22157	Drake Well Service	1/29/2024	12/16/23 to 1/27/24	$	145,075.74	52100-0000075938
Lansford #002	30-025-27271	Lansford #002 - Drake Inv. 22169	Drake Well Service	1/29/2024	12/18/23 to 1/17/24	$	89,429.66	52100-0000075938
Lansford #003	30-025-27396	Lansford #003 - Drake Inv. 22180	Drake Well Service	2/2/2024	1/4/2024 to 1/17/24	$	135,115.27	52100-0000075938
Lansford #004	30-025-26812	Lansford #004 - Drake Inv. 22181	Drake Well Service	2/7/2024	1/10/24 to 1/17/24	$	122,744.92	52100-0000075938
Lansford #005	30-025-27866	Lansford #005 - Drake Inv. 22199	Drake Well Service	2/7/2024	1/9/2024 to 1/23/24	$	197,772.25	5100-0000075938

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Lansford #006	30-025-27879	Lansford #006 - Drake Inv. 22223	Drake Well Service	2/8/2024	1/16/24 to 1/23/24	$	166,599.96	52100-0000075938
Lewis Neff #003	30-005-10432	Lewis Neff #003 - Drake Inv. 21930	Drake Well Service	11/13/2023	10/12/23 to 10/23/23	$	65,084.49	52100-0000075229
McDermott #001	30-005-60921	McDermott #001 - Drake Inv. 21924	Drake Well Service	11/14/2023	10/14/23 to 10/23/23	$	183,873.72	52100-0000075229
Mike #001	30-025-28661	Mike #001 - A-Plus Inv. 1962	A-Plus P&A LLC	2/23/2024	1/19/2024 to 1/26/24	$	86,416.72	52100-0000076015
Mike #002	30-025-28661	Mike #002 - A-Plus Inv. 1983	A-Plus P&A LLC	2/24/2024	1/26/24 to 2/4/24	$	92,623.43	52100-0000076015
Mike #003	30-025-28841	Mike #003 - A-Plus Inv. 1955	A-Plus P&A LLC	2/26/2024	1/9/24 to 1/22/24	$	147,724.35	
Mike #004	30-025-29139	Mike #004 - A-Plus Inv. 1989	A-Plus P&A LLC	2/26/2024	1/22/24 to 2/4/24	$	128,328.19	52100-0000076015
Miller Com #001	30-015-22552	Miller #001 - A-Plus Inv. 1972	A-Plus P&A LLC	2/26/2024	12/13/2023 to 1/9/24	$	204,077.38	52100-0000076015
00086 Miller Com #001		00086 Miller #001 - A-Plus Inv. 2226	A-Plus P&A LLC	5/21/2024		$	149,142.11	
00086 Miller Com #001		00086 Miller #001 - A-Plus Inv. 2227	A-Plus P&A LLC	5/21/2024		$	76,382.70	
Multiple Wells		Multiple - Drake Inv. 22167	Drake Well Service	1/30/2024	11/15/23 to 11/15/23	$	5,481.66	52100-0000075229
NA DZIS PAH #2		NA DZIS PAH #2 - Aztec Inv. 2024-00865	Aztec Well Servicing Co.	6/30/2024	6/24/2024	$	121,722.05	
NA DZIS PAH #1		NA DZIS PAH #1 - Aztec Inv. 2024-00866	Aztec Well Servicing Co.	6/30/2024	6/25/2024	$	104,801.86	
Nancy #001	30-005-61267	Nancy #001 - Drake Inv. 21946	Drake Well Service	11/14/2023	10/14/23 to 10/23/23	$	139,665.44	52100-0000075229
Oakson A Fed #002	30-005-20617	Oakson A Fed #002 - Drake Inv. 22309	Drake Well Service	3/4/2024	2/22/24 to 2/26/24	$	130,340.81	52100-0000076471
Pruitt #001	30-025-06927	Pruitt #001 - Drake Inv. 22245	Drake Well Service	2/12/2024	1/19/24 to 1/27/24	$	137,015.56	52100-0000075938
Robert #001	30-025-28664	Robert #001 - Drake Inv. 22243	Drake Well Service	2/13/2024	1/22/24 to 1/30/24	$	183,222.16	52100-0000075938
Robert #002	30-025-36826	Robert #002 - Drake Inv. 22244	Drake Well Service	2/13/2024	1/24/24 to 1/30/24	$	143,401.02	52100-0000075938
Schwalbe #001	30-025-23726	Schwalbe #001 - Drake Inv. 21755	Drake Well Service	2/27/2024	12/3/22 to 12/16/23	$	336,762.47	52100-0000075600
Schwalbe #002	30-025-25646	Schwalbe #002 - Drake Inv. 22111	Drake Well Service	1/31/2024	11/7/23 to 12/16/23	$	258,592.61	52100-0000075600
Seanna #001	30-005-60604	Seanna #001 - Drake Inv. 21951	Drake Well Service	11/14/2023	10/15/23 to 10/23/23	$	162,302.98	52100-0000075229
Seanna #002	30-005-60623	Seanna #002 - Drake Inv. 21974	Drake Well Service	11/29/2023	10/23/23 to 11/15/23	$	159,878.91	52100-0000075229
Seanna #003	30-005-60735	Seanna #003 - Drake Inv. 21967	Drake Well Service	11/15/2023	10/19/23 to 10/23/23	$	135,030.44	52100-0000075229
Siete Fed #4	30-005-20947	Siete Fed #4 - A-Plus Inv. 2032	A-Plus P&A LLC	3/18/2024	2/22/24 to 2/28/24	$	90,289.53	52100-0000076470
State Senate #2		State Senate #2 - Aztec Inv. 2024-00867	Aztec Well Servicing Co.	6/30/2024	6/27/2024	$	72,572.08	
Union Happy #001	30-005-60581	Union Happy #001 - Drake Inv. 22002	Drake Well Service	11/21/2023	10/28/23 to 11/15/23	$	96,791.27	52100-0000075229
Union Happy #002	30-005-60622	Union Happy #002 - Drake Inv. 22017	Drake Well Service	12/1/2023	10/31/23 to 11/15/22	$	168,938.10	52100-0000075229

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Well	API	Invoice Description	Vendor	Invoice Date	Plugging Dates	Amount	Purchase Order
Cato San Andres #009	30-005-10537	Cato SA #009 - Drake Inv. 20048	Drake Well Service	5/5/2022	4/18/22 to ?		52100-0000069514
Cato San Andres #13	30-005-20142	Cato SA #13 - Drake Inv. 19969	Drake Well Service	4/12/2022	3/28/22 to ?	$ 97,029.76	52100-0000069516
Cato San Andres Unit #14	30-005-20066	Cato SA Ut #14 - Drake Inv. 19917	Drake Well Service	3/28/2022	3/22/22 to 3/28/22	$ 70,320.80	52100-0000069517
Cato San Andres Unit 17	30-005-10501	Cato SA Ut 17 - Drake Inv. 19630	Drake Well Service	1/17/2022	12/21/21 to 1/18/22	$ 56,800.67	52100-0000069496
Cato San Andres Unit #020	30-005-10504	Cato SA Ut #020 - Drake Inv. 20223	Drake Well Service	6/17/2022	5/5/22 to 6/7/22	$ 95,428.82	52100-0000071384
Cato San Andres #032	30-005-10522	Cato SA #032 - Drake Inv. 20055	Drake Well Service	5/6/2022	4/20/22 to 5/2/22	$ 94,127.16	52100-0000071190
Cato San Andres 033	30-005-20006	Cato SA 033 - JMR Inv. 4265	JMR Services LLC 4706	6/12/2025	6/12/2025	$ 1,544.65	52100-0000079950
Cato San Andres Unit #35	30-005-20046	Cato SA Ut #35 - Drake Inv. 19911	Drake Well Service	3/28/2022	3/8/22 to 3/28/22	$ 98,123.80	52100-0000069518
Cato San Andres Unit 42	30-005-20089	Cato SA Ut 42 - Drake Inv. 19300	Drake Well Service	9/26/2021	9/15/21 to 9/24/21	$ 57,663.66	52100-0000069500
Cato San Andres Unit 045	30-005-20130	Cato SA Ut 045 - Drake Inv. 20094	Drake Well Service	5/22/2022	5/2/22 to 5/9/22	$ 86,748.04	52100-0000071191
Cato San Andres Unit #051	30-005-10539	Cato SA Ut #051 - Drake Inv. 20225	Drake Well Service	6/18/2022	5/20/22 to 6/13/22	$ 74,686.73	52100-0000071382
Cato San Andres Unit #055	30-005-10560	Cato SA Ut #055 - Drake Inv. 20281	Drake Well Service	6/24/2022	6/13/22 to 6/23/22	$ 48,854.40	52100-0000071471
Cato San Andres Unit #058	30-005-10500	Cato SA Ut #058 - Drake Inv. 20105	Drake Well Service	5/23/2022	5/9/22 to 5/16/22	$ 70,177.11	52100-0000071194
Cato San Andres Unit #059	30-005-10570	Cato SA Ut #059 - Drake Inv. 20106	Drake Well Service	5/23/2022	5/2/22 to 5/9/22	$ 56,792.81	52100-0000071196
Cato San Andres Unit #61	30-005-20005	Cato SA Ut #61 - Drake Inv. 19362	Drake Well Service	10/15/2021	10/6/21 to 11/2/21	$ 72,381.33	52100-0000069503
Cato San Andres Unit 63	30-005-20049	Cato SA Ut 63 - Drake Inv. 19610	Drake Well Service	12/28/2021	12/18/21 to 12/21/21	$ 67,007.07	52100-0000069504
Cato San Andres Unit #074	30-005-10573	Cato SA Ut #074 - Drake Inv. 20310	Drake Well Service	7/8/2022	6/22/22 to 6/30/22	$ 80,933.82	521000-000071474
Cato San Andres Unit #090	30-005-20088	Cato SA Ut #090 - Drake Inv. 20192	Drake Well Service	6/14/2022	5/30/22 to 6/6/22	$ 82,379.90	52100-0000071481
Cato San Andres #118	30-005-20077	Cato SA #118 - Drake Inv. 21530	Drake Well Service	7/5/2023	6/24/23 to 6/30/23	$ 132,804.89	52100-0000073110
Buckskin Federal #002	30-025-27024	Buckskin Fed #002 - Drake Inv. 23023	Drake Well Service	11/22/2024	10/12/24 to 10/31/24	$ 388,813.23	52100-0000077778
Buckskin Federal #002	30-025-27024	Buckskin Fed #002 - Drake Inv. 23185	Drake Well Service	1/30/2025	12/1/24 to 1/9/25	$ 527,122.43	52100-0000077778
Buckskin Federal #002	30-025-27024	Buckskin Fed #002 - Drake Inv. 23065	Drake Well Service	12/3/2024	11/1/24 to 11/21/24	$ 503,208.80	52100-0000077778
Buckskin Federal #002	30-025-27024	Buckskin Fed #002 - Drake Inv. 23258	Drake Well Service	2/11/2025	1/21/25 to 2/3/25	$ 1,349,041.59	52100-0000077778
Buckskin Federal #002	30-025-27024	Buckskin Fed #002 - Drake Inv. 23065	Drake Well Service	12/3/2024	11/1/24 to 11/21/24	$ 503,208.80	52100-0000077778
Harrison #2	30-025-24749	Harrison #2 - A-Plus Inv. 12364	A-Plus Well Service	11/17/2022	11/11/22 to 1/12/23	$ 130,846.24	52100-0000072806
Ingalls Unit 001	30-015-22451	Ingalls Ut 001 - Drake Inv. 19852	Drake Well Service	5/27/2022	3/3/22 to 4/22/22	$ 150,574.36	52100-0000070604
Ingalls Unit 002	30-015-28273	Ingalls Ut 002 - Drake Inv. 19801	Drake Well Service	2/23/2022	2/14/22 to 3/15/22	$ 189,939.73	52100-0000070605
Buckskin Federal #002	30-025-27024	Buckskin Fed #002 - Drake Inv. 23258	Drake Well Service	2/11/2025	1/21/25 to 2/3/25	$ 1,439,997.28	52100-0000077778
Cato San Andres Unit 067	30-005-20054	Cato SA Ut 067 - JMR Inv. 4125	JMR Services LLC	6/22/2025	5/15/25 to 6/4/25	$ 151,290.73	52100-0000079950
Cato San Andres Unit 033	30-005-20006	Cato SA Ut 033 - JMR Inv. 4164	JMR Services LLC	6/18/2025	5/5/25 to 6/4/25	$ 155,758.18	52100-0000079950
Tolmac State 002	30-005-61551	Tolmac St 002 - JMR Inv. 4138	JMR Services LLC	6/12/2025	5/27/25 to 6/3/25	$ 99,288.29	52100-0000080042
Cato San Andres Unit 039	30-005-20098	Cato SA Ut 039 - JMR Inv. 4178	JMR Services LLC	6/19/2025	4/24/25 to 6/12/25	$ 187,446.25	52100-0000079950
Cato San Andres Unit 066	30-005-20037	Cato SA Ut 066 - JMR Inv. 4202	JMR Services LLC	6/30/2025	4/24/25 to 6/20/25	$ 234,862.26	52100-0000079950
Lawton State #001	30-025-07119	Lawton St #001 - Drake Inv. 20923	Drake Well Service	12/19/2022	12/1/22 to 12/18/22	$ 306,856.92	52100-0000073068
NM 36 State 1		NM 36 St 1 - A-Plus Inv. 124969					
O'Brien Deming 6 #001	30-005-60634	O'Brien Deming 6 #001 - Drake Inv. 21151	Drake Well Service	3/7/2023	3/2/23 to 3/7/23	$ 129,142.42	52100-0000073062
O'Brien Deming 6 #002	30-005-60730	O'Brien Deming 6 #002 - Drake Inv. 21150	Drake Well Service	3/7/2023	3/3/23 to 3/6/23	$ 99,116.92	52100-0000073062
O'Brien Fee 18 #003	30-005-60725	O'Brien Fee 18 #003 - Drake Inv. 21095	Drake Well Service	2/14/2023	1/19/23 to ?		52100-0000073062
O'Brien Fee 18 #006	30-005-61246	O'Brien Fee 18 #006 - Drake Inv. 21123	Drake Well Service	2/27/2023	2/16/23 to 2/23/23	$ 78,033.37	52100-0000073062
O'Brien Fee 19 #001	30-005-60528	O'Brien Fee 19 #001 - Drake Inv. 21096	Drake Well Service	2/14/2023	1/25/23 to 2/6/23	$ 90,123.15	52100-0000073062
O'Brien Fee 19 #002	30-005-60565	O'Brien Fee 19 #002 - Drake Inv. 21122	Drake Well Service	2/27/2023	1/24/23 to 2/23/23	$ 122,323.28	52100-0000073062
O'Brien Fee 19 #003	30-005-60566	O'Brien Fee 19 #003 - Drake Inv. 21067	Drake Well Service	2/1/2023	1/18/23 to 1/25/23	$ 103,799.51	52100-0000073062
O'Brien Fee 19 #004	30-005-60654	O'Brien Fee 19 #004 - Drake Inv. 21062	Drake Well Service	2/1/2023	1/20/23 to 1/25/23	$ 74,329.61	52100-0000073062
O'Brien Fee 19 #006	30-005-60804	O'Brien Fee 19 #006 - Drake Inv. 21110	Drake Well Service	2/24/2023	2/5/23 to ?		52100-0000073062
O'Brien Fee 19 #008	30-005-61021	O'Brien Fee 19 #008 - Drake Inv. 21114	Drake Well Service	2/24/2023	2/7/23 to 2/17/23	$ 94,287.44	52100-0000073062
O'Brien Fee 24 #001	30-005-60803	O'Brien Fee 24 #001 - Drake Inv. 21187	Drake Well Service	3/22/2023	3/6/23 to ?		52100-0000073062
O'Brien Fee 18 #005	30-005-61020	O'Brien Fee 18 #005 - Drake Inv. 21148	Drake Well Service	3/7/2023	2/21/23 to 3/6/23	$ 65,563.77	52100-0000073062
Twin Lakes San Andres #065	30-005-60293	Twin Lakes SA #065 - Drake Inv. 20931	Drake Well Service	12/22/2022	12/13/22 to 1/19/23	$ 256,178.52	52100-0000072802
Twin Lakes San Andres 010	30-005-60571	Twin Lakes SA 010 - Drake Inv. 20772	Drake Well Service	12/8/2022	11/20/22 to ?		52100-0000072266
Twin Lakes San Andres #12	30-005-60578	Twin Lakes SA #12 - Drake Inv. 20853	Drake Well Service	11/20/2022	10/25/22 to 11/18/22	$ 320,480.98	52100-0000072264
Twin Lakes San Andres #113	30-005-61604	Twin Lakes SA #113 - Drake Inv. 21337	Drake Well Service	5/8/2023	4/16/23 to 4/20/23	$ 75,789.29	52100-0000072802
Twin Lakes San Andres Unit #41	30-005-60768	Twin lakes SA Ut #41 - Drake Inv. 20740	Drake Well Service	10/28/2022	9/27/22 to 10/19/22	$ 214,498.85	52100-0000072263
Twin Lakes San Andres #054	30-005-00349	Twin Lakes SA #054 - Drake Inv. 21471	Drake Well Service	6/20/2023	? to 6/20/23	$ 276,454.92	52100-0000072802
Twin Lakes San Andres #061	30-005-60920	Twin Lakes SA #061 - Drake Inv. 21448	Drake Well Service	6/14/2023	5/17/23 to ?	$ 135,809.82	52100-0000072802
Twin Lakes San Andres #81	30-005-60993	Twin Lakes SA #81 - Drake Inv. 21032	Drake Well Service	1/26/2023	1/11/23 to 1/19/23	$ 65,726.47	52100-0000072802
Twin Lakes San Andres #103	30-005-61075	Twin Lakes SA #103 - Drake Inv. 21311	Drake Well Service	4/21/2023	3/30/23 to 4/5/23	$ 78,610.86	52100-0000072802
Twin lakes San Andres #105	30-005-62068	Twin Lakes SA #105 - Drake Inv. 21333	Drake Well Service	5/5/2023	4/3/23 to ?	$ 60,974.74	52100-0000072802
Twin Lakes San Andres #108	30-005-61334	Twin Lakes SA #108 - Drake Inv. 21436	Drake Well Service	6/9/2023	5/10/23 to		52100-0000072802
Miscellaneous wells		Well Done Inv. 1109	Well Done New Mexico LLC	7/2/2025		$ 9,292.06	
Miscellaneous wells		Well Done Inv. 1110	Well Done New Mexico LLC	7/2/2025		$ 24,239.14	
Miscellaneous wells		Well Done Inv. 1111	Well Done New Mexico LLC	7/2/2025		$ 33,350.33	
Miscellaneous wells		Well Done Inv. 1112	Well Done New Mexico LLC	7/2/2025		$ 21,972.71	
Miscellaneous wells		Well Done Inv. 1113	Well Done New Mexico LLC	7/7/2025		$ 2,275.52	
Miscellaneous wells		Well Done Inv. 1108	Well Done New Mexico LLC	7/17/2025		$ 2,275.52	

EXHIBIT 14

Well Depth, FT	P&A Cost (No Reclamation)	$/ft
3390	$228,979.90	$67.55
11790	$139,066	$11.80
11500	$127,532	$11.09
12800	$125,153	$9.78
14840	$122,511	$8.26
11500	$117,838	$10.25
11500	$114,344	$9.94
7888	$104,000	$13.18
11384	$101,191	$8.89
4558	$94,068.54	$20.64
8303	$93,631	$11.28
3660	$92,713.59	$25.33
9300	$91,684	$9.86
4810	$85,807.08	$17.84
6757	$85,000	$12.58
13450	$84,603	$6.29
4000	$83,649.62	$20.91
3240	$68,653.49	$21.19
3309	$66,551.58	$20.11
3350	$64,316.12	$19.20
5775	$63,544.71	$11.00
3367	$62,000	$18.41
3200	$59,570.28	$18.62
3273	$58,727.96	$17.94
2900	$55,948.39	$19.29
3560	$55,769.38	$15.67
8250	$55,133	$6.68
5530	$54,470.41	$9.85
3531	$53,856.76	$15.25
4243	$52,897.29	$12.47
4401	$52,415.24	$11.91
3228	$51,723.55	$16.02
4560	$51,119.98	$11.21
3300	$50,804.18	$15.40
3610	$50,606.79	$14.02
2875	$50,348.60	$17.51
2703	$48,971.89	$18.12
3467	$48,399.33	$13.96
3542	$47,851.86	$13.51
4465	$47,447.22	$10.63
13600	$47,027	$3.46
3456	$45,581.00	$13.19
5025	$45,389.48	$9.03

EXHIBIT 14

3575	$45,389.12	$12.70
1901	$45,058.92	$23.70
3247	$44,831.48	$13.81
3628	$43,921.80	$12.11
3610	$43,921.80	$12.17
5400	$39,657.31	$7.34
4401	$39,581.42	$8.99
4730	$39,531.25	$8.36
3600	$39,301.29	$10.92
4650	$39,117.36	$8.41
4737	$38,942.51	$8.22
5181	$38,800.36	$7.49
5544	$38,794.73	$7.00
4616	$38,773.81	$8.40
3550	$37,632.15	$10.60
4520	$37,446.44	$8.28
4770	$37,336.18	$7.83
4360	$37,288.72	$8.55
3080	$37,278.89	$12.10
4542	$37,161.55	$8.18
4335	$36,672.32	$8.46
6445	$36,410.10	$5.65
6438	$36,352.81	$5.65
5260	$36,331.57	$6.91
4810	$35,930.26	$7.47
3380	$35,533.65	$10.51
4790	$35,528.57	$7.42
4856	$35,433.43	$7.30
4426	$35,433.43	$8.01
4375	$35,433.43	$8.10
4670	$35,253.72	$7.55
1837	$34,904.16	$19.00
1987	$34,107.13	$17.17
5450	$31,985.22	$5.87
1965	$29,212.85	$14.87
3503	$28,049.70	$8.01
1910	$27,723.08	$14.51

Average Plugging Cost (all wells)	**$58,512.00**
Average Plugging Cost (w/o depth consideration, 10-90%)	**$52,806**
Median Plugging Cost per well	**$47,237.11**

EXHIBIT 15

Methodology:

1.Averaged Least and Most expensive well based on Invoices provided((excluding the $5.2M Buckskin Federal #002)) for each year.

2. Using Measured Depth of the wells for that FY, calculated the average between the Most $$/ft and the Least $$/ft

**On a footage basis, costs appear to have increased almost 6 fold (577%)

	AVERAGE INVOICE COST	$/ft	HIGHEST COST MD'	$/ft	LOWEST COST MD'	$/ft	AVG $/ft
FY20	$30,208.86	$10.66/ft (possible bc all C	$50,359.25	$14.16	$18,415.18	$8.37	**$11.27**
			3621'		2200'		
FY21	$56,743.29		$120,233.81	$34.29	$32,380.59	$12.95	**$23.62**
			3506'		2500'		
FY22	$63,200.71		$92,061.04	$26.72	$38,571.56	$10.71	**$18.72**
			3445'		3600'		
FY23	$141,633.00		$266,620.34	$120.10	$37,904.00	$3.19	**$61.64**
			2220'		11900'		
FY24	$159,932.48		$776,110.18	$65.54	$63,667.63	$32.16	**$48.85**
			11842'		1980'		
9/15/2025	$120,235.63		$320,480.98	$116.54	$48,854.40	$13.57	**$65.05**
			2750'		3600'		

1. CANO PETRO – CATO SA Wells:

Looking just the Cato SA wells, because there are so many of them, as to be only category of wells with representation in each FY from invoices provided and minor deviations in depth, costs on a footage basis went from :

FY20 @ $9.85/ft to FY24@$31.85/ft -- still an 323% increase, compared to inflation running about 20-25%

EXHIBIT 15

API #	Column1	Current OGRID	Current Owner	Mineral Owner	Surface Owner	PA Rig Up Date	Date Plugged (Date Wellhead cut off)	Contractor Plugging	Funding Source used?	PO#	Line Number of PO	Estimated Plugging Cost	Plugging Invoice Number	Actual Plugging Cost	Performance Bond Cost	Pre Plugging Methane Cost	Post Pluigged Methane Cost	Methane Emission Pre Plug (g/hr)	Methane Emission Post Plug (g/hr)	Total Plugging Expenditures	Plugging Performance Bond amount (PA Contractor)	# Days to Plug Well
30-025-27(	BUCKSKIN FED. #002	373817	[373817] Energy Acumen LLC	Federal	Private	5/13/2024	2/22/2025	Drake Wel	BLM	)41, 77778	1, 2	$ 166,591.39	23331, 23373	$ 5,196,866.70	$ 6,672.06					$ 5,203,538.76	$ 6,672.06	285
30-015-22:	BRC MADERA #001	373817	[373817] Energy Acumen LLC	Private	Private	8/24/2023	9/24/2023	Drake Wel	Initial BIL	75008	1	$ 250,000.00	21793	$ 776,110.18	$ 8,097.00	$ 2,116.03	$ 2,116.03	$ 2,764.32	$ -	$ 788,439.24	$ 8,097.00	31
30-025-38:	BAGLEY #002	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	11/5/2023	12/16/2023	Drake Wel	REC	75600	5 & 6	$ 150,000.00	22090	$ 523,725.26	$ 5,432.40	$ 2,113.91	$ 2,113.91	$ 0.00	$ -	$ 533,385.48	$ 5,432.40	41
30-025-22:	J P COLLIER #004Y	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	11/27/2023	12/16/2023	Drake Wel	Initial BIL	75600	9 & 10	$ 150,000.00	22110	$ 513,954.99	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ 0.02	$ -	$ 523,501.30	$ 5,432.40	19
30-025-00!	J P COLLIER #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	11/5/2023	12/16/2023	Drake Wel	REC	75600	7 & 8	$ 150,000.00	22017	$ 476,334.72	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ -	$ -	$ 485,881.03	$ 5,432.40	41
30-025-38(	INBE 12 #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	10/18/2023	11/17/2023	Drake Wel	Initial BIL	75600	1 & 2	$ 150,000.00	22028	$ 474,439.27	$ 5,432.40	$ 2,085.82	$ 2,113.91	$ 0.42	$ -	$ 484,071.40	$ 5,432.40	30
30-025-06·	ALVES A #001	373817	[373817] Energy Acumen LLC	Private	Private	12/15/2023	1/23/2024	Drake Wel	REC	75938	4	$ 139,750.10	22226	$ 454,014.69	$ 4,975.63	$ 2,038.08	$ 1,763.58			$ 462,791.98	$ 4,975.63	39
30-015-22!	MILLER COM #001	373817	[373817] Energy Acumen LLC	Private	Private	12/14/2023	1/23/2024	A-Plus P&A	REC	76015	5	$ 199,525.00	2, 2226, 2227	$ 429,602.20	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 437,838.88	$ 4,435.02	40
30-025-37!	INBE 13 #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	10/21/2023	11/17/2023	Drake Wel	Initial BIL	75600	3 & 4	$ 150,000.00	22087	$ 414,032.31	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ 9,156.01	$ -	$ 423,578.62	$ 5,432.40	27
30-025-23:	SCHWALBE #001	37636	[37636] ROBINSON OIL INC	Private	Private	11/5/2023	12/16/2023	Drake Wel	REC	75600	11 & 12	$ 150,000.00	21755	$ 336,762.47	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ 0.00	$ -	$ 346,308.78	$ 5,432.40	41
30-005-20:	DOUBLE L QUEEN UNIT #004Q	269864	[269864] CANYON E & P COMPANY	Private	Private	8/25/2023	10/5/2023	A-Plus P&A	Initial BIL	75150	4	$ 150,000.00	1589	$ 326,128.34	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 332,870.73	$ 4,695.47	41
30-005-10·	CATO SAN ANDRES UNIT #098	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/13/2023	8/21/2023	Drake Wel	Initial BIL	.0 & 75010	4 & 2	$ 150,000.00	1532 & 21711	$ 303,936.24	$ 5,751.00	$ 2,127.92	$ 1,859.90	$ -	$ -	$ 313,675.06	$ 5,751.00	69
30-005-20(	CATO SAN ANDRES UNIT #100	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/14/2023	9/12/2023	Drake Wel	Initial BIL	75010	3	$ 150,000.00	21746	$ 279,433.00	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 289,358.85	$ 5,751.00	90
30-025-23!	BROWN 84 #001	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Federal	Private	5/29/2024	6/6/2024	Drake Wel	REC	77042	1	$ 140,776.10	22597	$ 276,444.71	$ 4,727.43	$ 1,991.50				$ 283,163.64	$ 4,727.43	8
30-025-25:	BROWN 84 #002	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Federal	Private	5/2/2024	5/18/2024	Drake Wel	REC	77042	2	$ 140,320.04	22516	$ 274,383.81	$ 4,727.43	$ 1,991.50				$ 281,102.74	$ 4,727.43	16
30-041-10(	JENNIFER CHAVEROO SA UNIT #001	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Federal	Federal	11/7/2024	11/21/2024	Drake Wel	REC	78827	1	$ 147,015.68	23082	$ 270,142.90	$ 5,300.38					$ 275,443.28	$ 5,300.38	14
30-015-02:	ARTESIA METEX UNIT #042	269864	[269864] CANYON E & P COMPANY	State	Private	5/4/2023	6/28/2023	A-Plus P&A	Initial BIL	73858	5	$ 82,000.00	1289	$ 269,015.45	$ 3,587.99	$ 2,116.67		$ -	$ -	$ 274,720.11	$ 3,587.99	55
30-041-10(	JENNIFER CHAVEROO SA UNIT #005	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Federal	Private	12/6/2024	12/19/2024	Drake Wel	REC	78827	4	$ 150,382.46	23180	$ 262,502.99	$ 5,300.38	$ 1,990.32		$ -		$ 269,793.69	$ 5,300.38	13
30-025-25(	SCHWALBE #002	37636	[37636] ROBINSON OIL INC	Private	Private	11/7/2023	11/16/2023	Drake Wel	Initial BIL	75600	13 & 14	$ 150,000.00	22111	$ 258,592.61	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ -	$ -	$ 268,138.92	$ 5,432.40	9
30-025-27(	BUCKSKIN FED. #001	373817	[373817] Energy Acumen LLC	Federal	Private	10/8/2024	10/18/2024	Drake Wel	BLM	77778	1	$ 205,439.98	22994	$ 257,865.52	$ 6,672.06	$ 2,116.03				$ 266,653.61	$ 6,672.06	10
30-005-60:	TWIN LAKES SAN ANDRES UNIT #065	300825	[300825] BLUE SKY NM, INC.	Private	Private	12/12/2022	1/18/2023	Drake Wel	Initial BIL	72802	1	$ 77,490.00	20931, 21265	$ 257,460.16	$ 4,199.29			$ -	$ -	$ 261,659.45	$ 4,199.29	37
30-005-10·	KM CHAVEROO SA UNIT #016	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	8/10/2024	8/29/2024	Drake Wel	REC	78094	1	$ 156,586.38	22852	$ 244,805.09	$ 5,616.56	$ 2,115.94				$ 252,537.59	$ 5,616.56	19
30-005-20:	CATO SAN ANDRES UNIT #119	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/12/2023	9/20/2023	Drake Wel	Initial BIL	75010	4	$ 150,000.00	21741	$ 241,297.97	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 251,223.82	$ 5,751.00	39
30-005-10!	KM CHAVEROO SA UNIT #111	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	9/23/2024	10/4/2024	Drake Wel	REC	78094	4	$ 156,586.38	22950	$ 236,898.82	$ 5,616.56	$ 2,115.94				$ 244,631.32	$ 5,616.56	11
30-005-10!	KM CHAVEROO SA UNIT #018	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	8/18/2024	8/29/2024	Drake Wel	REC	78094	2	$ 156,586.38	22854	$ 230,587.11	$ 5,616.56	$ 2,115.94				$ 238,319.61	$ 5,616.56	11
30-025-11:	FOWLER HAIR #005	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	1/3/2023	1/16/2023	A-Plus P&A	Initial BIL	73836	3	$ 139,400.00	12480	$ 230,534.28	$ 1,969.20	$ 2,000.00	$ 1,459.96	$ -	$ -	$ 235,963.44		13
30-005-60!	BARKNEHT #001	269864	[269864] CANYON E & P COMPANY	Private	Private	9/27/2023	10/12/2023	Drake Wel	Initial BIL	75229	1	$ 150,000.00	21812	$ 219,834.41	$ 5,890.81	$ 2,207.86	$ 2,112.00	$ -	$ -	$ 230,045.08	$ 5,890.81	15
30-025-24:	ALVES #003	373817	[373817] Energy Acumen LLC	Private	Private	11/27/2023	1/24/2024	Drake Wel	REC	75938	2	$ 150,057.61	22197	$ 214,185.83	$ 4,975.63	$ 2,116.03	$ 2,116.03	$ 2,036.40	$ 2,036.40	$ 223,393.52	$ 4,975.63	58
30-041-10(	CHAVEROO A STATE #001	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	9/3/2024	10/2/2024	A-Plus P&A	REC	78095	1	$ 162,000.00	3028	$ 211,462.72	$ 5,245.35	$ 1,991.50				$ 218,699.57	$ 5,245.35	29
30-041-10(	JENNIFER CHAVEROO SA UNIT #002	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Federal	Private	11/21/2024	12/5/2024	Drake Wel	REC	78827	2	$ 147,767.33	23102	$ 209,469.44	$ 5,300.38	$ 1,990.32		$ -		$ 216,760.14	$ 5,300.38	14
30-005-10!	CATO SAN ANDRES UNIT #097	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/21/2023	8/28/2023	Drake Wel	Initial BIL	75010	1	$ 150,000.00	21760	$ 207,466.58	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ 44.97	$ -	$ 217,311.44	$ 1,969.20	7
30-041-20:	CHAVEROO SAN ANDRES UNIT #005	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	9/23/2024	10/14/2024	A-Plus P&A	REC	78095	3	$ 159,500.00	3064	$ 205,731.70	$ 5,245.35	$ 2,117.93				$ 213,094.98	$ 5,245.35	21
30-005-10!	KM CHAVEROO SA UNIT #110	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	8/30/2024	10/4/2024	Drake Wel	REC	78094	3	$ 156,586.38	22951	$ 203,887.59	$ 5,616.56	$ 2,115.94				$ 211,620.09	$ 5,616.56	35
30-005-20:	CATO SAN ANDRES UNIT #083	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Federal	10/24/2024	10/31/2024	Drake Wel	BLM	78803	1	$ 205,930.67	23021	$ 202,325.91	$ 7,385.96					$ 209,711.87	$ 7,385.96	7
30-041-10(	JENNIFER CHAVEROO SA UNIT #003	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Federal	Private	11/22/2024	11/4/2024	Drake Wel	REC	78827	3	$ 145,941.61	23103	$ 200,712.75	$ 5,300.38	$ 1,990.32		$ -		$ 208,003.45	$ 5,300.38	-18
30-005-60:	ELIZABETH #002	269864	[269864] CANYON E & P COMPANY	Private	Private	9/27/2023	10/12/2023	Drake Wel	Initial BIL	75229	3	$ 150,000.00	21814	$ 199,555.14	$ 5,890.81		$ 2,112.00	$ 0.01	$ -	$ 207,557.95	$ 5,890.81	15
30-005-20:	CATO SAN ANDRES UNIT #012	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Private	12/3/2024	12/26/2024	A-Plus P&A	BLM	)9 & 79631	2	$ 191,417.50	3375	$ 199,436.37	$ 5,560.67					$ 204,997.04	$ 5,560.67	23
30-005-61:	TWIN LAKES SAN ANDRES UNIT #109	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/4/2023	6/20/2023	Drake Wel	Initial BIL	72802	19	$ 78,162.00	21494, 21510	$ 197,938.56	$ 4,199.29			$ -	$ -	$ 202,137.85	$ 4,199.29	47
30-005-60:	ELIZABETH #003	269864	[269864] CANYON E & P COMPANY	Private	Private	10/3/2023	10/12/2023	Drake Wel	Initial BIL	75229	4	$ 150,000.00	21880	$ 196,668.94	$ 5,890.81		$ 2,112.00	$ -	$ -	$ 204,671.75	$ 5,890.81	9
30-025-26:	JUDY #003	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	11/18/2022	1/12/2023	A-Plus P&A	Initial BIL	72806	8	$ 135,300.00	12399	$ 196,650.14	$ 1,969.20			$ 20.56	$ -	$ 198,619.34		55
30-025-06(	ALVES #002	373817	[373817] Energy Acumen LLC	Private	Private	12/3/2024	12/20/2023	Drake Wel	REC	75938	1	$ 142,374.01	22121	$ 194,690.23	$ 4,975.63	$ 2,038.08	$ 1,763.58			$ 203,467.52	$ 4,975.63	-349
30-041-20:	CHAVEROO SAN ANDRES UNIT #007	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	9/18/2024	10/3/2024	A-Plus P&A	REC	78095	4	$ 162,000.00	2977	$ 194,385.32	$ 5,245.35	$ 1,991.50				$ 201,622.17	$ 5,245.35	15
30-025-23!	BROWN 93 #001	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Federal	Private	5/18/2024	5/24/2024	Drake Wel	REC	77042	3	$ 123,960.25	22586	$ 189,275.69	$ 4,727.43	$ 1,991.50				$ 195,994.62	$ 4,727.43	6
30-005-20(	CATO SAN ANDRES UNIT #039	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Private	5/28/2025	6/12/2025	JMR Servic	BLM	79950	3	$ 177,741.00	4178	$ 187,446.25						$ 187,446.25	$ 5,120.00	15
30-025-36·	NEW MEXICO 36 STATE #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	State	State	1/17/2023	2/2/2023	A-Plus P&A	REC	73836	2	$ 187,000.00	12496	$ 187,355.60		$ 2,000.00				$ 189,355.60		16
30-041-20:	CHAVEROO SAN ANDRES UNIT #006	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	5/13/2024	6/4/2024	A-Plus P&A	REC	76993	3	$ 181,314.75	2284 &2461	$ 184,041.52	$ 5,379.00	$ 2,117.93				$ 191,538.45	$ 5,379.00	22
30-005-60!	MCDERMOTT #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/14/2023	10/23/2023	Drake Wel	Initial BIL	75229	9	$ 150,000.00	21924	$ 183,873.72	$ 5,890.81	$ 2,207.86	$ 2,112.00	$ -	$ -	$ 194,084.39	$ 5,890.81	9
30-025-28(	ROBERT #001	373817	[373817] Energy Acumen LLC	Private	Private	1/21/2024	1/29/2024	Drake Wel	REC	75938	12	$ 135,317.46	22243	$ 183,222.16	$ 4,975.63	$ 2,038.08	$ 1,763.58			$ 191,999.45	$ 4,975.63	8
30-041-20·	CHAVEROO SAN ANDRES UNIT #002	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	9/3/2024	9/19/2024	A-Plus P&A	REC	78095	2	$ 165,500.00	2957	$ 181,212.60	$ 5,245.35	$ 1,991.50				$ 188,449.45	$ 5,245.35	16
30-015-00!	ARTESIA METEX UNIT #040	269864	[269864] CANYON E & P COMPANY	State	Private	6/5/2023	6/12/2023	A-Plus P&A	Initial BIL	73858	3	$ 77,162.00	1359	$ 179,794.00	$ 3,587.99	$ 2,116.67		$ 0.01	$ -	$ 185,498.66	$ 3,587.99	7
30-025-11:	FOWLER HAIR #003	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	12/13/2022	1/3/2023	A-Plus P&A	Initial BIL	72806	5	$ 139,400.00	12454	$ 176,657.80	$ 1,969.20	$ 2,000.00	$ 1,459.96	$ 4.20	$ -	$ 182,086.96		21
30-041-20·	CHAVEROO SAN ANDRES UNIT #004	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	5/24/2024	6/10/2024	A-Plus P&A	REC	76993	2	$ 181,314.75	2414 & 2415	$ 176,444.71	$ 5,379.00	$ 2,117.93				$ 183,941.64	$ 5,379.00	17
30-005-20·	CATO SAN ANDRES UNIT #193	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Federal	1/7/2025	1/24/2025	A-Plus P&A	BLM	79156	1	$ 171,925.00	3460 & 3568	$ 175,731.16	$ 5,552.65					$ 181,283.81	$ 5,552.65	17
30-005-60:	GRAVES #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/10/2023	10/23/2023	Drake Wel	Initial BIL	75229	7	$ 150,000.00	21917	$ 174,233.85	$ 5,890.81	$ 2,207.86	$ 2,112.00	$ -	$ -	$ 184,444.52	$ 5,890.81	13
30-005-60(	UNION HAPPY #002	269864	[269864] CANYON E & P COMPANY	Private	Private	10/31/2023	11/15/2023	Drake Wel	Initial BIL	75229	15	$ 150,000.00	22017	$ 168,938.10	$ 5,890.81	$ 2,383.75	$ 2,112.00	$ 433.34	$ -	$ 179,324.66	$ 5,890.81	15
30-041-20·	CHAVEROO SAN ANDRES UNIT #003	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	6/10/2024	6/24/2024	A-Plus P&A	REC	76993	1	$ 181,314.75	2426	$ 168,526.06	$ 5,379.00	$ 2,117.93				$ 176,022.99	$ 5,379.00	14
30-005-60(	SEANNA #002	269864	[269864] CANYON E & P COMPANY	Private	Private	10/23/2023	11/15/2023	Drake Wel	Initial BIL	75229	12	$ 150,000.00	1974 & 22167	$ 165,360.57	$ 5,890.81		$ 2,112.00	$ -	$ -	$ 173,363.38	$ 5,890.81	23
30-005-20(	CATO SAN ANDRES UNIT #127	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/12/2023	8/21/2023	Drake Wel	Initial BIL	75010	5	$ 150,000.00	21710	$ 164,107.41	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 1.05	$ -	$ 174,033.26	$ 5,751.00	9
30-005-62!	ELIZABETH C #005	269864	[269864] CANYON E & P COMPANY	Private	Private	10/10/2023	10/23/2023	Drake Wel	Initial BIL	75229	6	$ 150,000.00	21901	$ 164,026.38	$ 5,890.81	$ 2,767.50	$ 2,112.00	$ -	$ -	$ 174,796.69	$ 5,890.81	13
30-005-60(	SEANNA #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/15/2023	10/23/2023	Drake Wel	Initial BIL	75229	11	$ 150,000.00	21951	$ 162,302.98	$ 5,890.81	$ 2,130.42	$ 2,112.00	$ -	$ -	$ 172,436.21	$ 5,890.81	8
30-005-61!	TWIN LAKES SAN ANDRES UNIT #110	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/27/2023	5/26/2023	Drake Wel	Initial BIL	72802	6	$ 78,162.00	21449, 21581	$ 161,733.17	$ 4,199.29			$ 1.12	$ -	$ 165,932.46	$ 4,199.29	29
30-005-27!	CATO SAN ANDRES UNIT #407	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Federal	9/30/2024	10/8/2024	Drake Wel	BLM	78614	1	$ 174,615.20	22971	$ 161,657.82	$ 6,246.75					$ 167,904.57	$ 6,246.75	8
30-005-20!	CATO SAN ANDRES UNIT #204	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Federal	1/21/2025	1/31/2025	A-Plus P&A	BLM	79156	3	$ 171,925.00	3523	$ 160,529.02	$ 5,552.65					$ 166,081.67	$ 5,552.65	10
30-005-60!	O'BRIEN FEE 19 #007	269864	[269864] CANYON E & P COMPANY	Private	Private	3/1/2023	4/3/2023	Drake Wel	Initial BIL	73062	16	$ 98,168.00	21286, 21564	$ 160,066.98		$ 1,474.10	$ 2,127.88	$ 0.09	$ -	$ 163,668.96		33
30-005-00:	TWIN LAKES SAN ANDRES UNIT #054	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/9/2023	6/20/2023	Drake Wel	Initial BIL	72802	8	$ 208,258.00	20931, 21471	$ 159,419.71	$ 4,199.29			$ 0.82	$ -	$ 163,619.00		42
30-025-36·	SHELLY 36 STATE #006	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	State	State	1/27/2023	2/6/2023	A-Plus P&A	REC	73836	1	$ 195,200.00	1018	$ 158,417.39	$ 1,969.20	$ 2,000.00				$ 162,386.59		10
30-015-00!	ARTESIA METEX UNIT #039	269864	[269864] CANYON E & P COMPANY	State	Private	5/23/2023	6/2/2023	A-Plus P&A	Initial BIL	73858	2	$ 82,000.00	1330, 1417	$ 156,922.40	$ 3,587.99	$ 2,116.67		$ -	$ -	$ 162,627.06	$ 3,587.99	10
30-005-20(	CATO SAN ANDRES UNIT #037	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Private	8/20/2024	9/19/2024	A-Plus P&A	BLM	77780	1	$ 159,965.00	2978	$ 156,132.11	$ 4,312.80	$ 3,078.86				$ 163,523.77	$ 4,312.80	30
30-005-20:	CATO SAN ANDRES UNIT #068	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	5/27/2023	6/8/2023	Drake Wel	Initial BIL	73110	1	$ 85,446.00	21472	$ 153,396.09		$ 2,127.92		$ 2.07	$ -	$ 155,524.01		12
30-015-27(	BIG EDDY UNIT #127	154303	[154303] PRIMAL ENERGY CORPORATION	State	State	2/27/2023	3/9/2023	A-Plus P&A	Initial BIL	73858	8	$ 131,200.00	1101	$ 151,867.35	$ 3,587.99	$ 2,116.67		$ 0.06	$ -	$ 157,572.01	$ 3,587.99	10
30-005-28(	CATO SAN ANDRES UNIT #574	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/18/2024	9/24/2024	Drake Wel	Initial BIL	75010	21	$ 150,000.00	21790	$ 150,495.66	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ -	$ -	$ 160,219.59	$ 5,751.00	-360
30-005-20!	CATO SAN ANDRES UNIT #200	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Federal	1/30/2025	2/17/2025	A-Plus P&A	BLM	79156	2	$ 171,925.00	3538 & 3575	$ 149,266.40	$ 5,552.65					$ 154,819.05	$ 5,552.65	18
30-005-20(	CATO SAN ANDRES UNIT #101	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/14/2023	6/29/2023	Drake Wel	Initial BIL	73110	6	$ 89,100.00	21529	$ 147,885.53	$ 2,954.13	$ 2,127.92		$ -	$ -	$ 152,967.58	$ 2,954.13	15
30-025-28!	MIKE #003	373817	[373817] Energy Acumen LLC	Private	Private	1/9/2024	1/22/2024	A-Plus P&A	REC	76015	3	$ 138,905.05	1955	$ 147,724.34	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 155,961.02	$ 4,435.02	13
30-005-29(	CATO SAN ANDRES UNIT #588	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/23/2023	10/12/2023	Drake Wel	Initial BIL	75010	24	$ 150,000.00	21810	$ 145,248.01	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 7.56	$ -	$ 154,971.94	$ 5,751.00	19
30-025-36:	ALVES #004	373817	[373817] Energy Acumen LLC	Private	Private	12/11/2023	12/20/2023	Drake Wel	REC	75938	3	$ 139,111.26	22122	$ 144,820.79	$ 4,975.63	$ 1,926.00	$ 1,651.50			$ 153,373.92	$ 4,975.63	9
30-025-36!	ROBERT #002	373817	[373817] Energy Acumen LLC	Private	Private	1/23/2024	1/28/2024	Drake Wel	REC	75938	13	$ 120,010.04	22244	$ 143,401.02	$ 4,975.63	$ 2,038.08	$ 1,763.58			$ 152,178.31	$ 4,975.63	5
30-005-61:	NANCY #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/14/2023	10/23/2023	Drake Wel	Initial BIL	75229	10	$ 150,000.00	21946	$ 139,665.44	$ 5,890.81	$ 2,000.00	$ 2,112.00	$ -	$ -	$ 149,668.25	$ 5,890.81	9
30-005-60(	ELIZABETH #001	269864	[269864] CANYON E & P COMPANY	Private	Private	9/27/2023	10/12/2023	Drake Wel	Initial BIL	75229	2	$ 150,000.00	21946	$ 139,665.44	$ 5,890.81		$ 2,112.00	$ -	$ -	$ 147,668.25	$ 5,890.81	15
30-005-60:	O'BRIEN FEE 18 #003	269864	[269864] CANYON E & P COMPANY	Private	Private	1/19/2023	2/6/2023	Drake Wel	Initial BIL	73062	6	$ 78,974.00	21366, 21170	$ 137,556.78		$ 1,474.10	$ 1,474.10	$ 1.69	$ -	$ 140,504.98		18
30-025-06!	PRUITT #001	373817	[373817] Energy Acumen LLC	Private	Private	1/18/2024	1/25/2024	Drake Wel	REC	75938	11	$ 133,673.70	22245	$ 137,015.56	$ 4,975.63		$ 1,763.58			$ 143,754.77	$ 4,975.63	7
30-005-60!	TWIN LAKES SAN ANDRES UNIT #061	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/17/2023	5/26/2023	Drake Wel	Initial BIL	72802	10	$ 78,246.00	21448, 21501	$ 136,781.21	$ 4,199.29			$ 0.01	$ -	$ 140,980.50		9
30-005-60:	DOUBLE L QUEEN UNIT #005	269864	[269864] CANYON E & P COMPANY	State	State	9/26/2023	10/25/2023	A-Plus P&A	Initial BIL	75150	5	$ 150,000.00	1639	$ 135,977.60	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 142,719.99	$ 4,695.47	29
30-005-60:	DOUBLE L QUEEN UNIT #004	269864	[269864] CANYON E & P COMPANY	State	State	9/25/2023	10/25/2023	A-Plus P&A	Initial BIL	75150	2	$ 150,000.00	1640	$ 135,947.96	$ 4,695.47		$ 2,046.92	$ 0.11	$ -	$ 142,690.35	$ 4,695.47	30
30-005-60:	SEANNA #003	269864	[269864] CANYON E & P COMPANY	Private	Private	10/19/2023	10/23/2023	Drake Wel	Initial BIL	75229	13	$ 150,000.00	21967	$ 135,030.44	$ 5,890.81	$ 2,000.00	$ 2,112.00	$ -	$ -	$ 145,033.25	$ 5,890.81	4
30-005-20:	CATO SAN ANDRES UNIT #137	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Private	11/12/2024	12/23/2024	A-Plus P&A	BLM	)4 & 79632	1	$ 194,400.00	3267	$ 133,955.55	$ 5,965.00					$ 139,920.55	$ 5,965.00	41
30-005-20(	CATO SAN ANDRES UNIT #118	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/24/2023	6/28/2023	Drake Wel	Initial BIL	73110	7	$ 87,420.00	21530	$ 132,804.89	$ 5,751.00	$ 2,127.92		$ -	$ -	$ 140,683.81		4
30-025-24(	HARRISON #001	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	2/7/2023	3/2/2023	A-Plus P&A	Initial BIL	73861	1	$ 150,060.00	1046	$ 132,569.07	$ 11,242.77	$ 1,459.96	$ 1,459.96	$ 121.43	$ -	$ 146,731.76		23
30-015-00!	ARTESIA METEX UNIT #045	269864	[269864] CANYON E & P COMPANY	State	State	6/16/2023	6/28/2023	A-Plus P&A	Initial BIL	73858	7	$ 82,000.00	1378	$ 132,493.66	$ 3,587.99	$ 2,116.67		$ -	$ -	$ 138,198.32	$ 3,587.99	12
30-025-24(	JUDY #001	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	2/15/2023	2/24/2023	A-Plus P&A	Initial BIL	73861	2	$ 147,600.00	1067	$ 130,854.23	$ 11,242.77	$ 1,459.96	$ 1,459.96	$ 26.84	$ -	$ 145,016.92		9
30-025-24:	HARRISON #002	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	11/14/2022	1/12/2023	A-Plus P&A	Initial BIL	72806	7	$ 127,100.00	12364	$ 130,846.24	$ 1,969.20			$ 0.06	$ -	$ 132,815.44		59
30-005-20(	OAKSON A FEDERAL #002	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Federal	2/22/2024	2/26/2024	Drake Wel	BLM	76471	1	$ 145,286.39	22309	$ 130,340.81						$ 130,340.81		4
30-005-60(	O'BRIEN FEE 25 #005	269864	[269864] CANYON E & P COMPANY	Private	Private	3/17/2023	4/5/2023	Drake Wel	Initial BIL	73062	20	$ 79,030.00	21308	$ 129,851.82		$ 2,127.88		$ 0.01	$ -	$ 131,979.70		19
30-005-60(	O'BRIEN DEMING 6 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	3/2/2023	3/6/2023	Drake Wel	Initial BIL	73062	2	$ 78,974.00	21151	$ 129,142.42		$ 1,474.10	$ 1,474.10	$ -	$ -	$ 132,090.62		4
30-025-29:	MIKE #004	373817	[373817] Energy Acumen LLC	Private	Private	1/22/2024	2/4/2024	A-Plus P&A	REC	76015	4	$ 140,458.36	1989	$ 128,328.19	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 136,564.87	$ 4,435.02	13
30-005-00(	Elks #001	214263	[214263] PRE-ONGARD WELL OPERATOR	Private	Federal	10/3/2023	10/11/2023	Drake Wel	REC	75613	1	$ 135,000.00	21804	$ 127,495.16	$ 2,987.06					$ 130,482.22	$ 2,987.06	8
30-005-61:	TWIN LAKES SAN ANDRES UNIT #099	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/27/2023	5/2/2023	Drake Wel	Initial BIL	72802	5	$ 78,246.00	21413	$ 126,143.32	$ 4,199.29			$ 0.29	$ -	$ 130,342.61	$ 4,199.29	5
30-045-29:	NE HOGBACK UNIT #056	279508	[279508] CHUZA OIL COMPANY	Federal	Private	2/25/2025	2/27/2025	Aztec Well	REC	78906	4	$ 135,459.65	2025-00376	$ 125,684.22	$ 4,601.87					$ 130,286.09	$ 4,601.87	2
30-005-60!	TWIN LAKES SAN ANDRES UNIT #078	300825	[300825] BLUE SKY NM, INC.	Private	Private	1/5/2023	1/19/2023	Drake Wel	Initial BIL	72802	11	$ 78,358.00	21027	$ 125,479.39	$ 4,199.29			$ -	$ -	$ 129,678.68		14
30-005-60:	DOUBLE L QUEEN UNIT #001D	269864	[269864] CANYON E & P COMPANY	State	State	10/16/2023	11/15/2023	A-Plus P&A	Initial BIL	75136	1	$ 150,000.00	1705	$ 124,649.73	$ 5,287.31		$ 2,046.92	$ 0.40	$ -	$ 131,983.96	$ 5,287.31	30
30-005-60!	O'BRIEN FEE 19 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	1/24/2023	2/23/2023	Drake Wel	Initial BIL	73062	11	$ 98,168.00	21122, 21561	$ 122,307.30		$ 1,474.10		$ 1.69	$ -	$ 123,781.40		30
30-045-10(	NA DZIS PAH #002	224717	[224717] BIYA OPERATORS INC.	Navajo	Private	6/16/2024	6/19/2024	Aztec Well	REC	77279	1	$ 106,036.90	2024-00865	$ 121,722.05		$ 2,120.42				$ 123,842.47		3
30-005-60(	DOUBLE L QUEEN UNIT #006	269864	[269864] CANYON E & P COMPANY	State	State	10/5/2023	10/26/2023	A-Plus P&A	Initial BIL	75150	7	$ 150,000.00	1666	$ 121,721.73	$ 4,695.47		$ 2,046.92	$ 0.13	$ -	$ 128,464.12	$ 4,695.47	21
30-005-27!	CATO SAN ANDRES UNIT #535	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/27/2023	9/2/2023	Drake Wel	Initial BIL	75010	13	$ 150,000.00	21747	$ 121,283.68	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ -	$ -	$ 131,128.54	$ 5,751.00	6
30-005-20:	DOUBLE L QUEEN UNIT #001P	269864	[269864] CANYON E & P COMPANY	Private	Federal	9/18/2023	10/18/2023	A-Plus P&A	Initial BIL	75136	4	$ 150,000.00	1643	$ 120,920.59	$ 5,287.31		$ 2,046.92	$ -	$ -	$ 128,254.82	$ 5,287.31	30
30-015-02:	ARTESIA METEX UNIT #043	269864	[269864] CANYON E & P COMPANY	State	Private	6/20/2023	6/27/2023	A-Plus P&A	Initial BIL	73858	6	$ 94,300.00	1398	$ 119,337.31	$ 3,587.99	$ 2,116.67		$ 0.01	$ -	$ 125,041.97	$ 3,587.99	7
30-005-60(	DOUBLE L QUEEN UNIT #001Y	269864	[269864] CANYON E & P COMPANY	State	Private	11/27/2023	12/7/2023	A-Plus P&A	Initial BIL	75136	7	$ 150,000.00	1882	$ 118,708.55	$ 5,287.31		$ 2,046.92	$ 24.74	$ -	$ 126,042.78	$ 5,287.31	10
30-005-29(	CATO SAN ANDRES UNIT #822	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/24/2023	10/12/2023	Drake Wel	Initial BIL	75010	25	$ 150,000.00	21811	$ 117,866.01	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 127,791.86	$ 5,751.00	18
30-005-20(	CATO SAN ANDRES UNIT #016	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Private	4/28/2025	6/4/2025	JMR Servic	BLM	79950	1	$ 177,741.00	4041	$ 116,173.14						$ 116,173.14	$ 5,120.00	37
30-005-60:	DOUBLE L QUEEN UNIT #001R	269864	[269864] CANYON E & P COMPANY	State	State	11/27/2023	12/12/2023	A-Plus P&A	REC	75136	6	$ 150,000.00	1884	$ 115,772.09	$ 5,287.31		$ 2,046.92	$ 1.60	$ -	$ 123,106.32	$ 5,287.31	15
30-005-60:	DOUBLE L QUEEN UNIT #001H	269864	[269864] CANYON E & P COMPANY	State	State	10/30/2023	11/7/2023	A-Plus P&A	Initial BIL	75136	2	$ 150,000.00	1858	$ 115,614.62	$ 5,287.31		$ 2,046.92	$ 0.05	$ -	$ 122,948.85	$ 5,287.31	8
30-005-29(	CATO SAN ANDRES UNIT #587	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/21/2023	9/24/2023	Drake Wel	Initial BIL	75010	23	$ 150,000.00	21794	$ 114,799.56	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 21.91	$ -	$ 124,523.49	$ 5,751.00	34
30-005-20!	DOUBLE L QUEEN UNIT #005Q	269864	[269864] CANYON E & P COMPANY	Private	Private	8/24/2023	10/5/2023	A-Plus P&A	Initial BIL	75150	6	$ 150,000.00	1569	$ 108,931.64	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 115,674.03	$ 4,695.47	42
30-005-60(	DOUBLE L QUEEN UNIT #004G	269864	[269864] CANYON E & P COMPANY	State	State	8/17/2023	9/18/2023	A-Plus P&A	Initial BIL	75150	3	$ 150,000.00	1546	$ 108,724.33	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 115,466.72	$ 4,695.47	32
30-005-28(	CATO SAN ANDRES UNIT #561	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/16/2023	9/20/2023	Drake Wel	Initial BIL	75010	19	$ 150,000.00	21785	$ 108,589.89	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 0.09	$ -	$ 118,313.82	$ 5,751.00	4
30-045-21!	INDIAN #003	224717	[224717] BIYA OPERATORS INC.	Navajo	Private	6/24/2024	6/27/2024	Aztec Well	REC	77279	4	$ 94,734.05	2024-00868	$ 107,681.62		$ 2,120.42				$ 109,802.04		3
30-005-10!	CATO SAN ANDRES UNIT #069	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/9/2023	6/15/2023	Drake Wel	Initial BIL	73110	2	$ 89,184.00	21500	$ 106,418.09		$ 2,127.92		$ 1.62	$ -	$ 108,546.01		6
30-043-20(	NATANI #014	13673	[13673] M & M PRODUCTION & OPERATION	Indian	Indian	9/23/2024	9/26/2024	Aztec Well	REC	78433	1	$ 108,215.06	2024-01448	$ 105,403.21	$ 5,013.18	$ 2,112.95				$ 112,529.34	$ 5,013.88	3
30-005-60·	TWIN LAKES SAN ANDRES UNIT #066	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/19/2023	5/3/2023	Drake Wel	Initial BIL	72802	2	$ 77,547.00	21411	$ 104,896.82	$ 4,199.29			$ 0.03	$ -	$ 109,096.11		14
30-045-09!	NA DZIS PAH #001	224717	[224717] BIYA OPERATORS INC.	Navajo	Private	6/19/2024	6/22/2024	Aztec Well	REC	77279	2	$ 95,502.90	2024-00866	$ 104,801.86		$ 2,120.42				$ 106,922.28		3
30-005-60:	DOUBLE L QUEEN UNIT #003Y	269864	[269864] CANYON E & P COMPANY	State	Private	10/16/2023	10/26/2023	A-Plus P&A	Initial BIL	75150	1	$ 150,000.00	1701	$ 104,377.24	$ 4,695.47		$ 2,046.92	$ 0.36	$ -	$ 111,119.63	$ 4,695.47	10
30-005-27!	CATO SAN ANDRES UNIT #531	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/21/2023	9/2/2023	Drake Wel	Initial BIL	75010	10	$ 150,000.00	21740	$ 104,186.39	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 114,112.24	$ 5,751.00	12
30-005-27!	CATO SAN ANDRES UNIT #516	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/15/2023	8/21/2023	Drake Wel	Initial BIL	75010	6	$ 150,000.00	21698	$ 103,464.72	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 0.05	$ -	$ 113,390.57	$ 5,751.00	6
30-005-60!	O'BRIEN FEE 19 #003	269864	[269864] CANYON E & P COMPANY	Private	Private	1/17/2023	1/25/2023	Drake Wel	Initial BIL	73062	12	$ 97,923.00	21067, 21166	$ 103,171.04		$ 1,474.10		$ 1.69	$ -	$ 104,645.14		8
30-005-60!	TWIN LAKES SAN ANDRES UNIT #014	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/13/2023	5/26/2023	Drake Wel	Initial BIL	72802	7	$ 78,162.00	21445, 21582	$ 102,179.53	$ 4,199.29			$ 0.82	$ -	$ 106,378.82		13
30-005-20:	DOUBLE L QUEEN UNIT #003L	269864	[269864] CANYON E & P COMPANY	Private	Federal	11/8/2023	12/6/2023	A-Plus P&A	Initial BIL	75149	7	$ 150,000.00	1872	$ 102,103.87	$ 5,282.41		$ 2,046.92	$ 0.01	$ -	$ 109,433.20	$ 5,282.41	28
30-005-20:	CATO SAN ANDRES UNIT #162	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Federal	11/25/2024	12/23/2024	A-Plus P&A	BLM	;2 & 79646	1	$ 194,400.00	3271	$ 101,699.57	$ 5,965.00					$ 107,664.57	$ 5,965.00	28
30-005-60:	O'BRIEN DEMING 6 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	3/3/2023	3/6/2023	Drake Wel	Initial BIL	73062	3	$ 78,974.00	21358, 21559	$ 101,327.84		$ 1,474.10	$ 1,474.10	$ -	$ -	$ 104,276.04		3
30-005-60(	DOUBLE L QUEEN UNIT #002G	269864	[269864] CANYON E & P COMPANY	State	State	10/6/2023	11/2/2023	A-Plus P&A	Initial BIL	75136	9	$ 150,000.00	1672	$ 100,131.59	$ 5,287.31		$ 2,046.92	$ -	$ -	$ 107,465.82	$ 5,287.31	27
30-005-20:	DOUBLE L QUEEN UNIT #002P	269864	[269864] CANYON E & P COMPANY	Private	Private	9/8/2023	10/19/2023	A-Plus P&A	Initial BIL	75149	1	$ 150,000.00	1590	$ 99,591.77	$ 5,282.41	$ 2,046.95	$ 2,046.92	$ 0.01	$ -	$ 108,968.05	$ 5,282.41	41
30-005-27!	CATO SAN ANDRES UNIT #545	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/7/2023	9/12/2023	Drake Wel	Initial BIL	75010	15	$ 150,000.00	21865	$ 99,512.66	$ 5,751.00	$ 1,952.90	$ 2,046.93	$ 0.08	$ -	$ 109,263.49	$ 5,751.00	5
30-005-61!	Tolmac State #002	330522	[330522] Acacia Operating Company, LLC	State	State	5/27/2025	6/3/2025	JMR	REC	80042	1	$ 239,004.00	4138	$ 99,288.29						$ 99,288.29	$ 6,882.00	7
30-005-61(	O'BRIEN FEE 19 #008	269864	[269864] CANYON E & P COMPANY	Private	Private	2/7/2023	2/17/2023	Drake Wel	Initial BIL	73062	17	$ 98,168.00	21437, 21168	$ 99,172.05		$ 1,474.10	$ 1,474.10	$ 1.69	$ -	$ 102,120.25		10
30-005-27!	CATO SAN ANDRES UNIT #404	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Federal	10/8/2024	10/11/2024	Drake Wel	BLM	78613	1	$ 172,470.68	22972	$ 99,012.92	$ 6,186.16					$ 105,199.08	$ 6,186.16	3
30-005-60!	O'BRIEN FEE 24 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	3/14/2023	3/18/2023	Drake Wel	Initial BIL	73062	19	$ 78,750.00	21190	$ 98,722.53		$ 2,127.88		$ 0.04	$ -	$ 100,850.41		4
30-005-60!	O'BRIEN FEE 24 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	3/6/2023	3/18/2023	Drake Wel	Initial BIL	73062	18	$ 78,862.00	21187	$ 97,440.63		$ 2,127.88		$ 0.02	$ -	$ 99,568.51		12
30-043-20:	NATANI #032	13673	[13673] M & M PRODUCTION & OPERATION	Navajo	Indian	10/3/2024	10/8/2024	Aztec Well	REC	78433	4	$ 106,057.20	2024-01441	$ 96,888.52	$ 5,013.18	$ 2,112.95				$ 104,014.65	$ 5,013.88	5
30-005-60!	UNION HAPPY #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/28/2023	11/15/2023	Drake Wel	Initial BIL	75229	14	$ 150,000.00	22002	$ 96,791.27	$ 5,890.81	$ 2,207.86	$ 2,112.00	$ -	$ -	$ 107,001.94	$ 5,890.81	18
30-005-60!	O'BRIEN LIGHTCAP 7 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	3/6/2023	3/18/2023	Drake Wel	Initial BIL	73062	22	$ 78,974.00	21197	$ 96,381.77		$ 2,000.00		$ -	$ -	$ 98,381.77		12
30-005-27!	CATO SAN ANDRES UNIT #532	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/21/2023	9/2/2023	Drake Wel	Initial BIL	75010	11	$ 150,000.00	21748	$ 96,065.48	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 105,991.33	$ 5,751.00	12
30-005-60!	O'BRIEN FEE 18 #004	269864	[269864] CANYON E & P COMPANY	Private	Private	2/28/2023	3/6/2023	Drake Wel	Initial BIL	73062	7	$ 78,974.00	21145, 21173	$ 95,105.42		$ 1,474.10	$ 1,474.10	$ -	$ -	$ 98,053.62		6
30-043-20:	NATANI #018	13673	[13673] M & M PRODUCTION & OPERATION	Navajo	Indian	9930-2024	10/2/2024	Aztec Well	REC	78433	3	$ 155,283.60	2024-01475	$ 94,413.51	$ 5,013.18	$ 2,112.95				$ 101,539.64	$ 5,013.88	#VALUE!
30-045-29:	NE HOGBACK UNIT #055	279508	[279508] CHUZA OIL COMPANY	Federal	Federal	2/10/2025	2/12/2025	Aztec Well	REC	78906	3	$ 105,607.95	2025-00265	$ 94,005.63	$ 4,601.87					$ 98,607.50	$ 4,601.87	2
30-005-61:	TWIN LAKES SAN ANDRES UNIT #057	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/18/2023	5/3/2023	Drake Wel	Initial BIL	72802	4	$ 78,246.00	21338	$ 93,901.73	$ 4,199.29			$ 12.02	$ -	$ 98,101.02	$ 4,199.29	15
30-005-60!	O'BRIEN FEE 19 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	1/24/2023	2/6/2023	Drake Wel	Initial BIL	73062	10	$ 100,373.00	21391, 21225	$ 92,886.29		$ 1,474.10		$ 1.69	$ -	$ 94,360.39		13
30-005-60:	ELIZABETH #004	269864	[269864] CANYON E & P COMPANY	Private	Private	10/7/2023	10/12/2023	Drake Wel	Initial BIL	75229	5	$ 150,000.00	21815	$ 92,842.93	$ 5,890.81		$ 2,112.00	$ -	$ -	$ 100,845.74	$ 5,890.81	5
30-025-05!	MIKE #002	373817	[373817] Energy Acumen LLC	Private	Private	1/26/2024	2/4/2024	A-Plus P&A	REC	76015	2	$ 153,887.25	1983	$ 92,623.43	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 100,860.11	$ 4,435.02	9
30-005-29(	CATO SAN ANDRES UNIT #586	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/21/2023	9/24/2023	Drake Wel	Initial BIL	75010	22	$ 150,000.00	21792	$ 92,162.82	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 1.20	$ -	$ 101,886.75	$ 5,751.00	3
30-005-60(	DOUBLE L QUEEN UNIT #007	269864	[269864] CANYON E & P COMPANY	State	State	10/23/2023	11/15/2023	A-Plus P&A	Initial BIL	75150	8	$ 150,000.00	1716	$ 91,343.31	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 98,085.70	$ 4,695.47	23
30-005-27!	CATO SAN ANDRES UNIT #533	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/24/2023	9/2/2023	Drake Wel	Initial BIL	75010	12	$ 150,000.00	21743	$ 90,943.94	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ -	$ -	$ 100,788.80	$ 5,751.00	9
30-005-60(	O'BRIEN FEE 18 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	3/17/2023	4/5/2023	Drake Wel	Initial BIL	73062	5	$ 78,974.00	21283, 21560	$ 90,591.77		$ 2,127.88		$ 35.38	$ -	$ 92,719.65		19
30-005-20!	SIETE FEDERAL #004	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Federal	Federal	2/23/2024	2/28/2024	A-Plus P&A	BLM	76470	1	$ 151,074.00	2032	$ 90,289.53						$ 90,289.53		5
30-005-20:	DOUBLE L QUEEN UNIT #003Q	269864	[269864] CANYON E & P COMPANY	Private	Federal	11/9/2023	11/16/2023	A-Plus P&A	REC	75149	8	$ 150,000.00	1865	$ 90,128.62	$ 5,282.41		$ 2,046.92	$ 16.25	$ -	$ 97,457.95	$ 5,282.41	7
30-005-20:	DOUBLE L QUEEN UNIT #001Q	269864	[269864] CANYON E & P COMPANY	Private	Federal	9/18/2023	10/18/2023	A-Plus P&A	Initial BIL	75136	5	$ 150,000.00	1603	$ 89,618.95	$ 5,287.31		$ 2,046.92	$ 0.65	$ -	$ 96,953.18	$ 5,287.31	30
30-005-60(	DOUBLE L QUEEN UNIT #002X	269864	[269864] CANYON E & P COMPANY	State	Private	12/5/2023	12/12/2023	A-Plus P&A	Initial BIL	75149	3	$ 150,000.00	1801	$ 89,502.61	$ 5,282.41		$ 2,046.92	$ 0.02	$ -	$ 96,831.94	$ 5,282.41	7
30-045-30(	NE HOGBACK UNIT #053	279508	[279508] CHUZA OIL COMPANY	Federal	Private	2/20/2025	2/24/2025	Aztec Well	REC	78906	2	$ 118,257.95	2025-00320	$ 89,241.25	$ 4,601.87					$ 93,843.12	$ 4,601.87	4
30-005-28(	CATO SAN ANDRES UNIT #520	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/1/2023	9/12/2023	Drake Wel	Initial BIL	75010	9	$ 150,000.00	21863	$ 88,628.09	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 0.03	$ -	$ 98,553.94	$ 5,751.00	11
30-005-61:	TWIN LAKES SAN ANDRES UNIT #100	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/6/2023	4/20/2023	Drake Wel	Initial BIL	72802	14	$ 79,618.00	21334	$ 87,618.16	$ 4,199.29			$ 0.00	$ -	$ 91,817.45		14
30-025-28(	MIKE #001	373817	[373817] Energy Acumen LLC	Private	Private	1/19/2024	1/25/2024	A-Plus P&A	REC	76015	1	$ 130,108.36	1962	$ 86,416.72	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 94,653.40	$ 4,435.02	6
30-005-27!	CATO SAN ANDRES UNIT #544	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/4/2023	9/12/2023	Drake Wel	Initial BIL	75010	14	$ 150,000.00	21864	$ 85,423.13	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ 0.01	$ -	$ 95,267.99	$ 5,751.00	8
30-005-27!	CATO SAN ANDRES UNIT #517	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/18/2023	8/29/2023	Drake Wel	Initial BIL	75010	7	$ 150,000.00	21705	$ 85,086.25	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 4.69	$ -	$ 95,012.10	$ 5,751.00	11
30-005-28(	CATO SAN ANDRES UNIT #560	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/15/2023	9/20/2023	Drake Wel	Initial BIL	75010	18	$ 150,000.00	21745	$ 84,151.73	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ -	$ -	$ 93,875.66	$ 5,751.00	5
30-005-28(	CATO SAN ANDRES UNIT #559	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/12/2023	9/14/2023	Drake Wel	Initial BIL	75010	17	$ 150,000.00	21744	$ 84,145.22	$ 5,751.00	$ 1,952.90	$ 2,046.93	$ -	$ -	$ 93,896.05	$ 5,751.00	2
30-005-27!	CATO SAN ANDRES UNIT #518	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/18/2023	8/21/2023	Drake Wel	Initial BIL	75010	8	$ 150,000.00	21699	$ 82,675.45	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 0.01	$ -	$ 92,601.30	$ 5,751.00	3
30-005-60:	DOUBLE L QUEEN UNIT #002	269864	[269864] CANYON E & P COMPANY	State	State	10/25/2023	11/2/2023	A-Plus P&A	Initial BIL	75136	8	$ 150,000.00	1717, 1626	$ 82,329.64	$ 5,287.31		$ 2,046.92	$ 0.01	$ -	$ 89,663.87	$ 5,287.31	8
30-045-30(	NE HOGBACK UNIT #052	279508	[279508] CHUZA OIL COMPANY	Federal	Private	11/22/2024	2/20/2025	Aztec Well	REC	78906	1	$ 106,991.40	2025-00310	$ 80,679.82	$ 4,601.87					$ 85,281.69	$ 4,601.87	90
30-045-30:	NE HOGBACK UNIT #060	279508	[279508] CHUZA OIL COMPANY	Federal	Private	2/13/2025	2/17/2025	Aztec Well	REC	78906	5	$ 91,339.90	2025-00296	$ 80,538.34	$ 4,601.87					$ 85,140.21	$ 4,601.87	4
30-015-02:	ARTESIA METEX UNIT #041	269864	[269864] CANYON E & P COMPANY	State	Private	6/13/2023	6/15/2023	A-Plus P&A	Initial BIL	73858	4	$ 82,000.00	1371	$ 80,024.66	$ 3,587.99	$ 2,116.67		$ 0.01	$ -	$ 85,729.32	$ 3,587.99	2
30-005-60!	O'BRIEN FEE 19 #006	269864	[269864] CANYON E & P COMPANY	Private	Private	2/4/2023	2/7/2023	Drake Wel	Initial BIL	73062	15	$ 98,168.00	21110, 21565	$ 79,557.24			$ 1,474.10	$ 1.69	$ -	$ 81,031.34		3
30-005-60(	O'BRIEN FEE 19 #004	269864	[269864] CANYON E & P COMPANY	Private	Private	1/20/2023	1/25/2023	Drake Wel	Initial BIL	73062	13	$ 97,923.00	21062, 21167	$ 79,475.43		$ 1,474.10		$ 1.69	$ -	$ 80,949.53		5
30-005-61:	TWIN LAKES SAN ANDRES UNIT #107	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/13/2023	4/20/2023	Drake Wel	Initial BIL	72802	17	$ 79,534.00	21336	$ 79,232.95	$ 4,199.29			$ 0.82	$ -	$ 83,432.24		7
30-005-28(	CATO SAN ANDRES UNIT #558	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/9/2023	9/12/2023	Drake Wel	Initial BIL	75010	16	$ 150,000.00	21749	$ 79,185.50	$ 5,751.00	$ 1,952.90	$ 2,046.93	$ 0.09	$ -	$ 88,936.33	$ 5,751.00	3
30-005-61:	TWIN LAKES SAN ANDRES UNIT #095	300825	[300825] BLUE SKY NM, INC.	Private	Private	3/22/2023	4/5/2023	Drake Wel	Initial BIL	72802	13	$ 79,758.00	21309	$ 79,018.03	$ 4,199.29			$ 0.19	$ -	$ 83,217.32	$ 4,199.29	14
30-005-61(	TWIN LAKES SAN ANDRES UNIT #103	300825	[300825] BLUE SKY NM, INC.	Private	Private	3/30/2023	4/5/2023	Drake Wel	Initial BIL	72802	15	$ 78,190.00	21311	$ 78,610.86	$ 4,199.29			$ 0.00	$ -	$ 82,810.15		6
30-005-61:	O'BRIEN FEE 18 #006	269864	[269864] CANYON E & P COMPANY	Private	Private	2/16/2023	2/23/2023	Drake Wel	Initial BIL	73062	9	$ 98,168.00	21123, 21169	$ 78,097.28		$ 1,474.10		$ 1.69	$ -	$ 79,571.38		7
30-005-61·	TWIN LAKES SAN ANDRES UNIT #111	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/15/2023	4/20/2023	Drake Wel	Initial BIL	72802	20	$ 78,582.00	21335	$ 78,026.48	$ 4,199.29			$ 0.82	$ -	$ 82,225.77		5

EXHIBIT 15

30-043-20:	NATANI #034	13673	[13673] M & M PRODUCTION & OPERATION	Indian	Indian	10/10/2024	10/11/2024	Aztec Well	REC	78433	6	$ 132,680.40	2024-01476	$ 76,160.08	$ 5,013.18	$ 2,112.95						$ 83,286.21	$ 5,013.88		1
30-005-60:	O'BRIEN FEE 18 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	2/19/2023	2/23/2023	Drake Well	Initial BIL	73062	4	$ 78,974.00	21174, 21361	$ 76,094.55		$ 1,474.10	$ 1,474.10	$ 1.69	$ -			$ 79,042.75			4
30-043-20:	NATANI #017	13673	[13673] M & M PRODUCTION & OPERATION	Navajo	Indian	9/26/2024	9/30/2024	Aztec Well	REC	78433	2	$ 104,340.86	2024-01449	$ 76,039.73	$ 5,013.18	$ 2,112.95						$ 83,165.86	$ 5,013.88		4
30-005-61:	TWIN LAKES SAN ANDRES UNIT #113	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/16/2023	4/20/2023	Drake Well	Initial BIL	72802	21	$ 78,358.00	21337	$ 75,826.57	$ 4,199.29			$ -	$ -			$ 80,025.86			4
30-005-20:	CATO SAN ANDRES UNIT #025	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	5/26/2022	5/3/2023	Drake Well	REC	71388	1	$ 71,699.60	20167	$ 73,736.31								$ 73,736.31			342
30-005-28:	CATO SAN ANDRES UNIT #573	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/19/2023	9/24/2023	Drake Well	Initial BIL	75010	20	$ 150,000.00	21791	$ 73,170.90	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 0.60	$ -			$ 82,894.83	$ 5,751.00		5
30-005-60:	O'BRIEN DEMING 13 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	2/22/2023	3/6/2023	Drake Well	Initial BIL	73062	1	$ 78,862.00	21154, 21171	$ 73,061.42		$ 1,474.10	$ 2,127.88	$ 0.01	$ -			$ 76,663.40			12
30-005-60:	DOUBLE L QUEEN UNIT #001K	269864	[269864] CANYON E & P COMPANY	State	Private	11/6/2023	11/16/2023	A-Plus P&A	Initial BIL	75136	3	$ 150,000.00	1864	$ 72,640.91	$ 5,287.31		$ 2,046.92	$ 5.84	$ -			$ 79,975.14	$ 5,287.31		10
30-045-09:	STATE SENATE #002	224717	[224717] BIYA OPERATORS INC.	Navajo	Private	6/22/2024	6/24/2024	Aztec Well	REC	77279	3	$ 86,466.20	2024-00867	$ 72,572.08		$ 2,120.42						$ 74,692.50			2
30-043-20:	NATANI #033	13673	[13673] M & M PRODUCTION & OPERATION	Navajo	Indian	10/8/2024	10/9/2024	Aztec Well	REC	78433	5	$ 117,688.80	2024-01442	$ 71,053.87	$ 5,013.18	$ 2,112.95						$ 78,180.00	$ 5,013.88		1
30-005-60:	O'BRIEN FEE 19 #005	269864	[269864] CANYON E & P COMPANY	Private	Private	2/2/2023	2/6/2023	Drake Well	Initial BIL	73062	14	$ 98,413.00	21365, 21563	$ 70,587.02		$ 1,474.10		$ 1.69	$ -			$ 72,061.12			4
30-005-60:	DOUBLE L QUEEN UNIT #003	269864	[269864] CANYON E & P COMPANY	State	State	10/31/2023	12/14/2023	A-Plus P&A	REC	75149	5	$ 150,000.00	1860	$ 69,279.31	$ 5,282.41		$ 2,046.92	$ 0.05	$ -			$ 76,608.64	$ 5,282.41		44
30-005-60:	DOUBLE L QUEEN UNIT #003G	269864	[269864] CANYON E & P COMPANY	State	State	11/3/2023	11/9/2023	A-Plus P&A	REC	75149	6	$ 150,000.00	1862	$ 69,148.62	$ 5,282.41		$ 2,046.92	$ -	$ -			$ 76,477.95	$ 5,282.41		6
30-005-61:	O'BRIEN FEE 18 #005	269864	[269864] CANYON E & P COMPANY	Private	Private	2/21/2023	3/6/2023	Drake Well	Initial BIL	73062	8	$ 98,168.00	21148, 21359	$ 67,764.04		$ 1,474.10	$ 2,127.88	$ 1.67	$ -			$ 71,366.02			13
30-005-60:	DOUBLE L QUEEN UNIT #002Z	269864	[269864] CANYON E & P COMPANY	State	State	11/14/2023	12/7/2023	A-Plus P&A	Initial BIL	75149	4	$ 150,000.00	1759	$ 66,862.97	$ 5,282.41	$ 2,046.95	$ 2,046.92	$ 23.72	$ -			$ 76,239.25	$ 5,282.41		23
30-005-20:	DOUBLE L QUEEN UNIT #002Q	269864	[269864] CANYON E & P COMPANY	Private	Federal	11/14/2023	12/6/2023	A-Plus P&A	Initial BIL	75149	2	$ 150,000.00	1760	$ 66,185.54	$ 5,282.41		$ 2,046.92	$ -	$ -			$ 73,514.87	$ 5,282.41		22
30-005-60:	TWIN LAKES SAN ANDRES UNIT #081	300825	[300825] BLUE SKY NM, INC.	Private	Private	1/5/2023	1/19/2023	Drake Well	Initial BIL	72802	12	$ 78,246.00	21032	$ 65,726.47	$ 4,199.29			$ 0.35	$ -			$ 69,925.76			14
30-005-10:	LEWIS NEFF #003	228270	[228270] ROGER SLAYTON DBA ESCUDILLA OIL COMPANY	Private	Private	10/12/2023	10/23/2023	Drake Well	Initial BIL	75229	8	$ 150,000.00	21930	$ 65,084.49	$ 5,890.81	$ 2,000.00	$ 2,112.00	$ 40.41	$ -			$ 75,087.30	$ 5,890.81		11
30-005-29:	CATO SAN ANDRES UNIT #827	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/23/2023	9/27/2023	Drake Well	Initial BIL	75010	26	$ 150,000.00	21789	$ 63,667.63	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ 44.97	$ -			$ 73,512.49	$ 5,751.00		4
30-005-61:	TWIN LAKES SAN ANDRES UNIT #108	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/10/2023	5/26/2023	Drake Well	Initial BIL	72802	18	$ 78,526.00	21436	$ 62,720.90	$ 4,199.29			$ 0.00	$ -			$ 66,920.19			16
30-005-60:	TWIN LAKES SAN ANDRES UNIT #086	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/25/2023	5/3/2023	Drake Well	Initial BIL	72802	3	$ 77,910.00	21412, 21571	$ 62,530.36	$ 4,199.29			$ 0.02				$ 66,729.65			8
30-015-00:	ARTESIA METEX UNIT #038	269864	[269864] CANYON E & P COMPANY	State	Private	5/18/2023	6/28/2023	A-Plus P&A	Initial BIL	73858	1	$ 79,294.00	1296, 1416	$ 61,949.37	$ 3,587.99	$ 2,116.67		$ 0.04	$ -			$ 67,654.03	$ 3,587.99		41
30-005-62:	TWIN LAKES SAN ANDRES UNIT #105	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/3/2023	4/20/2023	Drake Well	Initial BIL	72802	16	$ 79,282.00	21333	$ 60,974.74	$ 4,199.29			$ 0.82	$ -			$ 65,174.03			17
30-005-62:	TWIN LAKES SAN ANDRES UNIT #015	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/17/2023	4/20/2023	Drake Well	Initial BIL	72802	9	$ 79,170.00	21390, 21566	$ 53,645.59	$ 4,199.29			$ 1.21	$ -			$ 57,844.88			3
30-005-60:	O'BRIEN LIGHTCAP 7 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	3/14/2023	3/18/2023	Drake Well	Initial BIL	73062	21	$ 78,974.00	21204	$ 49,875.51		$ 2,207.86		$ -	$ -			$ 52,083.37			4
30-005-20:	CATO SAN ANDRES UNIT #052	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	10/12/2023	11/11/2023	Drake Well	REC	71469	1	$ 72,696.98		$ 40,114.82								$ 40,114.82			30

EXHIBIT 15

API #	Column1	Current OGRID	Current Owner	Mineral Owner	Surface Owner	PA Rig Up Date	Date Plugged (Date Wellhead cut off)	Contractor Plugging	Funding Source used?	PO#	Line Number of PO	Estimated Plugging Cost	Plugging Invoice Number	Actual Plugging Cost	Performance Bond Cost	Pre Plugging Methane Cost	Post Pluigged Methane Cost	Methane Emission Pre Plug (g/hr)	Methane Emission Post Plug (g/hr)	Total Plugging Expenditures	Plugging Performance Bond amount (PA Contractor)	# Days to Plug Well
30-015-22372	BRC MADERA #001	373817	[373817] Energy Acumen LLC	Private	Private	8/24/2023	9/24/2023	Drake Well Services Inc.	Initial BIL	75008	1	$ 250,000.00	21793	$ 776,110.18	$ 8,097.00	$ 2,116.03	$ 2,116.03	$ 2,764.32	$ -	$ 788,439.24	$ 8,097.00	31
30-025-38192	BAGLEY #002	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	11/5/2023	12/16/2023	Drake Well Services Inc.	REC	75600	5 & 6	$ 150,000.00	22090	$ 523,725.26	$ 5,432.40	$ 2,113.91	$ 2,113.91	$ 0.00	$ -	$ 533,385.48	$ 5,432.40	41
30-025-22133	J P COLLIER #004Y	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	11/27/2023	12/16/2023	Drake Well Services Inc.	Initial BIL	75600	9 & 10	$ 150,000.00	22110	$ 513,954.99	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ 0.02	$ -	$ 523,501.30	$ 5,432.40	19
30-025-00966	J P COLLIER #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	11/5/2023	12/16/2023	Drake Well Services Inc.	REC	75600	7 & 8	$ 150,000.00	22017	$ 476,334.72	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ -	$ -	$ 485,881.03	$ 5,432.40	41
30-025-38082	INBE 12 #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	10/18/2023	11/17/2023	Drake Well Services Inc.	Initial BIL	75600	1 & 2	$ 150,000.00	22028	$ 474,439.27	$ 5,432.40	$ 2,085.82	$ 2,113.91	$ 0.42	$ -	$ 484,071.40	$ 5,432.40	30
30-025-06430	ALVES A #001	373817	[373817] Energy Acumen LLC	Private	Private	12/15/2023	1/23/2024	Drake Well Services Inc.	REC	75938	4	$ 139,750.10	22226	$ 454,014.69	$ 4,975.63	$ 2,038.08	$ 1,763.58			$ 462,791.98	$ 4,975.63	39
30-015-22552	MILLER COM #001	373817	[373817] Energy Acumen LLC	Private	Private	12/14/2023	1/23/2024	A-Plus P&A LLC	REC	76015	5	$ 199,525.00	'2. 2226. 2227	$ 429,602.20	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 437,838.88	$ 4,435.02	40
30-025-37840	INBE 13 #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	Private	Private	10/21/2023	11/17/2023	Drake Well Services Inc.	Initial BIL	75600	3 & 4	$ 150,000.00	22087	$ 414,032.31	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ 9,156.01	$ -	$ 423,578.62	$ 5,432.40	27
30-025-23726	SCHWALBE #001	37636	[37636] ROBINSON OIL INC	Private	Private	11/5/2023	12/16/2023	Drake Well Services Inc.	REC	75600	11 & 12	$ 150,000.00	21755	$ 336,762.47	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ 0.00	$ -	$ 346,308.78	$ 5,432.40	41
30-005-20339	DOUBLE L QUEEN UNIT #004Q	269864	[269864] CANYON E & P COMPANY	Private	Private	8/25/2023	10/5/2023	A-Plus P&A LLC	Initial BIL	75150	4	$ 150,000.00	1589	$ 326,128.34	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 332,870.73	$ 4,695.47	41
30-005-10474	CATO SAN ANDRES UNIT #098	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/13/2023	8/21/2023	Drake Well Services Inc.	Initial BIL	0 & 75010	4 & 2	$ 150,000.00	1532 & 21711	$ 303,936.24	$ 5,751.00	$ 2,127.92	$ 1,859.90	$ -	$ -	$ 313,675.06	$ 5,751.00	69
30-005-20007	CATO SAN ANDRES UNIT #100	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/14/2023	9/12/2023	Drake Well Services Inc.	Initial BIL	75010	3	$ 150,000.00	21746	$ 279,433.00	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 289,358.85	$ 5,751.00	90
30-015-02138	ARTESIA METEX UNIT #042	269864	[269864] CANYON E & P COMPANY	State	Private	5/4/2023	6/28/2023	A-Plus P&A LLC	Initial BIL	73858	5	$ 82,000.00	1289	$ 269,015.45	$ 3,587.99	$ 2,116.67		$ -	$ -	$ 274,720.11	$ 3,587.99	55
30-025-25646	SCHWALBE #002	37636	[37636] ROBINSON OIL INC	Private	Private	11/7/2023	11/16/2023	Drake Well Services Inc.	Initial BIL	75600	13 & 14	$ 150,000.00	22111	$ 258,592.61	$ 5,432.40	$ 2,000.00	$ 2,113.91	$ -	$ -	$ 268,138.92	$ 5,432.40	9
30-005-60293	TWIN LAKES SAN ANDRES UNIT #065	300825	[300825] BLUE SKY NM, INC.	Private	Private	12/12/2022	1/18/2023	Drake Well Services Inc.	Initial BIL	72802	1	$ 77,490.00	20931, 21265	$ 257,460.16	$ 4,199.29			$ -	$ -	$ 261,659.45	$ 4,199.29	37
30-005-10497	KM CHAVEROO SA UNIT #016	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	8/10/2024	8/29/2024	Drake Well Services Inc.	REC	78094	1	$ 156,586.38	22852	$ 244,805.09	$ 5,616.56	$ 2,115.94				$ 252,537.59	$ 5,616.56	19
30-005-20103	CATO SAN ANDRES UNIT #119	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/12/2023	9/20/2023	Drake Well Services Inc.	Initial BIL	75010	4	$ 150,000.00	21741	$ 241,297.97	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 251,223.82	$ 5,751.00	39
30-005-10529	KM CHAVEROO SA UNIT #111	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	9/23/2024	10/4/2024	Drake Well Services Inc.	REC	78094	4	$ 156,586.38	22950	$ 236,898.82	$ 5,616.56	$ 2,115.94				$ 244,631.32	$ 5,616.56	11
30-005-10510	KM CHAVEROO SA UNIT #018	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	8/18/2024	8/29/2024	Drake Well Services Inc.	REC	78094	2	$ 156,586.38	22854	$ 230,587.11	$ 5,616.56	$ 2,115.94				$ 238,319.61	$ 5,616.56	11
30-025-11107	FOWLER HAIR #005	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	1/3/2023	1/16/2023	A-Plus P&A LLC	Initial BIL	73836	3	$ 139,400.00	12480	$ 230,534.28	$ 1,969.20	$ 2,000.00	$ 1,459.96	$ -	$ -	$ 235,963.44		13
30-005-60817	BARKNEHT #001	269864	[269864] CANYON E & P COMPANY	Private	Private	9/27/2023	10/12/2023	Drake Well Services Inc.	Initial BIL	75229	1	$ 150,000.00	21812	$ 219,834.41	$ 5,890.81	$ 2,207.86	$ 2,112.00	$ -	$ -	$ 230,045.08	$ 5,890.81	15
30-025-24180	ALVES #003	373817	[373817] Energy Acumen LLC	Private	Private	11/27/2023	1/24/2024	Drake Well Services Inc.	REC	75938	2	$ 150,057.61	22197	$ 214,185.83	$ 4,975.63	$ 2,116.03	$ 2,116.03	$ 2,036.40	$ 2,036.40	$ 223,393.52	$ 4,975.63	58
30-041-10633	CHAVEROO A STATE #001	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	9/3/2024	10/2/2024	A-Plus P&A LLC	REC	78095	1	$ 162,000.00	3028	$ 211,462.72	$ 5,245.35	$ 1,991.50				$ 218,699.57	$ 5,245.35	29
30-005-10567	CATO SAN ANDRES UNIT #097	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/21/2023	8/28/2023	Drake Well Services Inc.	Initial BIL	75010	1	$ 150,000.00	21760	$ 207,466.58	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ 44.97	$ -	$ 217,311.44	$ 1,969.20	7
30-041-20309	CHAVEROO SAN ANDRES UNIT #005	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	9/23/2024	10/14/2024	A-Plus P&A LLC	REC	78095	3	$ 159,500.00	3064	$ 205,731.70	$ 5,245.35	$ 2,117.93				$ 213,094.98	$ 5,245.35	21
30-005-10524	KM CHAVEROO SA UNIT #110	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	State	8/30/2024	10/4/2024	Drake Well Services Inc.	REC	78094	3	$ 156,586.38	22951	$ 203,887.59	$ 5,616.56	$ 2,115.94				$ 211,620.09	$ 5,616.56	35
30-005-60705	ELIZABETH #002	269864	[269864] CANYON E & P COMPANY	Private	Private	9/27/2023	10/12/2023	Drake Well Services Inc.	Initial BIL	75229	3	$ 150,000.00	21814	$ 199,555.14	$ 5,890.81		$ 2,112.00	$ 0.01	$ -	$ 207,557.95	$ 5,890.81	15
30-005-61772	TWIN LAKES SAN ANDRES UNIT #109	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/4/2023	6/20/2023	Drake Well Services Inc.	Initial BIL	72802	19	$ 78,162.00	21494, 21510	$ 197,938.56	$ 4,199.29			$ -	$ -	$ 202,137.85	$ 4,199.29	47
30-005-60744	ELIZABETH #003	269864	[269864] CANYON E & P COMPANY	Private	Private	10/3/2023	10/12/2023	Drake Well Services Inc.	Initial BIL	75229	4	$ 150,000.00	21880	$ 196,668.94	$ 5,890.81		$ 2,112.00	$ -	$ -	$ 204,671.75	$ 5,890.81	9
30-025-26262	JUDY #003	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	11/18/2022	1/12/2023	A-Plus P&A LLC	Initial BIL	72806	8	$ 135,300.00	12399	$ 196,650.14	$ 1,969.20			$ 20.56	$ -	$ 198,619.34		55
30-025-06662	ALVES #002	373817	[373817] Energy Acumen LLC	Private	Private	12/3/2024	12/20/2023	Drake Well Services Inc.	REC	75938	1	$ 142,374.01	22121	$ 194,690.23	$ 4,975.63	$ 2,038.08	$ 1,763.58			$ 203,467.52	$ 4,975.63	-349
30-041-20399	CHAVEROO SAN ANDRES UNIT #007	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	9/18/2024	10/3/2024	A-Plus P&A LLC	REC	78095	4	$ 162,000.00	2977	$ 194,385.32	$ 5,245.35	$ 1,991.50				$ 201,622.17	$ 5,245.35	15
30-025-36485	NEW MEXICO 36 STATE #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	State	State	1/17/2023	2/2/2023	A-Plus P&A LLC	REC	73836	2	$ 187,000.00	12496	$ 187,355.60		$ 2,000.00				$ 189,355.60		16
30-041-20386	CHAVEROO SAN ANDRES UNIT #006	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	5/13/2024	6/4/2024	A-Plus P&A LLC	REC	76993	3	$ 181,314.75	2284 &2461	$ 184,041.52	$ 5,379.00	$ 2,117.93				$ 191,538.45	$ 5,379.00	22
30-005-60921	MCDERMOTT #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/14/2023	10/23/2023	Drake Well Services Inc.	Initial BIL	75229	9	$ 150,000.00	21924	$ 183,873.72	$ 5,890.81	$ 2,207.86	$ 2,112.00	$ -	$ -	$ 194,084.39	$ 5,890.81	9
30-025-28664	ROBERT #001	373817	[373817] Energy Acumen LLC	Private	Private	1/21/2024	1/29/2024	Drake Well Services Inc.	REC	75938	12	$ 135,317.46	22243	$ 183,222.16	$ 4,975.63	$ 2,038.08	$ 1,763.58			$ 191,999.45	$ 4,975.63	8
30-041-20473	CHAVEROO SAN ANDRES UNIT #002	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	9/3/2024	9/19/2024	A-Plus P&A LLC	REC	78095	2	$ 165,500.00	2957	$ 181,212.60	$ 5,245.35	$ 1,991.50				$ 188,449.45	$ 5,245.35	16
30-015-00954	ARTESIA METEX UNIT #040	269864	[269864] CANYON E & P COMPANY	State	Private	6/5/2023	6/12/2023	A-Plus P&A LLC	Initial BIL	73858	3	$ 77,162.00	1359	$ 179,794.00	$ 3,587.99	$ 2,116.67		$ 0.01	$ -	$ 185,498.66	$ 3,587.99	7
30-025-11105	FOWLER HAIR #003	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	12/13/2022	1/3/2023	A-Plus P&A LLC	Initial BIL	72806	5	$ 139,400.00	12454	$ 176,657.80	$ 1,969.20	$ 2,000.00	$ 1,459.96	$ 4.20	$ -	$ 182,086.96		21
30-041-20417	CHAVEROO SAN ANDRES UNIT #004	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	5/24/2024	6/10/2024	A-Plus P&A LLC	REC	76993	2	$ 181,314.75	2414 & 2415	$ 176,444.71	$ 5,379.00	$ 2,117.93				$ 183,941.64	$ 5,379.00	17
30-005-60327	GRAVES #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/10/2023	10/23/2023	Drake Well Services Inc.	Initial BIL	75229	7	$ 150,000.00	21917	$ 174,233.85	$ 5,890.81	$ 2,207.86	$ 2,112.00	$ -	$ -	$ 184,444.52	$ 5,890.81	13
30-005-60622	UNION HAPPY #002	269864	[269864] CANYON E & P COMPANY	Private	Private	10/31/2023	11/15/2023	Drake Well Services Inc.	Initial BIL	75229	15	$ 150,000.00	22017	$ 168,938.10	$ 5,890.81	$ 2,383.75	$ 2,112.00	$ 433.34	$ -	$ 179,324.66	$ 5,890.81	15
30-041-20483	CHAVEROO SAN ANDRES UNIT #003	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	Private	6/10/2024	6/24/2024	A-Plus P&A LLC	REC	76993	1	$ 181,314.75	2426	$ 168,526.06	$ 5,379.00	$ 2,117.93				$ 176,022.99	$ 5,379.00	14
30-005-60623	SEANNA #002	269864	[269864] CANYON E & P COMPANY	Private	Private	10/23/2023	11/15/2023	Drake Well Services Inc.	Initial BIL	75229	12	$ 150,000.00	1974 & 22167	$ 165,360.57	$ 5,890.81		$ 2,112.00	$ -	$ -	$ 173,363.38	$ 5,890.81	23
30-005-20071	CATO SAN ANDRES UNIT #127	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/12/2023	8/21/2023	Drake Well Services Inc.	Initial BIL	75010	5	$ 150,000.00	21710	$ 164,107.41	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 1.05	$ -	$ 174,033.26	$ 5,751.00	9
30-005-62861	ELIZABETH C #005	269864	[269864] CANYON E & P COMPANY	Private	Private	10/10/2023	10/23/2023	Drake Well Services Inc.	Initial BIL	75229	6	$ 150,000.00	21901	$ 164,026.38	$ 5,890.81	$ 2,767.50	$ 2,112.00	$ -	$ -	$ 174,796.69	$ 5,890.81	13
30-005-60604	SEANNA #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/15/2023	10/23/2023	Drake Well Services Inc.	Initial BIL	75229	11	$ 150,000.00	21951	$ 162,302.98	$ 5,890.81	$ 2,130.42	$ 2,112.00	$ -	$ -	$ 172,436.21	$ 5,890.81	8
30-005-61556	TWIN LAKES SAN ANDRES UNIT #110	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/27/2023	5/26/2023	Drake Well Services Inc.	Initial BIL	72802	6	$ 78,162.00	21449, 21581	$ 161,733.17	$ 4,199.29			$ 1.12	$ -	$ 165,932.46	$ 4,199.29	29
30-005-60905	O'BRIEN FEE 19 #007	269864	[269864] CANYON E & P COMPANY	Private	Private	3/1/2023	4/3/2023	Drake Well Services Inc.	Initial BIL	73062	16	$ 98,168.00	21286, 21564	$ 160,066.98		$ 1,474.10	$ 2,127.88	$ 0.09	$ -	$ 163,668.96		33
30-005-00349	TWIN LAKES SAN ANDRES UNIT #054	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/9/2023	6/20/2023	Drake Well Services Inc.	Initial BIL	72802	8	$ 208,258.00	20931, 21471	$ 159,419.71	$ 4,199.29			$ 0.82	$ -	$ 163,619.00		42
30-025-36464	SHELLY 36 STATE #006	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORATED	State	State	1/27/2023	2/6/2023	A-Plus P&A LLC	REC	73836	1	$ 195,200.00	1018	$ 158,417.39	$ 1,969.20	$ 2,000.00				$ 162,386.59		10
30-015-00948	ARTESIA METEX UNIT #039	269864	[269864] CANYON E & P COMPANY	State	Private	5/23/2023	6/2/2023	A-Plus P&A LLC	Initial BIL	73858	2	$ 82,000.00	1330, 1417	$ 156,922.40	$ 3,587.99	$ 2,116.67		$ -	$ -	$ 162,627.06	$ 3,587.99	10
30-005-20236	CATO SAN ANDRES UNIT #068	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	5/27/2023	6/8/2023	Drake Well Services Inc.	Initial BIL	73110	1	$ 85,446.00	21472	$ 153,396.09		$ 2,127.92		$ 2.07	$ -	$ 155,524.01		12
30-015-27635	BIG EDDY UNIT #127	154303	[154303] PRIMAL ENERGY CORPORATION	State	State	2/27/2023	3/9/2023	A-Plus P&A LLC	Initial BIL	73858	8	$ 131,200.00	1101	$ 151,867.35	$ 3,587.99	$ 2,116.67		$ 0.06	$ -	$ 157,572.01	$ 3,587.99	10
30-005-28017	CATO SAN ANDRES UNIT #574	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/18/2024	9/24/2023	Drake Well Services Inc.	Initial BIL	75010	21	$ 150,000.00	21790	$ 150,495.66	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ -	$ -	$ 160,219.59	$ 5,751.00	-360
30-005-20010	CATO SAN ANDRES UNIT #101	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/14/2023	6/29/2023	Drake Well Services Inc.	Initial BIL	73110	6	$ 89,100.00	21529	$ 147,885.53	$ 2,954.13	$ 2,127.92		$ -	$ -	$ 152,967.58	$ 2,954.13	15
30-025-28841	MIKE #003	373817	[373817] Energy Acumen LLC	Private	Private	1/9/2024	1/22/2024	A-Plus P&A LLC	REC	76015	3	$ 138,905.05	1955	$ 147,724.34	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 155,961.02	$ 4,435.02	13
30-005-29027	CATO SAN ANDRES UNIT #588	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/23/2023	10/12/2023	Drake Well Services Inc.	Initial BIL	75010	24	$ 150,000.00	21810	$ 145,248.01	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 7.56	$ -	$ 154,971.94	$ 5,751.00	19
30-025-36383	ALVES #004	373817	[373817] Energy Acumen LLC	Private	Private	12/11/2023	12/20/2023	Drake Well Services Inc.	REC	75938	3	$ 139,111.26	22122	$ 144,820.79	$ 4,975.63	$ 1,926.00	$ 1,651.50			$ 153,373.92	$ 4,975.63	9
30-025-36826	ROBERT #002	373817	[373817] Energy Acumen LLC	Private	Private	1/23/2024	1/28/2024	Drake Well Services Inc.	REC	75938	13	$ 120,010.04	22244	$ 143,401.02	$ 4,975.63	$ 2,038.08	$ 1,763.58			$ 152,178.31	$ 4,975.63	5
30-005-61267	NANCY #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/14/2023	10/23/2023	Drake Well Services Inc.	Initial BIL	75229	10	$ 150,000.00	21946	$ 139,665.44	$ 5,890.81	$ 2,000.00	$ 2,112.00	$ -	$ -	$ 149,668.25	$ 5,890.81	9
30-005-60610	ELIZABETH #001	269864	[269864] CANYON E & P COMPANY	Private	Private	9/27/2023	10/12/2023	Drake Well Services Inc.	Initial BIL	75229	2	$ 150,000.00	21946	$ 139,665.44	$ 5,890.81		$ 2,112.00	$ -	$ -	$ 147,668.25	$ 5,890.81	15
30-005-60725	O'BRIEN FEE 18 #003	269864	[269864] CANYON E & P COMPANY	Private	Private	1/19/2023	2/6/2023	Drake Well Services Inc.	Initial BIL	73062	6	$ 78,974.00	21366, 21170	$ 137,556.78		$ 1,474.10	$ 1,474.10	$ 1.69	$ -	$ 140,504.98		18
30-025-06927	PRUITT #001	373817	[373817] Energy Acumen LLC	Private	Private	1/18/2024	1/25/2024	Drake Well Services Inc.	REC	75938	11	$ 133,673.70	22245	$ 137,015.56	$ 4,975.63		$ 1,763.58			$ 143,754.77	$ 4,975.63	7
30-005-60920	TWIN LAKES SAN ANDRES UNIT #061	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/17/2023	5/26/2023	Drake Well Services Inc.	Initial BIL	72802	10	$ 78,246.00	21448, 21501	$ 136,781.21	$ 4,199.29			$ 0.01	$ -	$ 140,980.50		9
30-005-60174	DOUBLE L QUEEN UNIT #005	269864	[269864] CANYON E & P COMPANY	State	State	9/26/2023	10/25/2023	A-Plus P&A LLC	Initial BIL	75150	5	$ 150,000.00	1639	$ 135,977.60	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 142,719.99	$ 4,695.47	29
30-005-60164	DOUBLE L QUEEN UNIT #004	269864	[269864] CANYON E & P COMPANY	State	State	9/25/2023	10/25/2023	A-Plus P&A LLC	Initial BIL	75150	2	$ 150,000.00	1640	$ 135,947.96	$ 4,695.47		$ 2,046.92	$ 0.11	$ -	$ 142,690.35	$ 4,695.47	30
30-005-60735	SEANNA #003	269864	[269864] CANYON E & P COMPANY	Private	Private	10/19/2023	10/23/2023	Drake Well Services Inc.	Initial BIL	75229	13	$ 150,000.00	21967	$ 135,030.44	$ 5,890.81	$ 2,000.00	$ 2,112.00	$ -	$ -	$ 145,033.25	$ 5,890.81	4
30-005-20077	CATO SAN ANDRES UNIT #118	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/24/2023	6/28/2023	Drake Well Services Inc.	Initial BIL	73110	7	$ 87,420.00	21530	$ 132,804.89	$ 5,751.00	$ 2,127.92		$ -	$ -	$ 140,683.81		4
30-025-24609	HARRISON #001	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	2/7/2023	3/2/2023	A-Plus P&A LLC	Initial BIL	73861	1	$ 150,060.00	1046	$ 132,569.07	$ 11,242.77	$ 1,459.96	$ 1,459.96	$ 121.43	$ -	$ 146,731.76		23
30-015-00959	ARTESIA METEX UNIT #045	269864	[269864] CANYON E & P COMPANY	State	State	6/16/2023	6/28/2023	A-Plus P&A LLC	Initial BIL	73858	7	$ 82,000.00	1378	$ 132,493.66	$ 3,587.99	$ 2,116.67		$ -	$ -	$ 138,198.32	$ 3,587.99	12
30-025-24641	JUDY #001	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	2/15/2023	2/24/2023	A-Plus P&A LLC	Initial BIL	73861	2	$ 147,600.00	1067	$ 130,854.23	$ 11,242.77	$ 1,459.96	$ 1,459.96	$ 26.84	$ -	$ 145,016.92		9
30-025-24749	HARRISON #002	154303	[154303] PRIMAL ENERGY CORPORATION	Private	Private	11/14/2022	1/12/2023	A-Plus P&A LLC	Initial BIL	72806	7	$ 127,100.00	12364	$ 130,846.24	$ 1,969.20			$ 0.06	$ -	$ 132,815.44		59
30-005-60655	O'BRIEN FEE 25 #005	269864	[269864] CANYON E & P COMPANY	Private	Private	3/17/2023	4/5/2023	Drake Well Services Inc.	Initial BIL	73062	20	$ 79,030.00	21308	$ 129,851.82		$ 2,127.88		$ 0.01	$ -	$ 131,979.70		19
30-005-60634	O'BRIEN DEMING 6 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	3/2/2023	3/6/2023	Drake Well Services Inc.	Initial BIL	73062	2	$ 78,974.00	21151	$ 129,142.42		$ 1,474.10	$ 1,474.10	$ -	$ -	$ 132,090.62		4
30-025-29139	MIKE #004	373817	[373817] Energy Acumen LLC	Private	Private	1/22/2024	2/4/2024	A-Plus P&A LLC	REC	76015	4	$ 140,458.36	1989	$ 128,328.19	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 136,564.87	$ 4,435.02	13
30-005-00054	Elks #001	214263	[214263] PRE-ONGARD WELL OPERATOR	Private	Federal	10/3/2023	10/11/2023	Drake Well Services Inc.	REC	75613	1	$ 135,000.00	21804	$ 127,495.16	$ 2,987.06					$ 130,482.22	$ 2,987.06	8
30-005-61261	TWIN LAKES SAN ANDRES UNIT #099	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/27/2023	5/2/2023	Drake Well Services Inc.	Initial BIL	72802	5	$ 78,246.00	21413	$ 126,143.32	$ 4,199.29			$ 0.29	$ -	$ 130,342.61	$ 4,199.29	5
30-005-60995	TWIN LAKES SAN ANDRES UNIT #078	300825	[300825] BLUE SKY NM, INC.	Private	Private	1/5/2023	1/19/2023	Drake Well Services Inc.	Initial BIL	72802	11	$ 78,358.00	21027	$ 125,479.39	$ 4,199.29			$ -	$ -	$ 129,678.68		14
30-005-60146	DOUBLE L QUEEN UNIT #001D	269864	[269864] CANYON E & P COMPANY	State	State	10/16/2023	11/15/2023	A-Plus P&A LLC	Initial BIL	75136	1	$ 150,000.00	1705	$ 124,649.73	$ 5,287.31		$ 2,046.92	$ 0.40	$ -	$ 131,983.96	$ 5,287.31	30
30-005-60565	O'BRIEN FEE 19 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	1/24/2023	2/23/2023	Drake Well Services Inc.	Initial BIL	73062	11	$ 98,168.00	21122, 21561	$ 122,307.30		$ 1,474.10		$ 1.69	$ -	$ 123,781.40		30
30-005-60097	DOUBLE L QUEEN UNIT #006	269864	[269864] CANYON E & P COMPANY	State	State	10/5/2023	10/26/2023	A-Plus P&A LLC	Initial BIL	75150	7	$ 150,000.00	1666	$ 121,721.73	$ 4,695.47		$ 2,046.92	$ 0.13	$ -	$ 128,464.12	$ 4,695.47	21
30-005-27983	CATO SAN ANDRES UNIT #535	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/27/2023	9/2/2023	Drake Well Services Inc.	Initial BIL	75010	13	$ 150,000.00	21747	$ 121,283.68	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ -	$ -	$ 131,128.54	$ 5,751.00	6
30-005-20332	DOUBLE L QUEEN UNIT #001P	269864	[269864] CANYON E & P COMPANY	Private	Federal	9/18/2023	10/18/2023	A-Plus P&A LLC	Initial BIL	75136	4	$ 150,000.00	1643	$ 120,920.59	$ 5,287.31		$ 2,046.92	$ -	$ -	$ 128,254.82	$ 5,287.31	30
30-015-02142	ARTESIA METEX UNIT #043	269864	[269864] CANYON E & P COMPANY	State	Private	6/20/2023	6/27/2023	A-Plus P&A LLC	Initial BIL	73858	6	$ 94,300.00	1398	$ 119,337.31	$ 3,587.99	$ 2,116.67		$ 0.01	$ -	$ 125,041.97	$ 3,587.99	7
30-005-60084	DOUBLE L QUEEN UNIT #001Y	269864	[269864] CANYON E & P COMPANY	State	Private	11/27/2023	12/7/2023	A-Plus P&A LLC	Initial BIL	75136	7	$ 150,000.00	1882	$ 118,708.55	$ 5,287.31		$ 2,046.92	$ 24.74	$ -	$ 126,042.78	$ 5,287.31	10
30-005-29028	CATO SAN ANDRES UNIT #822	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/24/2023	10/12/2023	Drake Well Services Inc.	Initial BIL	75010	25	$ 150,000.00	21811	$ 117,866.01	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 127,791.86	$ 5,751.00	18
30-005-60117	DOUBLE L QUEEN UNIT #001R	269864	[269864] CANYON E & P COMPANY	State	State	11/27/2023	12/12/2023	A-Plus P&A LLC	REC	75136	6	$ 150,000.00	1884	$ 115,772.09	$ 5,287.31		$ 2,046.92	$ 1.60	$ -	$ 123,106.32	$ 5,287.31	15
30-005-60127	DOUBLE L QUEEN UNIT #001H	269864	[269864] CANYON E & P COMPANY	State	State	10/30/2023	11/7/2023	A-Plus P&A LLC	Initial BIL	75136	2	$ 150,000.00	1858	$ 115,614.62	$ 5,287.31		$ 2,046.92	$ 0.05	$ -	$ 122,948.85	$ 5,287.31	8
30-005-29024	CATO SAN ANDRES UNIT #587	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/21/2023	9/24/2023	Drake Well Services Inc.	Initial BIL	75010	23	$ 150,000.00	21794	$ 114,799.56	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 21.91	$ -	$ 124,523.49	$ 5,751.00	34
30-005-20984	DOUBLE L QUEEN UNIT #005Q	269864	[269864] CANYON E & P COMPANY	Private	Private	8/24/2023	10/5/2023	A-Plus P&A LLC	Initial BIL	75150	6	$ 150,000.00	1569	$ 108,931.64	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 115,674.03	$ 4,695.47	42
30-005-60080	DOUBLE L QUEEN UNIT #004G	269864	[269864] CANYON E & P COMPANY	State	State	8/17/2023	9/18/2023	A-Plus P&A LLC	Initial BIL	75150	3	$ 150,000.00	1546	$ 108,724.33	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 115,466.72	$ 4,695.47	32
30-005-28029	CATO SAN ANDRES UNIT #561	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/16/2023	9/20/2023	Drake Well Services Inc.	Initial BIL	75010	19	$ 150,000.00	21785	$ 108,589.89	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 0.09	$ -	$ 118,313.82	$ 5,751.00	4
30-005-10586	CATO SAN ANDRES UNIT #069	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	6/9/2023	6/15/2023	Drake Well Services Inc.	Initial BIL	73110	2	$ 89,184.00	21500	$ 106,418.09		$ 2,127.92		$ 1.62	$ -	$ 108,546.01		6
30-005-60468	TWIN LAKES SAN ANDRES UNIT #066	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/19/2023	5/3/2023	Drake Well Services Inc.	Initial BIL	72802	2	$ 77,547.00	21411	$ 104,896.82	$ 4,199.29			$ 0.03	$ -	$ 109,096.11		14
30-005-60153	DOUBLE L QUEEN UNIT #003Y	269864	[269864] CANYON E & P COMPANY	State	State	10/16/2023	10/26/2023	A-Plus P&A LLC	Initial BIL	75150	1	$ 150,000.00	1701	$ 104,377.24	$ 4,695.47		$ 2,046.92	$ 0.36	$ -	$ 111,119.63	$ 4,695.47	10
30-005-27974	CATO SAN ANDRES UNIT #531	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/21/2023	9/2/2023	Drake Well Services Inc.	Initial BIL	75010	10	$ 150,000.00	21740	$ 104,186.39	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 114,112.24	$ 5,751.00	12
30-005-27973	CATO SAN ANDRES UNIT #516	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/15/2023	8/21/2023	Drake Well Services Inc.	Initial BIL	75010	6	$ 150,000.00	21698	$ 103,464.72	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 0.05	$ -	$ 113,390.57	$ 5,751.00	6
30-005-60566	O'BRIEN FEE 19 #003	269864	[269864] CANYON E & P COMPANY	Private	Private	1/17/2023	1/25/2023	Drake Well Services Inc.	Initial BIL	73062	12	$ 97,923.00	21067, 21166	$ 103,171.04		$ 1,474.10		$ 1.69	$ -	$ 104,645.14		8
30-005-60597	TWIN LAKES SAN ANDRES UNIT #014	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/13/2023	5/26/2023	Drake Well Services Inc.	Initial BIL	72802	7	$ 78,162.00	21445, 21582	$ 102,179.53	$ 4,199.29			$ 0.82	$ -	$ 106,378.82		13
30-005-20346	DOUBLE L QUEEN UNIT #003L	269864	[269864] CANYON E & P COMPANY	Private	Federal	11/8/2023	12/6/2023	A-Plus P&A LLC	Initial BIL	75149	7	$ 150,000.00	1872	$ 102,103.87	$ 5,282.41		$ 2,046.92	$ 0.01	$ -	$ 109,433.20	$ 5,282.41	28
30-005-60730	O'BRIEN DEMING 6 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	3/3/2023	3/6/2023	Drake Well Services Inc.	Initial BIL	73062	3	$ 78,974.00	21358, 21559	$ 101,327.84		$ 1,474.10	$ 1,474.10	$ -	$ -	$ 104,276.04		3
30-005-60069	DOUBLE L QUEEN UNIT #002G	269864	[269864] CANYON E & P COMPANY	State	State	10/6/2023	11/2/2023	A-Plus P&A LLC	Initial BIL	75136	9	$ 150,000.00	1672	$ 100,131.59	$ 5,287.31		$ 2,046.92	$ -	$ -	$ 107,465.82	$ 5,287.31	27
30-005-20337	DOUBLE L QUEEN UNIT #002P	269864	[269864] CANYON E & P COMPANY	Private	Private	9/8/2023	10/19/2023	A-Plus P&A LLC	Initial BIL	75149	1	$ 150,000.00	1590	$ 99,591.77	$ 5,282.41	$ 2,046.95	$ 2,046.92	$ 0.01	$ -	$ 108,968.05	$ 5,282.41	41
30-005-27984	CATO SAN ANDRES UNIT #545	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/7/2023	9/12/2023	Drake Well Services Inc.	Initial BIL	75010	15	$ 150,000.00	21865	$ 99,512.66	$ 5,751.00	$ 1,952.90	$ 2,046.93	$ 0.08	$ -	$ 109,263.49	$ 5,751.00	5
30-005-61551	Tolmac State #002	330522	[330522] Acacia Operating Company, LLC	State	State	5/27/2025	6/3/2025	JMR	REC	80042	1	$ 239,004.00	4138	$ 99,288.29						$ 99,288.29	$ 6,882.00	7
30-005-61021	O'BRIEN FEE 19 #008	269864	[269864] CANYON E & P COMPANY	Private	Private	2/7/2023	2/17/2023	Drake Well Services Inc.	Initial BIL	73062	17	$ 98,168.00	21437. 21168	$ 99,172.05		$ 1,474.10	$ 1,474.10	$ 1.69	$ -	$ 102,120.25		10
30-005-60923	O'BRIEN FEE 24 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	3/14/2023	3/18/2023	Drake Well Services Inc.	Initial BIL	73062	19	$ 78,750.00	21190	$ 98,722.53		$ 2,127.88		$ 0.04	$ -	$ 100,850.41		4
30-005-60803	O'BRIEN FEE 24 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	3/6/2023	3/18/2023	Drake Well Services Inc.	Initial BIL	73062	18	$ 78,862.00	21187	$ 97,440.63		$ 2,127.88		$ 0.02	$ -	$ 99,568.51		12
30-005-60581	UNION HAPPY #001	269864	[269864] CANYON E & P COMPANY	Private	Private	10/28/2023	11/15/2023	Drake Well Services Inc.	Initial BIL	75229	14	$ 150,000.00	22002	$ 96,791.27	$ 5,890.81	$ 2,207.86	$ 2,112.00	$ -	$ -	$ 107,001.94	$ 5,890.81	18
30-005-60816	O'BRIEN LIGHTCAP 7 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	3/6/2023	3/18/2023	Drake Well Services Inc.	Initial BIL	73062	22	$ 78,974.00	21197	$ 96,381.77		$ 2,000.00		$ -	$ -	$ 98,381.77		12
30-005-27964	CATO SAN ANDRES UNIT #532	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/21/2023	9/2/2023	Drake Well Services Inc.	Initial BIL	75010	11	$ 150,000.00	21748	$ 96,065.48	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ -	$ -	$ 105,991.33	$ 5,751.00	12
30-005-60902	O'BRIEN FEE 18 #004	269864	[269864] CANYON E & P COMPANY	Private	Private	2/28/2023	3/6/2023	Drake Well Services Inc.	Initial BIL	73062	7	$ 78,974.00	21145, 21173	$ 95,105.42		$ 1,474.10	$ 1,474.10	$ -	$ -	$ 98,053.62		6
30-005-61135	TWIN LAKES SAN ANDRES UNIT #057	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/18/2023	5/3/2023	Drake Well Services Inc.	Initial BIL	72802	4	$ 78,246.00	21338	$ 93,901.73	$ 4,199.29			$ 12.02	$ -	$ 98,101.02	$ 4,199.29	15
30-005-60528	O'BRIEN FEE 19 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	1/24/2023	2/6/2023	Drake Well Services Inc.	Initial BIL	73062	10	$ 100,373.00	21391, 21225	$ 92,886.29		$ 1,474.10		$ 1.69	$ -	$ 94,360.39		13
30-005-60747	ELIZABETH #004	269864	[269864] CANYON E & P COMPANY	Private	Private	10/7/2023	10/12/2023	Drake Well Services Inc.	Initial BIL	75229	5	$ 150,000.00	21815	$ 92,842.93	$ 5,890.81		$ 2,112.00	$ -	$ -	$ 100,845.74	$ 5,890.81	5
30-025-05523	MIKE #002	373817	[373817] Energy Acumen LLC	Private	Private	1/26/2024	2/4/2024	A-Plus P&A LLC	REC	76015	2	$ 153,887.25	1983	$ 92,623.43	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 100,860.11	$ 4,435.02	9
30-005-29025	CATO SAN ANDRES UNIT #586	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/21/2023	9/24/2023	Drake Well Services Inc.	Initial BIL	75010	22	$ 150,000.00	21792	$ 92,162.82	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 1.20	$ -	$ 101,886.75	$ 5,751.00	3
30-005-60099	DOUBLE L QUEEN UNIT #007	269864	[269864] CANYON E & P COMPANY	State	State	10/23/2023	11/15/2023	A-Plus P&A LLC	Initial BIL	75150	8	$ 150,000.00	1716	$ 91,343.31	$ 4,695.47		$ 2,046.92	$ -	$ -	$ 98,085.70	$ 4,695.47	23
30-005-27985	CATO SAN ANDRES UNIT #533	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/24/2023	9/2/2023	Drake Well Services Inc.	Initial BIL	75010	12	$ 150,000.00	21743	$ 90,943.94	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ -	$ -	$ 100,788.80	$ 5,751.00	9
30-005-60640	O'BRIEN FEE 18 #002	269864	[269864] CANYON E & P COMPANY	Private	Private	3/17/2023	4/5/2023	Drake Well Services Inc.	Initial BIL	73062	5	$ 78,974.00	21283, 21560	$ 90,591.77		$ 2,127.88		$ 35.38	$ -	$ 92,719.65		19
30-005-20338	DOUBLE L QUEEN UNIT #003Q	269864	[269864] CANYON E & P COMPANY	Private	Federal	11/9/2023	11/16/2023	A-Plus P&A LLC	REC	75149	8	$ 150,000.00	1865	$ 90,128.62	$ 5,282.41		$ 2,046.92	$ 16.25	$ -	$ 97,457.95	$ 5,282.41	7
30-005-20327	DOUBLE L QUEEN UNIT #001Q	269864	[269864] CANYON E & P COMPANY	Private	Federal	9/18/2023	10/18/2023	A-Plus P&A LLC	Initial BIL	75136	5	$ 150,000.00	1603	$ 89,618.95	$ 5,287.31		$ 2,046.92	$ 0.65	$ -	$ 96,953.18	$ 5,287.31	30
30-005-60093	DOUBLE L QUEEN UNIT #002X	269864	[269864] CANYON E & P COMPANY	State	Private	12/5/2023	12/12/2023	A-Plus P&A LLC	Initial BIL	75149	3	$ 150,000.00	1801	$ 89,502.61	$ 5,282.41		$ 2,046.92	$ 0.02	$ -	$ 96,831.94	$ 5,282.41	7
30-005-28027	CATO SAN ANDRES UNIT #520	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/1/2023	9/12/2023	Drake Well Services Inc.	Initial BIL	75010	9	$ 150,000.00	21863	$ 88,628.09	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 0.03	$ -	$ 98,553.94	$ 5,751.00	11
30-005-61105	TWIN LAKES SAN ANDRES UNIT #100	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/6/2023	4/20/2023	Drake Well Services Inc.	Initial BIL	72802	14	$ 79,618.00	21334	$ 87,618.16	$ 4,199.29			$ 0.00	$ -	$ 91,817.45		14
30-025-28661	MIKE #001	373817	[373817] Energy Acumen LLC	Private	Private	1/19/2024	1/25/2024	A-Plus P&A LLC	REC	76015	1	$ 130,108.36	1962	$ 86,416.72	$ 4,435.02	$ 2,038.08	$ 1,763.58			$ 94,653.40	$ 4,435.02	6
30-005-27986	CATO SAN ANDRES UNIT #544	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/4/2023	9/12/2023	Drake Well Services Inc.	Initial BIL	75010	14	$ 150,000.00	21864	$ 85,423.13	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ 0.01	$ -	$ 95,267.99	$ 5,751.00	8
30-005-27962	CATO SAN ANDRES UNIT #517	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/18/2023	8/29/2023	Drake Well Services Inc.	Initial BIL	75010	7	$ 150,000.00	21705	$ 85,086.25	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 4.69	$ -	$ 95,012.10	$ 5,751.00	11
30-005-28012	CATO SAN ANDRES UNIT #560	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/15/2023	9/20/2023	Drake Well Services Inc.	Initial BIL	75010	18	$ 150,000.00	21745	$ 84,151.73	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ -	$ -	$ 93,875.66	$ 5,751.00	5
30-005-28011	CATO SAN ANDRES UNIT #559	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/12/2023	9/14/2023	Drake Well Services Inc.	Initial BIL	75010	17	$ 150,000.00	21744	$ 84,145.22	$ 5,751.00	$ 1,952.90	$ 2,046.93	$ -	$ -	$ 93,896.05	$ 5,751.00	2
30-005-27963	CATO SAN ANDRES UNIT #518	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	8/18/2023	8/21/2023	Drake Well Services Inc.	Initial BIL	75010	8	$ 150,000.00	21699	$ 82,675.45	$ 5,751.00	$ 2,127.92	$ 2,046.93	$ 0.01	$ -	$ 92,601.30	$ 5,751.00	3
30-005-60159	DOUBLE L QUEEN UNIT #002	269864	[269864] CANYON E & P COMPANY	State	State	10/25/2023	11/2/2023	A-Plus P&A LLC	Initial BIL	75136	8	$ 150,000.00	1717, 1626	$ 82,329.64	$ 5,287.31		$ 2,046.92	$ 0.01	$ -	$ 89,663.87	$ 5,287.31	8
30-015-02136	ARTESIA METEX UNIT #041	269864	[269864] CANYON E & P COMPANY	State	Private	6/13/2023	6/15/2023	A-Plus P&A LLC	Initial BIL	73858	4	$ 82,000.00	1371	$ 80,024.66	$ 3,587.99	$ 2,116.67		$ 0.01	$ -	$ 85,729.32	$ 3,587.99	2
30-005-60804	O'BRIEN FEE 19 #006	269864	[269864] CANYON E & P COMPANY	Private	Private	2/4/2023	2/7/2023	Drake Well Services Inc.	Initial BIL	73062	15	$ 98,168.00	21110, 21565	$ 79,557.24			$ 1,474.10	$ 1.69	$ -	$ 81,031.34		3
30-005-60654	O'BRIEN FEE 19 #004	269864	[269864] CANYON E & P COMPANY	Private	Private	1/20/2023	1/25/2023	Drake Well Services Inc.	Initial BIL	73062	13	$ 97,923.00	21062, 21167	$ 79,475.43		$ 1,474.10		$ 1.69	$ -	$ 80,949.53		5
30-005-61104	TWIN LAKES SAN ANDRES UNIT #107	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/13/2023	4/20/2023	Drake Well Services Inc.	Initial BIL	72802	17	$ 79,534.00	21336	$ 79,232.95	$ 4,199.29			$ 0.82	$ -	$ 83,432.24		7
30-005-28010	CATO SAN ANDRES UNIT #558	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/9/2023	9/12/2023	Drake Well Services Inc.	Initial BIL	75010	16	$ 150,000.00	21749	$ 79,185.50	$ 5,751.00	$ 1,952.90	$ 2,046.93	$ 0.09	$ -	$ 88,936.33	$ 5,751.00	3
30-005-61107	TWIN LAKES SAN ANDRES UNIT #095	300825	[300825] BLUE SKY NM, INC.	Private	Private	3/22/2023	4/5/2023	Drake Well Services Inc.	Initial BIL	72802	13	$ 79,758.00	21309	$ 79,018.03	$ 4,199.29			$ 0.19	$ -	$ 83,217.32	$ 4,199.29	14
30-005-61075	TWIN LAKES SAN ANDRES UNIT #103	300825	[300825] BLUE SKY NM, INC.	Private	Private	3/30/2023	4/5/2023	Drake Well Services Inc.	Initial BIL	72802	15	$ 78,190.00	21311	$ 78,610.86	$ 4,199.29			$ 0.00	$ -	$ 82,810.15		6
30-005-61246	O'BRIEN FEE 18 #006	269864	[269864] CANYON E & P COMPANY	Private	Private	2/16/2023	2/23/2023	Drake Well Services Inc.	Initial BIL	73062	9	$ 98,168.00	21123, 21169	$ 78,097.28		$ 1,474.10		$ 1.69	$ -	$ 79,571.38		7
30-005-61453	TWIN LAKES SAN ANDRES UNIT #111	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/15/2023	4/20/2023	Drake Well Services Inc.	Initial BIL	72802	20	$ 78,582.00	21335	$ 78,026.48	$ 4,199.29			$ 0.82	$ -	$ 82,225.77		5
30-005-60619	O'BRIEN FEE 18 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	2/19/2023	2/23/2023	Drake Well Services Inc.	Initial BIL	73062	4	$ 78,974.00	21174, 21361	$ 76,094.55		$ 1,474.10	$ 1,474.10	$ 1.69	$ -	$ 79,042.75		4
30-005-61604	TWIN LAKES SAN ANDRES UNIT #113	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/16/2023	4/20/2023	Drake Well Services Inc.	Initial BIL	72802	21	$ 78,358.00	21337	$ 75,826.57	$ 4,199.29			$ -	$ -	$ 80,025.86		4
30-005-20294	CATO SAN ANDRES UNIT #025	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	5/26/2022	5/3/2023	Drake Well Services Inc.	REC	71388	1	$ 71,699.60	20167	$ 73,736.31						$ 73,736.31		342
30-005-28016	CATO SAN ANDRES UNIT #573	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/19/2023	9/24/2023	Drake Well Services Inc.	Initial BIL	75010	20	$ 150,000.00	21791	$ 73,170.90	$ 5,751.00	$ 1,926.00	$ 2,046.93	$ 0.60	$ -	$ 82,894.83	$ 5,751.00	5
30-005-60922	O'BRIEN DEMING 13 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	2/22/2023	3/6/2023	Drake Well Services Inc.	Initial BIL	73062	1	$ 78,862.00	21154, 21171	$ 73,061.42		$ 1,474.10	$ 2,127.88	$ 0.01	$ -	$ 76,663.40		12
30-005-60078	DOUBLE L QUEEN UNIT #001K	269864	[269864] CANYON E & P COMPANY	State	Private	11/6/2023	11/16/2023	A-Plus P&A LLC	Initial BIL	75136	3	$ 150,000.00	1864	$ 72,640.91	$ 5,287.31		$ 2,046.92	$ 5.84	$ -	$ 79,975.14	$ 5,287.31	10
30-005-60716	O'BRIEN FEE 19 #005	269864	[269864] CANYON E & P COMPANY	Private	Private	2/2/2023	2/6/2023	Drake Well Services Inc.	Initial BIL	73062	14	$ 98,413.00	21365. 21563	$ 70,587.02		$ 1,474.10		$ 1.69	$ -	$ 72,061.12		4
30-005-60161	DOUBLE L QUEEN UNIT #003	269864	[269864] CANYON E & P COMPANY	State	State	10/31/2023	12/14/2023	A-Plus P&A LLC	REC	75149	5	$ 150,000.00	1860	$ 69,279.31	$ 5,282.41		$ 2,046.92	$ 0.05	$ -	$ 76,608.64	$ 5,282.41	44
30-005-60079	DOUBLE L QUEEN UNIT #003G	269864	[269864] CANYON E & P COMPANY	State	State	11/3/2023	11/9/2023	A-Plus P&A LLC	REC	75149	6	$ 150,000.00	1862	$ 69,148.62	$ 5,282.41		$ 2,046.92	$ -	$ -	$ 76,477.95	$ 5,282.41	6
30-005-61020	O'BRIEN FEE 18 #005	269864	[269864] CANYON E & P COMPANY	Private	Private	2/21/2023	3/6/2023	Drake Well Services Inc.	Initial BIL	73062	8	$ 98,168.00	21148, 21359	$ 67,764.04		$ 1,474.10	$ 2,127.88	$ 1.67	$ -	$ 71,366.02		13
30-005-60151	DOUBLE L QUEEN UNIT #002Z	269864	[269864] CANYON E & P COMPANY	State	State	11/14/2023	12/7/2023	A-Plus P&A LLC	Initial BIL	75149	4	$ 150,000.00	1759	$ 66,862.97	$ 5,282.41	$ 2,046.95	$ 2,046.92	$ 23.72	$ -	$ 76,239.25	$ 5,282.41	23
30-005-20334	DOUBLE L QUEEN UNIT #002Q	269864	[269864] CANYON E & P COMPANY	Private	Federal	11/14/2023	12/6/2023	A-Plus P&A LLC	Initial BIL	75149	2	$ 150,000.00	1760	$ 66,185.54	$ 5,282.41		$ 2,046.92	$ -	$ -	$ 73,514.87	$ 5,282.41	22
30-005-60993	TWIN LAKES SAN ANDRES UNIT #081	300825	[300825] BLUE SKY NM, INC.	Private	Private	1/5/2023	1/19/2023	Drake Well Services Inc.	Initial BIL	72802	12	$ 78,246.00	21032	$ 65,726.47	$ 4,199.29			$ 0.35	$ -	$ 69,925.76		14
30-005-10432	LEWIS NEFF #003	228270	[228270] ROGER SLAYTON DBA ESCUDILLA OIL COMPANY	Private	Private	10/12/2023	10/23/2023	Drake Well Services Inc.	Initial BIL	75229	8	$ 150,000.00	21930	$ 65,084.49	$ 5,890.81	$ 2,000.00	$ 2,112.00	$ 40.41	$ -	$ 75,087.30	$ 5,890.81	11
30-005-29030	CATO SAN ANDRES UNIT #827	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	9/23/2023	9/27/2023	Drake Well Services Inc.	Initial BIL	75010	26	$ 150,000.00	21789	$ 63,667.63	$ 5,751.00	$ 2,046.93	$ 2,046.93	$ 44.97	$ -	$ 73,512.49	$ 5,751.00	4
30-005-61334	TWIN LAKES SAN ANDRES UNIT #108	300825	[300825] BLUE SKY NM, INC.	Private	Private	5/10/2023	5/26/2023	Drake Well Services Inc.	Initial BIL	72802	18	$ 78,526.00	21436	$ 62,720.90	$ 4,199.29			$ 0.00	$ -	$ 66,920.19		16
30-005-60794	TWIN LAKES SAN ANDRES UNIT #086	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/25/2023	5/3/2023	Drake Well Services Inc.	Initial BIL	72802	3	$ 77,910.00	21412, 21571	$ 62,530.36	$ 4,199.29			$ 0.02		$ 66,729.65		8
30-015-00950	ARTESIA METEX UNIT #038	269864	[269864] CANYON E & P COMPANY	State	Private	5/18/2023	6/28/2023	A-Plus P&A LLC	Initial BIL	73858	1	$ 79,294.00	1296, 1416	$ 61,949.37	$ 3,587.99	$ 2,116.67		$ 0.04	$ -	$ 67,654.03	$ 3,587.99	41
30-005-62068	TWIN LAKES SAN ANDRES UNIT #105	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/3/2023	4/20/2023	Drake Well Services Inc.	Initial BIL	72802	16	$ 79,282.00	21333	$ 60,974.74	$ 4,199.29			$ 0.82	$ -	$ 65,174.03		17
30-005-62565	TWIN LAKES SAN ANDRES UNIT #015	300825	[300825] BLUE SKY NM, INC.	Private	Private	4/17/2023	4/20/2023	Drake Well Services Inc.	Initial BIL	72802	9	$ 79,170.00	21390, 21566	$ 53,645.59	$ 4,199.29			$ 1.21	$ -	$ 57,844.88		3
30-005-60815	O'BRIEN LIGHTCAP 7 #001	269864	[269864] CANYON E & P COMPANY	Private	Private	3/14/2023	3/18/2023	Drake Well Services Inc.	Initial BIL	73062	21	$ 78,974.00	21204	$ 49,875.51		$ 2,207.86		$ -	$ -	$ 52,083.37		4
30-005-20009	CATO SAN ANDRES UNIT #052	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	Private	10/12/2023	11/11/2023	Drake Well Services Inc.	REC	71469	1	$ 72,696.98		$ 40,114.82						$ 40,114.82		30

EXHIBIT 15

API #	Well Name	OGRID	OPERATOR	Minerals	PA Rig Up Date	Date Plugged (D	Estimated Plugging Cost	Actual Plugging Cost	Contractor	Funding Sc	# days to Plug Well	depth	last production	$/ft Plugging Cost	time inactive	spud date	age of well at plugging
30-015-22372	BRC MADERA #001	373817	[373817] Energy Acumen LLC	Private	8/24/2023	9/24/2023	$250,000.00	$776,110.18	Drake Well Services Inc.	Initial BIL	31						
30-025-38192	BAGLEY #002	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORA	Private	11/5/2023	12/16/2023	$150,000.00	$523,725.26	Drake Well Services Inc.	REC	41						
30-025-22133	J P COLLIER #004Y	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORA	Private	11/27/2023	12/16/2023	$150,000.00	$513,954.99	Drake Well Services Inc.	Initial BIL	19						
30-025-00966	J P COLLIER #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORA	Private	11/5/2023	12/16/2023	$150,000.00	$476,334.72	Drake Well Services Inc.	REC	41						
30-025-38082	INBE 12 #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORA	Private	10/18/2023	11/17/2023	$150,000.00	$474,439.27	Drake Well Services Inc.	Initial BIL	30						
30-025-06430	ALVES A #001	373817	[373817] Energy Acumen LLC	Private	12/15/2023	1/23/2024	$139,750.10	$454,014.69	Drake Well Services Inc.	REC	39						
30-015-22552	MILLER COM #001	373817	[373817] Energy Acumen LLC	Private	12/14/2023	1/23/2024	$199,525.00	$429,602.20	A-Plus P&A LLC	REC	40						
30-025-37840	INBE 13 #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORA	Private	10/21/2023	11/17/2023	$150,000.00	$414,032.31	Drake Well Services Inc.	Initial BIL	27						
30-025-23726	SCHWALBE #001	37636	[37636] ROBINSON OIL INC	Private	11/5/2023	12/16/2023	$150,000.00	$336,762.47	Drake Well Services Inc.	REC	41						
30-005-20339	DOUBLE L QUEEN UNIT #004Q	269864	[269864] CANYON E & P COMPANY	Private	8/25/2023	10/5/2023	$150,000.00	$326,128.34	A-Plus P&A LLC	Initial BIL	41						
30-005-10474	CATO SAN ANDRES UNIT #098	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/13/2023	8/21/2023	$150,000.00	$303,936.24	Drake Well Services Inc.	Initial BIL	69						
30-005-20007	CATO SAN ANDRES UNIT #100	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/14/2023	9/12/2023	$150,000.00	$279,433.00	Drake Well Services Inc.	Initial BIL	90						
30-015-02138	ARTESIA METEX UNIT #042	269864	[269864] CANYON E & P COMPANY	State	5/4/2023	6/28/2023	$82,000.00	$269,015.45	A-Plus P&A LLC	Initial BIL	55						
30-025-25646	SCHWALBE #002	37636	[37636] ROBINSON OIL INC	Private	11/7/2023	11/16/2023	$150,000.00	$258,592.61	Drake Well Services Inc.	Initial BIL	9						
30-005-60293	TWIN LAKES SAN ANDRES UNIT #065	300825	[300825] BLUE SKY NM, INC.	Private	12/12/2022	1/18/2023	$77,490.00	$257,460.16	Drake Well Services Inc.	Initial BIL	37						
30-005-10497	KM CHAVEROO SA UNIT #016	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	8/10/2024	8/29/2024	$156,586.38	$244,805.09	Drake Well Services Inc.	REC	19	4342	Mar-22			8/8/1966	
30-005-20103	CATO SAN ANDRES UNIT #119	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/12/2023	9/20/2023	$150,000.00	$241,297.97	Drake Well Services Inc.	Initial BIL	39						
30-005-10529	KM CHAVEROO SA UNIT #111	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	9/23/2024	10/4/2024	$156,586.38	$236,898.82	Drake Well Services Inc.	REC	11	4344	Jul-19			10/8/1966	
30-005-10510	KM CHAVEROO SA UNIT #018	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	8/18/2024	8/29/2024	$156,586.38	$230,587.11	Drake Well Services Inc.	REC	11	4334	Apr-22			9/6/1966	
30-025-11107	FOWLER HAIR #005	154303	[154303] PRIMAL ENERGY CORPORATION	Private	1/3/2023	1/16/2023	$139,400.00	$230,534.28	A-Plus P&A LLC	Initial BIL	13						
30-005-60817	BARKNEHT #001	269864	[269864] CANYON E & P COMPANY	Private	9/27/2023	10/12/2023	$150,000.00	$219,834.41	Drake Well Services Inc.	Initial BIL	15						
30-025-24180	ALVES #003	373817	[373817] Energy Acumen LLC	Private	11/27/2023	1/24/2024	$150,057.61	$214,185.83	Drake Well Services Inc.	REC	58						
30-041-10633	CHAVEROO A STATE #001	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	9/3/2024	10/2/2024	$162,000.00	$211,462.72	A-Plus P&A LLC	REC	29	4338	May-06			11/26/1966	
30-005-10567	CATO SAN ANDRES UNIT #097	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/21/2023	8/28/2023	$150,000.00	$207,466.58	Drake Well Services Inc.	Initial BIL	7	3600	6/1/2009			11/26/1966	
30-041-20309	CHAVEROO SAN ANDRES UNIT #005	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	9/23/2024	10/14/2024	$159,500.00	$205,731.70	A-Plus P&A LLC	REC	21	4420	Jul-21			1/29/1970	
30-005-10524	KM CHAVEROO SA UNIT #110	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	State	8/30/2024	10/4/2024	$156,586.38	$203,887.59	Drake Well Services Inc.	REC	35	4336	Jul-21			9/29/1966	
30-005-60705	ELIZABETH #002	269864	[269864] CANYON E & P COMPANY	Private	9/27/2023	10/12/2023	$150,000.00	$199,555.14	Drake Well Services Inc.	Initial BIL	15						
30-005-61772	TWIN LAKES SAN ANDRES UNIT #109	300825	[300825] BLUE SKY NM, INC.	Private	5/4/2023	6/20/2023	$78,162.00	$197,938.56	Drake Well Services Inc.	Initial BIL	47						
30-025-27866	LANSFORD #005	373817	[373817] Energy Acumen LLC	Private	1/9/2024	1/17/2024	$137,507.82	$197,772.25	Drake Well Services Inc.	REC	8						
30-005-60744	ELIZABETH #003	269864	[269864] CANYON E & P COMPANY	Private	10/3/2023	10/12/2023	$150,000.00	$196,668.94	Drake Well Services Inc.	Initial BIL	9						
30-025-26262	JUDY #003	154303	[154303] PRIMAL ENERGY CORPORATION	Private	11/18/2022	1/12/2023	$135,300.00	$196,650.14	A-Plus P&A LLC	Initial BIL	55						
30-025-06662	ALVES #002	373817	[373817] Energy Acumen LLC	Private	12/3/2023	12/20/2023	$142,374.01	$194,690.23	Drake Well Services Inc.	REC	17						
30-041-20399	CHAVEROO SAN ANDRES UNIT #007	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	9/18/2024	10/3/2024	$162,000.00	$194,385.32	A-Plus P&A LLC	REC	15	4384	Dec-06			3/17/1975	
30-025-36485	NEW MEXICO 36 STATE #001	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORA	State	1/17/2023	2/2/2023	$187,000.00	$187,355.60	A-Plus P&A LLC	REC	16						
30-041-20386	CHAVEROO SAN ANDRES UNIT #006	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	5/13/2024	6/4/2024	$181,314.75	$184,041.52	A-Plus P&A LLC	REC	22	4400	Jan-08			11/10/1973	
30-005-60921	MCDERMOTT #001	269864	[269864] CANYON E & P COMPANY	Private	10/14/2023	10/23/2023	$150,000.00	$183,873.72	Drake Well Services Inc.	Initial BIL	9						
30-025-28664	ROBERT #001	373817	[373817] Energy Acumen LLC	Private	1/21/2024	1/29/2024	$135,317.46	$183,222.16	Drake Well Services Inc.	REC	8						
30-041-20473	CHAVEROO SAN ANDRES UNIT #002	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	9/3/2024	9/19/2024	$165,500.00	$181,212.60	A-Plus P&A LLC	REC	16	4343	Jan-08			Jan-08	
30-015-00954	ARTESIA METEX UNIT #040	269864	[269864] CANYON E & P COMPANY	State	6/5/2023	6/12/2023	$77,162.00	$179,794.00	A-Plus P&A LLC	Initial BIL	7						
30-025-11105	FOWLER HAIR #003	154303	[154303] PRIMAL ENERGY CORPORATION	Private	12/13/2022	1/3/2023	$139,400.00	$176,657.80	A-Plus P&A LLC	Initial BIL	21						
30-041-20417	CHAVEROO SAN ANDRES UNIT #004	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	5/24/2024	6/10/2024	$181,314.75	$176,444.71	A-Plus P&A LLC	REC	17	4378	Jul-17			5/24/1976	
30-005-60327	GRAVES #001	269864	[269864] CANYON E & P COMPANY	Private	10/10/2023	10/23/2023	$150,000.00	$174,233.85	Drake Well Services Inc.	Initial BIL	13						
30-005-60622	UNION HAPPY #002	269864	[269864] CANYON E & P COMPANY	Private	10/31/2023	11/15/2023	$150,000.00	$168,938.10	Drake Well Services Inc.	Initial BIL	15						
30-041-20483	CHAVEROO SAN ANDRES UNIT #003	164557	[164557] RIDGEWAY ARIZONA OIL CORP.	Private	6/10/2024	6/24/2024	$181,314.75	$168,526.06	A-Plus P&A LLC	REC	14	4325	Jul-21			5/4/1979	
30-025-27879	LANSFORD #006	373817	[373817] Energy Acumen LLC	Private	1/16/2024	1/17/2024	$129,932.82	$166,599.96	Drake Well Services Inc.	REC	1						
30-005-60623	SEANNA #002	269864	[269864] CANYON E & P COMPANY	Private	10/23/2023	11/15/2023	$150,000.00	$165,360.57	Drake Well Services Inc.	Initial BIL	23						
30-005-20071	CATO SAN ANDRES UNIT #127	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/12/2023	8/21/2023	$150,000.00	$164,107.41	Drake Well Services Inc.	Initial BIL	9						
30-005-62861	ELIZABETH C #005	269864	[269864] CANYON E & P COMPANY	Private	10/10/2023	10/23/2023	$150,000.00	$164,026.38	Drake Well Services Inc.	Initial BIL	13						
30-005-60604	SEANNA #001	269864	[269864] CANYON E & P COMPANY	Private	10/15/2023	10/23/2023	$150,000.00	$162,302.98	Drake Well Services Inc.	Initial BIL	8						
30-005-61556	TWIN LAKES SAN ANDRES UNIT #110	300825	[300825] BLUE SKY NM, INC.	Private	4/27/2023	5/26/2023	$78,162.00	$161,733.17	Drake Well Services Inc.	Initial BIL	29						
30-005-60905	O'BRIEN FEE 19 #007	269864	[269864] CANYON E & P COMPANY	Private	3/1/2023	4/3/2023	$98,168.00	$160,066.98	Drake Well Services Inc.	Initial BIL	33						
30-005-00349	TWIN LAKES SAN ANDRES UNIT #054	300825	[300825] BLUE SKY NM, INC.	Private	5/9/2023	6/20/2023	$208,258.00	$159,419.71	Drake Well Services Inc.	Initial BIL	42						
30-025-36464	SHELLY 36 STATE #006	372878	[372878] LEASE HOLDERS ACQUISITIONS, INCORPORA	State	1/27/2023	2/6/2023	$195,200.00	$158,417.39	A-Plus P&A LLC	REC	10						
30-015-00948	ARTESIA METEX UNIT #039	269864	[269864] CANYON E & P COMPANY	State	5/23/2023	6/2/2023	$82,000.00	$156,922.40	A-Plus P&A LLC	Initial BIL	10						
30-005-20236	CATO SAN ANDRES UNIT #068	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/27/2023	6/8/2023	$85,446.00	$153,396.09	Drake Well Services Inc.	Initial BIL	12						
30-015-27635	BIG EDDY UNIT #127	154303	[154303] PRIMAL ENERGY CORPORATION	State	2/27/2023	3/9/2023	$131,200.00	$151,867.35	A-Plus P&A LLC	Initial BIL	10						
30-005-28017	CATO SAN ANDRES UNIT #574	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/18/2024	9/24/2023	$150,000.00	$150,495.66	Drake Well Services Inc.	Initial BIL	-360						
30-005-20010	CATO SAN ANDRES UNIT #101	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/14/2023	6/29/2023	$89,100.00	$147,885.53	Drake Well Services Inc.	Initial BIL	15						
30-025-28841	MIKE #003	373817	[373817] Energy Acumen LLC	Private	1/9/2024	1/22/2024	$138,905.05	$147,724.34	A-Plus P&A LLC	REC	13						
30-005-29027	CATO SAN ANDRES UNIT #588	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/23/2023	10/12/2023	$150,000.00	$145,248.01	Drake Well Services Inc.	Initial BIL	19						
30-025-27211	LANSFORD #001	373817	[373817] Energy Acumen LLC	Private	12/16/2023	1/17/2024	$139,019.99	$145,075.74	Drake Well Services Inc.	REC	32						
30-025-36383	ALVES #004	373817	[373817] Energy Acumen LLC	Private	12/11/2023	12/20/2023	$139,111.26	$144,820.79	Drake Well Services Inc.	REC	9						
30-025-36826	ROBERT #002	373817	[373817] Energy Acumen LLC	Private	1/23/2024	1/28/2024	$120,010.04	$143,401.02	Drake Well Services Inc.	REC	5						
30-005-60610	ELIZABETH #001	269864	[269864] CANYON E & P COMPANY	Private	9/27/2023	10/12/2023	$150,000.00	$139,665.44	Drake Well Services Inc.	Initial BIL	15						
30-005-61267	NANCY #001	269864	[269864] CANYON E & P COMPANY	Private	10/14/2023	10/23/2023	$150,000.00	$139,665.44	Drake Well Services Inc.	Initial BIL	9						
30-005-60725	O'BRIEN FEE 18 #003	269864	[269864] CANYON E & P COMPANY	Private	1/19/2023	2/6/2023	$78,974.00	$137,556.78	Drake Well Services Inc.	Initial BIL	18						
30-025-06927	PRUITT #001	373817	[373817] Energy Acumen LLC	Private	1/18/2024	1/25/2024	$133,673.70	$137,015.56	Drake Well Services Inc.	REC	7						
30-005-60920	TWIN LAKES SAN ANDRES UNIT #061	300825	[300825] BLUE SKY NM, INC.	Private	5/17/2023	5/26/2023	$78,246.00	$136,781.21	Drake Well Services Inc.	Initial BIL	9						
30-005-60174	DOUBLE L QUEEN UNIT #005	269864	[269864] CANYON E & P COMPANY	State	9/26/2023	10/25/2023	$150,000.00	$135,977.60	A-Plus P&A LLC	Initial BIL	29						
30-005-60164	DOUBLE L QUEEN UNIT #004	269864	[269864] CANYON E & P COMPANY	State	9/25/2023	10/25/2023	$150,000.00	$135,947.96	A-Plus P&A LLC	Initial BIL	30						
30-025-27396	LANSFORD #003	373817	[373817] Energy Acumen LLC	Private	1/4/2024	1/17/2024	$143,484.93	$135,115.27	Drake Well Services Inc.	REC	13						
30-005-60735	SEANNA #003	269864	[269864] CANYON E & P COMPANY	Private	10/19/2023	10/23/2023	$150,000.00	$135,030.44	Drake Well Services Inc.	Initial BIL	4						
30-005-20077	CATO SAN ANDRES UNIT #118	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/24/2023	6/28/2023	$87,420.00	$132,804.89	Drake Well Services Inc.	Initial BIL	4						
30-025-24609	HARRISON #001	154303	[154303] PRIMAL ENERGY CORPORATION	Private	2/7/2023	3/2/2023	$150,060.00	$132,569.07	A-Plus P&A LLC	Initial BIL	23						
30-015-00959	ARTESIA METEX UNIT #045	269864	[269864] CANYON E & P COMPANY	State	6/16/2023	6/28/2023	$82,000.00	$132,493.66	A-Plus P&A LLC	Initial BIL	12						
30-025-24641	JUDY #001	154303	[154303] PRIMAL ENERGY CORPORATION	Private	2/15/2023	2/24/2023	$147,600.00	$130,854.23	A-Plus P&A LLC	Initial BIL	9						
30-025-24749	HARRISON #002	154303	[154303] PRIMAL ENERGY CORPORATION	Private	11/14/2022	1/12/2023	$127,100.00	$130,846.24	A-Plus P&A LLC	Initial BIL	59						
30-005-60655	O'BRIEN FEE 25 #005	269864	[269864] CANYON E & P COMPANY	Private	3/17/2023	4/5/2023	$79,030.00	$129,851.82	Drake Well Services Inc.	Initial BIL	19						
30-005-60634	O'BRIEN DEMING 6 #001	269864	[269864] CANYON E & P COMPANY	Private	3/2/2023	3/6/2023	$78,974.00	$129,142.42	Drake Well Services Inc.	Initial BIL	4						
30-025-29139	MIKE #004	373817	[373817] Energy Acumen LLC	Private	1/22/2024	2/4/2024	$140,458.36	$128,328.19	A-Plus P&A LLC	REC	13						
30-005-00054	Elks #001	214263	[214263] PRE-ONGARD WELL OPERATOR	Private	10/3/2023	10/11/2023	$135,000.00	$127,495.16	Drake Well Services Inc.	REC	8						
30-005-61261	TWIN LAKES SAN ANDRES UNIT #099	300825	[300825] BLUE SKY NM, INC.	Private	4/27/2023	5/2/2023	$78,246.00	$126,143.32	Drake Well Services Inc.	Initial BIL	5						
30-005-60995	TWIN LAKES SAN ANDRES UNIT #078	300825	[300825] BLUE SKY NM, INC.	Private	1/5/2023	1/19/2023	$78,358.00	$125,479.39	Drake Well Services Inc.	Initial BIL	14						
30-005-60146	DOUBLE L QUEEN UNIT #001D	269864	[269864] CANYON E & P COMPANY	State	10/16/2023	11/15/2023	$150,000.00	$124,649.73	A-Plus P&A LLC	Initial BIL	30						
30-025-26812	LANSFORD #004	373817	[373817] Energy Acumen LLC	Private	1/10/2024	1/17/2024	$127,103.60	$122,744.92	Drake Well Services Inc.	REC	7						
30-005-60565	O'BRIEN FEE 19 #002	269864	[269864] CANYON E & P COMPANY	Private	1/24/2023	2/23/2023	$98,168.00	$122,307.30	Drake Well Services Inc.	Initial BIL	30						
30-005-60097	DOUBLE L QUEEN UNIT #006	269864	[269864] CANYON E & P COMPANY	State	10/5/2023	10/26/2023	$150,000.00	$121,721.73	A-Plus P&A LLC	Initial BIL	21						
30-005-27983	CATO SAN ANDRES UNIT #535	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/27/2023	9/2/2023	$150,000.00	$121,283.68	Drake Well Services Inc.	Initial BIL	6						
30-005-20332	DOUBLE L QUEEN UNIT #001P	269864	[269864] CANYON E & P COMPANY	Private	9/18/2023	10/18/2023	$150,000.00	$120,920.59	A-Plus P&A LLC	Initial BIL	30						
30-015-02142	ARTESIA METEX UNIT #043	269864	[269864] CANYON E & P COMPANY	State	6/20/2023	6/27/2023	$94,300.00	$119,337.31	A-Plus P&A LLC	Initial BIL	7						
30-005-60084	DOUBLE L QUEEN UNIT #001Y	269864	[269864] CANYON E & P COMPANY	State	11/27/2023	12/7/2023	$150,000.00	$118,708.55	A-Plus P&A LLC	Initial BIL	10						
30-005-29028	CATO SAN ANDRES UNIT #822	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/24/2023	10/12/2023	$150,000.00	$117,866.01	Drake Well Services Inc.	Initial BIL	18						
30-005-60117	DOUBLE L QUEEN UNIT #001R	269864	[269864] CANYON E & P COMPANY	State	11/27/2023	12/12/2023	$150,000.00	$115,772.09	A-Plus P&A LLC	REC	15						
30-005-60127	DOUBLE L QUEEN UNIT #001H	269864	[269864] CANYON E & P COMPANY	State	10/30/2023	11/7/2023	$150,000.00	$115,614.62	A-Plus P&A LLC	Initial BIL	8						
30-005-29024	CATO SAN ANDRES UNIT #587	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/21/2023	9/24/2023	$150,000.00	$114,799.56	Drake Well Services Inc.	Initial BIL	34						
30-005-20984	DOUBLE L QUEEN UNIT #005Q	269864	[269864] CANYON E & P COMPANY	Private	8/24/2023	10/5/2023	$150,000.00	$108,931.64	A-Plus P&A LLC	Initial BIL	42						
30-005-60080	DOUBLE L QUEEN UNIT #004G	269864	[269864] CANYON E & P COMPANY	State	8/17/2023	9/18/2023	$150,000.00	$108,724.33	A-Plus P&A LLC	Initial BIL	32						
30-005-28029	CATO SAN ANDRES UNIT #561	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/16/2023	9/20/2023	$150,000.00	$108,589.89	Drake Well Services Inc.	Initial BIL	4						
30-005-10586	CATO SAN ANDRES UNIT #069	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/9/2023	6/15/2023	$89,184.00	$106,418.09	Drake Well Services Inc.	Initial BIL	6	3605					
30-005-60468	TWIN LAKES SAN ANDRES UNIT #066	300825	[300825] BLUE SKY NM, INC.	Private	4/19/2023	5/3/2023	$77,547.00	$104,896.82	Drake Well Services Inc.	Initial BIL	14						
30-005-60153	DOUBLE L QUEEN UNIT #003Y	269864	[269864] CANYON E & P COMPANY	State	10/16/2023	10/26/2023	$150,000.00	$104,377.24	A-Plus P&A LLC	Initial BIL	10						
30-005-27974	CATO SAN ANDRES UNIT #531	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/21/2023	9/2/2023	$150,000.00	$104,186.39	Drake Well Services Inc.	Initial BIL	12						
30-005-27973	CATO SAN ANDRES UNIT #516	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/15/2023	8/21/2023	$150,000.00	$103,464.72	Drake Well Services Inc.	Initial BIL	6						
30-005-60566	O'BRIEN FEE 19 #003	269864	[269864] CANYON E & P COMPANY	Private	1/17/2023	1/25/2023	$97,923.00	$103,171.04	Drake Well Services Inc.	Initial BIL	8						
30-005-60597	TWIN LAKES SAN ANDRES UNIT #014	300825	[300825] BLUE SKY NM, INC.	Private	5/13/2023	5/26/2023	$78,162.00	$102,179.53	Drake Well Services Inc.	Initial BIL	13						
30-005-20346	DOUBLE L QUEEN UNIT #003L	269864	[269864] CANYON E & P COMPANY	Private	11/8/2023	12/6/2023	$150,000.00	$102,103.87	A-Plus P&A LLC	Initial BIL	28						
30-005-60730	O'BRIEN DEMING 6 #002	269864	[269864] CANYON E & P COMPANY	Private	3/3/2023	3/6/2023	$78,974.00	$101,327.84	Drake Well Services Inc.	Initial BIL	3						
30-005-60069	DOUBLE L QUEEN UNIT #002G	269864	[269864] CANYON E & P COMPANY	State	10/6/2023	11/2/2023	$150,000.00	$100,131.59	A-Plus P&A LLC	Initial BIL	27						
30-005-20337	DOUBLE L QUEEN UNIT #002P	269864	[269864] CANYON E & P COMPANY	Private	9/8/2023	10/19/2023	$150,000.00	$99,591.77	A-Plus P&A LLC	Initial BIL	41						
30-005-27984	CATO SAN ANDRES UNIT #545	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/7/2023	9/12/2023	$150,000.00	$99,512.66	Drake Well Services Inc.	Initial BIL	5						
30-005-61551	Tolmac State #002	330522	[330522] Acacia Operating Company, LLC	State	5/27/2025	6/3/2025	$239,004.00	$99,288.29	JMR	REC	7						
30-005-61021	O'BRIEN FEE 19 #008	269864	[269864] CANYON E & P COMPANY	Private	2/7/2023	2/17/2023	$98,168.00	$99,172.05	Drake Well Services Inc.	Initial BIL	10						
30-005-60923	O'BRIEN FEE 24 #002	269864	[269864] CANYON E & P COMPANY	Private	3/14/2023	3/18/2023	$78,750.00	$98,722.53	Drake Well Services Inc.	Initial BIL	4						
30-005-60803	O'BRIEN FEE 24 #001	269864	[269864] CANYON E & P COMPANY	Private	3/6/2023	3/18/2023	$78,862.00	$97,440.63	Drake Well Services Inc.	Initial BIL	12						
30-005-60581	UNION HAPPY #001	269864	[269864] CANYON E & P COMPANY	Private	10/28/2023	11/15/2023	$150,000.00	$96,791.27	Drake Well Services Inc.	Initial BIL	18						
30-005-60816	O'BRIEN LIGHTCAP 7 #002	269864	[269864] CANYON E & P COMPANY	Private	3/6/2023	3/18/2023	$78,974.00	$96,381.77	Drake Well Services Inc.	Initial BIL	12						
30-005-27964	CATO SAN ANDRES UNIT #532	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/21/2023	9/2/2023	$150,000.00	$96,065.48	Drake Well Services Inc.	Initial BIL	12						
30-005-60902	O'BRIEN FEE 18 #004	269864	[269864] CANYON E & P COMPANY	Private	2/28/2023	3/6/2023	$78,974.00	$95,105.42	Drake Well Services Inc.	Initial BIL	6						
30-005-61135	TWIN LAKES SAN ANDRES UNIT #057	300825	[300825] BLUE SKY NM, INC.	Private	4/18/2023	5/3/2023	$78,246.00	$93,901.73	Drake Well Services Inc.	Initial BIL	15						
30-005-60528	O'BRIEN FEE 19 #001	269864	[269864] CANYON E & P COMPANY	Private	1/24/2023	2/6/2023	$100,373.00	$92,886.29	Drake Well Services Inc.	Initial BIL	13						
30-005-60747	ELIZABETH #004	269864	[269864] CANYON E & P COMPANY	Private	10/7/2023	10/12/2023	$150,000.00	$92,842.93	Drake Well Services Inc.	Initial BIL	5						
30-025-05523	MIKE #002	373817	[373817] Energy Acumen LLC	Private	1/26/2024	2/4/2024	$153,887.25	$92,623.43	A-Plus P&A LLC	REC	9						
30-005-29025	CATO SAN ANDRES UNIT #586	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/21/2023	9/24/2023	$150,000.00	$92,162.82	Drake Well Services Inc.	Initial BIL	3						
30-005-60099	DOUBLE L QUEEN UNIT #007	269864	[269864] CANYON E & P COMPANY	State	10/23/2023	11/15/2023	$150,000.00	$91,343.31	A-Plus P&A LLC	Initial BIL	23						
30-005-27985	CATO SAN ANDRES UNIT #533	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/24/2023	9/2/2023	$150,000.00	$90,943.94	Drake Well Services Inc.	Initial BIL	9						
30-005-60640	O'BRIEN FEE 18 #002	269864	[269864] CANYON E & P COMPANY	Private	3/17/2023	4/5/2023	$78,974.00	$90,591.77	Drake Well Services Inc.	Initial BIL	19						
30-005-20338	DOUBLE L QUEEN UNIT #003Q	269864	[269864] CANYON E & P COMPANY	Private	11/9/2023	11/16/2023	$150,000.00	$90,128.62	A-Plus P&A LLC	REC	7						
30-005-20327	DOUBLE L QUEEN UNIT #001Q	269864	[269864] CANYON E & P COMPANY	Private	9/18/2023	10/18/2023	$150,000.00	$89,618.95	A-Plus P&A LLC	Initial BIL	30						
30-005-60093	DOUBLE L QUEEN UNIT #002X	269864	[269864] CANYON E & P COMPANY	State	12/5/2023	12/12/2023	$150,000.00	$89,502.61	A-Plus P&A LLC	Initial BIL	7						
30-025-27271	LANSFORD #002	373817	[373817] Energy Acumen LLC	Private	12/18/2023	1/17/2024	$143,484.93	$89,429.66	Drake Well Services Inc.	REC	30						
30-005-28027	CATO SAN ANDRES UNIT #520	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/1/2023	9/12/2023	$150,000.00	$88,628.09	Drake Well Services Inc.	Initial BIL	11						
30-005-61105	TWIN LAKES SAN ANDRES UNIT #100	300825	[300825] BLUE SKY NM, INC.	Private	4/6/2023	4/20/2023	$79,618.00	$87,618.16	Drake Well Services Inc.	Initial BIL	14						
30-025-28661	MIKE #001	373817	[373817] Energy Acumen LLC	Private	1/19/2024	1/25/2024	$130,108.36	$86,416.72	A-Plus P&A LLC	REC	6						
30-005-27986	CATO SAN ANDRES UNIT #544	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/4/2023	9/12/2023	$150,000.00	$85,423.13	Drake Well Services Inc.	Initial BIL	8						
30-005-27962	CATO SAN ANDRES UNIT #517	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/18/2023	8/29/2023	$150,000.00	$85,086.25	Drake Well Services Inc.	Initial BIL	11						
30-005-28012	CATO SAN ANDRES UNIT #560	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/15/2023	9/20/2023	$150,000.00	$84,151.73	Drake Well Services Inc.	Initial BIL	5						
30-005-28011	CATO SAN ANDRES UNIT #559	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/12/2023	9/14/2023	$150,000.00	$84,145.22	Drake Well Services Inc.	Initial BIL	2						
30-005-27963	CATO SAN ANDRES UNIT #518	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	8/18/2023	8/21/2023	$150,000.00	$82,675.45	Drake Well Services Inc.	Initial BIL	3						
30-005-60159	DOUBLE L QUEEN UNIT #002	269864	[269864] CANYON E & P COMPANY	State	10/25/2023	11/2/2023	$150,000.00	$82,329.64	A-Plus P&A LLC	Initial BIL	8						
30-015-02136	ARTESIA METEX UNIT #041	269864	[269864] CANYON E & P COMPANY	State	6/13/2023	6/15/2023	$82,000.00	$80,024.66	A-Plus P&A LLC	Initial BIL	2						
30-005-60804	O'BRIEN FEE 19 #006	269864	[269864] CANYON E & P COMPANY	Private	2/4/2023	2/7/2023	$98,168.00	$79,557.24	Drake Well Services Inc.	Initial BIL	3						
30-005-60654	O'BRIEN FEE 19 #004	269864	[269864] CANYON E & P COMPANY	Private	1/20/2023	1/25/2023	$97,923.00	$79,475.43	Drake Well Services Inc.	Initial BIL	5						
30-005-61104	TWIN LAKES SAN ANDRES UNIT #107	300825	[300825] BLUE SKY NM, INC.	Private	4/13/2023	4/20/2023	$79,534.00	$79,232.95	Drake Well Services Inc.	Initial BIL	7						
30-005-28010	CATO SAN ANDRES UNIT #558	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/9/2023	9/12/2023	$150,000.00	$79,185.50	Drake Well Services Inc.	Initial BIL	3						
30-005-61107	TWIN LAKES SAN ANDRES UNIT #095	300825	[300825] BLUE SKY NM, INC.	Private	3/22/2023	4/5/2023	$79,758.00	$79,018.03	Drake Well Services Inc.	Initial BIL	14						
30-005-61075	TWIN LAKES SAN ANDRES UNIT #103	300825	[300825] BLUE SKY NM, INC.	Private	3/30/2023	4/5/2023	$78,190.00	$78,610.86	Drake Well Services Inc.	Initial BIL	6						
30-005-61246	O'BRIEN FEE 18 #006	269864	[269864] CANYON E & P COMPANY	Private	2/16/2023	2/23/2023	$98,168.00	$78,097.28	Drake Well Services Inc.	Initial BIL	7						
30-005-61453	TWIN LAKES SAN ANDRES UNIT #111	300825	[300825] BLUE SKY NM, INC.	Private	4/15/2023	4/20/2023	$78,582.00	$78,026.48	Drake Well Services Inc.	Initial BIL	5						
30-005-60619	O'BRIEN FEE 18 #001	269864	[269864] CANYON E & P COMPANY	Private	2/19/2023	2/23/2023	$78,974.00	$76,094.55	Drake Well Services Inc.	Initial BIL	4						
30-005-61604	TWIN LAKES SAN ANDRES UNIT #113	300825	[300825] BLUE SKY NM, INC.	Private	4/16/2023	4/20/2023	$78,358.00	$75,826.57	Drake Well Services Inc.	Initial BIL	4						
30-005-20294	CATO SAN ANDRES UNIT #025	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/26/2022	5/3/2023	$71,699.60	$73,736.31	Drake Well Services Inc.	REC	342						
30-005-28016	CATO SAN ANDRES UNIT #573	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/19/2023	9/24/2023	$150,000.00	$73,170.90	Drake Well Services Inc.	Initial BIL	5						
30-005-60922	O'BRIEN DEMING 13 #001	269864	[269864] CANYON E & P COMPANY	Private	2/22/2023	3/6/2023	$78,862.00	$73,061.42	Drake Well Services Inc.	Initial BIL	12						
30-005-60078	DOUBLE L QUEEN UNIT #001K	269864	[269864] CANYON E & P COMPANY	State	11/6/2023	11/16/2023	$150,000.00	$72,640.91	A-Plus P&A LLC	Initial BIL	10						
30-005-60716	O'BRIEN FEE 19 #005	269864	[269864] CANYON E & P COMPANY	Private	2/2/2023	2/6/2023	$98,413.00	$70,587.02	Drake Well Services Inc.	Initial BIL	4						

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30-005-60161	DOUBLE L QUEEN UNIT #003	269864	[269864] CANYON E & P COMPANY	State	10/31/2023	12/14/2023	$150,000.00	$69,279.31	A-Plus P&A LLC	REC	44
30-005-60079	DOUBLE L QUEEN UNIT #003G	269864	[269864] CANYON E & P COMPANY	State	11/3/2023	11/9/2023	$150,000.00	$69,148.62	A-Plus P&A LLC	REC	6
30-005-61020	O'BRIEN FEE 18 #005	269864	[269864] CANYON E & P COMPANY	Private	2/21/2023	3/6/2023	$98,168.00	$67,764.04	Drake Well Services Inc.	Initial BIL	13
30-005-60151	DOUBLE L QUEEN UNIT #002Z	269864	[269864] CANYON E & P COMPANY	State	11/14/2023	12/7/2023	$150,000.00	$66,862.97	A-Plus P&A LLC	Initial BIL	23
30-005-20334	DOUBLE L QUEEN UNIT #002Q	269864	[269864] CANYON E & P COMPANY	Private	11/14/2023	12/6/2023	$150,000.00	$66,185.54	A-Plus P&A LLC	Initial BIL	22
30-005-60993	TWIN LAKES SAN ANDRES UNIT #081	300825	[300825] BLUE SKY NM, INC.	Private	1/5/2023	1/19/2023	$78,246.00	$65,726.47	Drake Well Services Inc.	Initial BIL	14
30-005-10432	LEWIS NEFF #003	228270	[228270] ROGER SLAYTON DBA ESCUDILLA OIL COMPA	Private	10/12/2023	10/23/2023	$150,000.00	$65,084.49	Drake Well Services Inc.	Initial BIL	11
30-005-29030	CATO SAN ANDRES UNIT #827	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/23/2023	9/27/2023	$150,000.00	$63,667.63	Drake Well Services Inc.	Initial BIL	4
30-005-61334	TWIN LAKES SAN ANDRES UNIT #108	300825	[300825] BLUE SKY NM, INC.	Private	5/10/2023	5/26/2023	$78,526.00	$62,720.90	Drake Well Services Inc.	Initial BIL	16
30-005-60794	TWIN LAKES SAN ANDRES UNIT #086	300825	[300825] BLUE SKY NM, INC.	Private	4/25/2023	5/3/2023	$77,910.00	$62,530.36	Drake Well Services Inc.	Initial BIL	8
30-015-00950	ARTESIA METEX UNIT #038	269864	[269864] CANYON E & P COMPANY	State	5/18/2023	6/28/2023	$79,294.00	$61,949.37	A-Plus P&A LLC	Initial BIL	41
30-005-62068	TWIN LAKES SAN ANDRES UNIT #105	300825	[300825] BLUE SKY NM, INC.	Private	4/3/2023	4/20/2023	$79,282.00	$60,974.74	Drake Well Services Inc.	Initial BIL	17
30-005-62565	TWIN LAKES SAN ANDRES UNIT #015	300825	[300825] BLUE SKY NM, INC.	Private	4/17/2023	4/20/2023	$79,170.00	$53,645.59	Drake Well Services Inc.	Initial BIL	3
30-005-60815	O'BRIEN LIGHTCAP 7 #001	269864	[269864] CANYON E & P COMPANY	Private	3/14/2023	3/18/2023	$78,974.00	$49,875.51	Drake Well Services Inc.	Initial BIL	4
30-005-20009	CATO SAN ANDRES UNIT #052	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	10/12/2023	11/11/2023	$72,696.98	$40,114.82	Drake Well Services Inc.	REC	30

EXHIBIT 15

API #	Well Name	OGRID	OPERATOR	Minerals	PA Rig Up Date	Date Plugged (Date	Wellhead cl	Estimated Plugging Cost	Actual Plugging Cost	Contractor	Funding S	# days to Plug Well	depth	last productio n	$/ft Plugging Cost	time inactive	spud date	age of well at plugging
30-005-20066	CATO SAN ANDRES UNIT #014	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	3/22/2022	12/28/2022		$46,837.94	$70,320.80	Drake Wel	REC	281						
30-005-20142	CATO SAN ANDRES UNIT #013	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	3/28/2022	12/28/2022		$45,301.91	$97,029.76	Drake Wel	REC	275						
30-025-07119	Lawton State #001	214263	[214263] PRE-ONGARD WELL OPERATOR	State	12/1/2022	12/18/2022		$210,286.79	$306,856.92	Drake Wel	REC	17						
30-025-11103	FOWLER HAIR #001	154303	[154303] PRIMAL ENERGY CORPORATION	Private	12/2/2022	12/13/2022		$135,300.00	$170,322.58	A-Plus P&J	Initial BIL	11						
30-005-60563	TWIN LAKES SAN ANDRES UNIT #011	300825	[300825] BLUE SKY NM, INC.	Private	11/16/2022	12/12/2022		$75,424.08	$92,511.63	Drake Wel	REC	26						
30-005-60571	TWIN LAKES SAN ANDRES UNIT #010	300825	[300825] BLUE SKY NM, INC.	Private	11/20/2022	12/12/2022		$75,424.08	$243,104.81	Drake Wel	REC	22						
30-005-60578	TWIN LAKES SAN ANDRES UNIT #012	300825	[300825] BLUE SKY NM, INC.	Private	10/25/2022	11/18/2022		$75,424.08	$320,480.98	Drake Wel	REC	24						
30-025-07968	FOSTER #001	37636	[37636] ROBINSON OIL INC	Private	11/3/2022	11/11/2022		$180,400.00	$184,806.85	A-Plus P&J	Initial BIL	8						
30-005-60768	TWIN LAKES SAN ANDRES UNIT #041	300825	[300825] BLUE SKY NM, INC.	Private	9/27/2022	10/30/2022		$74,253.23	$216,664.53	Drake Wel	REC	33						
30-005-60033	TWIN LAKES SAN ANDRES UNIT #034	300825	[300825] BLUE SKY NM, INC.	State	10/18/2022	10/24/2022		$76,855.11	$70,926.92	Drake Wel	REC	6						
30-005-60572	TWIN LAKES SAN ANDRES UNIT #005	300825	[300825] BLUE SKY NM, INC.	Private	10/13/2022	10/19/2022		$79,847.27	$81,276.96	Drake Wel	REC	6						
30-005-60595	TWIN LAKES SAN ANDRES UNIT #030	300825	[300825] BLUE SKY NM, INC.	Private	9/15/2022	10/19/2022		$74,643.51	$84,192.90	Drake Wel	REC	34						
30-005-60596	TWIN LAKES SAN ANDRES UNIT #006	300825	[300825] BLUE SKY NM, INC.	Private	10/16/2022	10/19/2022		$74,903.70	$88,024.65	Drake Wel	REC	3						
30-005-60697	TWIN LAKES SAN ANDRES UNIT #048	300825	[300825] BLUE SKY NM, INC.	Private	9/18/2022	10/19/2022		$75,383.33	$97,018.69	Drake Wel	REC	31						
30-005-60795	TWIN LAKES SAN ANDRES UNIT #032	300825	[300825] BLUE SKY NM, INC.	Private	9/21/2022	10/19/2022		$74,253.23	$54,964.26	Drake Wel	REC	28						
30-005-10563	CATO SAN ANDRES UNIT #089	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/25/2022	6/30/2022		$72,946.34	$50,455.00	Drake Wel	REC	5						
30-005-10573	CATO SAN ANDRES UNIT #074	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/22/2022	6/30/2022		$72,946.34	$92,424.73	Drake Wel	REC	8						
30-005-10579	CATO SAN ANDRES UNIT #056	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/28/2022	6/30/2022		$72,696.98	$68,891.67	Drake Wel	REC	2						
30-005-10562	CATO SAN ANDRES UNIT #075	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/20/2022	6/22/2022		$72,696.98	$76,548.40	Drake Wel	REC	2						
30-005-10566	CATO SAN ANDRES UNIT #076	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/15/2022	6/17/2022		$72,946.34	$57,194.38	Drake Wel	REC	2						
30-005-10560	CATO SAN ANDRES UNIT #055	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/13/2022	6/15/2022		$72,946.34	$48,854.40	Drake Wel	REC	2						
30-005-10539	CATO SAN ANDRES UNIT #051	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/20/2022	6/13/2022		$72,572.31	$74,686.73	Drake Wel	REC	24						
30-005-10572	CATO SAN ANDRES UNIT #081	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	6/3/2022	6/7/2022		$72,696.98	$49,154.50	Drake Wel	REC	4						
30-005-10504	CATO SAN ANDRES UNIT #020	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/12/2022	6/6/2022		$72,946.34	$95,428.82	Drake Wel	REC	25						
30-005-10523	CATO SAN ANDRES UNIT #023	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/21/2022	6/6/2022		$71,507.10	$59,700.30	Drake Wel	REC	16						
30-005-20088	CATO SAN ANDRES UNIT #090	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/30/2022	6/6/2022		$71,200.91	$82,379.90	Drake Wel	REC	7						
30-005-10503	CATO SAN ANDRES UNIT #028	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/22/2022	6/1/2022		$72,946.34	$69,783.01	Drake Wel	REC	10						
30-005-10455	CATO SAN ANDRES UNIT #049	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/22/2022	5/31/2022		$72,946.34	$68,818.07	Drake Wel	REC	9						
30-005-10491	CATO SAN ANDRES UNIT #027	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/19/2022	5/31/2022		$72,198.30	$84,672.73	Drake Wel	REC	12						
30-005-20069	CATO SAN ANDRES UNIT #021	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/13/2022	5/23/2022		$72,572.31	$69,236.00	Drake Wel	REC	10						
30-005-20293	CATO SAN ANDRES UNIT #053	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/16/2022	5/23/2022		$71,450.25	$73,847.22	Drake Wel	REC	7						
30-005-29021	CATO SAN ANDRES UNIT #050	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/13/2022	5/23/2022		$71,405.25	$66,896.20	Drake Wel	REC	10						
30-005-10500	CATO SAN ANDRES UNIT #058	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/9/2022	5/16/2022		$71,325.58	$70,177.11	Drake Wel	REC	7						
30-005-10578	CATO SAN ANDRES UNIT #047	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/12/2022	5/16/2022		$71,325.58	$72,775.65	Drake Wel	REC	4						
30-005-10570	CATO SAN ANDRES UNIT #059	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/2/2022	5/9/2022		$70,076.24	$56,792.81	Drake Wel	REC	7						
30-005-10571	CATO SAN ANDRES UNIT #060	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/5/2022	5/9/2022		$71,325.58	$52,676.84	Drake Wel	REC	4						
30-005-20130	CATO SAN ANDRES UNIT #045	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	5/2/2022	5/9/2022		$70,452.87	$86,748.04	Drake Wel	REC	7						
30-005-10522	CATO SAN ANDRES UNIT #032	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	4/20/2022	5/2/2022		$71,325.58	$94,127.16	Drake Wel	REC	12						
30-005-10537	CATO SAN ANDRES UNIT #009	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	4/18/2022	5/2/2022		$46,618.51	$45,217.12	Drake Wel	REC	14						
30-005-10538	CATO SAN ANDRES UNIT #046	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	4/27/2022	5/2/2022		$71,699.60	$38,571.76	Drake Wel	REC	5						
30-005-20170	CATO SAN ANDRES UNIT #031	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	4/18/2022	5/2/2022		$70,328.20	$74,929.72	Drake Wel	REC	14						
30-005-20065	CATO SAN ANDRES UNIT #036	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	4/13/2022	4/18/2022		$60,579.92	$42,438.42	Drake Wel	REC	5						
30-005-20160	CATO SAN ANDRES UNIT #008	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	4/13/2022	4/18/2022		$45,301.91	$50,785.52	Drake Wel	REC	5						
30-005-20678	CATO SAN ANDRES UNIT #003	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	4/11/2022	4/18/2022		$50,129.43	$53,471.80	Drake Wel	REC	7						
30-005-20161	CATO SAN ANDRES UNIT #010	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	4/6/2022	4/11/2022		$45,301.91	$61,832.71	Drake Wel	REC	5						
30-005-20046	CATO SAN ANDRES UNIT #035	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	3/8/2022	3/28/2022		$46,837.94	$98,123.80	Drake Wel	REC	20						
30-015-22451	INGALLS #001	7899	[7899] FLARE OIL INC	Private	Missing	3/18/2022		$136,027.68	$150,574.36	Drake Wel	REC	#VALUE!						
30-015-28273	INGALLS #002	7899	[7899] FLARE OIL INC	Private	2/15/2022	3/14/2022		$136,027.68	$189,939.73	Drake Wel	REC	27						
30-005-20932	CATO SAN ANDRES UNIT #002	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	1/5/2022	1/19/2022		$50,458.58	$92,061.04	Drake Wel	REC	14						
30-005-10501	CATO SAN ANDRES UNIT #017	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	12/21/2021	1/18/2022		$46,289.36	$56,800.67	Drake Wel	REC	28						
30-005-10584	CATO SAN ANDRES UNIT #001	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	1/6/2022	1/18/2022		$46,837.94	$73,714.20	Drake Wel	REC	12						
30-005-20049	CATO SAN ANDRES UNIT #063	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	12/18/2021	12/21/2021		$46,179.64	$67,007.07	Drake Wel	REC	3						
30-005-21164	CATO SAN ANDRES UNIT #328	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	12/14/2021	12/21/2021		$48,352.03	$73,923.02	Drake Wel	REC	7						
30-005-21163	CATO SAN ANDRES UNIT #302	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	12/1/2021	12/14/2021		$48,352.03	$75,679.01	Drake Wel	REC	13						
30-005-21165	CATO SAN ANDRES UNIT #330	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	12/8/2021	12/14/2021		$48,352.03	$58,704.26	Drake Wel	REC	6						
30-005-20004	CATO SAN ANDRES UNIT #044	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/23/2021	11/2/2021		$46,618.51	$57,871.94	Drake Wel	REC	40						
30-005-20005	CATO SAN ANDRES UNIT #061	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	10/6/2021	11/2/2021		$46,618.51	$72,381.33	Drake Wel	REC	27						
30-005-20028	CATO SAN ANDRES UNIT #064	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	10/26/2021	11/2/2021		$46,837.94	$76,628.20	Drake Wel	REC	7						
30-005-20047	CATO SAN ANDRES UNIT #041	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/7/2021	9/24/2021		$46,837.94	$83,979.01	Drake Wel	REC	17						
30-005-20089	CATO SAN ANDRES UNIT #042	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	Private	9/15/2021	9/24/2021		$44,972.76	$57,663.66	Drake Wel	REC	9						
30-005-27987	CATO SAN ANDRES UNIT #546	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	6/18/2021	6/23/2021		$32,030.00	$42,759.46	Drake Wel	REC	5						
30-005-27988	CATO SAN ANDRES UNIT #547	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	6/18/2021	6/23/2021		$32,030.00	$40,154.63	Drake Wel	REC	5						
30-005-28022	CATO SAN ANDRES UNIT #507	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	6/15/2021	6/18/2021		$32,030.00	$52,235.00	Drake Wel	REC	3						
30-005-27980	CATO SAN ANDRES UNIT #505	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	6/14/2021	6/17/2021		$32,030.00	$38,592.76	Drake Wel	REC	3						
30-005-27971	CATO SAN ANDRES UNIT #504	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	6/2/2021	6/16/2021		$32,030.00	$34,609.59	Drake Wel	REC	14						
30-005-27981	CATO SAN ANDRES UNIT #506	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	6/10/2021	6/15/2021		$32,030.00	$39,414.25	Drake Wel	REC	5						
30-005-10536	CATO SAN ANDRES UNIT #007	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	5/24/2021	6/1/2021		$33,670.00	$52,453.53	Drake Wel	REC	8						
30-005-20001	CATO SAN ANDRES UNIT #006	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	5/18/2021	5/21/2021		$31,730.00	$51,733.91	Drake Wel	REC	3						
30-005-20271	CATO SAN ANDRES UNIT #005	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	5/12/2021	5/18/2021		$31,730.00	$62,282.16	Drake Wel	REC	6						
30-041-20542	STATE #002	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	5/6/2021	5/12/2021		$31,870.00	$58,373.65	Drake Wel	REC	6						
30-041-20445	STATE #001	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	4/27/2021	5/6/2021		$31,870.00	$92,479.26	Drake Wel	REC	9						
30-005-20022	CATO SAN ANDRES UNIT #093	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	4/21/2021	4/29/2021		$30,970.00	$49,450.30	Drake Wel	REC	8						
30-005-20677	CATO SAN ANDRES UNIT #094	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	4/21/2021	4/28/2021		$32,030.00	$55,541.70	Drake Wel	REC	7						
30-005-20018	CATO SAN ANDRES UNIT #092	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	4/6/2021	4/21/2021		$30,970.00	$60,230.85	Drake Wel	REC	15						
30-005-20023	CATO SAN ANDRES UNIT #095	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	4/8/2021	4/21/2021		$30,970.00	$120,233.81	Drake Wel	REC	13						
30-005-20021	CATO SAN ANDRES UNIT #072	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	4/5/2021	4/8/2021		$30,970.00	$51,160.07	Drake Wel	REC	3						
30-005-20017	CATO SAN ANDRES UNIT #073	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	3/30/2021	4/7/2021		$30,970.00	$49,729.03	Drake Wel	REC	8						
30-005-20020	CATO SAN ANDRES UNIT #071	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	3/25/2021	4/2/2021		$30,970.00	$80,235.46	Drake Wel	REC	8						
30-005-20019	CATO SAN ANDRES UNIT #070	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	3/23/2021	3/26/2021		$30,970.00	$44,462.65	Drake Wel	REC	3						
30-005-20035	CATO SAN ANDRES UNIT #124	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	3/10/2021	3/23/2021		$30,970.00	$108,889.47	Drake Wel	REC	13						
30-005-20041	CATO SAN ANDRES UNIT #121	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	2/20/2021	3/12/2021		$30,970.00	$111,495.02	Drake Wel	REC	20						
30-005-20042	CATO SAN ANDRES UNIT #123	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	2/20/2021	3/12/2021		$30,970.00	$85,442.96	Drake Wel	REC	20						
30-005-20032	CATO SAN ANDRES UNIT #103	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	2/2/2021	3/5/2021		$30,970.00	$43,239.95	Drake Wel	REC	31						
30-005-20002	CATO SAN ANDRES UNIT #096	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	2/24/2021	2/26/2021		$30,970.00	$51,353.46	Drake Wel	REC	2						
30-005-20033	CATO SAN ANDRES UNIT #105	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	2/10/2021	2/26/2021		$30,970.00	$50,758.82	Drake Wel	REC	16						
30-005-20039	CATO SAN ANDRES UNIT #102	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	2/20/2021	2/26/2021		$30,970.00	$61,187.48	Drake Wel	REC	6						
30-005-21167	CATO SAN ANDRES UNIT #355	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	2/9/2021	2/20/2021		$32,030.00	$56,485.02	Drake Wel	REC	11						
30-005-20034	CATO SAN ANDRES UNIT #122	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	2/4/2021	2/10/2021		$30,970.00	$47,959.26	Drake Wel	REC	6						
30-005-20040	CATO SAN ANDRES UNIT #104	248802	[248802] CANO PETRO OF NEW MEXICO, INC.	State	2/2/2021	2/10/2021		$30,970.00	$41,971.53	Drake Wel	REC	8						
30-025-38561	Eumont State #001	294619	[294619] M&M Energy, LLC	State				$205,204.00		Drake	REC	0						

EXHIBIT 15

API #	Column1	Current OC	Current Ov	Date Plugged (Date Wellhead cut off)	Actual Plugging Cost	Measured Depth	True Vertical Depth	$Plugging /Ft MD	Last Production	Spud Date	Age at Plugging (Years)	Inactive Time (Years)
30-005-10567	CATO SAN ANDRES UNIT #097	248802	[248802] C	8/28/2023	207,466.58	3600	3600	$57.63	6/1/2009	11/26/1966	56	14.24
30-005-10586	CATO SAN ANDRES UNIT #069	248802	[248802] C	6/15/2023	106,418.09	3605	3605	$29.52	7/1/2016	12/28/1966	56	6.95
30-005-20010	CATO SAN ANDRES UNIT #101	248802	[248802] C	6/29/2023	147,885.53	3488	3488	$42.40	7/1/2011	1/10/1967	56	12.00
30-005-20071	CATO SAN ANDRES UNIT #127	248802	[248802] C	8/21/2023	164,107.41	3700	3700	$44.35	7/1/2011	5/13/1967	56	12.14
30-005-20077	CATO SAN ANDRES UNIT #118	248802	[248802] C	6/28/2023	132,804.89	3650	3650	$36.38	11/1/2014	5/28/1967	56	8.66
30-005-20236	CATO SAN ANDRES UNIT #068	248802	[248802] C	6/8/2023	153,396.09	3450	3450	$44.46	7/1/2016	2/25/1968	55	6.93
30-005-20294	CATO SAN ANDRES UNIT #025	248802	[248802] C	5/3/2023	73,736.31	3642	3642	$20.25	7/1/2011	6/10/1969	53	11.84
30-005-27962	CATO SAN ANDRES UNIT #517	248802	[248802] C	8/29/2023	85,086.25	4015	4015	$21.19	8/1/2016	11/19/2007	15	7.07
30-005-27963	CATO SAN ANDRES UNIT #518	248802	[248802] C	8/21/2023	82,675.45	4081	4081	$20.26	8/1/2016	12/7/2007	15	7.05
30-005-27964	CATO SAN ANDRES UNIT #532	248802	[248802] C	9/2/2023	96,065.48	4062	4062	$23.65	8/1/2016	12/28/2007	15	7.09
30-005-27973	CATO SAN ANDRES UNIT #516	248802	[248802] C	8/21/2023	103,464.72	4006	4006	$25.83	5/1/2015	12/16/2007	15	8.31
30-005-27974	CATO SAN ANDRES UNIT #531	248802	[248802] C	9/2/2023	104,186.39	4030	4030	$25.85	8/1/2016	12/28/2007	15	7.09
30-005-27983	CATO SAN ANDRES UNIT #535	248802	[248802] C	9/2/2023	121,283.68	4020	4020	$30.17	1/1/2018	1/5/2008	15	5.67
30-005-27984	CATO SAN ANDRES UNIT #545	248802	[248802] C	9/12/2023	99,512.66	3990	3990	$24.94	12/1/2016	1/8/2008	15	6.78
30-005-27985	CATO SAN ANDRES UNIT #533	248802	[248802] C	9/2/2023	90,943.94	4005	4005	$22.71	3/1/2018	1/13/2008	15	5.51
30-005-27986	CATO SAN ANDRES UNIT #544	248802	[248802] C	9/12/2023	85,423.13	3940	3940	$21.68	9/1/2017	2/6/2008	15	6.03
30-005-28010	CATO SAN ANDRES UNIT #558	248802	[248802] C	9/12/2023	79,185.50	3960	3960	$20.00	11/1/2014	2/19/2008	15	8.86
30-005-28011	CATO SAN ANDRES UNIT #559	248802	[248802] C	9/14/2023	84,145.22	3960	3960	$21.25	11/1/2014	2/8/2008	15	8.87
30-005-28012	CATO SAN ANDRES UNIT #560	248802	[248802] C	9/20/2023	84,151.73	4000	4000	$21.04	11/1/2014	3/11/2008	15	8.89
30-005-28016	CATO SAN ANDRES UNIT #573	248802	[248802] C	9/24/2023	73,170.90	4010	4010	$18.25	2/1/2018	4/9/2008	15	5.64
30-005-28017	CATO SAN ANDRES UNIT #574	248802	[248802] C	9/24/2023	150,495.66	4045	4045	$37.21	12/1/2016	4/15/2008	15	6.81
30-005-28027	CATO SAN ANDRES UNIT #520	248802	[248802] C	9/12/2023	88,628.09	4500	4500	$19.70	1/1/2012	7/20/2008	15	11.70
30-005-28029	CATO SAN ANDRES UNIT #561	248802	[248802] C	9/20/2023	108,589.89	4100	4100	$26.49	4/1/2015	10/22/2008	14	8.47
30-005-29024	CATO SAN ANDRES UNIT #587	248802	[248802] C	9/24/2023	114,799.56	3995	3995	$28.74	8/1/2016	5/6/2008	15	7.15
30-005-29025	CATO SAN ANDRES UNIT #586	248802	[248802] C	9/24/2023	92,162.82	3995	3995	$23.07	1/1/2017	4/23/2008	15	6.73
30-005-29027	CATO SAN ANDRES UNIT #588	248802	[248802] C	10/12/2023	145,248.01	4050	4050	$35.86	12/1/2017	7/10/2008	15	5.86
30-005-29028	CATO SAN ANDRES UNIT #822	248802	[248802] C	10/12/2023	117,866.01	4000	4000	$29.47	3/1/2018	8/10/2008	15	5.62
30-005-29030	CATO SAN ANDRES UNIT #827	248802	[248802] C	9/27/2023	63,667.63	1155	1155	$55.12	10/8/2008	10/8/2008	14	14.97

EXHIBIT 15

API #	Well Name	Current OGRID	Current Owner	Date Plugged (Date Wellhead cut off)	Actual Plugging Cost	Measured Depth	True Vertical Depth	$Plugging /Ft MD	Last Production	Spud Date	Age at Plugging (Years)	Inactive Time (Years)
30-005-60	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	1/19/2023	$65,726.47	2880	2880	$22.82	5/1/2012	6/20/1981	41	10.72
30-005-60	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	1/19/2023	$125,479.39	2825	2825	$44.42	6/1/2012	6/29/1981	41	10.63
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	4/5/2023	$78,610.86	2840	2840	$27.68	6/1/2012	8/9/1981	41	10.84
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	4/5/2023	$79,018.03	2840	2840	$27.82	6/1/2012	9/5/1981	41	10.84
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	4/20/2023	$79,232.95	2840	2840	$27.90	2/1/2012	9/1/1981	41	11.21
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	4/20/2023	$87,618.16	2780	2780	$31.52	6/1/2012	9/2/1981	41	10.88
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	4/20/2023	$78,026.48	2781	2781	$28.06	2/1/2012	3/16/1982	41	11.21
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	4/20/2023	$75,826.57	2793	2793	$27.15	10/1/2011	5/20/1982	40	11.55
30-005-62	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	4/20/2023	$60,974.74	2726	2726	$22.37	2/1/2012	11/27/1983	39	11.21
30-005-62	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	4/20/2023	$53,645.59	2907	2907	$18.45	2/1/2012	12/6/1987	35	11.21
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	5/2/2023	$126,143.32	2710	2710	$46.55	5/1/2011	12/20/1981	41	12.00
30-005-60	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	5/3/2023	$104,896.82	2615	2615	$40.11	6/1/2011	2/8/1978	45	11.92
30-005-60	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	5/3/2023	$62,530.36	2800	2800	$22.33	6/1/2012	10/28/1980	42	10.92
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	5/3/2023	$93,901.73	2770	2770	$33.90	6/1/2012	9/30/1981	41	10.92
30-005-60	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	5/26/2023	$102,179.53	2875	2875	$35.54	10/1/2011	1/22/1980	43	11.65
30-005-60	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	5/26/2023	$136,781.21	2960	2960	$46.21	6/1/2012	3/23/1981	42	10.98
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	5/26/2023	$62,720.90	2775	2775	$22.60	5/1/2011	1/21/1982	41	12.07
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	5/26/2023	$161,733.17	2750	2750	$58.81	11/1/2011	6/1/1982	40	11.57
30-005-00	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	6/20/2023	$159,419.71	7666	7666	$20.80	2/1/2012	8/14/1950	72	11.38
30-005-61	TWIN LAKES SAN ANDRES UNI	300825	[300825] BLUE SKY NM, INC.	6/20/2023	$197,938.56	2745	2745	$72.11	5/1/2012	9/28/1982	40	11.13

STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

IPANM'S CLOSING ARGUMENT AND PROPOSED FINDINGS AND CONCLUSIONS

The Independent Petroleum Association of New Mexico ("IPANM") submits its Closing Argument, Proposed Findings of Fact, and Conclusions of Law outlining the evidence and authority for the Oil Conservation Commission ("Commission") to reject the Applicants' proposed amendments to 19.15.2, 19.15.5, 19.15.8, 19.15.9, and 19.15.25 ("WELC Changes"). As to some of the proposed rulemaking, if the Commission does not reject making changes, it should also adopt IPANM and NMOGA amendments filed contemporaneously herewith.

I. CLOSING ARGUMENT

This rulemaking has centered on Applicants' use of two proxies—incentive and risk—in the absence of actual quantitative analysis establishing causation or the supposed benefits of the WELC Changes. First, Applicants claim that current financial assurance levels fail to "incentivize" plugging and abandonment of wells in New Mexico by operators, thus causing orphan wells.[1] Second, Applicants assert that low producing wells are more "at risk" of being orphaned by otherwise responsible and prudent operators because those wells generate less revenue and therefore cannot self-pay plugging costs on a single well basis. In fact, Applicants' production threshold has nothing to do with well-economics. Instead, it is justified by the June 2025

[1] *See, e.g.*, Testimony of WELC Expert Dwayne Purvis, Tr. 380:4-381:8 (Oct. 21, 2026) (acknowledging but not examining that other incentives exist for operators to plug wells, like avoiding litigation, maintaining authority to transport oil and gas, and authority to continue operating wells). IPANM citations to the record are illustrative, not exhaustive. The complete evidentiary record is comprised of all party submissions, testimony, and public comment in Case No. 24683.

Legislative Finance Committee Spotlight Report on Orphan Wells ("LFC Report"), which evaluated production averages prior to plugging—**not orphaning**.[2] Further undermining Applicants' theories, testimony from witnesses with real-world industry experience, including WELC's operational expert Thomas Alexander[3] and OCD employee Justin Wrinkle, disproves the concept that operators fund decommissioning costs on an individual well basis. Finally, no testimony or evidence in the record supports the assumption that low producing wells are at a greater risk of becoming orphaned.[4]

Regarding Applicants' incentive theory for increasing financial assurance, Applicants assume, without evidence, that a certain pain-point will motivate operators to P&A wells that otherwise would be orphaned. Applicants presented evidence that various states increased financial assurance requirements over the past 20 or so years and New Mexico did so in 2018. Quite tellingly, despite all these potential data points, not a shred of evidence indicates those reforms decreased the rate wells were orphaned or public expenditures on orphaned wells.[5] None of the operators testifying in the rulemaking identified recouping financial assurance as a factor in deciding when to plug wells. Testimony on the subject recounted operators' delay and difficulty in obtaining releases of financial assurance, exacerbating the "double-bind" to pay out of pocket to plug the very well for which the plugging bonds were provided. Operators and financial surety experts explained to the Commission that the exponential increase in bonding levels in the WELC

[2] WELC Exhibit 4 at 0111, LFC Report at 7, Chart 2 (using Enverus data, of 13,134 wells plugged between 2007-2025, averaged 2 barrels per day); *see also id.* at 0113, LFC Report at 9 (OCD has plugged 967 wells since 2002, about 5%, while operators plugged over 16,000 wells during roughly the same time period).
[3] Testimony of WELC Expert Thomas Alexander,Tr.182:22-183:1 (Oct. 20, 2025) (agreeing that a well does not need to be self-sufficient, such that the production threshold from a single well need not generate sufficient revenue to plug and reclaim that well); *Id.* 183:9-14 (agreeing that an operator can manage P&A budget by applying funds from other sources).
[4] No analysis of OCD Exhibit 17, or why the wells listed on OCD Exhibit 17 Master Orphan well Spreadsheet ("MOSS") became orphaned, presented during written or live testimony. *Cf.* Matthew D. Merrill, *Analysis of the United States Documented Unplugged Orphaned Oil and Gas Well Dataset*, U.S.G.S. Publication (February 17, 2023, revised April 6, 2023), *available at* https:///doi.org/10.3133.dr1167 (last accessed 03/16/2026).
[5] Testimony of WELC Expert Dwayne Purvis, Tr. 385:7-386:10 & 390:5-21 (Oct. 21, 2025) (Applicants did not perform any work to quantify "how the taxpayer [is] going to be protected by this rulemaking.").

Changes removes working capital otherwise available to address decommissioning costs and will drive both operators and surety providers out of the state, creating more orphaned wells.[6]

In trying to prevent orphan wells and reduce risk to the state, the WELC Changes exacerbate the very issue Applicants set out to address.. The WELC Changes will accelerate orphaning of wells while imposing unsustainable costs—detrimental to the State and to the backbone of independent operators that sustain an industry responsible for 70% of the State's General Fund. These costs are neither hyperbolic nor speculative. First, WELC's double-bonding of low producing wells and "high risk" operator wells—combined with complete abandonment of the established tiered bonding framework—increases total financial assurance requirements across all operators by over **$750 million**.[7] No evidence in the record establishes that industry or the surety market could meet that demand or that compliance is feasible or expected. Where OCD already identified 113 Operators with 1,213 state and fee wells long out of compliance, it admits that the same will not comply with increased bonding demands.[8] Moreover, out of the 500-plus operators in New Mexico, 75% of orphan wells are concentrated in just ten known bad actors.[9] Second, the Commission need only look across state lines to comprehend the poor outcomes of bonding reform in Colorado, where regulators now face a quadrupling of orphan wells but are hamstrung by decreasing levels of statewide financial assurance.[10]

[6] Testimony of WELC Expert Dwayne Purvis, Tr. 389:3-14 (Oct. 21, 2026) ("I wrote also that the rulemaking will create pain for some companies…and the orphaning would happen sooner."); *see also id*. at 390:13-21("I have not tried to predict the behavior of every individual company," and that the resulting financial assurance under the WELC changes will result in "much, much less" than the maximum predicted).
[7] OCD Ex. 29, WELC Exs. 40 & 52; *see also* Motion to Reopen, Note 8.
[8] OCD Ex. 33; Hearing Testimony of OCD Deputy Director Brandon Powell, Tr. 129:16-130:24, & 130:25-131:5 (Oct. 27, 2025).
[9] OCD Ex. 17; IPANM Rebuttal Testimony of Jim Winchester at 5:8-12; Winchester, Tr. 28:6-12 (Nov. 3, 2025); IPANM Dem. Ex. 9.
[10] IPANM Trevor Gilstrap, Tr. 167:20-25, 168:1-19 (Nov. 3, 2025); IPANM Direct Written Testimony of Sam Bradley,4:1-9.

Having heard from a wide array of witnesses with both operational and financial expertise, the Commission should reject the WELC Changes which contravene the Commission's "two major duties" under the Oil and Gas Act to prevent waste and protect correlative rights.[11] As demonstrated throughout the record, because of the astronomical increase in bonding and corresponding squeeze on accessible working capital, the WELC changes will lead to one of three outcomes: (1) the premature plugging of viable, active wells where operators cannot comply with FA increases; (2) the accelerated orphaning of low-producing wells, or (3) the production of wells in uneconomic conditions. The latter being the same historical circumstances for which the Oil and Gas Act itself was adopted to address. *See Spindletop, etc.* In sum, the shortsighted WELC Changes introduce an uneconomic and inefficient one-size fits-all bonding approach that punishes responsible operators, ignores future stages of recovery, creates waste, and falls far short of a meaningful response to a 1% issue.[12]

A. THE COMMISSION LACKS STATUTORY AUTHORITY TO REQUIRE BONDS WHICH EXCEED LEGISLATIVE LIMITS

The WELC changes to 19.15.8.9(D), (E) & (F) NMAC exceed the express blanket bonding amount of $250,000 in the financial assurance enabling provision of the New Mexico Oil and Gas Act, NMSA 1978, §§ 70-2-1 to -44 (the "Act"), and legislative direction to consider well characteristics in establishing single well bonding levels. Applicants and OCD argue that the Act provides for unlimited categories of wells which can be stacked and layered relying on Section 70-2-14(A)'s direction that "The oil conservation division shall establish categories of financial

[11] *Santa Fe Explor. Co. v. Oil Conservation Comm'n*, 1992-NMSC-044, ¶ 27, 835 P.2d 819.
[12] *See USGS Orphan Well Report* Figure 4*;* (analyzing the rate of orphaning wells across six decades, and finding the range to at 0.8%-2%, peaking in the 1980s following the nationwide oil and gas shortage, but steadily decreasing in the decades since); *see also* Federal Orphan Well Program Legislative Report (November 2025) (citing that USGS has created methodology to analyze and predict orphan wells, not yet released); see Testimony of Representative Mark Murphy, Tr.194:3-6 (Nov. 4, 2025) (commenting on historical abandonment rate of industry); *Compare* OCD Exhibit 17 (approximately 1,700 orphan wells) *to* OCD Permitting, "Well Search", https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Data/Wells.aspx (last accessed 03/30/2026) (showing 123,481 total wells of record in the state, including plugged wells, equating to 1.4%) .

assurance after notice and hearing." Section 70-2-14(A) authorizes three forms of financial assurance: (1) a blanket bond for active wells, (2) a blanket bond for wells in temporary abandoned status greater than two years, and (3) a single well bond linked to the costs of plugging the subject well. In no prior circumstances would these categories overlap: an active well is eligible for either blanket or single well bonding, with an inactive well in temporary abandoned status remaining eligible for a TA blanket bond or a single well bond. Applicants and OCD propose the Commission add new categories of financial assurance for low producing wells and for high-risk operator wells, which are otherwise covered by the active blanket well bond under NMAC 19.15.8.9(B), leading to double-bonding which far exceeds existing financial assurance requirements. *See* WELC Ex.89-C , 19.15.8.9(D)&(E). Further, Applicants propose that all single well bonds, for active, low-producing, and TA wells be set at $150,000 rather than evaluated under any of the factors required by Section 70-2-14(A).[13] There is simply no room under the authority granted by the Act or under Section 70-2-14(A) to effect such sweeping policy changes and concomitant economic results by regulation alone.

The Legislature has considered and rendered policy decisions on financial assurance and reclamation funding. on four occasions in the past decade. Each new category or increase has been expressly authorized. In 2015, the Legislature amended Section 70-2-14(A) to create a specific category for "temporarily abandoned status wells" and to authorize blanket bonding for those wells in amounts exceeding $50,000.[14] In 2018, under Senate Bill 189, the Legislature approved an increase of the blanket plugging bond from $50,000 to $250,000,[15] and revisited FA again in

[13] WELC Ex.89-C , 19.15.8.9(B), (D) & (F).
[14] *See* Laws 2015, ch. 99, § 1 Laws 2015, ch. 79, § 1, https://nmonesource.com/nmos/nmsl/en/item/4457/index.do#c79s1, last accessed September 8, 2025; *see also* OCC Case No. 15314, Order R-13996.
[15] *See* Laws 2018, ch. 16, § 2, available at: https://nmonesource.com/nmos/nmsl/en/item/4477/index.do#c16s2, last accessed September 8, 2025, codified NMSA 1978, §70-2-14(A) (2019); *see also* OCC Case No. 16078.

2024.[16] In the Commission rulemaking which followed SB189 and in the committee debates on House Bill 133, representatives and commissioners were especially sensitive to the adverse economic consequences to the state and to smaller, independent operators created by increased financial assurance levels.[17] For example, under the bonding reforms proposed in HB133, the LFC Fiscal Impact Report estimated an $800 million decrease in revenue to the state, which was admittedly underreported in being limited to future permitted wells.[18] As of March 9, 2026, the Legislature and the Governor approved changes to the Reclamation Fund which will yield $1 billion in funds available for plugging, reclamation and remediation.[19] Thus, the Legislature has demonstrated that when it intends to authorize new categories of financial assurance or increased funding to the Reclamation Fund, it does so expressly.[20] There is no such direction to the Commission here.

Moreover, stripping the active well blanket plugging bond of meaning or effect controverts decades of agency and industry interpretation, understanding, and custom. *See High Ridge Hinkle Joint Venture v. City of Albuquerque,* 1994-NMCA-139, ¶ 45, 888 P.2d 475, 488 ("Courts generally show little deference to an agency's interpretation of its own statute when the interpretation is an unexplained reversal of a previous interpretation or consistent

[16] *See* Legislation Listing "HB133", New Mexico Legislature, available at: https://www.nmlegis.gov/Legislation/Legislation?Chamber=H&LegType=B&LegNo=133&year=24, last accessed September 8, 2025.
[17] *See*, *e.g.*, Case No. 16078, Tr. 16:19-17:25 (July 20, 2018) (noting "quandary" Commission faced in balancing the right of small operators, the "backbone" of New Mexico production and a critical industry component with increasing bonding levels), *see also id.*, Tr. 27:24-25:3 (expressing concern that increasing bonding levels could orphan more wells); 43:19-25 (increasing bonds to put operators out of business compounds the problem); *and id.*, Tr. 50:4-10 (acknowledging outer limit of rule change to $250,000).
[18] *See* IPANM Ex. 41, HB 133, LFC FIR at 3, 4 ("If this legislation negatively impacts production from already permitted wells, the financial costs estimated on page one could increase significantly and commence earlier than indicated.").
[19] *See* HB 80, Laws 2026, ch. 60, §§ 1-2 (to be codified at NMSA 1978, § 7-1-6.21 & 70-2-37).
[20] *See also* History of Amendments to the Oil and Gas Act, discussed in *Joint Reply in Support of Dismissal*, Exhibit A (from enactment, a $10,000 per well plugging bond under Laws of 1935, Ch. 72, Section 10, codified at NMSA 1935, § 97-8101; 1977 amendment introduced blanket plugging bond, single well bond tied to reasonable cost of plugging the well, and "in addition to the blanket plugging bond," a one-well bond on well in TA status more than 2 years; NMSA 1954, § 65-3-1.2 (1977)).

practice….[which] raises genuine doubts regarding whether the Council decision reflected an interpretation…as opposed to a policy decision").

Separately, Applicants' proposal to impose a flat $150,000 single well bond disregards Section 70-2-14(A)'s express directive that financial assurance amounts account for factors such as well depth, production history, and comparable plugging costs to "reasonably pay the cost of plugging the well." NMSA 1978, §70-2-14(A). The WELC Changes one-size-fits-all approach that departs from the statute and precedent falls outside the boundaries of the Commission's jurisdiction. Where the Act requires that one-well plugging bonds be tied to the characteristics of the well, New Mexico is not alone. Nearly every other oil or gas producing state links single-well financial assurance and well characteristics.[21]

Under the rules of statutory interpretation and construction followed by New Mexico Courts, for which agency determinations are afforded little deference, if any,[22] the first principle is to discern and effectuate legislative intent, aided by the canons of construction for plain language, ordinary meaning, and to give effect to every provision. *PRC,* 2007-NMSC-053, ¶ 20. Here the Commission should, considering the history and background of the Act, Section 70-2-14 and its predecessors, seek to read "[a]ll parts of a statute…together to ascertain legislative intent, and we are to read the statute in its entirety and construe each part in connection with every other part to produce a harmonious whole," thereby rendering "no part of the statute...surplusage or

[21] *See*, *e.g.*, Al. Admin Code 400-1-1-.01 thru 400-7-1-.23. For the few producing states with single well bonds in a fixed amount consist, see Alaska ($400,000 1-5 wells); Arkansas ($3,000); North Dakota ($50,000); Ohio ($5,000); West Virginia ($5,000). Summary: State Oil and Gas Bonding Requirements, *National Conference of State Legislatures* (Jan. 26, 2022), available at https://www.ncsl.org/energy/state-oil-and-gas-bonding-requirements (last visited 10/3/2025).

[22] *See Marbob Energy Corp. v. New Mexico Oil Conservation Comm'n*, 2009-NMSC-013, ¶ 7, 206 P.3d 135, 139 ("Nothing in the [Oil and Gas] Act requires the Commissioners to be trained in matters of statutory interpretation. Thus, we conclude that statutory construction is not within the Commission's specialized expertise."); *see also Pub. Serv. Co. of N.M. v. N.M. Pub. Util. Comm'n,* 1999–NMSC–040, ¶ 14, 992 P.2d 860 (statutory construction not a matter within agency expertise); *see also New Mexico Indus. Energy Consumers v. PRC*, 2007-NMSC-053, ¶ 19, 168 P.3d 105, 111–12 (court "troubled" by "legal conclusions of Commission staff with respect to matters of statutory construction as well as the Commission's apparent reliance on those legal conclusions").

superfluous." *Amdor v. Grisham*, S-1-SC-40105, ¶ 30, 2025 WL 718840, at *7 (N.M. Mar. 6, 2025) (slip. op.) (quoting *Grisham v. Romero*, 2021-NMSC-009, ¶¶ 23, 27 483 P.3d 545). Where Applicants' proposed bonding changes render the active well blanket plugging bond and its $250,000 cap superfluous, such changes must be rejected. Statutory interpretation requires the same rejection of Applicants' flat $150,000 plugging bond, WELC Ex. 89-C , 19.15.8.9(B), without reference to well depth, production history, or the costs of plugging similar wells.

Finally, IPANM observes that Applicants and OCD contest the interpretation of Section 70-2-14 advanced by IPANM and other industry participants. If the Commission has some view that it may have the power to enact the proposed financial assurance rules, it should decline to do so. This Commission always has followed the Legislature on FA issues, not taken the lead. In the most recent Session, the Legislature created a funding mechanism to generate a billion dollars that will directly flow to the Reclamation Fund. In contrast, whatever bonds are posted if this rulemaking is adopted will only flow to the Reclamation Fund after three contingencies have occurred: the operator orphans the well after securing bonding, the OCD plugs the well, and the OCD successfully redeems the bond.

B. APPLICANTS' PROPOSED CHANGES ARE AN INEFFICIENT FUTURE SOLUTION TO HISTORICAL ENFORCEMENT PRACTICES.

No party contests that industry plugs wells more efficiently, more expediently, and at a much lower cost than OCD. Much of that disparity is attributable to three factors: (1) OCD plugs orphan wells according to an internal scoring system which appropriately prioritizes orphan wells presenting a risk to health and safety,[23] (2) the wells that OCD plugs have been inactive for a much longer period of time, due to enforcement lag and other factors;[24] and (3) required pricing

[23] WELC Ex. 4 at 0147, LFC Report at Appx. E (wells with active leaks, history of integrity defects, and without wellhead control entitled to maximum weight).
[24] *See* OCD Rosa Romero, Tr. 74:3-13; Direct Testimony of Rosa Romero, OCD Ex. 10 at 5:9-18; Testimony of Brandon Powell, Tr. 202:24-25 (Oct. 27, 2025).

procedures and limited plugging contractors drive OCD costs up with little oversight, competition, and cost control.[25] In short, OCD plugging costs are not reflective of amounts "sufficient to reasonably pay the cost of plugging the wells," NMSA 1978, § 70-2-14(A), or "the cost of plugging similar wells." *Id.* Rather than rely on anomalous, outlier OCD costs to calculate financial assurance levels, the reasonable plugging bond should derive from industry costs which represent the costs of plugging 95% of similar wells across the state. Moreover, OCD's poster problem-child well, the Buckskin Federal #002, is "an extreme example of difficult well[] to plug,"[26] and Applicants new FA levels would not apply to the federal well.[27]

This means that Applicants' FA reforms assume an excessively high starting point with respect to 95% of wells.[28] On top of that inflated cost, the WELC Changes also incorporate the

[25] *See* WELC Ex. 4 at 0107, LFC Report, *Key Recommendations* (recommending EMNRD require a "company man" on site for well plugging); *id.* at 0117 (reporting state costs have risen 450% in past 5 years, more than 8 times average oilfield inflation rates, and increase in costs equivalent across emergency and nonemergent plugging); *see also id.* at 0128 ("**OCD struggles to control both the cost and quality of state-contracted plugging.**") (emphasis in original).
[26] OCD Exhibit 6 at 28, OCD Witness Loren Diede Slides; WELC Ex. 4 at 0129, 0117 (plugging the Buckskin Federal #002 cost $5.2 million to plug, which is not excluded from the LFC report of $163,000 average per well plugging costs).
[27] *See* NMAC 19.15.8.9(A) (financial assurance requirement applies to state and fee wells). The Buckskin Federal #002 is also excellent example of OCD enforcement delays and the compounding effect of such delays on plugging costs to the state: As a salt water disposal well, the Buckskin Fed #002 last reported injection volumes in February 2012. While no injection was reported thereafter, the well later failed two mechanical integrity tests in 2014, and the operator's authority was revoked in correspondence dated October 2014 and January 2016. Plugging activities did not commence until July 2024. Under today's rules and statute, NSMA 1978, §70-2-31, the OCD could pursue civil penalties against the Buckskin Federal No. 2 as soon as the well was out of compliance.
[28] Direct Testimony of Robert Arscott, Ph.D., IPANM Technical Expert, *In the Matter of Proposed Amendments to 19.15.2, 19.15.5, 19.15.8, 19.15.9, and 19.15.25 NMAC*, No. 24683, OCC, Aug. 8, 2025, at 2. *See also* Direct Testimony of Daniel Arthur, P.E., NMOGA Technical Expert, *In the Matter of Proposed Amendments to 19.15.2, 19.15.5, 19.15.8, 19.15.9, and 19.15.25 NMAC*, No. 24683, OCC, Aug. 8, 2025, at 29-30 ("One of the problems with the single well financial assurance approach under consideration, and described above by well type affected, is that it bears no relationship to risk or lived experience. It is true that some wells can be expensive to plug and abandon. It is equally true that some wells – in my view, many wells – can be fully plugged and abandoned for far less than $150,000. The Applicants' proposal (and the OCD proposal) does not reflect this fact. In my experience, the cost of plugging and abandoning an oil and gas well can vary enormously. That is why I think a bonding regime should take experience, risk, well characteristics, and other factors into account. I've witnessed many wells that were plugged and abandoned for $20,000 or even less. A shallow vertical well might be plugged and abandoned for even less than $20,000."). *See also* Direct Testimony of Harold McGowen, P.E., NMOGA Technical Expert, *In the Matter of Proposed Amendments to 19.15.2, 19.15.5, 19.15.8, 19.15.9, and 19.15.25 NMAC*, No. 24683, OCC, Aug. 8, 2025, at 85 ("Depth correlates so strongly with cost that any logical bonding regime should take it into account, rather than impose a flat figure."), 91 ("Given the wide variability in plugging costs and the importance of well-specific risk factors, it is far more sensible to adopt a flexible financial assurance scheme rather than a 'one-size-fits-all' $150,000 per-well bond. Regulators should establish bond levels according to the assessed risk and clearly documented

novel economic theory of "holdback" promoted by WELC Expert Mr. Dwayne Purvis.[29] First, holdback relies on the same single-well analysis already discussed and dismissed by WELC, OCD, and industry witnesses. Second, and more importantly, it ignores fundamental economic principles concerning the time value of money.[30] This fundamental omission leads to Mr. Purvis incorrectly identifying when an oil and gas well has "no value."[31] Mr. Purvis's holdback theory has never been peer-reviewed.[32] No state has adopted FA reforms based on the concept of Mr. Purvis' holdback theory.[33] There is good reason why New Mexico should not be the first.

New Mexico is not alone in revisiting or adopting financial assurance regulations in the past decade, especially considering the influx of federal funds made available under the IIJA. Applicants point to four states as exemplars: North Dakota, Texas, Colorado, and Arkansas. But for the Commission to rely blindly on that comparison would be a mistake four times over. WELC witness Peter Morgan testified that FA reforms decreased drilling incidents in North Dakota when bonding levels increased from $10,000 per well to $20,000,[34] but the drilling of new wells is so far removed from the concern Applicants attach to low-producing wells or IPANM's concerns about the WELC Changes as to be irrelevant to this rulemaking.[35] With respect to Texas, identified in the Boomhower Study, the 2001 FA reform introduced the concept of blanket bonds ranging from $25,000 to $250,000, but such effects took place before the Permian Basin horizontal

characteristics of specific well categories within an operator's portfolio, thereby ensuring that required securities correspond to actual potential plugging and abandonment liabilities.").
[29] Testimony of WELC Expert Mr. Dwayne Purvis, Tr. 391:19-20 (Oct. 21, 2025) ("…I'm the sole author of the idea [of holdback] in all contexts.")
[30] Rebuttal Testimony of IPANM Expert Robert Arscott at 1-14.[31] *Compare id*. at 4-5 with Direct Testimony of WELC Expert Dwayne Purvis (WELC Ex. 30) at 28-30.
[31] *Compare id*. at 4-5 with Direct Testimony of WELC Expert Dwayne Purvis (WELC Ex. 30) at 28-30.
[32] Testimony of D. Purvis, Tr. 391:15-392:3 (Oct. 21, 2025).
[33] *Id.* at 392:10-15 (acknowledging that no other state has implemented single-well bonding based on holdback).
[34] Testimony of WELC Expert Peter Morgan, Tr. 683:16-684:7 (Oct. 22, 2025).
[35] *See* Direct Testimony of WELC Expert Peter Morgan, WELC Ex. 15, 34:8-18; Testimony of WELC Expert Peter Morgan, Tr. 683:16-684:7 (Oct. 22, 2025); *Cf.* Murphy, Tr. 147:11-21 & 149:8-20 (Nov. 4, 2025); *see also* Murphy, Tr. 161:23-25 & 163:6-9 (Nov. 4, 2025).

revolution.[36] Neither state imposed additional bonding requirements to marginal or low producing wells. In Colorado, WELC's witness explained that less FA is now required under the rules and that the state has seen an increase in wells formally orphaned by operators.[37] Notably, Colorado provided a much more flexible framework for small operators to remain in compliance through annual fee contributions, and still experienced marked increases in orphan well numbers.[38] Anecdotally, the number of operators in Colorado has shrunk from a diverse field to the consolidation of Colorado wells in just a handful of large operators. To put the magnitude of Colorado's effect on scale here, however, New Mexico produces five times the crude oil and twice the amount of natural gas as Colorado.[39]

Finally, the "full cost bonding" trumpeted by Applicants as adopted in Arkansas actually equates to a $30,000 single well bond on gas wells and only on transfer.[40] Moreover, the existing financial assurance levels in Arkansas range from $3,000 to $100,000,[41] where Applicants' proposals easily put single-operator FA requirements in the millions of dollars. And WELC's operational expert witness, Thomas Alexander, whose experience was most recently with Southwestern Energy in Arkansas, responded that he had "nowhere near those kinds of FA requirements" compared to the WELC Changes.[42] Yet, Mr. Alexander's company was a responsible, prudent operator that exceeded regulations—even without the "incentive" of punitive FA levels.[43] In sum, the analogs proffered by Applicants offer no relevant or helpful comparison

[36] *Id.* at 32:20-33:6
[37] *See* Testimony of WELC Expert witness Adam Peltz, Tr. 845:16-23 & 846:8-10 (Oct. 22, 2026).
[38] *See* Testimony of WELC Expert witness Adam Peltz, Tr. 899:12-19 (Oct. 22, 2026).
[39] U.S. Energy Information Administration, Total Energy Production and Consumption by State, U.S. States, https://www.eia.gov/states/overview, last accessed April 1, 2026; *see also* IPANM Ex. 40, EIA Historical NM Field Production of Crude Oil.
[40] Testimony of WELC Expert Adam Peltz, Tr. 900:25-901:9 (Oct. 22, 2025).
[41] WELC Ex. 4 at 0144, LFC Report at Appx B.
[42] Testimony of WELC Expert Thomas Alexander, Tr. 148:18-149:17 (Oct. 20, 2025).
[43] *Compare* Direct Testimony of WELC Expert Thomas Alexander, WELC Ex. 3 at 006:8-17 ("We [SWN] took our corporate responsibilities very seriously. We were exceedingly careful…to timely plug and abandon, remove surface equipment, and restore locations in order to meet and exceed regulations and expectations… [Our] company-wide motto: 'We don't follow or exceed all regulations because we have to, we follow or exceed them because we want

to the scale and scope of FA increases in the WELC changes, either on a strictly numerical, monetary basis or on overall economic effect to the state as a whole. Only Texas outranks New Mexico in terms of oil and gas production, but oil and gas production in Texas comprises a much smaller fraction of the state budget, state GDP, and share of state and local revenue when compared to New Mexico.

C. THE WELC CHANGES CONTRAVENE THE OIL & GAS ACT AND THE COMMISSION's PRIMARY DUTY TO PREVENT WASTE

New Mexico adopted the 1935 Oil and Gas Act in response to events like the Spindletop field and uncontrolled, overproduction which flooded the market to the tune of $0.04/barrel in 1933, reinforcing the need to conserve oil and gas production to prevent both economic and physical waste. Thus, the Commission was originally created with the fundamental purpose it has now, "the conservation of oil or gas in this State," Laws of 1935, Ch. 72 at Section 4, "...to prevent the waste prohibited by this act." *Id.* at Section 9.[44] WELC's expert witness Thomas Alexander agrees that arbitrary production thresholds may create economic waste.[45] WELC's economic expert, Dwayne Purvis, also acknowledges that adoption of the WELC Changes drastically increasing FA will likely force operators into one of three responses: to prematurely plug or TA well, to increase production to avoid single well bonding, or to orphan the well.[46] Therefore, Applicants' proposed rule changes create waste, and as such, falls outside of the Commission's authority to adopt regulations in support of and to enforce the Act.

The Commission, as a creature of statute, must act strictly within the bounds of its enabling

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to.'"), *and* Alexander, Tr. 44:21-45:2 (Oct. 20, 2025) ("repeatedly involved in process of plugging and abandonment wells in…the Arkoma Basin in Arkansas"), *to id.* at 160:7-12 (explaining how Southwestern Energy left Arkansas and did not plug and abandon their wells, but sold to a smaller operator).

[44] Waste, defined under Section 2, included underground waste resulting from dissipation of reservoir energy or lost recovery, loss of beneficial use of gas, crude, or any petroleum product, and production in excess of reasonable market demand. *See* Laws of 1935, Ch. 72, Section 2(a), (b), & (c).

[45] Testimony of WELC Expert Thomas Alexander, Tr. 156:11-25 (Oct. 20, 2025).

[46] Testimony of WELC Expert Dwayne Purvis, Tr. 386:20-387:3 (Oct. 21, 2025).

legislation. *Sims v. Mechem*, 1963-NMSC-103, ¶11, 382 P.2d 183; *see also Public Serv. Co. of N.M. v. N.M. Env't Improvement Bd.*, 1976–NMCA–039, ¶7, 549 P.2d 638. In *Sims*, the Court emphasized that the Commission "must fully comply with its creating law to possess any jurisdiction in a matter." *Id.* Moreover, upon *de novo* judicial review of statutory construction, adopted rules will only be upheld if in keeping with the agency's express statutory authority or fairly implied as necessary to exercise those same powers. *N.M. Mining Ass'n v. N.M. Mining Comm'n*, 1996–NMCA–098, ¶15, 924 P.2d 741; *see also Marbob*, 2009-NMAC-013, ¶7 (concluding "statutory construction is not within the Commission's specialized expertise" and therefore, not entitled to special deference) (citing *N.M. Indus. Energy Consumers*, 2007-NMSC-053, ¶19, 168 P.3d 105).

The same statute which grants the Commission rulemaking authority also sets the outer bounds of that authority. *Gonzales*, 1990-NMSC-024, ¶11; Rule 1-075(R)(3) NMRA; NMSA 1978, § 70-2-12.2(C)(1). Thus, all rules promulgated by the Commission must serve and promote its twin duties to prevent waste and protect correlative rights. Here, the WELC changes, as acknowledged by their own witnesses,[47] create results which run contrary to the Commission's primary purposes, and the New Mexico Supreme Court has soundly rejected prior attempts by the Commission to ignore those mandates. *Marbob*, 2009-NMSC-013, ¶ 24. As in *Marbob*, the specific bonding language of Section 70-2-14, overrules WELC arguments that the Commission has broad powers to take any action which is "reasonably necessary" to enforce the provisions of the Act. *Id*., ¶¶14–15. The WELC Changes which promote waste and endanger correlative rights must be dismissed as *ultra vires* and outside the scope of the Commission's rulemaking authority. *Unite N.M. v. Oliver*, 2019–NMSC–009, ¶ 8, 438 P.3d 343; *see generally Santa Fe Expl. Co.*, 1992-NMSC-044, ¶¶ 26–27.

[47] The WELC Witnesses who were aware of the statutory charge of the Commission.

Finally, the setting of statewide policy is reserved to the Legislature. *Dona Ana Mut. Domestic Water Consumers Ass'n v. N.M. Pub. Regulation Comm'n*, 2006-NMSC-032, ¶ 7, 139 P.3d 166, 169; *State ex rel. Egolf v. N.M. Publ. Reg. Comm'n*, 2020-NMSC-018, ¶ 33, 476 P.3d 896. Previously, the Legislature paused at the devastating $800 million price tag on prior FA reforms under HB133 and elected to act in this session by allocating more of the Conservation Tax to the Reclamation Fund to address any perceived shortfalls in plugging orphan wells. Where Applicants now seek to alter the scheme expressly set forth in the Act, "any enhancements to the Commission's authority must come from the same legislative body that created the Commission in the first instance." *Marbob*, 2009-NMSC-013, ¶ 23.

D. CONCLUSION

On a general basis, most of the remaining regulations proposed increase regulatory burden on industry and the OCD. OCD is staffed by good people who take their jobs seriously. However, this hearing made clear that OCD is unable to fulfill its current duties. Despite public statements to the contrary prior to the hearing, OCD contended that redeeming bonds posted by operators are relatively easy to redeem after OCD plugs an orphaned well. However, in the five fiscal years prior to the hearing OCD barely ever redeemed a bond after plugging an orphan well. It was not until industry submitted its direct testimony pointing out the huge increases in FA were a pointless burden given OCD's historic failure to redeem bonds that OCD sent out letters to a few sureties concerning three of the repeat offenders on the Master Orphan Well Spreadsheet. Thus, even if Applicants and the Division satisfy their burden that portions of the WELC Changes are desirable policy, this Commission must ask whether meaningful enforcement of those WELC Changes is first feasible and at what cost to other Division duties, especially the ramping up that the Division will have to perform in order to be a good steward of the burgeoning Reclamation Fund..

II. PROPOSED FINDINGS OF FACT

A. Definitions under WELC Ex. 89-A ; NMAC 19.15.2.7

FOF 1. WELC seeks to combine definitions of approved temporary abandonment and temporary abandonment into a single definition. WELC Ex. 89-A at 19.15.2.7(A)(13); Ex. 89-A at 19.15.2.7.T(3).

FOF 2. Allison Marks, Director of Oil, Gas, and Minerals Leasing with the New Mexico State Land Office ("SLO") affirmed t her prior testimony in the 2018 FA rulemaking, Case No. 16078, explaining that the definition of temporary abandonment means inactive wells regardless of approved or expired status, and that "approved temporary abandonment" is a different term.[48]

FOF 3. NMSA 1978, § 70-2-14(A) provides for additional FA, in excess of the statutory cap, only for temporary abandoned wells in that status for more than two years. *Id.*[49]

FOF 4. Low producing well[50] is defined to be an oil or gas well that produces less than 180 days and less than 1,000 barrels of oil equivalent within a consecutive 12 month period. Ex 89-A , at proposed NMAC 19.15.2.7(L)(6).

FOF 5. The proposed definition of low producing well does not contain an express economic evaluation or consider whether the well or the lease is producing in paying quantities. *Id.*[51] The definition contains no exceptions for conditions outside of the operator's control in the

[48] *See* Allison Marks Testimony, Tr. 210:19-211:4 (Oct. 27. 2025) (WELC changes could cause great confusion); *id.* 212:25-213:8; *See* Oct. 20. 2025 Joint Exception to Recommendation at Exhibit A, Case No. 16078, Vol I, Tr. 9:7-13 & 10:18-20 (" 'temporary abandonment' is synonymous with the term 'inactive' [while] 'approved temporary abandoned' and 'approved temporarily abandoned status' is a different term."), ("'Temporary abandonment'…simply means that the well is inactive."); *id.* at 27:14-16 & 29:24-30:3 (explaining again that TA is synonymous with inactive, and operators required to post TA bonding after two years).
[49] *See also* Testimony of Oxy witness Tiffany Wallace, Tr. 24:4-25:7 (Oct. 27, 2025) (statute gives wells in initial TA status 2 years to remain under blanket bond); *Id.* at 25:12-25 (proposal to adjust FA levels with CPI can only apply to inactive wells and wells in TA status *more* than two years).
[50] During the hearing, Applicants proposed (and the parties and witnesses all used) the term "marginal well" to have the regulatory definition now proposed as a definition for low producing well. IPANM uses the term "low producing well" in these Findings but notes that the record citations concerning such wells will use the "marginal" terminology.
[51] Alexander, Tr. 156:22-25 (Oct. 20, 2025); Wrinkle, Tr. 195:4-20 (Oct. 24, 2025).

proposed definition of low producing well, and now only a limited and administratively burdensome waiver exists. *Id.*[52]

FOF 6. OCD agrees that the Commission could adopt a lower number of 700 BOE to be consistent with the LFC report. Powell, Tr. 221:19-222:1 (Oct. 24, 2025).

FOF 7. Under the metrics proposed by Applicants for low producing wells based on 2024 production results, there are 2,200 low producing wells in New Mexico.[53]

FOF 8. WELC concedes that low producing wells contribute $55 million to $1 billion dollars to the state economy on an annual basis.[54]

FOF 9. The LFC Report analyzed production levels of 13,134 wells from 2007-2025 and identified the average production prior to plugging in "recent years" to be "roughly two barrels of oil equivalent (BOE) per day." WELC Ex. 4 at 0111, Chart 2. Production of 2 BOE per day is approximately 730 BOE per year.

FOF 10. Wells can be economical at much lower levels of production than 2 BOE per day, depending on the operator, market conditions, and well performance.[55]

B. Changes to Enforcement and Compliance in WELC Exhibit 89-B, NMAC 19.15.5.9

FOF 11. Applicants propose removing the noncompliance allowance under Part A(4) of 19.15.5.9 NMAC. *See* WELC Exhibit 89-B.

FOF 12. Industry witnesses refer to this change as the "death penalty" provision because removal of the existing allowance is administratively and operationally unworkable.[56]

[52] Alexander, Tr. 135:9-12, 247:3-6 (Oct. 20,2025); Purvis, Tr. 497:4-498:4; McGowen, Tr. 203:3-24 (Oct. 29, 2025); *see also* WELC Ex. 89-C .
[53] OCD Exhibit 16, WELC Exhibit 40
[54] Purvis, Tr. 396:3 & 397:3-16 (Oct.21,2025); *id.* Tr. 442:16-443:5.
[55] Wrinkle, Tr. 195:4-20 (Oct. 24, 2025); Winchester, Tr. 39:2-16 (Nov. 3, 2025); Murphy, Tr. 156:25-157:7 (Nov. 4, 2025).
[56] Winchester, 26:3-8 (Nov. 3, 2025); Arthur, Tr. 178:1-4, 187:14-188:7, 196:7-197:4 (Oct. 28, 2025).

FOF 13. For example, the presence of just one (1) well that is not in compliance with now stricter provisions of 19.15.25.8 NMAC, *see* WELC Ex. 89-E, renders the operator out of compliance as to all wells.

FOF 14. The rule change leads to the scenario where the status of a single well jeopardizes an operator's entire ability and authority to operate remaining wells.

FOF 15. There is no evidence that operators who have few FA violations but are primarily in compliance with FA requirements are likely to orphan wells.

C. FA Reform in Other States

FOF 16. Applicants point to FA reforms in other states like Texas in 2002, North Dakota in 2010, and Arkansas in 2018, where bonding was imposed or increased.[57]

FOF 17. The Texas *Boomhower* study upon which Applicants rely examined the 2002 initial imposition of bonding levels, in which blanket bonds were enforced for the first time ranging from $25,000 to $250,000.[58]

FOF 18. *Boomhower* concluded that the adoption of initial blanket bonds in Texas did not have a material effect on the statewide amount of production.[59]

FOF 19. While the *Boomhower* article reports a slight decrease in orphaned wells, the underlying data is not publicly available, the methodology has not been applied to New Mexico, the article has not been peer reviewed, and Boomhower's conclusion may be discrete to the initial imposition of plugging bonds and not applicable to the increases in existing FA requirements sought by Applicants in this rulemaking.

[57] Peltz, Tr. 845:16-23 & 846:8-10, 899:12-19 (Oct. 22, 2026).
[58] Peltz, Tr. 900:25-901:9 (Oct. 22, 2025); Morgan, Tr. 304:9-10, 683:10-684:12 (Oct. 21, 2025); Purvis, Tr. 516:25-517:17 (Oct. 21, 2025).
[59] *Id.*

FOF 20. In North Dakota, although bonding increases from $10,000 to $20,000 in 2010 did not have a significant effect on production, that change also occurred at the beginning of large-scale development of the Bakken shale obscuring production offsets.[60]

FOF 21. In Arkansas, the increase in FA applied only to low producing gas wells on transfer and was capped at a cost of $30,000 per well, which is not analogous to FA increases proposed by Applicants.[61]

FOF 22. After Colorado implemented FA increases, the number of orphan wells doubled and then quadrupled and the bonding reforms accelerated the orphaning of wells. Peltz, Tr. 871:22-872:5.

FOF 23. Bonding reforms like Applicants' Proposed Rules enacted in California, Alaska, and Colorado led to delays, early abandonment, businesses exiting California and Colorado, increased concerns regarding insolvency of operators and stranded assets, and consolidation of wells and associated risk into fewer operators. Dan Arthur, Tr. 204:4-25 (Oct. 28, 2025).

FOF 24. Prior to his work in this rulemaking, WELC expert Dwayne Purvis performed "analyses" of California, Colorado, Ohio, Pennsylvania, West Virginia, and Wyoming after those states revised their FAs laws or regulations. Purvis Tr. 392: 4-16 (Oct. 21, 2025).

FOF 25. Applicants' intent in proposing $150,000 single well bonding on certain wells is "to provide [FA] to protect the state." Purvis Tr. at 432:21-23 (Oct. 21, 2025).

FOF 26. There is no record evidence that links imposed or increased bonding requirements for oil and gas wells to increased rates of bond recovery to cover any portion of the state's cost for plugging and abandoning wells in the absence of an operator willing and able to do so.

[60]Morgan, Tr. 683:10-684:12 (Oct. 21, 2025)
[61] Peltz, Tr. 900:21-901:9 (Oct. 22, 2025); Alexander, Tr. 149:2-17 (Oct. 20, 2025).

FOF 27. There is no record evidence for states imposing or increasing bonding requirements for oil and gas wells that experienced a net (or any) decrease in public funds used to plug and abandon orphaned wells and Applicants did not attempt to quantify "how the taxpayer [is] going to be protected by this rulemaking." Purvis Tr. :385-386: 10 & 390: 5-21 (Oct. 21, 2025).

FOF 28. There is no record evidence which supports that states increasing bonding requirements on oil and gas wells experienced a lower incidence of wells abandoned by the operator for the state to plug and abandon. Following the Colorado FA rulemaking, orphan well counts increased from 236 to 941 by 2024, and were reported to approach 1,200 orphan wells in 2025. At the same time, statewide FA fell by $4 million almost immediately, with an additional $70 million still to be refunded to larger operators. Orphaned well sites in Colorado increased after the 2022 rulemaking from 500 to 2,000. Direct Testimony of Sam Bradley, 4:1-9.

FOF 29. The Colorado Rulemaking increased financial pressure on operators without reducing or addressing the orphan well problem. Gilstrap, Tr.178:15-25, 179:1-4 (Nov. 3, 2025).

FOF 30. For example, one small operator in Colorado was not able to comply with the revised FA obligations, which led to violations and revocation of operating authority, and as a result 107 wells will become the responsibility of the State of Colorado for plugging and reclamation. Gilstrap, Tr. 179:8-14 (Nov. 3, 2025).

FOF 31. In Utah blanket bonds are a privilege, rather than a right, which is distinct from New Mexico's FA framework under Section 70-2-14. Peltz, Tr. 878:9-14 (Oct. 23, 2025).

FOF 32. New Mexico competes with Texas and Oklahoma, and many operators testified that their costs to bond and to plug are lower in those states. *See*, *e.g.* Nabors, Tr. 111:2-16 & (Nov. 6, 2025), Harvard, Tr. 71:25-72:6 (Nov. 6, 2025); Mitchell, Tr. 180:23-25 & 182:16-183:16 (Oct. 31, 2025); Murphy, Tr. 207:11-16 , 207:9-16 (Nov. 4, 2025).

FOF 33. Reasonable bonding limits consistent with neighboring states ensures that New Mexico remains a competitive market for development. Murphy, 215:23-216:1 (Nov. 4, 2025).

D. Error to Rely on OCD Cost Basis to set FA levels-

FOF 34. Applicants propose increasing one well plugging FA to $150,000 per well, striking all references which correlate plugging FA to well depth WELC Ex. 89-B at Part C(1) of 19.15.8.9 NMAC,

FOF 35. Applicants propose to strike the existing tiered blanket plugging FA, *see* Parts (C)(2)(a)-(d) of NMAC 19.15.8.9, and increase all blanket plugging bonds to the statutory cap of $250,000.

FOF 36. During the 2018 FA Rulemaking, the Commission was cautious to balance increases in FA with effects on operators.[62]

FOF 37. Applicants rely on the LFC Report and OCD plugging costs[63] of an average $163,000 to plug orphan wells as a reliable indicator of the "amount sufficient to reasonably pay the cost of plugging the well" under Section 70-2-14.

FOF 38. Applicants' expert Adam Peltz assisted and advised the LFC in preparing its report, but no input from industry members was sought or permitted by LFC in drafting or issuing the report. *Compare* Peltz, Tr. 857:13-18, *to* Rep. Murphy, Tr.141:22, 142:16-18 & 161:1-3 (Nov. 3, 2025).

FOF 39. Industry is responsible for 95% of the wells plugged every year in the State of New Mexico. Industry plugs wells at a different point than the wells that become orphaned and experience "years and years of neglect" prior to being plugged by OCD. Powell, Tr. 212:7-15 (Oct.

[62] *See* Joint Motion on Recommendation, Exhibits A-C (transcript of Case No. 16078 hearing and deliberations).
[63] *See* OCD Exhibit 17, Master Orphan Well Spreadsheet (portraying costs for about 300 wells plugged by OCD).

24, 2025); Tr. 69:13-17 (Oct. 27, 2025).

FOF 40. Industry single well plugging costs are much lower than OCD's costs and correlate to well depth. Powell, Tr. 211:23-212:6 (Oct. 24, 2025); Mitchell, Tr. 197:19-198:5 (Oct. 31, 2025) (Longfellow plugs wells for about $30,000); Murphy, Tr. 204:3-8 (Nov. 4, 2025) (Strata plugs and reclaims wells at $100,000 to $120,000); Armstrong, Tr. 98:25-99:11 (Nov. 3, 2025) (Armstrong plugged and reclaimed four wells in the past two years at an average cost of $120,000).

FOF 41. Well depth is a significant factor to plugging costs.[64] Applicants did not consider or analyze plugging costs associated with the depth of a marginal wells in relation to their proposed new bonding requirements, which is a fact required for consideration in setting single well bonds under Section 70-2-14(A). Peltz, Tr. 879:11-22 (Oct. 23., 2025).

FOF 42. The LFC Report cites a lack of oversight, quality, and price competition as contributing to OCD rising plugging costs. WELC Ex. 4 at 0128-132. OCD plugging costs have outpaced regular oilfield inflation by a magnitude of eight times, rising 443% in the past five years to $43.85 per foot.. WELC Ex. 4 at 0117 & 0121. OCD plugging costs likely include extreme outliers like the Buckskin Federal No. 2, which cost $5.2 million to plug, which are not reflective of normal plugging operations.[65]

FOF 43. In comparison, Texas plugging costs average $15.60 per foot, and generally range from $6-$20 per foot in FY2024, excluding emergencies as outliers. WELC Ex. 4 at 0121 & 0146; *see also id.* at 0109 (reporting rising incidence of well emergencies).

FOF 44. One of OCD's examples, the Coll No. 1, was plugged in 1953 in accordance with

[64] Arthur, Tr. 187:14 – 188:7(Oct. 28, 2025); Diede, Tr. 107:14-108:4 (Oct. 23, 2025).
[65] *See* OCD Ex. 17 (line 36) Testimony of Loren Diede, Tr.101:24-102:19 (Oct. 23, 2025) (OCD witness unable to say with certainty whether the $5.2 million cost of plugging the Buckskin Federal No. 2 included in costs used to calculate average of $163,000); *id.*, Tr. 92:4-92:14 & 113:9-113:18 (Oct. 23, 2025); Diede, Tr. 113:19-114:3 (Oct. 23, 2025) (anticipating a "high percentage" of wells plugged by OCD experience less difficulty); Arthur, Tr. 201:14-25. (Oct. 28, 2025).

regulations then in place. Applicants' Proposed Rules will not prevent or address scenarios like the Coll No. 1. Diede, Tr. 98:25-99:13 & 100:4-100:9 (Oct. 23, 2025).

FOF 45. Not all orphan wells are alike. Diede, Tr. 97:21-98:6 (Oct. 23, 2025).

FOF 46. Opinions offered by OCD witnesses regarding environmental remediation costs centered on facilities like tank batteries rather than plugging wells, and relied on extreme outlier examples in the millions. This limited sample size prevents an accurate average cost from being determined. Further, where with past invoices demonstrate overbilling, OCD agrees that further inquiry is needed. Romero, Tr. 38:13-40:18, 63:1-7; 64:3-14 (Oct. 24, 2025)

FOF 47. In opining as to the economics of marginal and low-producing wells, OCD witness Justin Wrinkle did not use or compare average P&A costs by operators. Justin Wrinkle, Tr. 180:14-24 (Oct. 24, 2025).

FOF 48. None of Applicants' witnesses have direct experience operating or plugging wells in New Mexico. *See, e.g.*, Peltz, 856:9-22 (Oct. 23, 2025).

FOF 49. Applicants' Proposed Rules do not address reclamation and remediation costs associated with orphaned tank batteries and facilities. WELC Ex. 4 at 0117; WELC Ex. 89-C .

FOF 50. OCD explained the Division's prioritizing of plugging orphan wells with the biggest "surface impact," Powell, Tr. 68:15-18, but FA is linked by statute to plugging, not reclamation or remediation costs. Surface reclamation costs are not indicative or contribute to downhole plugging costs. Powell, Tr. 68:15-18 (Oct. 27, 2025). Remediation costs are outside the scope of Applicants' proposal and the bond required under the Oil and Gas Act. Romero, Tr. 79:611 (Oct. 24, 2025).

E. FA does not prevent or plug orphan wells.

FOF 51. Neither Applicants nor OCD performed a quantitative analysis examining or

determining the cause of abandonment for wells orphaned and listed on OCD Exhibit 17 ("MOSS").

FOF 52. Applicants' witnesses claim that reforming and increasing FA levels will "incentivize" operators to timely plug and abandon wells, thus "prevent" orphan wells.

FOF 53. Ten (10) operators account for 75% of the orphaned wells on OCD's MOSS.[66]

FOF 54. The two operators with the largest numbers of orphan wells, Ridgeway Arizona and Cano Petro, were in compliance with FA requirements prior to bankruptcy.[67]

FOF 55. Without the "incentive" of punitive increases in FA proposed by Applicants, industry already plugs 95% of wells in the state.

FOF 56. FAs are just one incentive for operators to plug wells. Arscott, Tr. 240:17-241:19; Purvis, Tr. 380:4-8.

FOF 57. OCD does not have a demonstrated history of pursuing FA for orphaned wells. Winchester, Tr. 26:10-28:12(Nov. 3, 2025); OCD Reclamation Reports, IPANM Exs. 11-14 & 43. Over the past 7 years, OCD has only collected $249,722, just 1.67% of the division's total plugging costs. Rebuttal Testimony of Jim Winchester, 5:9-10. OCD Annual Reclamation Fund Reports show that the OCD spent $15 million plugging 193 wells from 2019 to 2024, but recovered only $250,000 from FA forfeitures. WELC Peter Morgan, Tr. 534:111 (Oct. 21, 2025). The LFC Report analyzed reclamation fund reports and found that OCD recovered $0 in FA forfeitures in 3 out of 5 years, and had not successfully redeemed any FA since 2018. WELC Ex. 4; Morgan, Tr. 534:1-11 (Oct. 21, 2025).

FOF 58. EMNRD Deputy Secretary Ben Shelton testified before the Legislative Finance Committee in June 2025 that the "juice just wasn't worth the squeeze." Winchester, Tr. 26:10-

[66] Winchester, Tr 29:9-30.5 (Nov. 3, 2025); IPANM Dem. Ex. 9.
[67] OCD Ex. 29, Gilstrap, 190:20-191:8 (Nov. 4, 2025);Winchester, Tr. 34:25-36:3 (Nov. 3, 2025)

28:12 (Nov. 3, 2025)

FOF 59. OCD witnesses testified to the difficulty in pursuing and recovering forfeited FA from surety companies, which can only occur after the costs of plugging have been incurred.[68]

FOF 60. WELC admits that, as a consequence of Applicants' Proposed Rules, more small operators who cannot afford increased bonding requirements will abandon marginal wells, accelerating the amount of orphan wells in New Mexico.[69]

FOF 61. OCD assumes that increased FA levels will "deter undercapitalized operators" because operators who comply with new FA requirements will be better prepared to P&A wells. OCD Witness Rosa Romero, Tr. 60:4-61:9 (Oct. 24, 2025).

FOF 62. When operators acquire well packages with mixed age-assets, wells are evaluated for plugging. Harvard, Tr. 83:13-20 (Nov. 6, 2025) (plugged three wells after acquiring package).

FOF 63. Operators have the best information to judge if a well is economic and the demonstrated preference of operators for wells that have become uneconomic is to plug. Harvard, Tr. 85:16-86:11 & 88:4-15(Nov. 6, 2025); Nabors, Tr. 109:8-24 (Nov. 6, 2025).

FOF 64. Operators generally plan a year or more in advance to budget, allocate capital reserves, and manage cash flows to plug wells. Oxy has an entire department of people dedicated to evaluating lower-producing wells. Wallace, Tr. 123:15-124:12 & 125:3-8 (Oct. 28, 2025); Harvard, Tr. 86:12-20 & 87:7-23(Nov. 6, 2025).

FOF 65. SLO has successfully pursued lessees of record to P&A wells through its accountability and enforcement programs. Allison Marks, Tr. 221:19-222:19 (Oct. 27, 2025).At the time of the hearing, the SLO had required lessees of record to P&A 746 state wells, and that many of those cases are resolved without pursuing a lawsuit. Marks, Tr. 222:1-22 (Oct. 27, 2025).

[68] Powell, Tr. 42:5-22 (Oct. 27, 2025).
[69] Peltz, Tr. 842:13-843:16 (Oct 22, 2025).

FOF 66. OCD does not hold the opinion that Applicants' proposal will result in more or easier recovery of FA, just that ***if*** forfeiture of FA pursued potentially more funds flow into Reclamation Fund. Justin Wrinkle, Tr. 192:310 (Oct. 24, 2025).

FOF 67. OCD does not bond federal or tribal wells, such that Applicants' and OCD's alleged number of affected wells by the Proposed Rules is likely significantly less, because federal and tribal wells are exempted from potential increases in FA. Powell, Tr. 43:16-44:15 (Oct. 27, 2025).

FOF 68. Strata Production Company has operated wells in New Mexico since the 1980s and has plugged 38 wells, and 100% of their own wells. Murphy, Tr. 131:7-8 & 132:21 (Nov. 4, 2025).

FOF 69. At the end of the day, bonds do not plug wells, operators and contractors plug wells, either by industry directly or with industry monies in the Reclamation Fund, or rarely, as forfeited and recovered FA. Murphy, Tr. 132:5-8 & 135:21-22 (Nov. 4, 2025). There was no evidence presented that bonding protects the taxpayer. Increasing bond levels creates hardship only for compliant operators. Winchester, 28:6-12 (Nov. 3, 2025).

FOF 70. Applicants' increases in FA levels will increase the annual premium amounts for some operators in the range of $3-$5million, resulting in more capital spent on maintaining surety bonds, rather than plugging wells. Murphy, 220:8-222:16 (Nov. 4, 2025).

FOF 71. Increasing FA alone will not "prevent" orphan wells. FA potentially offsets OCD's costs if an operator does not plug a bonded well. Armstrong, Tr. 151:7-19 (Nov. 3, 2025).

FOF 72. Bonds do not shift risk, they function as a financial guarantee. But the guarantee is not automatic or comprehensive, typically the state must initiate a claims process after plugging the well which can be time-consuming and uncertain. Gilstrap, 182:2-15 (Nov. 3, 2025).

FOF 73. In the case of a surety bond, the state must first declare the operator in default and then initiate a formal claims process with the surety. The process can involve documentation of non-compliance, negotiation or dispute resolution, legal proceedings if the surety contests the claim. It can take months, years, during which the wells may remain unplugged or the state is out-of-pocket on funds already expended. Gilstrap, 185:14-21 (Nov. 3, 2025).

FOF 74. Increases in bonding amounts can lead to more orphan wells, like in Colorado, because operators who cannot meet new thresholds may walk or go under. Gilstrap, 186:25, 187:1-7 (Nov. 3, 2025).

FOF 75. Comparing OCD Exhibit 17 to OCD Exhibit 29, demonstrates why a surety's evaluation cannot function as a proxy for risk of orphaning: Eight of the top ten operators of orphan wells were able to obtain surety bonds. OCD Ex. 17, OCD Ex. 29, Gilstrap, 190:24-5, 191:1-5 (Nov. 3, 2025).

FOF 76. Annual premiums of $562,000 to $787,000 on a $22.5 million bond are sunk costs that never go to future plugging expenses. Insurance-based products like One-Nexus use premiums to pre-fund plugging costs. Gilstrap, 206:13-19 (Nov. 3, 2025).

FOF 77. Insurance based products also allow an operator to contribute over time to future plugging expenses on a per-barrel rather than lump sum basis, which better protects the state in the event the operator defaults. Gilstrap, 207:4-9 (Nov. 3, 2025).

F. WELC Expert Theory of "HOLDBACK" Should be Disregarded.

FOF 78. No state has adopted Mr. Purvis's holdback methodology as a basis for setting levels of FAs for plugging. Purvis, Tr. 392:4-16.

FOF 79. Applicants' economic rationale for the FAs portion of the rulemaking—Mr. Purvis's holdback methodology of which he is the "sole author"—has never been peer reviewed. Purvis, Tr. 391:15-392:3 (Oct. 21, 2025).

FOF 80. Applicants presented no evidence and performed no analysis to determine the "reduction in ultimate recovery" of oil and gas as a result of the financial burdens imposed on operators by the proposed rulemaking. Purvis, Tr. 445:18-24 & 446:14–447:1.

FOF 81. Applicants did not seek to determine, and there is no record evidence, "whether any potential reduction in ultimate recovery or financial impacts on operators would be offset by any potential economic benefits derived from the increased FA." Purvis, Tr. 447: 7-16.

FOF 82. Applicants performed no analysis and presented no evidence that, given the net reduction in ultimate recovery the proposed rulemaking would create, the rulemaking would prevent waste. Purvis, Tr. 449:13-19.

G. Applicants' Proposed Rules Disproportionately Affect Smaller Operators without Economic Basis.

FOF 83. The costs of the rulemaking will primarily fall on smaller companies. Purvis, Tr. 481:13-25; 484:8-18; WELC Ex. 30 (Purvis) at 44; Peltz, Tr. 834:19-835:1 & 836:23-837:9 (Oct. 22, 2025).

FOF 84. New Mexico's current bonding requirements for Longfellow's 100 wells is already 2.5 times that of its 1,300 Texas wells. David Mitchell, Tr. 182:22-183:16 (Oct. 31, 2025).

FOF 85. Under Applicants' proposed increases, however, Longfellow anticipates bonding to increase by $3.5 million for marginal wells, and around $15 million under the "high risk portfolio" requirement. Mitchell, Tr. 189:23-190:23 (Oct. 31, 2025).

FOF 86. Where total increases in FA anticipated to exceed $15 million, an additional capital expenditure of $15 million would disproportionately affect small operators. Alexander, Tr. 148:18-22; 149:2-10; & 185:1-186:3 (Oct. 20, 2025). Applicants are unable to say how many companies the proposed rulemaking will drive out of business or simply out of New Mexico to

invest and operate elsewhere.[70] Although they admit the proposed rules will drive companies out of business, Applicants' have not introduced data or performed an analysis regarding how many wells or what volume of production might result under implementation of the Proposed Rules. Alexander, Tr. 226:18-227:2 (Oct. 20, 2025). Applicants' changes to FA are "unworkable," Arthur, Tr. 196:7-197:4 (Oct. 28, 2025), and will unnecessarily increase bonding for wells that pose the least risk and are most prevalent, resulting in "driv[ing] business and tax revenue out of the state." *Id.*; *see also id.* at Tr. 199:3-13 (predicting "devastating impact").

FOF 87. Applicants are unable to predict how many wells would be required to bond at $150,000 each, or what the cumulative burden under Applicants' proposed rules would be on operators. Alexander, Tr. 252:4-17 & 226:18-227:2 (Oct. 20, 2025).

FOF 88. A reduction in the production threshold of low producing wells, from 1,000 BOE to 750 BOE, would reduce the impact on production by from 2.3% to 0.6%. Tiffany Wallace, Tr. 48:19-49:15 (Oct. 28, 2025); *see also* WELC Exhibit 52.

FOF 89. Applicants offered no explanation why otherwise active, compliant wells should be bonded at an additional $150,000 under the operator portfolio, especially when 50% of the state's operators will be affected. Peltz, Tr. 35:12-38:18 (Oct. 23, 2025).

FOF 90. Applicants recommend that affected operators just "plug this one," even though prematurely plugging wells will create waste when proceeding to waterflood recovery and later stages of recovery will require drilling additional wells at each production profile in the life of the field. Peltz, Tr. 40:15-41:13 (Oct. 23, 2025).

FOF 91. Oxy anticipates increases in bonding requirements under Applicants' changes for low producing wells by $50 to $60 million, and under the portfolio FA, would be required to pay

[70] Purvis, WELC Ex. 30 at 44, Armstrong, Tr. 105:6-106:18 (Nov. 3, 2025) Hanagan, 215:11-19, 217:16-18 & 221:16-19 (Oct. 31, 2025).

another $22 to $23 million in bonding. Wallace, Tr. 52:17-56:23 (Oct. 28, 2025).

FOF 92. The SLO has proposed a new rule requiring additional bonding on state leases, which could lead to double-bonding on state wells. Allison Marks, Tr. 213:9-214:4 (Oct. 27, 2025).

FOF 93. Because New Mexico plugging bonds are non-cancellable and conditioned on the plugging of the well, funds securing bonds are not available until the well has been plugged, remediated, inspected, and released by OCD. Alexander, Tr. 151:13-24. Non-cancellable bonds magnify the risk of exposure to the surety, tie up more operational capital for operators, and leave less for operations and plugging. NMOGA Emerick, Tr. 121:10-124:3 (Oct. 29, 2025).

FOF 94. Applicants' proposed increases in FA would require the company to reevaluate wells on an economic basis and higher FA levels will consume capital and thereby limit development, workovers, restoration of production, and even plugging plans. Mitchell, Tr. 191:13-192:4 (Oct. 31, 2025); Nabors, Tr. 111:2-16 (Nov. 6, 2025).

FOF 95. Small and medium-sized operators are most likely to experience collateral requirements, which will only increase under FA levels proposed by Applicants. Emerick, Tr. 127:14-127:17 (Oct. 29, 2025); Armstrong. Tr. 105:6-106:18 (Nov. 3, 2025).

FOF 96. Applicants propose that the increased one-well plugging FA of $150,000 is effective immediately as to low producing wells on change of operator or transfer. WELC Ex. 89-C at Part D(1) of 19.15.8.9 NMAC.

FOF 97. Applicants have also proposed changes that require bonding to be in place prior to acquiring wells. WELC Ex. 89-C at Part A of 19.15.8.9 NMAC.

FOF 98. Raising FA amounts on marginal or low producing wells will impact transfers and changes of operators. Dan Arthur, Tr. 192:13-23 (Oct. 28, 2025).

FOF 99. Many smaller operators acquire wells in packages from larger companies that no longer want to operate the wells for a myriad of reasons. Jeff Harvard, Tr. 72:21-74:1 (Nov. 6,

2025); Kyle Armstrong, Tr. 99:12-100:25, 101:1-20, & 110:21-111:25 (Nov. 3, 2025).

FOF 100. While wells in these packages may not be economically viable for larger or "major" companies to operate, independent operators can take over, rework or recomplete the wells, and keep the wells operating and profitable. Harvard, Tr. 72:21-74:1 (Nov. 6, 2025); Armstrong, Tr. 101:1-20 (Nov. 3, 2025).

FOF 101. Purchasers of low producing wells can significantly increase production, increasing revenues in taxes to the State of New Mexico and increasing royalties for interest owners. Harvard, Tr. 74:2-75:8 & 75:9–76:21(Nov. 6, 2025); Armstrong, Tr. 101:1-20 (Nov. 3, 2025). Conversely, the premature plugging of those marginal wells will result in losses of revenue to the State, private mineral owners, and working interests partners in the well. Armstrong, Tr. 104:10-105:5 (Nov. 3, 2025).

FOF 102. Under Applicants' proposed changes, some wells in such packages will require single well bonds prior to acquiring the wells, which will significantly increased the acquisition cost of the package. Mitchell, Tr. 186:5-187:17 (Oct. 31, 2025); Harvard, Tr. 77:19-78:7 (Nov. 6, 2025). Operators report already experiencing a chilling effect on transactions because of Applicants' rulemaking, discouraging buyers from acquiring packages. Arthur, Tr. 212:13-20 (Oct. 27, 2025); McGowen, Tr. 24:5-9 (Oct. 28, 2025); Ezzell, Tr. 50:17-51:1 (Nov. 4, 2025); Hanagan, 216:5-15 (Oct. 31, 2025). Mitchell, Tr. 186:5-187:17 (Oct. 31, 2025).

FOF 103. Applicants' proposed changes to Part A of NMAC 19.15.8.9 would turn the Oil Conservation Division into a "gatekeeper" over oil and gas acquisitions and transactions in the state; leading to increased legal review, delays closing deals, higher overhead for operators, and expanded internal compliance staffing, which will reduce access to capital for small and mid-size operators. Andrea Felix, Tr. 61:5-15 (Oct. 31, 2025); Dan Arthur, Tr. 203:6-204:3 (Oct. 29, 2025).

FOF 104. Applicants' proposed changes to Part A of 19.15.8.9 requiring bonding prior to

acquisition does not adequately address transactions where more than one entity is acquiring a well or package of wells. Dan Arthur, Tr. 56:3-58:1 (Oct. 29, 2025).

FOF 105. Applicants' proposals requiring bonding prior to acquisition or transfer will discourage participation in asset acquisition, farmout agreements, and result in premature plugging because small operators are squeezed out of the picture. Arthur, Tr. 203:6-204:3 (Oct. 29, 2025).

FOF 106. As small operators are eliminated, larger operators are not going to be able to convert low-producing assets because of their larger overhead, which result in viable wells being plugged with recoverable hydrocarbons. Arthur, Tr. 203:6-204:1 (Oct. 29, 2025); Armstrong, Tr. 104:10-105:5 (Nov. 3, 2025).

FOF 107. OCD Deputy Director was surprised that one of the smaller, responsible operators like Merrion Oil & Gas with a high reputation in the industry and community would be adversely affected by the Proposed Rules, an example of an unintended consequence of adopting arbitrary production thresholds. Powell, Tr. 35:12-17. In fact, because Merrion has been diligent in taking care of its low-producing and marginal wells, it has not needed to plug any wells in the past 3-4 years. Powell, Tr. 38:22-39:6 (Oct. 27, 2025).

FOF 108. Increase bonding amounts at that level would likely force Armstrong Energy to stop operating in New Mexico, after almost a half-century of stewardship and prudent, responsible operation. Armstrong, Tr. 105:6-106:18 (Nov. 3, 2025). At a minimum, the impact on cash flow and capital would require Armstrong cut jobs. Tr. 106:19-107:13 (Nov. 3, 2025).

FOF 109. Applicants' Proposed Rules will discourage or eliminate small operators from acquiring marginal wells due to the prohibitive bonding costs, especially with the looming portfolio effect. Armstrong, Tr. 110:21-111:25 (Nov. 3 2025).

FOF 110. WELC Expert Dwayne Purvis' dismissal of the role of small operators, and the impact of those companies on the state and local communities, demonstrates reckless disregard for

the livelihoods of thousands of New Mexicans. Armstrong, Tr. 121:12-122:9.

FOF 111. Smaller and independent operators are responsible for maintaining the infrastructure during down times and remain active in the state when majors exit. Fifteen years ago, at least 7 of the 8 majors had little to presence in New Mexico. Again, in the late 1980s and early 1990s, all the major companies like Chevron and Exxon left New Mexico, and only returned after independent field discoveries introducing the shale boom. Murphy, Tr. 147:11-21 & 149:8-20 (Nov. 4, 2025); *see also* Murphy, Tr. 161:23-25 & 163:6-9 (Nov. 4, 2025) (explaining that the 97% of statewide production would not exist without the small operator discovering the play).

H. Applicants' Ignore that "Low-Producing" Wells have Value and fail to demonstrate that Low-Producing Wells at greater risk of becoming orphan wells.

FOF 112. Applicants' reliance on arbitrary production thresholds to determine beneficial use ignores operational value, regulatory infrastructure-related functions, leasehold maintenance, reservoir management, and environmental compliance purposes that a low producing well may serve. Dan Arthur, Tr. 185:8-15 (Oct. 28, 2025).

FOF 113. Low producing wells do not experience releases or environmental compliance issues at a higher frequency than other active, producing wells. Romero, Tr. 40:19-41:4 (Oct. 24, 2025).

FOF 114. OCD's position that remediation and reclamation noncompliance act as a predictor of orphan wells was based on one staff member's experience from 2022-2025, but not on a comprehensive review of OCD data, operator history, the MOSS, or enforcement actions. Romero, Tr. 71:16-72:12 & 70:11-71:6.

FOF 115. The number of reported incidents is even across all categories of wells, including low producing and No Beneficial Use wells. Romero, Tr. 68:15-68:21. Further, OCD analysis of incidents does not review severity of the incident or release with respect to well category. Romero,

Tr. 97:20-98:13 (Oct. 24, 2025).

FOF 116. Marginal inactive wells tend to be low risk and can be managed without environmental incident. Arthur, Tr. 220:4-12 (Oct. 28, 2025). TA wells can be reactivated and have less risk than active producing wells. Marginal, inactive, and TA wells have future benefit beyond production or injection in primary recovery. Arthur, 220:4-12 (Oct. 28, 2025).

Evaluating the value and future potential of a well "really, really depends on a – on a well by well basis." Wrinkle, Tr. 195:4-20 (Oct. 24, 2025); Winchester, 38:3-8 (Nov. 3, 2025). Many factors are in play in evaluating the benefits and use of a well, including well location, field, reservoirs and stacked plays, age of the well, condition of the well. Alexander, Tr. 194:2-11 (Oct. 20, 2025). In evaluating wells, capital expenditures and operating expenses are distinct, with allocation affecting the average lease expense and resulting economics on a well basis. Wrinkle, Tr. 179:25-80:7.

FOF 117. Many of the $1,900 costs OCD Witness Justin Wrinkle relied on were lease operating expenses shared across many or several wells, and some expenses are not common to most wells. Winchester, 38:3-8 (Nov. 3, 2025). IPANM members reported monthly well cost figures ranging from $600 to $1300 per month for marginal wells, because smaller and independent operators have less overhead and more expertise in lower-producing wells, and can therefore operate a marginal well more efficiently. Winchester, 39:2-16 (Nov. 3, 2025); Justin Wrinkle, Tr. 167:20-168:9 (Oct. 24, 2025).

FOF 118. Lease operating expenses are highly dependent on a well's characteristics: kind, age, kind of gas, oil. Wrinkle, Tr. 168:20-24 (Oct. 24, 2025).

FOF 119. Even assuming OCD Witness Justin Wrinkle's operating expense figures, at $65 per barrel, less a $1.35 barrel marketing fee, a one (1) barrel-per-day well still breaks even. Winchester, 39:2-16 (Nov. 3, 2025).

FOF 120. Operators regularly plan to recomplete and/or workover "low producing" wells. Jeff Harvard, Tr. 84:11-85:6 (Nov. 6, 2025). OCD agrees that "[A]nything is possible with technology advances" including the ability for industry to rework and produce from wells that are 50-100 years old. Diede, Tr. 120:5-13 (Oct. 23, 2025).

FOF 121. OCD knows that low producing wells may be maintained while new wells are drilled, and after new wells are online and producing, it is common for the operator to go back and plug—not orphan—the older well. Justin Wrinkle, Tr. 164:1-24 (Oct. 24, 2025).

FOF 122. New Mexico recently adopted the Well Repurposing Act for carbon and other energy storage, which Applicants' proposal did not consider. Alexander, Tr. 174:12-15 (Oct. 20. 2025); *see also* NMSA 1978, §71-9A-1 *et seq*.

FOF 123. Energy capture, carbon storage, produced water disposal, geothermal energy production, and bio-fuel disposal are all viable, beneficial uses for marginal, low producing, and possibly orphan wells. Alexander, Tr. 175:5-7 (Oct. 20, 2025); Wrinkle, 199:8-201:14 (Oct. 24, 2025); Arthur, 268:22-3 (Oct. 28, 2025); and, id. at 298:24-269:2.

FOF 124. It is more economic to use existing, drilled wells that test safely than to drill new wells. OXY witness Tiffany Wallace, Tr. 22:23-23:4 (Oct. 28, 2025). Once a well is plugged, that resource is permanently lost. Rebuttal Testimony of Mike Cantrell, 2:20-3:8. Premature plugging eliminates future and alternate uses for vertical wells, like carbon capture, injection, and energy storage and generation. Armstrong, Tr. 112:16-113:17 (Nov. 3, 2025).

FOF 125. Marginally producing wells contribute a meaningful share of national production and significant portions of New Mexico's oil and gas portfolio and are not necessarily at end-of-life. NMOGA Dan Arthur, Tr. 193:1-15)(Oct. 28, 2025). Low producing wells are low-risk, high-option value assets that contribute $14 million in tax revenue, 3,160 jobs, and $30 million in royalties in New Mexico. Cantrell Rebuttal Testimony, 4:14-17 & 9:7-22.; Murphy, Tr.

141:2-22 (Nov. 4, 2025)

FOF 126. In FY2024, industry contributed 49%, about $7.4 billion, to the State of New Mexico general fund and a significant portion derived from marginal wells, over a billion dollars. Arthur, Tr. 85:21-26:6 & 195:13-19 (Oct. 28, 2025).

FOF 127. Longfellow Energy's Loco Hills project started by acquiring 45 low producing vertical wells, and in a year drilled 40 horizontal wells and increased production from 200 barrels to 6, 000 barrels per day. David Mitchell, Tr. 181:17-182:10 & 183:17-184:2 (Oct. 31, 2025).

FOF 128. Spur Energy individually evaluates a marginal well at least twice before coming to the decision to plug the well: first, by examining fluid levels and determining if a workover is economic. Second, a closer review of remaining reserves in place and for potential uphole development for recompletion. Johnny Nabors, Tr. 109:8-24 (Nov. 6, 2025).

FOF 129. Spur Energy is evidence that just because a small operator has marginal wells in its portfolio, the Division cannot assume that the small operator will orphan marginal wells. Nabors, Tr. 110:12-111:1 (Nov. 6, 2025).

FOF 130. Operators can and do take a full field development approach when viewing marginal wells future potential, and "marginal wells play a very important role in an operator's development program." Wallace, Tr. 39:3-40:2 (Oct. 28, 2025).

FOF 131. Operators consider a variety of factors in deciding to rework or recomplete wells, to include: the availability of marginal wells, oil pricing, economics, new technology, and rig proximity and availability. Wallace, Tr. 39:3-40:2 (Oct. 28, 2025).

FOF 132. The performance of three Oxy wells classified as marginal under Applicants' proposals based on 2024 production evidence the unintended consequences of arbitrary production thresholds and days of production: the Harroun #91, the FNR 35 Fed 3H, and the Cedar Canyon 15 2H (the "three Oxy Wells"). Wallace, Tr. 40:10-44:6 (Oct. 28, 2025).

FOF 133. After refracking, installing artificial lift optimization, and recompletion with additional fracks, each of the three Oxy Wells were increasing in production during 2025. Wallace, Tr. 40:10-44:6 (Oct. 28, 2025).

FOF 134. If Oxy had been forced to choose between bonding or plugging the three Oxy Wells, that production would have been lost and created waste. Wallace, Tr. 44:7-24 (Oct. 28, 2025).

FOF 135. Oxy is heavily involved and invested in enhanced oil recovery ("EOR") projects, like the Hobbs unit that converted 49 TA wells to production or injection. Oxy witness Kelley Montgomery, Tr. 139:3-19 (Oct. 28, 2025). But that process can take a long time with economics, regulatory hurdles, infrastructure concerns and timelines. Montgomery, Tr. 139:9-19 (Oct. 28, 2025).

FOF 136. WELC experts agree that it makes sense for extended TA status for marginal wells for CO2 EOR projects and other potential uses. *See*, *e.g.*, Peltz, Tr. 930:17-931:21 & 932:13-933:12.

FOF 137. At present in the shale boom of primary production, wells will decline in production in the future being in a naturally tight reservoirs, recovering less than previous reservoirs. In turn, even greater amounts of oil will remain in place at the end this phase, leaving an even larger potential resource during secondary. Murphy, Tr. 140:3-10 (Nov, 4, 2025). However, if operators are forced to plug marginal wells, rather than preserve the well bores in place, that will destroy future potential and value of the wells. Murphy, Tr. 140:23-25.

FOF 138. If wells are plugged prematurely at the end of their primary phase of production, the economic viability of secondary and tertiary recovery projects is diminished because the operator will have to re-drill those wells to establish the best pattern for efficiency and recovery from the field. This makes low producing and inactive wells long term assets, not liabilities,

because these wellbores provide key, strategic access to discovered reserves. Murphy, 211:8-25 (Nov. 4, 2025).

FOF 139. Armstrong Energy Corporation has operated marginal and low-producing wells for 44 years and never orphaned a well, which undercuts Applicants' assumption that marginal well operators or portfolios with a higher percentage of low producing wells are high risk. Armstrong, Tr. 101:21-102:25 (Nov. 3, 2025).

I. Applicants' Proposed Rules do not individually Evaluate Wells for Risk of Abandonment.

FOF 140. OCD's Master Orphan Well list, Exhibit 17, includes federal, state, and private wells. Both the Bureau of Land Management and the State Land Office have adopted a recent approach of seeking out every owner of an interest in the lease to plug abandoned wells, which includes operators, working interest owners, record title owners and lessees of record.[71] When a party other than the operator plugs an abandoned well, the process is referred to as "forced plugging."

FOF 141. There are likely many wells on OCD's MOSS, Ex. 17, which have been plugged by industry parties as forced plugging incidents, but it is not clear that OCD tracks those numbers. Loren Diede, Tr. 123:25-124:5 (Oct. 23, 2025). It is undisputed that not every abandoned well is plugged by OCD.

FOF 142. There are many factors that go into determining and evaluating production on a lease basis than reported volumes alone. Marks, Tr. 219:25-220:18 (Oct. 27, 2025).

FOF 143. Applicants' proposal relies on proxies of production levels to assign risk to active wells rather than a "risk-based framework" which is critical to targeted reform. McGowen,

[71] *See*,*e.g.*, LFC Report, WELC Ex. 4 at Table 17, page33 ("Trailing Liability"); Marks, Tr. 222:1-22 (Oct. 27, 2025) (746 forced plugging of wells).

Tr. 181:18-188:25 (Oct. 30, 2025). Applicants concede they could have proposed a risk-based FA structure, rather than relying on production levels as a proxy for risk. Peltz, Tr. 830:2-19 (Oct. 22, 2025).

FOF 144. The transfer or assignment of a low producing well is not a step towards orphaning, and if an operator cannot sell a well, the operator plugs the well. Wrinkle, Tr. 181:12-182:4 (Oct. 24, 2025).

FOF 145. Not every orphan well is a problem well and many states are making advances to repurpose or convert the wells for other uses. Arthur, Tr. 268:17-269.

FOF 146. WELC expert Tom Alexander erroneously assumed that Applicants performed an engineering or reservoir analysis in support of the Proposed Rules, but added that if he was an operator he would look at production numbers, decline curve, a "P over Z plat" based on the type of reservoir, pressure, geology, offset operators, other stacked horizons, other opportunities, potential for EOR, in order to determine viability and value of a well. Alexander, Tr. 209:13-211:4.

FOF 147. Low producing wells may produce at a low level because of market conditions and midstream constraints stemming from compression problems, both of which are outside of an operator's control. Johnny Nabors, Tr. 108:11-109:7 (Nov. 6, 2025). Neither midstream constraints nor market conditions are a reliable indicator of a well's future ability to produce or likelihood of being orphaned. Nabors, Tr. 108:11 - 109:7 (Nov. 6, 2025). Production levels for a well can vary due to market, seasonal, and infrastructure factors, to include pipeline takeaway capacity and gas plant downtime. Dan Arthur, Tr. 176:24-177:8 (Oct. 28, 2025).

FOF 148. An operator could be forced to bond a well experiencing prolonged, constrained takeaway issued due to delays in infrastructure, corrosion issues in the pipeline, and shutdown pipelines. Powell, Tr. 119:4-15 (Oct. 27, 2025). There may be circumstances outside of an operator's control that affect production and revenue from a well. Justin Wrinkle, 154:3-154:9

(Oct. 24, 2025).

FOF 149. Operators may elect to produce by exception for force majeure purposes. Wrinkle, Tr. 155:6-8 & 176:24-177:8 (Oct. 24, 2025).

FOF 150. Armstrong Energy's experience demonstrates the unreliability of the inflexible 180 days requirement in the propose low producing well definition is not is flawed as it had five wells where the midstream company could not transport gas for a period of 117 days out of 180 days. As an operator, there was no way to predict whether the pipeline would be available again, and whether he would be able to produce those five wells 180 days out of the remaining 180 days. Testimony of Kyle Armstrong, Tr. 109:1-21 153:13-155:5 (Nov. 3, 2025).

FOF 151. Pipeline repair and maintenance, contract disputes between the midstream company and a third parties, and other events entirely outside of the operator's control can lead to curtailment and production restrictions for a certain operator or even certain fields and areas. Armstrong, Tr. 109:22-110:20 (Nov. 3, 2025).

FOF 152. Applicants assert that temporary abandoned status wells are at a very high risk of becoming orphaned wells. Alexander, Tr. 62:14-18 , 83:3-5 & 98:3-5 (Oct. 20, 2025)..

FOF 153. A well in temporary abandoned status must pass pressure and mechanical integrity tests and satisfy re-tests periodically during the TA period. NMAC 19.15.25.12 (current). Wells that are placed in TA status are monitored and controlled. NMAC 19.15.25.12 (current).

FOF 154. WELC Expert witness Tom Alexander did not review records of wells remaining in TA status beyond five (5) years for mechanical integrity failures, yet deemed these wells the highest risk to the State. Alexander, Tr. 137:8-11 (Oct. 20, 2025).

FOF 155. Applicants could not point to data or analysis to demonstrate that the current TA rules, which require OCD approval, mechanical integrity testing, and pressure monitoring, are insufficient to protect against risks or have otherwise failed to reduce risks. Alexander, Tr. 133:21-

134:1 (Oct. 20, 2025).

FOF 156. As Representative Murphy explained, the initial pressure test ensures the mechanical integrity of well being placed in TA, which are typically wells with very low to zero bottom hole pressures. Murphy, 210:9-211:2 (Nov. 4, 2025). At those pressures, fluid can only migrate a short distance, maybe 300 or 400 feet, and never get to the surface. Once the well is placed in TA status, everything is sealed which preserves future potential of the wellbore much better than plugging. Murphy, 210:9-211:2 (Nov. 4, 2025).

FOF 157. Applicants had not determined how many of the TA wells portrayed in WELC Exhibits 61 (Wells in Expired TA Status) and Exhibit 62 (TA Wells by time since last production), had been reactivated or plugged. Peltz, Tr. 862:22-863:18 (Oct 23, 2025).

FOF 158. OCD Exhibit 23 identifies all inactive wells in TA status as of August 8, 2025. OCD Ex. 23.OCD Exhibit 33 identifies operators with unreported production for a period of 12 months or more. Almost all the operators on MOSS are on OCD's Exhibit 33. Powell, Tr. 31:14-16 (Oct. 27, 2025).

FOF 159. Of the 1,366 orphan wells belonging to the to the top ten offending operators on MOSS, including those like Cano Petro, Canyon E&P, Ridgeway Arizona, Acacia Operating, Energy Acumen, Remnant Oil, and Northern Pacific Oil & Gas, orphan wells placed in temporary abandonment status account for 1.4%. *Compare* OCD Ex. 17 *to* OCD Ex. 23. Compared to Applicants; proffered 5% orphan rate across all wells, TA wells are significantly less likely to be orphaned.

FOF 160. Well over 100 out of 113 operators on OCD's Ex. 33 appear on OCD's inactive well lists (OCD Exhibits 21, 22, and 23) and are responsible for 1750 inactive wells, or roughly 2/3 of inactive wells. There are 30 common operators on MOSS that appear on OCD's Ex. 33 and collectively account for 952 inactive state wells with no reported production for greater than 12

months, which is 78% of the state wells reported on OCD Ex. 33. *Compare* OCD Ex. 17 *to* OCD Ex. 33.

FOF 161. OCD will not recover additional FA from operators that are already out of compliance. Winchester, 69:25; 70:1-4 (Nov. 3, 2025)Comparing the top 19 companies on OCD's orphan and inactive well exhibits, there is a combined quarter billion dollars that will never be realized as additional FA to the State, because the capacity of those operators is simply not there. Winchester, 35:4-9 (Nov. 3, 2025).

FOF 162. The top ten operators by well count on OCD's Exhibit 33, for failing to report production for 12 months or more, account for just 26 TA wells. OCD Ex. 33, OCD Ex. 23.

FOF 163. Those top ten operators on OCD's Ex. 33 are responsible for over 1,440 wells, which means that just 1.8% of their wells were ever placed in TA status.

FOF 164. In contrast, the operators with the most TA wells, like Hilcorp, are considered to be responsible, prudent operators. Brandon Powell, Tr. 85:17-24 (Oct. 27, 2025). Hilcorp has over 140 TA wells, OCD Ex. 23, and although it is a great example of a responsible operator reworking and transforming old wells into individual success stories and actively plugging wells—they are low-risk yet the Proposed Rules would impose an additional $15 million in bonding. The Proposed Rules do not make sense to saddle good operators with a solid plugging and repurposing track record with excessive bonding costs. OCD Ex. 23, Winchester, 32:4-21 & 35:4-9 (Nov. 3, 2025).

FOF 165. Oxy witness Tiffany Wallace pointed out to the Commission that in order to place a well into temporary abandoned status, the operator must prove to the division that the well protects against waste and protects correlative rights by providing data about a number of factors, including casing, cement, and mechanical integrity of the well. Tr. 24:4-25:7 (Oct. 29, 2025).

FOF 166. OCD Deputy Director Brandon Powell does not expect that any of the operators

on OCD Ex. 33 will comply with bonding increases or contribute additional funds to FA accessible by the state upon orphaning of their wells. OCD Brandon Powell, Tr. 99:7-13 (Oct. 27, 2025). Powell expected that, of the 51% of operators affected by the high-risk portfolio Proposed Rule, at least 25% are not going to pay for additional bonding, and that "maybe 26%" would comply with additional bonding requirements. Powell, Tr. 129:16-130:24, & 130:25-131:5 (Oct. 27, 2025).

FOF 167. Therefore, even if Applicants' proposals adopted, it would be unreasonable to expect noncompliant operators to contribute additional FA. At a minimum, the 952 wells likely requiring single well bonds of $150,000, will not result in expected $143 million in additional FA.

FOF 168. WELC Expert Adam Peltz did not verify or examine the proposed 180 days of production for marginal, now low-producing, wells as reasonable or economically supported. Peltz, Tr. 868:20-869:2. In contrast, each well has its own personality which can determine maximum beneficial production days for ultimate recovery to avoid waste. Murphy, Tr.157:1-22 (Nov. 4, 2025).

FOF 169. OCD proposed a days of production component to low-producing well definition to identify wells operating as "full capacity" under the belief that a limited number of days of production, even with high barrel of oil equivalent output, could indicate "an issue with the well." OCD did not support this theory with specific examples of individual wells or perform a quantitative comparison between wells with low days of production and wells which become orphaned. Testimony of Brandon Powell, Tr. 215:13-23 (Oct. 24, 2025).

FOF 170. OCD Deputy Director pointed to Hilcorp, who operates a substantial number of TA wells, as a "great example" of an operator in the Northwest that is "doing a strong re-complete process…perforating other zones." Powell, Tr. 85:17-24 (Oct. 27, 2025).

FOF 171. Applicants' Proposed Rules, rather than "showing what's at risk, [ ] show[] what's already failed." Powell, Tr. 143:12-144:4. Applicants' FA proposals "wouldn't pick up

very many additional companies that are failing, it more identified those companies that already failed." Powell, Tr. 143:12-144:4 (Oct. 27, 2025).

FOF 172. Applicants' speculation that the state may have an orphan well problem in the future, but that is contradicted by one hundred years of industry history which indicates somewhere between 2-5% of wells that are abandoned. Murphy, Tr. 194:3-6 & 208:7-18 (Nov. 4, 2025).

FOF 173. Applicants' Proposed Rules will increase costs on all operators, including those with decades of responsible compliance history that have never orphaned a well. Armstrong, Tr. 150:13-17 (Nov. 3, 2025); Murphy, 131:4-8 (Nov. 4, 2025).

FOF 174. Applicants' portfolio provision which requires single-well bonding on all active and low-producing wells may aim or claim to protect the state against the most high-risk wells by the riskiest operators, but has not accounted for the follow-on effect of putting otherwise 85-70% of productive wells at risk of abandonment. Armstrong, Tr. 158:18-160:1.

FOF 175. According to MOSS, ten operators account for almost 75% of total orphan wells in the state. Winchester, 28:6-12 (Nov. 3, 2025).

FOF 176. There no reasonable basis to think that those ten operators will contribute or comply with increased bonding levels. Picking just five of those operators eliminates over $150 million from anticipated FA increases under the Proposed Rules. Winchester, 31:3-18 (Nov. 3, 2025).

FOF 177. Applicants and OCD present no evidence that operators of the wells most likely to be orphaned will comply with any new FA requirements.

FOF 178. Compliance with new FA requirements will be by operators with established records of compliance with rules, including plugging and abandoning, adding unnecessary cost to their operations and/or premature plugging of wells to avoid those costs.

FOF 179. The costs of the proposed new FA requirements would fall most heavily on the

smallest operators, likely driving some into bankruptcy thereby orphaning wells. Arscott, Tr. 265:18- 266:2 (Nov. 4, 2025); and Tr. 30:1-11 (Nov. 5, 2025); Winchester, 70:13-17 (Nov. 3, 2025)..

J. Applicants' Proposed FA Increases will negatively influence Surety Market in New Mexico.

FOF 180. IPANM witness David Mitchell, of Longfellow Energy, LP, explained that although it currently obtains surety bonds at 3%, if FA demands increased to $15 million as predicted under Applicants' changes, Longfellow would expect both its premium rate to increase to 10% and to be required to post cash collateral. Mithcell, Tr. 205:1-205:14 (Oct. 31, 2025).

FOF 181. Under the above, Longfellow would pay $1.5 million to the surety just to meet the new bonding requirements, which is $1.5 million that Longfellow would otherwise put toward plugging old wells and developing new wells. Mitchell, Tr. 205:15-206:11 (Oct. 31, 2025).

FOF 182. Surety companies would more likely exit New Mexico under the Proposed Rules, because meeting such increased bonding regulations would be difficult, such that only very large companies could obtain bonding, which in turn would "decimate the—[ ] smaller companies…the mom and pops that are really the local..heroes of their small communities." Mitchell, Tr. 206:12-207:8

FOF 183. Applicants' assumed premium rates of 1% based on a study of offshore surety bonds, which are $2 million per well. WELC expert Peltz, Tr. 907:8-19 (Oct. 22, 2025).

FOF 184. When total bond amounts dramatically increase, as proposed by Applicants, a surety may refuse to write additional bonds for the operator. NMOGA expert Emerick, 120:11-24 (Oct. 29, 2025).

FOF 185. A surety company looks not only to the operator principal, but also to the state as obligee in setting premium rates and requiring cash collateral. A state regulatory environment

that is onerous or adverse to development will result in higher collateral demands. Emerick, Tr. 121:6-7 (Oct. 29, 2025).

FOF 186. The form of bond required in New Mexico combined with the increase FA levels proposed by Applicants will reduce the number of sureties willing to write bonds. Emerick, 125:10-12 (Oct. 29, 2025).

FOF 187. Regulatory risk, like the adverse operational environment introduced by Applicants' Proposed Rules, can drive surety rates higher.

FOF 188. According to the current FA report, OCD Exhibit 29, there are 1,097 surety bonds in place in the State of New Mexico, securing $95 million in FA, representing 80% of statewide FA. OCD Exhibit 29.

FOF 189. Applicants' proposal jeopardizes future and existing surety bonds. Emerick, Tr. 125:10-12 , 140:10-13, 141:17-24 (Oct. 29, 2025).

FOF 190. None of Applicants' witnesses had any surety underwiring experience. Emerick, Tr. 151:16-18. No input or analysis from the surety industry was consulted in drafting Applicants' rules.

FOF 191. The surety market has contracted in recent years as has surety providers "appetite," such that only the largest operators will be eligible to obtain surety bonds at the level Applicants' propose. Comment of the Surety and Fidelity Association of America (Nov. 7, 2025).

FOF 192. Applicants' Proposed Rules will introduce additional risk and transaction costs to the surety market, while requiring additional collateral even for good operators with a long-standing relationship with surety companies. Armstrong, Tr. 103:1-22 (Nov. 3, 2025).

FOF 193. Under the existing bond form promulgated by OCD and the requirements of Section 70-2-14(A) which condition release of the bond on the plugging of the well, operators and surety experts are concerned that once a low-producing single well bond is in place, a surety will

not release the bond unless the well is plugged. Armstrong, Tr. 106:19-107:13 &107:14-108:17 (Nov. 3, 2025).

FOF 194. The surety market is not just tighter or more difficult for small operators, it is mostly unavailable. Therefore, a small operator is mostly limited to cash bond options which tie up 100% of the capital associated with the level of the bond during the entirety of that well's operational life. Winchester, 84:1-5 & 84:16-17 (Nov. 3, 2025).

FOF 195. IPANM Witness Trevor Gilstrap was the only witness with surety and bonding experience in New Mexico from the side of the surety company as a broker. Gilstrap, 164:10-12, 164:22-23, 165:7-9 (Nov. 3, 2025).

FOF 196. His experience is in obtaining and locating bonding for oil and gas service contractors, operators, and nonoperators involved in domestic production. Gilstrap, 166:14-18 (Nov. 3, 2025).

FOF 197. Mr. Gilstrap was also involved in the Colorado bonding rulemaking in 2022, which has created an incredibly hard current market for bonds, both in increased premiums up to and beyond 3.5% and increased collateral requirements up to 50-100% of the bond. Gilstrap, 167:20-25, 168:1-19 (Nov. 3, 2025).

FOF 198. His concern is that Applicants' Proposed Rules push bond amounts so high, that operators will experience severe constraints on available capital. Gilstrap, 167:20-25, 168:1-19 (Nov. 3, 2025).

FOF 199. For example, an operator with 150 wells requiring single-well bonds of $150,000 under Applicants' Proposed Rules, will need a $22.5 million bond, which equates to $11.5 million in collateral at 50%, plus annual premium fees of $787,500. Gilstrap, 169:1-10:21-25, 170:1-10 (Nov. 3, 2025).

FOF 200. Applicants' Proposed Rules increasing bonding level will drive premium rates

even higher. Gilstrap, 170:9-11 (Nov. 3, 2025).

FOF 201. All bond collateral requirements tie up funds for an operator, often by depositing cash in an investable fund with a de minimus growth rate, but those monies are inaccessible to the operator. Gilstrap, 171:20-25, 172:1-6 (Nov. 3, 2025).

FOF 202. The surety market is not like a demand-responsive market like car insurance. In fact, increased demand generally has the opposite effect, because the surety market is capacity-driven. For example, sureties may not have the appetite, bandwidth, or interest to respond quickly or at scale with regulatory changes which dramatically increase the demand for bonding, which Gilstrap has experienced in Colorado. Gilstrap, 182:24-25, 183:1-5 Nov. 3, 2025); Gilstrap, 183:24-25; 184:1-3 (Nov. 3, 2025); Gilstrap, 188:22-24 (Nov. 3, 2025).

FOF 203. Applicants' use of surety premium rates for offshore wells is not an accurate basis to predict costs under the Proposed Rules FA increases for New Mexico onshore oil and gas wells. Gilstrap, 189:7-17 (Nov. 3, 2025).

FOF 204. Plugging bonds are noncancellable, which is part of the reason you see higher premium and collateral requirements. Gilstrap, 209:20-24 (Nov. 3, 2025).

K. Applicants' have not demonstrated that Proposed Rules can be implemented with any degree of expected certainty or success.

FOF 205. There is no evidence in the record that OCD is equipped or staffed to administer another complex evaluation like the presumption against beneficial use proposed under 19.15.25.9 NMAC. *See* WELC Ex. 89-E . The rebuttal demonstration imposes excessive and burdensome documentation requests. Dan Arthur, Tr. 188:19-189:1 (Oct. 28, 2025).

FOF 206. WELC expert witness Tom Alexander was unfamiliar with OCD's current regulatory hearing docket, how many hearings are scheduled each month, availability for new applications, and limited hearing capacity. Alexander, 224:13-225:6 (Oct. 20, 2025).

FOF 207. Applicants did not analyze any of the administrative burdens, in terms of personnel, man-hours, or costs, imposed by their Proposed Rules. Alexander, 179:12-14 (Oct. 20, 2025).

FOF 208. If the Proposed Rules were to be adopted, OCD would need to devote staff to enforcing those rules including staff time spent reviewing low producing well reporting and resulting changes to FA; looking for NBU wells and pursuing the operator to comply; reviewing TA renewals; and, reviewing the complex information to be provided on well transfer and new operator applications. No evidence was presented to inform the Commission what staff resources that OCD will need to reallocate to enforce the Proposed Rules and, after any such reallocation, what OCD tasks will have less staff resources.

FOF 209. OCD's Environmental Bureau Chief Rosa Romero, was not aware that OCD had taken authority for the Reed Estate No. 1 wellsite (API 30-025-07258), OCD had taken over the well and plugged it in 2015, but did not commence remediation efforts until late 2023.Romero, 74:3-13; Direct Testimony of Rosa Romero, OCD Ex. 10 at 5:9-18.

FOF 210. Ms. Romero was not surprised that the first NOV issued with respect to the Reed Estate No. 1 well was back in July 2008. Romero, Tr. 74:17-75:19.

FOF 211. OCD witness Loren Diede was not aware that the Buckskin Federal No. 2 well was subject to an ACOI and OCD approved two operator transfers for the well. Diede, Tr. 109:4-16.

FOF 212. OCD witness Justin Wrinkle testified that OCD already has the expertise and background at current staffing levels to evaluate the value and beneficial use of wells on a case by case assessment. Wrinkle, Tr. 197:2-198:2 (Oct. 24, 2025).

FOF 213. While the State has existing $118 million in FA, the total FA sum is not a "bucket" that OCD can use to plug every well which is orphaned. FA is tied to specific operators

and not all operators will orphan wells. OCD Brandon Powell, Tr. 220:222-221:7 (Oct. 24, 2025).

FOF 214. The OCD has not recovered many plugging bonds and there is nothing in the current or proposed rules that requires OCD to pursue or recover a plugging bond. OCD Brandon Powell, Tr. 73:11-13 & 74:2-7 (Oct. 27, 2025).

FOF 215. OCD enforcement does not support pursuing plugging bonds on an individual bases, because "the juice is not worth the squeeze" and OCD would not consider pursuing individual well bonds until packaged, because "pursuing them individual[ly] doesn't make any sense." Powell, Tr. 97:15-25 (Oct. 27, 2025).

FOF 216. Based on OCD's current docket capacity, OCD Deputy Director agrees that the first five years of TA status should be determined administratively. Powell, Tr. 156:15-157:9.

FOF 217. Operators are likewise concerned that with current levels of staffing, OCD will not be able to keep pace and track the thousands of new bonds under Applicants' Proposed Rules, given existing administrative burdens. Armstrong, Tr. 107:14-108:17 (Nov. 3, 2025).

FOF 218. Applicants' witnesses provided no testimony how the Proposed Rules would effect the vast number of wells subject to Joint Operating Agreements and other contractual arrangements, which provide for certain designated costs to be billed to the non-operating working interest onwers but not bonding costs. *Cf.* Armstrong, Tr. 115:14-117:7 (Nov. 3, 2025); *See generally* Ezzell Direct Testimony, 11:1-18:16.

FOF 219. An operator with little or no interest in a well has no incentive to pay a single well bonding cost. More often than not, the registered operator of a well owns a percentage working interest, and is responsible to several other parties, including non-operating working interest owner, nonparticipating royalty interest owners, and royalty owners. Ezzell, Tr. 226:1-12 Nov. 3, 2025).

FOF 220. The relationship between working interest owners is typically governed by a

Joint Operating Agreement (JOA), of which there are several widely adopted forms. Ezzell Direct Testimony, 7:19-22. But as to the ability of an operator to recoup increased FA under Applicants' Proposed Rules, the specific version is immaterial. *See generally* Ezzell Direct Testimony, 11:1-18:16.

FOF 221. JOAs contractually allocate certain costs of operation and provide the procedures for operation of the well. Ezzell Direct Testimony, 6:11-17. Under the most relevant provisions of a JOA (abandonment, expenses, force majeure, and resignation), none provide a clear path for an operator to share increased FA costs proportionally with other working interest owners in the well. Ezzell Direct, 12:8-9, 14:21-15:2, & 18:9-10. New Mexico case law does not support a different result. Ezzell, Tr. 236:9-18.

FOF 222. Under the accounting form included with most JOAs, the 1974 COPAS, an operator may not pass increased bonding costs along to non-ops unless expressly agreed as a direct charge. Ezzell Direct Testimony, 23:1-19; *id.* 25:14-26:19 (same conclusion under 1962 and 1984 COPAS).

FOF 223. Applicants' Proposed Rules do not contemplate or work under existing industry contracts or practice. Ezzell, Tr. 225:24-25 (Nov. 3, 2025).

FOF 224. Applicants' Proposed Rules which encourage premature plugging of wells, or uneconomic production create waste, endanger correlative rights, and expose operators to liability and lawsuits brought by those interests owners. Ezzell, Tr. 225:2-7 (Nov. 3, 2025); Ezzell Direct Testimony, 37:7-10 (production during low pricing to avoid bonding low-producing well places operator "at legal peril").

FOF 225. Applicants' Proposed Rules do not account for common terms of oil and gas leases, and that the lease is extended as long as a well is capable of production. During a maintenance or recompletion period, it is not unusual for a well to be down six months before

production is restored, if not longer due to the constraints on rigs, crews, and contractors. Ezzell Direct Testimony, 33:5-34:14.

FOF 226. Applicants' Low-Producing well definition fails to consider that leases also provide for shut-in royalty payments on gas wells for wells capable of production, but lacking infrastructure or during low market price conditions. Ezzell Direct Testimony, 34:17-35:18.

FOF 227. Under Applicants' proposed increases in FA, operators with lower working interests will be incentivized to abandon wells or resign entirely, forcing inexperienced non-op owners to take over. Ezzell, Tr. 237:19-238:10 (Nov. 3, 2025).

FOF 228. Where the OCD was created in part to prevent the drilling of unnecessary wells, Ezzell Tr. 225-14-17 (Nov. 3, 2025), Applicants' proposal plugs low-producing wells and removes wellbores from available inventory to economically accomplish secondar and tertiary recovery units. Ezzell, Tr. 256:18-257:10 (Nov. 3, 2025).

FOF 229. Restrictions on takeaway capacity in the Permian are not just limited to gas wells, because if there is no market or capacity for oil wells producing low amounts of casinghead gas, the operator will be forced to shut in the well entirely. Ezzell, Tr. 260:7-262:8.

FOF 230. As drafted, the definition of low-producing well and the corresponding bonding requirement does not give OCD discretion to make exceptions in periods of low commodity prices, in contrast to state trust land policy to delay revenues in those environments to avoid economic waste. Ezzell, Tr. 113:3-115:3. (Nov. 4, 2025).

FOF 231. Current rules in Rule 19.15.5.9(A)(4) and 19.15.25 NMAC recognize reality of lapses in time between determining need to plug and proceeding with approved plugging activities, due to constraints on resources and services like availability of plugging crews, service companies, and processing and approval of plugging plans. Applicants' Proposed Rule eliminates any

tolerance for compliance. Testimony of Jim Winchester, 23:23-25; 24:1-25 (Nov. 3, 2025).

FOF 232. By adopting a "one strike" framework under the Proposed Rules, which severely restricts an operators authority and eligibility to operate wells, the Proposed Rules will create orphan wells. Winchester, 26:3-8 (Nov. 3, 2025).

FOF 233. Because the State Land Office has proposed competing bonding rules on a lease and possibly well basis, it would be wise for the Commission to consider the cumulative effect of both proposed rule changes on operators of state leases and wells. Winchester, 78:11-22 (Nov. 3, 2025).

L. Applicants' Proposed Rules Create Waste and fail to protect Correlative Rights.

FOF 234. Applicants' and OCD's proposed presumption against beneficial use characterizes all wells that produced less than 90 BOE as without beneficial use or purpose. WELC Ex. 89-E , 19.15.25.9 NMAC.

FOF 235. The presumption will have a disproportionate impact on smaller operators, discourage incremental development, disrupt unit agreements, and cause possible loss of leasehold rights. NMOGA Dan Arthur, Tr. 184:20-185:7.

FOF 236. The presumption will promote premature plugging of viable wells, which creates waste. NMOGA Dan Arthur, Tr. 184:20-185:7.

FOF 237. SLO witness Allison Marks agrees that there are many factors that go into determining and evaluating production on a lease basis and that reporting volumes alone are not determinative. Marks, Tr. 219:25-220:18 (Oct. 27, 2025).

FOF 238. Applicants' proposal relies on proxies of production levels rather than a "risk-based framework" which is critical to targeted reform.

FOF 239. A substantial percentage of hydrocarbons can be recovered in secondary and tertiary recover within the lifecycle of a field or reservoir, but it takes a long time to develop a

secondary recovery unit because it is very complicated and "Unitization can take forever." Alexander, Tr. 16117-162:13 (Oct. 20, 2025); Murphy, Tr. 136:1-7 & 137:20-24 (Nov. 4, 2025) (some projects take up to and over 15 years).

FOF 240. Oxy witnesses testified that, based on their experience, a 500-well EOR project requires constant re-evaluation of spacing, wells included, project economics, and how to best develop the resource. "It takes a very long time to understand how that program is going to work." Oxy Tiffany Wallace, Tr. 37:20-21 & 37:10-38:1 (Oct. 28, 2025).

FOF 241. Applicants' proposed rules not only accelerate the timeline to plug wells, but also constrain an operator's ability to keep wells in TA status while making it significantly more expensive to do so. WELC Ex. 89-E at19.15.25.9 & 19.15.25.13, and WELC Ex. 89-C at Part F of 19.15.8.9 NMAC.

FOF 242. IPANM witness Representative Mark Murphy explained how plugging wells following primary production restricts and limits an operators ability to develop waterflood and secondary recovery because of spacing and design in a field. Rep. Mark Murphy, Tr.136:23-137:24 (Nov. 4, 2025).

FOF 243. At the end of primary production, 60-80% of the original oil remains in place in the reservoir, Murphy, Tr. 136:23-25, and the formation and operation of secondary recovery projects has resulted in hundreds of millions, if not billions, of revenue to the state. Murphy, Tr. 138:16-139:4.

FOF 244. Producing a well at a low commodity prices to meet arbitrary production thresholds causes losses and creates waste. WELC Tom Alexander, Tr. 156:11-17 (Oct. 20, 2025).

FOF 245. Applicants' proposed changes incentivize operators to produce wells in excess of economic limits, which creates waste. Alexander, Tr. 156:22-25 (Oct. 20, 2025); Powell, Tr.

147:14-17 (Oct. 27, 2025).

FOF 246. Applicants' proposed definition of low producing well does not directly consider economic factors. Alexander, Tr. 158:1-3 (Oct. 20, 2025).

FOF 247. No witness on behalf of Applicants or the Division analyzed the effect or impact of Applicants' proposed rules on waste or correlative rights. Alexander, Tr. 228:4-12 (Oct. 20, 2025). Applicants admit and acknowledge that many parties may own an interest in a well, however, Applicants' proposals have not considered or evaluated impact on correlative rights. WELC expert witness Adam Peltz, Tr. 902:6-24; 904:7-15 (Oct. 22, 2025).

FOF 248. Applicants' witnesses could not explain how the proposed rules account for or consider various cycles in the typical petroleum process or a typical oil field, to include tertiary recovery. Alexander, Tr. 243:7-244:3, 245:3-5, & 249:11-21 (Oct. 20, 2025).

FOF 249. WELC expert witness Tom Alexander limited an operator's ability to pursue secondary and tertiary recovery under the proposed rules to "nearby fields in a particular reservoir that have been successful after primary into secondary and tertiary," which eliminates or fails to account for new discoveries or technology. Alexander, Tr. 246:7-22 (Oct. 20, 2025).

FOF 250. A low-producing well with access to a reservoir with remaining, recoverable reserves in primary production could maintain substantial value for the remainder of primary production, and also for future EOR and secondary recovery. OCD Justin Wrinkle, Tr. 195:4-6 (Oct. 24, 2025).

FOF 251. Applicants have not considered the inefficiencies in requiring a well to proceed automatically from primary recovery to water injection. Peltz, Tr. 38:24-39:18 (Oct. 23, 2025).

FOF 252. The failure to consider secondary and tertiary stages of recovery by Applicants' proposal will result in waste, because operators will be required to plug marginal wells, and drill new wells at each production profile in the life of an oil field. Peltz, Tr. 41:4-10 (Oct. 23, 2025).

FOF 253. It is unclear in Applicants' analysis of wells in temporary abandoned status and return to activity, whether the sample size of wells analyzed encompasses secondary and tertiary recovery process. WELC Tom Alexander, Tr. 249:11-249:21 (Oct. 20, 2025); *see also* WELC Ex. 13 (bar chart based on a "sample of wells that reactivated following 12+ months of no production, using production data from 2010-2024)

FOF 254. WELC witness Tom Alexander's testimony regarding temporary abandoned status wells was based on data and analysis performed by Environmental Defense Fund staff, none of whom were made available for examination during the hearing. Alexander, Tr. ___: __ (Oct. 20, 2025).

FOF 255. Applicants' rules will result in premature abandonment of wells that have significant remaining, recoverable hydrocarbons depriving the state of additional royalties, tax revenues, and significantly increased production from the wells. Jeff Harvard, Tr. 98:10-99:10 (Nov. 6, 2025).

FOF 256. A significant amount of concern has been expressed by small operators that they will not be able to comply with the new FA levels, and they will either go out of business or exit operating in New Mexico. Harvard, Tr. 99:20-102:16 (Nov. 6, 2025).

FOF 257. Without a market of available smaller operators to take over marginal wells, those wells will be plugged instead of managed or recompleted, creating waste. Armstrong, Tr. 112:1-15 (Nov. 3, 2025).

FOF 258. Fluctuations in commodity prices can make it reasonable and economic for an operator to idle a well instead of plug, but the Applicants' Proposed Rules do not allow for operational flexibility or exception. For example, an operator will not rework and develop uphole formations on a marginal well while prices are low, because discovery would lead to uneconomic production and waste. Armstrong, Tr. 113:18-115:13 & 120:22-121:11 (Nov. 3, 2025).

FOF 259. Under the proposed Rules, "all an operator has to do is produce for 181 days" regardless of the market conditions or impact on well performance to avoid low producing well status. Powell, Tr. 215-24-216:6 (Oct. 24, 2025).

FOF 260. Powell agreed that the Proposed Rules may force some operators to abandon wells sooner, Tr. 135:23-136:22 (Oct. 27, 2025), or to prematurely plug wells, but the Division has not analyzed or evaluated the anticipated impact. Tr. 137:7-21.

FOF 261. Neither the Applicants nor the Division attempted a comprehensive analysis of the Proposed Rules on waste. Powell, Tr. 1381-139:5 & 139:6-13, 152:24-153:10 (Oct. 27, 2025) To the extent the Commission wanted to conduct its own analysis, the available data is limited to production from a single calendar year. Powell, Tr. 139:18-140:11.

FOF 262. When faced with WELC expert Dwayne Purvis's estimate that the Proposed Rules would capture 51% of operators and 2.3% of production at 17 million barrels, which excludes otherwise active, producing wells that must be double-bonded under the high-risk operator provision of the Proposed Rules, OCD Deputy Director testified that he was "hoping actually it's not that high." Tr. 140:19-142:25.

FOF 263. OCD's orphan well program monitors methane or natural gas emissions from orphan wells and found that 60% of orphan wells are leaking methane. Powell, Tr. 177:25-178:6. However, as presented in the October 2025 Water and Natural Resource Committee meeting, the New Mexico Environment Department Report on oil and gas greenhouse emissions for methane and carbon dioxide in 2023 from inactive oil and gas wells was so low, the level was not even graphed. Testimony of Rep. Murphy, Tr. 228:19-229:17 (Nov. 4, 2025).

M. Commission without Authority to adopt FA levels Exceeding Oil and Gas Act.

FOF 264. WELC expert Tom Alexander understands the blanket plugging bond not to exceed $250,000 set by NMSA 1978, § 70-2-14 applies to all active and inactive wells. Alexander, Tr. 201:24-201:11 & 202:18-21 (Oct. 20, 2025).

FOF 265. WELC Expert Adam Peltz was also involved in 2024 proposed legislation to increase bonding requirements which the legislature rejected. Peltz, Tr. 911:13-17 (Oct. 22, 2025).

FOF 266. No witness in support of Applicants' proposal was a licensed New Mexico attorney offering a legal opinion on the interpretation of Section 70-2-14 based on the Commission's primary duty under the Oil and Gas Act or its authority as interpreted by New Mexico courts. *See,e.g*, Peltz, 915:12-916:10 (not an expert in NM law).

FOF 267. Each prior change in FA promulgated by the Commission followed amendments to the Oil and Gas Act by the Legislature.[72]

FOF 268. WELC witness Adam Peltz agreed that Utah interprets its blanket plugging bond differently than New Mexico. WELC Adam Peltz, Tr. 878:9-14 & 917:18-918:3(Oct. 23, 2025).

FOF 269. Applicants' theory of authority to exceed bonding levels set in Section 70-2-14(A) and require new FA for low-producing and high-risk operator wells relies entirely on the phrase "shall establish categories." WELC Peter Morgan, Tr. 572:14-20 (Oct. 21, 2025), Morgan, Tr. 657:16-25 (Oct. 22, 2025).

FOF 270. Representative Murphy identified the need for direction from the Legislature prior to acting on Applicants' Proposed Rules and highlighted the constraints early leadership in New Mexico adopted under the Oil and Gas Act as indicative of how important oil and gas is the statewide economy. Murphy, Tr. 196:14-21 & 197:21-25.

[72] *See Joint Industry Reply* (October 10, 2025), Exhibit A.

N. HB80 and the Reclamation Fund Better Address funding source for Orphan Well Plugging.

FOF 271. The Reclamation Fund both plays and pays into the solution of the orphan well problem. Winchester, 95:19-25; 96:1 (Nov. 3, 2025).

FOF 272. NMSA 1978, §70-2-37 (2010) establishes the Oil and Gas Reclamation Fund and appropriates "all funds" to the Energy, Minerals and Natural Resources Department for use by the Oil Conservation Division. Powell, Tr. 176:25-177:8 (Oct. 27, 2025).

FOF 273. Section 70-2-38 of the Oil and Gas Act permits expenditures of reclamation funds for the plugging, restoration, and remediation of abandoned well sites and mandates the OCD director "reclaim and properly plug all abandoned wells and shall restore and remediate abandoned well sites and associated production facilities" as funds become available.

FOF 274. Under HB80, the New Mexico Legislature has allocated increasing percentages of the Oil and Gas Conservation Tax to the Reclamation Fund.[73]

FOF 275. As of July 2025, the Reclamation Fund was reported to be $72.2 million.[74]

FOF 276. Under HB80 Fiscal Impact Reports, the Reclamation Fund is anticipated to reach $261 million by 2031.[75]

FOF 277. By FY2028, the annual contributions to Reclamation Fund will likely exceed $100 million, such that total funding by 2037 is anticipated to exceed $1 billion.[76]

FOF 278. Based on average plugging rates and the OCD's Annual Reclamation Fund

[73] HB80, available at: https://www.nmlegis.gov/Sessions/26%20Regular/final/HB0080.pdf (last visited March 30, 2026).
[74] Fund Balance Projection (FY 2026), New Mexico Department of Finance and Administration, p. 104. https://www.nmdfa.state.nm.us/wp-content/uploads/2026/01/DFA-FY26-Fund-Balance-Projections-FINAL.pdf
[75] General Fund Consensus Revenue Estimate, December 2025, pp. 20-21. Available at: https://www.nmlegis.gov/Entity/LFC/Documents/Revenue_Reports/General_Fund_Revenue_Forecast/2025/Dec%2025%20Consensus%20Revenue%20Brief%20Compiled.pdf
[76] Ezzell, Tr. 102:1-5 (Nov. 4, 2025); Murphy, Tr. 153:20-24 (Nov. 4, 2025); *see also* EMNRD HB 80 Agency Bill Analysis dated January 27, 2026, available at https://www.nmlegis.gov/Legislation/Agency_Analysis?chamber=H&legType=B&legNo=80&year=26 (last accessed March 30, 2026).

report, the OCD plugged 360 wells between FY19 and FY24, and expended $46.4 million, averaging $128,888 per well and 72 wells per year.[77] At this rate, it would take close to a decade for OCD to address only the wells which OCD already has plugging authority. *Id.* ; Murphy, 178:25-179:6 (Nov. 4, 2025).

FOF 279. Available state and federal funds far exceed OCD capacity to plug and remediate orphan wells and well sites. *Id.*

FOF 280. Using the LFC Report average of $163,000 per well, in ten years under HB80, the Reclamation Fund will provide a funding source to plug an additional 6,250 wells, which would take OCD approximately 87 years. LFC Report, WELC Ex. 4; *see also* LFC Fiscal Impact Report for HB80, *supra*; Murphy,Tr. 178:19-23 (Nov. 4, 2025).

FOF 281. Incorporating the LFC Report's assumption of $83,000 reclamation costs per well or wellsite, making total plugging and reclamation costs $246,000, the anticipated $1 billion Reclamation Fund provides for over 4,000 wells. LFC Report, WELC Ex. 4; *see also* LFC Fiscal Impact Report for HB80, *supra*; *see also* ENMRD Annual Reclamation Fund Reports, IPANM Ex. 10-14, & 43.

FOF 282. WELC expert Dwayne Purvis anticipates that 5% of the currently active wells in New Mexico will need to be plugged, being just over 3,000 wells.[78]

FOF 283. Rationally, if Mr. Purvis is correct, many if not most of the wells that will be orphaned will not have any of the additional FA contemplated by the Proposed Rules. See FOF ____, supra. (at least 952 wells will be orphaned without single wells bonds).

FOF 284. HB80's contribution to the Reclamation Fund far surpasses anticipated plugging

[77] *See LFC Fiscal Impact Report HB 80* (dated Jan 26, 2026, updated Feb. 5, 2026), available at: https://www.nmlegis.gov/Sessions/26%20Regular/firs/HB0080.PDF (last accessed Mar. 30, 2026).
[78] *See* WELC Exhibit 31 for Mr. Purvis's estimate of unplugged wells in the State (reporting 62,720 "unplugged" a.k.a. active wells in New Mexico); *see also* Direct Testimony of Dwayne Purvis, P.E., WELC Exhibit 30, 34:14-15. ("Historically, 5% of U.S. onshore wells documented as plugged were orphans plugged by State agencies."). Therefore, 5% x 62,720 = 3,136 wells.

and remediation needs of the State proposed by Applicants.

FOF 285. Prior to HB80, WELC Expert Peter Morgan claimed: "There's simply not enough money in the Reclamation Fund to cover the shortfall between existing FA levels and the current and anticipated inventory of orphaned wells." Direct Testimony of Peter Morgan WELC Exhibit 15, 65:20-21.[79]

FOF 286. Because the Reclamation Fund derives from the Oil and Gas Conservation Tax, the cost of plugging abandoned wells is borne equally across all operators and other oil and gas industry participants on a per-barrel basis, regardless of whether that barrel of oil equivalent produced from a marginal, 50 year old vertical well or a newly drilled 3 mile lateral. LFC Report, WELC Ex. 4, see also LFC Fiscal Impact Report for HB80 (explaining history of Conservation Tax and Reclamation Fund).

FOF 287. WELC Expert Adam Peltz agreed that "solving the orphan well problem will require a lot of money from industry" but that Applicants' rulemaking on FA could not provide a framework to better "socialize...cost across industry." Rebuttal Testimony of Adam Pelz , WELC Exhibit 82, 16:5-10.

FOF 288. HB80 and the increased contributions to the Oil and Gas Reclamation Fund adequately address perceived "shortfall" in funding to address abandoned and orphan well plugging liability. *Compare* LFC Report, WELC Ex. 4 (estimating liability in range of $700 million to $1.6 billion) *to* LFC Fiscal Impact Report for HB80 (reflecting anticipated growth of Reclamation Fund from $67 million to $261 million in five years, and over $1billion in the next decade).

FOF 289. HB 80 solves the orphan well crisis without any of the disruption and burden of

[79] *See also id.*, Morgan, 67:3-6 ("Indeed, all of the funds in the Reclamation Fund will not be sufficient to plug even the existing inventory of orphaned wells, even assuming the availability of additional federal funding. Additional orphaned wells will only add to this burden to the state.").

the Proposed Rules.

III. MIXED FINDINGS OF FACT AND CONCLUSIONS OF LAW

A. The Oil and Gas Industry is the Primary Driving Force of New Mexico's Economy and has been for over 100 years.

F/C 1. Oil and gas industry contributes over $13 billion in total revenue to State of New Mexico annually, with $7.4 billion to the State General Fund, and responsible for over 100,000 direct and indirect jobs. FOF 126.

F/C 2. Over 50% of New Mexico's budget tied to oil and gas, with $2.4 billion of industry dollars funding education in the state. FOF 126.

F/C 3. Although low-producing wells may account for a smaller amount of total production and revenue, 2.3% and $17 million, smaller operators responsible for low-producing wells have an outsized-effect on communities, local employment, and maintenance of industry infrastructure. FOF 125, FOF 88, FOF 101& **Error! Reference source not found.**, FOF 125, **Error! Reference source not found.**.

F/C 4. New Mexico has experienced several cycles of development in its hundred-year history with oil and gas. While all wells decline in production gradually during primary recovery, operators respond to decreasing primary production by discovering of new trends, redeveloping underdeveloped fields, and implementing enhanced recovery projects in existing, older fields. FOF 248.

F/C 5. Throughout this boom-bust cycle, independent operators have been at the forefront of discovery and development. FOF 111.

F/C 6. Existing, available wellbores are critical to secondary and enhanced recovery projects which target the remaining 60-70% of reserves after primary production. **Error! Reference source not found.**, FOF 109, FOF 120.

F/C 7. Although horizontal drilling and advances in hydraulic fracturing have increased statewide production by a factor of 10 from 2010 to 2020, and doubled that again in the last five years, those increases are driven by notoriously "tight" formations, leaving 80-90% of the original oil in place remains after primary recovery. FOF 136- FOF 138.

F/C 8. Adopting rules which introduce uncertainty to the New Mexico regulatory landscape may drive operators out of New Mexico, leading to more orphan wells. FOF 60 & FOF 61.

F/C 9. Adopting rules which impose unnecessary financial burdens on responsible operators may drive operators out of New Mexico, leading to more orphan wells. FOF 60, FOF 74.

F/C 10. Applicants' Proposed Rules target and disproportionately impact smaller, independent operators. FOF 83- FOF 111.

F/C 11. Applicants' Proposed Rules will lead to the premature plugging of wells. *Id.*; *see also* FOF 234-FOF 261.

F/C 12. If adopted, Applicants' Proposed Rules will reduce both the inventory of available wells for secondary and enhanced recovery, as well as the roster of small, independent operators responsible for the discovery new trends, redeveloping underdeveloped fields, and initiating secondary projects. *See* FOF 111, FOF 136- FOF 138.

F/C 13. Without either, New Mexico will be poorly positioned to meet the next phases of development and Applicants' Proposed Rules will in drastic consequences for the State's economy. FOF 242-FOF 243; FOF 239.

F/C 14. Applicants target low-producing wells and temporary abandoned wells as the wells most "at risk" of orphaning. Applicants freely admit that the removal of these 3,400 wells

from production will remove anywhere from $55 million to $1 billion in revenue to the state. FOF 7, FOF 8.

F/C 15. The kind of dire economic consequences and wide deviations in policy objectives resulting from Applicants' Proposed Rules are best left to New Mexico's elected representatives, not the appointed members of the Commission.

IV. CONCLUSIONS OF LAW

A. All Commission authority derives from the Oil and Gas Act.

COL 1. The Oil Conservation Commission was created by the New Mexico Legislature under the Oil and Gas Act (the "Act") for the purpose of conserving oil and gas, preventing waste, and protecting correlative rights. NMSA 1978, §§ 70-2-4 & 70-2-11. As a creature of statute, its exercise of rulemaking powers is circumscribed by the express delegation of authority, not implied. Ezzell Rebuttal Testimony, 2:16-22; *Continental Oil Co. v. Oil Conservation Comm'n*, 1962-NMSC-062, ¶ 11.

COL 2. The Commission is empowered with concurrent authority to make rules "[t]o that end" of preventing waste and protecting rights to "carry out the purpose" of the Act. *Id.* §§ 70-2-11(A) & -11(B). Waste and all acts that result in waste are prohibited. *Id.* 70-2-2.

COL 3. The Act defines "Waste" to include underground waste in the form of inefficient use or dissipation of reservoir energy or the operation of wells in a manner which reduces the total quantity ultimately recovered, *id.*, § 70-2-3(A); surface waste resulting from the production of oil or gas in excess of reasonable market demand, *id.*, § 70-2-3(B), or any other production in excess of reasonable market demand. *Id.*, §§ 70-2-3(C) & (E).

COL 4. The Commission may adopt rules for the safe drilling, operating, and production of wells and "to identify the ownership of oil or gas producing leases, properties, wells," and other facilities. *Id.*, § 70-2-12(B)(7) & (8).

COL 5. The Commission may adopt rules "to spend the oil and gas reclamation fund and do all acts necessary and proper to plug dry and abandoned oil and gas wells…." *Id.*, § 70-2-12(B)(18).

COL 6. Pursuant to Section 70-2-12(B)(1) of the Act, the Commission may make rules to require abandoned wells to be plugged and to require FA ("FA") pursuant to Section 70-2-14, conditioned for the performance of plugging wells.

COL 7. Section 70-2-14(A) of the Act requires the Commission include three categories of plugging bonds: (i) a blanket plugging FA set by rule not to exceed $250,000; (ii) a blanket plugging FA for temporarily abandon status wells set by rule at amounts greater than $50,000, and (iii) a one-well plugging FA "in amounts determined sufficient to reasonably pay the cost of plugging the wells covered by the FA." *Id.*

COL 8. In establishing categories of FA, the Commission "shall consider the depth of the well involved, the length of time since the well was produced, the cost of plugging similar wells," and other relevant factors. *Id.*

COL 9. New Mexico adopted the Oil and Gas Act in response to market depression caused by overproduction and as part of an interstate cooperative to conserve resources responsibly, recovering the greatest amount of resources for the greatest economic gain..

B. Applicants' Proposed Rules Will not Prevent Orphan Wells.

COL 10. No party presented a risk-based framework to evaluate wells for the potential, statistical probability that a well is likely to be abandoned. FOF 51.

COL 11. Instead, Applicants' rely on average daily production of a well as a "proxy" for evaluating risk of abandonment, based on the assumption that an uneconomic well is unable to "pay for itself" under Mr. Purvis' "holdback" theory. FOF 4 - FOF 10. There was no evidence presented to the Commission that operators budget and plan for well plugging on an individual

well, self-pay basis. FOF 62-FOF 64; **Error! Reference source not found.**. Nor was evidence presented in the record that the ten operators responsible for 75% of the orphan wells on OCD Exhibit 17 abandoned their wells because those wells produced below a certain number of days or barrels equivalent in a year.

COL 12. Applicants' and OCD witnesses admitted that well economics are highly individualized and that many low producing wells are economical at just 1 BOE per day. FOF 119.

COL 13. The Commission heard from several operators, both large and small, that wells are plugged only after the operator has evaluated all other alternatives or additional development and production established. The Commission also heard credible testimony that operators plan a year or more in advance to plug wells, outside of emergency circumstances. FOF 62-FOF 64, **Error! Reference source not found.**& FOF 94, FOF 99-FOF 102, **Error! Reference source not found.** - FOF 135.

COL 14. The Act has required operators post a plugging bond since the 1970s, and always provided enforcement mechanisms to plug wells, but there are an estimated 1700 orphan wells for which OCD has plugging authority, such that the existence of both FA and penalties has not wholly prevented wells from being abandoned.

COL 15. Applicants' theory that increasing FA will prevent orphan wells is based on a series of assumptions about well economics, which if true are prohibited by the Act: First, Applicants assume at lower levels of production a well cannot self-fund plugging costs; Second, an operator cannot justify paying higher premiums or meeting higher collateral demands resulting from Applicants' proposed FA levels on low-producing wells; Third, faced with keeping a low-producing well active or prematurely plugging, the operator will plug the low-producing well, "prevents" the well from being abandoned but at the cost of creating waste.

COL 16. If the Commission were to adopt Applicants' "self-funding" theory of plugging wells, testimony from IPANM and OCD confirms that wells are economic at 1 BOE per day or less. FOF 119. Therefore, the asserted purpose of Applicants' Proposed Rules defining a low-producing well is still met at the lower production threshold of 365 BOE per year or less.

COL 17. Of the ten operators which account for over 75% of currently orphaned wells, all were able to obtain FA, and the presence of FA did not prevent the Operator from orphaning those 952 wells. FOF 52- FOF 55.

C. Applicants' Proposed Rules will not Plug Existing or Future Orphan Wells.

COL 18. The OCD cannot use funds from forfeited FA until the OCD has first initiated and completed enforcement actions to obtain plugging authority over the subject well, and second, actually plugged the well to satisfy the condition precedent under Section 70-2-14.

COL 19. There are numerous reasons why the OCD enforcement process is delayed, to include insufficient staffing and funding, but the result is that the wells which OCD plugs have been abandoned, inactive, and unmonitored for many years. FOF 37- **Error! Reference source not found.**; **Error! Reference source not found.**- FOF 46; **Error! Reference source not found.**- **Error! Reference source not found.**- **Error! Reference source not found.**.

COL 20. In contrast, the wells plugged by operators are very different in integrity and production history, leading to lower plugging costs overall and higher efficiency in plugging wells in comparison to Division-plugged wells. FOF 39, FOF 40, **Error! Reference source not found.**- **Error! Reference source not found.**.

COL 21. To fund plugging activities, the operator must draw on alternate capital or cash flow, because like OCD, the funds secured by plugging FA, which are non-cancelable, are not available for release and return until after the well is plugged.

COL 22. Therefore, neither OCD nor the Operator may access plugging FA to accomplish the plugging of wells in accordance with 19.15.25 NMAC, and the presence of FA—and even higher levels of FA under Applicants' Proposed Rules—does not plug wells.

COL 23. In addition, while the OCD has not historically pursued or recovered FA for abandoned wells, funding for plugging orphan wells has never been the limiting factor. FOF 53-FOF 59. The recent influx of federal funding and new state funds allocated under HB80 to plug orphaned wells will far exceed historical and current OCD capacity to plug wells.

COL 24. At current and anticipated levels of funding in the Reclamation Fund and OCD well-plugging capacity, there exists funding for almost 80 years to plug Applicants predicted 5% of active wells that are likely to be abandoned.

COL 25. Whether OCD spends funds from the Oil & Gas Conservation Tax or from recovered FA, neither of these sources are "taxpayer" money as claimed by Applicants' and that concern is rejected as valid support for Applicants' Proposed Rules.

COL 26. It is undisputed that industry plugs 95% of wells on an annual basis, but as explained above, none of the operators plugging those 95% of wells relies on FA to plug wells.

COL 27. Increasing FA amounts under Applicants' Proposed Rules will reduce available capital for the 95% of wells currently plugged by industry, and will therefore reduce the capability of operators to plug additional wells, such that Applicants' Proposed Rules may lead to less wells plugged statewide on an annual basis.

COL 28. Under Applicants' Proposed Rules, the Division does not anticipate that operators substantially out of compliance, identified on OCD Exhibits 17 and 33, will contribute any additional FA. Therefore, the only operators which OCD anticipates complying with new FA levels are compliant operators who are already responsibly plugging their own wells and are the *least* likely to orphan wells. FOF 232 - **Error! Reference source not found.**.

COL 29. If the only increased FA under Applicants' Proposed Rules is provided by compliant operators who are least likely to orphan wells, then the OCD will not have the opportunity to forfeit the increased FA, because those operators are unlikely to default. The only party anticipated to receive more funding under Applicants' Proposed Rules will be surety providers recouping grossly inflated annual premiums. FOF 180 - FOF 204.

D. Commission cannot exceed $250,000 blanket bond for active wells.

COL 30. Section 70-2-14(A) has historically provided for three (3) types of plugging FA: a blanket plugging bond for active wells, an additional blanket bond for wells in TA status more than two years, and a single-well bond. Applicants' Proposed Rules introduce two new categories of single-well bonds that will apply to active, producing wells: the single-well bond for Low-Producing wells at Subpart D of 19.15.8.9 NMAC and the High-Risk Operator Portfolio Well at Subpart E of 19.15.8.9 NMAC. But the Act provides the blanket plugging bond as a right to operators and caps the blanket plugging bond at $250,000. COL 31- **Error! Reference source not found.**; **Error! Reference source not found.**.

COL 31. Section 70-2-14 requires that "one-well plugging FA" be set "in amounts determined sufficient to reasonably pay the cost of plugging the wells covered by the FA." Section 70-2-14 also mandates that in establishing FA, the division "shall consider the depth of the well involved, the length of time since the well was produced, the cost of plugging similar wells and such other factors as the oil conservation division deems relevant."

COL 32. In establishing new categories of FA, the Act requires the Commission to consider the factors of depth, age, and cost of plugging similar wells, but neither Applicants' Low-Producing single well bond nor their High-Risk Operator Portfolio single well bond does

not account for depth, age, or the cost of plugging similar wells. FOF 34- FOF 35; Ezzell Rebuttal, 6:2-4 & 6:15-18.

COL 33. Under Section 70-2-14, only the one-well plugging FA is tied to amounts sufficient to reasonably pay the cost of plugging well covered by the FA. Section 70-2-14 directs the division to adopt a blanket plugging FA not to exceed $250,000.

COL 34. Section 70-2-14(A) clearly contemplates individual well considerations by reference to depth, age, and the reasonable cost of plugging similar wells. Ezzell Rebuttal, 7:6-11. Applicants' universal single well bond of $150,000 denies operators the substantive opportunity to demonstrate a reasonable or similar plugging costs. *Id*

COL 35. In the 2018 rulemaking which increased FA levels from $50,000 to tiered levels approaching $250,000, the Commission was cognizant of impermissibly "double-bonding" wells and carved out federal wells from Part A of 19.15.8.9 NMAC. **Error! Reference source not found.**. Here, where Applicants' seek to double-bond additional categories of wells but do not consider or account for mandatory factors, **Error! Reference source not found.**, FOF 35,& FOF 37, Applicants' Proposed Rules to adopt Low-Producing and High-Risk Operator single well plugging FA do not comport with the Act.

COL 36. Where the Legislature declined to increase FA and well transfer oversight in 2024 under HB133, the Commission has its answer that it remains without authority to do so by rule. IPANM Exhibit 41, Ezzell Rebuttal, 9:10-21, LFC Report, WELC Ex. 4 at 32.

COL 37. The Commission does not have the power to adopt Applicants' Proposed Rules at Parts D and E of 19.15.8.9 NMAC to the extent changes would require operators to bond active wells in amounts greater than $250,000, the statutory cap set by the Legislature in Section 70-2-14(A).

COL 38. Section 70-2-14(A) provides that the Commission shall require a one-well bond on any well that has been held in temporary abandoned status for more than two years. Applicants' proposal to amend and combine the definitions of temporary abandonment and approved temporary abandonment unnecessarily limits the Division's ability to require additional bonding for inactive wells that are inactive greater than two years. FOF 1 – FOF 3.

COL 39. Reflecting on the adopted and proposed changes to the Oil and Gas Act over the past two decades, Ezzell Rebuttal, 2:5-7, the Legislature has only approved **additional** single well bonding for wells in temporary abandoned status greater than two years. NMSA 1978, § 70-2-14(A); Ezzell Rebuttal, 7:12-18. This reflects the Legislature's balanced decision that while unproductive wellbores retain value, industry should provide additional bonding after two years in amounts which reasonable reflect the cost of plugging the well, currently keyed to depth under Part C of 19.15.8.9 NMAC. Ezzell Rebuttal, 7:13-8:6.

COL 40. Where the Commission previously adopted rules to enforce civil penalties in conflict with then existing statute, it was without authority to do so. *Marbob Energy Corp. v. N.M. Oil Conservation Comm'n,* 2009-NMSC-013, ¶8; Ezzell Rebuttal, 3:1-13. There, as here, the remedy lies with the Legislature and amendment of the Oil and Gas Act. NMSA 1978, § 14-4-5.7(A).

COL 41. The Commission does not have authority to repeal, circumvent, or render sections of a statute moot through rulemaking. Ezzell Rebuttal, 8:13-15; NMSA 1978, § 14-4-5.7(A) ("No rule is valid or enforceable if it conflicts with statute. A conflict between a rule and a statute is resolved in favor of the statute.").

E. Applicants' Proposed Rules create Waste and threaten Correlative Rights; The Act prohibits Waste or the adoption of rules which permit Acts of Waste.

COL 42. While the Commission has concurrent authority under the Act to adopt rules which promote the primary purpose of the Act, it does not have authority to require acts which

create or permit waste by reducing total recovery through inefficient operation or production in excess of reasonable market demand.

COL 43. Applicants' definition of Low-Producing well encourages operators to create waste through one of three options: prematurely plug low-producing wells to avoid punitive, new FA levels; produce the wells in a manner which is inefficient to meet arbitrary days or volume threshold; or produce the well at low market prices in excess of reasonable demand (again to meet arbitrary thresholds proposed by Applicants).

COL 44. Applicants' argument that emissions from orphan wells represent waste should be rejected. The insignificant volumes of leaked methane, Murphy, Tr. 228:19-229:17 (Nov. 4, 2025); is dwarfed by the demonstrated waste of 70-90% remaining recoverable reserves left in the ground as a result of Applicants' Proposed Rules. Ezzell Rebuttal, 10:2-11:5.

COL 45. The same choices are also raised by Applicants' and OCD' proposed presumption against beneficial use for wells producing less than 90 BOE per year. In either scenario a plugged well is removed from all future secondary or tertiary recovery projects because of New Mexico's stringent formation isolation requirements which makes re-entry prohibitive. Therefore, plugging wells that do not otherwise demonstrate a risk to health or safety limits—if not forecloses completely—future methods of recovery and access to reservoirs. This reduces total recovery by inefficient operation of wells and creates waste.

COL 46. On the other hand, in the scenario where operators elect to produce wells to exceed Applicants' arbitrary thresholds in disregard of well performance profiles or market economics, that qualifies as operation in a manner that either dissipates reservoir energy inefficiently or results in production in excess of market demand, which also create waste.

COL 47. Applicants direct the Commission's attention to FA reforms enacted by other states, FOF 16 - **Error! Reference source not found.**, but none provide direct analogs in

terms of scale or economic cost to the reforms proposed by Applicants. Further, the Commission remains far from convinced that the increase in orphan well counts and elimination of small operators experienced in Colorado will not also result from Applicants' changes. FOF 22-FOF 30.

COL 48. There are many interest owners in a well to which the operator is responsible: non-operated working interests, royalty interests, and overriding royalty interest owners. FOF 218. The Commission is charged with the duty of protecting all correlative rights by ensuring the proportionate share of recoverable oil and gas without waste, and to a similar share of reservoir energy. Applicants' Proposed Rules unnecessarily constrain an operator's duty to interest owners in each well and endangers owners' correlative rights. The Commission is without authority to adopt rules which fail to protect correlative rights and rejects Applicants' Low-Producing Well definition, the Low-Producing single well FA, and High-Risk Operator Portfolio single well bonding proposals.

F. Applicants' Zero-Tolerance Proposal is Unnecessary and Operationally Ill-Advised.

COL 49. Applicants strike allowances under the Part A(4) of 19.15.85.9, which OCD asserts is necessary to close the "inactive well" loophole. FOF 11 - FOF 14. Section 70-2-14(A) already provides for additional FA for wells greater than 2 years inactive, and the Commission may set blanket TA bonds not *less* than $50,000. **Error! Reference source not found.**. This additional FA, combined with OCD's increased enforcement and penalty violations of up to $200,000 per well, undercuts any need to tie operator standing to "absolute" compliance. Applicants' proposed "zero tolerance" amendments do not allow the Division discretion and flexibility for responsible operators and regulators to adjust to changing circumstances, which are often outside of either parties' control. FOF 218-FOF 232. The Commission finds that sufficient

tools are available under the current rules to allow the Division to prosecute noncompliant operators for inactive wells and to protect the state from wells inactive greater than two years.

COL 50. Although within its authority to adopt rules regarding the operation of wells, the Commission declines to adopt Applicants' changes to Part A(4) 19.15.5.9 presented in WELC Exhibit 89-B .

COL 51. The policy of the State of New Mexico requires looking at potential uses for non-productive oil and gas wells. NMSA 1978, §71-9A-1 *et seq.*

V. CONCLUSION AND REQUESTS FOR RELIEF

For the foregoing reasons, IPANM respectfully requests that the Commission enter a Final Order that:

A. Declines to adopt Applicants' proposed changes to the following:

1. Proposed definition of temporary abandonment and inactive wells. 19.15.2.7(I)(4) & 19.15.2.7(T)(13) NMAC

2. Proposed deletion of OCD discretion as to well allowances. 19.15.5.9(A)(4) NMAC.

3. Insertion of intervention in TA procedures without standing or injury requirement, as proposed in 19.15.25.13(C)(2) NMAC.

B. Rejects the following proposed provisions as exceeding the Commission's and Division's statutory authority under the Oil and Gas Act, and identifies in the Final Order the specific statutory basis for each rejection:

1. Proposed 19.15.8.9(D) NMAC: "low producing well" one-well FA category exceeding the $250,000 active well blanket bond cap and creating waste. NMSA 1978, §§ 70-2-3, 70-2-14(A).

2. Proposed 19.15.8.9(E) NMAC: "high-risk portfolio" one-well FA category exceeding the $250,000 active well blanket bond cap and creating waste. NMSA 1978, §§ 70-2-3, 70-2-14(A).

3. Proposed 19.15.8.9(F) NMAC: elimination of the two-year TA threshold. NMSA 1978, § 70-2-14(A).

4. Proposed 19.15.8.9(A): "acquisition" pre-approval language. NMSA 1978, §§ 70-2-6, 70-2-14(A).

5. Proposed 19.15.9.9(B), 19.15.9.9(C)(6), 19.15.9.9(D), and 19.15.9.9(E) NMAC to the extent they impose unauthorized transfer-screening, asset retirement obligation-based denial, or FA-based transfer restrictions. NMSA 1978, § 70-2-14(A).

6. Proposed 19.15.25.9(D)(4) NMAC: P&A plan as condition of beneficial use rebuttal. NMSA 1978, § 70-2-14(A).

7. Proposed 19.15.9.9(D) and (E) NMAC: transfer restrictions based on FA compliance. NMSA § 70-2-14(A).

C. Adopts the following modifications proposed by IPANM and NMOGA:

1. Broaden the "beneficial use" and "inactive well" definitions in proposed 19.15.2.7(B)(7) and (I)(4) NMAC to include "but not limited to" production, injection, monitoring, enhanced oil recovery, water flooding operations, regulatory compliance, and participation in reservoir management, pressure maintenance, or infrastructure optimization programs for the prevention of waste, and to exclude wells subject to compliance or final order.

2. Waive FA under 19.15.8.9(A) NMAC for operators with ongoing or planned P&A programs, or wells to be plugged upon acquisition.

3. Except federal and state-bonded wells from additional FA requirements under 19.15.8.9(A).

4. Replace or otherwise revise the flat $150,000 single-well bond amount in proposed 19.15.8.9 and any related provisions to comply with Section 70-2-14(A)'s individualized inquiry requirement. *See* NMSA § 70-2-14(A).

5. Delay implementation of additional FA on transfer of low producing wells for compliant operators and provide path for operators to remain in good standing if unable to satisfy escalated FA requirements. 19.15.8.9(D), 19.15.8.9(E)(2).

6. Reduce the lookback period in operator registration or change of operator provisions to time at point of transfer or five years, consistent with the existing regulatory framework. 19.15.9.8(B), 19.15.9.8(C)(2), 19.15.9.9(B), and 19.15.9.9(C)(2) NMAC.

7. Clarify in proposed 19.15.25.9(D) that OCD may extend the 30-day rebuttal period and revise proposed 19.15.25.9(D)(1) to recognize that a well may "produce or operate" in an economically beneficial manner.

D. Specifies in the Final Order that the Joint Stipulation is non-precedential and non-evidentiary as to any future proceeding, consistent with paragraph 9 of the Joint Stipulation.

E. Retains jurisdiction to address any implementation issues arising from the adoption of the Final Order.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served to counsel of record by electronic mail this 3rd day of April 2026, as follows:

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STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO'S SUPPLEMENTAL CLOSING ARGUMENT

The Independent Petroleum Association of New Mexico ("IPANM"), submits this Supplemental Closing Argument pursuant to the Hearing Officer's March 30, 2026 decision allowing five additional (5) pages of briefing on the impact or implications of HB80 vis-a-vis Applicants' Proposed Rules, and that the Commission may take administrative notice of the official analyses of HB80 by TRD, DFA, LFC, and EMNRD. *See* Joint Motion to Reopen as Attachments A-D, respectively.

INTRODUCTION

Applicants' initial *Application for Rulemaking* filed June 25, 2024, claimed their amendments were necessary to reduce the risk of plugging and remediation costs to the state, citing a billion-dollar funding gap. Thereafter, no single document was referenced or relied upon more by Applicants than the June 24, 2025 LFC *Policy Spotlight: Orphan Wells*,[1] which trumpeted estimated orphan wells liability in the range of $700 million-$1.6 billion. WELC Ex. 4 at 1 & 15 (0105, 0119). This rulemaking was litigated on the premise that current financial assurance (FA) levels were insufficient to address the shortfall because the Reclamation Fund could not cover the gap. Setting aside Applicants' theories and assumptions about operator intent, incentive, and risk-

[1] *See WELC Ex. 4.* Albeit, as discussed by Representative Murphy and WELC expert Adam Peltz, *see* FOF40, the LFC Report was notably biased and excluded industry perspectives, Applicants adopted the LFC Report findings and recommendations without qualification.

proxies, Applicants assert that the State will be responsible for plugging 5% of roughly 60,000 active oil and gas wells, and a Reclamation Fund which grows by $9-$10 million per year would never catch up to the looming price tag of $470 million.[2] Now signed into law, HB80 creates a Reclamation Fund that will exceed $1 billion in the next decade, if not earlier. The Commission should dispense with Applicants' fearmongering that funding shortfalls justify exponential increases in FA. In contrast to the attenuated potential recovery of FA (5% orphaning rate multiplied by whatever speculative but low percentage of those wells bonded and further multiplied by an even smaller percentage forfeited), OCD will now have access to hundreds of millions in the Reclamation Fund to plug and remediate orphan wells in the next five years.

The Legislature and the Governor have solved Applicants' concern and the first of Representative Murphy's "three-legged" solution of the orphan well problem: payment. *See* Testimony of Rep. Mark Murphy, Tr. 132:10-16 & 135:16-20 (Nov. 4, 2025). With respect to the remaining "legs"—procurement and process—Applicants' Proposed Rules are either silent or misguided.

ARGUMENT

A. Anticipated Gains to the Reclamation Fund from HB80 Dwarf Estimated Recovery of Financial Assurance Under Applicants' Proposed Rules.

HB80 changes the proportion of Conservation Tax revenue raised from industry on the production of oil and gas in the state allocated to the Oil and Gas Reclamation Fund. Prior to HB80, less than 20% of Conservation Tax revenue was allocated to the Fund: 10.5% when oil prices were below $70 per barrel; 19.7% when oil prices were above $70 per barrel. HB80 replaces that

[2] 62,720 active oil and gas wells x 5% orphan rate = 3,136 wells; 3,136 orphaned wells x $150,000 FA = $470,400,000. *See* WELC Ex. 31; *see also* Direct Testimony of Dwayne Purvis, WELC Ex. 30 at 34 ("[h]istorically, 5% of U.S. onshore wells documented as plugged were orphans plugged by State agencies.")

allocation with the following, regardless of price:

Period	%	Annual Contribution in Millions[3]	Fund Balance in Millions
April 2025			$66.7
FY2026	10.5/19.7%	$9.55 / $17.87	$76.25 - $84.57
FY2027	10.5/19.7%	$10.32/ $19.31	$86.57 - $103.88
FY2028	50 percent	$46.5 - $52.7	$133.07 – $156.58
FY2029	75 percent	$76.5- $79.58	$209.57 - $236.16
FY2030-37	100 percent	$108.7	$1,079.2 - $1,105.8
FY2038+	50 percent	$43	**$1,122.2 - $1,148.8**

The re-allocation of Conservation Tax revenue to the purpose for which it was established significantly increases the funds available to OCD for plugging and remediation of orphan wells. Using Conservation Tax projections from the LFC's December 2025 estimates, the amount allocated to the Fund over the next five years is expected to well exceed $200 million.[4] **In ten years, the Fund will be more than $1 billion.** As Representative Murphy testified before the Commission, the problem is not funding, but the ability of the Division to deploy the Reclamation Fund to economically, expediently, and efficiently plug abandoned wells. Murphy, Tr. 134:14-22 & 143:9-13 (Nov. 4, 2025). The LFC Fiscal Impact Report for HB80 and the LFC Spotlight Report echo those same concerns, citing that OCD spent $46.4 million in five years from FY19-24 to plug just 360 wells, "indicating that available state and federal funds exceed the division's near-term capacity to deploy [funds] through plugging and remediation activities." Att. C to Joint Mtn. to Reopen at 3; WELC Ex. 4 at 32 (0136) (recommending goal of rulemaking and policy changes should be to keep plugging in industry hands because of OCD's poor cost control and oversight). It is immensely counterproductive to adopt Applicants' proposals that add to OCD's administrative

[3] Contribution numbers reflect ranges cited by TRD, DFA, LFC, and EMNRD in Agency Bill Analyses for HB80, Attachments A-D to the Joint Motion to Reopen.
[4] General Fund Consensus Revenue Estimate, December 2025, pp. 20-21. Available at: https://www.nmlegis.gov/Entity/LFC/Documents/Revenue_Reports/General_Fund_Revenue_Forecast/2025/Dec%2025%20Consensus%20Revenue%20Brief%20Compiled.pdf

burdens but do nothing to address the gargantuan OCD workload needed to ensure responsible stewardship of the HB80 funds.

In contrast to the certainty of available Reclamation Funds under HB80, Applicants' Proposed Rules which increase FA and add new categories of FA suffer from known and admitted deficiencies. First, the ability of an operator to obtain a surety bond bears little relationship, if any, to an operator's tendency to orphan or abandon wells. *Compare* OCD Exhibit 17 Orphan Wells *to* OCD Exhibit 29 Financial Assurance, FOF93. Second, OCD's Deputy Director agreed that noncompliant operators are unlikely to post additional FA if Applicants' Proposed Rules adopted estimating that of the 51% of operators targeted by Applicants' high-risk category, "maybe" 26% would comply. Powell, Tr. 129:16-130:24, & 130:25-131:5 (Oct. 27, 2025); FOF212. IPANM Executive Director Jim Winchester explained that of the millions in additional FA Applicants' hoped to generate, $216 million was highly unlikely to materialize. Winchester Rebuttal Testimony, 6:20-7:1. Third, of the additional FA collected from responsible, compliant operators—those are the same operators who are least likely to abandon a well. Under the proposed rules, increased FA will be financially painful to many responsible operators who will plug in any event, drive some responsible operators into insolvency thereby orphaning their wells, and do nothing for wells "operated" by thinly capitalized bad actors who were never going to plug.

At the end of a two-year rulemaking, it is telling that not a single witness for Applicants or the Division could predict whether statewide financial assurance levels would increase under Applicants' Proposed Rules, and at what level. Even if the Commission were to assume 100% compliance under Applicants' proposal, such that each low-producing and high risk well was individually bonded at $150,000, and OCD recovered 100% of corresponding financial assurance, recovery contributions to the Reclamation Fund result in just 1/10th of the anticipated funds

available under HB80 and just 40% if significantly more orphaning occurs: [5]

Type of Well	Number	Historic Orphan Rate	Maximum Potential Recovered FA
Low Producing	2,200	5%	$16,500,000
High Risk	11,290	5%	$84,672,000
			$101,172,000
compare to			
Type of Well	**Number**	**Quadrupled Orphan Rate**	**Maximum Potential Recovered FA**
Low Producing	2,200	20%	$66,000,000
High Risk	11,290	20%	$338,688,000
			$404,688,000

However, the Commission cannot assume perfect compliance because OCD has already admitted that at least 25% of affected operators will not post additional financial assurance.

CONCLUSION

HB 80 fundamentally changes the landscape of this rulemaking and directly addresses Applicants' motivating concern that current FA levels are insufficient to meet estimated orphan well liabilities. HB80 solves the payment problem. As much as Applicants rely on the LFC Spotlight Report, they willfully ignore its most salient recommendation regarding process, which calls out this very rulemaking, explaining that Applicants' proposed changes "have the potential to simply replicate…existing problems." WELC Ex. 4 at 32. IPANM encourages the Commission to heed the Legislature's decision on how to provide the money needed to address orphan wells, but also to compare the positive outcome worked by HB80 to the drastic economic consequences of Applicants' proposals to small and independent operators. The Commission and Division should focus on spending the HB 80 funds prudently and efficaciously.

[5] *See* WELC Ex. 40 (scatterplot by WELC expert witness Dwayne Purvis based on 2024 production, reporting 2,200 low producing wells); WELC Ex. 52, High Risk Portfolio Analysis (showing 51% of operators and 18% of wells captured at 15% threshold, 18% x 62,720 wells = 11,290 "high risk" wells); WELC Ex. 31 (62,720 active wells in New Mexico).

Respectfully submitted,

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Energy Resources Program

Analysis of the United States Documented Unplugged Orphaned Oil and Gas Well Dataset



Data Report 1167
Version 1.1, April 2023

U.S. Department of the Interior
U.S. Geological Survey

EXHIBIT 17

Cover: Photograph of a pump jack in Guadalupe Mountains National Park, Texas. Photograph by National Park Service.

EXHIBIT 17

Analysis of the United States Documented Unplugged Orphaned Oil and Gas Well Dataset

By Matthew D. Merrill, Claire A. Grove, Nicholas J. Gianoutsos, and Philip A. Freeman

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Horizontal coordinate information is referenced to the North American Datum of 1983 (NAD 83).

Abbreviations

API	American Petroleum Institute
BIL	Bipartisan Infrastructure Law
DOI	Department of the Interior
DOW	Documented unplugged orphaned oil and gas well
GHG	greenhouse gas
IOGCC	Interstate Oil and Gas Compact Commission
R^2	linear regression coefficient of determination
USGS	U.S. Geological Survey

Analysis of the United States Documented Unplugged Orphaned Oil and Gas Well Dataset

By Matthew D. Merrill, Claire A. Grove, Nicholas J. Gianoutsos, and Philip A. Freeman

Abstract

In coordination with the U.S. Department of the Interior (DOI) and in response to the Bipartisan Infrastructure Law (BIL), the U.S. Geological Survey (USGS) produced a documented unplugged orphaned oil and gas well dataset (called the DOW dataset hereafter) that contains the location and status of these wells nationwide as of 2022. The DOW dataset includes 117,672 wells across 27 states. The data were compiled from publicly available, and often online, state agency sources. The USGS reformatted, produced coordinate locations when needed, and conducted quality control evaluations on the source material. The DOW dataset has numerous potential uses related to the topic of orphaned well locations. For example, the DOW dataset has contributed to the template behind the DOI's future orphaned well program database. Until the DOI database is complete, the USGS's DOW dataset may serve as an interim product, helping the DOI fulfill obligations in the BIL legislation. The DOW dataset can also be utilized in future USGS estimates of greenhouse gas emissions from Federal lands.

The DOW dataset is available as a USGS data release with metadata describing the sources and processing steps used in its production. An online map is also available for exploration and interaction with the DOW data. In addition to describing the DOW dataset and its generation, this report includes analyses of orphaned well completion year and well depth, produced by combining the DOW dataset with the proprietary IHS Markit database.

Introduction

Fugitive or leaking greenhouse gas (GHG) emissions, particularly methane from nonproductive oil and gas wells, impact human and environmental health (Kang and others, 2021). A well that is unplugged, nonproducing, and has no responsible operator is referred to as an orphaned well. If they are a source of emissions, these problematic wells can be remediated through proper plugging (Kang and others, 2021). The magnitude of methane emissions from orphaned wells has been documented in numerous studies (Brandt and others, 2014; Kang and others, 2014, 2016; Townsend-Small and others, 2016; Pekney and others, 2018; Riddick and others, 2019; Saint-Vincent and others, 2020; Townsend-Small and Hoschouer, 2021). In addition to releasing methane, one of the most potent GHGs, to the atmosphere, leaking wells are reported as having negative impacts on drinking water (McMahon and others, 2018; Schout and others, 2019), as well as ecosystems (Nallur and others, 2020). Emissions from these wells can also have negative economic impacts (Raimi and others, 2021).

Due to poor record keeping during much of the 150-year history of oil and gas exploration in the United States, the locations of most unplugged orphaned wells are unknown. Wells without known locations are referred to as undocumented. Based on information from most oil and gas producing states, the Interstate Oil and Gas Compact Commission (IOGCC) estimates the number of undocumented orphaned wells to be between 310,000 and 800,000 (IOGCC, 2021), though the true amount including all states is probably higher. By current estimates, there are fewer documented than undocumented wells (IOGCC, 2021). Undocumented orphaned wells, although important, are not the focus of this report because, by definition, limited information exists about them, and such wells will need to be identified using historical records, citizen reporting, gas sensors, metal detectors, remote sensing techniques, or predictive modeling (for example, Frischknecht and others, 1985; Kaminski and others, 2018; de Smet and others, 2021). Once located, an orphaned well becomes documented.

This report describes a U.S. Geological Survey (USGS) compiled dataset of documented, or location-known, orphaned oil and gas wells (hereafter called the documented orphaned well or DOW dataset for brevity and to avoid confusion with other datasets mentioned in this report). This report also provides an analysis of the DOW dataset using an additional proprietary well data source, IHS Markit (2022), to explore trends in well completion dates and well depths. The DOW dataset itself and the metadata describing its generation are available in a USGS data release (Grove and Merrill, 2022). An interactive online map of the dataset is available at https://tableau.usgs.gov/views/USOrphanedWell/Map.

A publicly available national dataset of the locations of these wells did not exist prior to the release of the DOW dataset. Maps based on unpublished datasets from the

Environmental Defense Fund/McGill University (2021) and Fellow Environmental Partners (2022) did exist prior to the publication of the DOW dataset. Since publication of the DOW, updated versions of the Environmental Defense Fund and McGill University data have been released and are publicly available (Boutot and others, 2022).

Passage of the Bipartisan Infrastructure Law (BIL) in November 2021, and specifically, "Title VI—methane reduction infrastructure, Sec. 40601: Orphaned well site plugging, remediation, and restoration" (Public Law 117-58, 135 Stat. 429), included $4.675 billion to plug these wells for the purpose of reducing GHG emissions and protecting water and ecosystem resources. Approximately 91 percent of BIL orphaned well funds were to be distributed directly to the states. The DOW dataset has contributed to BIL activities by serving as the template for the U.S. Department of the Interior's (DOI) future orphaned well program database (DOI, 2022). States received initial BIL funds in October 2022 and have begun to submit data to the DOI. Because the DOI's BIL associated database of orphaned wells is not yet complete, the USGS's DOW dataset of 117,672 documented orphaned oil and gas wells, serves as an interim product helping the DOI fulfill obligations in the BIL legislation. The DOW dataset has applications outside the DOI's BIL work as well; this information can be used for numerous purposes, ranging from academic research to land management and commercial activities to policy planning.

Methods

The DOW dataset is a compilation of well data from 27 oil and gas producing states that are thought to contain the vast majority of the orphaned wells in the United States (IOGCC, 2021) (table 1). Most oil and gas producing states maintain records of these documented unplugged orphaned wells with varying completeness. Some states, which only recently reported orphaned wells, were not included in the DOW dataset due to when the data were collected. Arizona, excluded from the 2022 DOW dataset, has 263 documented orphaned wells according to Boutot and others (2022). As states actively increase their efforts to document these wells and access funding under the BIL for remediation, well number inconsistencies and even state exclusions are a potential result of the rapidly changing condition of orphaned well reporting.

The first step in producing the DOW dataset was to search for published orphaned well data. Some existing orphaned well lists include not only confirmed orphaned wells, but also pending or presumed orphaned wells. These wells were included in the DOW dataset, unless communications with the originating state agency suggested otherwise. When specifically labelled orphaned well information was not publicly available in reports or online databases, the applicable state agency was contacted to request data directly or inquire how the USGS could generate an orphaned wells list using available datasets and specific filtering terms. If contact could not be established, a dataset of all state wells was obtained from public state sources and filtered to approximate, as best as possible, a set of wells that met USGS criteria to be considered orphaned. The well criteria used to presume orphaned status were that the well was unplugged, had no responsible operator, and had no production for at least one year. Well status terms used by the 27 states in the DOW dataset to indicate a well is orphaned are provided in table 1. Terms or statuses in the table followed by a parenthetical USGS label indicate that a state-provided orphaned well list was not available at the time of data collection and that the authors used that term as part of applying the orphaned well criteria. State-specific sources and data compilation steps for producing the DOW dataset are provided in the metadata of the USGS data release (Grove and Merrill, 2022).

Once the datasets were collected from the 27 states, they were reformatted and compiled. Although the original well information from the states often contained numerous parameters, the goal of the DOW dataset is to provide only well location coordinates and basic well identification information (for example, a unique identification number, well or lease name, and well number). No other information from the state agencies were included. Wells without locations or with dubious locations, such as a general or uniform generic location for all unknown locations within a county, were excluded. Due to this filtering process, and the specific date the data were obtained, the total number of wells in this DOW dataset may not match counts published elsewhere (for example, Boutot and others, 2022). Wells without an American Petroleum Institute (API) number, a unique well identifier standard, but with a viable location, were assigned a unique USGS identification number relevant only to the DOW dataset. Additional analyses, research, and reporting is possible using the included unique identification information to link to other public and proprietary datasets.

Most of the data in the DOW dataset were not modified from the source material, resulting in a less curated, but highly transparent, dataset that preserves the original source material. Modifications of existing data were limited to basic quality control checks, such as purging duplicate wells, general coordinate checking, and API number formatting. Well-by-well location verification using satellite imagery or political boundaries was not performed, and data were not checked against other public or proprietary sources to confirm their validity. Supplementary information included in the DOW dataset was limited to adding missing location or identification data, and informational notes. For example, some states provided location information in the public land survey system format and this information was converted into latitude and longitude coordinates. Full citations of sources and process steps for the DOW dataset are provided in the metadata of the USGS data release (Grove and Merrill, 2022).

Table 1. Summary information including state, well counts, the data file date, and terms or statuses used by the state or the U.S. Geological Survey to generate the list of orphaned wells.

[USGS, U.S. Geological Survey; NA, not applicable]

State	Orphaned wells	Data file date	Terms/statuses used
Alabama	49	1/18/2021	Abandoned (USGS)
Alaska	12	3/4/2021	Orphan
Arkansas	349	6/17/2021	Abandoned orphan
California	3,338	12/31/2019	Deserted, potentially deserted, orphan
Colorado	409	7/1/2019	Orphan
Illinois	8,480	5/3/2022	Orphan
Indiana	575	1/24/2022	Orphan
Kansas	5,477	4/18/2022	Abandoned
Kentucky	12,695	7/1/2021	Orphan
Louisiana	4,484	12/10/2021	Orphan
Michigan	472	5/27/2022	Orphan
Mississippi	30	5/2/2022	Orphan
Missouri	4,893	6/29/2020	Abandoned, abandoned known location, abandoned no evidence found, abandoned unknown location, orphaned (USGS)
Montana	221	4/14/2021	Orphan
Nebraska	479	12/13/2021	Abandoned, shut in
Nevada	63	1/6/2020	Abandoned (USGS)
New Mexico	652	4/22/2022	Orphan, needs both plugging and reclamation
New York	7,029	12/6/2021	Unknown, unknown located, unknown not located
North Dakota	953	1/6/2022	Abandoned (USGS)
Ohio	20,557	5/11/2022	Orphan, potential orphan, additional card, record review
Oklahoma	15,971	11/19/2021	Orphan
Pennsylvania	19,160	5/9/2022	Orphan
Tennessee	481	12/9/2021	Forfeited
Texas	5,854	12/31/2021	Orphan
Utah	72	11/8/2021	Orphan
West Virginia	3,594	8/11/2021	Abandoned and operator unknown (USGS)
Wyoming	1,323	6/2/2022	Orphan, gas orphaned, oil orphaned, disposal orphaned, injector orphaned, monitor well orphaned
Total	117,672	NA	NA

Results

There are 117,672 wells in the DOW dataset (Grove and Merrill, 2022); the well counts by state are provided in table 1 and illustrated in figure 1. The national orphaned well count is constantly evolving owing to efforts by the states to update their databases, and as new orphaned wells are identified and plugged. Furthermore, the number of documented unplugged orphaned oil and gas wells is likely to increase as states use funding from the BIL to identify more wells. A data file date is provided for each state in table 1 to show the recency of the information compiled for the DOW dataset. Figure 1 shows the quantity of orphaned wells by state. Higher orphaned well counts are recorded in the eastern and midwestern states. Figure 2 provides greater detail on the concentration of the documented unplugged orphaned wells. The map indicates the number of wells per 10 by 10-mile (100 square mile) grid cell.

EXHIBIT 17

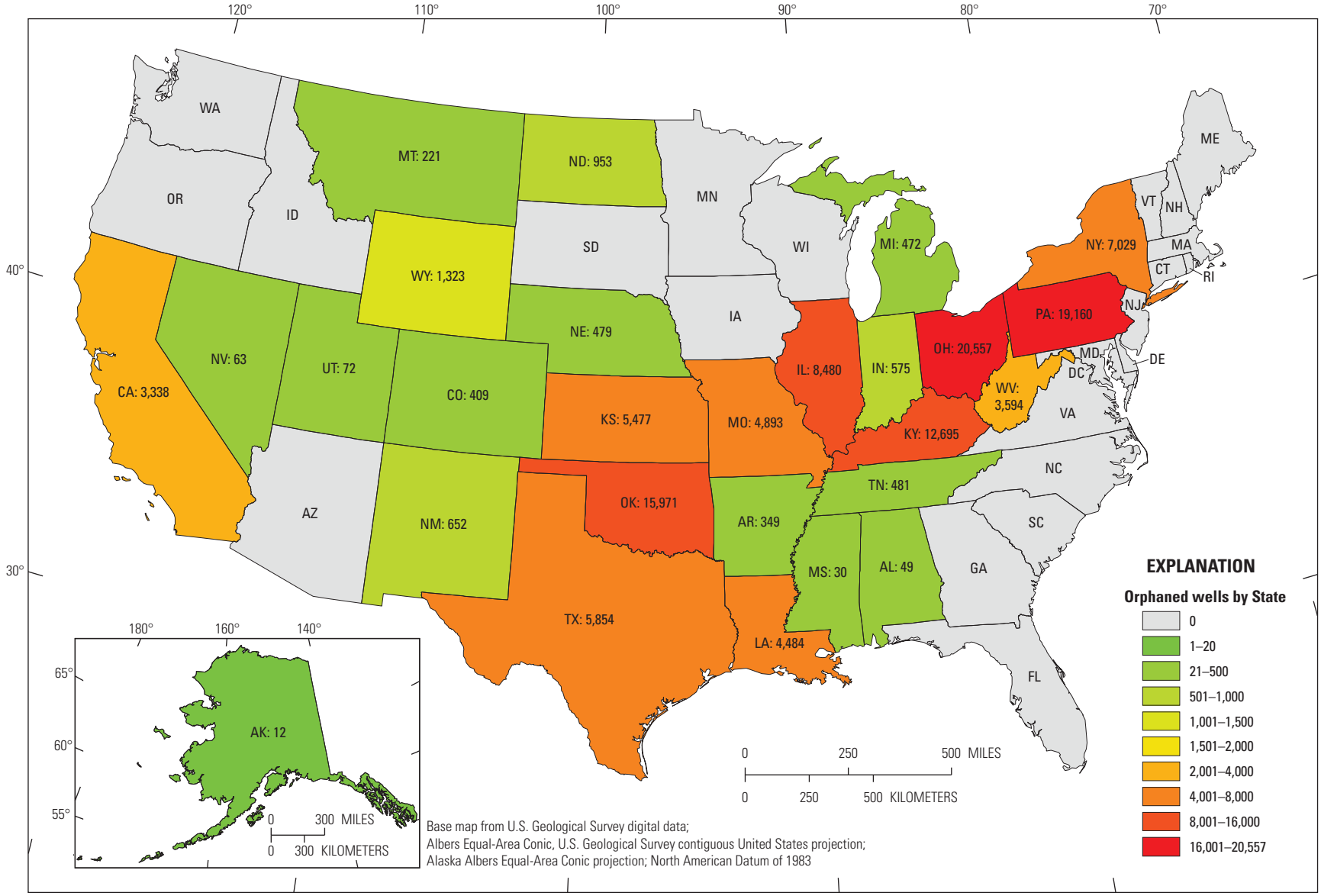


Figure 1. Map of the continental United States showing the number of orphaned wells in each state. States where no well data were collected are shown in grey, although those states may contain documented orphaned wells.

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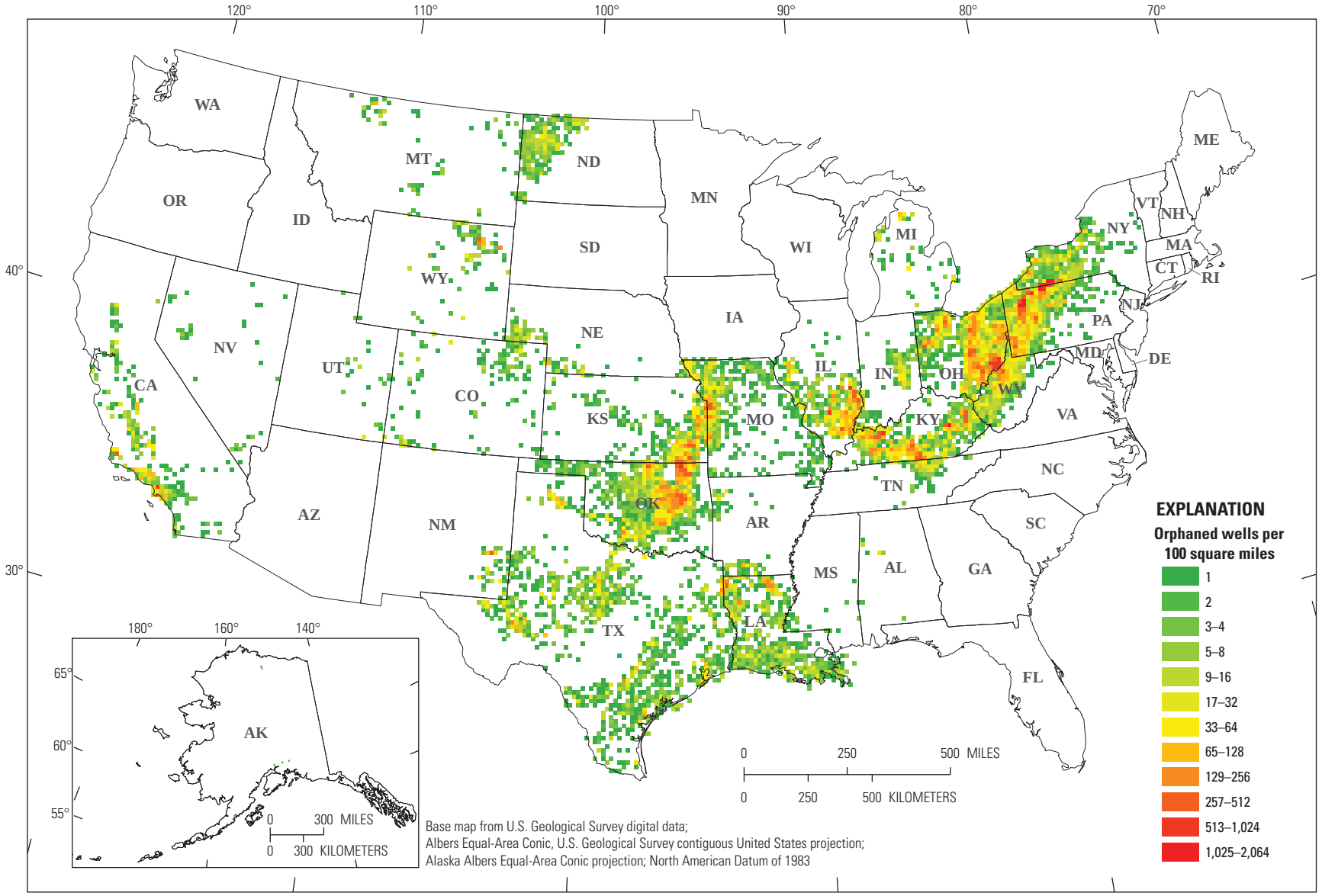


Figure 2. Map of the continental United States indicating the well density per 100 square mile grid cell of 117,672 unplugged orphaned wells in the 27 states included in the documented orphaned oil and gas well (DOW) dataset. Note the exponential scale of the coloring scheme used to preserve detail across both lower and higher well densities.

Discussion

The DOW dataset contains a limited number of parameters from the original state sources in order to produce a more complete compiled product. Location information from the DOW show there are higher numbers of wells in the eastern and midwestern states, where oil and gas exploration got an earlier start. This reflects a time in the second half of the 19th century when record keeping was less regulated. Limited record keeping and well-plugging regulations during that early period has resulted in more documented, and presumably undocumented, orphaned wells in those states (IOGCC, 2021). To provide a more in-depth discussion of the DOW dataset, additional information from other databases is included in the following text.

Analysis of the DOW dataset using data from the proprietary IHS Markit (2022) database (hereafter, IHS Markit) provides additional context to the orphaned well information in the DOW. Each well in the DOW dataset has a unique identifier which, in most instances, is an API number. This API number acts as a cross reference value with the IHS Markit database. Of the 117,672 wells in the DOW dataset, 110,976 wells (94 percent) have API numbers. Those missing an API number include all 5,477 wells in Kansas, all 575 wells in Indiana, a subset of 334 wells in Illinois, a subset of 242 wells in Louisiana, and a subset of 68 wells in Kentucky. Wells without an API number in the DOW dataset were not included in the following data parameter analysis of the orphaned wells.

IHS Markit provides additional well information not included in the DOW dataset. Well data from the proprietary IHS Markit database were accessed for the 110,976 wells in the DOW dataset with API numbers. The DOW and IHS Markit data are paired for this orphaned well parameter analysis because IHS Markit does not contain orphaned well status information. In addition, the proprietary nature of the commercial database precludes releasing well-specific information publicly, therefore IHS Markit data is neither included in the DOW dataset nor used to confirm any DOW dataset information.

The IHS Markit data provide "Completion Date" and "Driller Total Depth" for 69,347 of the orphaned wells in the DOW dataset; these parameters were combined with the DOW dataset to produce a DOW/IHS Markit merged subset used in the following discussion. Completion dates are depicted in figure 3, showing the number of orphaned wells by the year drilling was completed. In the merged subset data, 11,866 wells had a completion year of 1801; these wells were not included in figure 3 since they pre-date drilling in the United States, however the date is presumably a place holder for unknown drilling dates from the 1800s. Similarly, 1,983 wells in Pennsylvania have a completion year of 1901 in the DOW/IHS Markit subset; it is presumed that this is a similar place holder, but these wells are included in figure 3 to show their magnitude. Annual well completions, for wells that are currently orphaned, increase and decrease between 1860 and 2022, with a stark increase around 1940, followed by a rise in the 1950s, and a peak around 1980 (fig. 3). The three years with the most completed wells that were later orphaned happened in succession in 1980 (2,070 wells), 1981 (2,555 wells), and 1982 (2,151 wells). There was a small surge in annual well completions in 2007 followed by a decline through 2022 (fig. 3).

To gain a sense of the proportion of wells drilled that later become orphaned, figure 3 also includes the total wells drilled annually from 1949 to 2021 (U.S. Energy Information Administration, 2022); this shows that annual drilling

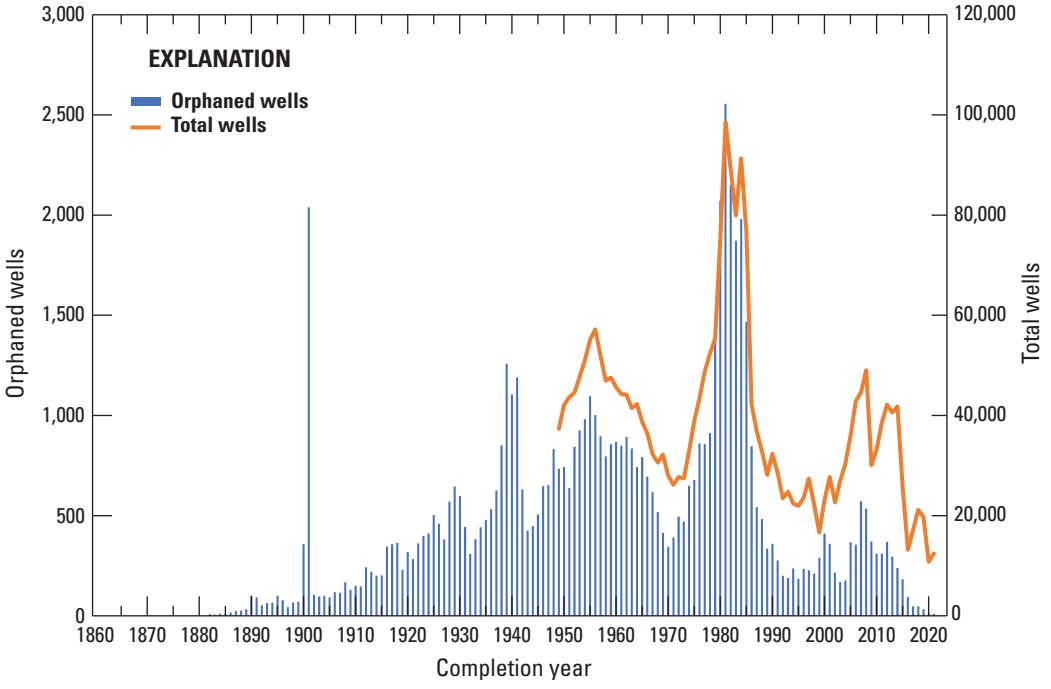


Figure 3. A histogram of 69,347 orphaned wells from the documented orphaned well (DOW) dataset displaying the number of orphaned wells drilled per year (1860–2022) using the completion date from IHS Markit (2022) in blue (left axis). Total annual wells from U.S. Energy Information Administration (2022) are in orange at a different scale (right axis).

completions for wells that later became orphaned correlate with overall annual drilling completions for all wells. When drilling increases, so do the number of wells that eventually become orphaned (fig. 4). Figure 4 shows orphaned wells in the DOW/IHS subset plotted against the total number of wells drilled in the United States by the year they were completed. The ratio of the two datasets to each other represent the proportion of wells over time that later become orphaned. The overall ratio of DOW/IHS orphaned wells to total wells drilled annually in the United States is indicated by the best fit trendline near 2 percent (R^2 = 0.91 linear regression with a forced 0 intercept); additional ratio lines of 0.5, 1, and 3 percent show that the best fitting ratio is not consistent across the years of the dataset (fig. 4). The ratio of orphaned wells in the DOW/IHS Markit subset to the total number of U.S. wells drilled annually in the years 1949 to 2021 ranges from a low of 0.08 percent in 2021 to a peak of 2.74 percent in 1980, with an average of 1.42 percent (fig. 5). The ratio is relatively consistent from 1949 to 1978 (except for a drop in the late 1960s), followed by a spike from 1979 to 1984, the same approximate years when total well drilling also spiked during the energy crisis. Since 1985, the ratio has decreased at a general overall rate of 0.05 percent per year to 2021, where the ratio is 0.08 percent. This declining orphaned well proportion is expected as new and more expensive wells are generally still producing and state agencies now require improved accountability from operators. Because the DOW dataset contains only documented orphaned wells, the orphaned ratios reported herein do not suggest that an average of 1.42 percent of all wells become orphaned in all years. These results are only relevant to documented orphaned wells and, therefore, are probably most applicable to years since the middle of the 1900s where few, if any, undocumented wells are expected to exist. Trends for the larger and, generally, older unknown population of undocumented orphaned wells may be significantly different.

The depths of the wells in the DOW/IHS Markit subset are plotted by the year of completion in figure 6. Well depth provides additional context for well remediation and risk assessment. Knowing which formations are penetrated by the well and what other wells or faults may be in the same depth space is important for determining potential leakage pathways. The data shown in figure 6 is the "Driller Total Depth" from IHS Markit, more commonly known as the measured depth, and is essentially the total length of the well bore rather than the true vertical depth from the surface. Ninety-eight percent of the data in figure 6 are from vertical wells, where the measured depth and vertical depth are marginally the same; however, horizontal wells can have significantly greater lengths, or measured depth, compared to their true vertical depth. The nationwide increase in the proportion of horizontal wells starting in 1990 is also seen in the dataset shown in figure 6. The graph shows that wells before 1925 were generally less than 5,000 feet deep, and measured depth increased through time. Many wells from 2010 to 2019 exceed 20,000 feet in length, with the longest well, a horizontal one, drilled to a measured depth of 23,670 feet in 2011. Despite these recent significant depths, 90 percent of wells in the DOW/IHS Markit subset, that also had measured depth information (59,881/66,205 wells), are less than 5,000 feet long.

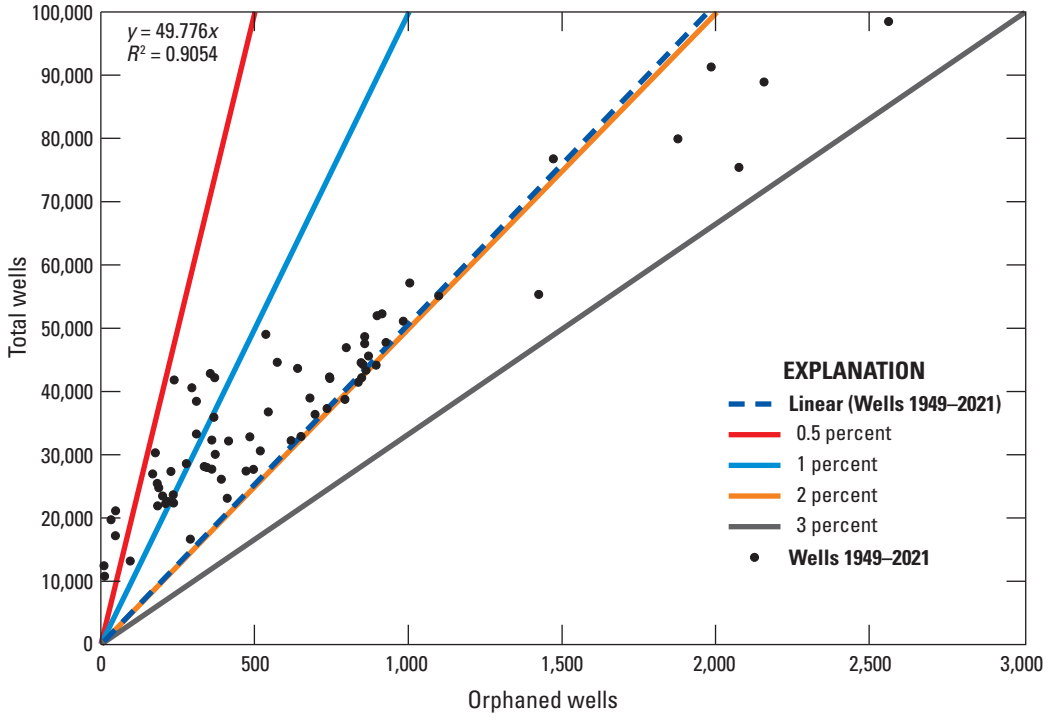


Figure 4. Graph showing the correlation between the orphaned wells in the documented orphaned oil and gas wells (DOW)/IHS Markit merged dataset and total number of wells in the United States by the year they were completed between 1949 and 2021 (U.S. Energy Information Administration, 2022). This relation can be used to generate a ratio of documented orphaned wells to total wells. Lines indicating ratios from 0.5 to 3 percent are included. In the top right of the graph are 6 points that plot with a ratio of between 2 and 3 percent, these points represent the highest ratios of orphaned to total wells and are associated with a spike in drilling from 1980 to 1985 in response to the energy crisis.

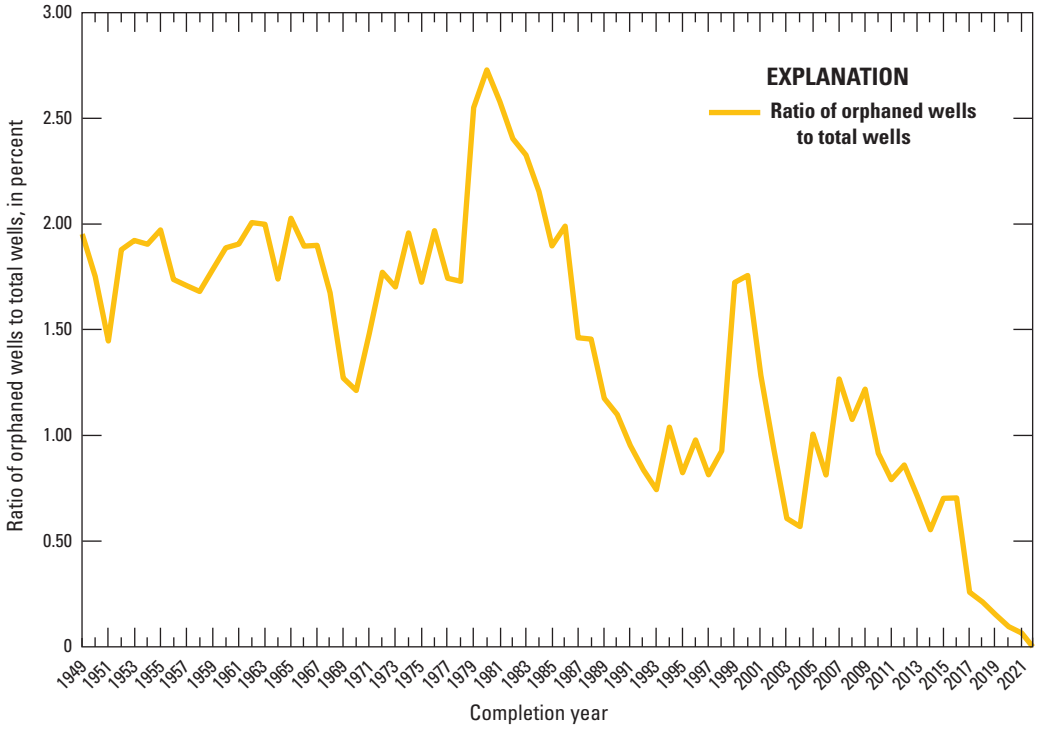


Figure 5. Graph showing the ratio of the orphaned wells in the documented orphaned oil and gas wells (DOW)/IHS Markit merged dataset to the total number of wells in the United States by completion year as a percentage.

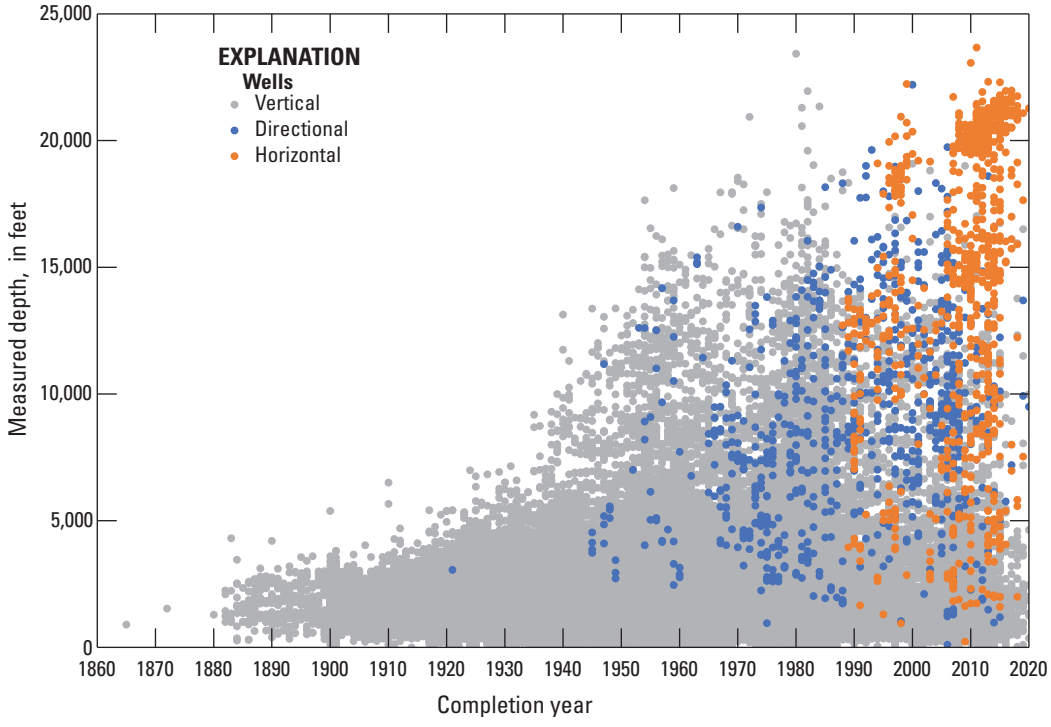


Figure 6. Graph of 66,205 orphaned wells with measured depth by completion year and well direction (vertical, directional, and horizontal) using IHS Markit (2022) data.

Summary

The U.S. Geological Survey (USGS) produced a dataset of documented, unplugged, orphaned oil and gas wells referred to as the documented orphaned oil and gas well (DOW) dataset (Grove and Merrill, 2022). As of 2022, the dataset includes 117,672 wells across 27 states that are presumed to include the majority of documented orphaned wells in the United States. These data capture the status of orphaned wells within the United States and are an initial effort at producing a publicly available dataset of national orphaned wells. This dataset was also compiled in support of the Bipartisan Infrastructure Law (BIL) "Title VI—methane reduction infrastructure, Sec. 40601: Orphaned well site plugging, remediation, and restoration" (Public Law 117-58, 135 Stat. 429), which included nearly $4.7 billion to reduce greenhouse gas (GHG) emissions and protect water and ecosystem resources through well plugging and remediation.

Combining the DOW with the proprietary IHS Markit (2022) database provided the opportunity to evaluate trends in the orphaned well data that could not be achieved with either data source on their own. The full 117,672 wells of the DOW were not able to be paired with the IHS Market data, but a subset of approximately 70,000 wells revealed trends over time in the proportion of all wells that eventually became orphaned. This ratio peaked in 1980 at 2.74 percent and corresponds with increased drilling during the energy crisis.

The DOW dataset can be applied to other federal activities related to orphaned wells and GHG emissions. The DOW contributed to the template generated by the U.S. Department of the Interior (DOI) for tracking orphaned wells and progress on their reclamation (DOI, 2022). Until the DOI's own orphaned well database is complete, the DOW dataset may be used by the DOI to fulfill additional obligations in the BIL. The DOW dataset could also be used in any future updates to the USGS's "Federal Lands Greenhouse Gas Emissions and Sequestration in the United States: Estimates for 2005–2014" (Merrill and others, 2018). These emissions and sequestration estimates follow the general methods described in the "Inventory of U.S. Greenhouse Gas Emissions and Sinks" (U.S. Environmental Protection Agency, 2022), and could be improved with a better understanding of orphaned well numbers and locations. The DOW dataset may lead to improved emissions estimates per well using DOW location data. Such research could benefit both the USGS and Environmental Protection Agency emissions estimates.

The overarching and long-term contribution of the DOW dataset is providing previously uncompiled, and therefore unavailable, information to everyday users. This legacy infrastructure data can help inform decisions about lands and their use. Leaking wells can release methane, one of the most potent GHGs, to the atmosphere. In addition to climate implications, these releases also have negative impacts on drinking water, ecosystems, and the economy (McMahon and others, 2018; Schout and others, 2019; Nallur and others, 2020; Raimi and others, 2021). Datasets like the DOW can provide a foundation for future research into these impacts and potentially their remediation.

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New Mexico Oil and Gas Liability Assessment

Prepared for:
New Mexico State Land Office

Prepared by:
Vertex Resources Services Inc.

Submission Date:
March 2021

FINAL

EXHIBIT 19

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Version Control Log

Version	Date	Description of Changes
IFR	July 31, 2020	Draft Issued for Review
IFR Rev 1	September 30, 2020	Updated counts to reflect all wells in New Mexico (on State Lands and otherwise)
IFR Rev 2	October 14, 2020	Updated Surface Reclamation sections and removed discussion of expanded scope
IFR Rev 3	November 2020	Updated plugging and abandonment costs to reflect New Mexico-specific rates
IFR Rev 4	March 2021	Updated all formatting, completed data gap discussions and included section for Commercial Lease liabilities

EXHIBIT 19

1.0 Introduction

Vertex Resource Services Inc. (Vertex) completed an assessment of oil and gas assets to determine a liability estimate for all assets located within lands owned by the New Mexico State Land Office (SLO). The SLO owns lands throughout the state of New Mexico, with landholdings directly or indirectly related to oil and gas production concentrated within the Permian and San Juan Basins. Figures 1 and 2 below indicate the locations of lands owned by the SLO; Figure 1 presents the entire boundary of State lands and Figure 2 presents the locations of participating areas within those boundaries.

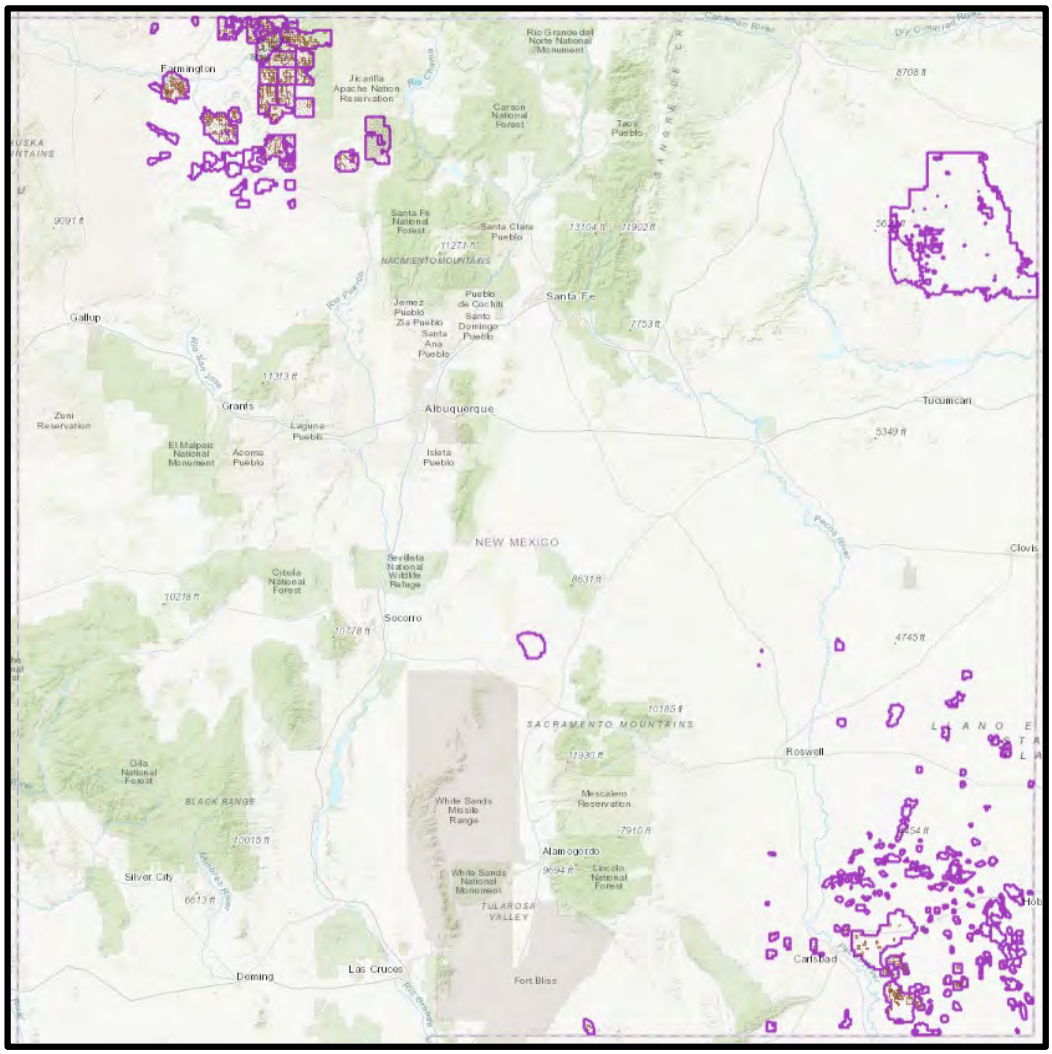


Figure 1. Map of Boundary Areas (Source: New Mexico State Land Office)

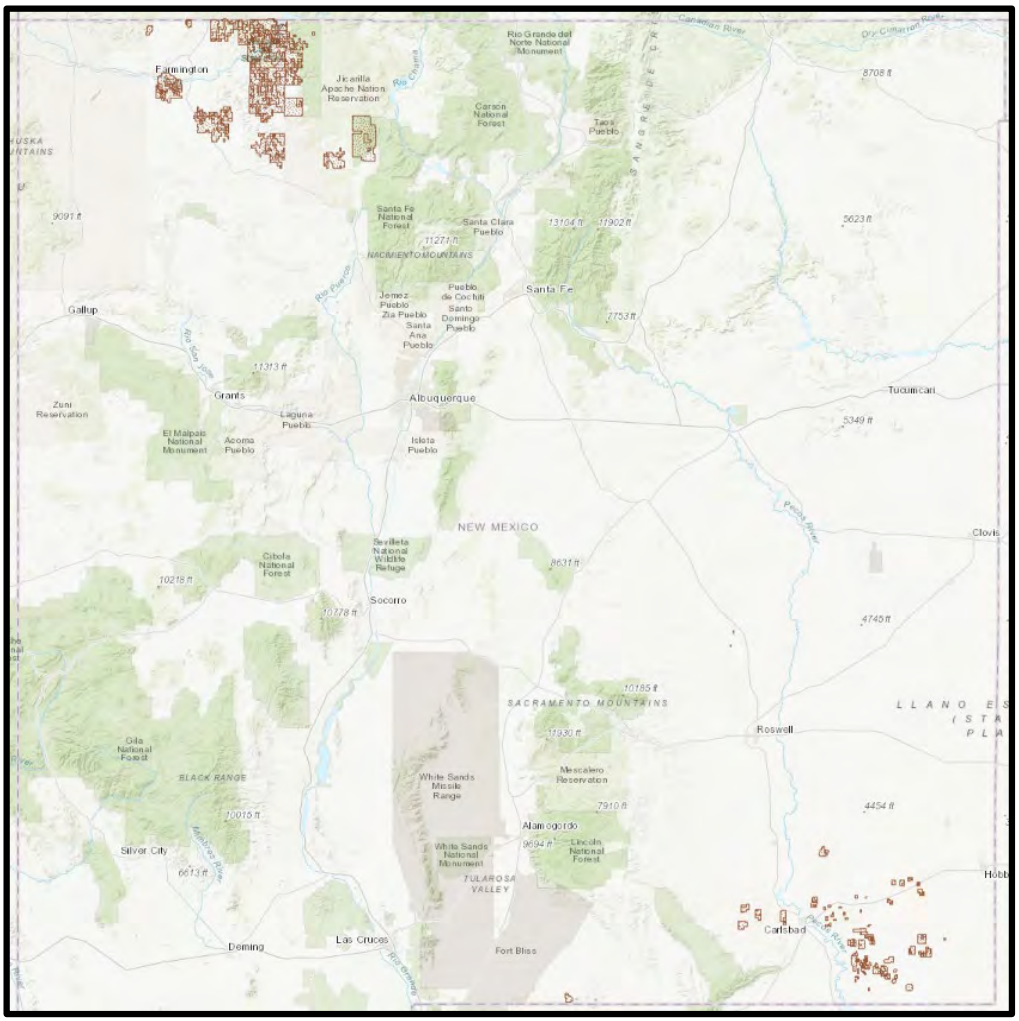


Figure 2. Map of Participating Areas (Source: New Mexico State Land Office)

A review of state-owned assets indicates that there are three primary types of oil and gas-related activities associated with SLO lands:

- Oil and gas well leases
- Oil and gas pipeline rights-of-way (ROW)
- Oil and gas-related commercial leases

1.1 Oil and Gas Well Leases

A review of asset inventory from data provided indicates that there is a total of 14,061 wells located on SLO lands. Of this total, 14,051 will require plugging, abandonment and reclamation activity; the remainder are classified as "Abandoned" and "Never Drilled". Table 1 presents a breakdown of well status.

For comparison purposes, a secondary review was completed to include all wells in the State, on state land or otherwise. A review of asset inventory from data obtained from the New Mexico Oil Conservation Division (OCD) as of July 23, 2020, indicates that there is a total of 123,223 wells located across the State. Of this total, 66,128 wells will require plugging, abandonment and reclamation activity; the remainder are classified as "Cancelled", "Never Drilled" and "Plugged (site released)". Table 2 presents a breakdown of the status of all wells within New Mexico.

Table 1. Status Breakdown of Wells on State Lands

Well Status	Well Count	Required to be Plugged and Abandoned?
Abandoned	1	No
Active	12,480	Yes
Dry Hole	1	Yes
Never Drilled	9	No
New	1,211	Yes
Shut In	10	Yes
Temporary Abandonment	276	Yes
Temporary Abandonment (Expired)	71	Yes
Zone Plugged (Permanent)	1	Yes
Zone Plugged (Temporary)	1	Yes
Total	**14,050 wells**	

Table 2. Status Breakdown of All Wells in New Mexico (includes wells on State Lands)

Well Status	Well Count	Required to be Plugged & Abandoned?
Active	57,431	Yes
Cancelled	13,664	No
Dry Hole	11	Yes
Never Drilled	22	No
New	6,290	Yes
Plugged (Not Released)[1]	1,202	Yes
Plugged (Site Released)[2]	43,409	No
Shut In	128	Yes
Temporary Abandonment	751	Yes
Temporary Abandonment (Expired)	272	Yes
Zone Plugged (Permanent)	28	Yes
Zone Plugged (Temporary)	14	Yes
Observation	1	Yes
Total	**64,915 wells**	

[1] Wells have had some downhole plugging work completed but have yet to be cut and capped

[2] Wells have been plugged, cut and capped, and sites reclaimed

1.2 Pipeline Rights-of-Way

Pipeline inventory for the entire state of New Mexico was obtained utilizing data from S&P Global Platts, 2020. The pipeline inventory data was used in conjunction with geographical information system (GIS) data for SLO lands to

approximate the total length of pipeline located on SLO-managed lands, or roughly 15% of the pipelines in the state. A similar analysis was completed for all pipelines within the state, whether SLO managed or not, for a total calculation of approximately 16,087 miles of pipeline within the state of New Mexico.

1.3 Oil and Gas-Related Commercial Leases

A final component of oil and gas-related activities occurring on SLO-managed lands is broadly defined as oil and gas commercial leases. This designation covers a wide range of activities that can be tied to oil and gas production but, in some instances, may include midstream or final processing facilities. While detailed information and inventory data for this subsection of oil and gas-related activity is not currently available to the public, a thorough evaluation of the potential SLO liabilities arising from oil and natural gas activities would not be complete with discussing this commercial lease aspect.

1.4 Total Liability Assessment

The total liability assessment for New Mexico SLO related to oil and gas interests on SLO lands is a summation of the estimated liabilities for each type of activity occurring on those lands.

The total liability assessment for all oil and gas activities includes estimated costs for:

- Downhole Abandonment
- Wellpad Surface Facility Decommissioning
- Pipeline Decommissioning
- Commercial Lease Surface Facility Decommissioning
- Surface Reclamation

2.0 Downhole Abandonment – Basis of Estimate

2.1 Scope

Per the OCD, plugging and abandonment of wells is regulated by 19.15.25 of the New Mexico Administrative Code (NMAC). Section 10A states:

- Before an operator abandons a well, the operator shall plug the well in a manner that permanently confines all oil, gas and water in the separate strata in which they are originally found. The operator may accomplish this by using mud-laden fluid, cement and plugs singly or in combination as approved by the division on the notice of intention to plug

Conditions for Plugging and Abandonment according to the OCD – Southern District (Appendix A) have been developed to ensure the above Regulation is maintained. This document defines the following downhole conditions to be met:

- A cement evaluation tool is required to ensure isolation of producing formations, protection of water and correlative rights. A cement bond log or other accepted cement evaluation tool is to be provided to the division for evaluation if one has not been previously run or if the well did not have cement circulated to surface during

the original casing cementing job or subsequent cementing jobs

- Mud laden fluids must be placed between all cement plugs mixed at 25 sacks per 100 bbls of water
- All cement plugs will be a minimum 100 ft in length or a minimum of 25 sacks of cement, whichever is greater
- Class 'C' cement will be used above 7,500 ft; Class 'H' cement will be used below 7,500 ft
- A cement plug is required to be set 50 ft above and 50 ft below:
    - Casing stubs
    - DV tools
    - Attempted casing cut offs
    - Cement tops outside casing
    - Salt sections
    - Anywhere the casing is perforated
- All casing shoes will be perforated 50 ft below shoe depth and attempted to be squeezed; cement needs to be 50 ft above and 50 ft below casing shoe inside the production casing
- A Cast Iron Bridge Plug (CIBP) is to be set within 100 ft of production perforations and capped with 100' of cement (35 ft of cement may be used if set with a bailer within 100 ft of the top perforation)
- No more than 3,000 ft is allowed between cement plugs in cased hole and 2,000 ft in open hole
- Formations to be isolated with cement plugs are:
    - Fusselman
    - Devonian
    - Morrow
    - Wolfcamp
    - Bone Springs
    - Delaware
    - Any salt sections
    - Abo
    - Glorieta
    - Yates
    - Potash (in the R-111-P Potash Mine Area) – a salt saturated cement plug must be set across the section, solid from 50 ft below formation bottom to 50ft above formation top

  If cement does not exist behind casing at these formation depths, perforations will be shot and cement squeezed behind the casing. These plugs will be set 50 ft below formation bottom to 50 ft above formation top inside the casing

It is the intent of this evaluation to present a realistic range of cost values to be expected for downhole plugging and abandonment of the wells in the State. A range is provided to allow for reasonable assumptions to be made on a smaller scale that is representative of the larger magnitude of wells.

All wells were grouped according to the following criteria:

- District
- Fluid (oil, gas, saltwater disposal)
- Profile (vertical/directional, horizontal)

- Depth (shallower than 5,000 ft; 5,000 ft to 10,000 ft; deeper than 10,000 ft)

Wells were randomly selected from each grouping and the well files from the OCD web database were reviewed to determine the following information, and to assign the groupings into an estimate category per Table 1.

- Well type (flowing, pumping, injection)
- Completion type (cased and perforated, open hole)
- Number of producing zones / pools
- Casing profiles (surface, intermediate, production, liners)
- Record of Cement Bond Logs
- Cement Tops

Table 3. Well Abandonment Cost Estimate Categories

Estimate Name	Well Total Measured	Downhole Equipment	Producing Pools
ST1	<5,000 ft	Tubing	1 zone
ST2	<5,000 ft	Tubing	2 zones
MT1	5,000ft – 10,000ft	Tubing	1 zone
MT2	5,000ft – 10,000ft	Tubing	2 zones
DT1	>10,000 ft	Tubing	1 zone
DT2	>10,000 ft	Tubing	2 zones
SR1	<5,000 ft	Pump and Rods	1 zone
SR2	<5,000 ft	Pump and Rods	2 zones
MR1	5,000ft – 10,000ft	Tubing	1 zone
MR2	5,000ft – 10,000ft	Tubing	2 zones
DR1	>10,000 ft	Pump and Rods	1 zone
DR2	>10,000 ft	Pump and Rods	2 zones
E	All depths	Empty wellbore	Dry hole / plugged well

Each grouping was then assigned abandonment requirements, per downhole well abandonment activities consisting of:

- Removal of all downhole equipment including, but not limited to:
  - Pump and rods
  - Tubing
  - Packers
- If a cement evaluation is not available in the well file or cement was not circulated to surface during the original casing cementing job or subsequent cementing jobs, run a Cement Bond Log (does not apply to all wells)
- Set a CIBP within 100 ft of perforations and dump bail 35 ft of cement on the plug. Repeat for each producing zone, ensuring no more than 3,000 ft between plugs
- If an intermediate string is installed, perforate 50 ft below shoe depth. Run a Cast Iron Cement Retainer (CICR), set within 50 ft of perforations and squeeze (does not apply to all wells)
- If a low cement top is known and/or calculated and/or cement does not exist behind casing at the above noted formations, perforate 50 ft below the flagged formation bottom. Run a CICR, set within 50 ft of perforations

and squeeze. Perforate 50 ft above the formation top. Run a CICR, set within 50 ft of the perforations and squeeze. Repeat for each exposed formation (does not apply to all wells)

- Perforate 50 ft below surface casing shoe depth. Run a CICR, set within 50 ft of perforations and squeeze
- Excavate the wellhead area to cut the casing 3 ft below ground level. Install and weld on casing cap with information marker plate
- If a well was recorded as previously plugged or dry hole, it was assumed that no downhole equipment requiring removal was in place and the well had been appropriately plugged per the abandonment requirements set above. These wells were designated Empty (cost estimate type E) and require only wellhead cut and cap procedures

2.1.1 Wells on State Lands

A map of the wells on state lands in New Mexico according to District is presented on Figure 3.

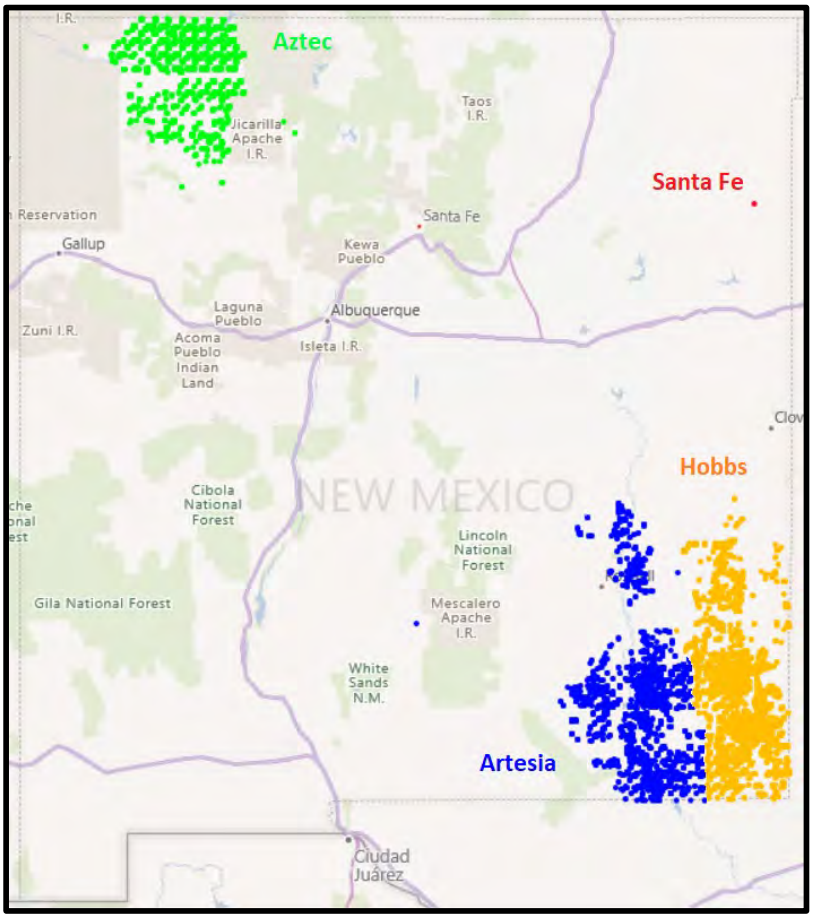


Figure 3. Map of Wells on State Lands by District (Source: Cartofact, August 2020)

Of the 14,061 wells located on State Lands, 14,051 wells will require plugging, abandonment and reclamation activity. Of this total, 1,300 wells do not have a public record of a final measured well depth. If an actual drill depth was not

available in the data pull, the Well Target Depth (as assigned by the operator) was used in order to assign each well a category. For the 148 wells that did not have record of a Well Target Depth, the category was assumed based on offset well information. A summary of the well grouping per the scope requirements in Section 2.1 and well file inspection results is included in Appendix B.

2.1.2 All Wells in New Mexico

The extended scope includes all wells in New Mexico; the wells requiring abandonment activities are mapped according to District on Figure 4.

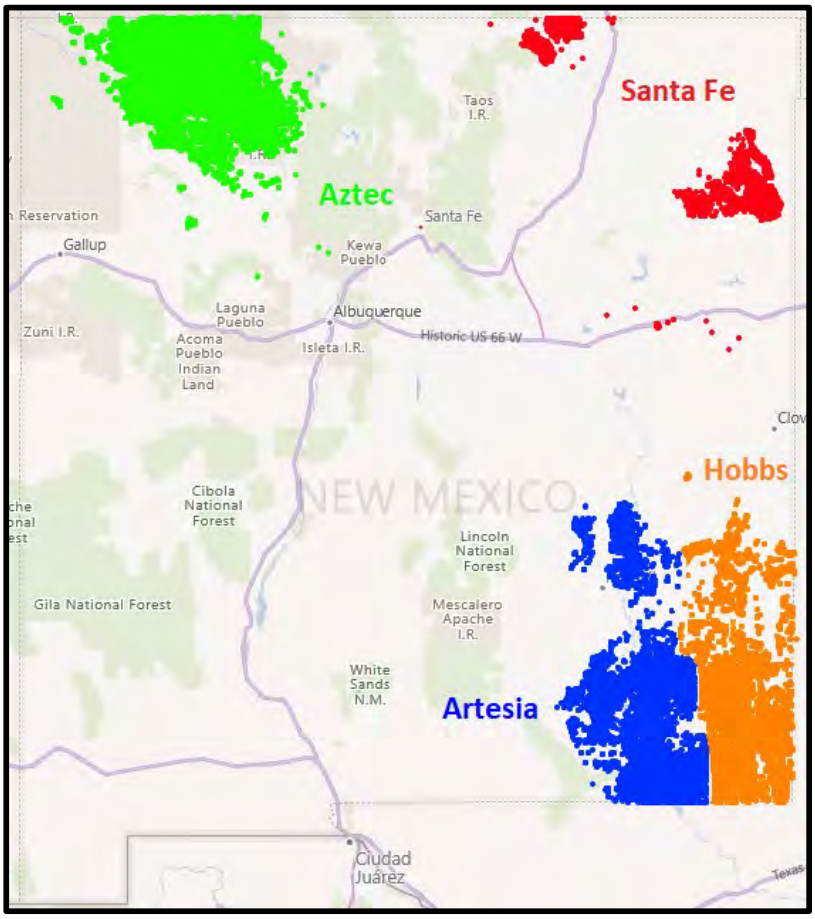


Figure 4. Map of All Wells in New Mexico by District (Source: Cartofact, September 2020)

Of the 123,223 total wells located across the State, 64,915 wells will require plugging, abandonment and reclamation activity. Over 7,300 of these wells do not have public record of a final measured well depth; therefore, the assumption was made to use the Well Target Depth to assign each well a category. For the approximately 1,300 wells that did not have a Well Target Depth, the category was assumed based on offset well information. A summary of the well grouping per the scope requirements in Section 2.1 and well file inspection results is included in Appendix B.

2.2 Cost Estimate Details

Abandonment activities were determined for each category in Table 3 per scope requirements in Section 2.1. Cost estimates were generated according to the standard abandonment activities required for each well type that would apply to all wells in the category. Activities and time required were determined based on Vertex abandonment experience across North America. Rates local to the state of New Mexico were included in the estimates, according to the actual invoices received from the SLO for recent abandonment activities (see additional details in Section 2.3).

Table 4. Standard Well Abandonment Activities and Cost

	Abandonment Activities (number of days)						
Estimate Name	**MIRU, hot-wash rods and pull BHP**	**Pull tubing, bit and scraper**	**Set plug to isolate perfs**	**Balance cement plug**	**Perf shoes, run retainer, cement squeeze**	**Total Days**	**Total Cost**
ST1		1.0	0.5	0.5	1.0	3.0	$50,400
ST2		1.0	1.0	0.5	1.0	3.5	$59,900
MT1		1.0	0.5	1.0	1.0	3.5	$57,000
MT2		1.0	1.0	1.0	1.0	4.0	$66,500
DT1		1.5	0.5	1.0	1.5	4.5	$70,400
DT2		1.5	1.0	1.0	1.5	5.0	$79,800
SR1	1.0	1.0	0.5	0.5	1.0	4.0	$64,300
SR2	1.0	1.0	1.0	0.5	1.0	4.5	$73,800
MR1	1.0	1.0	0.5	1.0	1.0	4.5	$71,000
MR2	1.0	1.0	1.0	1.0	1.0	5.0	$82,000
DR1	1.0	1.5	0.5	1.0	1.5	5.5	$84,300
DR2	1.0	1.5	1.0	1.0	1.5	6.0	$93,800

A portion of the wells in each category will require additional activities per the regulatory standards.

- If a Cement Bond Log (CBL) does not exist in State records, a log must be conducted
- If an intermediate casing string is installed, the casing shoe must be perforated and squeezed
- If the cement top is low and a flagged zone (per Section 3.1) is not isolated, the casing must be perforated and squeezed

Table 5. Additional Well Abandonment Activities and Cost

Abandonment Activity	**Total Days**	**Total Cost**
Run CBL	0.5	$8,500
Intermediate shoe: perf, run retainer, cement squeeze	1.0	$18,500
Low cement top: perf, run retainer, cement squeeze	1.5	$30,200

The portion of wells in each grouping requiring additional activities per the regulatory standards was estimated based on a review of randomly selected well files. These percentages are assumed to be relative to the investigation sampling but could change with additional study. To account for potential discrepancies in the assumptions made regarding the

areas with higher well counts, variances are presented.

- Cement Bond Logs:
  - Based on the limited number of logs found in the public database, the number of wells requiring a cement evaluation to be completed is estimated. This value could be reduced should existing evaluations be presented, so this count is adjusted down for the lower boundary of the estimate range
- Low Cement Top:
  - If a Cement Bond Log was not available, the cement top was calculated for the sampling of wells investigated; however, results are dependent on the limited information provided in the drilling reports. The remedial cement work required to protect the flagged zones noted in Section 3.1 could be much higher, so this count is adjusted up for the higher boundary of the estimate range

2.2.1 Wells on State Lands

Based on the well count, a summary of the total costs for the standard abandonment activities is presented in Table 6.

Table 6. Standard Well Abandonment Cost Summary for Wells on State Lands

Estimate Name	Well Count	Cost Estimate	Cost Total
ST1	697	$50,400	$35,129,000
ST2	404	$59,900	$24,200,000
MT1	736	$57,000	$41,952,000
MT2	676	$66,500	$44,954,000
DT1	1,659	$70,400	$116,794,000
DT2	1,179	$79,800	$94,084,000
SR1	3,554	$64,300	$228,522,000
SR2	234	$73,800	$17,269,000
MR1	1,348	$71,000	$95,708,000
MR2	1,452	$82,000	$119,064,000
DR1	978	$84,300	$82,445,000
DR2	1,133	$93,800	$106,275,000
Total	**14,050**		**$1,006,426,000**

The portion of wells in each grouping requiring additional activities per the regulatory standards was estimated based on a review of selected well files and an estimated adjusted value to account for discrepancies due to the sample size.

Table 7. Additional Well Abandonment Cost Summary for Wells on State Lands

Estimate Name	Well Count		Cost Estimate	Cost Total	
	Expected	Adjusted		Expected	Adjusted
CBL	11,857	5,876	$8,500	$100,785,000	$49,946,000
Intermediate shoe	8,246	-	$18,500	$152,551,000	-
Low cement top	3,508	9,161	$30,200	$105,942,000	$276,662,000

2.2.2 All Wells In New Mexico

Based on the well count, a summary of the total costs for the standard abandonment activities is presented in Table 8.

Table 8. Standard Well Abandonment Cost Summary for All Wells in New Mexico

Estimate Name	Well Count	Cost Estimate	Cost Total
ST1	10,283	$50,400	$518,263,000
ST2	3,688	$59,900	$220,911,000
MT1	7,703	$57,000	$439,071,000
MT2	6,799	$66,500	$452,134,000
DT1	4,229	$70,400	$297,755,000
DT2	4,773	$79,800	$380,885,000
SR1	10,633	$64,300	$683,702,000
SR2	660	$73,800	$48,708,000
MR1	4,694	$71,000	$333,274,000
MR2	5,126	$82,000	$420,332,000
DR1	3,830	$84,300	$322,869,000
DR2	2,468	$93,800	$231,498,000
E[1]	29		$0
Total	**66,128**		**$4,349,369,000**

[3] Cost for cut and cap are capture in surface decommissioning estimates.

The portion of wells in each group requiring additional activities per the regulatory standards was estimated based on a review of selected well files and an estimated adjusted value to account for discrepancies due to the sample size.

Table 9. Additional Well Abandonment Cost Summary for All Wells in New Mexico

Estimate Name	Well Count		Cost Estimate	Cost Total	
	Expected	Adjusted		Expected	Adjusted
CBL	52,052	25,848	$8,500	$442,442,000	$219,708,000
Intermediate shoe	29,861	-	$18,500	$552,429,000	
Low cement top	18,188	39,595	$30,200	$549,278,000	$1,195,769,000

2.3 Offsetting and Historical Abandonment Cost Consideration

Consideration was given to historical spending on abandonment by reviewing a publication by the Railroad Commission of Texas (RRC) regarding plugging costs prior to 2020. These costs are calculated by the RRC or its delegate for each foot of well depth plugged based on average actual plugging costs for wells plugged by the RRC for the preceding State fiscal year based on the Commission Oil and Gas Division district in which the inactive well is located. Per the map of Texas in Figure 5, District 8 and 8A are representative of wells in the Permian Basin. These costs can be considered comparable to plugging costs for wells in Southeast New Mexico, within the Hobbs and Artesia fields.

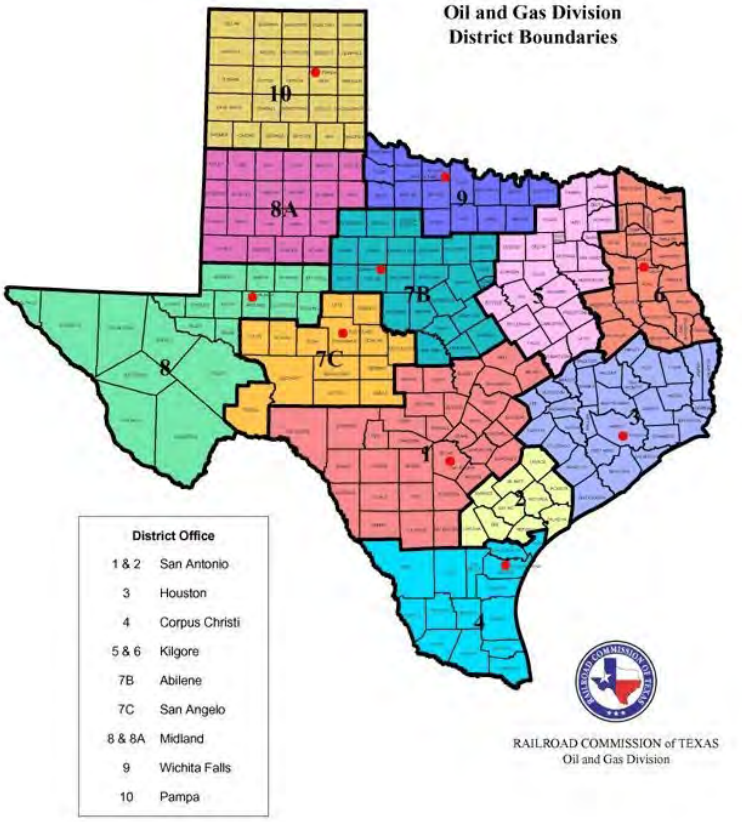


Figure 5. Map of Texas Railroad Commission Oil and Gas Division District Boundaries (Source: Texas RRC)

The calculated per foot costs in Fiscal Year 2019 were $10.29 and $10.62 for Texas RRC Districtss 8 and 8A, respectively, averaging $10.46 per foot. This value likely is not as applicable to New Mexico's Northwest operations as the San Juan Basin wells are typically shallower and will, on average, cost less to abandon. However, for the purposes of this study, the rate will be used across the State.

Actual cost records for recent abandonments in New Mexico were reviewed for six wells in the Artesia district[4]. The relevance of these limited cost summaries may be minimal considering the scope of this project, but as most operators and service providers in the state are hesitant to provide access to their historical cost records, the expenditures will be documented. Note that all six wells were vertical. The well files for these abandonments were reviewed to determine potential problems encountered during plugging operations.

[4] N. Khalsa (personal communication re: J&B Well Service for Reclamation Fund well plugging for Artesia Metex Unit, September 18, 2020)

Table 10. State of New Mexico Abandonment Well Cost Actuals

Well Name	Spud Year	Depth	Total Cost	Cost per foot	Comments
30-015-00956	1951	2,014 ft	$26,975	$13.39	No wellhead, casing broke off, parted tubing had to be fished from wellbore
30-015-00986	1955	1,939 ft	$26,004	$13.41	Pump and rods in wellbore, no issues
30-015-00990	1952	2,025 ft	$23,945	$11.82	Pump and rods in wellbore, well on vacuum issues during cementing
30-015-00991	1952	2,020 ft	$23,513	$11.64	Parted tubing had to be fished from wellbore
30-015-27192	1992	2,180 ft	$20,596	$9.45	Pump and rods in wellbore, no issues
30-015-27196	1992	2,200 ft	$19,590	$8.90	Pump and rods in wellbore, no issues
Average Well Abandonment Cost Per Foot Based on Actuals				**$11.44/ft**	

Review of the cost per foot to plug and abandon these wells indicates that the older wells (pre-1980) cost approximately 25% more to plug. This can be expected due to possible casing integrity issues in older wells, potential gas migration issues due to poor cement isolation, and often unexpected wellbore schematics due to a poor record history or a situation where a well has been left unsecured for a long period. Approximately 40% of the total wells to be abandoned in New Mexico were drilled prior to 1980. An incremental cost has not been applied to this scope as the individual cost estimates include a 5% contingency, regardless of well age.

2.4 Liability Summary

The total costs estimated to plug and abandon the wells in the inventory are summarized below.

Table 11. Overall Well Abandonment Cost Comparison: Wells on State Lands

Description	Cost Total, $MM
High Range Cost Estimate	**$1,536**
Standard Well Abandonment Costs	$1,006
Cement Bond Log Costs (high end)	$101
Intermediate Shoe Isolation	$153
Remedial Work to Isolate Formations due to Low Cement Top (high end)	$277
Low Range Cost Estimate	**$1,315**
Standard Well Abandonment Costs	$1,006
Cement Bond Log Costs (low end)	$50
Intermediate Shoe Isolation	$153
Remedial Work to Isolate Formations due to Low Cement Top (low end)	$106
Cost Estimate based on Recent SLO Plugging Actuals[5]	**$1,352**
Texas RRC Plugging Cost Estimate (Historical) [5]	**$1,233**

[5] This value is based on the summary of an average rate multiplied by the measured depth of each well. A number of wells do not have measured depths recorded; therefore, this value will be conservative.

Table 12. Overall Well Abandonment Cost Comparison: All Wells in New Mexico

Description	Cost Total, $MM	Cost per foot, $ / ft
High Range Cost Estimate	**$6,540**	**$13.48**
Standard Well Abandonment Costs	$4,349	
Cement Bond Log Costs (high end)	$442	
Intermediate Shoe Isolation	$552	
Remedial Work to Isolate Formations due to Low Cement Top (high end)	$1,196	
Low Range Cost Estimate	**$5,671**	**$11.69**
Standard Well Abandonment Costs	$4,349	
Cement Bond Log Costs (low end)	$220	
Intermediate Shoe Isolation	$552	
Remedial Work to Isolate Formations due to Low Cement Top (low end)	$549	
Cost Estimate based on Recent SLO Plugging Actuals [5]	**$5,549**	**$11.44**
Texas RRC Plugging Cost Estimate (Historical) [5]	**$5,074**	**$10.46**

[5] This value is based on the summary of an average rate multiplied by the measured depth of each well. A number of wells do not have measured depths recorded; therefore, this value will be conservative.

2.5 Assumptions

For the purposes of this assessment the following assumptions have been made:

- Well Categorization Review
  - Wells were initially grouped according to County, fluid, profile and total measured depth. Random selections were made through the lists to further identify abandonment requirements, but not all the wells were reviewed within in grouping. Additional review is recommended to confirm assumptions made on downhole equipment and casing profiles
  - If an actual drill depth was not available in the data pull, the assumption was made to use the Well Target Depth (as assigned by the operator) to assign each well a category. For the wells that did not have record of a Well Target Depth, the category was assumed based on offset well information
- Producing Perforations
  - The isolation of each producing pool is assumed to be accomplished by setting a single CIBP at the top of the perforations. If multiple sets of perforations within a wellbore in the same pool are encountered over ranges larger than 2,000 ft, multiple plugs must be set, which will increase the cost estimates
- Low Cement Top
  - The regulations found for the Southern District do not represent formations in the Northern District that require isolation. As such, if a cement top is known to be low for wells in the San Juan Basin (per calculation or available CBL), it will be assumed that similar remedial work will be required as in the Southern District (i.e, perforate production casing, run a CICR, set within 50 ft of perforations and squeeze to achieve isolation)
  - If a Cement Bond Log was not available, the cement top was calculated for the sampling of wells investigated; however, results are dependent on the limited information provided in the drilling reports. The remedial cement work that would be required to protect the flagged zones noted in

Section 3.1 could be much higher

- Cement Bond Logs:
  - Based on the limited number of logs found in the public database, the count of wells assumed to require a cement evaluation to be completed could be reduced should existing evaluations be presented
- Access
  - All sites are accessible by workover rigs and auxiliary equipment. No costs are estimated for access remediation
- Orphan Wells
  - Orphan wells refer to well sites that have been permanently taken out of production that do not have any party legally or financially responsible to deal with decommissioning and reclamation obligations
  - Currently, New Mexico has 708 known orphaned wells [6]

2.6 Data Sources and Limitations

Data used to determine well counts were obtained from state regulatory and lease data. The grouping criteria used to divide wells into categories were based on a limited review of well file data available on publicly accessible New Mexico Oil and Gas websites. Per well type costs were generated according to the standard abandonment activities required for each well type that would apply to all wells in the category. Some limited well cost information was available from recently plugged and abandoned wells in New Mexico, as well as information provided by the RRC outlining historical costs in parts of that state. The majority of well costs were developed from historical and/or typical estimates for similar types of work completed in Canada and North Dakota, with respect to budgeting for duration to complete and equipment/services required. Hourly rate quotes from various service providers in the state of New Mexico, as well as typicals seen in other regions for similar work, were applied to the duration and equipment/services estimates to develop locally applicable costs.

Some data gaps that were encountered when developing this liability assessment include: limited information on specific abandonment requirements and, when average abandonment costs were available, those sources did not include what regulations were applied to those abandonments. Standardized regulatory requirements for well abandonment, applicable across the state, would streamline efforts at liability assessments by reducing the variables that can be involved in the well abandonment process. During the well file review that was used to extrapolate well data across the types of wells, missing depth data and other well data resulted in assumptions made based on offsets rather than actual depths. The depth of a well directly affects abandonment costs so the lack of clear data can greatly affect liability assessments.

Additionally, a lack of cement evaluation logs in the well files could be the result of incomplete information upload to the public database, or it could be an indicator that cement evaluation logs have not been run in large numbers of wells. The availability of cement evaluation log data can reduce abandonment costs significantly.

[6] Adrienne Sandoval, June 2020.

3.0 Wellpad Surface Facility Decommissioning – Basis of Estimate

3.1 Scope

Surface facility decommissioning on wellpads consists of:

- Removal of all surface facilities including, but not limited to
  - Pumps and pump jacks
  - Process buildings
  - Compressors
  - Storage tanks and containment
  - Chemical tanks
  - Wellhead shacks and temporary fencing and barricades
- Disconnection and removal of wellhead
- Cutting and capping of the well below grade
- Disconnection and isolation of flowlines from surface infrastructure
- Removal of foundations including, but not limited to:
  - Concrete pads
  - Driven or screw piles (cut off below grade or removed)
- Equipment will be transported to a central location for storage or disposal
  - Costs for disposal of equipment (except scrap steel) are not included
  - Recovery of costs from sale of equipment is not included

Wellpad surface facility decommissioning does not include the following items, these are included in Section 6.0 as part of Surface Reclamation:

- Removal of wellsite or facility fencing
- Removal of roads and pads
- Environmental testing and assessment
- Reclamation of land to pre-oil and gas use

3.2 Cost Estimate Details

The cost estimate consists of a unit rate cost on a per well basis for:

- Oil Well – Flowing
  - With Flowline: $13,363/site
- Oil Well – Pumping
  - With Storage: $27,523/site
  - With Flowline: $20,319/site
- Gas Well – Flowing
  - With Storage: $12,157/site
  - With Flowline: $5,500/site

- Gas Well – Pumping
  - With Storage: $12,769/site
  - With Flowline: $6,418/site
- Disposal Wells
  - All: $3,226/site

These rates have been applied to an estimated quantity, discussed in Section 3.3, for each well type to develop the overall estimate for wellpad surface facility decommissioning. For gas sites, additional cost estimates were developed for sites with and without process equipment (i.e., separators) and the pricing presented reflects the average of the two costs for each scenario. It is assumed that there is no additional process equipment for the oil well sites.

Table 13. Cost Estimate for Surface Facility Decommissioning: Wells on State Lands

Well Type	Total Count	With Storage				With Flowline				Total Cost
		%	Count	$ / Site	SubTotal	%	Count	$ / Site	SubTotal	
Oil - Flowing	1,874					100%	1,874	$13,363	$25,043,012	$25,043,012
Oil - Pumping	8,088	50%	4,044	$27,523	$111,304,629	50%	4,044	$20,319	$82,171,653	$193,476,282
Gas - Flowing	3,166	10%	317	$12,157	$3,848,906	90%	2,849	$5,500	$15,672,441	$19,521,347
Gas - Pumping	605	50%	303	$12,769	$3,862,471	50%	303	$6,418	$1,941,297	$5,803,768
Disposal	317					100%	317	$3,226	$1,022,648	$1,022,648
Total Estimated Cost										**$244,867,057**

Table 14. Cost Estimate for Surface Facility Decommissioning: All Wells in New Mexico

Well Type	Total Count[6]	With Storage				With Flowline				Total Cost
		%	Count	$ / Site	SubTotal	%	Count	$ / Site	SubTotal	
Oil - Flowing	5,292					100%	5,292	$13,363	$70,719,113	$70,719,113
Oil - Pumping	26,352	50%	13,176	$27,523	$362,648,318	50%	13,176	$20,319	$267,728,414	$630,376,733
Gas - Flowing	28,050	10%	2,805	$12,157	$34,100,385	90%	25,245	$5,500	$138,854,064	$172,954,449
Gas – Pumping	1,052	50%	526	$12,769	$6,716,231	50%	526	$6,418	$3,375,610	$10,091,841
Disposal	4,155					100%	4,155	$3,226	$13,404,113	$13,404,113
Total Estimated Cost										**$897,546,249**

[6] Total count does not include those wells classified as "Empty" during Well Categorization Activities.

3.3 Assumptions

For the purposes of this assessment the following assumptions have been made:

- All costs should be considered Class 5 (+50/-30%)
- All counts (oil, gas and disposal, flowing vs pumping) are based on the same representative sample used for

the Downhole Abandonment Well Categorization

- Oil Wells
  - All flowing wells have direct connections to flowlines and are not utilizing breakout tankage for storage
  - 50% of pumping wells have on-site storage with the remaining pumping directly to flowlines
- Gas Wells
  - 10% of flowing wells and 50% of pumping wells have on-site storage, with the remaining wells pumping/flowing directly to flowlines
  - 50% of wells have additional process equipment (dehy towers, compressors, chemical injection, etc.)
- Disposal Wells
  - All have flowline connections
- Wells classified as Empty have not been included in surface decommissioning account as it is assumed that no surface improvements were made for these locations
- Storage consists of one (1) 400 bbl tank in containment
- Flowline includes a single riser connection with no pigging facilities
- Wells will be cut and capped below grade
- Pipeline risers will be cut and capped below grade
- Piles will be removed or cut and capped below grade
- Internal water jet cutters will be used where possible to avoid need for excavation
- Excavations will be backfilled with excavated material where possible
- All equipment will be staged at a central location to reduce shipping costs during decommissioning activities
- No costs are included for third-party equipment removal, electrical disconnect or power pole removal along with any associated legal or administrative charges

3.4 Data Sources and Limitations

The initial well sample assessments and totals used in developing abandonment costs in Section 2.0 were used in the facility decommissioning cost assessment. Any data gaps pertaining to the well abandonment work would have transferred to this portion of the liability assessment, such as a lack of, or incomplete, standardized regulatory requirements for site decommissioning, applicable across the state, which would streamline efforts at liability assessments by reducing the variables that can be involved in the well abandonment and site decommissioning process.

A shortage of information regarding wellsite surface equipment and utilization of flowline connections versus tankage resulted in multiple and significant assumptions about the numbers of sites with flowline connections and those with tankage on-site.

4.0 Pipeline – Basis of Estimate

4.1 Scope

Pipeline abandonment consists of:

- Cleaning/Purging all hydrocarbons from the line with air or other inert fluid
- Removal and disposal of fluids

- Cutting and capping the ends of the flowlines below grade
    - All attempts should be made to the abandon an entire system and not leave dead legs on operating lines
- Removal of all surface piping and risers where applicable
- Disconnection of any cathodic protect systems that may be in place

Pipeline abandonment typically does not include the following items as this is generally considered cost prohibitive:

- Physical removal of buried pipe
- Physical remove of cathodic protection infrastructure (i.e., anode beds)

For the purposes of this assessment, a secondary cost will be presented in the next section for the physical removal of pipelines based on average metrics.

4.2 Cost Estimate Details – Typical Decommissioning

The cost estimate consists of a unit rate cost on a per mile basis for:

- Buried Pipe – Less than 8" diameter: $5,430/mile
- Buried Pipe – 10" to 16" diameter: $10,010/mile
- Buried Pipe – 18" to 24" diameter: $16,275/mile
- Buried Pipe – Over 24" diameter: $37,455/mile
- Surface Pipe – Less than 8" diameter: $6,455 /mile
- Surface Pipe – 10" to 16" diameter: $11,935/mile
- Surface Pipe – 18" to 24" diameter: $19,725/mile
- Surface Pipe – Over 24" diameter: $32,055/mile

Pipeline inventory for the entire state of New Mexico was obtained utilizing data from S&P Global Platts, 2020. Of this total inventory, roughly 15% of the pipelines are located on lands managed by the SLO.

The following table presents the inventory quantity broken down by pipeline diameter. This inventory was then utilized to determine the total program cost.

Table 15. Inventory of Pipelines: Pipelines on State Lands

Diameter (")	Measured from Database		Calculated	Total
	Length (miles)	% of Known	Length (miles)	Length (miles)
Under 8	253	30%	435	688
10 through 16	205	24%	353	559
18 through 24	242	28%	417	659
Over 24	151	18%	260	411
Total	**852**		**1,465**	**2,317**

Table 16. Inventory of Pipelines: All Pipelines in New Mexico

Diameter (")	Measured from Database		Calculated	Total
	Length (miles)	% of Known	Length (miles)	Length (miles)
Under 8	2,731	25%	1,354	4,085
10 through 16	3,135	29%	1,554	4,689
18 through 24	1,725	16%	855	2,581
Over 24	3,164	29%	1,569	4,733
Total	**10,755**		**5,332**	**16,087**

These rates have been applied to an estimated quantity, discussed in Section 4.3, for each line type to develop the overall estimate for the pipeline abandonment portion of this assessment.

Table 17. Cost Estimate for Typical Decom of Pipelines: Pipelines on State Lands

Diameter (")	Location	% of total	Length (mile)	$ / Mile	Sub Total
Under 8	Buried	50%	918	$5,430	$4,983,750
10 through 16		50%	746	$10,010	$7,465,971
18 through 24		80%	1,407	$16,275	$22,898,306
Over 24		90%	988	$27,455	$27,128,957
Under 8	Surface	50%	918	$6,455	$5,924,513
10 through 16		50%	746	$11,935	$8,901,735
18 through 24		20%	352	$19,725	$6,938,081
Over 24		10%	110	$32,055	$3,519,370
				Total Estimated Cost	**$87,760,684**

Table 18. Cost Estimate for Typical Decom of Pipelines: All Pipelines in New Mexico

Diameter (")	Location	% of total	Length (mile)	$ / Mile	Sub Total
Under 8	Buried	50%	2,042	$5,430	$11,090,393
10 through 16		50%	2,345	$10,010	$23,469,782
18 through 24		80%	2,064	$16,275	$33,599,289
Over 24		90%	4,259	$27,455	$116,938,182
Under 8	Surface	50%	2,042	$6,455	$13,183,884
10 through 16		50%	2,345	$11,935	$27,983,202
18 through 24		20%	516	$19,725	$10,180,430
Over 24		10%	473	$32,055	$15,170,090
				Total Estimated Cost	**$251,615,253**

4.3 Assumptions – Typical Decommissioning

For the purposes of this assessment, the following assumptions have been made:

- All costs should be considered Class 5 (+50/-30%)
- Approximately 58% of the pipelines contained in the available GIS database had diameter information included in the metadata. The ratio of pipeline sizes from these known datapoints was applied to the entire

pipeline inventory

- Mix of steel and HDPE pipe throughout the system (50/50)
- Mix of buried and surface lines through the system at ratios deemed reasonable based on size (the larger the pipe the more likely it is to be buried)
    - Under 16": 50/50
    - 18 through 24": 80/20
    - Over 24": 90/10
- No costs to reclaim the surface of the pipeline ROWs have been included
- No excavation or disturbance will be required along length of ROW for buried pipelines
    - All work can be completed within the limits of existing surface leases
- Surface flow lines will be cut up, removed from location and disposed of
    - Access to the entire pipeline rOW will be required

4.4 Cost Estimate Details – Full Removal

As mentioned in Section 4.1, cost estimates are generally not provided for the full removed of buried pipelines as this is a cost prohibitive process that effectively replicates the construction process. A typical metric for estimating the construction of a buried pipeline is to utilize a $/inch·mile cost. The costs used for this assessment are:

- Buried Pipe – Less than 8" diameter: $140,000/mile
- Buried Pipe – 10" to 16" diameter: $544,000/mile
- Buried Pipe – 18" to 24" diameter: $1,620,000/mile
- Buried Pipe – Over 24" diameter: $2,880,000/mile

This results in the following total costs for complete removal of the buried pipelines in the state of New Mexico. Surface pipeline removal will remain as presented in Section 4.2.

Table 19. Cost Estimate for Full Removal of Pipelines: Pipelines on State Lands

Diameter (")	Buried			
	% of total	Length (mile)	$ / Mile	Sub Total
Under 8	50%	918	$140,000	$128,494,482
10 through 16	50%	746	$761,600	$568,040,345
18 through 24	80%	1407	$2,268,000	$3,190,989,772
Over 24	90%	988	$4,032,000	$3,984,117,752
			Total Estimated Cost	**$7,871,642,351**

Table 20. Cost Estimate for Full Removal of Pipelines: All Pipelines in New Mexico

Diameter (")	Buried			
	% of total	Length (mile)	$ / Mile	Sub Total
Under 8	50%	2042	$100,000	$204,242,974
10 through 16	50%	2345	$544,000	$1,275,480,682
18 through 24	80%	2064	$1,620,000	$3,344,445,399
Over 24	90%	4259	$2,880,000	$12,266,689,655
			Total Estimated Cost	**$17,090,858,710**

4.5 Assumptions – Full Removal

For the purposes of this assessment, the following assumptions have been made:

- All costs should be considered Class 5 (+50/-30%)
- All surface pipeline will follow the costing provided in Section 4.2
- Cost per mile derived from 2014 study completed by the Interstate Natural Gas Association of America (INGAA, 2014) which determined the $/inch·mile of all natural gas pipeline construction in North America in 2012. These values have been reduced by 50% to account for:
    - Industry benchmarks have reduced from peak in 2012 by up to 20% due to overall market downturn
    - Reduction in scope vs construction (i.e., no land acquisition, engineering and design, reduced regulatory and environmental consulting scope, no line pipe coating etc.)
    - Study metrics up to 16” only, larger diameter metric inferred based on trend
- The per mile costs are based on the largest pipe diameter in the range
- No significant difference in the costs of natural gas vs oil pipelines
- Complete removal of the buried pipeline by:
    - Open trenching: the line would be purged and cleaned, excavated, cut into sections, removed, backfilled and the surface reclaimed to natural state
    - Trenchless: pipeline is cut into segments at bellhole locations and a specialized rig utilized to pull the pipe out one end
    - Both options have pros and cons related to cost, surface impacts and feasibility which would need to be assessed independently for each pipeline project

4.6 Data Sources and Limitations

Pipeline inventory for the entire state of New Mexico was obtained utilizing data from S&P Global Platts, 2020 (S&P Global). The GIS for the state total pipeline inventory was intersected with GIS data for SLO lands obtained from the SLO (Figure 2), to determine the estimated length of pipeline located on SLO lands. Using this method, roughly 15% of the total pipeline lengths in the state of New Mexico are located on lands managed by the SLO.

Data gaps are expected to exist in the pipeline length estimates. S&P Global provides high quality data; however, as conditions are constantly changing on the ground, there will always be a lag between known and recorded pipeline data and updates regarding the construction of new pipeline or decommissioning or removal of existing pipeline. The S&P Global data presented in this report should be viewed as a snapshot of existing pipeline at a singular point in time rather

than a consistent measure of current pipeline infrastructure and condition. Additionally, smaller surface pipelines or surface pipelines that are intended to be temporary, such as lay-flat or poly lines, may not be recorded due to different permitting requirements. Accordingly, the actual quantity of surface lines shown in this report is expected to be an underestimation of actual pipelines present within the more active portions of the San Juan and Permian basins.

Finally, challenges with estimating decommissioning and full removal costs for pipelines throughout the state can be attributed to a lack of standardized regulatory requirements for pipeline decommissioning applicable across the state, which would streamline efforts at liability assessments by reducing the variables that may be involved in the pipeline decommissioning and/or removal process.

5.0 Commercial Lease Site Decommissioning

5.1 Scope

Data obtained from the SLO regarding its Commercial Lease – Oil and Gas Portfolio showed a total of 616 commercial lease sites covering a broad range of oil and gas activities, including but not limited to:

- Compressor Sites
- Frac Ponds
- Storage Sites and Storage Tanks
- Processing/Dehydration Facilities
- Maintenance/Metering Sites
- Rule 34 Recycling Facilities
- Truck Stops

Limited data regarding SLO commercial lease sites are publicly available; no information could be obtained regarding standard equipment present on each type of lease, year each site was developed, or historical site closure and reclamation costs. Commercial lease site data was limited to:

- Type of site
- Site size (in acres)
- Number of sites by type

Commercial lease site decommissioning consists of:

- Removal of all surface facilities including, but not limited to
    - Buildings and equipment storage structures
    - Compressors, dehydration facilities and other processing equipment
    - Transfer stations and truck staging areas
    - Frac ponds, storage tanks and containments
    - Chemical tanks
    - Water, electrical or other lines not included in the pipeline decommissioning discussion in Section 4.0
- Removal of foundations including, but not limited to:

  - Concrete pads
  - Driven or screw piles (cut off below grade or removed)
  - Parking areas or runways
- Equipment will be transported to a central location for storage or disposal
  - Costs for disposal of equipment are not included
  - Recovery of costs from sale of equipment is not included

Commercial lease site decommissioning does not include the following items; these are included in Section 6.0 as part of Surface Reclamation:

- Removal of facility fencing
- Removal of roads and pads
- Environmental testing and assessment
- Reclamation of land to pre-facility use

5.2 Cost Estimate Details

The basis for developing cost estimates for commercial lease site decommissioning was drawn from the cost estimates developed for wellpad surface facility decommissioning as shown in Section 3.0. The estimated costs for wellpad surface facility decommissioning are broken down to a per/acre cost as shown in Table 21.

Table 21. Average Per Acre Surface Facility Decommissioning Costs for Commercial Lease Sites on State Lands

Total Decommissioning Cost for Wells on State Lands	Total Well Count on State Lands	Average Per Well Decommissioning Cost	Average Wellpad Size for Wells on State Lands	Average Per Acre Decommissioning Cost
$244,867,057	14,051	$17,427.22	1.89	$9,220.65

The average per acre decommissioning cost was applied to the average site size for each type of commercial site, multiplied by the total number for each type of commercial site, and summed to obtain a total estimated decommissioning cost for all oil and gas commercial leases on SLO lands.

Table 22. Cost Estimate for Surface Decommissioning: Commercial Lease Sites on State Lands

Type of Commercial Site	Number of Sites	Average Site Size (Acres)	Estimated Decommissioning Cost per Site	Total Estimated Commercial Lease Surface Decommissioning Costs (By Type)
Compressor Site	135	3.73	$ 34,363.64	$ 4,639,091.15
Electrical Power Related	29	11.35	$ 104,676.58	$ 14,131,338.67
Frac Pond	80	5.39	$ 49,724.64	$ 6,712,825.84
Land Strip/ Airport	1	9.52	$ 87,780.54	$ 11,850,373.55
Maintenance / Metering site	36	2.36	$ 21,801.70	$ 2,943,230.03
Private Mobile Radio	11	4.47	$ 41,233.05	$ 5,566,461.75

Office Building/Maintenance Yard	5	9.83	$ 90,602.06	$ 12,231,278.41
Oil and Gas Related	3	11.30	$ 104,162.56	$ 14,061,945.37
Other Oil and Gas Related	28	85.78	$ 790,923.92	$ 106,774,728,70
Processing / Dehydration Facility	26	9.97	$ 91,887.28	$ 12,404,782.59
Reclamation	4	1.47	$ 13,531.30	$ 1,826,725.12
Residential	1	0.23	$ 2,120.75	$ 286,301.04
Rule 34 Recycling Facility	25	18.16	$ 167,487.49	$ 22,610,811.48
Storage Site	44	12.54	$ 115,631.09	$ 15,610,196.52
Storage Tank	55	153.96	$ 1,419,645.78	$ 191,652,180.54
Transfer Site	2	6.20	$ 57,168.00	$ 7,717,680.25
Telemetry Paging	23	2.84	$ 26,142.53	$ 3,529,242.14
Truck Stop	20	12.84	$ 118,360.82	$ 15,978,710.09
Storage/Warehouse	7	9.34	$ 86,160.35	$ 11,631,646.67
Well Pad Lease	75	6.24	$ 57,515.93	$ 7,764,650.22
Water Related	6	17.74	$ 163,589.62	$ 22,084,598.47
			Total	**$ 492,008,798.62**

5.3 Assumptions

For the purposes of this assessment the following assumptions have been made:

- All costs should be considered Class 5 (+50/-30%)
- All counts are based on the same representative sample and costs used for the Wellpad Surface Facility Decommissioning for wells on state lands
- There is minimal variation in safety requirements, removal methods, transport, and handling of equipment present on the various types of commercial lease sites, and any variations are deemed insignificant to affect overall cost estimates
- Pipeline risers will be cut and capped below grade
- Piles will be removed or cut and capped below grade
- Internal water jet cutters will be used where possible to avoid need for excavation
- Excavations will be backfilled with excavated material where possible
- All equipment will be staged at a central location to reduce shipping costs during decommissioning activities
- No costs are included for third-party equipment removal, electrical disconnect or power pole removal along with any associated legal or administrative charges

5.4 Data Sources and Limitations

The initial well sample assessments and totals used in developing wellpad surface facility decommissioning costs in Section 3.0 were used in the commercial lease site decommissioning cost assessment. Any data gaps pertaining to the well abandonment work would have transferred to this portion of the liability assessment, such as a lack of, or incomplete, standardized regulatory requirements for site decommissioning, applicable across the state, which would streamline efforts at liability assessments by reducing the variables that can be involved in the site decommissioning process.

Ill-defined definitions for each type of commercial lease site and a shortage of publicly available information regarding commercial lease site surface equipment, and the broad array of possible equipment and configurations that could be present at each type of site, resulted in multiple and significant assumptions about the standardization possibilities between types of commercial lease sites and even amongst different sites of the same type.

6.0 Surface Reclamation – Basis of Estimate

6.1 Scope

Per the OCD, Surface Reclamation must be conducted on all sites associated with oil and gas exploration and production (E&P) activities, including lease access ROWs, supporting mid-stream facilities and transmission pipeline ROWs, once no longer in use. Unless a site closure and reclamation plan are included in the well permit or lease, surface reclamation of a site is generally regulated by 19.15.29.12 and 19.15.29.13 of the NMAC. Section 13D states:

> ***Reclamation of areas no longer in use.*** *The responsible party shall reclaim all areas disturbed by the remediation and closure, except areas reasonably needed for production operations or for subsequent drilling operations, as early and as nearly as practical to their original condition or their final land use and maintain those areas to control dust and minimize erosion to the extent practical.*

Surface reclamation activities are usually conducted immediately following facility and/or pipeline decommissioning, as outlined in Sections 3.0 thru 5.0 of this report. Surface reclamation consists of:

- Environmental testing and assessment
- Removal and disposal of wellsite or facility fencing
- Excavation and removal of contaminated soils, such that constituents of concern remaining onsite meet the closure criteria requirements outlined in Table I of 19.15.29.12 NMAC (Appendix D)
- Ripping and turning of all compacted soils to approximate depths of 2 to 4 ft below ground surface
- Emplacement of backfill material, as needed, to reconstruct the site to its naturally occurring grade
- Contouring the site to achieve erosion control, long-term stability and preservation of surface water flow patterns commiserate with the surrounding undisturbed areas
- Re-establishing vegetation, typically through seeding the restored site with a native seed-mix appropriate for the area

Surface reclamation does not include the following items; these are included in Section 2.0, as part of Downhole Abandonment, and Sections 3.0 thru 5.0 as part of Surface Facility and Pipeline Decommissioning:

- Removal of downhole equipment
- Plugging the abandoned well
- Disconnection or isolation of flowlines
- Removal or disposal of facility surface or subsurface infrastructure, including concrete foundations/pads

6.2 Cost Estimate Details – Wellpad Reclamation

The cost estimate for surface reclamation of well sites consists of a unit rate cost on a per well basis using an average site size for categories defined by the following variables:

- Age of well by drilling date (pre-2012, post-2012)
- Well type (oil, gas, salt-water disposal [SWD])
- Basin

Average per-well reclamation cost for each category, as well as totals for all wells in the category, are shown in Table 23 for well sites on SLO land and Table 24 for all wells in New Mexico.

Table 23. Cost Estimate for Surface Reclamation: Wells on State Lands

Basin	Well Type	Age of Well	Average Per Well Cost	Well Count[7]	Estimated Cost
Permian	Oil	Pre-2012	$78,280.13	5,737	$ 449,093,078.60
		> 2012	$176,140.65	3,964	$ 698,221,520.37
	Gas	Pre-2012	$90,836.13	1,664	$ 151,151,319.84
		> 2012	$225,285.14	610	$ 137,423,933.15
	SWD	All Years	$193,037.75	300	$ 57,911,324.21
			Sub-Total	**12,275**	**$ 1,493,801,176.17**
San Juan	Oil	Pre-2012	$ 55,743.41	93	$ 5,184,137.55
		> 2012	$203,252.28	56	$ 11,382,127.95
	Gas	Pre-2012	$ 66,600.28	1,465	$ 97,569,403.28
		> 2012	$220,010.65	29	$ 6,380,308.96
	SWD	All Years	$132,770.38	16	$ 2,124,326.10
			Sub-Total	**1,659**	**$ 122,640,303.84**
Other	Oil	Pre-2012	$ 40,783.50	108	$ 4,404,618.45
		> 2012	$ 33,479.11	13	$ 435,228.37
	Gas	Pre-2012	$ 99,903.56	3	$ 299,710.69
		> 2012	N/A	1	N/A
	SWD	All Years	$ 27,195.84	2	$ 54,391.68
			Sub-Total	**127**	**$ 5,193,949.18**
			Total	**14,061**	**$ 1,621,635,429.19**

[7] Total count DOES include those wells classified as "Empty" during Well Categorization Activities.

Table 24. Cost Estimate for Surface Reclamation: All Wells in New Mexico

Basin	Well Type	Age of Well	Average Per Well Cost	Well Count[7]	Estimated Cost
Permian	Oil	Pre-2012	$ 99,705.12	17,658	$ 1,760,593,008.96
		> 2012	$116,899.84	12,033	$ 1,406,655,756.54
	Gas	Pre-2012	$ 78,544.84	5,252	$ 412,517,494.07
		> 2012	$195,698.03	2,460	$ 481,417,152.21
	SWD	All Years	$ 80,198.86	857	$ 68,730,421.65
			Sub-Total	**38,260**	**$ 4,129,913,833.43**
San Juan	Oil	Pre-2012	$ 53,893.73	1,664	$ 89,679,160.87
		> 2012	$164,304.82	539	$ 88,560,299.55
	Gas	Pre-2012	$ 53,866.22	19,595	$1,055,508,631.43
		> 2012	$ 39,761.69	385	$ 15,308,249.01
	SWD	All Years	$136,567.88	104	$ 14,192,659.45
			Sub-Total	**22,287**	**$ 1,263,249,000.31**
Other	Oil	Pre-2012	$ 28,675.56	299	$ 8,573,992.18
		> 2012	$ 33,973.52	79	$ 2,683,908.26
	Gas	Pre-2012	$ 29,732.72	888	$ 26,402,655.10
		> 2012	$ 29,712.22	27	$ 802,229.89
	SWD	All Years	$105,993.76	23	$ 2,437,856.50
			Sub-Total	**1,316**	**$ 40,900,641.93**
			Total	**61,863**	**$5,434,063,475.67**

[7] Total count DOES include those wells classified as "Empty" during Well Categorization Activities.

These rates have been applied to an estimated quantity, discussed in Section 6.5, for each well type to develop the overall estimate totals for surface reclamation of all wells on New Mexico State-owned lands and for all wells in New Mexico.

6.3 Cost Estimate Details – Pipeline Right of Way Reclamation

The cost estimate for surface reclamation of pipeline ROWs consists of a unit rate cost on a per pipeline mile basis using an average ROW size for the following categories.

Table 25. Cost Estimate for Surface Reclamation: Pipelines on State Lands

Buried Pipelines				
Diameter (")	**% of total**	**Length (mile)**	**$ / Mile**	**Sub Total**
Under 8	50%	918	$180,625.68	$ 165,814,370.07
10 through 16	50%	746		$ 134,746,753.89
18 through 24	80%	1,407		$ 254,140,325.36
Over 24	90%	988		$ 178,458,167.35
			Total Estimated Cost	**$ 733,159,616.67**
Diameter (")	**% of total**	**Length (mile)**	**$ / Mile**	**Sub Total**
Under 8	50%	918	$229,916.40	$ 211,063,250.75
10 through 16	50%	746		$ 171,517,630.78
18 through 24	80%	352		$ 80,930,571.09
Over 24	90%	110		$ 25,290,803.47
			Total Estimated Cost	**$ 488,802,256.09**

Table 26. Cost Estimate for Surface Reclamation: All Pipelines in New Mexico

Buried Pipelines				
Diameter (")	**% of total**	**Length (mile)**	**$ / Mile**	**Sub Total**
Under 8	50%	2,042	$180,625.68	$ 368,837,629.28
10 through 16	50%	2,345		$ 423,567,208.94
18 through 24	80%	2,064		$ 372,811,394.14
Over 24	90%	4,259		$ 769,284,751.76
			Total Estimated Cost	**$ 1,934,500,984.12**
Surface Pipelines				
Diameter (")	**% of total**	**Length (mile)**	**$ / Mile**	**Sub Total**
Under 8	50%	2,042	$229,916.40	$ 469,489,278.90
10 through 16	50%	2,345		$ 539,153,946.63
18 through 24	80%	516		$ 118,636,859.90
Over 24	90%	473		$ 108,750,454.91
			Total Estimated Cost	**$ 1,236,030,540.33**

These rates have been applied to an estimated quantity, discussed in Section 6.5, for each pipeline to develop the overall estimate totals for surface reclamation of all pipeline ROWs on New Mexico State-owned lands and for all pipeline ROWs in New Mexico.

6.4 Cost Estimate Details – Commercial Lease Site Reclamation

The cost estimate for commercial lease site surface reclamation is drawn from the cost estimates developed for wellpad surface reclamation as shown in Section 6.2. The estimated costs for wellpad surface reclamation were broken down to a per acre cost as shown in Table 27.

Table 27. Average Per Acre Decommissioning Costs for Commercial Lease Sites on State Lands

Total Surface Reclamation Cost for All Wells on State Lands (Across All Wells, All Counties, All Years)	Total Well Count on State Lands	Average Per Well Decommissioning Cost	Average Wellpad Size for Wells on State Lands	Average Per Acre Decommissioning Cost
$1,401,061,638.30	14,051	$99,713	1.89	$52,758

The average per acre surface reclamation cost was applied to the average site size for each type of commercial site, multiplied by the total number for each type of commercial site, and summed to obtain a total estimated surface reclamation cost for all oil and gas commercial leases on SLO lands.

Table 28. Cost Estimate for Surface Reclamation: Commercial Lease Sites on State Lands

Type of Commercial Site	Number of Sites	Average Site Size (Acres)	Estimated Surface Reclamation Cost per Site	Total Estimated Commercial Lease Surface Reclamation Costs (By Type)
Compressor Site	135	3.73	$ 196,620.05	$ 26,543,706.12
Electrical Power Related	29	11.35	$ 598,932.93	$ 80,855,945.47
Frac Pond	80	5.39	$ 284,511.79	$ 38,409,091.48
Land Strip/ Airport	1	9.52	$ 502,258.07	$ 67,804,840.00
Maintenance / Metering site	36	2.36	$ 124,743.84	$ 16,840,417.78
Private Mobile Radio	11	4.47	$ 235,925.08	$ 31,849,886.17
Office Building/Maintenance Yard	5	9.83	$ 518,402.08	$ 69,984,281.29
Oil and Gas Related	3	11.30	$ 595,991.81	$ 80,458,894.52
Other Oil and Gas Related	28	85.78	$ 4,525,466.59	$ 610,937,989.82
Processing / Dehydration Facility	26	9.97	$ 525,755.77	$ 70,977,028.30
Reclamation	4	1.47	$ 77,422.66	$ 10,452,059.11
Residential	1	0.23	$ 12,134.39	$ 1,638,142.14
Rule 34 Recycling Facility	25	18.16	$ 958,321.07	$ 129,373,344.09
Storage Site	44	12.54	$ 661,611.82	$ 89,317,596.01
Storage Tank	55	153.96	$ 8,122,854.08	$ 1,096,585,300.17
Transfer Site	2	6.20	$ 327,100.85	$ 44,158,614.29
Telemetry Paging	23	2.84	$ 149,580.97	$ 20,193,430.84
Truck Stop	20	12.84	$ 677,230.65	$ 91,426,137.46
Storage/Warehouse	7	9.34	$ 492,987.70	$ 66,553,340.10
Well Pad Lease	75	6.24	$ 329,091.59	$ 44,427,364.56
Water Related	6	17.74	$ 936,018.42	$ 126,362,486.31
			TOTAL	**$ 2,815,149,896.01**

6.5 Assumptions

For purposes of the surface reclamation cost assessments the following assumptions have been made:

6.5.1 Wellpad Reclamation

- Surface reclamation costs are directly correlated to the size of the site being reclaimed
    - To find the average wellpad size, a random selection of wells across all counties, well types, drilling directions and years were measured using aerial photos to determine, in acres, the size of the reclamation area (wellpad)
- Well locations were divided into groups by production basin, well type, and year brought into production
    - Each production basin may have different production methods, drilling and access challenges, and may even have different specifications for pad sizes
    - Each well type is assumed to have varying levels of contamination based on the commodity produced
    - Pad development and drilling methods began to change drastically around 2012, resulting in larger pads, better environmental protection controls, and better best management practices to reduce potential long-term contamination issues, all of which could affect the final remediation levels needed at each site
- Wells with the status of “Cancelled” and “Never-drilled” are not included in the estimated costs; wells with the status of “Dry” or “Empty” are included
- Multi-well pads are a relatively new approach to oil and gas drilling. The extremely small number of sites containing multiple wells is insignificant enough to distinguish well and pad numbers differently
- Current un-remediated pits and frac ponds are NOT included in estimated reclamation costs due to the infrequency of occurrence, as well as because these types of facilities are associated with new well development and are often remediated by the producers shortly after production begins
- Remediation requirements include excavation and disposal of contaminated soils to a depth of approximately 4 ft below ground surface (bgs) based on NM OCD restoration and reclamation guidance provided in 19.15.29.13 NMAC. Contaminated soil removal volumes can drastically affect reclamation costs. To provide a range of costs, per pad estimated contaminated soil removal volumes are based on four contamination levels
    - Low contamination – approximately 10% of pad needs to be excavated and disposed
    - Medium-low contamination – approximately 25% of the pad needs to be excavated and disposed
    - Medium-high contamination – approximately 40% of the pad needs to be excavated and disposed
    - High contamination – approximately 60% of the pad needs to be excavated and disposed
- Contamination levels are not going to be the same at all pads in a category, thus it is assumed that a percentage of all well pads in a group will fall into the low, medium-low, medium-high and high contamination range. This is referred to as the contamination rate
- Contamination rates at gas well pads are expected to be different than those at oil well pads and SWD pads, due to the volatile, gaseous state of the resource being handled. When a release occurs at a gas well, the released material tends to dissipate into the air rather than soak into the soil. To capture this disparity, the following breakdown of total wells within each contamination level was used
    - Gas Well Contamination Rates
        - 25% of all wells have a low level of contamination
        - 60% of all wells have a medium-low level of contamination

- 10% of all wells have a medium-high level of contamination
- 5% of all wells have a high level of contamination

- Oil Wells and SWDs Contamination Rates
  - 15% of all wells have a low level of contamination
  - 60% of all wells have a medium-low level of contamination
  - 20% of all wells have a medium-high level of contamination
  - 5% of all wells have a high level of contamination

6.5.2 Pipeline Right-of-Way Reclamation

- Surface reclamation costs are directly correlated to the size of the site surface being reclaimed
  - To find the average surface area of a pipeline ROW to be reclaimed, the standard New Mexico ROW width of 30 ft was used in conjunction with the pipeline lengths presented in Section 4
- Pipeline ROWs were divided into two groups: buried and surface
  - The potential for pipeline leaks may be greater for surface pipelines exposed to the elements, vandalism and oilfield traffic, compared to buried pipelines
  - Leaks from surface pipelines may have been recognized and addressed in a timely manner
  - Vegetation around surface lines may not recover as quickly due to continued access along the pipeline ROW, e.g. visual inspections, thus surface pipeline ROWs may require a greater proportion of revegetation efforts
- Remediation requirements include excavation and disposal of contaminated soils to a depth of approximately 4 ft bgs based on NM OCD restoration and reclamation guidance provided in 19.15.29.13 NMAC. Contaminated soil removal volumes can drastically affect reclamation costs. To provide a range of costs, estimated pipeline ROW reclamation costs were grouped into three Reclamation Effort Levels.

Table 29. Reclamation Effort Categories

	Buried Pipeline ROWs		Surface Pipeline ROWs	
	% of ROW contaminated	% of ROW requiring revegetation	% of ROW contaminated	% of ROW requiring revegetation
Low Effort	10%	20%	15%	40%
Medium Effort	20%	40%	30%	40%
High Effort	40%	40%	50%	50%

- Pipeline ROW estimated contaminated soils removal volumes are based on a percentage of the total ROW that is expected to fall under each contamination level to the NM OCD reclamation depths of 4 ft bgs
- The total surface area of the pipeline ROWs requiring re-seeding is expected to differ slightly by contamination category, as shown in Table 29
- The level of reclamation effort required for buried pipeline ROWs are expected to be slightly lower than those for surface pipeline ROWs. To capture this disparity, the following breakdown of total pipeline miles within each reclamation effort level was used.
  - Buried Pipelines
    - 60% of all pipelines require low effort reclamation

- 30% of all pipelines require medium effort reclamation
- 10% of all pipelines require high effort reclamation

- Surface Pipelines
  - 70% of all pipelines require low effort reclamation
  - 25% of all pipelines require medium effort reclamation
  - 5% of all pipelines require high effort reclamation

6.5.3 Commercial Lease Surface Reclamation

- Surface reclamation costs are directly correlated to the size of the site being reclaimed.
  - To find the average wellpad size, a random selection of wells across all counties, well types, drilling directions and years were measured using aerial photos to determine, in acres, the size of the reclamation area (wellpad)
- Well locations were divided into groups by production basin, by well type, and by year brought into production
  - Each production basin may have different production methods, drilling and access challenges, and may even have different specifications for pad sizes
  - Each well type is assumed to have varying levels of contamination based on the commodity produced
  - Pad development and drilling methods began to change drastically around 2012, resulting in larger pads, better environmental protection controls, and better best management practices to reduce potential long-term contamination issues, all of which could affect the final remediation levels needed at each site
- Wells with the status of “Cancelled” and “Never-drilled” are not included in the estimated costs
- Multi-well pads are a relatively new approach to oil and gas drilling. The extremely small number of sites containing multiple wells is insignificant enough to distinguish well and pad numbers differently
- Current un-remediated pits and frac ponds are NOT included in estimated reclamation costs due to the infrequency of occurrence, as well as because these types of facilities are associated with new well development and are often remediated by the producers shortly after production begins.
- Remediation requirements include excavation and disposal of contaminated soils to a depth of approximately 4 ft bgs based on NM OCD restoration and reclamation guidance provided in 19.15.29.13 NMAC. Contaminated soil removal volumes can drastically affect reclamation costs. To provide a range of costs, per pad estimated contaminated soil removal volumes are based on four contamination levels
  - Low contamination – approximately 10% of pad needs to be excavated and disposed
  - Medium-low contamination – approximately 25% of the pad needs to be excavated and disposed
  - Medium-high contamination – approximately 40% of the pad needs to be excavated and disposed
  - High contamination – approximately 60% of the pad needs to be excavated and disposed
- Contamination levels are not going to be the same at all pads in a category, thus it is assumed that a percentage of all well pads in a group will fall into the low, medium-low, medium-high and high contamination range. This is referred to as the contamination rate
- Contamination rates at gas well pads are expected to be different than those at oil well pads and SWD pads, due to the volatile, gaseous state of the resource being handled. When a release occurs at a gas well, the released material tends to dissipate into the air rather than soak into the soil. To capture this disparity, the following breakdown of total wells within each contamination level was used
  - Gas Well Contamination Rates

- 25% of all wells have a low level of contamination
- 60% of all wells have a medium-low level of contamination
- 10% of all wells have a medium-high level of contamination
- 5% of all wells have a high level of contamination

- Oil Wells and SWDs Contamination Rates
  - 15% of all wells have a low level of contamination
  - 60% of all wells have a medium-low level of contamination
  - 20% of all wells have a medium-high level of contamination
  - 5% of all wells have a high level of contamination

6.5.4 All Reclamations

- Because trucking is typically charged by the hour, the distance from each site to an appropriate disposal location can have a dramatic impact on final reclamation costs. To account for this, trucking times are broken into three average round trip times with one-third of all wells from each basin and well-type falling into each range and one-third of each reclamation effort level for each category of pipeline falling into each range
  - Short-duration trucking is an average round trip time of approximately 1.5 hours
  - Medium-duration trucking is an average round trip time of approximately 3 hours
  - Long-duration trucking is an average round trip time of approximately 5.5 hours
- To avoid additional field crew mobilization and demobilization costs, it is assumed that the same companies who are completing surface decommissioning activities will be conducting surface reclamation concurrent with, or immediately subsequent to, final surface decommissioning or pipeline decommissioning
- The surface reclamation costs presented here DO include environmental assessment and testing via field screening methods as part of the overall contaminated soil excavation costs
- It is assumed that full laboratory analysis and closure reporting will not be required. If laboratory analysis and closure reporting are required, those costs would be in addition to the surface reclamation estimates presented in this report
- The costs for purchase and emplacement of topsoil and initial re-seeding of the reclaimed areas with a native seed mix are included. The cost of follow-on watering, re-seeding or long-term revegetation monitoring activities are not included as these activities would likely be provided by state experts

6.6 Data Sources and Limitations

The initial well sample assessments and totals used in developing abandonment costs in Section 2.0, decommissioning costs in Section 3.0. pipeline decommissioning and removal costs in Section 4.0, and commercial lease site facility decommissioning costs in Section 5.0 were used in the surface reclamation cost assessment. Any data gaps pertaining to the well abandonment, decommissioning and pipeline work would have transferred to this portion of the liability assessment.

Information on well types, locations and wellpad sizes was gleaned from asset lists obtained from the SLO and OCD. Trucking, disposal and backfill costs were obtained from Vertex records for previous spill remediation and site reclamation work conducted within the Permian and San Juan Basins.

Data gaps in wellsite and pipeline reclamation costs largely stem from a lack of, or incomplete, standardized regulatory requirements for full site reclamation, applicable across the state, which would streamline efforts at liability assessments by reducing the variables that can be involved in site reclamation activities.

7.0 Total Liabilities Summary

Table 30. Total Well Abandonment, Decommissioning and Reclamation Costs

Activity	New Mexico State Lands			All New Mexico Wells	
	High	Low		High	Low
Downhole Abandonment	$1,536,000,000	$1,315,000,000		$6,540,000,000	$5,671,000,000
Surface Facility Decommissioning	$244,867,057	$244,867,057		$897,546,249	$897,546,249
Surface Reclamation	$1,621,635,429	$1,621,635,429		$5,434,063,476	$5,434,063,476
Total Liabilities	**$3,402,502,486**	**$3,181,502,486**		**$12,871,609,725**	**$12,002,609,725**

Table 31. Pipeline Decommissioning and Reclamation Costs

Activity	New Mexico State Lands			All New Mexico Wells	
	Typical Decommissioning	Full Removal		Typical Decommissioning	Full Removal
Pipeline	$87,760,684	$7,871,642,351		$251,615,253	$17,090,858,710
Pipeline Surface Reclamation	$1,221,961,873	$1,221,961,873		$3,170,531,524	$3,170,531,524
Total Liabilities	**$1,309,722,557**	**$9,093,604,224**		**$3,422,146,777**	**$20,261,390,234**

Table 32. Commercial Lease Site Decommissioning and Reclamation Costs

Activity	New Mexico State Lands		All New Mexico Wells	
	Estimated		High	Low
Commercial Lease Site Decommissioning	$492,008,798.62		N/A	N/A
Commercial Lease Site Surface Reclamation	$2,815,149,896.01		N/A	N/A
Total Liabilities	**$3,307,158,694.63**		**N/A**	**N/A**

8.0 References

New Mexico Geological Society Guidebook. (1993). *44th Field Conference, Carlsbad Region, New Mexico and West Texas*. Retrieved from http://nmgs.nmt.edu/publications/guidebooks/44

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9.0 Disclosure

This report has been prepared as a result of Vertex Resource Services Inc (Vertex) research and interest in the potential availability of remediation and reclamation work in the state of New Mexico. Any use of this report by a third party, or any reliance on decisions made based on it, or damages suffered as a result of the use of this report are the sole responsibility of the user.

The information and conclusions contained in this report are based upon work undertaken by trained professional and technical staff in accordance with generally accepted practices current at the time the work was performed. The conclusions and recommendations presented represent the best judgement of Vertex based on the data available during the assessment. Due to the nature of the assessment and the data available, Vertex cannot warrant against undiscovered environmental liabilities. Conclusions presented in this report should not be considered legal advice.

Sincerely,



Natalie Gordon, M.Sc., BA, B.Acc., P.Biol.
PROJECT MANAGER – US OPERATIONS

EXHIBIT 19

APPENDIX A

EXHIBIT 19

CONDITIONS FOR PLUGGING AND ABANDONMENT

OCD - Southern District

The following is a guide or checklist in preparation of a plugging program, this is not all inclusive and care must be exercised in establishing special plugging programs in unique and unusual cases, **Notify NMOCD District Office II at (575)-748-1283 at least 24 hours before beginning work.** After MIRU rig will remain on well until it is plugged to surface. OCD is to be notified before rig down. Company representative will be on location during plugging procedures.

1. A notice of intent to plug and abandon a wellbore is required to be approved before plugging operations are conducted. A cement evaluation tool is required in order to ensure isolation of producing formations, protection of water and correlative rights. A cement bond log or other accepted cement evaluation tool is to be provided to the division for evaluation if one has not been previously run or if the well did not have cement circulated to surface during the original casing cementing job or subsequent cementing jobs.
2. Closed loop system is to be used for entire plugging operation. Upon completion, contents of steel pits are to be hauled to a permitted disposal location.
3. Trucking companies being used to haul oilfield waste fluids to a disposal – commercial or private – shall have an approved NMOCD C-133 permit. A copy of this permit shall be available in each truck used to haul waste products. It is the responsibility of the operator as well as the contractor, to verify that this permit is in place prior to performing work. Drivers shall be able to produce a copy upon request of an NMOCD Field inspector.
4. Filing a subsequent C-103 will serve as notification that the well has been plugged.
5. A final C-103 shall be filed (and a site inspection by NMOCD Inspector to determine if the location is satisfactorily cleaned, all equipment, electric poles and trash has been removed to Meet NMOCD standards) before bonding can be released.
6. If work has not begun within 1 Year of the approval of this procedure, an extension request must be file stating the reason the well has not been plugged.
7. **Squeeze pressures are not to exceed 500 psi, unless approval is given by NMOCD.**
8. Produced water **will not** be used during any part of the plugging operation.
9. Mud laden fluids must be placed between all cement plugs mixed at 25 sacks per 100 bbls of water.
10. All cement plugs will be a minimum of 100' in length or a minimum of 25 sacks of cement, whichever is greater. 50' of calculated cement excess required for inside casing plugs and 100% calculated cement excess required on outside casing plugs.
11. **Class 'C' cement will be used above 7500 feet.**
12. **Class 'H' cement will be used below 7500 feet.**
13. **A cement plug is required to be set 50' above and 50' below, casing stubs, DV tools, attempted casing cut offs, cement tops outside casing, salt sections and anywhere the casing is perforated, these plugs require a 4 hour WOC and then will be tagged**
14. **All Casing Shoes Will Be Perforated 50' below shoe depth and Attempted to be Squeezed, cement needs to be 50' above and 50' Below Casing Shoe inside the Production Casing.**

EXHIBIT 19

16. When setting the top out cement plug in production, intermediate and surface casing, wellbores should remain full at least 30 minutes after plugs are set
17. **A CIBP is to be set within 100' of production perforations, capped with 100' of cement, WOC 4 hours and tag.**
18. A CIBP with 35' of cement may be used in lieu of the 100' plug if set with a bailer. This plug will be placed within 100' of the top perforation, **(WOC 4 hrs and tag).**
19. No more than **3000' is allowed between cement plugs in cased hole and 2000' in open hole.**
20. Some of the Formations to be isolated with cement plugs are: These plugs to be set to isolate formation tops
    A) Fusselman
    B) Devonian
    C) Morrow
    D) Wolfcamp
    E)Bone Springs
    F) Delaware
    G) Any salt sections
    H) Abo
    I) Glorieta
    J) Yates.
    K) **Potash---** (In the R-111-P Area (Potash Mine Area), a solid cement plug must be set across the salt section. Fluid used to mix the cement shall be saturated with the salts that are common to the section penetrated and in suitable proportions, not more than 3% calcium chloride (by weight of cement) will be considered the desired mixture whenever possible, **WOC 4 hours and tag, this plug will be 50' below the bottom and 50' above the top of the Formation.**
21. **If cement does not exist behind casing strings at recommended formation depths,** the casing can be cut and pulled with plugs set at recommended depths. If casing is not pulled, perforations will be shot and cement squeezed behind casing, WOC and tagged. These plugs will be set 50' below formation bottom to 50' above formation top inside the casing

DRY HOLE MARKER REQUIRMENTS

The operator shall mark the exact location of the plugged and abandoned well with a steel marker not less than four inches in diameter, 3' below ground level with a plate of at least ¼" welded to the top of the casing and the dry hole marker welded on the plate with the following information welded on the dry hole marker:

1. Operator name 2. Lease and Well Number 3.API Number 4. Unit Letter 5. Quarter Section (feet from the North, South, East or West) 6. Section, Township and Range 7. Plugging Date 8. County (SPECIAL CASES)-------AGRICULTURE OR PRARIE CHICKEN BREEDING AREAS

In these areas, a below ground marker is required with all pertinent information mentioned above on a plate, set 3' below ground level, a picture of the plate will be supplied to NMOCD for record, the exact location of the marker (longitude and latitude by GPS) will be provided to NMOCD (We typically require a current survey to verify the GPS)

EXHIBIT 19

APPENDIX B

EXHIBIT 19

New Mexico Well Categorization and Wellfile Review Summary - All Wells In New Mexico

County	Fluid	Profile	Depth	Count	File Reviews	% Reviewed	Type	Completion	Pools	Type Count	ABD Estimate	Intermediate Casing %	Intermediate Casing Count	CBL Req'd %	CBL Req'd Count	Flagged Zones Low Cement Top %	Flagged Zones Low Cement Top Count
Chaves	Gas	Vertical / Directional	<5,000'	749	11	1%	Flow	Perforated	1	749	ST1		0	75%	562	50%	375
			5,000-10,000'	486	8	2%	Flow	Perforated	1	486	MT1	75%	0	75%	365	50%	243
			>10,000'	19	6	32%	Flow	Perforated	2	19	DT2	100%	19	100%	19	50%	10
		Horizontal	<5,000'														
			5,000-10,000'	36	3	8%	Flow	Perforated	2	36	MT2		0	100%	36	0%	0
			>10,000'														
	Oil	Vertical / Directional	<5,000'	1018	23	2%	Pump	Perforated	1	1018	SR1		0	100%	1018	50%	509
			5,000-10,000'	54	3	6%	Pump	Perforated	2	54	MR2	100%	54	100%	54	0%	0
			>10,000'	23	6	26%	Pump	Perforated	2	23	DR2	100%	23	100%	23	0%	0
		Horizontal	<5,000'	6	1	17%	Pump	Perforated	2	6	SR2		0	0%	0	0%	0
			5,000-10,000'	62	5	8%	Flow	Perforated	2	28	MT2	100%	28	100%	28	0%	0
							Pump	Frac port liner	2	34	MR2	100%	34	100%	34	0%	0
			>10,000'	53	4	8%	Pump	Frac port liner	2	53	DR2	100%	53	100%	53	0%	0
	SWD	Vertical / Directional	<5,000'	162	3	2%	Injection	Perforated	2	162	ST2	100%	162	25%	41	50%	81
			5,000-10,000'	13	5	38%	Injection	Perforated	2	13	MT2	100%	13	25%	3	50%	7
			>10,000'	7	3	43%	Injection	Perforated	2	7	DT2	100%	7	25%	2	0%	0
		Horizontal	<5,000'														
			5,000-10,000'	7	1	14%	Injection	Perforated	2	7	MT2		0	25%	2	0%	0
			>10,000'														
	Empty			138						138	E						
Catron	Empty			1						1	E						
Colfax	Gas	Vertical / Directional	<5,000'	846		0%	Flow	Perforated	1	846	ST1	50%	423	50%	423	50%	423
			5,000-10,000'	12		0%	Flow	Perforated	1	12	MT1	50%	6	50%	6	50%	6
			>10,000'														
Curry	Empty			1						1	E						
Lea	Gas	Vertical / Directional	<5,000'	978	27	3%	Flow	Perforated	2	380	ST2	50%	190	100%	380	50%	190
							Pump	Perforated	2	598	SR2	0%	0	100%	598	50%	299
			5,000-10,000'	245	1	0%	Flow	Perforated	2	245	MT2	0%	0	100%	245	75%	184
			>10,000'	666	4	1%	Flow	Perforated	2	333	DR2	100%	333	50%	167	0%	0
							Pump	Perforated	2	333	SR2	0%	0	100%	333	50%	167
		Horizontal	<5,000'	1	0	0%	Flow		2	1	ST2	0%	0	100%	1	50%	1
			5,000-10,000'	2	0	0%	Flow		2	2	MT2	0%	0	100%	2	50%	1
			>10,000'	85		0%	Flow	Perforated	2	36	DT2	50%	18	75%	27	50%	18
							Pump	Perforated	2	49	DR2	50%	25	75%	37	50%	25
	Oil	Vertical / Directional	<5,000'	4045	14	0%	Pump	Perforated	1	4045	SR1	50%	2023	25%	1011	25%	1011
			5,000-10,000'	4575	12	0%	Pump	Perforated	2	4575	MR2	75%	3431	75%	3431	25%	1144
			>10,000'	1236	4	0%	Pump	Perforated	2	1236	DR2	100%	1236	100%	1236	0%	0
		Horizontal	<5,000'	2	1	50%	Pump	Perforated	1	2	SR1		0	100%	2	0%	0
			5,000-10,000'	165	1	1%	Pump	Perforated	1	165	MR1		0	100%	165	0%	0
			>10,000'	5048	25	0%	Flow	Perforated	1	2615	DT1	100%	2615	100%	2615	25%	654
							Pump	Perforated	1	2433	DR1	100%	2433	25%	608	25%	608
	SWD	Vertical / Directional	<5,000'	1522	4	0%	Injection	Perforated	1	761	ST1		0	25%	190	0%	0
							Injection	OH	1	761	ST1		0	25%	190	0%	0
			5,000-10,000'	849	4	0%	Injection	Perforated	1	849	MT1		0	25%	212	50%	425
			>10,000'	237	2	1%	Injection	Perforated	1	237	DT1	100%	237	25%	59	50%	119
		Horizontal	<5,000'														
			5,000-10,000'	4	0	0%	Injection	Perforated	1	4	MT1	0%	0	25%	1	50%	2
			>10,000'	2	0	0%	Injection	Perforated	1	2	DT1	0%	0	25%	1	50%	1
	Empty			540						540	E						
Luna	Empty			1						1	E						

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Roosevelt	Gas	Vertical / Directional	<5,000'	23	1	4%	Flow	OH	1	23	ST1	0%	0	100%	23	0%	0
			5,000-10,000'	27	2	7%	Flow	Perforated	2	18	MT2	0%	0	100%	18	0%	0
							Pump	Perforated	2	9	MR2	0%	0	100%	9	0%	0
			>10,000'	1	0	0%	Pump	Perforated	2	1	DR2	0%	0	100%	1	0%	0
		Horizontal	<5,000'														
			5,000-10,000'	2	1	50%	Pump	Perforated	2	2	MR2	100%	2	100%	2	0%	0
			>10,000'														
	Oil	Vertical / Directional	<5,000'	289	9	3%	Flow	Perforated	1	172	ST1		0	100%	172	0%	0
							Pump	Perforated	1	117	SR1		0	100%	117	0%	0
			5,000-10,000'	51	3	6%	Pump	Perforated	2	51	MR2	100%	51	100%	51	0%	0
			>10,000'	3	1	33%	Pump	Perforated	2	3	DR2	100%	3	100%	3	0%	0
		Horizontal	<5,000'	2	1	50%	Flow	Perforated	1	2	ST1		0	100%	2	0%	0
			5,000-10,000'	8	3	38%	Flow	Perforated	1	8	MR1		0	100%	8	0%	0
			>10,000'	8	2	25%	Pump	Perforated	1	8	DR1		0	100%	8	0%	0
	SWD	Vertical / Directional	<5,000'	39	1	3%	Injection	Perforated	2%	39	ST2	0%	0	25%	10	0%	0
			5,000-10,000'	12	1	8%	Injection	Perforated	2%	12	MT2	50%	6	25%	3	0%	0
			>10,000'	3	1	33%	Injection	Perforated	2%	3	DT2	100%	3	25%	1	0%	0
	Empty			10						10	E						
Eddy	Gas	Vertical / Directional	<5,000'	48	2	4%	Flow	Perforated	2	48	ST2	100%	48	100%	48	0%	0
			5,000-10,000'	816	8	1%	Flow	Perforated	2	816	MT2	100%	816	100%	816	50%	408
			>10,000'	1577	28	2%	Flow	Perforated	2	1577	DT2	100%	1577	50%	789	50%	789
		Horizontal	<5,000'	3	1	33%	Flow	Perforated	1	3	ST1	100%	3	100%	3	0%	0
			5,000-10,000'	58	4	7%	Flow	Perforated	1	58	MT1	100%	58	75%	44	0%	0
			>10,000'	1719	75	4%	Flow	Perf / frac port liner	2	1719	DT2	100%	1719	75%	1289	50%	860
	Oil	Vertical / Directional	<5,000'	4859	24	0%	Pump	Perforated	1	4859	SR1		0	100%	4859	25%	1215
			5,000-10,000'	3749	27	1%	Pump	Perforated	1	3749	MR1	75%	2812	75%	2812	25%	937
			>10,000'	1159	13	1%	Flow	Perforated	2	583	DT2	100%	583	100%	583	25%	146
							Pump	Perforated	2	576	DR2	100%	576	100%	576	25%	144
		Horizontal	<5,000'	19	2	11%	Pump	Perforated	1	19	SR1	0%	0	100%	19	0%	0
			5,000-10,000'	506	2	0%	Pump	Perforated	1	506	MR1		0				
			>10,000'	2467	15	1%	Flow	Perforated	1	1218	DT1	100%	1218	100%	1218	25%	305
							Pump	Perforated	1	1249	DR1	100%	1249	100%	1249	25%	312
	SWD	Vertical / Directional	<5,000'	620	5	1%	Injection	Perforated	2	620	ST2	0%	0	25%	155	0%	0
			5,000-10,000'	141	2	1%	Injection	Perforated	2	141	MT2	50%	71	25%	35	0%	0
			>10,000'	391	7	2%	Injection	Perf / frac port liner	2	391	DT2	50%	196	25%	98	0%	0
	Empty			480						480	E						
Otero	Oil	Vertical / Directional	<5,000'	1	0	0%	Flow		1	1	ST1	0%	0	100%	1	25%	0
			5,000-10,000'	2	0	0%	Flow		1	2	MT1	0%	0	100%	2	25%	1
			>10,000'														
Guadalupe	Gas	Vertical / Directional	<5,000'														
			5,000-10,000'														
			>10,000'	1	0	0%	Flow		1	1	DT1	0%	0	100%	1	0%	0
	Oil	Vertical / Directional	<5,000'	1	0	0%	Pump		1	1	SR1	0%	0	100%	1	0%	0
			5,000-10,000'														
			>10,000'														
Harding	CO2	Vertical / Directional	<5,000'	385	0	0%	Flow		1	385	ST1	0%	0	100%	385	0%	0
			5,000-10,000'														
			>10,000'														
	SWD	Vertical / Directional	<5,000'	3	0	0%	Injection		1	3	ST1	0%	0	25%	1	0%	0
			5,000-10,000'														
			>10,000'														

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McKinley	Gas	Vertical / Directional	<5,000'	18	2	11%	Pump	Perforated	1	18	SR1	0%	0	100%	18	0%	0
			5,000-10,000'														
			>10,000'														
	Oil	Vertical / Directional	<5,000'	153	3	2%	Pump	OH	1	153	SR1	0%	0	100%	153	0%	0
			5,000-10,000'	4	0		Pump		1	4	MR1	0%	0	100%	4	0%	0
			>10,000'														
	SWD	Vertical / Directional	<5,000'	20	0	0%	Injection		1	20	ST1	0%	0	25%	5	0%	0
			5,000-10,000'	2	0	0%	Injection		1	2	MT1	0%	0	25%	1	0%	0
			>10,000'														
	Empty			7						7	E						
Quay	Gas	Vertical / Directional	<5,000'														
			5,000-10,000'	11	0	0%	Flow	Perforated	1	11	MT1						
			>10,000'														
	Oil	Vertical / Directional	<5,000'	1	0	0%	Pump		1	1	SR1	0%	0	100%	1	0%	0
			5,000-10,000'	1	0	0%	Flow		1	1	MT1	0%	0	100%	1	0%	0
			>10,000'														
Rio Arriba	Gas	Vertical / Directional	<5,000'	2438	6	0%	Flow	Perforated	2	2438	ST2	25%	610	100%	2438	0%	0
			5,000-10,000'	4880	15	0%	Flow	Perforated	2	4880	MT2	25%	1220	100%	4880	0%	0
			>10,000'	2	0	0%	Flow	Perforated	2	2	DT2	25%	1	100%	2	0%	0
		Horizontal	<5,000'	43	1	2%	Pump	Perforated	1	43	SR1	100%	43	100%	43	0%	0
			5,000-10,000'	372	6	2%	Flow	Perforated	1	372	MT1	100%	372	100%	372	0%	0
			>10,000'	42	0	0%	Flow	Perforated	1	42	DT1	100%	42	100%	42	0%	0
	Oil	Vertical / Directional	<5,000'	56	0	0%	Pump	Perforated	2	56	SR2	0%	0	100%	56	0%	0
			5,000-10,000'	741	10	1%	Pump	Perforated	2	372	MR2	0%	0	100%	372	0%	0
							Flow	Perforated	2	369	MT2	0%	0	100%	369	0%	0
			>10,000'														
		Horizontal	<5,000'														
			5,000-10,000'	6	1	17%	Pump	Perforated	1	6	MR1	100%	6	100%	6	0%	0
			>10,000'	92	2	2%	Flow	Perforated	1	92	DT1	100%	92	100%	92	0%	0
	SWD	Vertical / Directional	<5,000'	2			Injection	Perforated	1	2	ST1	100%	2	25%	1	0%	0
			5,000-10,000'	16	1		Injection	Perforated	1	16	MT1	100%	16	25%	4	0%	0
			>10,000'	2			Injection	Perforated	1	2	DT1	100%	2	25%	1	0%	0
	Empty			5						5	E						
San Juan	Gas	Vertical / Directional	<5,000'	5896	25	0%	Flow	Perforated	1	5896	ST1	25%	1474	100%	5896	50%	2948
			5,000-10,000'	5621	19	0%	Flow	Perforated	1	5621	MT1	25%	1405	100%	5621	50%	2811
			>10,000'	5	0	0%	Flow	Perforated	1	5	DT1	25%	1	100%	5	50%	3
		Horizontal	<5,000'	72	1	1%	Flow	Frac port liner	1	72	ST1	0%	0	100%	72	0%	0
			5,000-10,000'	233	4	2%	Flow	Perf / frac port liner	2	233	MT2	0%	0	100%	233	0%	0
			>10,000'	105	2	2%	Flow	Perf / frac port liner	2	105	DT2	0%	0	100%	105	0%	0
	Oil	Vertical / Directional	<5,000'	326	2	1%	Pump	Perforated	1	326	SR1	0%	0	100%	326	100%	326
			5,000-10,000'	297	8	3%	Flow	Perforated	1	198	MT1	0%	0	100%	198	100%	198
							Pump	Perforated	1	99	MR1	0%	0	100%	99	100%	99
			>10,000'	3	1	33%	Flow	Perforated	1	3	DT1	0%	0	100%	3	0%	0
		Horizontal	<5,000'	1	0		Pump	Frac port liner	2	1	SR1	0%	0	50%	1	0%	0
			5,000-10,000'	29	3		Pump	Frac port liner	2	29	MR2	100%	29	50%	15	0%	0
			>10,000'	194	1	1%	Pump	Frac port liner	2	194	DR2	100%	194	50%	97	0%	0
	SWD	Vertical / Directional	<5,000'	33	2	6%	Injection	Perforated	1	33	ST1	0%	0	25%	8	50%	17
			5,000-10,000'	59	2	3%	Injection	Perforated	1	59	MT1	0%	0	25%	15	50%	30
			>10,000'	2	0	0%	Injection	Perforated	1	2	MT1	0%	0	25%	1	50%	1
	Empty			40						40	E						

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Sandoval	Gas	Vertical / Directional	<5,000'	198	2	1%	Flow	Perforated	1	198	ST1	0%	0	100%	198	25%	50
			5,000-10,000'	8	0	0%	Flow	Perforated	1	8	MT1	0%	0	100%	8	0%	0
			>10,000'														
		Horizontal	<5,000'														
			5,000-10,000'	1		0%	Flow	Perforated	1	1	MT1	0%	0	100%	1	0%	0
			>10,000'	8		0%	Flow	Perforated	1	8	DT1	0%	0	100%	8	0%	0
	Oil	Vertical / Directional	<5,000'	31	0	0%	Pump	Perforated	1	31	SR1	0%	0	100%	31	0%	0
			5,000-10,000'	135	2	1%	Pump	Perforated	1	135	MR1	0%	0	100%	135	0%	0
			>10,000'	2	1	50%	Pump	Perforated	1	2	DR1	0%	0	100%	2	0%	0
		Horizontal	<5,000'	1	0	0%	Pump	Perforated	1	1	SR1	0%	0	100%	1	0%	0
			5,000-10,000'	22	2	9%	Pump	Frac port liner	1	22	MR1	0%	0	100%	22	0%	0
			>10,000'	138	4	3%	Pump	Frac port liner	1	138	DR1	0%	0	100%	138	0%	0
	SWD	Vertical / Directional	<5,000'	4		0%	Injection	Perforated	1	4	ST1	0%	0	25%	1	50%	2
			5,000-10,000'	1		0%	Injection	Perforated	1	1	MT1	0%	0	25%	0	50%	1
			>10,000'														
Socorro	Gas	Vertical / Directional	<5,000'	1		0%	Pump	Perforated	1	1	SR1	0%	0	100%	1	25%	0
			5,000-10,000'														
			>10,000'	2	0	0%	Flow	Perforated	1	2	DT1	0%	0	100%	2	0%	0
Union	Gas	Vertical / Directional	<5,000'	361		0%	Flow	Perforated	1	361	ST1	0%	0	100%	361	25%	90
			5,000-10,000'														
			>10,000'														
	SWD	Vertical / Directional	<5,000'	2	1	50%	Injection	Tubing	1	2	ST1		0	25%	1	0%	0
			5,000-10,000'														
			>10,000'														
	Empty			4						4	E						
													29861		**52052**		**18188**

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Chaves	Gas	Vertical / Directional	<5,000'	104	9	9%	Flow	Perforated	1	104	ST1		0	100%	104	50%	52
			5,000-10,000'	168	7	4%	Flow	Perforated	1	168	MT1		0	100%	168	50%	84
			>10,000'	9	6	67%	Flow	Perforated	2	9	DT2	100%	9	100%	9	50%	5
		Horizontal	<5,000'														
			5,000-10,000'	5	3	60%	Flow	Perforated	2	5	MT2		0	100%	5	0%	0
			>10,000'														
	Oil	Vertical / Directional	<5,000'	291	25	9%	Pump	Perforated	1	291	SR1		0	100%	291	50%	146
			5,000-10,000'	21	3	14%	Pump	Perforated	2	21	MR2	100%	21	100%	21	0%	0
			>10,000'	7	5	71%	Pump	Perforated	2	7	DR2	100%	7	100%	7	0%	0
		Horizontal	<5,000'	1	1	100%	Pump	Perforated	2	1	SR2		0	0%	0	0%	0
			5,000-10,000'	16	5	31%	Flow	Perforated	2	10	MT2	100%	10	100%	10	0%	0
							Pump	Frac port liner	2	6	MR2	100%	6	100%	6	0%	0
			>10,000'	22	5	23%	Pump	Frac port liner	2	22	DR2	100%	22	100%	22	0%	0
	SWD	Vertical / Directional	<5,000'	3	1	33%	Injection	Perforated	2	3	ST2	100%	3	25%	1	50%	2
			5,000-10,000'	8	4	50%	Injection	Perforated	2	8	MT2	100%	8	25%	2	50%	4
			>10,000'	3	3	100%	Injection	Perforated	2	3	DT2	100%	3	25%	1	0%	0
		Horizontal	<5,000'														
			5,000-10,000'	1	1	100%	Injection	Perforated	2	1	MT2		0	25%	0	0%	0
			>10,000'														
Lea	Gas	Vertical / Directional	<5,000'	466	27	6%	Flow	Perforated	2	233	ST2	50%	117	100%	233	50%	117
							Pump	Perforated	2	233	SR2		0	100%	233	50%	117
			5,000-10,000'	37	1	3%	Flow	Perforated	2	37	MT2	0%	0	100%	37	75%	28
			>10,000'	366	2	1%	Pump	Perforated	2	366	DR2	100%	366	50%	183	0%	0
		Horizontal	<5,000'														
			5,000-10,000'														
			>10,000'	16	1	6%	Flow	Perforated	2	16	DT2	100%	16	100%	16	25%	4
	Oil	Vertical / Directional	<5,000'	1660	14	1%	Pump	Perforated	1	1660	SR1		0	25%	415	25%	415
			5,000-10,000'	1388	12	1%	Pump	Perforated	2	1388	MR2	100%	1388	100%	1388	0%	0
			>10,000'	539	4	1%	Pump	Perforated	2	539	DR2	100%	539	100%	539	0%	0
		Horizontal	<5,000'	1	1	100%	Pump	Perforated	1	1	SR1		0	100%	1	0%	0
			5,000-10,000'	74	1	1%	Pump	Perforated	1	74	MR1		0	100%	74	0%	0
			>10,000'	1770	15	1%	Flow	Perforated	1	1193	DT1	100%	1193	100%	1193	25%	298
							Pump	Perforated	1	577	DR1	100%	577	25%	144	25%	144
	SWD	Vertical / Directional	<5,000'	19	3	16%	Injection	Perforated	1	10	ST1		0	25%	3	0%	0
							Injection	OH	1	9	ST1		0	25%	2	0%	0
			5,000-10,000'	57	3	5%	Injection	Perforated	1	57	MT1		0	25%	14	50%	29
			>10,000'	71	2	3%	Injection	Perforated	1	71	DT1	100%	71	25%	18	50%	36
Roosevelt	Gas	Vertical / Directional	<5,000'	1	1	100%	Flow	OH	1	1	ST1		0	100%	1	0%	0
			5,000-10,000'	2	2	100%	Flow	Perforated	2	2	MT2		0	100%	2	0%	0
			>10,000'														
		Horizontal	<5,000'														
			5,000-10,000'	1	1	100%	Pump	Perforated	2	1	MR2	100%	1	100%	1	0%	0
			>10,000'														
	Oil	Vertical / Directional	<5,000'	104	9	9%	Flow	Perforated	1	52	ST1		0	100%	52	0%	0
							Pump	Perforated	1	52	SR1		0	100%	52	0%	0
			5,000-10,000'	6	3	50%	Pump	Perforated	2	6	MR2	100%	6	100%	6	0%	0
			>10,000'	1	1	100%	Pump	Perforated	2	1	DR2	100%	1	100%	1	0%	0
		Horizontal	<5,000'	2	1	50%	Flow	Perforated	1	2	ST1		0	100%	2	0%	0
			5,000-10,000'	5	3	60%	Flow	Perforated	1	5	MR1		0	100%	5	0%	0
			>10,000'	2	2	100%	Pump	Perforated	1	2	DR1		0	100%	2	0%	0
	SWD	Vertical / Directional	<5,000'														
			5,000-10,000'	1	1	100%	Injection	Perforated	2	1	MT2	100%	1	25%	0	0%	0
			>10,000'														

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Eddy	Gas	Vertical / Directional	<5,000'	14	1	7%	Flow	Perforated	2	14	ST2	100%	14	100%	14	0%	0
			5,000-10,000'	213	8	4%	Flow	Perforated	2	213	MT2	100%	213	100%	213	50%	107
			>10,000'	518	18	3%	Flow	Perforated	2	518	DT2	100%	518	100%	518	50%	259
		Horizontal	<5,000'	2	1	50%	Flow	Perforated	1	2	ST1	100%	2	100%	2	0%	0
			5,000-10,000'	8	1	13%	Flow	Perforated	1	8	MT1	100%	8	100%	8	0%	0
			>10,000'	347	12	3%	Flow	Perf / frac port liner	2	347	DT2	100%	347	100%	347	50%	174
	Oil	Vertical / Directional	<5,000'	1518	14	1%	Pump	Perforated	1	1518	SR1		0	100%	1518	25%	380
			5,000-10,000'	1167	18	2%	Pump	Perforated	1	1167	MR1	100%	1167	100%	1167	25%	292
			>10,000'	358	25	7%	Flow	Perforated	2	179	DT2	100%	179	100%	179	25%	45
							Pump	Perforated	2	179	DR2	100%	179	100%	179	25%	45
		Horizontal	<5,000'	5	2	40%	Pump	Perforated	1	5	SR1		0	100%	5	0%	0
			5,000-10,000'	80	1	1%	Pump	Perforated	1	80	MR1		0				
			>10,000'	776	14	2%	Flow	Perforated	1	388	DT1	100%	388	100%	388	25%	97
							Pump	Perforated	1	388	DR1	100%	388	100%	388	25%	97
	SWD	Vertical / Directional	<5,000'	12	3	25%	Injection	Perforated	2	12	ST2		0	25%	3	0%	0
			5,000-10,000'	31	2	6%	Injection	Perforated	2	31	MT2	50%	16	25%	8	0%	0
			>10,000'	94	9	10%	Injection	Perf / frac port liner	2	94	DT2	50%	47	25%	24	0%	0
Otero	Oil	Vertical / Directional	<5,000'	1	1	100%	Abandoned	Abandoned	-	0		0%	0	0%	0	0%	0
			5,000-10,000'														
			>10,000'														
McKinley	Gas	Vertical / Directional	<5,000'	2	2	100%	Pump	Perforated	1	2	SR1		0	100%	2	0%	0
			5,000-10,000'														
			>10,000'														
	Oil	Vertical / Directional	<5,000'	5	3	60%	Pump	OH	1	5	SR1		0	100%	5	0%	0
			5,000-10,000'														
			>10,000'														
Rio Arriba	Gas	Vertical / Directional	<5,000'	142	6	4%	Flow	Perforated	2	142	ST2	25%	36	100%	142	0%	0
			5,000-10,000'	333	15	5%	Flow	Perforated	2	333	MT2	25%	83	100%	333	0%	0
			>10,000'														
		Horizontal	<5,000'	3	1	33%	Pump	Perforated	1	3	SR1	100%	3	100%	3	0%	0
			5,000-10,000'	17	6	35%	Flow	Perforated	1	17	MT1	100%	17	100%	17	0%	0
			>10,000'														
	Oil	Vertical / Directional	<5,000'														
			5,000-10,000'	37	10	27%	Pump	Perforated	2	19	MR2		0	100%	19	0%	0
							Flow	Perforated	2	18	MT2		0	100%	18	0%	0
			>10,000'														
		Horizontal	<5,000'														
			5,000-10,000'	1	1	100%	Pump	Perforated	1	1	MR1	100%	1	100%	1	0%	0
			>10,000'	5	2	40%	Flow	Perforated	1	5	DT1	100%	5	100%	5	0%	0
	SWD	Vertical / Directional	<5,000'														
			5,000-10,000'	1	1		Injection	Perforated	1	1	MT1	100%	1	25%	0	0%	0
			>10,000'														

EXHIBIT 19

New Mexico Well Categorization and Wellfile Review Summary - Wells on State Lands

County	Fluid	Profile	Depth	Count	File Reviews	% Reviewed	Type	Completion	Pools	Type Count	ABD Estimate	Intermediate Casing		CBL Req'd		Flagged Zones Low Cement Top	
												%	Count	%	Count	%	Count
San Juan	Gas	Vertical / Directional	<5,000'	503	25	5%	Flow	Perforated	1	503	ST1	25%	126	100%	503	50%	252
			5,000-10,000'	457	19	4%	Flow	Perforated	1	457	MT1	25%	114	100%	457	50%	229
			>10,000'														
		Horizontal	<5,000'	4	1	25%	Flow	Frac port liner	1	4	ST1		0	100%	4	0%	0
			5,000-10,000'	17	4	24%	Flow	Perf / frac port liner	2	17	MT2		0	100%	17	0%	0
			>10,000'	13	2	15%	Flow	Perf / frac port liner	2	13	DT2		0	100%	13	0%	0
	Oil	Vertical / Directional	<5,000'	17	2	12%	Pump	Perforated	1	17	SR1		0	100%	17	100%	17
			5,000-10,000'	32	8	25%	Flow	Perforated	1	20	MT1		0	100%	20	100%	20
							Pump	Perforated	1	12	MR1		0	100%	12	100%	12
			>10,000'	2	1	50%	Flow	Perforated	1	2	DT1		0	100%	2	0%	0
		Horizontal	<5,000'														
			5,000-10,000'	11	3		Pump	Frac port liner	2	11	MR2	100%	11	50%	6	0%	0
			>10,000'	19	1	5%	Pump	Frac port liner	2	19	DR2	100%	19	50%	10	0%	0
	SWD	Vertical / Directional	<5,000'	7	2	29%	Injection	Perforated	1	7	ST1		0	25%	2	50%	4
			5,000-10,000'	8	2	25%	Injection	Perforated	1	8	MT1		0	25%	2	50%	4
			>10,000'														
Sandoval	Gas	Vertical / Directional	<5,000'	3	2	67%	Flow	Perforated	1	3	ST1		0	100%	3	0%	0
			5,000-10,000'														
			>10,000'														
	Oil	Vertical / Directional	<5,000'														
			5,000-10,000'	6	2	33%	Pump	Perforated	1	6	MR1		0	100%	6	0%	0
			>10,000'	2	1	50%	Pump	Perforated	1	2	DR1		0	100%	2	0%	0
		Horizontal	<5,000'														
			5,000-10,000'	3	1	33%	Pump	Frac port liner	1	3	MR1		0	100%	3	0%	0
			>10,000'	9	2	22%	Pump	Frac port liner	1	9	DR1		0	100%	9	0%	0
Union	SWD	Vertical / Directional	<5,000'	1	1	100%	Injection	Tubing	1	1	ST1		0	25%	0	0%	0
			5,000-10,000'														
			>10,000'														

EXHIBIT 19

APPENDIX C

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type ST1

Well Data:	**1**	Tubing only
	2	TMD < 5000 ft
	3	1 Producing Pool

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

2020-07-07

EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type ST1 OPERATION: Abandonment

Days:	1.0	0.5	0.5	1.0	1.0					4.00
Activity Description:	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Balance cement plug	Shoes: perf / run retainer / cement squeeze	Cut and cap					**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap					**2000**					**2,000**
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	**7500**	**3750**	**3750**	**7500**						**22,500**
Coiled Tubing										-
Cementing			**2500**	**6500**						**9,000**
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	**1250**	**1250**	**1250**	**1250**						**5,000**
Tank Truck		**1000**	**1000**	**1000**						**3,000**
Hot Oiling										-
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid										-
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL		**3500**		**1500**						**5,000**
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**350**	**175**	**175**	**350**	**350**					**1,400**
Packers, Plugs, Cutting tools	**500**	**1500**		**1500**						**3,500**
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking		**1500**			**1500**					**3,000**
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	**295**	**148**	**148**	**295**	**295**					**1,180**
Wellsite Supervisor	**1200**	**600**	**600**	**1200**	**1200**					**4,800**
Wellsite Unit	**125**	**63**	**63**	**125**	**125**					**500**
Vehicle	**100**	**50**	**50**	**100**	**100**					**400**
Subsistence										-
SUBTOTALS:	**11,320**	**13,535**	**9,535**	**21,320**	**5,570**					**61,280**

OVERHEAD (3, 2, 1):		
COST +	**5%**	**$ 2,740**
COST ESTIMATE TOTAL:		**$ 64,020**

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type ST2

Well Data:	**1**	Tubing only
	2	TMD < 5000 ft
	3	2 Producing Pools

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug. Repeat for next set of perforations.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

2020-07-07

EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type ST2 OPERATION: Abandonment

Days:	1.0	0.5	0.5	0.5	1.0	1.0				4.50
Activity Description:	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Set plug to isolate perfs and dump cement	Balance Cement Plug	Shoes: perf / run retainer / cement squeeze	Cut and cap				**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap						**2000**				**2,000**
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	**7500**	**3750**	**3750**	**3750**	**7500**					**26,250**
Coiled Tubing										-
Cementing				**2500**	**6500**					**9,000**
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	**1250**	**1250**	**1250**	**1250**	**1250**					**6,250**
Tank Truck		**1000**	**1000**	**1000**	**1000**					**4,000**
Hot Oiling										-
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid										-
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL		**3500**	**3500**		**1500**					**8,500**
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**350**	**175**	**175**	**175**	**350**	**350**				**1,575**
Packers, Plugs, Cutting tools	**500**	**1500**	**1500**		**1500**					**5,000**
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking		**1500**	**1500**			**1500**				**4,500**
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	**295**	**148**	**148**	**148**	**295**	**295**				**1,328**
Wellsite Supervisor	**1200**	**600**	**600**	**600**	**1200**	**1200**				**5,400**
Wellsite Unit	**125**	**63**	**63**	**63**	**125**	**125**				**563**
Vehicle	**100**	**50**	**50**	**50**	**100**	**100**				**450**
Subsistence										-
SUBTOTALS:	**11,320**	**13,535**	**13,535**	**9,535**	**21,320**	**5,570**				**74,815**

OVERHEAD (3, 2, 1):		
COST +	**5%**	**$ 3,376**
COST ESTIMATE TOTAL:		**$ 78,191**

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type MT1

Well Data:	**1**	Tubing only
	2	TMD 5000 ft to 10,000 ft
	3	1 Producing Pool

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type MT1 OPERATION: Abandonment

Days:	1.0	0.5	1.0	1.0	1.0					4.50
Activity Description:	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Balance cement plug	Shoes: perf / run retainer / cement squeeze	Cut and cap					Total Days
LOCATION										TOTAL
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap					2000					2,000
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	7500	3750	7500	7500						26,250
Coiled Tubing										-
Cementing			2500	6500						9,000
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	1250	1250	1250	1250						5,000
Tank Truck		1000	1000	1000						3,000
Hot Oiling										-
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid										-
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL		3500		1500						5,000
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	350	175	350	350	350					1,575
Packers, Plugs, Cutting tools	500	1500		1500						3,500
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking		1500			1500					3,000
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	295	148	295	295	295					1,328
Wellsite Supervisor	1200	600	1200	1200	1200					5,400
Wellsite Unit	125	63	125	125	125					563
Vehicle	100	50	100	100	100					450
Subsistence										-
SUBTOTALS:	11,320	13,535	14,320	21,320	5,570					66,065

OVERHEAD (3, 2, 1):		
COST +	5%	$ 2,939
COST ESTIMATE TOTAL:		$ 69,004

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type MT2

Well Data:	**1**	Tubing only
	2	TMD 5000 ft to 10,000 ft
	3	2 Producing Pools

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug. Repeat for next set of perforations.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

2020-07-07

EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type MT2 OPERATION: Abandonment

Days:	1.0	0.5	0.5	1.0	1.0	1.0				5.00
Activity Description:	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Set plug to isolate perfs and dump cement	Balance Cement Plug	Shoes: perf / run retainer / cement squeeze	Cut and cap				**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap						**2000**				**2,000**
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	**7500**	**3750**	**3750**	**7500**	**7500**					**30,000**
Coiled Tubing										-
Cementing				**2500**	**6500**					**9,000**
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	**1250**	**1250**	**1250**	**1250**	**1250**					**6,250**
Tank Truck		**1000**	**1000**	**1000**	**1000**					**4,000**
Hot Oiling										-
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid										-
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL		**3500**	**3500**		**1500**					**8,500**
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**350**	**175**	**175**	**350**	**350**	**350**				**1,750**
Packers, Plugs, Cutting tools	**500**	**1500**	**1500**		**1500**					**5,000**
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking		**1500**	**1500**			**1500**				**4,500**
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	**295**	**148**	**148**	**295**	**295**	**295**				**1,475**
Wellsite Supervisor	**1200**	**600**	**600**	**1200**	**1200**	**1200**				**6,000**
Wellsite Unit	**125**	**63**	**63**	**125**	**125**	**125**				**625**
Vehicle	**100**	**50**	**50**	**100**	**100**	**100**				**500**
Subsistence										-
SUBTOTALS:	**11,320**	**13,535**	**13,535**	**14,320**	**21,320**	**5,570**				**79,600**

OVERHEAD (3, 2, 1):		
COST +	**5%**	**$ 3,575**
COST ESTIMATE TOTAL:		**$ 83,175**

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type DT1

Well Data:	**1**	Tubing only
	2	TMD > 10,000 ft
	3	1 Producing Pool

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type DT1 OPERATION: Abandonment

Days:	1.5	0.5	1.0	1.5	1.0					5.50
Activity Description:	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Balance Cement Plugs	Shoes: perf / run retainer / cement squeeze	Cut and cap					Total Days
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap					2000					2,000
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	11250	3750	7500	11250						33,750
Coiled Tubing										-
Cementing			5000	6500						11,500
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	1250	1250	1250	1250						5,000
Tank Truck		1000	1000	1000						3,000
Hot Oiling										-
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid										-
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL		3500		1500						5,000
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	525	175	350	525	350					1,925
Packers, Plugs, Cutting tools	500	1500		1500						3,500
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking		1500			1500					3,000
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	443	148	295	443	295					1,623
Wellsite Supervisor	1800	600	1200	1800	1200					6,600
Wellsite Unit	188	63	125	188	125					688
Vehicle	150	50	100	150	100					550
Subsistence										-
SUBTOTALS:	16,105	13,535	16,820	26,105	5,570					78,135

OVERHEAD (3, 2, 1):		
COST +	5%	$ 3,461
COST ESTIMATE TOTAL:		$ 81,596

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type DT2

Well Data:	**1**	Tubing only
	2	TMD > 10,000 ft
	3	2 Producing Pools

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug. Repeat for next set of perforations.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type DT2 OPERATION: Abandonment

Days:	1.5	0.5	0.5	1.0	1.5	1.0				6.00
Activity Description:	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Set plug to isolate perfs and dump cement	Balance Cement Plugs	Shoes: perf / run retainer / cement squeeze	Cut and cap				**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap						**2000**				**2,000**
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	**11250**	**3750**	**3750**	**7500**	**11250**					**37,500**
Coiled Tubing										-
Cementing				**5000**	**6500**					**11,500**
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	**1250**	**1250**	**1250**	**1250**	**1250**					**6,250**
Tank Truck		**1000**	**1000**	**1000**	**1000**					**4,000**
Hot Oiling										-
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid										-
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL		**3500**	**3500**		**1500**					**8,500**
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**525**	**175**	**175**	**350**	**525**	**350**				**2,100**
Packers, Plugs, Cutting tools	**500**	**1500**	**1500**		**1500**					**5,000**
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking		**1500**	**1500**			**1500**				**4,500**
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	**443**	**148**	**148**	**295**	**443**	**295**				**1,770**
Wellsite Supervisor	**1800**	**600**	**600**	**1200**	**1800**	**1200**				**7,200**
Wellsite Unit	**188**	**63**	**63**	**125**	**188**	**125**				**750**
Vehicle	**150**	**50**	**50**	**100**	**150**	**100**				**600**
Subsistence										-
SUBTOTALS:	**16,105**	**13,535**	**13,535**	**16,820**	**26,105**	**5,570**				**91,670**

OVERHEAD (3, 2, 1):		
COST +	**5%**	**$ 4,098**
COST ESTIMATE TOTAL:		**$ 95,768**

EXHIBIT 19

VERTEX

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type SR1

Well Data:	**1**	Tubing & rods
	2	TMD < 5000 ft
	3	1 Producing Pool

Program:	**1**	Move in workover rig and support equipment.
	2	Unseat bottom-hole pump, hot-wash tubing and rods, pull and lay down rods.
		Nipple down wellhead and install blow out preventer (BOP), pull and
	3	stand tubing in derrick.
	4	Run bit and scraper, reciprocate scraper over perforated interval.
	5	Pull and stand tubing, lay down bit and scraper.
		Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top.
		Pressure test retainer and casing to 1,000 psi for 10 minutes.
	6	Dump bail 35' cement on top of the plug.
		Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug.
	7	Repeat as necessary to ensure no more than 3000' between plugs.
	8	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
		Run hydraulic set CICR , set retainer within 50 ft of upper perforations.
	9	Pressure test retainer and casing to 1,000 psi for 10 minutes.
		Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe.
		Apply positive pressure until achieving a stabilized flatline pressure.
		Sting out of retainer and place remaining cement atop retainer (at min.
	10	10 sacks cement), pull and lay down tubing.
	11	Move out workover rig and support equipment.
		Excavate wellhead area to cut casing 6 ft below ground level. Install
		and weld on casing cap, mark the cap using the wells file number and
		document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type SR1 OPERATION: Abandonment

Days:	1.0	1.0	0.5	0.5	1.0	1.0				5.00
Activity Description:	Move in, hot-wash rods and pull	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Balance Cement Plug	Shoes: perf / run retainer / cement squeeze	Cut and cap				**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap						**2000**				**2,000**
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	**7500**	**7500**	**3750**	**3750**	**7500**					**30,000**
Coiled Tubing										-
Cementing				**2500**	**6500**					**9,000**
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	**1250**	**1250**	**1250**	**1250**	**1250**					**6,250**
Tank Truck			**1000**	**1000**	**1000**					**3,000**
Hot Oiling	**1600**									**1,600**
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid	**2000**									**2,000**
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL			**3500**		**1500**					**5,000**
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**350**	**350**	**175**	**175**	**350**	**350**				**1,750**
Packers, Plugs, Cutting tools		**500**	**1500**		**1500**					**3,500**
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking	**1500**		**1500**			**1500**				**4,500**
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	**295**	**295**	**148**	**148**	**295**	**295**				**1,475**
Wellsite Supervisor	**1200**	**1200**	**600**	**600**	**1200**	**1200**				**6,000**
Wellsite Unit	**125**	**125**	**63**	**63**	**125**	**125**				**625**
Vehicle	**100**	**100**	**50**	**50**	**100**	**100**				**500**
Subsistence										-
SUBTOTALS:	**15,920**	**11,320**	**13,535**	**9,535**	**21,320**	**5,570**				**77,200**

OVERHEAD (3, 2, 1):		
COST +	**5%**	**$ 3,455**
COST ESTIMATE TOTAL:		**$ 80,655**

EXHIBIT 19

VERTEX

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type SR2

Well Data:	**1**	Tubing & rods
	2	TMD < 5000 ft
	3	2 Producing Pools

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug. Repeat for next set of perforations.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type SR2 OPERATION: Abandonment

Days:	1.0	1.0	0.5	0.5	0.5	1.0	1.0			5.50
Activity Description:	Move in, hot-wash rods and pull	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Set plug to isolate perfs and dump cement	Balance Cement Plug	Shoes: perf / run retainer / cement squeeze	Cut and cap			**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap							**2000**			**2,000**
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	**7500**	**7500**	**3750**	**3750**	**3750**	**7500**				**33,750**
Coiled Tubing										-
Cementing					**2500**	**6500**				**9,000**
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	**1250**	**1250**	**1250**	**1250**	**1250**	**1250**				**7,500**
Tank Truck			**1000**	**1000**	**1000**	**1000**				**4,000**
Hot Oiling	**1600**									**1,600**
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid	**2000**									**2,000**
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL			**3500**	**3500**		**1500**				**8,500**
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**350**	**350**	**175**	**175**	**175**	**350**	**350**			**1,925**
Packers, Plugs, Cutting tools		**500**	**1500**	**1500**		**1500**				**5,000**
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking	**1500**		**1500**	**1500**			**1500**			**6,000**
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	**295**	**295**	**148**	**148**	**148**	**295**	**295**			**1,623**
Wellsite Supervisor	**1200**	**1200**	**600**	**600**	**600**	**1200**	**1200**			**6,600**
Wellsite Unit	**125**	**125**	**63**	**63**	**63**	**125**	**125**			**688**
Vehicle	**100**	**100**	**50**	**50**	**50**	**100**	**100**			**550**
Subsistence										-
SUBTOTALS:	**15,920**	**11,320**	**13,535**	**13,535**	**9,535**	**21,320**	**5,570**			**90,735**

OVERHEAD (3, 2, 1):		
COST +	**5%**	**$ 4,091**
COST ESTIMATE TOTAL:		**$ 94,826**

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type MR1

Well Data:	**1**	Tubing & rods
	2	TMD 5000 ft to 10,000 ft
	3	1 Producing Pool

Program:	**1**	Move in workover rig and support equipment.
	2	Unseat bottom-hole pump, hot-wash tubing and rods, pull and lay down rods.
		Nipple down wellhead and install blow out preventer (BOP), pull and
	3	stand tubing in derrick.
	4	Run bit and scraper, reciprocate scraper over perforated interval.
	5	Pull and stand tubing, lay down bit and scraper.
		Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top.
		Pressure test retainer and casing to 1,000 psi for 10 minutes.
	6	Dump bail 35' cement on top of the plug.
		Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug.
	7	Repeat as necessary to ensure no more than 3000' between plugs.
	8	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
		Run hydraulic set CICR , set retainer within 50 ft of upper perforations.
	9	Pressure test retainer and casing to 1,000 psi for 10 minutes.
		Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe.
		Apply positive pressure until achieving a stabilized flatline pressure.
		Sting out of retainer and place remaining cement atop retainer (at min.
	10	10 sacks cement), pull and lay down tubing.
	11	Move out workover rig and support equipment.
		Excavate wellhead area to cut casing 6 ft below ground level. Install
		and weld on casing cap, mark the cap using the wells file number and
		document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type MR1 OPERATION: Abandonment

Days:	1.0	1.0	0.5	1.0	1.0	1.0				5.50
Activity Description:	Move in, hot-wash rods and pull	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Balance Cement Plug	Shoes: perf / run retainer / cement squeeze	Cut and cap				**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap						**2000**				**2,000**
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	**7500**	**7500**	**3750**	**7500**	**7500**					**33,750**
Coiled Tubing										-
Cementing				**2500**	**6500**					**9,000**
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	**1250**	**1250**	**1250**	**1250**	**1250**					**6,250**
Tank Truck			**1000**	**1000**	**1000**					**3,000**
Hot Oiling	**1600**									**1,600**
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid	**2000**									**2,000**
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL			**3500**		**1500**					**5,000**
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**350**	**350**	**175**	**350**	**350**	**350**				**1,925**
Packers, Plugs, Cutting tools		**500**	**1500**		**1500**					**3,500**
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking	**1500**		**1500**			**1500**				**4,500**
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	**295**	**295**	**148**	**295**	**295**	**295**				**1,623**
Wellsite Supervisor	**1200**	**1200**	**600**	**1200**	**1200**	**1200**				**6,600**
Wellsite Unit	**125**	**125**	**63**	**125**	**125**	**125**				**688**
Vehicle	**100**	**100**	**50**	**100**	**100**	**100**				**550**
Subsistence										-
SUBTOTALS:	**15,920**	**11,320**	**13,535**	**14,320**	**21,320**	**5,570**				**81,985**

OVERHEAD (3, 2, 1):		
COST +	**5%**	**$ 3,654**
COST ESTIMATE TOTAL:		**$ 85,639**

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type MR2

Well Data:	**1**	Tubing & rods
	2	TMD 5000 ft to 10,000 ft
	3	2 Producing Pools

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug. Repeat for next set of perforations.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type MR2 OPERATION: Abandonment

Days:	1.0	1.0	0.5	0.5	1.0	1.0	1.0			6.00
Activity Description:	Move in, hot-wash rods and pull	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Set plug to isolate perfs and dump cement	Balance Cement Plug	Shoes: perf / run retainer / cement squeeze	Cut and cap			**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap							**2000**			**2,000**
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	**7500**	**7500**	**3750**	**3750**	**7500**	**7500**				**37,500**
Coiled Tubing										-
Cementing					**2500**	**6500**				**9,000**
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	**1250**	**1250**	**1250**	**1250**	**1250**	**1250**				**7,500**
Tank Truck			**1000**	**1000**	**1000**	**1000**				**4,000**
Hot Oiling	**1600**									**1,600**
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid	**2000**									**2,000**
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL			**3500**	**3500**		**1500**				**8,500**
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**350**	**350**	**175**	**175**	**350**	**350**	**350**			**2,100**
Packers, Plugs, Cutting tools		**500**	**1500**	**1500**		**1500**				**5,000**
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking	**1500**		**1500**	**1500**			**1500**			**6,000**
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	**295**	**295**	**148**	**148**	**295**	**295**	**295**			**1,770**
Wellsite Supervisor	**1200**	**1200**	**600**	**600**	**1200**	**1200**	**1200**			**7,200**
Wellsite Unit	**125**	**125**	**63**	**63**	**125**	**125**	**125**			**750**
Vehicle	**100**	**100**	**50**	**50**	**100**	**100**	**100**			**600**
Subsistence										-
SUBTOTALS:	**15,920**	**11,320**	**13,535**	**13,535**	**14,320**	**21,320**	**5,570**			**95,520**

OVERHEAD (3, 2, 1):			
COST +	**5%**	**$**	**4,290**
COST ESTIMATE TOTAL:		**$**	**99,810**

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type DR1

Well Data:	**1**	Tubing & rods
	2	TMD > 10000 ft
	3	1 Producing Pool

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type DR1 OPERATION: Abandonment

Days:	1.0	1.5	0.5	1.0	1.5	1.0				6.50
Activity Description:	Move in, hot-wash rods and pull	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Balance Cement Plugs	Shoes: perf / run retainer / cement squeeze	Cut and cap				**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap						**2000**				**2,000**
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	**7500**	**11250**	**3750**	**7500**	**11250**					**41,250**
Coiled Tubing										-
Cementing				**5000**	**6500**					**11,500**
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	**1250**	**1250**	**1250**	**1250**	**1250**					**6,250**
Tank Truck			**1000**	**1000**	**1000**					**3,000**
Hot Oiling	**1600**									**1,600**
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid	**2000**									**2,000**
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL			**3500**		**1500**					**5,000**
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**350**	**525**	**175**	**350**	**525**	**350**				**2,275**
Packers, Plugs, Cutting tools		**500**	**1500**		**1500**					**3,500**
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking	**1500**		**1500**			**1500**				**4,500**
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	**295**	**443**	**148**	**295**	**443**	**295**				**1,918**
Wellsite Supervisor	**1200**	**1800**	**600**	**1200**	**1800**	**1200**				**7,800**
Wellsite Unit	**125**	**188**	**63**	**125**	**188**	**125**				**813**
Vehicle	**100**	**150**	**50**	**100**	**150**	**100**				**650**
Subsistence										-
SUBTOTALS:	**15,920**	**16,105**	**13,535**	**16,820**	**26,105**	**5,570**				**94,055**

OVERHEAD (3, 2, 1):		
COST +	**5%**	**$ 4,176**
COST ESTIMATE TOTAL:		**$ 98,231**

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type DR2

Well Data:	**1**	Tubing & rods
	2	TMD > 10000 ft
	3	2 Producing Pools

Program:	**1**	Move in workover rig and support equipment.
	2	Nipple down wellhead and install blow out preventer (BOP), pull and stand tubing in derrick.
	3	Run bit and scraper, reciprocate scraper over perforated interval.
	4	Pull and stand tubing, lay down bit and scraper.
	5	Run hydraulic set Cast Iron Bridge Plug (CIBP), set within 100' of perforation top. Pressure test retainer and casing to 1,000 psi for 10 minutes. Dump bail 35' cement on top of the plug. Repeat for next set of perforations.
	6	Run tubing to land no more than 3000' from CIBP. Conduct a 100' balanced cement plug. Repeat as necessary to ensure no more than 3000' between plugs.
	7	With wireline, perforate 50 ft below the surface casing shoe, conduct injection test and record ISIP.
	8	Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes.
	9	Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	10	Move out workover rig and support equipment.
	11	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type DR2 OPERATION: Abandonment

Days:	1.0	1.5	0.5	0.5	1.0	1.5	1.0			7.00
Activity Description:	Move in, hot-wash rods and pull	Pull tubing / bit and scraper	Set plug to isolate perfs and dump cement	Set plug to isolate perfs and dump cement	Balance Cement Plugs	Shoes: perf / run retainer / cement squeeze	Cut and cap			**Total Days**
LOCATION										**TOTAL**
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap							2000			2,000
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	7500	11250	3750	3750	7500	11250				45,000
Coiled Tubing										-
Cementing					5000	6500				11,500
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck	1250	1250	1250	1250	1250	1250				7,500
Tank Truck			1000	1000	1000	1000				4,000
Hot Oiling	1600									1,600
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid	2000									2,000
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL			3500	3500		1500				8,500
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	350	525	175	175	350	525	350			2,450
Packers, Plugs, Cutting tools		500	1500	1500		1500				5,000
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking	1500		1500	1500			1500			6,000
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	295	443	148	148	295	443	295			2,065
Wellsite Supervisor	1200	1800	600	600	1200	1800	1200			8,400
Wellsite Unit	125	188	63	63	125	188	125			875
Vehicle	100	150	50	50	100	150	100			700
Subsistence										-
SUBTOTALS:	15,920	16,105	13,535	13,535	16,820	26,105	5,570			107,590

OVERHEAD (3, 2, 1):		
COST +	5%	$ 4,813
COST ESTIMATE TOTAL:		$ 112,403

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Type E

Well Data:	**1**	Empty wellbore (dry hole or plugged)
Program:	**1**	Excavate wellhead area to cut casing 6 ft below ground level. Install and weld on casing cap, mark the cap using the wells file number and document each step in the tour report and include photos.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Type E OPERATION: Abandonment

Days:	1.0									1.00
Activity Description:	Cut and cap									**Total Days**

LOCATION										TOTAL
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap	**2000**									**2,000**
Crop Compensation, Equipment Washing										-

SERVICES										
Service Rig (includes swabbing)										-
Coiled Tubing										-
Cementing										-
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-

SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck										-
Tank Truck										-
Hot Oiling										-
Hot Shot										-
Equipment Hauling										-

FLUIDS & MATERIALS										
Completion / Stimulation Fluid										-
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-

WIRELINE										
Cement Bond Log										-
Plug Setting, Perforating, CCL										-
Specialty Logging (noise-temp/inspection)										-
Slickline										-

EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	**350**									**350**
Packers, Plugs, Cutting tools										-
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-

DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking	**1500**									**1,500**

ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-

SUPERVISION & ENGINEERING										
Engineering	**295**									**295**
Wellsite Supervisor	**1200**									**1,200**
Wellsite Unit	**125**									**125**
Vehicle	**100**									**100**
Subsistence										-

SUBTOTALS:	**5,570**									**5,570**

OVERHEAD (3, 2, 1):			
COST +	5%	$	198
COST ESTIMATE TOTAL:		$	5,768

EXHIBIT 19

COST ESTIMATE TO ABANDON WELL

New Mexico State Land Office
Additional Abandonment Work

Activity:	**1**	Run CBL
	2	Intermediate casing shoes: perf / run retainer / cement squeeze
	3	Low cement top (unisolated flagged formations): perf / run retainer / cement squeeze

Program:	**1**	MIRU wireline unit, run CBL.
	2	With wireline, perforate 50 ft below the intermediate casing shoe, conduct injection test and record ISIP. Run hydraulic set CICR , set retainer within 50 ft of upper perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes. Conduct a squeeze to ensure cement inside the casing minimum 50' above and 50' below shoe. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.
	3	With wireline, perforate 50 ft below the bottom of the zone to be isolated, conduct injection test and record ISIP. Run hydraulic set CICR , set retainer within 50 ft of perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes. Conduct a squeeze to ensure cement inside the casing minimum 50' below formation bottom. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing. With wireline, perforate 50 ft above the top of the zone to be isolated, conduct injection test and record ISIP. Run hydraulic set CICR , set retainer within 50 ft of perforations. Pressure test retainer and casing to 1,000 psi for 10 minutes. Conduct a squeeze to ensure cement inside the casing minimum 50' above formation top. Apply positive pressure until achieving a stabilized flatline pressure. Sting out of retainer and place remaining cement atop retainer (at min. 10 sacks cement), pull and lay down tubing.

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EXHIBIT 19

VERTEX

COST ESTIMATE

CLIENT: New Mexico State Land Office WELL: Additional Abandonment Work OPERATION: Abandonment

Days:	0.50	1.0	1.5							3.00
Activity Description:	Run CBL	Shoes: perf / run retainer / cement squeeze	Low top: perf / run retainer / cement squeeze							Total Days
LOCATION										TOTAL
Grading, Plowing, Towing										-
Back Hoe, Excavating, Cut and Cap										-
Crop Compensation, Equipment Washing										-
SERVICES										
Service Rig (includes swabbing)	3750	7500	11250							22,500
Coiled Tubing										-
Cementing		6500	13000							19,500
Acidizing										-
Fracturing										-
Snubbing										-
Fishing										-
Boiler / Steamer										-
Safety (SABA, shower unit, air monitoring)										-
Safety (medic and MTC)										-
Production Testing										-
Gas & Fluid Analysis										-
Wellhead Equipment / Service										-
SERVICE TRUCKS										
Vacuum Truck										-
Pressure Truck		1250	1250							2,500
Tank Truck		1000	1000							2,000
Hot Oiling										-
Hot Shot										-
Equipment Hauling										-
FLUIDS & MATERIALS										
Completion / Stimulation Fluid										-
Water Management										-
Chemical (de-waxing, H2S scrubber, inhibitor)										-
Disposal										-
WIRELINE										
Cement Bond Log	4500									4,500
Plug Setting, Perforating, CCL		1500	3000							4,500
Specialty Logging (noise-temp/inspection)										-
Slickline										-
EQUIPMENT RENTAL										
Tubing, Collars, Handling Tools										-
Inspection and Repair										-
Motor, Casing Scraper, Bits, Power Swivel										-
Communication, Light Tower										-
Wellhead (isolation tool, valves, etc.)	175	350	525							1,050
Packers, Plugs, Cutting tools		1500	3000							4,500
Matting, Pipe Racks										-
Tanks, Garbage, Toilet etc.										-
Trucking										-
DOWNHOLE EQUIPMENT										
Tubing										-
Packer, Anchor, Profiles										-
Trucking										-
ARTIFICIAL LIFT										
Rod String										-
Downhole Pump										-
Fittings, Piping, etc. (includes installation)										-
Surface Equipment (pump jack, tanks, lines)										-
Trucking										-
SUPERVISION & ENGINEERING										
Engineering	148	295	443							885
Wellsite Supervisor	600	1200	1800							3,600
Wellsite Unit	63	125	188							375
Vehicle	50	100	150							300
Subsistence										-
SUBTOTALS:	9,285	21,320	35,605							66,210

OVERHEAD (3, 2, 1):		
COST +	5%	$ 3,068
COST ESTIMATE TOTAL:		$ 69,278

EXHIBIT 19

APPENDIX D

EXHIBIT 19

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 29 RELEASES

19.15.29.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.29.1 NMAC - Rp, 19.15.29.1 NMAC, 8/14/2018]

19.15.29.2 SCOPE: 19.15.29 NMAC applies to persons engaged in oil and gas development and production within New Mexico.
[19.15.29.2 NMAC - Rp, 19.15.29.2 NMAC, 8/14/2018]

19.15.29.3 STATUTORY AUTHORITY: 19.15.29 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-11 NMSA 1978 (1977) and Section 70-2-12 NMSA 1978 (2004).
[19.15.29.3 NMAC - Rp, 19.15.29.3 NMAC, 8/14/2018]

19.15.29.4 DURATION: Permanent.
[19.15.29.4 NMAC - Rp, 19.15.29.4 NMAC, 8/14/2018]

19.15.29.5 EFFECTIVE DATE: August 14, 2018, unless a later date is cited at the end of a section.
[19.15.29.5 NMAC - Rp, 19.15.29.5 NMAC, 8/14/2018]

19.15.29.6 OBJECTIVE: To require persons who operate or control the release or the location of the release to report the unauthorized release of oil, gases, produced water, condensate or oil field waste including regulated NORM or other oil field related chemicals, contaminants or mixtures of those chemicals or contaminants that occur during drilling, producing, storing, disposing, injecting, transporting, servicing or processing and to establish reporting, site assessment, remediation, closure, variance and enforcement procedures.
[19.15.29.6 NMAC - Rp, 19.15.29.6 NMAC, 8/14/2018]

19.15.29.7 DEFINITIONS:

A. "Major release" means:

(1) an unauthorized release of a volume, excluding gases, of 25 barrels or more;

(2) an unauthorized release of a volume that:

(a) results in a fire or is the result of a fire;

(b) may with reasonable probability reach a watercourse;

(c) may with reasonable probability endanger public health; or

(d) substantially damages property or the environment;

(3) an unauthorized release of gases exceeding 500 MCF; or

(4) a release of a volume that may with reasonable probability be detrimental to fresh water.

B. "Minor release" means an unauthorized release, which is not a major release and is a volume greater than five barrels but less than 25 barrels; or for gases, greater than 50 MCF but less than 500 MCF.

C. "Responsible party" means the operator, as defined in 19.15.2 NMAC. Notwithstanding the foregoing, the division, in its sole discretion, may also consider a person causing the release, or controlling the location of the release as the responsible party.

D. "Wellstream" means the gas, oil, water, suspended constituents, or any combination thereof, which comes from the wellbore.
[19.15.29.7 NMAC - Rp, 19.15.29.7 NMAC, 8/14/2018]

19.15.29.8 RELEASES:

A. Requirements. For all releases regardless of volume, the responsible party shall comply with 19.15.29.8 NMAC and shall remediate the release. For major and minor releases, the responsible party shall also comply with 19.15.29.9, 19.15.29.10, 19.15.29.11, 19.15.29.12 and 19.15.29.13 NMAC.

B. Initial response. The responsible party must take the following immediate actions unless the actions could create a safety hazard that would result in injury.

(1) Source elimination and site security. The responsible party must take appropriate measures to stop the source of the release and limit access to the site as necessary to protect human health and the environment.

(2) Containment. Once the site is secure, the responsible party must contain the materials released by construction of berms or dikes, the use of absorbent pads or other containment actions to limit the area affected by the release and prevent potential fresh water contaminants from migrating to watercourses or areas that could pose a threat to public health and environment. The responsible party must monitor the containment to ensure that it is effectively containing the material and not being degraded by weather or onsite activity.

(3) Site stabilization. After containment, the responsible party must recover any free liquids and recoverable materials that can be physically removed from the surface within the containment area. The responsible party must deliver material removed from the site to a division-approved facility.

(4) Remediation. The responsible party may commence remediation immediately.

[19.15.29.8 NMAC - Rp, 19.15.29.8 NMAC, 8/14/2018]

19.15.29.9 RELEASE NOTIFICATION:

A. The responsible party must notify the division on form C-141 of a major or minor release occurring during the drilling, producing, storing, disposing, injecting, transporting, servicing or processing of oil, gases, produced water, condensate or oil field waste including regulated NORM, or other oil field related chemicals, contaminants or mixture of the chemicals or contaminants, in accordance with the requirements of 19.15.29 NMAC.

B. If state, federal or tribal lands are involved, the responsible party must send a copy of the form C-141 to the appropriate land managing agency including the state land office, the BLM or tribal authority, as applicable.

[19.15.29.9 NMAC - Rp, 19.15.29.9 NMAC, 8/14/2018]

19.15.29.10 RELEASE NOTIFICATION REPORTING REQUIREMENTS: The responsible party must notify the division of releases in 19.15.29.9 NMAC as follows.

A. Reporting a major release.

(1) The responsible party must notify the division's environmental bureau chief and the appropriate division district office verbally or by e-mail within 24 hours of discovery of the release. The notification must provide the information required on form C-141.

(2) The responsible party must also notify the appropriate division district office in writing within 15 days of discovering the release by completing and filing form C-141. The written notification must verify the prior verbal or e-mail notification and include additions or corrections to the information contained in the prior verbal or e-mail notification.

B. Reporting a minor release. The responsible party must notify the appropriate division district office in writing within 15 days of discovery of the release by completing and filing form C-141.

[19.15.29.10 NMAC - Rp, 19.15.29.10 NMAC, 8/14/2018]

19.15.29.11 SITE ASSESSMENT/CHARACTERIZATION: After the responsible party has removed all free liquids and recoverable materials, the responsible party must assess soils both vertically and horizontally for potential environmental impacts from any major or minor release containing liquids.

A. Characterization requirements. The responsible party must submit information characterizing the release to the appropriate division district office within 90 days of discovery of the release or characterize the release by submitting a final closure report within 90 days of discovery of the release in accordance with Subsection E of 19.15.29.12 NMAC. The responsible party may seek an extension of time to submit characterization information for good cause as determined by the division. The responsible party must submit the following information to the division.

(1) Site map. The responsible party must provide a scaled diagram that shows the potentially impacted area, significant surface features including roads and site infrastructure, location of borings, sample points, monitoring wells and subsurface features such as known pipelines to the extent known at the time of submittal including the source of information regarding subsurface features.

(2) Depth to ground water. The responsible party must determine the depth to ground water where the release occurred. If the exact depth to ground water is unknown, the responsible party must provide a reasonable determination of probable ground water depth using data generated by numeric models, cathodic well lithology, water well data, published information or other tools as approved by the appropriate division district office. If the responsible party uses water well data, the responsible party must provide all pertinent well information.

(3) Wellhead protection area. The responsible party must determine the horizontal distance from all known water sources within a half mile of the release including private and domestic water sources. Water

sources are wells, springs or other sources of fresh water extraction. Private and domestic water sources are those water sources used by less than five households for domestic or stock purposes.

(4) Distance to nearest significant watercourse. The responsible party must determine the horizontal distance to the nearest significant watercourse as defined in Subsection P of 19.15.17.7 NMAC within a half mile of any horizontal boundary of the release.

(5) Soil/waste characteristics. The responsible party must determine the lateral and vertical extents of soil contamination, as follows.

(a) If the release occurred within a lined containment area, the responsible party must demonstrate liner integrity after affected material is removed and the affected area of the liner is exposed and provide:

(i) certification on form C-141 that the responsible party has visually inspected the liner where the release occurred and the liner remains intact and had the ability to contain the leak in question; and

(ii) at least two business days' notice to the appropriate division district office before conducting the liner inspection.

(b) If the responsible party is unable to demonstrate liner integrity or the release occurred outside of a lined containment area, the responsible party must delineate the release horizontally and vertically using Table I of 19.15.29.12 NMAC constituents or as required by Subparagraph (e) of Paragraph (5) of Subsection A of 19.15.29.11 NMAC based on the type of release. The responsible party shall use one or more of the following soil sampling methods for characterization:

(i) NRCS Field Guide;

(ii) EPA SW-846;

(iii) ASTM Method 4547;

(iv) EPA 600; or

(v) or other division-approved methods.

(c) In addition to Subparagraph (b) of Paragraph (5) of Subsection A of 19.15.29.11 NMAC, if the release occurred outside of a lined containment area and is in an area where depth to ground water is greater than 50 feet and less than or equal to 100 feet, the responsible party must delineate the vertical extent of the release to the greater of 600 mg/kg chloride or background chloride level, if:

(i) the release contains produced water that exceeds 10,000 mg/l of chloride (if the responsible party contends the fluid is less than 10,000 mg/l, the responsible party must provide current sample results to the division); and

(ii) the release is of an unknown quantity or results in greater than 200 barrels of unrecovered produced water.

(d) If the conditions are met in Subparagraph (c) of Paragraph (5) of Subsection A of 19.15.29.11 NMAC, the responsible party must submit at least two soil samples for laboratory analysis from each borehole or sample point (highest observed contamination and deepest depth investigated). Field screening and assessment techniques are acceptable (headspace, titration, electrical conductivity [include algorithm for validation purposes], electromagnetics, etc.), but the sampling procedures must be clearly defined. The responsible party must submit copies of field notes attributable to field sampling and provide copies of the actual laboratory results including chain of custody documentation.

(e) If a known release of other oil field related chemicals occurs that is not included in Table I of 19.15.29.12 NMAC, and does not include oil, gas, produced water or other fluids from the wellstream, the standards for remediation shall be as follows:

(i) if the constituent appears on Table 1 of 40 C.F.R. 261.24(b), then that constituent shall be remediated according to 40 C.F.R. 261.24;

(ii) if the constituent is not identified in Table 1 of 40 C.F.R. 261.24(b), but is identified in the New Mexico environment department's Risk Assessment Guidance for Site Investigations and Remediation Volumes I and II (assessment), the division will determine the appropriate Assessment Volume and remediation shall occur pursuant to the assessment;

(iii) if the constituent is not identified in Items (i) or (ii) of Subparagraph (e) of Paragraph (5) of Subsection A of 19.15.29.11 NMAC, the division shall consult with the responsible party to determine appropriate remediation of the release.

B. Unless the site characterization report includes completed efforts at remediation, the report must include a proposed remediation plan in accordance with 19.15.29.12 NMAC, which includes the anticipated timelines for beginning and completing the remediation.

C. If the division determines that more information is needed to understand the character of the release and its potential impact on fresh water, public health and the environment, the division may request the responsible party submit additional information. Should the division request additional information, it must do so in writing to the responsible party within 30 days from receipt of the characterization report or remediation plan with what specific information the division is requesting and reasons why the additional information is needed. The responsible party has 14 days to respond to a written request for additional information. If the responsible party disagrees with the request for additional information, it may consult with the division, or file an application for hearing pursuant to 19.15.4 NMAC within 30 days of the issuance of the request for additional information. [19.15.29.11 NMAC - Rp, 19.15.29.11 NMAC, 8/14/2018]

19.15.29.12 REMEDIATION AND CLOSURE:

A. The responsible party must remediate all releases regardless of volume.

B. Remediation requirements.

(1) Unless remediation is completed, and a final closure report submitted, within 90 days of discovery of the release, the responsible party must complete division-approved remediation for releases either pursuant to a remediation plan approved pursuant to 19.15.29.12 NMAC or pursuant to an abatement plan in accordance with 19.15.30 NMAC. If the director determines that the release has caused water pollution in excess of the standards and requirements of 19.15.30 NMAC, the director may notify the responsible party that an abatement plan may be required pursuant to 19.15.30 NMAC.

(2) Any remediation under 19.15.29 NMAC should be completed as soon as practicable. Any remediation that exceeds 90 days must follow the division-approved timeline in the remediation plan. The responsible party may request an extension of time to remediate upon a showing of good cause as determined by the division.

C. Remediation plan requirements. The responsible party must take the following action for any major or minor release containing liquids.

(1) The responsible party must submit a detailed description of proposed remediation measures in accordance with the findings of the site assessment/characterization plan that includes:

(a) delineation results, including laboratory analysis;

(b) a scaled sitemap showing release area with horizontal and vertical delineation points;

(c) estimated volume of impacted material to be remediated;

(d) proposed remediation technique; and

(e) proposed timeline for remediation activities.

(2) The responsible party shall restore the impacted surface area of a release occurring on a developed well pad, central tank battery, drilling site, compressor site or other exploration, development, production or storage sites to meet the standards of Table I of 19.15.29.12 NMAC or other applicable remediation standards and restore and reclaim the area pursuant to 19.15.29.13 NMAC. If contamination is located in areas immediately under or around production equipment such as production tanks, wellheads and pipelines where remediation could cause a major facility deconstruction, the remediation, restoration and reclamation may be deferred with division written approval until the equipment is removed during other operations, or when the well or facility is plugged or abandoned, whichever comes first. The deferral may be granted so long as the contamination is fully delineated and does not cause an imminent risk to human health, the environment, or ground water. Final remediation and reclamation shall take place in accordance with 19.15.29.12 and 19.15.29.13 NMAC once the site is no longer being used for oil and gas operations.

(3) The responsible party shall remediate the impacted surface area of a release not occurring on a lined, bermed or otherwise contained exploration, development, production or storage site to meet the standards of Table I of 19.15.29.12 NMAC or other applicable remediation standards and restore and reclaim the area pursuant to 19.15.29.13 NMAC.

(4) If a release occurs within the following areas, the responsible party must treat the release as if it occurred less than 50 feet to ground water in Table I of 19.15.29.12 NMAC:

(a) within

(i) 300 feet of any continuously flowing watercourse or any other significant watercourse, or

(ii) 200 feet of any lakebed, sinkhole or playa lake (measured from the ordinary high-water mark);

(b) within 300 feet from an occupied permanent residence, school, hospital, institution or church;

(c) within

(i) 500 feet of a spring or a private, domestic fresh water well used by less than five households for domestic or stock watering purposes, or

(ii) 1000 feet of any fresh water well or spring;

(d) within incorporated municipal boundaries or within a defined municipal fresh water well field covered under a municipal ordinance adopted pursuant to Section 3-27-3 NMSA 1978 as amended, unless the municipality specifically approves;

(e) within 300 feet of a wetland;

(f) within the area overlying a subsurface mine;

(g) within an unstable area; or

(h) within a 100-year floodplain.

(5) The division has 60 days from receipt of the proposed remediation plan to review and approve, approve with conditions or deny the remediation plan. If 60 days have lapsed without response from the division, then the plan is deemed denied. If the plan is approved with conditions or affirmatively denied, the division shall provide a written summary of deficiencies on which the decision is based. If the responsible party disagrees with any conditions of approval or denial of the plan, it shall consult with the division or file an application for hearing pursuant to 19.15.4 NMAC within 30 days of the denial or issuance of the conditions.

D. Closure requirements. The responsible party must take the following action for any major or minor release containing liquids.

(1) The responsible party must test the remediated areas for contamination with representative five-point composite samples from the walls and base, and individual grab samples from any wet or discolored areas. The samples must be analyzed for the constituents listed in Table I of 19.15.29.12 NMAC or constituents from other applicable remediation standards.

(a) The responsible party must verbally notify the appropriate division district office two business days prior to conducting final sampling. If the division district office does not respond to the notice within the two business days, the responsible party may proceed with final sampling. The responsible party may request a variance from this requirement upon a showing of good cause as determined by the division.

(b) The responsible party may submit a composite and grab sample plan for the division's review and approval separately or with the remediation plan.

(c) Alternately, without division approval, the responsible party may elect to perform a composite and grab sample plan of the remediated area where each composite sample is not representative of more than 200 square feet.

(2) If all composite and grab sample concentrations are less than or equal to the parameters listed in Table I of 19.15.29.12 NMAC or any conditions of approval, then the responsible party may proceed to backfill any excavated areas.

E. Closure reporting. The responsible party must take the following action for any major or minor release containing liquids.

(1) The responsible party must submit to the division a closure report on form C-141, including required attachments, to document all closure activities including sampling results and the details on any backfilling, capping or covering, where applicable. The responsible party must certify that all information in the closure report and attachments is correct and that the responsible party has complied with all applicable closure requirements and conditions specified in division rules or directives. The responsible party must submit closure report along with form C-141 to the division within 90 days of the remediation plan approval. The responsible party may apply for additional time to submit the final closure report upon a showing of good cause as determined by the division. The final report must include:

(a) a scaled site and sampling diagram;

(b) photographs of the remediated site prior to backfill;

(c) laboratory analyses of final sampling; and

(d) a description of all remedial activities.

(2) The division district office has 60 days to review and approve or deny the closure report. If 60 days have lapsed without response from the division, then the report is deemed denied. If the report is affirmatively denied, the division shall provide a written summary of deficiencies on which the decision is based. If the responsible party disagrees with denial of the closure report, it may consult with the division or file an application for hearing pursuant to 19.15.4 NMAC within 30 days of the denial.

Table I Closure Criteria for Soils Impacted by a Release			
Minimum depth below any point within the horizontal boundary of the release to ground water less than 10,000 mg/l TDS	Constituent	Method*	Limit**
≤ 50 feet	Chloride***	EPA 300.0 or SM4500 Cl B	600 mg/kg
	TPH (GRO+DRO+MRO)	EPA SW-846 Method 8015M	100 mg/kg
	BTEX	EPA SW-846 Method 8021B or 8260B	50 mg/kg
	Benzene	EPA SW-846 Method 8021B or 8260B	10 mg/kg
51 feet-100 feet	Chloride***	EPA 300.0 or SM4500 Cl B	10,000 mg/kg
	TPH (GRO+DRO+MRO)	EPA SW-846 Method 8015M	2,500 mg/kg
	GRO+DRO	EPA SW-846 Method 8015M	1,000 mg/kg
	BTEX	EPA SW-846 Method 8021B or 8260B	50 mg/kg
	Benzene	EPA SW-846 Method 8021B or 8260B	10 mg/kg
>100 feet	Chloride***	EPA 300.0 or SM4500 Cl B	20,000 mg/kg
	TPH (GRO+DRO+MRO)	EPA SW-846 Method 8015M	2,500 mg/kg
	GRO+DRO	EPA SW-846 Method 8015M	1,000 mg/kg
	BTEX	EPA SW-846 Method 8021B or 8260B	50 mg/kg
	Benzene	EPA SW-846 Method 8021B or 8260B	10 mg/kg

*Or other test methods approved by the division.
**Numerical limits or natural background level, whichever is greater.
***This applies to releases of produced water or other fluids, which may contain chloride.
[19.15.29.12 NMAC - N, 8/14/2018]

19.15.29.13 RESTORATION, RECLAMATION AND RE-VEGETATION:

A. The responsible party must substantially restore the impacted surface areas to the condition that existed prior to the release or their final land use. Restoration of the site must include the replacement of removed material and must be replaced to the near original relative positions and contoured to achieve erosion control, long-term stability and preservation of surface water flow patterns.

B. Areas reasonably needed for production operations or for subsequent drilling operations must be compacted, covered, paved or otherwise stabilized and maintained in such a way as to minimize dust and erosion to the extent practical.

C. The responsible party must construct the soil cover to the site's existing grade and prevent ponding of water and erosion of the cover material.

D. Reclamation of areas no longer in use. The responsible party shall reclaim all areas disturbed by the remediation and closure, except areas reasonably needed for production operations or for subsequent drilling

operations, as early and as nearly as practical to their original condition or their final land use and maintain those areas to control dust and minimize erosion to the extent practical.

(1) The reclamation must contain a minimum of four feet of non-waste containing, uncontaminated, earthen material with chloride concentrations less than 600 mg/kg as analyzed by EPA Method 300.0, or other test methods approved by the division. The soil cover must include a top layer, which is either the background thickness of topsoil or one foot of suitable material to establish vegetation at the site, whichever is greater.

(2) The responsible party must reseed disturbed area in the first favorable growing season following closure of the site.

(3) The division will consider reclamation of all disturbed areas complete when uniform vegetative cover has been established that reflects a life-form ratio of plus or minus fifty percent of pre-disturbance levels and a total percent plant cover of at least seventy percent of pre-disturbance levels, excluding noxious weeds.

(4) For any major or minor release containing liquids, the responsible party must notify the division when reclamation and re-vegetation are complete.

E. The surface restoration, reclamation and re-vegetation obligations imposed by federal or state agencies or tribes on lands managed or owned by those agencies supersede these provisions and govern the obligations of any responsible party subject to those provisions, provided that the other requirements provide equal or better protection of fresh water, human health and the environment.

[19.15.29.13 NMAC - N, 8/14/2018]

19.15.29.14 VARIANCES:

A. A responsible party may file a written request for a variance from any requirement of 19.15.29 NMAC with the appropriate division district office. The variance request must include:

(1) a detailed statement explaining the need for a variance; and

(2) a detailed written demonstration that the variance will provide equal or better protection of fresh water, public health and the environment.

B. The division district office must approve or deny the variance in writing within 60 days of receipt. If the division district office denies the variance, it must provide the responsible party with the reasons for denial.

C. If the division district office does not approve or deny a request for variance from the requirements of 19.15.29 NMAC within 60 days of the date the request for variance is received by the division district office, then the request for variance is deemed denied and the responsible party may file an application for a hearing pursuant to 19.15.4 NMAC within 30 days of the denial.

D. If the responsible party requests a hearing pursuant to 19.15.4 NMAC within 30 days after receipt of notice, the division must set the matter for hearing with notice to the responsible party and appropriate division district office.

E. In addition to the notice provisions in 19.15.4 NMAC, the responsible party must provide notice of the hearing on the request for variance to the surface owner of the site by certified mail, return receipt requested, at least 20 days prior to the date of the hearing.

F. Variances must receive division approval prior to implementation.

[19.15.29.14 NMAC - N, 8/14/2018]

19.15.29.15 ENFORCEMENT:

A. The responsible party must comply with all the requirements of 19.15.29 NMAC. The division may take enforcement action against any responsible party who does not comply with 19.15.29 NMAC pursuant to 19.15.5.10 NMAC.

B. A responsible party may enter an agreed compliance order with the division for any violation of 19.15.29 NMAC, except for 19.15.29.9 NMAC. An agreed compliance order may be entered prior to or after the filing of an application by the division or any other party for an administrative compliance proceeding. Any administrative compliance order will have the same force and effect as a compliance order issued after an adjudicatory hearing.

C. The director or the director's designee may deny any application or permit, including but not limited to, a permit to drill, deepen or plug back a well if the responsible party is not in compliance with a court order, agreed compliance order or administrative compliance order arising from 19.15.29 NMAC.

D. If the division or other party files an administrative enforcement application, the provisions of 19.15.4 NMAC apply to the enforcement proceeding, unless altered or amended by 19.15.5.10 NMAC or 19.15.29 NMAC.

[19.15.29.15 NMAC - N, 8/14/2018]

19.15.29.16 TRANSITIONAL PROVISIONS:

A. Responsible parties with current ongoing corrective actions/remediation with approved plans and timelines as of August 14, 2018 do not have to submit revised plans.

B. Responsible parties with ongoing corrective actions/remediation without approved timelines or plans as of August 14, 2018 must submit a characterization plan or corrective action/remediation plan with proposed timeframes within 90 days of August 14, 2018.

[19.15.29.16 NMAC - N, 8/14/2018]

HISTORY of 19.15.29 NMAC:

History of Repealed Material:

19.15.3 NMAC, Drilling (filed 10/29/2001) repealed 12/1/2008.

19.15.29 NMAC, Release Notification (filed 12/1/2008) was repealed effective 8/14/2018.

NMAC History:

That applicable portion of 19.15.3 NMAC, Drilling (Section 116) (filed 10/29/2001) was replaced by 19.15.29 NMAC, Release Notification, effective 12/1/2008.

19.15.29 NMAC, Release Notification (filed 12/1/2008) was repealed and replaced by 19.15.29, Releases, effective 8/14/2018.

EXHIBIT 21

United States Government Accountability Office

Report to Congressional Requesters

September 2019

OIL AND GAS

Bureau of Land Management Should Address Risks from Insufficient Bonds to Reclaim Wells

GAO-19-615

GAO Highlights

Highlights of GAO-19-615, a report to congressional requesters

September 2019

OIL AND GAS

Bureau of Land Management Should Address Risks from Insufficient Bonds to Reclaim Wells

Why GAO Did This Study

The oil and natural gas produced from wells on federal lands are important to the U.S. energy supply and bring in billions in federal revenue each year. However, when wells are not properly managed, the federal government may end up paying to clean up the wells when they stop producing. Specifically, wells on federal lands that an operator does not reclaim and for which there are no other liable parties fall to BLM to reclaim (restore lands to as close to their original natural states as possible). These wells become orphaned if the operator's bond held by BLM is not sufficient to cover reclamation costs. BLM regulations set minimum bond values at $10,000 for all of an operator's wells on an individual lease, $25,000 for all of an operator's wells in a state, and $150,000 for all of an operator's wells nationwide.

GAO was asked to review the status of oil and gas bonding for federal lands. This report (1) describes the value of bonds for oil and gas wells in 2018 compared to 2008, and (2) examines the extent to which BLM's bonds ensure complete and timely reclamation and thus prevent orphaned wells. GAO analyzed agency data on bonds and wells and interviewed BLM officials.

What GAO Recommends

Congress should consider giving BLM the authority to obtain funds from operators to reclaim orphaned wells, and requiring BLM to implement a mechanism to do so. GAO also recommends that BLM take steps to adjust bond levels to more closely reflect expected reclamation costs. BLM concurred. BLM did not concur with a proposed recommendation to develop a mechanism to obtain funds, citing lack of authority. GAO changed it to a matter for Congressional consideration.

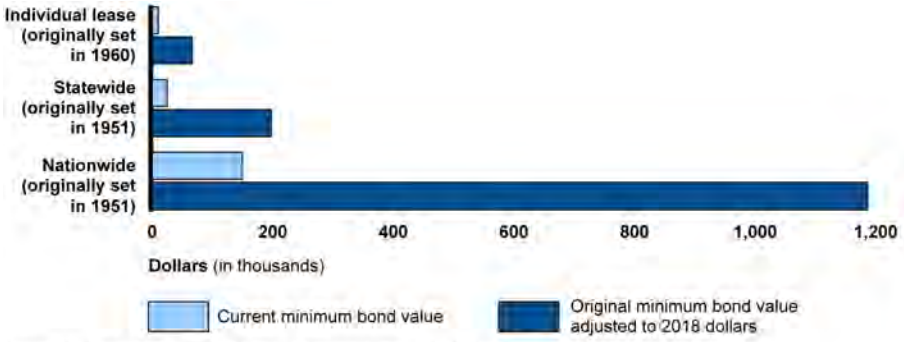
View GAO-19-615. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

What GAO Found

The average value of bonds held by the Bureau of Land Management (BLM) for oil and gas wells was slightly lower on a per-well basis in 2018 ($2,122) as compared to 2008 ($2,207), according to GAO's analysis of BLM data. The total value of bonds held by BLM for oil and gas operations increased between these years, as did the number of wells on federal land.

Bonds held by BLM have not provided sufficient financial assurance to prevent orphaned oil and gas wells (wells that are not reclaimed by their operators and, among other things, whose bonds were not sufficient to cover remaining reclamation costs, leaving BLM to pay for reclamation). Specifically, BLM identified 89 new orphaned wells between July 2017 and April 2019, and BLM offices identified to GAO about $46 million in estimated potential reclamation costs associated with orphaned wells and with inactive wells that officials deemed to be at risk of becoming orphaned in 2018. In part, bonds have not prevented orphaned wells because bond values may not be high enough to cover the potential reclamation costs for all wells under a bond, as may be needed if they become orphaned. GAO's analysis indicates that most bonds (84 percent) that are linked to wells in BLM data are likely too low to reclaim all the wells they cover. Bonds generally do not reflect reclamation costs because most bonds are set at their regulatory minimum values, and these minimums have not been adjusted since the 1950s and 1960s to account for inflation (see figure). Additionally, these minimums do not account for variables such as number of wells they cover or other characteristics that affect reclamation costs, such as well depth. Without taking steps to adjust bond levels to more closely reflect expected reclamation costs, BLM faces ongoing risks that not all wells will be completely and timely reclaimed, as required by law. It falls to BLM to reclaim orphaned wells, but the bureau does not assess user fees to cover reclamation costs, in part because it believes it does not have authority to do so. Providing such authority and developing a mechanism to obtain funds from operators for such costs could help ensure that BLM can completely and timely reclaim wells.

Bureau of Land Management Current Regulatory Minimum Oil and Gas Bond Values Compared to Original Minimum Bond Values Adjusted to 2018 Dollars



Source: GAO analysis of Bureau of Land Management data. | GAO-19-615

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Abbreviations

AFMSS	Automated Fluid Minerals Support System
BLM	Bureau of Land Management
EPAct 2005	Energy Policy Act of 2005
LR2000	Legacy Rehost 2000
OGOR	Oil and Gas Operations Report

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EXHIBIT 21

U.S. GOVERNMENT ACCOUNTABILITY OFFICE
441 G St. N.W.
Washington, DC 20548

September 18, 2019

The Honorable Raúl M. Grijalva
Chairman
Committee on Natural Resources
House of Representatives

The Honorable Alan S. Lowenthal
Chairman
Subcommittee on Energy and Mineral Resources
Committee on Natural Resources
House of Representatives

Oil and natural gas produced from wells on federal lands are important to the U.S. energy supply and bring in billions in federal revenue each year. However, when oil and gas wells are not properly managed, the federal government may end up paying to clean up the wells when they stop producing. According to the Department of the Interior's Bureau of Land Management (BLM), at the end of fiscal year 2018, BLM oversaw private entities operating over 96,000 oil and gas wells on leased federal lands. BLM is responsible for managing onshore federal oil and gas resources and determining requirements for operators to reclaim leased lands, which BLM defines as restoring lands to as close to their original natural states as possible.[1] The oil and gas industry's boom-and-bust cycles can lead operators to drill wells when prices for oil and gas are high but can contribute to bankruptcies when prices are low. As a result, operators may not always have the resources to reclaim lands around wells that have been degraded by drilling and production.[2] When wells are not fully

[1]BLM is responsible for issuing leases for private entities to develop oil and gas resources on and under roughly 700 million acres of (1) BLM land, (2) other federal agencies' land, and (3) private land where the federal government owns the mineral rights. According to BLM, approximately 26 million acres were leased for oil and gas operations at the end of fiscal year 2018. BLM's regulatory responsibilities also extend in part to development of oil and gas on Indian trust and restricted lands, but those lands and programs are outside the scope of this report.

[2]For the purposes of this report, "operator" refers to lessees, owners of operating rights, and operators of an oil or gas operation, unless indicated otherwise. We use the term "reclamation" to refer to all of the actions and costs to reclaim a well, including well plugging and surface reclamation, and to restoring any lands or surface waters adversely affected by oil and gas operations.

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reclaimed, there may be risks of leaking methane or groundwater contamination, among other things.[3]

BLM uses bonds to reimburse at least some of the costs of well reclamation in the event that operators or other liable parties do not reclaim wells. The Mineral Leasing Act of 1920, as amended, requires that federal regulations ensure that an adequate bond is established before operators begin preparing land for drilling to ensure complete and timely reclamation of the land, among other things.[4] BLM regulations set minimum bond values: $10,000 for all of an operator's wells on an individual lease (known as an individual lease bond), $25,000 for all of an operator's wells in a state (known as a statewide bond), and $150,000 for all of an operator's wells nationwide (known as a nationwide bond).[5] In January 2010, we reported on the number and value of bonds BLM held for oil and gas operations for fiscal years 1988 through 2008 and the value of individual lease, statewide, and nationwide bonds as of December 2008.[6] These bonds are designed to help prevent or reduce taxpayer losses because the bond money may be used to reclaim wells when operators or other liable parties do not. When the bonds covering those wells are insufficient to cover reclamation expenses, and there are no other responsible or liable parties to do so, wells are considered "orphaned."

Federal laws and BLM regulations and policies contain requirements aimed at managing BLM's potential oil and gas well liabilities and

[3]In this report, we refer to a well and the site surrounding it as a well.

[4]Specifically, BLM "shall, by rule or regulation, establish such standards as may be necessary to ensure that an adequate bond, surety, or other financial arrangement will be established prior to the commencement of surface-disturbing activities on any lease, to ensure the complete and timely reclamation of the lease tract, and the restoration of any lands or surface waters adversely affected by lease operations after the abandonment or cessation of oil and gas operations on the lease." 30 U.S.C. § 226(g).

[5]BLM coordinates with the Forest Service regarding oil and gas development on National Forest System lands. Where oil or gas development involves surface disturbance of National Forest System lands, the Forest Service must assess whether the existing BLM bond is adequate to meet the estimated cost to the Forest Service to reclaim those surface areas to be disturbed and to restore any lands or surface waters adversely effected by lease operations. If the Forest Service determines that bond is not adequate, the operator has the options of increasing the BLM bond amount or obtaining a separate bond to meet such estimated costs.

[6]GAO, *Oil and Gas Bonds: Bonding Requirements and BLM Expenditures to Reclaim Orphaned Wells*, GAO-10-245 (Washington, D.C.: Jan. 27, 2010).

preventing orphaned wells, including through ongoing oversight of wells and bonds provided by operators. For example, BLM's well review policy calls for field offices to, among other things, periodically review all inactive wells to determine whether they are capable of producing oil or gas or have a future beneficial use and, if not, have operators submit plans to reclaim the wells.[7] In May 2018, we reported on BLM's challenges in implementing these reviews, including differing understandings among field offices of the specific actions that constitute a well review.[8] In that report, we recommended that BLM develop and communicate specific instructions on what actions constitute a well review for annual reporting purposes. BLM concurred with this recommendation, and officials told us they are developing new reporting requirements.

Similar to its well review policy, BLM has a bond adequacy review policy that calls for BLM to regularly review bonds when certain events occur or periodically. Based on these reviews, BLM is to seek to increase bonds as necessary to ensure they reflect risks posed by the operator.[9] In our May 2018 report, we also reported on BLM's challenges in implementing bond adequacy reviews and made recommendations to improve their implementation.[10] In that report, we recommended that BLM strengthen its approach to monitoring field offices' implementation of the bond adequacy review policy, such as by collecting and analyzing data on performance indicators and ensuring the quality of those data. BLM concurred with this recommendation, and officials told us they are working on revising their guidance on data validation and are implementing quality reviews of their data.

You asked us to review issues related to bonds for oil and gas wells on federal lands. This report (1) describes the value of bonds for oil and gas wells in 2018 compared to 2008, and (2) examines the extent to which BLM's bonds ensure complete and timely reclamation and thus prevent orphaned wells.

[7]Bureau of Land Management, *Instruction Memorandum 2012-181* (Sept. 5, 2012).

[8]GAO, *Oil and Gas Wells: Bureau of Land Management Needs to Improve Its Data and Oversight of Its Potential Liabilities*, GAO-18-250 (Washington, D.C.: May 16, 2018).

[9]These bond adequacy reviews use a points-based system to examine aspects of an operator's wells (such as its number of wells idle for at least 7 years), compliance history (such as its number of incidents of drilling without approval), and reclamation stewardship (such as its number of reclamation incidents of noncompliance issued in the last 5 years).

[10]GAO-18-250.

To describe the value of bonds for oil and gas wells in 2018 compared to 2008, we analyzed oil and gas well data from BLM's Automated Fluid Minerals Support System (AFMSS) as of May 2018 and data on bonds from BLM's Legacy Rehost 2000 (LR2000) system as of May 2018. We compared these data to the 2008 data from these systems that we reported in 2010.[11] We matched the May 2018 data from the two systems based on the bond number—a variable in both systems—to identify how many wells were covered by each bond and to determine the average bond value per well for each bond category. To assess the reliability of these AFMSS and LR2000 data elements, we reviewed agency documents, met with relevant agency officials, and performed electronic testing. We found these data to be sufficiently reliable for our purposes.

To examine the extent to which BLM's bonds ensure complete and timely reclamation and thus prevent orphaned wells, we analyzed several sources of data, including AFMSS well data, LR2000 bond data, Office of Natural Resources Revenue's Oil and Gas Operations Report (OGOR) well production data, and well reclamation cost estimates from proofs of claim that BLM files with the Department of Justice when an operator files for bankruptcy.[12] First, we examined whether bonds are sufficient to cover potential reclamation costs for the wells they cover. To do this, we analyzed cost estimates on proofs of claim and identified typical high- and low-cost well reclamation scenarios. We then compared the cost scenarios to the average bond value available per well, for each bond, calculated using bond values in LR2000 and the number of wells covered by each bond in AFMSS. Next, we examined a subset of wells that are at increased risk of becoming orphaned and whether bonds are sufficient to cover their potential reclamation costs. To do this, we used OGOR production data to identify wells that had not produced since at least June 2008 and that met several other criteria. For those at-risk wells, we compared reclamation cost scenarios to the average bond value available for each—calculated by dividing bond value by the number of at-risk wells covered by the bond—using well data from AFMSS and bond value data from LR2000. To assess the reliability of the AFMSS, LR2000, and OGOR data elements we used, we reviewed agency documents, met with relevant agency officials, and performed electronic testing. We found these data to be sufficiently reliable for our purposes.

[11]GAO-10-245.

[12]The Office of Natural Resources Revenue manages and ensures full payment of revenues owed for the development of the nation's energy and natural resources offshore, on the Outer Continental Shelf, and onshore, on federal and Indian lands.

In addition, we examined the number of orphaned wells, comparing the number of orphaned wells identified by BLM as of April 2019 to those identified by BLM as of July 2017 and 2009, the two previous times we reported on orphaned wells.[13] To assess the reliability of the 2019 orphaned well list, we reviewed agency documents and met with relevant agency officials. Though we identified shortcomings with these data, which we discuss in the report where appropriate, we nevertheless found these data to be sufficiently reliable for the purpose of describing the orphaned wells BLM has identified.

To understand how BLM manages bonds, we reviewed BLM's policies and interviewed officials from four BLM state offices and four BLM field offices.[14] We selected these state and field offices because they were responsible for managing the largest numbers of wells on federal land. We also interviewed officials from BLM's headquarters office in Washington, D.C. Findings from the selected BLM offices cannot be generalized to offices we did not interview, but they provide a range of views. Appendix I provides additional information on our scope and methodology.

We conducted this performance audit from January 2018 to September 2019 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

Life Cycle of Oil and Gas Wells

Oil and gas exploration and production involves disturbing lands in several ways. For example, when operators drill oil and gas wells, they typically remove topsoil and construct a well pad, where the drilling rig will be located. Other equipment on-site can include generators and fuel tanks. In addition, reserve pits are often constructed to store or dispose of water, mud, and other materials that are generated during drilling and

[13]See GAO-10-245 and GAO-18-250.

[14]The four selected BLM state offices are California, New Mexico, Wyoming, and Utah. The four selected BLM field offices are Bakersfield, Buffalo, Carlsbad, and Farmington.

production, and roads and access ways are often built to move equipment to and from the wells.

Once wells cease production, which may occur many decades after they are drilled, they can become inactive. Inactive wells have the potential to create physical and environmental hazards if operators do not properly reclaim them, a process that may involve plugging the well, removing structures, and reshaping and revegetating the land around the wells. For example, inactive wells that are not properly plugged can leak methane into the air or contaminate surface water and groundwater. Well sites that are not properly reclaimed can contribute to habitat fragmentation and soil erosion, and equipment left on-site can interfere with agricultural land use and diminish wildlife habitat.

Costs for well reclamation vary widely and are affected by factors such as the depth of the well. Although BLM does not estimate reclamation costs for all wells, it has estimated reclamation costs for thousands of wells whose operators have filed for bankruptcy. Based on our analysis of these estimates, we identified two cost scenarios: low-cost wells typically cost about $20,000 to reclaim, and high-cost wells typically cost about $145,000 to reclaim.[15]

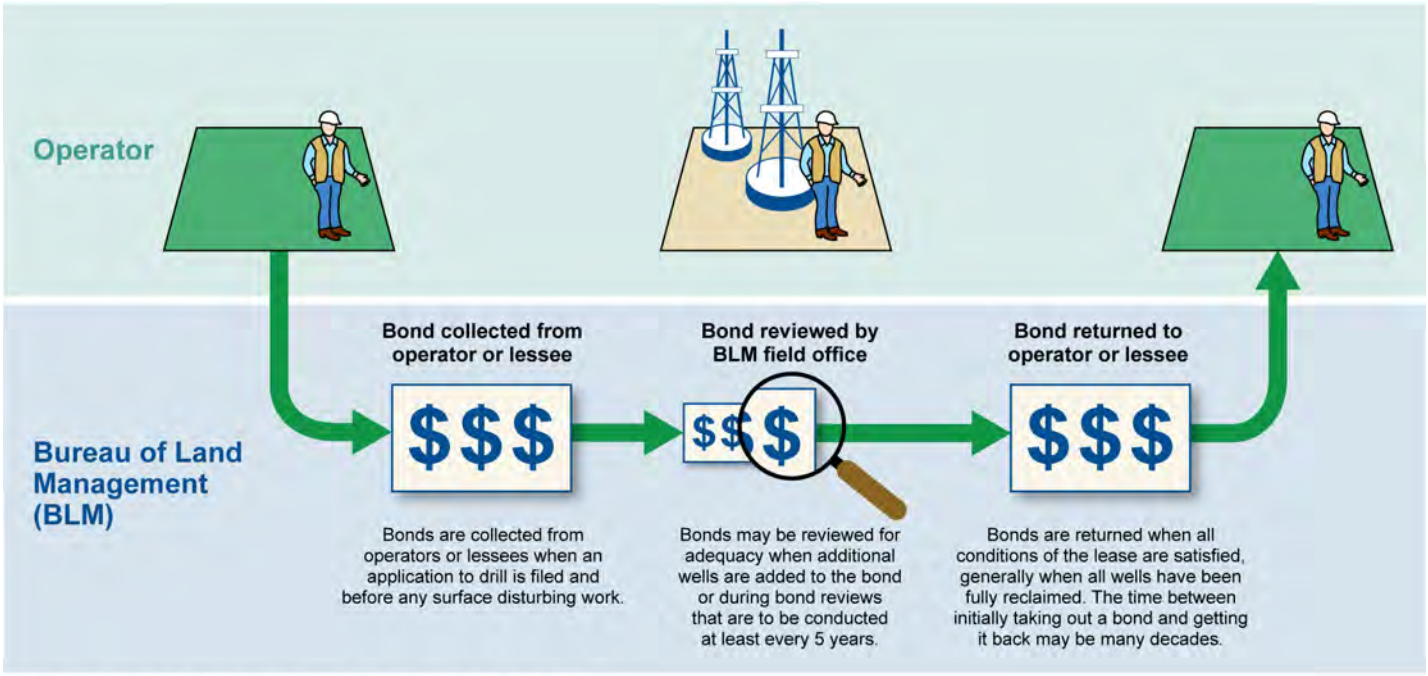
BLM's Bonding Regulations and Policies

As shown in figure 1, BLM regulations or policies outline how BLM is to initially collect bonds from operators, review bonds, and ultimately return the bond to the operator or use it to cover costs of reclamation.

[15]Based on our analysis of BLM reclamation cost estimates, the costs to reclaim wells were clustered into distinct groups: relatively low-cost and relatively high-cost wells. Due to this pattern of clustering and a wide variation in reclamation costs, we used these data as a basis to define two scenarios of potential reclamation costs for any individual well. Although we do not have information about the reclamation costs for all BLM wells, or the extent to which the proofs of claim sample is representative of all BLM wells, we consider these two scenarios to reflect a reasonable range of potential reclamation costs for a typical well.

The low-cost scenario is based on the 25th percentile of average well reclamation costs in proofs of claim, and the high-cost scenario is based on the 75th percentile. These scenarios do not encompass the complete range of BLM's well reclamation cost estimates. For example, on the low end, the 5th percentile average was about $15,000, and the lowest average estimate was $3,096. On the high end, the 95th percentile average was about $174,000, and the highest estimate was $603,000. Reclamation costs can vary based on a number of factors, such as well depth or location.

Figure 1: Life Cycle of a Bureau of Land Management Bond for Oil and Gas Operations



Source: GAO analysis of Bureau of Land Management information. | GAO-19-615

Bonds collected from operator. BLM regulations require operators to submit a bond to ensure compliance with all of the terms and conditions of the lease, including, but not limited to, paying royalties and reclaiming wells.[16] BLM regulations generally require operators to have one of the following types of bond coverage:[17]

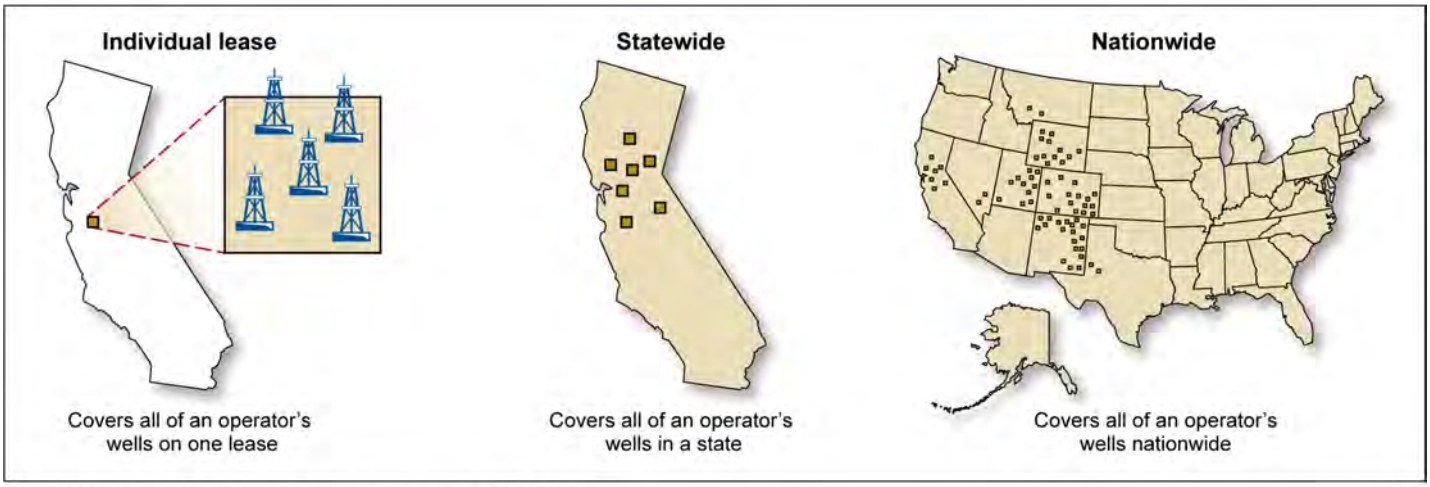
[16]43 C.F.R. § 3104.1(a).

[17]Other bonds include unit operator bonds that cover all operations conducted on leases within a specific unit agreement and bonds for leases in the National Petroleum Reserve in Alaska. Unit agreements refer to multiple lessees who unite to adopt and operate under a single plan for the development of any oil or gas pool, field, or like area. The amount of a unit operator bond is determined on a case-by-case basis by BLM officials, and the minimum amount of a National Petroleum Reserve in Alaska bond is set in regulation—not less than $100,000 for a single lease or not less than $300,000 for a reserve-wide bond (submitted separately or as a rider to an already existing nationwide bond).

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- individual lease bonds, which cover all of an operator's wells under one lease;[18]
- statewide bonds, which cover all of an operator's leases and operations in one state;[19] or
- nationwide bonds, which cover all of an operator's leases and operations nationwide.[20] (See figure 2.)

Figure 2: Bureau of Land Management Individual Lease, Statewide, and Nationwide Bonds for Oil and Gas Operations



Source: GAO analysis of Bureau of Land Management information. | GAO-19-615

BLM can accept two types of bonds: surety bonds and personal bonds. A surety bond is a third-party guarantee that an operator purchases from a private insurance company approved by the Department of the Treasury. The operator pays a premium to the surety company that can vary depending on various factors, including the amount of the bond and the assets and financial resources of the operator. If operators fail to reclaim

[18]An individual lease bond posted by a lessee may cover all operators on a lease. Otherwise, each operator on a lease must provide a separate bond covering just the wells operated by that operator. As we previously reported, according to BLM officials, most leases have only one operator. See GAO, *Oil and Gas Bonds: BLM Needs a Comprehensive Strategy to Better Manage Potential Oil and Gas Well Liability*, GAO-11-292 (Washington, D.C.: Feb. 25, 2011).

[19]A statewide bond posted by a lessee can cover all well operators with the consent of the company providing the bond.

[20]A nationwide bond posted by a lessee can cover all well operators with the consent of the company providing the bond.

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their wells, the surety company is responsible for paying BLM up to the amount of the bond to help offset reclamation costs.

A personal bond must be accompanied by one of the following financial instruments:

- certificates of deposit issued by a financial institution whose deposits are federally insured, granting the Secretary of the Interior full authority to redeem it in case of default in the performance of the terms and conditions of the lease;
- cashier's checks;
- certified checks;
- negotiable Treasury securities, including U.S. Treasury notes or bonds, with conveyance to the Secretary of the Interior of full authority to sell the security in case of default in the performance of the lease's terms and conditions; or
- irrevocable letters of credit that are issued for a specific term by a financial institution whose deposits are federally insured and meet certain conditions and that identify the Secretary of the Interior as sole payee with full authority to demand immediate payment in case of default in the performance of the lease's terms and conditions.

BLM bond reviews. BLM regulations provide flexibility to increase bonds above minimums and require increases above minimum amounts if operators meet certain criteria. Specifically, BLM regulations require BLM to increase the bond amount when an operator who applies for a new drilling permit had previously failed to reclaim a well in a timely manner. For such an operator, BLM must require a bond in an amount equal to its cost estimate for reclaiming the new well if BLM's cost estimate is higher than the regulatory minimum amount. BLM regulations also authorize increases in the bond amount—not to exceed the estimated cost of reclamation and any royalties or penalties owed—whenever the authorized officer determines that the operator poses a risk due to factors such as that the expected reclamation costs exceed the present bond.

In response to our previous recommendation in 2011 that BLM develop a comprehensive strategy to revise its bond adequacy review policy to more clearly define terms and conditions that warrant a bond increase,[21] BLM issued a bond adequacy review policy in July 2013, Instruction

[21]GAO-11-292.

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Memorandum 2013-151. The policy contained directives for conducting reviews when bonds meet certain criteria. Specifically, the 2013 bond adequacy review policy called for field offices to, among other things, review each bond at least every 5 years to determine whether the bond value appropriately reflected the level of potential risk posed by the operator. If it did not, authorized officers were to propose an increase (or decrease) in the bond value.

In November 2018, BLM issued a revised bond adequacy review policy, Instruction Memorandum 2019-014, which supersedes the 2013 policy. The 2018 policy continues to call for field offices to review each bond at least every 5 years, but it revised the point system worksheet that field offices are to use when determining whether a bond increase (or decrease) is warranted. Also, in response to our 2018 recommendation that BLM ensure that the reviews of nationwide and statewide bonds reflect the overall risk presented by operators, the 2018 policy calls for additional coordination between BLM headquarters, state offices, and field offices when reviewing nationwide and statewide bonds.

BLM returns or uses bond. If operators reclaim their wells, BLM returns the bond to the operator.[22] Many decades may pass between when BLM collects a bond and when it is returned. If operators do not reclaim their wells, BLM may redeem the certificate of deposit, cash the check, sell the security, or make a demand on the letter of credit to pay the reclamation costs. Liability for reclaiming a well on onshore federal lands can fall to either the lease holder or the operator, and BLM may also hold past owners or operators liable. The liability for past owners or operators extends only to reclamation obligations that accrued before BLM approved the transfer of their lease to a subsequent lessee. They are not liable for reclamation and lease obligations incurred after that transfer is approved.

[22]Bonds are released after final abandonment is approved by BLM, indicating compliance with all lease terms, including reclamation. Statewide or nationwide bonds are not released until final approval of abandonment of all activities under those bonds.

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Average Bond Values Per Well Were Slightly Lower in 2018 as Compared to 2008

Based on our review of BLM data, the value of bonds held by BLM for oil and gas operations on a per-well basis were slightly lower in 2018 as compared to 2008. Although the total value of bonds held by BLM for oil and gas operations was higher in 2018 than in 2008 (about $204 million compared to about $188 million, in 2018 dollars), the average bond value per well was slightly lower because the number of wells on federal land was also higher in 2018 than in 2008 (96,199 wells compared to 85,330). Specifically, in 2008, BLM held bonds worth an average of $2,207 per well in 2018 dollars.[23, 24] BLM held bonds worth an average of $2,122 per well in 2018, a decrease of 3.9 percent as compared to 2008 (see table 1).[25]

Table 1: Bureau of Land Management's Oil and Gas Bonds and Wells in 2008 and 2018, in 2018 dollars

	Value of Bonds	Number of Wells	Average Bond Value Per Well
2008	188,316,757	85,330	2,207
2018	204,181,121	96,199	2,122
Percent Change	8.4	12.7	-3.9

Source: GAO analysis of Bureau of Land Management data. | GAO-19-615

Note: The value of bonds in 2008 is as of September 2008. The value of bonds in 2018 is as of May 2018. Data on the number of wells are as of September 2008 and September 2018.

We used BLM data to identify how many wells were covered by each bond and to determine the average bond value per well for each bond

[23]BLM bonds do not typically cover an individual well; however, we calculated the average bond value on a per-well basis (bond amount divided by the number of wells covered by the bond) to compare the value over time adjusted for the increased number of wells. When reporting on all wells, we calculated the average bond value per well as the aggregate value of all BLM bonds divided by the total number of producible well bores. Appendix I provides additional information on our scope and methodology.

[24]GAO-10-245.

[25]Data on the value of bonds in 2008 are as of September 2008. Data on the value of bonds in 2018 are as of May 2018. Data on the number of wells in 2008 are as of September 2008. Data on the number of wells in 2018 are as of September 2018.

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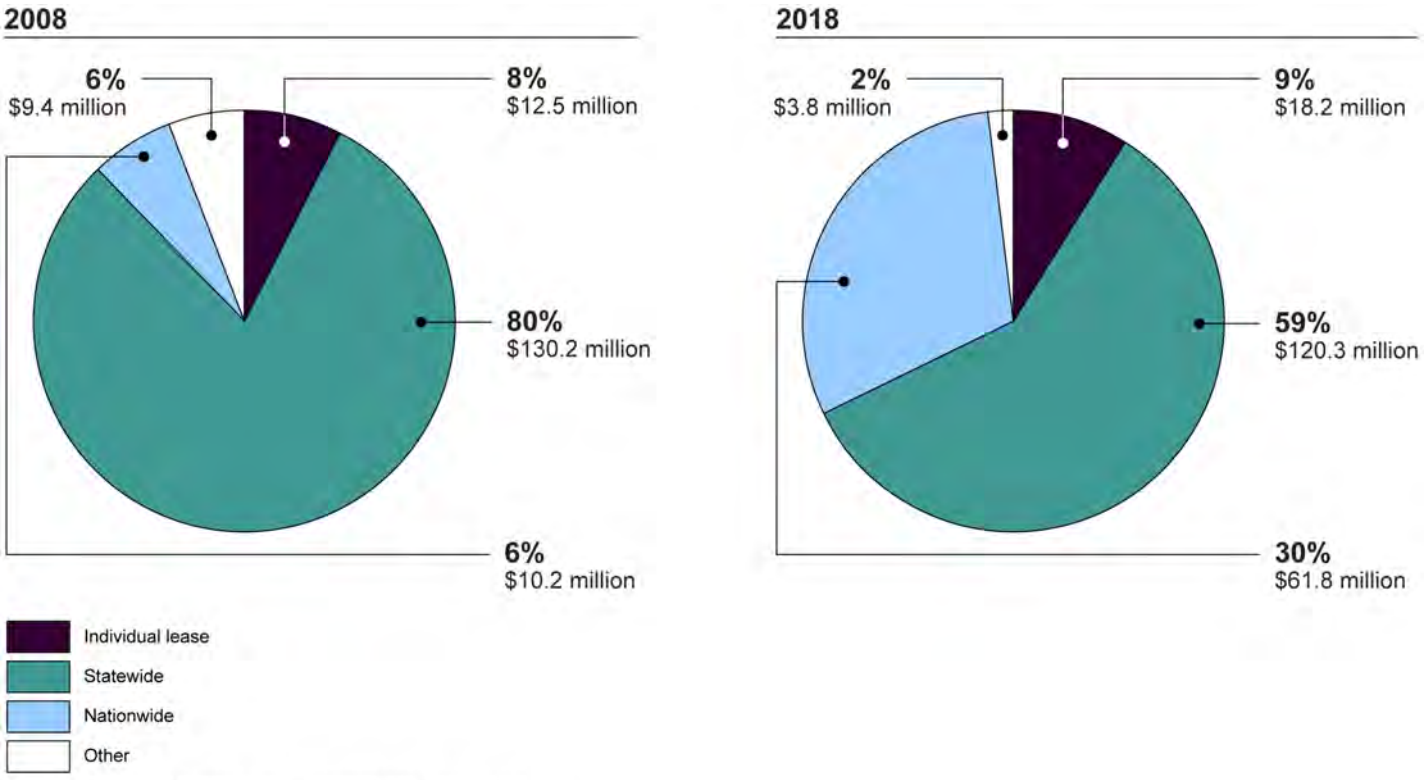
category for bonds that were linked to wells in the data.[26] We found that, on average, as of 2018 an individual lease bond covered about 10 wells, a statewide bond covered about 49 wells, and a nationwide bond covered 374 wells. However, some bonds cover more than the typical number of wells and some fewer. As of 2018, individual lease bonds had the highest average bond value per well at $2,691, and nationwide bonds had the lowest average bond per well value at $890. Statewide bonds had an average bond value per well of $1,592.

The share of the total value of bonds held by BLM that are individual lease, statewide, or nationwide bonds differed in 2018 from 2008 (see Figure 3). The share of individual lease bonds was slightly higher in 2018 as compared to 2008 (about 8 percent in 2008 and about 9 percent in 2018). In 2008, statewide bonds represented about 80 percent (approximately $130 million) of the total value of bonds. In 2018, statewide bonds represented about 59 percent of total bond value (approximately $120 million), but this category still represented the largest share of total bond value. In contrast, nationwide bonds were a lower share of total bond value in 2008 (about 6 percent, approximately $10.2 million) than in 2018 (30 percent, approximately $61.8 million).

[26]To report on the average number of wells per bond by bond category and the average bond value per well by bond category, we analyzed bonds that were linked to wells in BLM's data. Specifically, of 3,357 unique bond numbers in LR2000, 1,547 showed wells were tied to them in AFMSS. These 1,547 bonds covered about 80 percent of the wells in AFMSS. The other 20 percent of wells in AFMSS did not match a bond number in LR2000. These wells may not have listed a bond number, or the bond number listed may not have appeared in LR2000.

Based on this sample, the average bond value per well by bond category is calculated as the aggregate value of BLM bonds in a category divided by the total number of wells covered by bonds of that category. Due to the difference in samples, the total bond value used in the calculations of average bond value per well by bond category differs from the total bond value for all bonds in LR2000. Appendix I provides additional information on our scope and methodology.

Figure 3: Value of Bonds Held by Bureau of Land Management, by Bond Category, in 2008 and 2018



Source: GAO analysis of Bureau of Land Management data. | GAO-19-615

Note: Other category consists of National Petroleum Reserve-Alaska and unit bonds.

BLM officials told us that changes in the composition of the oil and gas industry may have contributed to these changes in the composition of bonds. In particular, officials said some larger companies may have expanded their operations in recent years, sometimes acquiring smaller companies. Large companies with expansive operations are more likely than small companies to have nationwide bonds because such bonds can cover operations in multiple states, which statewide and individual lease bonds do not. Therefore, an industry shift to larger companies would tend to increase the share of nationwide bonds.

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Bonds Held by BLM Are Insufficient to Prevent Orphaned Wells

Bonds Do Not Provide Sufficient Financial Assurance to Prevent Orphaned Wells

Bonds do not provide sufficient financial assurance to prevent orphaned wells for several reasons. First, BLM has identified new orphaned wells—wells whose bonds were not sufficient to pay for needed reclamation when operators or other parties failed to reclaim them. As we reported in May 2018, BLM does not track the number of orphaned wells over time and so cannot identify how many wells became orphaned over specific time frames.[27] However, our analyses of BLM's orphaned well lists from different years have shown that BLM has continued to identify new orphaned wells since 2009. We reported in January 2010 that BLM identified 144 orphaned wells in 2009.[28] Then, in May 2018, we reported that BLM identified 219 orphaned wells in July 2017—an increase of 75 orphaned wells.[29] In April 2019, BLM provided a list of 296 orphaned wells that included 89 new wells that were not identified on the July 2017 list.[30]

Bonds are not sufficient to prevent orphaned wells in part because they do not reflect full reclamation costs for the wells they cover. Bonds that are high enough to cover all reclamation costs provide complete financial assurance to prevent orphaned wells because, in the event that an operator does not reclaim its wells, BLM can use the bond to pay for reclamation. On the other hand, bonds that are less than reclamation

[27]See GAO-18-250. We recommended that BLM systematically and comprehensively track orphaned wells. BLM concurred with our recommendation, and officials told us they were exploring making changes to their data systems to improve their ability to track orphaned wells.

[28]GAO-10-245.

[29]GAO-18-250.

[30]BLM headquarters officials told us that some of the wells on the April 2019 list may no longer be orphaned, based on their well status. However, according to officials in one field office, at least some wells in those statuses are still orphaned. As a result, we included all the wells identified in AFMSS as orphaned in our analysis.

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costs may not create an incentive for operators to promptly reclaim wells after operations cease because it costs more to reclaim the wells than the operator could collect from its bond. We analyzed bonds that are linked to wells in BLM's data, and found that most of these bonds would not cover reclamation costs for their wells.[31] Specifically, we compared the average bond coverage available for these wells to the two cost scenarios we described above. About 84 percent of these bonds—covering 99.5 percent of these wells—would not fully cover reclamation costs under a low-cost scenario (these bonds have an average value per well of less than $20,000).[32] Less than 1 percent of bonds—covering less than 0.01 percent of these wells—would be sufficient to reclaim all the wells they cover if they were high cost (these bonds have an average value per well of $145,000 or more). The remaining bonds—about 16 percent—have average bond values per well of between $20,000 and less than $145,000.

The majority of bond values do not reflect reclamation costs in large part because most bonds—82 percent—remain at their regulatory minimum

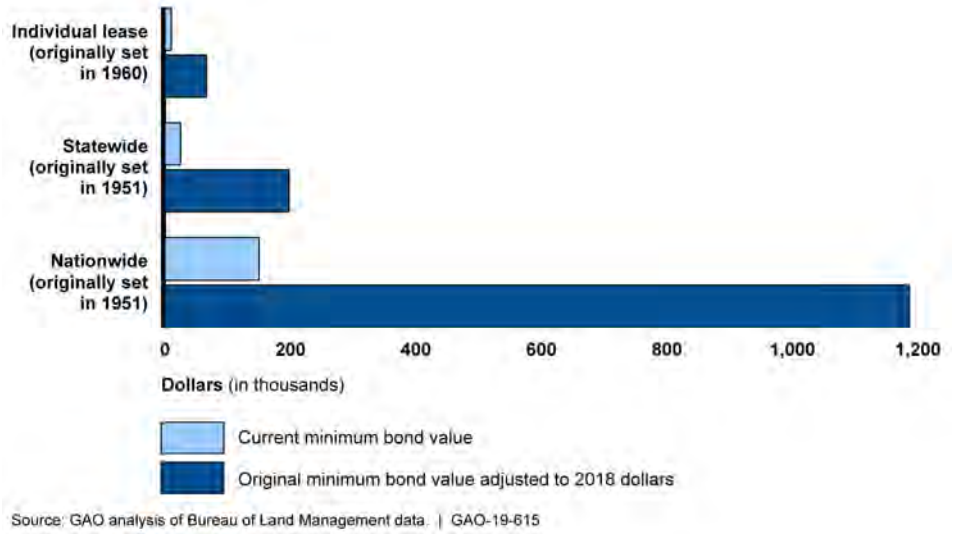
[31]We analyzed bonds that were linked to wells in BLM's data. Specifically, of 3,357 unique bond numbers in LR2000, 1,547 showed wells were tied to them in AFMSS. These 1,547 bonds covered about 80 percent of the wells in AFMSS. The other 20 percent of wells in AFMSS did not match a bond number in LR2000. These wells may not have listed a bond number, or the bond number listed may not have appeared in LR2000. Appendix I provides additional information on our scope and methodology. In our May 2018 report, we found problems with the quality of data in AFMSS, and recommended that the Director of BLM take steps to improve its data quality, for example, by conducting more edit checks and by having data stewards certify the quality of the data. BLM concurred with this recommendation and stated that it would update its policy to provide guidance on standard procedures for data validation review and certification. See GAO-18-250.

[32]We calculated average bond value per well—for each bond—as the bond's value divided by the total number of wells covered the bond, for the sample of wells that were linked to bonds in BLM data. This assessed whether the bond amount is sufficient to cover the reclamation costs associated with all wells covered by the bond. Appendix I provides additional information on our scope and methodology.

values.[33] These regulatory minimums are not reflective of reclamation costs for a number of reasons:

- Regulatory bond minimums have not been adjusted since the 1950s and 1960s to account for inflation. As shown in figure 4, when adjusted to 2018 dollars, the $10,000 individual lease bond minimum would be about $66,000, the $25,000 statewide bond minimum would be about $198,000, and the $150,000 nationwide bond minimum would be about $1,187,000.

Figure 4: Bureau of Land Management Current Regulatory Minimum Oil and Gas Bond Values Compared to Original Minimum Bond Values, Adjusted to 2018 Dollars



Source: GAO analysis of Bureau of Land Management data. | GAO-19-615

- Bond minimums are based on the bond category and do not adjust with the number of wells they cover, which can vary greatly. According to BLM's data, in 2018 the number of wells covered by a single bond

[33]About 14 percent of bonds are above their regulatory minimum values. About 1 percent of bonds are in the other category. About 3 percent of bonds are below their regulatory minimum values. According to BLM officials, bonds below regulatory minimums either (1) do not cover any wells and therefore have no associated liability, or (2) were put in place when regulatory minimums were lower. According to the 2018 BLM bond adequacy review policy, field offices are to review bonds and cannot adjust values to be less than the regulatory minimum values. In 2018, we recommended that BLM strengthen its approach to monitoring field office implementation of bond adequacy review policies, such as collecting and analyzing data on performance indicators and ensuring the quality of the data. Officials told us they are working on revising their guidance on data validation and are implementing quality reviews of their data. See GAO-18-250.

ranged from one well to 6,654 wells. On average, a single bond covered about 68 wells.[34] As wells are added to a bond, the total associated reclamation cost increases even if the bond value does not. A bond that increases with each additional well it covers and then decreases as wells are reclaimed could increase the financial incentive for operators to reclaim their wells in a timely manner. This is because operators would have to contribute additional bond value or would recover some bond value when they add or reclaim a well, respectively. Currently, bond minimums do not automatically adjust in this manner and therefore provide limited financial incentives for an operator to reclaim wells in a timely manner.

- Bond minimums do not reflect characteristics of individual wells such as depth or location, but such characteristics can affect reclamation costs, according to BLM officials. Wells are being drilled deeper than in the past; in 1950, well depth averaged about 3,700 feet, and in 2008, it averaged about 6,000 feet. Newer wells may be drilled 10,000 feet vertically. Officials from one BLM field office told us they assume a cost of $10 per foot of well depth to plug a well, so as wells are drilled deeper, plugging costs typically increase proportionally. Additionally, the location of some wells makes them more expensive to reclaim. For example, BLM officials told us about several wells that may cost three times more to reclaim than other nearby wells because they are located in the middle of a river, making them hard to reach.

In addition to BLM having identified orphaned wells over the last decade, we identified inactive wells at increased risk of becoming orphaned and found their bonds are often not sufficient to reclaim the wells. Our analysis of BLM bond value data and Office of Natural Resources Revenue production data showed a significant number of inactive wells remain unplugged and could be at increased risk of becoming orphaned. Specifically, we identified 2,294 wells that may be at increased risk of becoming orphaned because they have not produced since June 2008 and have not been reclaimed.[35] Further, for a majority of these at-risk wells, their bonds are too low to cover typical reclamation costs for just these at-risk wells. Our analysis of oil and gas production data showed

[34]The number of wells covered by a single bond was calculated using wells that are linked to bonds in BLM's data.

[35]Our analysis used conservative assumptions to estimate a lower bound of the number of wells at the end of their useful life that have not been reclaimed. In particular, our lower-bound estimate does not include some coalbed methane wells that have been inactive for less than 9 years but are unlikely to produce at current prices because of the relatively higher cost of coalbed methane production. Appendix I provides additional information on our scope and methodology.

these wells have not produced oil or gas or been used in other ways, such as serving as injection wells, since at least June 2008, when oil and gas prices were at or near record highs.[36] Given that the Energy Information Administration projects oil and natural gas prices will remain at levels significantly below the 2008 highs through 2050, it is unlikely price will motivate operators to reopen these wells. Some of these wells have been inactive for far longer.[37] Since these at-risk wells are unlikely to produce again, an operator bankruptcy could lead to orphaned wells unless bonds are adequate to reclaim them. If the number of at-risk wells is multiplied by our low-cost reclamation scenario of $20,000, it implies a cost of about $46 million to reclaim these wells. If the number of these wells is multiplied by our high-cost reclamation scenario of $145,000, it implies a cost of about $333 million.[38] When we further analyzed the available bonds for these at-risk wells, we found that most of these wells (about 77 percent) had bonds that would be too low to fully reclaim the at-risk wells under our low-cost scenario.[39] More than 97 percent of these at-risk wells have bonds that would not fully reclaim the wells under our high-cost scenario.

BLM has a policy for reviewing the adequacy of bonds but has not been able to consistently secure bond increases when needed, and this policy

[36]According to the Energy Information Administration, the weekly spot price for West Texas Intermediate oil at Cushing, Oklahoma, was $142.52 per barrel the first week of July 2008. As of the first week of May 2019, the price was $62.90 per barrel. Similarly, the Energy Information Administration reported that the Henry Hub weekly spot price for natural gas was $13.20 per million British thermal units the first week of July 2008. It was $2.59 per million British thermal units the first week of May 2019.

[37]We reported in May 2018 on over 1,000 wells that had been inactive for 25 years or more. That number includes some wells on Indian land, which are not included in the scope of this report. GAO-18-250.

[38]Not all of these wells may become orphaned, although they are at an increased risk of becoming orphaned as compared to active wells or wells that have been inactive for fewer years.

[39]We analyzed bonds linked to at-risk wells in BLM's data. Of the 2,294 at-risk wells, 2,041 were linked to bonds in BLM's data (about 89 percent) and these formed the basis of our analysis of bond value per at-risk well; the remaining wells were not tied to any bonds in LR2000. In addition, we examined costs associated with at-risk wells covered by these bonds and did not count any other wells covered by the bond if they were not at risk. Appendix I provides additional information on our scope and methodology.

has not resulted in bonds that would be adequate to reclaim most wells.[40] BLM's bond adequacy review policy calls for field office staff to review oil and gas bonds at least every 5 years to determine whether the bond amount appropriately reflects the level of potential risk posed by the operator. However, according to BLM documentation, its offices did not secure about 84 percent of the proposed bond increases in fiscal years 2016 and 2017. BLM officials at one field office and one state office noted it is difficult to secure increases from bond reviews when firms are already in difficult financial situations. In November 2018, BLM updated its bond adequacy review policy and called for the agency to focus on securing bond increases from operators that show the highest risk factors. BLM's updated policy more explicitly lays out steps to secure bond increases, including that BLM should not approve new applications to drill from an operator while waiting for a bond increase. The new policy also gives BLM officials discretion to not pursue a bond increase after considering other priorities demanding staff time and workload. It is unclear whether the update will improve BLM's ability to secure bond increases, as it may not address the underlying challenge of attempting to increase bonds from operators who are already in a difficult financial position.

While BLM's federal oil and gas bond minimums do not sufficiently reflect the costs of well reclamation, requirements for bond amounts for other federal mining and energy development activities account for potential reclamation costs to some extent. For example, for bonds for surface coal mining and hardrock mining on federal lands, the Department of the Interior requires bond amounts based on the full estimated cost of reclamation.[41] For grants of federal rights-of-way for wind and solar energy development in designated leasing areas, BLM requires bonds based on a minimum amount per wind turbine or per acre of solar. For such grants in all other areas, the bonds are based on the estimated cost of reclamation but cannot be less than the per-turbine or per-acre amounts previously mentioned.

[40]BLM's bond adequacy reviews use a points-based system to examine aspects of an operator's well status (such as its number of wells idle for at least 7 years), compliance history (such as its number of incidents of drilling without approval), and reclamation stewardship (such as its number of reclamation related incidents of noncompliance issued in the last 5 years).

[41]GAO, *Financial Assurances for Reclamation: Federal Regulations and Policies for Selected Mining and Energy Development Activities*, GAO-17-207R (Washington, D.C.: Dec. 16, 2016).

Additionally, some states have minimum bond requirements for oil and gas wells on lands in the state that, unlike federal bond minimums, adjust with the number of wells they cover or the characteristics of the wells, or both. For example, Texas and Louisiana offer operators with wells on lands in those states the choice of a bond based on total well depth or based on the number of wells. Specifically, the Texas Railroad Commission lets operators choose bonds based on either the total depth of all wells on lands in the state multiplied by $2 per foot, or minimums based on the number of wells covered. If operators choose the latter, the bond for 0 to 10 wells is $25,000; the bond for 11 to 99 wells is $50,000; and the bond for 100 or more wells is $250,000. In Louisiana, the Office of Conservation offers operators with wells on lands in the state the choice of a bond based on total well depth or based on the number of wells. Louisiana further specifies a multiplier that varies depending on the total depth of the well. For example, the bond calculation is $2 per foot for wells less than 3,000 feet deep, $5 per foot for wells from 3,001 to 10,000 feet deep, and $4 per foot for wells 10,001 feet deep or deeper. Operators in Louisiana can alternatively choose to follow a system based on number of wells, with a minimum bond for 10 or fewer wells set at $50,000, a minimum bond for 11 to 99 wells set at $250,000, and a minimum bond for 100 or more wells set at $500,000. Pennsylvania's Department of Environmental Protection requires bonds for unconventional wells that vary based on the number of wells and well bore length.[42]

The Mineral Leasing Act of 1920, as amended, requires federal regulations to ensure that an adequate bond is established before operators begin surface-disturbing activities on any lease, to ensure complete and timely reclamation of the lease tract as well as land and surface waters adversely affected by lease operations. The Mineral Leasing Act of 1920 does not require that BLM set bonds at full reclamation costs. However, the gap between expected reclamation costs and minimum bond amounts has grown over time because the minimums have not been adjusted since they were established in the 1950s and 1960s, whereas reclamation costs have increased due to inflation and the changing characteristics of wells being drilled. In the absence of bond

[42]Pennsylvania defines conventional wells as those that produce oil or gas from a conventional formation. It defines an unconventional well as a gas well that is drilled into an unconventional formation, which is defined as a geologic shale formation below the base of the Elk Sandstone or its geologic equivalent where natural gas generally cannot be produced economically except by horizontal or vertical well bores stimulated by hydraulic fracturing or other techniques to expose more of the formation to the well bore.

levels that more closely reflect expected reclamation costs, such as by increasing regulatory minimums and incorporating consideration of the number of wells on each bond and their characteristics, BLM will continue to face risks that its bonds will not provide sufficient financial assurance to prevent orphaned wells. In particular, adjusting bond minimums so that bonds more closely reflect expected reclamation costs up front could help decrease the need for bond increases later when companies are potentially in financial distress.

BLM Does Not Currently Assess User Fees to Fund Orphaned Well Reclamation

In addition to fulfilling its responsibility to prevent new orphaned wells, it falls to BLM to reclaim wells that are currently orphaned, and BLM has encountered challenges in doing so. We reported in May 2018 that 13 BLM field offices identified about $46.2 million in estimated potential reclamation costs associated with orphaned wells and with inactive wells that officials deemed to be at risk of becoming orphaned. There is also a risk more wells will become orphaned in coming years, as we described above. Based on the most recent orphaned well lists we received from BLM, 51 wells that BLM identified in 2009 as orphaned had not been reclaimed as of April 2019.

The Energy Policy Act of 2005 (EPAct 2005) directs Interior to establish a program that, among other things, provides for the identification and recovery of reclamation costs from persons or other entities currently providing a bond or other financial assurance for an oil or gas well that is orphaned, abandoned, or idled.[43] One way in which BLM may be able to accomplish this is through the imposition of user fees.[44] In 2008, we found that well-designed user fees can reduce the burden on taxpayers to finance those portions of activities that provide benefits to identifiable

[43]The Secretary of the Interior is to establish this program in cooperation with the Secretary of Agriculture.

[44]Generally, under the miscellaneous receipts statute, money an agency receives for the government from a source outside of the agency must be deposited into the Treasury. 31 U.S.C. § 3302. However, BLM "may establish reasonable filing and service fees and reasonable charges, and commissions with respect to applications and other documents relating to the public lands and may change and abolish such fees, charges, and commissions." 43 U.S.C. § 1734(a). All such fees "for processing, recording, or documenting authorizations to use . . . public land natural resources (including . . . mineral) and for providing specific services to public land users, and which are not presently being covered into any [BLM] appropriation accounts, and not otherwise dedicated by law for a specific distribution, shall be made immediately available for program operations in this account and remain available until expended." *Id*. § 1734a.

users.[45] Further, according to Office of Management and Budget guidance, it may be appropriate for an agency to request authority to retain the fee revenue if the user fees offset the expenses of a service that is intended to be self-sustaining.[46]

The volume of drilling applications and inactive wells provide an opportunity to fund reclamation costs. According to BLM data, the agency processes more than 3,500 applications to drill each year, on average, and has over 14,000 inactive wells. Based on our calculations, a separate fee of about $1,300 charged at the time a drilling application is submitted (in addition to the current drilling application filing fee, which is $10,050), or an annual fee of less than $350 for inactive wells could generate enough revenue to cover, in a little over a decade, the entire $46 million potential reclamation costs field offices identified to us.[47] In commenting on a draft of this report, BLM stated that it does not have the authority to seek or collect fees from lease operators to reclaim orphaned wells. Developing a mechanism to obtain funds from operators to cover the costs of reclamation, consistent with EPAct 2005, could help ensure that BLM can completely and timely reclaim wells without using taxpayer dollars.

Other federal programs, including other BLM programs, collect fees from users to fund reclamation activities. For example, the federal government collects fees from mining companies to reclaim abandoned mines. Specifically, the federal abandoned mine reclamation program is funded in part by fees on coal production. We reported in March 2018 that the

[45]In May 2008, we issued a user fee design guide that examined how the four key design and implementation characteristics—how fees are set, collected, used, and reviewed—may affect the economic efficiency, equity, revenue adequacy, and administrative burden of the fees. GAO, *Federal User Fees: A Design Guide*, GAO-08-386SP (Washington, D.C.: May 2008).

[46]According to Office of Management and Budget Circular A-25, every 2 years, agencies should review programs that are not currently funded by user fees to determine whether fees should in fact be assessed for government services. Once user fees are implemented, revenue from the fees will be credited to the general fund of the U.S. Treasury as miscellaneous receipts unless otherwise specified by law. (See: Office of Management and Budget, Circular No. A-25 Revised, Memorandum for Heads of Executive Departments and Establishments (July 8, 1993).

[47]To arrive at these example fees, we divided the $46 million in potential reclamation costs by 10 and divided the result by the number of drilling permits and inactive wells, respectively, in 2018.

program had spent about $3.9 billion to reclaim abandoned mine lands since the program's creation in 1977.[48]

Additionally, some states with oil and gas development have dedicated funds for reclaiming orphaned wells. In Wyoming, the state's Oil and Gas Conservation Commission's Orphan Well Program reclaims orphaned wells on state or private lands for which bonds and operator liability are unavailable or insufficient to fund reclamation. The program is funded through a conservation tax assessed on the sale of oil and natural gas produced in Wyoming. Through this program, the Wyoming Oil and Gas Conservation Commission has reclaimed approximately 2,215 wells since 2014, according to a Commission official. Similarly, in Arkansas, operators make annual payments to its abandoned well plugging fund based on the number of wells and permits they have, on a sliding scale. For example, at the low end, operators with one to five wells or permits pay $100 per well, and at the high end, operators with over 300 wells or permits pay $4,000 per operator.[49] The Arkansas fund was used to reclaim 136 wells in fiscal years 2016 through 2018, according to an official with the state's Oil and Gas Commission. Virginia's Orphaned Well Fund is funded through a $200 surcharge on each permit application. The fund is administered by the Virginia Division of Gas and Oil, which prioritizes wells to reclaim according to their condition and potential threat to public safety and the environment.

Conclusions

BLM oversees private entities operating thousands of oil and gas wells on leased federal lands and has taken steps over the years to strengthen its management of the potential liability that oil and gas operations represent should operators not fully reclaim wells and return lands to their original condition when production ceases. For example, the agency's 2013 bond adequacy review policy outlined how bonds were to be reviewed every 5 years and bond amounts adjusted depending on risks presented by operators. However, we found average bond values were slightly lower in 2018 as compared to 2008 and BLM has not obtained bond increases for the majority of instances in which its reviews identify that increases are

[48]GAO, *Coal Mine Reclamation: Federal and State Agencies Face Challenges in Managing Billions in Financial Assurances*, GAO-18-305 (Washington, D.C.: Mar. 6, 2018).

[49]According to an Arkansas Oil and Gas Commission official, the state also makes transfers from other agency sources and deposits forfeited bonds into the abandoned well plugging fund.

needed. Instead, most bonds are at their regulatory minimum values, which are not sufficient to cover reclamation costs incurred by BLM. Without adjusting bond levels to more closely reflect expected reclamation costs—such as by considering the effects of inflation, the number of wells covered by a single bond, and the characteristics of those wells—BLM faces ongoing risks that not all wells will be completely and timely reclaimed, resulting in additional orphaned wells.

Further, BLM faces a backlog of orphaned wells to reclaim—with 51 dating back at least 10 years. Unlike some other federal and state programs that obtain funds from industry through fees or dedicated funds, BLM does not do so for reclaiming orphaned wells. According to BLM, it does not have the authority to seek or collect fees from lease operators to reclaim orphaned wells. Authorizing and requiring the implementation of a mechanism to obtain funds from oil and gas operators to cover the costs of reclamation could help ensure BLM can completely and timely reclaim wells.

Matter for Congressional Consideration

Congress should consider giving BLM the authority to obtain funds from operators to reclaim orphaned wells, and requiring BLM to implement a mechanism to obtain sufficient funds from operators for reclaiming orphaned wells. (Matter for Consideration 1)

Recommendation for Executive Action

The Director of BLM should take steps to adjust bond levels to more closely reflect expected reclamation costs, such as by increasing regulatory minimums to reflect inflation and incorporating consideration of the number of wells on each bond and their characteristics. (Recommendation 1)

Agency Comments and Our Evaluation

We provided a draft of this product to BLM for comment. In its written comments, reproduced in appendix II, BLM concurred with the recommendation. BLM stated that it is committed to ensuring that its field offices continue to review oil and gas bonds at least every 5 years, or earlier when warranted, and noted its November 2018 Instruction Memorandum 2019-014 updated its bond review policy. BLM further stated that, while the adjustment of bond values may not reflect the inflation index, the policy is intended to increase bond amounts while fostering an environment conducive to BLM's leasing operations. As we

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point out in this report, BLM has historically had difficulties securing bond increases through bond reviews, and so additional steps may be needed to adjust bond levels to more closely reflect expected reclamation costs.

In the draft we provided to BLM for comment, we included a recommendation that the Director of BLM should take steps to obtain funds from operators for reclaiming orphaned wells. BLM did not concur with this recommendation, saying it does not have the authority to seek or collect fees from lease operators to reclaim orphaned wells. We continue to believe a mechanism for BLM to obtain funds from oil and gas operators to cover the costs of reclamation for orphaned wells could help ensure BLM can completely and timely reclaim these wells, some of which have been orphaned for at least 10 years. We have therefore instead made a matter for Congressional consideration.

BLM also provided technical comments, which we incorporated as appropriate.

We are sending copies of this report to the appropriate congressional committees, the Secretary of the Interior, and other interested parties. In addition, the report is available at no charge on the GAO website at http://www.gao.gov.

If you or your staff have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix III.



Frank Rusco
Director,
Natural Resources and Environment

Appendix I: Objectives, Scope, and Methodology

This report (1) describes the value of bonds for oil and gas wells in 2018 compared to 2008, and (2) examines the extent to which the Bureau of Land Management's (BLM) bonds ensure complete and timely reclamation and thus prevent orphaned wells.

To describe the value of bonds for oil and gas wells in 2018 compared to 2008, we analyzed oil and gas well data from BLM's Automated Fluid Minerals Support System (AFMSS) as of May 2018 and data from BLM's Legacy Rehost 2000 (LR2000) system on bonds as of May 2018. Bond data we reviewed included the bond category (e.g., individual lease or nationwide) and bond value. We compared these data to data obtained from the same systems for 2008 and reported by GAO in 2010.[1] We matched the May 2018 data from the two systems based on the bond number—a variable in both systems—to identify how many wells were covered by each bond and to determine the average bond value per well for each bond category. To assess the reliability of AFMSS and LR2000 data elements, we reviewed agency documents, met with relevant agency officials, and performed electronic testing. We found these data to be sufficiently reliable for our purposes. We also interviewed BLM headquarters officials to understand why bond composition may have changed over time. To report on the number of bonded wells held by BLM, we used a published BLM value for producible well bores—wells capable of production—which should represent a lower bound on the number of bonded wells in September 2018 because some wells may be plugged or temporarily incapable of production but would still require a bond if the surrounding site had not been fully reclaimed. To determine the average value of bonds per well in 2018, we divided the total value of all bonds held by BLM by the total number of producible well bores.

To examine the extent to which BLM's bonds ensure complete and timely reclamation and prevent orphaned wells, we conducted the following analyses:

- Reclamation cost scenarios: To determine whether bonds are sufficient to cover potential reclamation costs for the wells they cover, we identified typical high- and low-cost scenarios for well reclamation (including plugging the well and reclaiming the surrounding well site) and compared those scenarios to the average bond value available per well. To determine high- and low-cost reclamation scenarios, we

[1]GAO, *Oil and Gas Bonds: Bonding Requirements and BLM Expenditures to Reclaim Orphaned Wells*, GAO-10-245 (Washington, D.C.: Jan. 27, 2010).

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analyzed BLM's well reclamation cost estimates on proofs of claim submitted to the Department of Justice from calendar year 2016 through May 2018.[2] These 59 proofs of claim listed estimated reclamation costs for 8,664 well sites. We calculated the average reclamation cost per well for each individual proof of claim by dividing the total dollar value claimed for reclamation liability (actual liability plus potential liability) by the total number of wells listed in each proof of claim document. We found the average reclamation cost estimates for each proof of claim have a bimodal distribution, meaning that data are clustered around two distinct cost levels, rather than clustered around a single average cost. As a result, we determined that using two separate measures that indicate typical values for separate groups of low-cost and high-cost wells would provide more meaningful statistics about cost. We therefore selected reclamation costs of $20,000 for the low-cost reclamation scenario and $145,000 for the high-cost scenario based on the 25th and 75th percentiles of the distribution of average estimated reclamation cost per proof of claim, weighted by the number of wells on each proof of claim.

- Bond value per well: To determine the average bond value available per well, we analyzed bonds listed in LR2000 that were tied to wells listed in AFMSS using the bond number—a variable in both systems. We found that 1,547 out of the 3,357 unique bond numbers in LR2000 had wells tied to them in AFMSS. These 1,547 bonds covered about 80 percent of the wells in AFMSS.[3] The other 20 percent of wells in AFMSS either did not list a bond number, or the bond number listed was not in LR2000. For each bond in LR2000 covering wells in AFMSS, we calculated the bond available per well as the bond value divided by the number of wells it covers. We then compared the bond values per well against both high ($145,000 per well) and low ($20,000 per well) reclamation cost scenarios to identify which bonds would be adequate to reclaim all the wells they covered under different cost scenarios. If AFMSS bond information was incomplete, it is possible that there are more wells covered by bonds than we were able to identify—and therefore the bond value per well would be lower than we found.

[2]These estimates come from proofs of claim that BLM submits when an operator files for bankruptcy.

[3]In this report we refer to the wells that the bonds were tied to as the wells the bonds covered.

- At-risk wells: To identify wells that may be at greater risk of becoming orphaned and determine whether their bonds are sufficient to cover potential reclamation costs, we used well production data from the Office of Natural Resources Revenue's Oil and Gas Operations Report (OGOR) as of June 2017 and bond values from LR2000. First, we defined wells as "at risk of becoming orphaned" if they met several criteria. Specifically, we identified wells that (1) had recent OGOR reports (on or after March 2017); (2) had not been used productively from at least June 2008 through the most recent record (meaning the well did not report producing any volume of oil or gas during this timeframe, nor were any volume of water or materials injected into the well during this timeframe); (3) were not being used as a monitoring well in the most recent record, which we considered a productive use; and (4) had not been plugged and abandoned. We selected June 2008 as the cutoff date for productivity because in June and July of 2008, oil and gas prices hit peaks that have not since been reached again, and which the Energy Information Administration does not expect prices to reach again through at least 2050.[4] We believe our analysis is a conservative estimate of wells at greater risk, in part because we did not include wells that produced when prices were at their peaks and stopped producing soon afterward and may be unlikely to produce in the future unless prices reach the same peaks again. In addition, our lower-bound estimate does not include some coalbed methane wells that have been inactive for less than 9 years but are unlikely to produce at current prices because of the relatively higher cost of coalbed methane production. We also excluded wells that reported any volume of oil or gas production or water injection since June 2008, although some very low-producing wells may also be at risk of becoming orphaned.
- Bond value for at-risk wells: To calculate the average bond value per at-risk well, we identified bonds listed in LR2000 that were tied to at-risk wells in AFMSS to determine the value of bonds available to reclaim these at-risk wells if needed. We identified 2,041 of the 2,294 at-risk wells were linked to bonds. For each bond, we divided the bond value by the number of at-risk wells it covered to determine the bond amount per at-risk well. In cases in which an at-risk well was linked to more than one bond, we additionally calculated the average

[4]According to the Energy Information Administration, the weekly spot price for West Texas Intermediate oil at Cushing, OK was $142.52 per barrel the first week of July 2008. As of the first week of May 2019 the price was $62.90 per barrel. Similarly, Energy Information Administration reported the Henry Hub weekly spot price for natural gas was $13.20 per million British thermal units the first week of July 2008. It was $2.59 per million British thermal units the first week of May 2019.

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of the bond value per at-risk well for each bond linked to the well. To determine the sufficiency of bonds for at-risk wells, we identified the number of wells with an average bond value per at-risk well equal to or greater than $20,000 (low cost reclamation scenario) or $145,000 (high cost reclamation scenario).

- Orphaned wells: We compared three lists of orphaned wells based on data provided by BLM in 2009, July 2017, and April 2019. The 2009 data are from our January 2010 report, which used Orphaned Well Scoring Checklists that list information such as the well's name and location.[5] The July 2017 data are from our May 2018 report, which used an orphaned well list generated through a query of AFMSS by BLM.[6] The April 2019 list was generated through a query of an updated version of AFMSS known as AFMSS 2.[7] We compared the lists to identify how many wells that were on the 2009 list remained on the 2019 list, and how many wells that were on the 2017 list were on the 2019 list.

To assess the reliability of the AFMSS, LR2000, and OGOR data elements we used, we reviewed agency documents, met with relevant agency officials, and performed electronic testing. We found these data elements to be sufficiently reliable for our purposes. Similarly, to assess the reliability of the 2019 orphaned well list, we reviewed agency documents and met with relevant agency officials. Though we identified shortcomings with data on orphaned wells, we nevertheless found these data to be sufficiently reliable for the purpose of describing the orphaned wells BLM has identified. To assess the reasonableness of proofs of claim data, we interviewed relevant agency officials and reviewed agency documents.

To understand how BLM manages bonds, we reviewed BLM's policies and interviewed officials from four BLM state offices and four BLM field offices. We selected these state and field offices because, according to AFMSS data, they were responsible for managing the largest numbers of wells on federal land. These BLM state offices were California, New

[5]GAO-10-245

[6]GAO, *Oil and Gas Wells: Bureau of Land Management Needs to Improve Its Data and Oversight of Its Potential Liabilities*, GAO-18-250 (Washington, D.C.: May 16, 2018).

[7]BLM headquarters officials told us that some of the wells on the list may no longer be orphaned, based on their well status. However, according to officials in one field office, at least some wells in those statuses are still orphaned. As a result, we included all the wells identified in AFMSS as orphaned in our analysis.

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Mexico, Utah, and Wyoming. These BLM field offices were Bakersfield, Buffalo, Carlsbad, and Farmington. We also interviewed officials from BLM's headquarters office in Washington, D.C. Findings from the selected BLM offices cannot be generalized to officials we did not interview but provide a range of views. To understand how some states with oil and gas development on state lands set minimum bonds and fund orphaned well reclamation, we contacted officials from oil and gas oversight agencies in Arkansas, Louisiana, Pennsylvania, Texas, Virginia, and Wyoming.[8]

We conducted this performance audit from January 2018 to September 2019 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

[8]The state agencies we contacted are the Arkansas Oil and Gas Commission; the Louisiana Office of Conservation; the Pennsylvania Department of Environmental Protection; the Texas Railroad Commission; the Virginia Department of Mines, Minerals, and Energy; and the Wyoming Oil and Gas Conservation Commission.

Appendix II: Comments from the Department of the Interior

United States Department of the Interior
BUREAU OF LAND MANAGEMENT
Washington, D.C. 20240
http://www.blm.gov

AUG 30 2019

Mr. Frank Rusco
Director, Natural Resources and Environment
U.S. Government Accountability Office
441 G Street, NW
Washington, DC 20548

Dear Mr. Rusco:

Thank you for providing the Department of the Interior (Department) the opportunity to review and comment on the draft Government Accountability Office (GAO) report entitled, *Oil and Gas: Bureau of Land Management Should Address Risks from Insufficient Bonds to Reclaim Wells* (GAO-19-615). We appreciate GAO's review of the bonds that operators, operating rights owners, or lessees submit to BLM to ensure compliance with the Mineral Leasing Act (30 U.S.C. §§ 181 *et seq.*), including complete and timely plugging of the oil and gas wells and reclamation of the lease(s).

The GAO issued BLM two recommendations to address its findings. Below is BLM's response to GAO's recommendations.

Recommendation 1: The Director of BLM should take steps to adjust bond levels to more closely reflect expected reclamation costs, such as by increasing regulatory minimums to reflect inflation and incorporating consideration for the number of wells on each bond and their characteristics.

Response: Concur. The BLM recently updated its bonding program policy by issuing Instruction Memorandum 2019-014. The BLM is committed to ensuring that its field offices continue to review oil and gas bonds at least every five years, or earlier when warranted. The updated policy requires BLM to review oil and gas bonds to determine whether the bond amount appropriately reflects the level of potential risk(s) (liability) posed by the operators along with their positive compliance history. While the adjustment of bond levels may not reflect the inflation index, it is intended to increase bond amounts while fostering an environment conducive to BLM's leasing operations.

Recommendation 2: The Director of BLM should take steps to develop a mechanism to obtain funds from operators for reclaiming orphaned wells and if needed, request additional authority from Congress for such a mechanism.

Response: Do Not Concur. The BLM does not have the authority to seek or collect fees from lease operators to reclaim orphaned wells. To the extent Congress decides

to authorize this activity as in Section 349 of the Energy Policy Act of 2005, it is within Congress' purview.

The enclosure contains comments for your consideration when finalizing the report.

If you have any questions about this response, please contact Corey Grant, Acting Chief, Division for Evaluations and Management Services, at (202) 912-7040 or LaVanna Stevenson, Audit Liaison Officer, at (202) 912-7077.

Sincerely,

Joseph R. Balash
Assistant Secretary
Land and Minerals Management

Enclosure

Appendix III: GAO Contact and Staff Acknowledgments

GAO Contact

Frank Rusco at (202) 512-3841 or ruscof@gao.gov

Staff Acknowledgments

In addition to the contact named above, Quindi Franco (Assistant Director), Marietta Mayfield Revesz (Analyst-in-Charge), Marie Bancroft, William Gerard, Cindy Gilbert, Gwen Kirby, Joe Maher, Shaundra Patterson, Dan Royer, and Jerry Sandau made key contributions to this report.

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EXHIBIT 22

STATE LEASES AND STATE WELLS IN TOP TEN PRODUCING COUNTIES IN NEW MEXICO

	County	# State Leases	# State wells	Avg wells/ lease	# State wells on Fee surf	acres	Oil Production (BBLs)	Natural Gas Production (MCF)	Regional Basin
1	**Lea**	2485	6357	2.56	974	710,896	30,299,006	123,022,789	Permian Basin
2	**Eddy**	1692	4065	2.4	1059	420,090	30,273,809	153,220,678	Permian Basin
3	**San Juan**	703	970	1.38	81	107,677	638,839	22,937,071	San Juan Basin
4	**Rio Arriba**	120	519	4.325	5	45,147	163,798	20,960,996	San Juan Basin
5	**Sandoval**	21	26	1.23	0	8,573	145,470	641,782	San Juan Basin
6	**Chaves**	301	610	2.026	68	99,089	99,850	607,409	Permian Basin
7	**Roosevelt**	34	129	3.79	5	9,092	29,435	57,204	Permian Basin
8	**Harding**	227	121	0.533	43	189,482	0	2,164,214	Bravo Dome
9	**Union**	94	51	.0532	8	79,510	0	1,932,074	Bravo Dome
10	**Colfax**	0					0	879,395	Raton Basin

Numbers of active oil and gas leases by county obtained from ONGARD, SLO Reports, "Active Lease by County," http://web.slo.state.nm.us/Applications/NewActiveLease/SearchByCounty.aspx (last accessed May 22, 2026); Numbers of active wells, all types, obtained from Oil Conservation Division Permitting, Well Search, https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/Data/Wells.aspx (last access May 22, 2026); Production by county reported by New Mexico Tech, Petroleum Recovery Research Center, Go-Tech Website, https://octane.nmt.edu/gotech/Petroleum_Data/allwells.aspx (last accessed May 2, 2026).

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County: Lea
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*	Grantor	Grantee	Document Type	Document ID	File Date	Instrument Date	Plat Volume	Survey	Section	Township	Range	Quarter	Half	Acreage	Book	Type	Volume	Page	Ref Volume	Ref Page	Consideration	Pages
☐	RICHARD STEPHANIE GARCIA	PERMIAN RADIATOR AND SUPPLY LLC	CLERKS TRANSCRIPT OF JUDMENT	007143	6/10/2021	03/23/2021									OPR		2181	672			9094.36	2
	STATE OF NEW MEXICO																					
☐	COMMISSIONER OF PUBLIC LANDS	PERMIAN RADIATOR AND SUPPLY LLC	CLERKS TRANSCRIPT OF JUDGMENT	007143	6/10/2021	03/16/2021									OPR		2181	672			9141.76	2
	KOLUNCICH NICHOLAS ATTORNEY	PERMIAN RADIOTOR AND SUPPLY LLC																				
	RICHARD STEPHANIE GARCIA																					
	STATE OF NEW MEXICO																					
☐	NEW MEXICO COMMISSIONER OF PUBLIC LANDS	ENLINK PERMIAN II LLC	BUSINESS LEASE	015488	12/17/2021	12/02/2021			22	24S	33E	NENW		3.2900	OPR		2189	970				8
	RICHARD STEPHANIE GARCIA								22	24S	33E	NWNW		1.7100								
☐	COMMISSIONER OF PUBLIC LANDS	EOG RESOURCES INC	CERTIFICATE OF APPROVAL	019032	3/16/2022	01/10/2022			25	24S	33E		E2	320.0000	OPR		2193	505				10
	RICHARD STEPHANIE GARCIA	LLOYD ERIN							24	24S	33E	SESE		240.0000								
									24	24S	33E	N2SE		240.0000								
									24	24S	33E	SWSE		80.0000								
									25	24S	33E		E2									
							Too many to display see instr for details.															
☐	RICHARD STEPHANIE GARICA	PERMIAN RADIATOR AND SUPPLY LLC	AMENDED RELEASE OF CLERKS TRANSCRIPT OF JUDGMENT	26291	9/12/2022	08/10/2022									OPR		2200	742	2181	672		1
☐	BIERNOFF ARI ATTORNEY	MMCP EQUIPMENT L P	CLERKS TRANSCRIPT OF JUDGMENT	059609	12/23/2024	2024-09-24									OPR		02234	0023			$3,150.00	2
	GENERAL LAND OFFICE	MMCP LEASING L P																				
	RICHARD STEPHANIE GARCIA	SMITH & MARRS INC																				
	STATE OF NEW MEXICO																					
☐	NEW MEXICO STATE LAND OFFICE	BARKSDALE ALAN	CLERKS TRANSCRIPT OF JUDGMENT	059608	12/23/2024	2024-09-17									OPR		02234	0022			$5,142,151.00	2
	RICHARD STEPHANIE GARCIA	CROSS BORDER RESOURCES INC																				
	STATE OF NEW MEXICO	NORTHERN PACIFIC OIL AND GAS INC																				
☐	BIEMOFF ARI ATTORNEY	FEATHERSTONE DEVELOPMENT CORPORATION	CLERKS TRANSCRIPT OF JUDGMENT	010560	8/28/2025	2025-08-06									OPR		02244	0700			$60,000.00	
	COMMISSIONER OF PUBLIC LANDS	NEW MEXICO DOMESTIC																				

		CORPORATION																		
	RICHARD STEPHANIE GARCIA																			
	STATE OF NEW MEXICO																			

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☐	BIERNOFF ARI ATTORNEY	MMCP EQUIPMENT L P	CLERKS TRANSCRIPT OF JUDGEMENT	056392	10/17/2024	2024-09-10		OPR	02230	0798	$7,492,229.85	2
	NEW MEXICO STATE LAND OFFICE	MMCP LEASING L P										
	STATE OF NEW MEXICO	SMITH & MARRS INC										
☐	BIERNOFF ARI ATTORNEY	MMCP EQUIPMENT L P	CLERKS TRANSCRIPT OF JUDGMENT	059609	12/23/2024	2024-09-24		OPR	02234	0023	$3,150.00	2
	GENERAL LAND OFFICE	MMCP LEASING L P										
	RICHARD STEPHANIE GARCIA	SMITH & MARRS INC										
	STATE OF NEW MEXICO											

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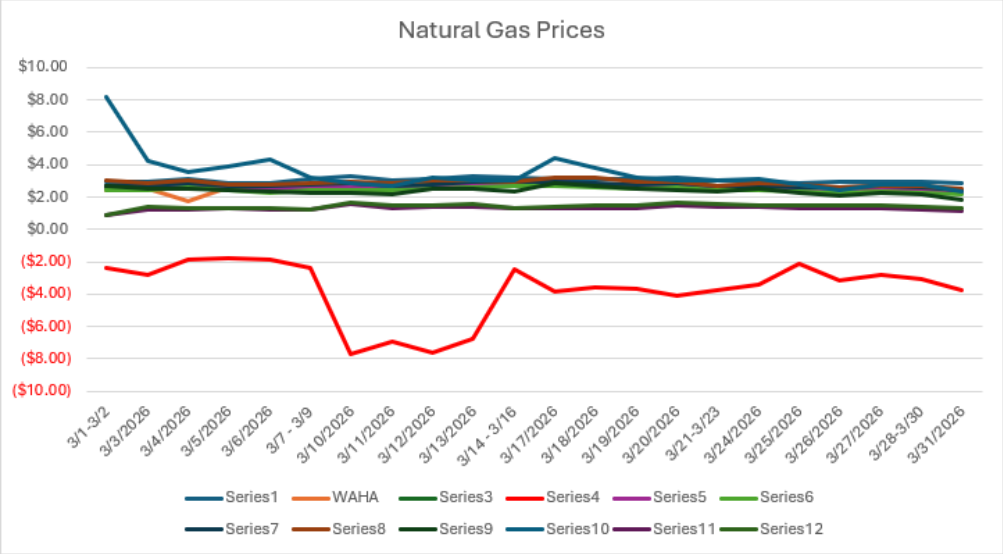
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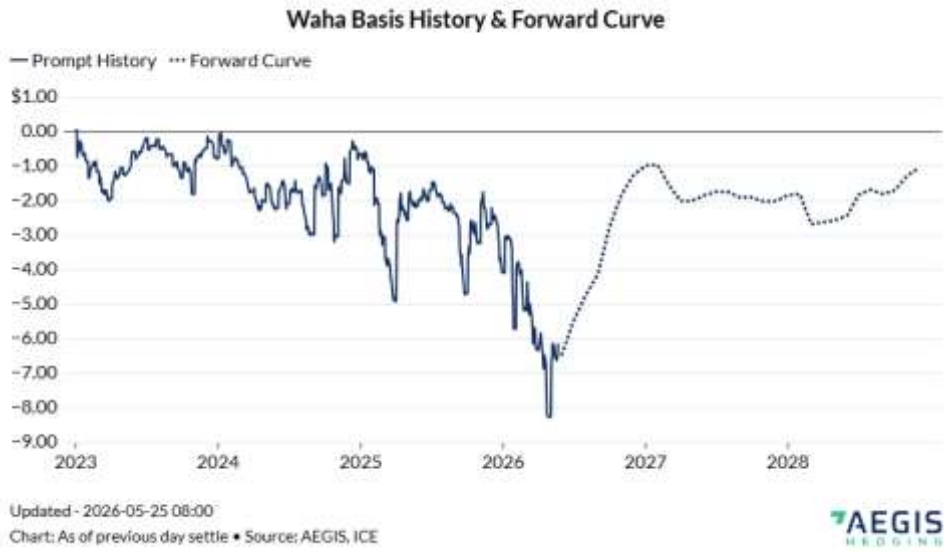
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EXHIBIT 24

WAHA HUB NATURAL GAS PRICING



Provided by IPANM member



From Jay Stevens, Permian Basin Gas Price and Fundamentals, Aegis Hedging (May 22, 2026) https://aegis-hedging.com/insights/basis-brief-waha-gas

Many IPANM members in west Texas and southeastern New Mexico sell gas through the Waha Natural Gas hub. While the Henry Hub price, located in Louisiana, may be the benchmark price for natural gas in the United States and the primary delivery point for NYMEX futures contracts, it represents a highly liquid, nationally significant market connected to extensive pipeline networks and major LNG export terminals.

EXHIBIT 24

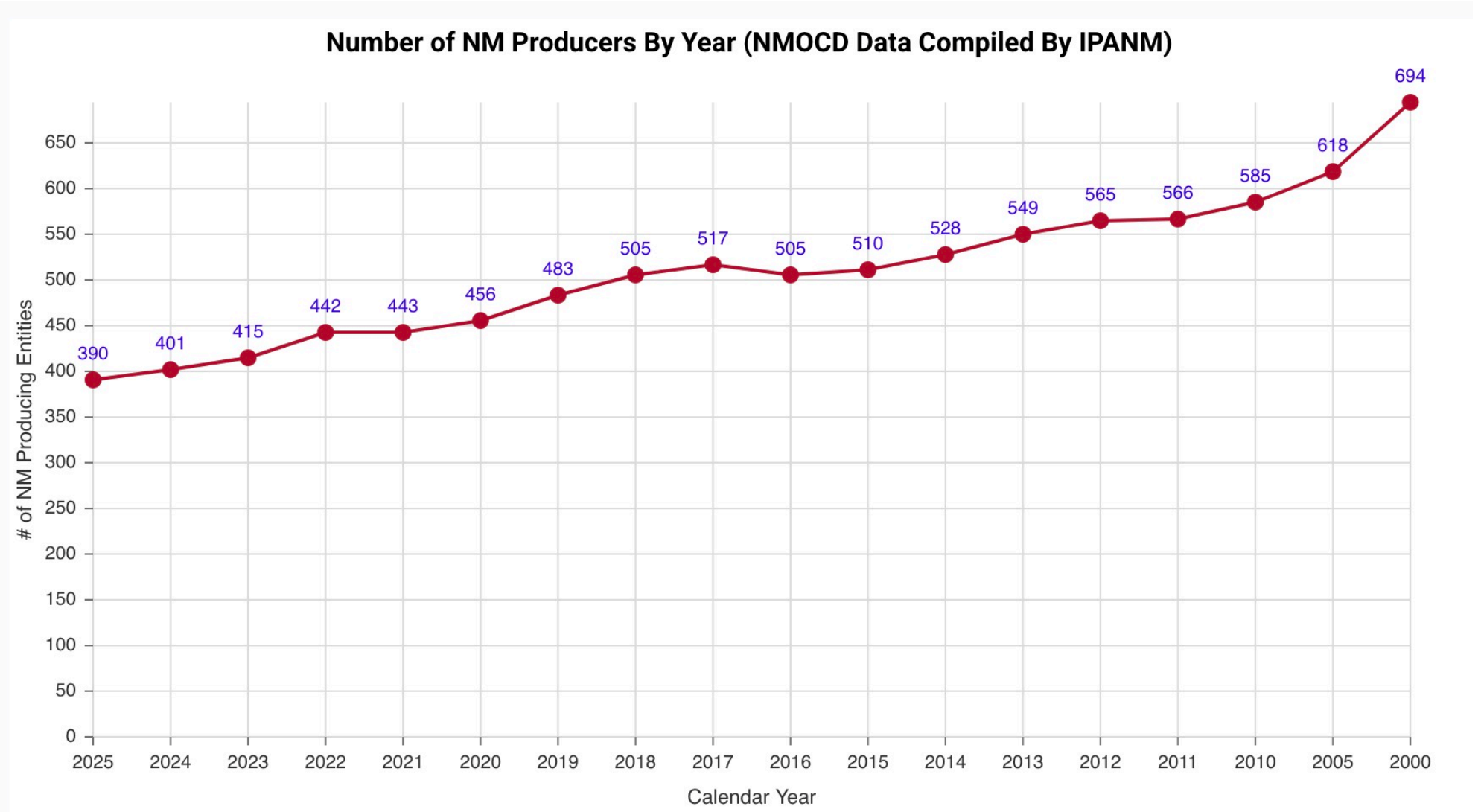
In contrast, the Waha Hub in West Texas, is located in the heart of the Permian Basin. This is a regional pricing point for natural gas produced alongside oil and from dry wells as well, but Waha prices are highly sensitive to local pipeline capacity (takeaway) and routine maintenance. The first graphs above shows 12 different major markets for natural gas all over the United States. Compared to other markets trading positive, the Waha natural gas price was negative for the entire month of March 2026. It has been negative every day in April 2026 and has been this way for nearly 2 years, with consistently and severely depressed pricing in 2024 and 2025. The second graph shows historical Waha prices from 2023 forward. Note the record low of -$9.50/MMBtu on April 16, 2026.

But the above prices do not reflect total cost to the producer: it costs another $1.50/mmbtu to $1.75/mmbtu on top of that to get the gas to market. For a producer with dry gas leases and wells, making no no oil or natural gas liquids, they are paying gathering companies every month just to move gas to market under current sustained low and now negative pricing. Even with statutory and regulatory exceptions designed to protect state trust beneficiaries, lessees continue to produce dry gas wells to maintain leases and hope that in the next 9 to 12 months, the pricing at WAHA improves.

EXHIBIT 25

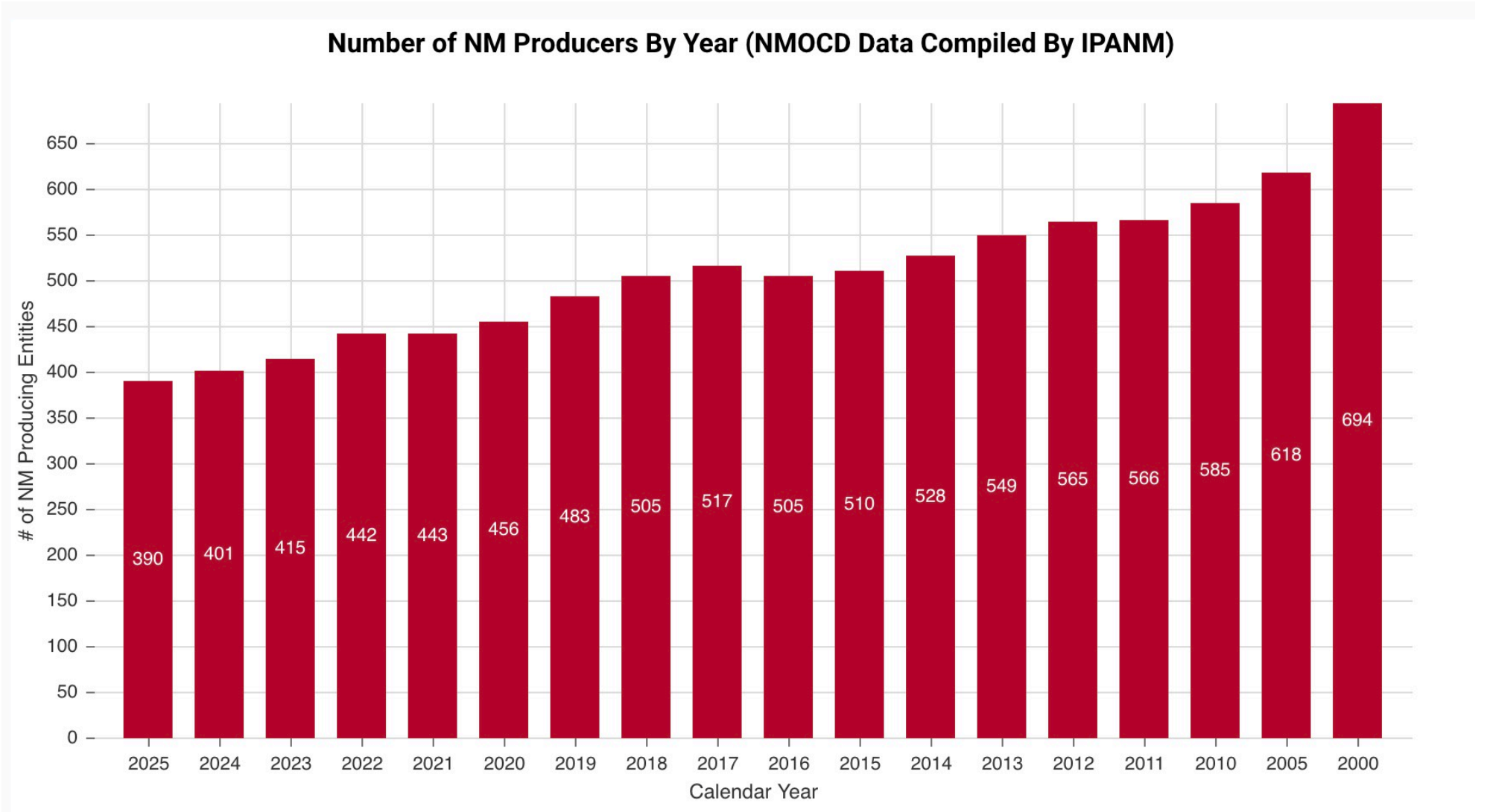
Calendar Year	# of OG Entities Reporting Production
2025	390
2024	401
2023	415
2022	442
2021	443
2020	456
2019	483
2018	505
2017	517
2016	505
2015	510
2014	528
2013	549
2012	565
2011	566
2010	585
2005	618
2000	694

EXHIBIT 25



IPANM000881

EXHIBIT 25



IPANM000882

EXHIBIT 26

STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

DIRECT TESTIMONY OF JAMES WINCHESTER

Intervenor Independent Petroleum Association of New Mexico submits the following technical testimony of James Winchester:

Q: Please introduce yourself to the Commission.

A: My name is James Winchester. I am the Executive Director of the Independent Petroleum Association of New Mexico which I will refer to as "IPANM."

Q: What is the purpose of your testimony to the Commission, Mr. Winchester?

A: IPANM solicited and got a lot of member comments about the rulemaking proposed by Western Environmental Law Center and others (which I will call the "WELC Proposal"). Different members commented on different parts of the rule. Most of our association's focus, and a lot of the testimony we are proposing, concerns the marginal well definitions and financial assurances. As to the other portions of the proposals, we thought it most efficient to concentrate comments from multiple members in one set of testimony and hope that this effort will assist the Commission in its work.

Q: So, you are not offering your personal comments?

A: I agree with and join in all the testimonial comments that I am making. I just wish to be clear that all the matters to which I am testifying were also raised by IPANM members who are the people who the proposed rules would actually affect if adopted.

These are not abstract comments by me alone. I also wish to point out that I will try to avoid testifying about matters which other IPANM witnesses are testifying about.

Q: How would we best proceed?

A: I propose going sequentially through the WELC Amended Proposal.

Q: What is your first comment about the WELC Proposal?

A: The proposal for amending Rule 19.15.8.9 is vague and very broad. It would not allow an operator to "proceed with any proposed…acquisition until the operator has furnished the required financial assurance." On one level, this may mean that an operator cannot do anything to acquire a marginal well, even if that well is bonded properly, until the prospective operator also bonds the well. Obviously, that is absurd and will not happen. No matter how you interpret that language, no rational operator is going to bond a well until after acquisition. This proposal seems to prohibit talks and negotiations over a well acquisition absent both the seller and prospective buyer(s) are bonded. If adopted and enforced, WELC's proposal will halt sales and purchases of New Mexico oil and gas wells. While IPANM agrees that an operator should not be authorized to conduct operations by the OCD until approved (which approval should include any bonding lawfully required), prohibiting "acquisition" or taking steps to acquire is unnecessary.

Q: What is your next comment?

A: The WELC Proposal suggests adding to Rule 19.15.5.9(A)(4) that for an operator to be in good standing, the operator needs to meet the waste prevention requirements of Sections 27 and 28 of the OCD Rules. Several IPANM members are concerned that a single waste prevention violation would result in revocation of an operator's ability to operate any of its wells. The basic understanding in the industry is that, unless you are

the OCD-approved operator, you cannot "put your hands" on anything associated with the well. Pulling the OCD-approved operator's authority would thus create wells where nobody can "put their hands" on the well which seems unnecessarily dangerous. It is also disproportionately punitive. As the Division emphasized repeatedly during the civil penalty rulemaking, the OCD has a number of what it called "tools" in its enforcement "toolbox." The Division should be given discretion to adjudge the severity of a waste prevention violation based on the facts and circumstance in that case. It is imprudent and punitive to impose an immediate, automatic termination of an operator's right to operate any well based on a single violation and without the process attendant to imposition of civil penalties.

Q: What is the next comment you have?

A: There were various concerns expressed with the WELC Proposal concerning change of operator rule 19.15.9.9(B), the new operator can meet those requirements, and the number of new requirements added that the OCD must evaluate. It is probably best if I break them up. First, WELC proposes some form of "certification…that the new operator is in compliance with the federal and state oil and gas laws and regulations in each state in which the new operator does business." WELC Revised Proposal, Ex. 1-D at 19.15.9.9.B. It is not clear what laws to which the proposed regulation is referring. For instance, my understanding is that federal royalty reporting requirements are quite detailed, especially for natural gas royalties. If an operator is out of compliance on certain federal royalty calculations with respect to production from a federal lease in Wyoming, is that operator now ineligible in New Mexico? More importantly, how is the Division to check this? What happens if an operator certifies that it is in compliance and it is later

discovered there was some minor existing violation in some other state? A comment that I will make a few times, is that I am not sure how the Division is supposed to devote manpower and resources to enforce this proposed provision. For operators, the provision is quite vague. For the Division, it is going to be very difficult to police.

Q: What is your next comment about the change of operator proposal?

A: Again, it is a policing comment like my last answer in that I am not sure how the Division has the personnel or expertise to review and determine the adequacy of "plugging and abandonment plan...in light of all the operator's assets and liabilities." and how the Division is supposed to arrive at that determination. I am not aware of the Division having any real experience in corporate finance issues. Additionally, if you follow the stock market news cursorily, it is obvious that the financial situation of any entite can change over time. . Assuming the Division obtains the internal expertise to evaluate these financial matters as proposed, the Division is just going to be evaluating those matters as of a date certain. Let me illustrate: the single, biggest offender in New Mexico history orphaning wells was a publicly traded company called Cano Petroleum that went bankrupt. The strength of Cano's financial situation at the time it became operator (which some OCD wells files indicate was in 2007) and when it obviously was not insolvent, is not relevant to these now-abandoned wells. In 2012, Cano filed for bankruptcy and abandoned its New Mexico wells some of which have been plugged by the OCD. Even if OCD has the staff and expertise to conduct such financial reviews, those reviews would do little to nothing to assure the State that the operator will have funds available in the future to plug and abandon.

Q: Do you have any other concerns you wish to express with the change of operator provisions?

A: Yes. WELC's proposal requires the "disclosure of any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25%," who was in the past five years in any of those positions with another operator that is "currently" or "is or was in the past five years" out of compliance with Rule 19.15.5.9(A). In addition to being highly problematic for Division enforcement, this provision is very difficult for operators to monitor and completely unfair.

Q: How do you mean unfair?

A: Well, for example, most of the independents are small shops with relatively few employees. In addition to owners, there may be a single landman who is the "director" or "officer" in charge of land issues. Assume a situation in which Ms. Landman works for Company X as its Vice President of Land, leaves for the same job but better pay at Company Y, and three years later, just before Company Y applies to be an operator in New Mexico, Company X went out of compliance with the spill rule. Under the proposal, Company Y is not eligible to be an operator in New Mexico despite the facts that (a) Ms. Landman did not work at Company X when it had its violation; and, (b) Company X's violation has nothing to do with the work Ms. Landman performed at either Company—it was an operational violation, not a Land Department issue. In addition to the enforcement and reporting difficulties attendant to this proposal, it is hard to see what purpose this serves. It will work substantial injustices on prospective operators or individual employees who could lose their jobs because of a former employer's current non-compliance. It is complete overkill and much more likely to visit injustices than promote

any interest that the Commission has in making sure that the new operators are good operators.

Q: If the Commission is inclined to do something in this area, do you have any suggestions?

A: I realize that there have been a few operators in the past with a very poor history of compliance with the important rules and policies of this Commission. The list of those folks is, I think, discrete. If the Commission wants to empower the Division to create a list of individuals, whether an operator or those who exercised significant control over an operator, that have had material, serial compliance issues and have prospective operators certify that those non-compliant individuals are not involved, that would reduce the administrative burden on both sides and better address the "shell company" concerns the Commission might perceive.

Q: Why are you sensitive to the enforcement practicalities of WELC's proposal?

A: I think it is telling that virtually all of WELC's proposal comes from parties that have little-to-zero understanding or experience on either side of the coin, be it government or industry. And I see this play out in multiple ways. First, I worked at EMNRD for four years and have spent the past eight years representing independent operators in New Mexico. I am empathetic to the challenges at OCD, especially after the Legislature took most of the Oil and Gas Conservation Tax, which was dedicated to enforcing the Oil and Gas Act, enhancing the Reclamation Fund, and funding OCD, and rolled it into the general fund. As New Mexico became the third-largest energy producing state, and second in oil production, funding and capacity at the Division level has not kept pace. In FY24, OCD was budgeted for 80 full time employees, but their July 2025 roster lists just 67 with 8

vacancies. Piling on labor-intensive reviews of annual certifications submitted by compliant operators, as proposed by WELC, expends already-precious resources—time and experience—in the wrong direction and in too many directions. Second, on the other end of WELC's proposal, increasing financial assurance on marginal wells does not put more money in the State's coffers to plug abandoned wells. At the recent Legislative Finance Committee meeting in June 2025, which I was present for, ENMRD's Deputy Secretary Ben Shelton admitted that OCD has "barely pursued financial assurance, and the answer is because the juice isn't worth the squeeze. [EMNRD] has three attorneys to process a hundred percent of the enforcements. It's not worth the juice; is not worth the squeeze….We don't collect enough to make it worth our while." LFC Transcript, 62:18-63:9. At last report, OCD went after just one bond in the past 8 years. Raising FA levels on individual wells will not save the State any money.

Q: What problems do you see with OCD-led plugging initiatives?

A: Even when OCD has accessible funds, like the $66 million sitting in the Reclamation Fund right now, the Division is not best suited to efficiently deploy that money to plug wells. Deputy Secretary Shelton explained in that same meeting in Taos with the Legislative Finance Committee that OCD only has 5 approved plugging contractors, all 5 are situated in the far Northwest corner of the state, yet the majority of wells are located in the Southeast. This leads to increased travel and stand-by costs (sometimes referred to as mobilization costs) and, as the LFC Report concluded, OCD "struggles to control both the cost and quality of state contracted plugging and remediation work." LFC Transcript, 9:22-10:1, which is found in IPANM Exhibit 28. With industry plugging over 90% of the wells, and being more efficient in doing so, it bears to reason that Reclamation

Funds should be available to responsible operators to best deploy, especially since the money in that fund originates with owners of oil and gas produced from existing wells. In fact, the recent report by the Legislative Finance Committee supports an industry-led approach, noting how inefficient OCD's well plugging program is in comparison and that "OCD struggles to control both the cost and quality of state-contracted plugging" under the current Statewide Price Agreement scheme. IPANM Ex. 27, LFC Report 24, 26-27. Based on member feedback, when an operator sought to establish a plugging-focused subsidiary to contract with OCD, leveraging their own decades of experience and knowledge, the inefficiency wrought by OCD's piecemealing services and materials was glaring. The "priority" list used by OCD ping-pongs crews across the state rather than invite bids on regional or location-oriented packages of wells that could be plugged faster and cheaper by operators. Invoices from 2023 plugging and reclamation contracts indicate OCD is paid an average of $153,000 per well that year, and the number increased again in 2024 to $163,000. The State is now under pressure to spend initial and follow-on federal sums awarded under the IIJA. But without including current operators in the effort, OCD will remain capacity-limited, endangering future awards.

Q: Do you know how much bonding the OCD is able to recover from financial assurances bonds?

A: Available evidence suggests that is slight or non-existent confirming Secretary Shelton's testimony that I just quoted. IPANM Exhibits 10 through 13 are the Division's annual reports concerning the Reclamation Fund for fiscal years 2020-2023. Combined, those four reports indicate that OCD used the Reclamation Fund to plug 108 wells. Each annual report has a line item for monies collected by the Reclamation Fund for "Bond

Forfeitures, Salvage and Reimbursement Recoveries" or a similar category that clearly includes any monies that may have been recovered from financial assurance bonds. Three of those four reports state that the Reclamation Fund received no revenues for that category. The 2022 Report which is IPANM Exhibit 12 reflects $161,250 of revenue for that category and it is not clear what, if any, of that sum is bond forfeitures as opposed to revenues from salvage or reimbursement. The LFC review also notes that even in circumstances where OCD pursues forfeiture, investigations, bankruptcies, and litigation frequently delay and diminish recovery, if any. Based on information available to me, I do not fault the OCD. Rather, the record of almost no recovery is likely a product of the proverbial "three D's" of the insurance industry—delay, deny, and defend.

Q: Did IPANM Members have other comments relative to plugging operations in New Mexico?

A: Yes, we heard from several of our members about how expensive and how difficult plugging a well in New Mexico is currently, without even considering the effects of WELC's proposal. What is interesting is that the plugging cost in New Mexico, which is nominally higher because of the requirement to plug each strata, does not appear to be the main driver of cost, nor the primary complaint. Our members are experiencing extended cement-curing requirements enforced by OCD without explanation, costly delays when OCD staff are unavailable, non-responsive, or inexperienced, and difficulty in meeting stringent and varying reclamation and remediation standards across state, federal, and fee lands often divorced from native or background soil levels. For instance, the reported average cost of OCD plugging in IPANM Exhibit 10 covering Fiscal Year 2020 was $31,600. The Applicants in this case are basing their request for individual well bonds at

what they claim is about OCD's current average at a figure about five times the 2020 average cost.

Q: Can you go into more detail why increasing the FA levels impacts smaller operators?

A: The surety market is not just tighter, or more difficult for small operators, it is unavailable. That means the only available method for a smaller operator to satisfy financial assurance is to obtain a cash bond or irrevocable letter of credit from a financial institution. For example, based on a discussion I had with one member, an increase from a blanket bond tying up $250,000 of operating capital, which was predictable and planned for, to an unpredictable $9,000,0000 bond on sixty wells is fatal to a company without access to the surety market. Even with a surety at the highest premium rates, operators of stripper wells are not likely to be able to service those bonds at $900,000 in annual premiums and simultaneously maintain operations of existing wells, which provide the income stream to service those bonds.

Q: Does IPANM have any other suggestions or revisions regarding WELC's proposal?

A: We would remind the Commission of its source of authority and the direction from the Legislature to protect correlative rights and prevent waste. IPANM has long been involved in the rulemaking proceedings following legislative revisions to the Oil and Gas Act. For example, the 2018 rulemaking followed explicit direction from the Legislature to the Commission to develop rules which increased financial assurance levels and the Legislature set a specific monetary cap in SB-189. Here, bipartisan bills on the plugging of abandoned wells and use of the Reclamation Fund have been proposed for two

consecutive legislative sessions and failed. Therefore, it is IPANM's position that the legislative mandate to act which existed previously in 2018, and which the Commission honorably performed under, is absent today and should proceed with caution.

JAMES WINCHESTER

EXHIBIT 26

I hereby affirm under the penalty of perjury of the laws of the State of New Mexico that the above statements are true and correct to the best of my knowledge, information, and belief.

DATE: 8-8-25

JAMES WINCHESTER

EXHIBIT 26

STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

REBUTTAL TESTIMONY OF JAMES WINCHESTER

Intervenor Independent Petroleum Association of New Mexico submits the following rebuttal testimony of James Winchester:

Q: Mr. Winchester, you submitted direct testimony in this rulemaking proceeding and introduced yourself in that testimony?

A: I did.

Q: What is the purpose of your rebuttal testimony?

A: I seek to make various points in my rebuttal testimony. I have broken my testimony down into sections and each section is a discrete area of my rebuttal testimony.

OCD Exhibit 17: OCD Master Orphan Spreadsheet

Q: What is the first area you want to testify?

A: I want to make some observations about OCD Exhibit 17 which is the OCD's Master Orphan Spreadsheet. That Exhibit lists 1,815 different wells which is a number that sometimes is used in this rulemaking as the number of orphan wells in New Mexico. In particular, I believe that there is information in that Exhibit which indicates that some of the wells should no longer be classified as orphan wells under any rational definition of that term and to observe that there are other wells listed that are not going to be affected

by this rulemaking and never would have been affected by State of New Mexico financial assurances requirements.

Q: Let's start with the orphan well issue. What definition of orphan well are you using?

A: A number of witnesses have testified that there is no standard definition of the term orphan well and there is none proposed in this rulemaking. I define an orphan well as a well that: (a) requires plugging, abandoning and/or legally required site reclamation work; (b) but the OCD approved operator of that well will not and/or cannot perform that work.

Q: Applying that definition, what is your concern about Exhibit 17?

A: In summary, Exhibit 17 includes wells for which all plugging, abandoning, and reclamation work has already been performed and approved by the Division. There are likely valid regulatory reasons why the OCD maintains an orphan well list that includes wells that have been plugged, abandoned, reclaimed, and released. However, as that list includes such wells, I think it is important to point out that while those wells <u>were</u> orphan wells, they <u>are</u> no longer orphan wells. Those wells now are in the category of wellbores in New Mexico that have been successfully plugged, abandoned, and the site reclaimed in accordance with regulations by the operator or the OCD and the OCD has satisfied itself that the work was properly performed. For that category of wells, there is no longer an operator, there is no bonding or financial assurance requirement, and this rulemaking, if adopted, would not impose any financial assurance requirements.

Q: How do you determine that?

A: The various columns in OCD Exhibit 17(which is a Microsoft Excel Spreadsheet) that have filters available in them. The relevant column to this part of my testimony is the

"Status" column (column C) that has various categories that include "Plugged, site released" and "Plugged, not released." I am not the author of this spreadsheet but considering those terms as they are commonly used, the phrase "Plugged, site released" signifies to me that all work to close the well has been performed and approved by the OCD. Spot checking a few well files confirmed this understanding.

Q: Before we talk about the number of wells that fall in those categories, please explain how you counted items in OCD Exhibit 17?

A: Each count was made by using the "sort" functionality for the "Status" column to check or select only category. Prior to making those selections, I made sure that under each column the "(Select all)" was checked under the column sort function. Prior to making any count, the spreadsheet contains 1,817 lines with the first two lines being part of the column headings so that there are 1,815 wells listed. I highlighted the well names in "Column 1" of the spreadsheet and used the count function in Microsoft Excel and when each well name was highlighted that function showed the same 1,815 number. I repeated the process of highlighting and counting in the "Status" column of Exhibit and again got the same 1,815 number. I did each count of Exhibit 17 content in the exact same manner except that I ceased using the "(Select All)" in the Status column and selected one of the status categories that I describe in my testimony below.

Q: How many "Plugged, site released" wells are listed on OCD Exhibit 17?

A: There are 317 of those wells listed on Exhibit 17 when the "Plugged, site released" is the only box checked in the Status column. As I stated earlier, I do not see any way that any of those 317 wells can be characterized as presently being an orphan well.

Q: Why did you look at the "Plugged, not released" category?

A: Again, as I am not the author of the spreadsheet and I did not see any explanatory testimony, I can only interpret this "status" as those words are commonly used in the industry. Based on that common usage, I understand that all these wells have been plugged. The terminology also suggests that the site on which the well is located has not been released by the OCD. I can see three reasons why there may not be such a release: (i) no reclamation work has been done on the site, (ii) reclamation work is in progress, and/or (iii) reclamation work has been completed but the OCD has not approved that work and released the site. Based on the "Plugged, site released" language discussed above, it seems to me that the third option is what this category, "Plugged, not released," encompasses. However, since there is not a status category that, at least in my reading, indicates that work is in progress, it may mean one or both the first two options. Thus, this designation indicates that at least the plugging work and perhaps all the work has been done on this site to move the well to "Plugged, site released" status once the Division inspects the well and finalizes the appropriate paperwork. Under my definition, these wells are close (and perhaps just lacking paperwork) to being former orphan wells.

Q: How many "Plugged, not released" wells are listed on OCD Exhibit 17?

A: After checking on the "Plugged, not released" box in the sort function of the Status column and the same counting methodology that I just described, there are 518 of these wells in Exhibit 17.

Q: What is the purpose of your testimony concerning Exhibit 17?

A: As I mentioned, I want it to be clear to the Commission that the entirety of Exhibit 17 does not identify the number of orphan wells that need to be addressed in New Mexico. That Exhibit includes at least 317 and perhaps as many as 835 wells where the work to

plug, abandon, and reclaim has been done and at least 317 that are basically in the same status as any well that was never on OCD's "Orphan Well List" for which the OCD has approved the former operator's work to plug, abandon, and reclaim a well.

Q: What other observations do you have regarding OCD Exhibit No. 17?

A: I believe that Exhibit 17 supports my Direct Testimony on page 6 in which I emphasized that a few companies that are well known to be out of compliance are the source of many of the issues which Applicants and the Division are expressing concern. As I testified, most operators are responsible and plug their uneconomic wells. Rounding to the nearest whole number, three-quarters of the wells listed on OCD Exhibit 17 are or were operated by ten operators as follows:

OPERATOR	# of Wells on Ex.17	% of Total
Cano Petro of New Mexico Inc.	329 wells	18.13%
Ridgeway Arizona Oil Corp	299 wells	16.47%
Canyon E&P Company	235 wells	12.95%
LLJ Ventures LLC DBA Marker Oil & Gas	149 wells	8.21%
Northern Pacific Oil and Gas Inc	83 wells	4.57%
Xeric Oil and Gas Corp	69 wells	3.8%
Marks and Garner Production Ltd Co	64 wells	3.53%
Remnant Oil Operating LLC	52 wells	2.87%
Energy Acumen LLC	50 wells	2.75%
Blue Sky NM Inc.	41 wells	2.26%
TOTAL	**1,371 wells**	**74.54%**

OCD EXHIBITS 21, 22, and 23

Q: What other exhibits did you analyze?

A: The OCD submitted three other lists of wells in Exhibits 21, 22 and 23 that for which there was little to no explanatory testimony from any of the OCD witnesses. I think it is obvious from the title of those Exhibits that Exhibit 21 is a list of wells that the OCD has classified as inactive as of August 8, 2025, but did not include wells that either were

classified as temporarily abandoned ("TA") or subject to an agreed compliance order ("ACOI"). Exhibit 22 adds the ACOI wells into the Exhibit 21 list and Exhibit 23 adds the TA wells to Exhibit 21 without including the ACOI wells. Many of the Exhibit 17 wells appear on each of the lists. As there is significant overlap between those three Exhibits, I will offer more detailed testimony about Exhibit 23 and, while the exact numbers of wells will vary somewhat between Exhibits 21 and 22, the observations in my testimony are the same except for relatively small variance in the exact numbers.

Q: How many wells on the Master Orphan Well List, Exhibit 17, appear on the Inactive Well List, Exhibit 23?

A: Converting the API numbers in OCD Exhibit 23 (which is a pdf) to text and running a comparison against the API numbers in Exhibit 17, there appear to be approximately 870 wells on both Exhibits. I say "approximately" because converting portions of a pdf document to text is not foolproof, so the exact number may differ somewhat. However, spot checking suggests that the 870 number is at least close.

Q: Any other observations for the Commission regarding those Exhibits?

A: Here are the ten operators with the most wells on OCD Exhibit 23 with a column calculating the extra bonding that would be required under this proposed rulemaking and another column ("Notes") with some information that is available regrading those operators from public sources including OCD Exhibit 17:

OPERATOR	**#Wells on Ex. 23**	**Extra Bond**	**Notes**
Ridgeway Arizona	287	$43,050,000	Subject to ACOI--OCD will P&A 304 wells and Ridgeway pays $2/bbl. sold, $30,000/month

			minimum.[1] 299 Wells on OCD Ex. 17 ten.
Acacia Operating	231	$34,650,000	One well on OCD Ex. 17
LLJ Ventures (Marker)	134	$20,100,000	149 wells on OCD Ex. 17.
LH Operating	131	$19,650,000	Acquired by EON Resources, Inc. 11/2023. Waterfloods planned.[2]
Dominion Production	124	$18,600,000	Three Agreed Compliance Orders with two regarding financial assurances violations.[3]
Cano Petro	118	$17,700,000	Filed bankruptcy in March 2012. Abandoned its NM wells. 329 wells on OCD Ex. 17. Order R-14795-A.[4]
Hilcorp Energy	102	$15,300,000	Active plugging and reworking programs. Not on OCD Ex.17
OLEUM Energy	92	$13,800,000	At least 2 wells on OCD Ex. 17
Empire NM LLC	80	$12,000,000	Not on OCD Ex. 17; $1M blanket TA Bond in place 8/3/2022 on all 80 TA wells.
Maverick Permian	76	$11,400,000	Not on OCD Ex.17; $1M blanket TA Bond in place 4/15/2024 on all 76 TA wells. ACOI-201959.[5]
Northern Pacific	65	$9,750,000	83 wells on OCD Ex. 17
Total	1440	$216,000,000	39.41% of Exhibit 23 Wells

I do not know all these companies. The publicly available information that I reviewed suggests that five of these ten operators (Ridgeway, LLJ, Dominion, Cano, and Northern) are unwilling or unable to plug, abandon, and reclaim those wells let alone post the extra bonding that Applicants seek. At the other end of the process, the Annual Reclamation Fund reports entered by the WELC Applicants as exhibits,[6] in addition to the recently

[1] IPANM Ex. 46.
[2] https://www.morningstar.com/news/accesswire/1056003msn/eon-resources-inc-announces-funding-design-for-the-settlement-of-the-seller-agreement-and-debt-payoff-and-the-grayburg-jackson-field-development
[3] ACOI-266 (IPANM Ex. 47); ACOI-285 (IPANM Ex. 48); and ACOI-2016-312 (IPANM Ex. 49).
[4] IPANM Ex. 53.
[5] IPANM Ex. 52.
[6] *See* WELC Exhibits 17-21 (2019-2023 Reclamation Fund Reports); *see also* IPANM Exhibit 43 (2024 Reclamation Fund Report).

issued 2024 Reclamation Fund report, show that even the posted bonds are unreachable. As reported on July 1, 2025, OCD has again recovered $0.00 from Bond Forfeitures, making it five years out of the last seven with zero dollars from financial assurance bonds. *Id.* I know that one of the remaining five companies (Hilcorp) is an active company with a history of plugging and abandoning wells. Both Hilcorp and Maverick do not appear in the "Past Owner" or "Current Owner" columns in OCD Exhibit 17. Please note that "Extra Bond" column in my table is the number of wells in the table multiplied by $150,000 and does not factor in that one or more of these operators may operate wells that are not on the list which the rulemaking would require bonding if, for instance, the operator has more that 15% of its wells producing at "marginal well" levels. I cannot testify to the financial condition of any of those operators. However, we know that neither Ridgeway nor Cano will be posting any additional financial assurances on the 405 wells they operate. As to five of the remaining eight operators, I think any reasonable person would recognize that the publicly available information that I note suggests that there is some material risk (the degree of which varies between those five) that each might not be able to comply with the proposed, elevated financial assurance levels.

Q: How did you calculate the percentage at the end of the table you presented in the previous answer?

A: At the top of OCD Exhibit 23, the Exhibit indicates that there are 3,654 wells on the list. I assumed that number to be correct and used that as the denominator and the total wells in the "#Wells on Ex. 23" column of the table as the numerator to create the percentage.

Q: In that table, are you counting the wells the same way you did in Exhibit 17?

A: No. OCD Exhibit 23 is a PDF, and the well counts in my testimony were manually derived. While someone with the ability to analyze the document in its native format might identify minor discrepancies in my numbers, I exercised care in preparing them. Any such variance, if it exists, would not be material to my overall point: to the extent Exhibit 23 reflects wells at greater risk of becoming orphaned, that risk is concentrated among a small subset of New Mexico operators.

Q: Were there any other problem companies that you are thinking about in your Direct Testimony?

A: Yes, and they each appear on OCD Exhibits 21, 22, and 23. These are companies for which IPANM members have been approached by either BLM or the New Mexico State Land Office to plug, abandon and reclaim wells operated by that operator as the operator is unreachable or uncooperative. *See*, *e.g.*, Direct Testimony of Loren Diede, OCD Ex. 4, 2:1-4 ("forced plugging"). It also includes members of the "top 10" on OCD Ex. 17 who I did not identify as "top 10" on Ex. 23. Those operators and the number of wells assigned to each as listed in Exhibit 23 are:

Operator	**# of Ex. 23 wells**	**Extra Bond**	**Notes**
Northern Pacific	65 wells	$9,750,000	83 wells on OCD Ex. 17
Sellers & Fulton	36 wells	$5,400,000	36 wells on OCD Ex. 17
Canyon E&P Co.	36 wells	$5,400,000	235 wells on OCD Ex. 17
M&M Production	34 wells	$5,100,000	Owner plead guilty to federal fraud charges.[7] 9 wells on OCD Ex. 17.
CFM Oil	25 wells	$3,750,000	Two Stipulated Final Orders resolving no financial assurances: ACOI-344

[7] https://www.justice.gov/usao-nm/pr/us-attorneys-office-announces-sentencing-farmington-woman-oil-and-gas-fraud

			3/26/18; and ACOI-201946 1/27/22.[8] 2 wells on OCD Ex. 17.
Energy Acumen	20 wells	$3,000,000	50 wells on OCD Ex. 17.
G&G Operating	6 wells	$900,000	Filed Ch. 7 Bankruptcy 8/6/25 in Bankr. D.N.M. Case No. 25-10975-j7
Marks & Garner Prod. Ltd. Co.	4 wells	$600,000	64 wells on OCD Ex. 17
Blue Sky NM Inc.	1 well	$150,000	41 wells on OCD. Ex. 17
Total	227 wells	$34,050,000	6.21% of wells on Ex. 23

I organized the table above in the same manner as the "top ten" table concerning OCD Exhibit 23 earlier in my rebuttal testimony. Again, I do not have personal knowledge regarding the financial circumstances of any of these operators, but the information noted together with the fact that other regulators have sought to have IPANM members plug and abandon wells for many of these operators suggests substantial risk that these operators would not be able to respond or comply with additional financial assurance requirements.

Q: Any other comments regarding these OCD exhibits?

A: Yes, OCD Exhibits 17, 21, 22 and 23 also contain a number of wells that are subject to Federal or tribal jurisdiction and, therefore, outside the scope of this rulemaking proceeding. In Exhibit 17, there are functions to sort by Federal or tribal minerals and/or surface to try to identify these wells. In Exhibits 21, 22 and 23, that task is much more difficult. Some Federal wells can be identified by a word "Federal" or the abbreviation "Fed" in that well name. However, that is not the entire universe as there are many "Unit" wells indicating that the well is part of a unit and it is not always possible to determine

[8] IPANM Exhibits 50 & 51.

which unit wells are subject to BLM jurisdiction versus subject to State imposed financial assurances requirements.

Q: What is the purpose of you making this point?

A: Again, there are certainly going to be valid reasons why the regulator will include Federal or tribal wells on such lists. I point it out because it would not be correct to assume that the population of those lists are all subject to this rulemaking proceeding.

Lease Operating Expenses

Q: What is the next area you would like to comment on for the Commission?

A: Justin Wrinkle of the OCD offered testimony concerning a range of lease operating expenses. Breaking down his direct testimony visual aid, OCD Ex. 9, results in an estimate of $60,000 to $300,000 in projected monthly operating costs per marginal well. IPANM circulated that testimony and a summary of Mr. Wrinkle's costs to membership for comment and we received responses from seven different companies. All those responses indicate that, even if Mr. Wrinkle's testimony reflects his experience at Marathon, no member believed those costs were accurate for low producing wells. Please recall that various IPANM Members testified earlier about buying lower producing wells from big companies and being able to operate those wells more efficiently or at a lower cost right away.[9] Mr. Wrinkle's testimony does more to illuminate the big company cost structure than describe the costs incurred by smaller, lower cost operators.

Q: What did IPANM Members say about Mr. Wrinkle's testimony?

[9] Direct Testimony of Jeff Harvard at 2-9; Direct Testimony of Kyle Armstrong at 3:1 to 4:12; Direct Testimony of George Sharpe at 3.

A: On an overall basis, there were two common comments. First, as I noted, members thought that Mr. Wrinkle's testimony was not accurate as to costs of smaller operators but rather reflected his experience at a very large company that sells lower producing wells to more nimble and efficient small operators. Second, members completely rejected the notion that operating costs correlate with BOEs produced. On a specific cost items, members had a number of concerns.

Q: What was Members' largest concern?

A: The fact that while Mr. Wrinkle acknowledges some difference between capital expenditures ("CAPEX") and true lease operating expenditures ("OPEX"), he adds the two together as if they have some bearing on operating costs. OPEX and CAPEX are treated differently in the oil and gas industry in evaluating the economics of a producing well. While he states that certain costs "could be considered CAPEX," OCD Ex. 9, 4-5, and that "one-time costs can be categorized as Capital Expenditures," *See* Direct Testimony of Justin Wrinkle, OCD Ex. 7, 2:12-16, his testimony is not definitive, and he adds these costs as operating expenses on marginal wells.

Q: What capital expenditures are you referring to?

A: Our Members all reported that tanks, meters, piping, shut-off valves, SCADA and remote monitoring equipment, flare stacks, and infrastructure costs are all capital costs that are depreciated and rarely, if ever, show up in monthly joint interest billings for lease operating expenses. Instead, they are charged out in an authorization for expenditure which requires approval of a certain level of working interest owners and virtually always are expenses incurred at the beginning of the life of a well. Moreover, all our Membership's responses indicated that those costs are almost never incurred late in a

producing well's life so that it is extremely unlikely that any so-called "marginal well" would incur those categories of costs. These items are all installed at the time the well is being drilled, completed, and equipped. In instances, these items are installed or constructed after completion of a well and the determination that the well is productive so in a large company like Marathon may become the responsibility of the operating or production group and be overseen by lease operators like Mr. Wrinkle at the time. Members report that such CAPEX generally amortized over the first 5-years of production and segregated from ongoing, true operational expenses of the well. There might be some occasional repair that would need to occur, but none of those expenses identified by Mr. Wrinkle are recurring and almost never are incurred when a well is a low volume producer.

Q: Are there any other costs that your IPANM Membership identified as not occurring on low volume producing wells?

A: Yes. The vapor recovery unit costs that Mr. Wrinkle testified about. Members all, again, agreed that a prudent operator simply does not incur those costs on a well producing less than 1,000 BOE per year. Additionally, Mr. Wrinkle asserts that a monthly expense of $600-$2400 would be required for hot oil treatments. OCD Ex. 9 at 4. IPANM Membership unanimously disputes the rate and frequency as applied to marginal wells, which, by definition, operate at lower-production levels and hot oiling is almost entirely inapplicable to gas wells. At the most, members report hot oiling tanks on marginal wells once a year. Regarding installation of flare stacks, described above as a capital expenditure, marginal wells rarely produce enough gas consistently to spark an auto-ignite flare, entirely negating the purpose of installation. Another category of expense that members identified as extremely well and field dependent that it could not be

"averaged" into a marginal well economics is that of H2S mitigation, which is wholly dependent on well type and location. But in wells where H2S mitigation is required, at marginal levels the cost and level required is nominal. Also, membership generally observed that late life wells and stripper oil wells typically have no compression costs, an expense Mr. Wrinkle assesses at $400-$1600 per month. Furthermore, SCADA equipment or other remote monitoring equipment is never installed on low volume producing well in the first instance and are only present on such wells if installed long before a well reaches "marginal" status. Finally, stripper wells and marginal wells vary widely across operators, type, location, and access and are highly independent of each other. One member who operates over 200 wells could not point to a single well and identify it as a serviceable average example of the other 199 wells. This aligns with the some of the other testimony offered by OCD witnesses regarding exactly why a "one-size-fits-all" approach does not address the realities of operating wells. *See*, *e.g.*, Direct Testimony of Loren Diede, OCD Ex.4, 3-4 (costs "very difficult to forecast" and can be "vastly different" even among same field, same operator, and same contractor).

Q: Any other comments about costs as set forth by Mr. Wrinkle?

A: One member comment that Mr. Wrinkle's "high" number for road costs was "insane" and other members agreed with exactly that word. I do not doubt Mr. Wrinkle experienced one such cost (for what length of time or how many wells that cost was spread over are both unclear) in his career, but IPANM's membership reports nothing remotely comparable as a cost for any usage of private roads. I do not see how that one figure is of any value to the Commission. Most members report no cost or only the cost

of blading a rancher's roads used by the operator once per year with the blading cost being spread over many wells.

Q: Overall, how does the inclusion of capital expenses in OCD Exhibit 9 affect the analysis of marginal well economics?

A: Even if you eliminate those one-time costs acknowledged by Mr. Wrinkle, his LOE estimates still sum from $46,000 to $293,000 per month. In comparison, our members looked at their late-life wells and report operating expenses ranging from $600 to $1300 per month. In fact, using Mr. Wrinkle's numbers but excluding capex, the analysis results in LOE of about $1925 per month, at which even a marginal well breaks even at $65/bbl WTI producing just 1.01 barrels of oil per day, which is well below the WELC Applicant's proposed 1000 BOE cutoff for marginal wells. Mr. Wrinkle testifies that his experience is that wells have Lease Operating Expenses of $500-$1500 per Barrel of Oil Equivalent produced. Wrinkle, OCD Ex. 7, 6:19-20. But in the above analysis using his own numbers, a marginal well producing 1.01 barrels per day has an average LOE of $63 per BOE.[10] I think it is worthwhile to review the financial realities of operating stripper and marginal wells because Mr. Wrinkle claims that production from marginal wells does not cover "everyday operating costs," Wrinkle, OCD Ex. 7, 2:19–20, and that marginal wells "never came close" to breaking even. *Id.*, 6:7. I do not dispute that may have been Mr. Wrinkle's experience. But as I have demonstrated above, this is obviously not the case for every marginal well and certainly not reflective of our membership's experience or operation of marginal wells.

Mr. Purvis' Percentages

[10] $1925 LOE / [($65.00 WTI - $1.35 Marketing)*(30 days)] = 1.01 Bbl Oil per Day

Q: Did you have any commentary about any other witnesses' testimony?

A: Yes. That of Mr. Purvis.

Q: What area of Mr. Purvis' testimony would you like to comment on?

A: Mr. Purvis' testimony about small operators is condescending and insulting. He basically suggests that this Commission should consider a rulemaking to drive most, if not all, small operators out of business. IPANM has many operator members who are residents of the State of New Mexico, employ other New Mexicans on a full-time basis, use New Mexico service companies and are otherwise contributing to the State and local communities' wellbeing. I do, however, appreciate Mr. Purvis' candor that the aim of this rulemaking is, as my membership and I suspected, to drive small operators out of business more than to provide financial assurances to New Mexico taxpayer. Of course, of all of those companies that are going to be driven out of business as Mr. Purvis predicts, I cannot imagine that any of them will be posting $150,000.00 bonds on each marginal well as they are going out of business. In fact, human nature suggests that, if the financial assurances rulemaking is driving companies out of business, the last bill the company would consider paying would be to the state to secure those financial assurances.

Q: What about the point that the production from these operators represents a small portion of New Mexico production overall?

A: In recent years, the State of New Mexico has been very fortunate that vast quantities of oil have been produced from shale formations that generally were not productive historically. In the past 10-15 years, a combination of drilling and completion technologies were perfected, allowing horizontal drilling into a formation and the ability to produce significant volumes of oil and gas. New Mexico went from flat or declining

production over many decades to record setting production in almost every year for the past 10 years. IPANM Exhibit 40 is the United States Energy Information Administration's chart and data of New Mexico oil production from 1981 to 2025. It shows that from 1981 to 2011 New Mexico produced between 162,000 barrels of oil per day as a low (in 2007) to a high of 217,000 barrels per day (in 1984). Beginning in 2012, New Mexico exceeded the 1984 production figures and production volumes have increased each year since. In 2025, New Mexico is producing 2,023,000 barrels of oil per day—almost ten times the 1984 production. For the 25 year period ending in 2011, low producing wells and so called "marginal" wells were a significant economic driver for New Mexico tax revenues, especially the various forms of severance taxes imposed by the State of New Mexico, and royalites paid to the State government. Because of gains in technology and development, horizontal wells now contribute a much higher percentage of production but given the growth in production volumes by a figure of 10, stripper and marginal wells continue to contribute significant volumes and revenues, even at lower percentages.

Change of Facility Operator Form

Q: What is your concern about the Chage of Facility Operator form promulgated by the Division?

A: IPANM Exhibit 44 is the Change of Facility Operator form revised in August 2025 concerning which I have received member comments after my Direct Testimony had been filed on August 8. The concern relates to Paragraph No. 7 on the second page of that Form which provides that the new operator is to certify: "No person with an interest exceeding 25% in the undersigned company is, or was within the last five years, an officer, director, partner or person with a 25% or greater interest in another entity that is not

currently in compliance with subsection A of 19.15.5.9 NMAC." The OCD regulations currently provide for such certification only if an entity is registering to become an operator for the first time. That provision is in subsection B.3 of 19.15.9.8 NMAC. This form is only for a change of operator, there is no regulation requiring such a certification from one approved operator to another. However, that is a proposed requirement in Applicants' proposed amendments to 19.15.9.9 NMAC. I have had members inquire whether some sort of fix is in on this rulemaking and the Division has foreknowledge that the Commission will adopt at least certain portions of the rulemaking despite opposition. While I do not share that concern, I find it quite troubling that the Division is promulgating forms and requiring operator certification based on either the Division's extra-regulatory judgment or provisions on proposed rulemaking that this Commission has not adopted. As I appreciate the current rules, the Division does not have the authority to condition transfers of facilities between approved operators on this basis and am troubled that the Division would add this requirement a few months before the Commission decides whether to adopt this requirement in a rule.



JAMES WINCHESTER

I hereby affirm under the penalty of perjury of the laws of the State of New Mexico that the above statements are true and correct to the best of my knowledge, information, and belief.



DATE: September 19, 2025

JAMES WINCHESTER

EXHIBIT 26

STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

VERIFICATION OF SONYA MARES

My name is Sonya Mares. I am a legal assistant employed by Hinkle Shanor LLP. I am over the age of eighteen (18) and am otherwise competent to testify.

1. I obtained the June 24, 2025 testimony of Deputy Secretary Ben Shelton and others before the Legislative Finance Committee in Taos, New Mexico, during the Legislative Finance Committee program evaluation, "Policy Spotlight: Orphaned Wells", via recording downloaded from nmlegis.gov Webcast, available at https://sg001-harmony.sliq.net/00293/Harmony/en/PowerBrowser/PowerBrowserV2/20250624/-1/77293.

2. After receiving the recording of the Legislative Finance Committee Meeting on June 24, 2025, I sent the audio to be transcribed by REV, which used the computer program at Rev.com to transcribe a rough transcript of the presentation, Deputy Secretary Shelton's testimony, and questions from the committee members.

3. After Rev.com generated a rough transcript of Secretary Shelton's testimony, I reviewed that rough transcript while listening to the recording and made corrections in order to create a more accurate transcript.

4. Attached hereto as Exhibit IPANM # 28-A is a true and accurate copy of my transcription of the LFC Program Evaluators presentation, Deputy Secretary Shelton's

testimony, and other testimony during the June 24, 2025 New Mexico Legislative Finance Committee meeting in Taos, New Mexico.

5. I understand that I am making this Declaration under penalty of perjury under the laws of the State of New Mexico.

/s/ Sonya Mares
Sonya Mares
Date: August 7, 2025

EXHIBIT 26

TRANSCRIPT OF LFC MEETING RE
ABANDONED OR ORPHANED WELLS
June 24, 2024

SPEAKERS – In Order of Appearance

1. Rep. Nathan P. Small, Chair
2. Stephanie Joyce – Project Evaluation Team ("PET")
3. Elizabeth Dodson, MA – (PET)
4. Ben Shelton, Deputy Cabinet Secretary (ENMRD)
5. Rep. Jack Chatfield
6. Rep. Harlan Vincent
7. Rep. Mark Duncan
8. Rep. Tara L. Lujan
9. Sen. Steve D. Lanier
10. Rep. Rebecca Dow
11. Rep. Susan K. Herrera
12. Ismael Torres – Chief Economist LFC
13. Sen. Pat Woods
14. Sen. Benny Shendo, Jr.
15. Sen. Nicole Tobiason
16. Sen. George K. Munoz, Vice Chair
17. Rep. Meredith A. Dixon
18. Jim Winchester (IPANM)
19. Ashley Wagner, VP, Governmental Affairs for NMOGA
20. Margaret Klug (PET)
21. Brendan Gray (PET)
22. Rep. Derrick J. Lente

Transcript by Rev.com

Chair: (00:00:00):

That said, thank you for this conversation. Thank you all for very much for taking the time. Thank you all for continuing to work together, and a big thanks to the committee, I think, for really good questions from a lot of different perspectives. Great. Okay, now we're going to go into a presentation on orphaned and abandoned wells. A couple of quick notes as we're doing this. I'm going to invite up Mr. Winchester and Ashley from NMOGA after the presentation should they wish. This is a staff report led by nonpartisan staff with excellent expertise. Mr. Winchester, and I think Ashley, have requested the opportunity to sort of address or offer perspective given that their industries are very much at the center of the report, which is fine. Obviously, we're working under time constraints. I do very much if there are any sort of questions. The LFC staff work very hard to do the very best job that they can. It's for us in our elected roles to sort of hash through that. But any sort of ascribing of motive, or this or that, sort of tipping the scales one way or another on the staff. Staff is doing the best job that they can, and I think we all always benefit deeply from that. So, with that, just as a look ahead, and Mr. Winchester, Ashley, thank you for being here. We'll look forward to visiting a little bit later. With that, we'll turn it over to staff.

Joyce: (00:01:49):

Thank you Mr. Chair, members of the committee. My name is Stephanie Joyce. I am one of your LFC program evaluators, and today I'll be presenting this LFC policy spotlight report on orphaned oil and gas wells, along with my colleague Elizabeth Dodson. The report is in Tab D of your binder and it looks like this. If we can get the technology to work, we will also be tracking where we are in the report up on the screen. They're working on it. Just before we dive in, I wanted to thank Secretary Kenderdine, Deputy Secretary Shelton of the Energy Minerals and Natural Resources Department, and the Staff at the Oil Conservation Division (OCD) for their collaboration on this report. I also want to thank the researchers

and oil and gas workers who generously lent us their valuable time and expertise. So, Mr. Chair, members of the Committee, just to set the stage a little bit, the goals of this report were twofold.

(00:02:56):

First, to understand why the number of orphaned wells reported by OCD has continued to rise despite record funding allocated to OCD for plugging those wells. And second, to understand how much it has cost, is costing, and will cost the state to plug those wells. If you'll please turn to page one, you will see a summary of the report. The key point that I will draw your attention to is that the state faces significant and growing financial liabilities for oil and gas well cleanup. As you can see here in Chart one on page one, the report estimates the current and likely liability to be between $200 million and $700 million, with possible liabilities as high as $1.6 billion. We'll get into how we arrived at those estimates in a bit and why there is such a large range but, first, if you will turn to page four of the report. We'll start with a little bit of background about the oil and gas industry in New Mexico and how it is that the state sometimes ends up responsible for plugging and decommissioning oil and gas wells.

(00:04:14):

So, as you all know, New Mexico has been an oil and gas producing state for more than a century and, during that time, companies have drilled more than 120,000 wells in the state. Many of those wells tap hydrocarbon reservoirs a mile or even two miles deep, and wells aren't built to last forever. Over time, as the oil and gas reservoir is depleted, it gets harder and harder to get oil and gas out of the well and a well reaches the end of its life. At that point, the well needs to be sealed or plugged. That's been a requirement in New Mexico since the very earliest days of oil and gas production, and it's important for a few reasons. One, unplugged and inactive wells can pollute groundwater by acting as a conduit for fluids and gases to

migrate underground. Two, they can pose a risk to human health and safety if they leak gas or produced water to the surface.

(00:05:13):

And three, they can impede the efficient extraction of nearby resources. If you'll turn to page five of the report, here in Figure one, you can see, you can see how plugging can mitigate some of those undesirable outcomes. So here on the left of figure one is a diagram of an unplugged well, and on the right is a diagram of a plugged well. The basic idea is that you use cement to isolate each underground water or hydrocarbon formation from the ones above and below it, and I know I'm speaking to some folks who are experts in this, so bear with me. Using specialized equipment, cement is pumped down the well bore to specific depths where it sets up and, when done correctly, keeps all the gases and fluids in their original places. Now, once a well has been plugged, the well site needs to be remediated and reclaimed.

(00:06:14):

If you'll turn to page six of the report, you can see that remediation means removing any polluted soil and addressing any impacts to surface or groundwater and reclamation, as OCD defines it, includes removing debris and equipment and closing any above ground pits. Figure two here on page six on the left shows an example of in-progress remediation and on the right a well site that has been reclaimed. If you'll turn the page again to page seven, you'll see that when wells are producing any volume of oil or gas, OCD typically leaves it to the discretion of operators to decide when to plug and reclaim. The well chart two here on page seven shows that, in recent years, the average well produced about 700 barrels of oil equivalent in the year before it was plugged, or about two barrels of oil equivalent a day. Operators, of course, take many variables into consideration when deciding when it makes sense to plug a well.

(00:07:21):

A few include the cost to get oil or gas to market, the cost to dispose of produced water, which is the salt water that comes up alongside oil and gas, and the vast majority of wells are plugged by industry. But, as you can see here in the middle of page seven, when a well becomes fully inactive and is not plugged by its operator, OCD can pursue the authority to plug the well itself in order to prevent some of those outcomes that I mentioned earlier. If you'll turn to page nine of the report, you'll see a figure that shows how OCD pursues authority to plug a well. The first step is issuing a notice of violation to an operator with too many inactive wells, and then there are a few different pathways that can result in OCD receiving authority to plug the well. On this same page, page nine in Chart three, you can see the number of wells plugged historically by OCD versus industry.

(00:08:20):

Light blue is industry, dark blue is OCD. I do want to note here that OCD did not keep robust records until recently of the wells it had plugged historically. So, these numbers are almost certainly low, but according to its budget performance measures, OCD has plugged at least 967 wells since 2002, which is an average of 51 wells a year or about 5% of all wells plugged in the state since 2002. Here at the bottom of page nine, these next few pages, starting here at the bottom of page nine, these next few pages of the report explain the various ways the state pays for plugging when it has to plug a well. Historically, the main source of funding has been the Oil and Gas Reclamation Fund, which is discussed on page 11 if you'll turn the page again. As you can see in the first finding or the first paragraph on this page, the legislature created the Reclamation Fund in 1977 and directed a portion of the oil conservation tax proceeds to it. The share of the tax going to the Reclamation Fund has grown a thousand fold since then. Currently, 10.5% of the tax goes to the Reclamation Fund when the price of West Texas intermediate crude oil is below $70, as it

was this morning, and nearly 20% when it is above $70. As you can see here on this page, page 11, in chart four, the balance of the Reclamation Fund was $65 million at the end of fiscal year 2024.

(00:09:59):

Here at the bottom of page 11, you can see, and onto page 12, you can see that that's because, recently, OCD hasn't actually been using much in the way of state funds to plug wells. Instead, the division has been using federal grants allocated to the states under the Infrastructure Investment and Jobs Act or the bipartisan infrastructure law. New Mexico has received $55.5 million in grants from the federal government in the last two years, and is eligible for another a hundred million dollars in the coming years. Further down here on page 12, you'll see that OCD has used that funding to increase its rate of well plugging. But, if you turn the page to page 13, you'll see that the cost of well plugging has also gone up in FY 19. The average state plugged well cost $30,000 to plug; in FY 24 it was $163,000. A different measure is that is often used as the per foot cost, because deeper wells are more expensive to plug. If you look at chart six here on page 13, you'll see that the per foot cost has gone from about $11 to $43 since FY 19. We'll talk a little bit about why that might be in a moment, but first I'm going to hand the presentation over to Elizabeth to discuss the report's estimates of the state's current and future liability.

Dodson: (00:11:31):

Thank you Stephanie. Mr. Chair, members of this committee. If you'll turn to page 15, you'll see the overarching finding of this chapter is that the state faces current liability of roughly $200 million and likely liability exceeding $700 million for orphaned wells, which is considerably more than the funds available through the federal grants or the Reclamation Fund. Before we get into those numbers though, I'm going to spend a minute on the term “orphaned wells.” As you can see on page 16, the term is commonly used in both industry and the media to refer to wells that have no viable operator and, therefore, have become

the responsibility of the state. However, neither New Mexico statute nor code actually defines the term "orphaned wells." News stories cite a few different numbers for how many orphan wells there are in New Mexico, like 700, 1,700, 3,000 because OCD has used the term differently, depending on the context.

(00:12:35):

For example, if we are only talking about wells on state or private land that OCD has already pursued the authority to plug, then the number of orphaned wells is going to be on that lower end. But if we're talking about all inactive wells in the state, regardless of the landowner that may not plug the wells, or their operator may not plug the wells, then it's going to be much higher. For this report, we were primarily interested in understanding the potential cost to the state, so we defined orphan wells as wells on state or private land a/k/a their surface owner that OCD has pursued and received the authority to plug. That's the first section of this chapter. Then we'll look at wells that OCD does not currently have the authority to plug, but which the state believes will ultimately become its responsibility. And finally, we look at wells that are at risk of being orphaned because the expected cost of their cleanup far exceeds their predicted future revenues.

(00:13:34):

So, again, this chapter is going to go current, likely and then possible liability for orphaned wells. Here at the bottom of page 16, you'll see that based on OCD's internal list of wells, it has received the authority to plug, there are 702 currently orphaned wells on state and private land. Turning to page 17, table seven shows that the report estimates that at recent plugging rates, it will likely cost OCD at least $130 million to plug those orphaned wells and it could take close to a decade to complete that. Now, OCD will also have to remediate and reclaim those well sites and their associated infrastructure. On top of the 700 orphaned wells that we've identified, the division also has a large backlog of cleanup for previously

plugged orphaned wells. The report estimates that remediation and reclamation work will cost at least another $100 million dollars, and possibly much more just for that current liability of plugged and unplugged orphan wells.

(00:14:43):

So that's where our estimate of $200 million comes from: plugging, remediation, and reclamation of wells and their associated infrastructure that the state is currently responsible for. Now, turning to page 18, you'll see the next section of the report estimates the cost of plugging and remediating wells that have been inactive for at least 15 months, but for which OCD has not yet pursued the plugging authority for. These are not orphaned wells as the report defines those, but OCD considers them to be almost certain future orphan wells, so they often include them in their estimates of the number of orphan wells in the state. As you can see at the bottom of page 19, the estimated cost for plugging, remediation and reclamation of those 1,400 inactive wells on state and private land is at least $468 million plus. So, this number plus our $200 million in current liability that we estimate, is how the report concludes the low end of our likely orphaned well liability to be about $700 million.

(00:15:55):

That brings us to page 20. This next section of the report looks at a category of wells that are not orphaned or inactive, but which are producing extremely low quantities of oil and gas; such low quantities that they are likely not generating enough revenues to cover the cost of their own plugging and reclamation. These are the wells that the report terms possible liability. You've probably heard a lot about stripper wells, which are wells that have produced less than 10 barrels of oil equivalent in a day. The wells that the report is talking about in this section are wells that are producing at volumes that are 1/10th or 1/20th of that stripper well, As you can see in chart nine here on page 20, there are a lot of those really low producing

wells. Those categories furthest to the left here and, in fact, New Mexico's well inventory is quite skewed towards them.

(00:16:53):

However, most production is from really high volume wells, as you can see in chart 10 below there. The profitability of these low producing wells depends a lot on the price of oil and gas, but as the report notes on page 22, Table 12, there are about, yes, table 12. There are about 3,000 wells on state or private land that produce less than a barrel of oil equivalent a day for three years straight between 2021 and 2023, meaning they are consistently producing in very low quantities and are probably nearing the end of their lives. Most of those wells are owned by privately held companies, which makes it difficult to say whether they have money set aside to plug and reclaim them.

(00:17:42):

But if a third of those wells were to end up on the state's books, it would cost many hundreds of millions of dollars to plug and reclaim them and, if all of them were to end up the state's responsibility, the liability could be close to a $1 billion at current plugging and reclamation rates. So, adding the estimations discussed for current, likely, and possible plugging reclamation and remediation liability, the report estimates a total cost between $700 million to $1.6 billion. Now, I'll turn the presentation back over to Stephanie for more about the various factors that could reduce that liability.

Joyce: (00:18:23):

Thank you, Elizabeth. Mr. Chair, members of the Committee. If you'll turn to page 24 of the report, you can see that the report finds that reforms that prioritize operator led cleanup can limit the state's financial exposure. A key component of that conclusion is the report's finding that OCD was not set up to operate as a large scale plugging contractor, and struggles to control both the cost and quality of state contracted

plugging and remediation work. As I noted earlier, the cost of plugging has risen dramatically in recent years. That's partly attributable to factors outside of OCD's control, including the fact that it's been plugging deeper, more expensive wells recently. Oil field inflation has also been quite significant since the pandemic, but not as significant as the cost increases that we've seen. If you'll turn to page 26 of the report, there and on the next few pages, the report discusses the finding that OCD's procurement practices are likely contributing to rising costs.

(00:19:29):

To summarize, some of the contributing factors may be that the Division relies on contractor estimates for plugging, and does not competitively bid projects. In general, the report recommends that OCD change a number of its contracting practices, and that it strengthen oversight of its spending to ensure state funds are being used efficiently. Specifically, the report recommends that OCD follow the lead of a number of other states that require a State representative to be on site for all plugging operations, both for quality control and to ensure invoicing is accurate. If you'll flip ahead a few pages to page 31, the second finding of this chapter of the report is that financial assurance requirements are insufficient to cover the costs of plugging and reclamation. So, earlier in the background section, I mentioned that the state mostly pays for plugging out of the Reclamation Fund and federal funds but, in statute, OCD is also required to collect upfront financial assurance from operators "sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance."

(00:20:38):

Right now, statute says the maximum amount of financial assurance that OCD can require for all of a company's active wells in the state is $250,000 or up to $1 million if the company has a lot of inactive wells. As you can see in that second paragraph here on page 31, for many operators that translates to less

than $1,000 per well and, in some cases, just about $100. As a reminder, the average cost to plug a well last fiscal year was $163,000. So, right now, the amount of financial assurance required from most companies is not enough to cover the costs of plugging and reclamation. Further down on page 31, you can see that OCD has successfully recovered $870,000 in the last 20 years from operators whose wells it has had to plug, but has spent tens of millions of dollars on plugging and reclamation.

(00:21:34):

If you'll turn to page 32, the report recommends that New Mexico adopt policies that incentivize operators to plug wells before they become the responsibility of the state, leveraging industry's capacity to do the work more efficiently and likely more cost effectively. Different states and countries have used different statutory and regulatory mechanisms to try to align incentives towards that goal. Each of them has their own pros and cons. This section of the report provides an overview of many of those options, including increasing the upfront financial assurance required, and allowing the regulator to review the sale of wells between operators to ensure the purchaser has the cash flow to plug the wells. Many of these regulatory mechanisms are summarized in Table 17 on page 33. We'd be happy to discuss any of these more in depth, but if you'll turn again to page 36 of the report, I'd like to particularly draw your attention to a somewhat novel approach that several states are taking to this issue, which involves basically setting up trust funds associated with either specific wells or their operators the companies pay into at a fixed rate.

(00:22:52):

You could think of it something like a retirement account for a well, where companies put money into it over the course of a well's life, so that the money is there when it's needed later. Different states have structured those trusts in different ways, but the report finds that it's a policy option that you, as a legislature, might consider adopting. Which brings us to our key findings and recommendations. As we've

discussed, the state faces current and midterm liabilities in excess of $700 million, and possibly more, significantly more than the funds currently available for plugging and reclamation. If you'll turn back to page two of the report with me, you'll see that in light of that we're recommending both some statutory changes and some regulatory changes. All of these recommendations are intended to improve transparency around how much the state is spending to plug and reclaim wells, and to reduce the chances of the state's liability growing in the future. With that, and with the permission of the chair, we'd like to invite Deputy Secretary Shelton with the Energy Minerals and Natural Resources Department, to present the agency's response, and then we'd be very happy to stand for your questions.

Shelton: (00:24:10):

Thank you, Mr. Chair and members. Thank you for having me here today. I'm here in place of our new Oil Conservation Division Director, Albert Chang, who started on the job yesterday morning. He was presiding over the Oil Conservation Commission. He sends his regrets. The overall response on behalf of me and the entire staff at the Oil Conservation Division is, “thank you.” This is an exhaustive, comprehensive, well-researched, accurate and fair report. It's an accurate assessment of the challenges the Division is facing with regards to orphan well liability, the challenges the Division wrestles with every day regarding financial assurance, sufficiency, and basically how to manage this enormous level of work that OCD is candidly not set up to do. We are a regulatory agency set up to permit the operation of the oil and gas industry in New Mexico. This is something that has become a bit of an elephant that the Division is dealing with.

(00:25:14):

I would like to try to give a little bit more context to some of the tools that the state uses right now around cost containment, for plugging specifically, and I'm not talking about a lot of the environmental work. I just want to use my time here, because I know we are a little over time, to talk about the plugging costs

and the way that we approach them sort of compared to other states. A couple of the examples that were actually highlighted in the report are great examples to sort of illustrate the variability and the wide range of outcomes that we see when we actually begin the work of attempting to plug a well, and I would start with the two wells that are highlighted on page 29.

(00:25:56):

So, if you look at these two wells you've got. I should have checked on the pronunciation of this. I believe it's Bartnet and O'Brien. Starting with the cheaper well, the O'Brien well, and you can kind of see from the diagram on the page that they're very, very close together. These wells are going, we think, into similar formations, so there's reason to believe that you should just be looking at the map, that they should be comparable in price. What they found when they went in to start plugging O'Brien was that at every single depth, there was good casing integrity. The amount of cement that it took and the time that it took to lay that cement in is exactly what you would hope for. It took a single plug, a worth of cement to establish the plug at the required depth, and generally speaking, everything stayed on target.

(00:26:47):

This is the exception. We see more commonly is with, what you see with the Bartnet well, which costs what, almost three times, almost three times that much? They pumped cement down that well to assess plugs at those depths day and night. They plugged more cement. They had to plug four plugs to lay the base plug, and these are costs that you just do not begin to see until you are down and you are pumping the cement and seeing if you have circulation or not. What's happening is that there are perforations in that casing, and when you pump cement to attempt to plug, your cement is escaping into the formation. So, effectively, you pump until you have stability in that formation and it backfills into the well bore, and that is how you're going to seal all that off. You feed it until it stops eating. I mean, that is the approach

and that's not just the OCD approach. This is the approach industry wide. This is how we plug wells in the state.

(00:27:43):

We pumped various plugs multiple, multiple times. The only plug on Bartnet that went really according to plan was plug number four and, when you factor in the time that was spent because the two main drivers of costs are the time that we spend with the rig, and the time for the crew to actually operate it. When you factor in the time that was spent plugging and pumping, and the actual cement utilized, this actually came in pretty close. We didn't see overruns based on, based on the actual time. The reason that we are highlighting the cost of this, in particular, is because I don't want to put ourselves in a situation where we think we can take these actions, and we're taking a lot of actions legislatively, or OCD is taking actions, and expecting big deltas downward in terms of what we're paying per well because, candidly, the flag that popped for us on this is that when we compare our costs of plugging a well with what the costs are on the private side, they're comparable.

(00:28:39):

Ours are higher for reasons I'll talk about in just a second, but they're not two to three times higher. They're about 10% to 15% higher. So, this is the cost that we are seeing right now in the private industry, just anecdotally, and we ask them, we meet with probably three to four times a month. We have different operators in sort of checking in and one of our questions on the list is always, “What are you paying right now approximately to plug?” And the answer recently, and by recently I mean in the last eight to 12 months, has been $120,000 to $150,000. Our OCD average is $155,000 to $160,000.

(00:29:14):
Moving into slide three on mine, which is mostly text just to compare, people want to compare us to Texas a lot. As I understand it, our plugging requirements are more stringent than Texas. We have a statute that says that we need to seal off every single strata, which means that we lay multiple plugs at the required depths. We pump concrete and cement in there; not concrete. We pump cement in there until we get the plug established at the required depth. The way operators tell us they do it in Texas is you plug the bottom, you fill with drilling bud, and you plug the top. It's cheaper and it's faster and it'll help contain your costs, but it does not result in the sort of predictable isolation of strata that we are required to comply with here in New Mexico because presumably it's more environmentally protective.
(00:30:00):
The other well I would draw your attention to, just because it's an important story to tell, was on page 28, the Buckskin Federal #2 well. This is a well that got very, very expensive very quickly. The way that we approve costs with contractors is that they, effectively, if they need to go over what is bid, so we have statewide price agreements where we lay out the criteria for billing and we generally do cross-reference that we're being billed for each task order, for each sort of item in our price orders, is comparable to what's getting billed on the private side. We assess this because the contractors that we are using are the same contractors that a lot of the private industry is using, but when those overages come, we tell them to just pump it and Buckskin Federal #2 is the reason why this is a terrifying plug.
(00:30:51):
This is something that this well had the potential to contaminate water supplies. We were very, very worried about this, and we advised them to go. And this kind of thing happens more commonly than you would think. Again, we have a statutory requirement to plug at strata and protect environmental

resources, and the reason that I'm glad that Buckskin Federal #2 was identified in this is that that is a plug job, and that is a well that is talked about to this day at OCD, as what could have gone wrong if we didn't have the ability to react quickly to use our purchase order approval and sort of our overage approval process, to just keep crews working on that in a timely way to get that plugged.

(00:31:35):

Moving on, and I want to just use this as sort of a visual reference. You can see these are just two invoices that we get. On the left, you can see a daily report that we get, that we have that's an example. It's a few years old of just a daily report that we get. One of the recommendations is going to having a specific inspector or a company man reporting daily from the site. We do have an analog to that and that is this daily reporting process. It's a desk. It gets reviewed at the desk from our office either in Albuquerque, Santa Fe, Artesia or Hobbs. There'll be staff who are receiving and reviewing those daily reports, so we don't have people on site. That's a capacity determination that we just have to make. We do have inspectors who will drop in periodically, but we do not have staff on site every single day.

(00:32:20):

What we do have is this reporting process. So, you'll see the day report on the left. On the right is an example of the invoice that we get, for broken down by activities per day at the end of the plug, and that gets reviewed as well by staff. The cost for specific pieces of our plugging are taken from the statewide price agreement. They are itemized out in purchase orders. That is a piece of context that is probably useful. It didn't make into the report robustly; that is our fault. We did not get that information communicated properly to LFC staff. So, it didn't get into some of this, but some of the things that they are asking for in terms of oversight of individual well plugging, the work orders oversight of the actual work done from a day-to-day basis we do do, but we just didn't get that information to staff.

(00:33:09):

That's our fault. I apologize for that. And then finally on slide five and six, this is sort of a thumbnail quickie proposed response to some of the recommendations. The first one at least is incorrect. That was based on the preliminary report, not the final, so you can throw that one out. The range of our responses to most of these recommendations are a good idea. We'll get to work. Good idea. We're in process to incorporate it. We don't, or something along the lines of we don't do this because we don't feel like we've got the capacity currently to do it, or we're not sure it would necessarily help the problem but, for the most part, I think that a lot of these recommendations are things that we are currently addressing, certainly regarding characterization of inactive wells and orphan wells that we are looking at as part of a rulemaking response.

(00:33:53):

There's a petition that is before the OCC right now that has been filed by an external party to reexamine some of the financial assurance rules that we have in place enacting the statutory legislation. A lot of the things that are going to be in that rule are going to be really on point for some of the recommendations in here so we're excited to get started. But, yeah, the wrap in conclusion, it's good to be heard. This is something that we have been struggling to say as clearly and comprehensively as you have it before you today. Thanks to LFC. We've been trying to say this for a few years now, and this is the clearest and best way that the case has been made yet around the state's coming issue with orphan well liability and the tools and the limitations of some of the tools that OCD currently has to meet at the moment.

Chair: (00:34:45):

Great, thank you. Okay, we will go straight to Committee questions. So, just as a quick reminder, we're going to, I think, go through questions for the presenters. We're going to invite up Mr. Winchester and

Ms. Wagner after. There's questions for the presenters to share perspective and to address any questions that the committee might have. So, we're going to start with Representative Sanchez then go to, oops, we'll come back to him, Representative Chatfield, then Representative Vincent, then Representative Duncan. Representative Chatfield, please?

Chatfield: (00:35:29):

Hey, thank you all for the presentation. Can you just go through it for me how the Reclamation Fund is funded?

Dodson: (00:35:40):

Sure. Mr. Chair, Representative, thank you. Yes. The Reclamation Fund is funded through the oil conservation tax, which actually I have the appendix if you wanted to turn to Appendix C at the end of the report. But it's funded through a portion of the reclamation tax or the conservation tax that is on produced revenue from produced oil and gas, and then it gets a portion of that tax. Right now, the portion is, let's see, it is 0.24% of the revenue of the tax when the price, I'm sorry, I'm lost. Sorry.

Joyce: (00:36:29):

Let me jump in here. Yeah, so right now the Reclamation Fund gets a portion of the conservation tax, and the portion that it gets depends on the current price of WTI of West Texas Intermediate crude oil. And, so when the price is below $70 a barrel, 10.5% of the conservation tax goes to the Reclamation Fund and, when it's above, 19.7%, I believe, goes to the Reclamation Fund.

Chatfield: (00:36:58):

So, in fairness, I'll tell you that I don't know the answer to the questions that I'm asking, but it's not my first bounce off the tater truck. So, I know a little bit about what I'm asking. So, where does the rest of the conservation fund go? This conservation fund?

Joyce: (00:37:14):

Conservation tax. It goes to the general fund. The rest of the conservation tax goes to the general fund. And, as you'll see here in Appendix C, historically the conservation tax, when it was introduced in 1959, was used to fund, to enforce the Oil and Gas Act. That's what the statute said when the oil conservation tax was passed. Eventually over time, I believe different appropriators, different legislators, made the decision to have more flexibility. So, rather than directing all of that tax specifically to the Oil Conservation Commission, it went to the general fund principally in order, and then you fund the operations of the Oil Conservation Division out of the General Fund. In 1977, the legislature also created the Reclamation Fund and, at the time, 0.01% of the conservation tax went to the Reclamation Fund. That's obviously grown over time.

Chatfield: (00:38:16):

So, I wasn't here in 1977, but I've been around the roundhouse a good while before I got elected and I've seen, I've seen the fund rated before. I'll just say before, I'm not going to say for what or how many or by who, but I have seen this money used when the state kind of gets in tough times and the money's sitting there. So, I guess my question is this. In the past, a lot of money has been appropriated by the oil companies to plug wells in the time whenever they become useless, and how much of that money is still in the fund? Number one, how much money's in the fund? Number two, how much money isn't in the fund what was put up by the industry in the past to plug wells?

Joyce: (00:39:19):

Mr. Chair, Representative. If you will turn to page 11, I believe, of the report, you can see the oil Reclamation Fund balance currently as of the end of FY 24. And, as you can see, the amount of money that the fund has been receiving has grown considerably in the last few years as a result of high oil and

gas prices and high production. As I said, the Fund has not been used very much in recent years to plug wells. They've been using federal grant funding to plug wells here in New Mexico, which is why you see that high balance currently in the fund. Now, if I can direct you, sorry to make you jump around in the report here, but if you can go to Appendix A here in the report that's on page 38, you can see over time NMENRD has had to report to you about how that fund has been used, and there are a number of moments when the fund has been used for things like paying for OCD staff, for example. So, that has certainly been the case that's detailed here in Appendix A and some of these report card updates.

Chatfield: (00:40:48):

So how many wells did OCD plug last year?

Joyce: (00:40:56):

Mr. Chair, Representative. It was more than a hundred wells that OCD plugged last year. Let me see if I can find a specific page.

Chatfield: (00:41:06):

Excuse me, Mr. Chair, with state funds, not the federal funds? Mr. Chair?

Joyce: (00:41:14):

Mr. Chair, Representative. I don't know the answer to that question. I can tell you how much they cost and how much each well cost to plug, but in terms of whether the funding used was specifically state funds or federal funds? I can't answer that question.

Chatfield: (00:41:33):

Mr. Chair, I guess where I'm going with that is, just looking at the report here, it looks like the federal government pays for wells on federal lands and that the OCD pays for wells on state and private lands. Is that true with plugging?

Joyce: (00:41:51):

Mr. Chair, Representative. Historically, that is true. In recent years, the federal government, as part of the Infrastructure Investment and Jobs Act or the bipartisan infrastructure law, the federal government has allocated funding to the states for plugging on state and private land with the goal of addressing the large backlog of orphaned wells that many states have, including New Mexico. So, those recent federal funds are grant funds from the federal government for plugging on state and fee land.

Chatfield: (00:42:26):

So, I'm very supportive and happy to see federal money going into plugging our wells. And, I guess where I'm going with that is, how much better if we used this fund to plug some more wells and have we been?

Shelton: (00:42:45):

Mr. Chairman, if I may, we also, I would add, do plug federal wells. We are effectively the contractor; OCD is for BLM to plug BLM wells, so we get paid for that out of an additional and separate fund that BLM specifically supplies to us. It takes a little longer, BLM, and the federal government has a lot more processes they go through before they will let you plug a well but, in addition to using federal money to plug state and private, we're also using federal money to plug federal wells.

Chatfield: (00:43:17):

So, Mr. Chair, thank you. You're talking about physically plugging the federal wells. I'm talking about using the Reclamation Fund funding to plug state and private wells in New Mexico.

Shelton: (00:43:34):

Mr. Chairman, as Stephanie mentioned, we have been using almost exclusively federal funds. So the reason that you have not seen that you've seen that rec fund balance climb in the last two, three years, is

because just about all the activity you've been doing on state, private and federal. Well, yeah, state and private land is using those I-I-J-A-B-I-L federal dollars.

Chatfield: (00:43:57):

So ,Mr. Chair, are we going to reduce the money that the oil companies are putting up to that fund? Is that what we're doing? I mean, I know that's not what we're doing. What I'm saying is if we have federal money coming in and we're plugging wells with it, we've got a fund over here of money that's been put up by the oil companies and we're not using it to plug wells with, what are we doing? Why are we not doing that?

Joyce: (00:44:31):

Mr. Chair, Representative. I believe the total of the federal grant funding that we are eligible for and/or have received and the current balance of the Reclamation Fund still is insufficient for our estimate of the likely liability posed by orphan wells.

Chatfield: (00:44:49):

So, Mr. Chair, that is insufficient for the likely liability. How about, is it sufficient to plug some of the wells that we have orphaned now?

Shelton: (00:45:02):

Yes. $66 million will certainly plug some wells. Our priority has been to utilize federal dollars. I think, Mr. Chairman and Representative, going to your question of whether or not we can collect less of the conservation tax based on the availability of federal funds, the answer to that is no. That is set in the statute. The collection and the amount of the collection is out of our hands.

Chatfield: (00:45:24):

So, Mr. Chair, I apologize. That was more of a smart alec answer than anything. I am saying we've got money. Why are we not plugging wells with it? That's, the simple thing is, the federal government is appropriating money and you all are doing the contracting and we have money there and I hear a lot about orphan wells, so I don't understand why we don't use the money that's appropriated to plug wells. Maybe even the money that goes in that goes to the conservation fund instead of putting it in the general fund? We're not short on funding right now, but I understood it, and maybe years past when we were desperate, but maybe we should think about using that money to plug wells. Thank you, Mr. Chair.

Chair: (00:46:19):

Thank you very much, Representative Chatfield. We'll go next to Representative Vincent then Representative Duncan. Representative Vincent?

Vincent: (00:46:29):

Thank you, Mr. Chair. So, whenever we talk about you guys being the contractors, do you have a company that does it? Do you have multiple companies that plug these wells? Mr. Chair?

Shelton: (00:46:44):

Mr. Chairman, Representative. We have five contractors right now on our statewide price agreement. That is what I realized in my presentation. I didn't get back to something I promised to get back to, which was our why we do pay more. All five of our contractors are currently in San Juan County. That is who bid. We took every single bid in 2022 or 23 when they bid into the statewide price agreement, and just happened to be the case that all five that we got at that moment were in San Juan County. So, we pay for them to drive across the state and we pay for them to stand by occasionally if we need it to plug in the Permian, which adds costs, adds about 10 to 15%. We do pay a little bit more than the private industry,

and that's one of the reasons why we reopened with GSD that statewide price agreement in March of this year. We are currently trying to get some more bids in trying to get some more contractors in the Permian so that we can sort of cut down on some of those transportation costs.

Vincent: (00:47:37):

Thank you, Mr. Chair. So, always, whenever I see that kind of money, I always know that there's contractors following that money around, and we only have five in the state and they're in the San Juan area, and they're having to drive completely across the state, which makes costs go way up. Are you telling me that there's nobody in the southeast that would be willing to plug these wells?

Shelton: (00:47:59):

When that, Mr. Chairman and Representative, when that first bid went out for the statewide price agreement, that was the case. We are working right now, and hopeful that we will have contractors on the statewide price agreement in the Permian on this new round of bidding.

Vincent: (00:48:17):

Thank you, Mr. Chair. And, so when will that price agreement come available and how often does it come available?

Shelton: (00:48:26):

Mr. Chairman. Representative. The price agreement gets opened to GSDs basically when we ask GSD, which we asked them earlier this year to do. In terms of when that will be concluded, I don't have an exact answer for that. I can connect with GSD and follow up on that for you.

Vincent Speaker 6 (00:48:40):

Thank you, Mr. Chair.

Chair: (00:48:43):

Thank you very much. Representative Vincent, Representative Duncan, and then Representative Lujan. Representative Duncan?

Duncan: (00:48:49):

Thank you, Mr. Chair. I was at that meeting in 1959. Yeah, I was there. I would suspect every one of those dollars at that point in time was supposed to go into this fund to take care of the wells. Mr. Chair, I would recommend that we put all that money back and we delegate all of that money to go into this fund to take care of that. If we do that, will we be a long way towards the goal of meeting that $700 million?

Joyce: (00:49:31):

Mr. Chair, Representative. If you would like to turn back to page 11, you'll see in Table four the Reclamation Fund sources and uses, and you can see the cash balance as it's increased in recent years. Last year the Reclamation Fund received a record $27 million from the conservation tax. Even at those revenues, I think you'll find there's a significant gap between the revenues going into the fund and the estimated liability.

Duncan: (00:50:08):

Thank you, Mr. Chair. What I was meaning is, if we took all of that tax, everything that's going to the general fund, we brought it all back and diverted it all back into that fund, would then we have a whole lot more money to work with since we're using what, ten percent?

Joyce: (00:50:29):

10% to 20% depending on the price of oil. Yeah, with the Chair's permission, I'd be happy to have our Chief Economist come up and speak to the impact to the general fund of diverting all of the conservation tax to the Reclamation Fund. I will note that it is generally this Committee's policy not to recommend

earmarking tax revenues because it ties the hands of future legislatures. So, this report really focuses on encouraging industry to plug wells since they are more likely to be able to do it efficiently and cost effectively.

Duncan: (00:51:04):

Mr. Chairman, thank you for that. But who's paying those taxes right now? Is it industry or is it me going shopping into Walmart?

Joyce: (00:51:13):

Mr. Chair, Representative. The conservation tax is a tax on oil and gas produced here in New Mexico.

Duncan: (00:51:20):

Okay, so thank you, Mr. Chair. So that industry is already paying this in, and then we're diverting it. As the legislature, we've diverted it and it's going somewhere else. So, I'm saying we should do the right thing, bring all that money back that the industry is paying into this and plug those wells, and that's why I'm recommending that. Mr. Chair, thank you.

Chair: (00:51:42):

Thank you very much, Representative Duncan. Next we're going to go to Representative Lujan, then Senator Lanier and then keep going from there.

Lujan: (00:51:50):

Thank you.

Chair: (00:51:50):

A Lot of hands came up.

Lujan: (00:51:52):

Thank you, Mr. Chair. I think some of my questions have been answered already, but I'm looking at some of the issues you brought forward on page three for EMNERD, and there's, and some of the problems you have with just filling those wells. Is it due to the drilling practices or how deep, I mean, can you explain that a little bit? Why? And each is different obviously, but geographically, but due to this, how many have you measured? How many more difficult wells there are or is there a prioritization that you have for these orphan wells and how we spend the money to plug them? Mr. Chair?

Shelton: (00:52:42):

Thank you, Mr. Chair. Representative Lujan. Yes, we do score based on priority for the orphan wells. One of the recommendations in the report that's a great recommendation is be more proactive on that list about going back and examining those orphan wells to see the conditions that led us to score it where we did have changed, that we don't do, but we do score based on environmental hazard, age, all sorts of things that results in, is we wind up tackling wells that tend to be a little bit more expensive, a little bit earlier, when we get in there. It's another reason that it's difficult occasionally to compare our costs to private industry costs. The private industry will be frequently plugging a well that they've been producing for years sometimes. We'll find wells in rough shape, old casings that were poured sometimes around World War II and that drives costs up.

Lujan: (00:53:36):

Thank you, Mr. Chair. That's really what I'm kind of driving here. I mean, what are the, on your prioritization list, what are your estimate the highest cost? I guess what is the highest cost you're estimating on just may be one in the worst wells, Mr. Chair?

Shelton: (00:53:55):

Mr. Chair and Representative. I don't want to get too far out over my skis, but when we put that list together, we don't necessarily assess it on cost. We assign a numeric score based on criteria. The cost is determined when you're actually down hole pouring cement. We have specific sort of costs for different actions and different pieces that are in the statewide price agreement, but in terms of what the whole project is going to cost, that's just not really possible to assess until you're down hole trying to do the work.

Joyce: (00:54:24):

Mr. Chair, Representative. I will just point you in the report to Appendix E, which is on page 43, which does show how OCD prioritizes its well plugging, and I did just want to note that so, to date, as far as we are aware, and OCD has not historically tracked costs systematically, but the most expensive well the state has was plugged earlier this year and it cost $5.2 million.

Lujan: (00:54:49):

Thank you. Exactly. That's where I'm getting at. Where are those costs and how are we estimating them and when we're, we have these unknowns, I guess, is what we're really looking at? It's going to take more work and even more money to really, if we find a way to estimate those costs, and how that's going to happen. But I am aware that and, just to your point, that private industry, when they do the vast majority of taking care of plugging their wells and that's good. Those are good intentions, but it's going to cost them a lot less than what we're left with because we didn't have policies in place and we didn't have a directive in place, so to speak, as we do today. So, I want to thank you for the work. The other point is, maybe I'll ask that one offline, but do we know the ownership or previous ownership of those wells? Is that something that's on record? Mr. Chair?

Shelton: (00:55:46):

Mr. Chair, Representative. Yes. You can go in and type in what's called the OGRID. It's the unique identifier number for different operators, and you can kind of search by well and get an idea of, we have a list of the OGRIDs associated with a different well over its lifetime.

Lujan: (00:56:00):

Thank you. And yeah, better technology in the way that we're doing business, so to speak, now is going to be more cost effective and we have to plug these wells. But where we're left right now is where the conundrum is. So, thank you for the work in doing that. But the other offline, just to prompt you, the safety of this and the work that's around it, I'd like to discuss a little bit more later. Thank you, Mr. Chair, for the time.

Chair: (00:56:24):

Thank you very much, Representative Lujan. Next we have Senator Lanier, then Representative Dow.

Lanier: (00:56:30):

Thank you, Mr. Chairman. Can you just walk me through, when did we start plugging these wells? So, for example, did we have a major accident in the state that caused us to do that? What started the plugging process?

Joyce: (00:56:53):

Mr. Chair, Senator. It has been a requirement since the very early days of oil and gas development, since the 1935 Oil and Gas Act, for operators to plug wells at the end of their life for the reasons that I mentioned earlier for groundwater protection. It was actually originally intended to preserve resources because when you have an unplugged well, it can lead to pressure drops or water intrusions that actually impede the extraction of nearby oil and gas resources. So that was really the initial goal. And then, over time,

regulators realized that there were these other sort of corollary benefits to plugging wells. So, if that's your question?

Lanier: (00:57:38):

So, it was kind of driven by the industry itself?

Joyce: (00:57:42):

Yes.

Lanier: (00:57:42):

They wanted to plug them to

Joyce: (00:57:45):

Save

Lanier: (00:57:45):

Their other wells, things like that.

Joyce: (00:57:47):

Mr. Chair?

Lanier: (00:57:48):

So, Mr. Chair, then we have, so we don't know the exact number that we need plugged in New Mexico, correct? I mean, we have three different numbers: 700, 1,400 and 3,000, but nobody seems to agree on exactly how many we need. Pick a number of those numbers. Is that driven by the industry? Is that driven by environmental industry or is that by government?

Joyce: (00:58:24):

Mr. Chair, Senator. I do want to just walk through a little bit those different estimates in the report if I can. So, for the purposes of this report, we really wanted to quantify what the potential liability to the

state is from these unplugged and inactive wells. As we mentioned, orphan well is not defined in statute or rule. It's just a commonly used term and people refer to many different numbers of orphan wells. For the purposes of this report, we refer to orphan wells only as those wells for which the state OCD has plugging authority so they have gone through an administrative law process and they have received authority to plug those wells. We also further narrowed that to only wells on state or private land because those are the wells that the state is likely to be paying for. As the Deputy Secretary mentioned, the state does also plug wells for the federal government. It's reimbursed by the federal government for those wells. So that 700 number is the number of wells that the state currently has responsibility for plugging and reclaiming. The 1,400 inactive wells are the wells, that are wells that have been inactive for at least 15 months. And if I can draw your attention to the table on,

Lanier: (00:59:51):

I hate to interrupt, Mr. Chair. So, when you mean inactive, what's the barrel count?

Joyce: (00:59:58):

Zero.

Lanier: (01:00:00):

Zero. So, at two, you start looking at it? If it's only producing two barrels, you start looking at it, and then when it gets to zero, it has to be plugged?

Joyce: (01:00:12):

Mr. Chair, Senator. The inactive wells that OCD tracks have been inactive for at least 15 months and, if you look at table nine here on page 19, you'll see that many of them have been active for much longer than that. At that point, those wells, when they've been inactive for 12 months, OCD offers a three month grace period for an operator to either apply for approved temporary abandonment of the well, to plug

the well, or to resume production from the well. If they do none of those three things, they're out of compliance with the Oil and Gas Act and OCD can pursue authority to either ask the operator to plug their own well or to plug the well themself. So those 1,400 inactive wells are all out of compliance with the Oil and Gas Act and are subject to enforcement. OCD historically, and I'll let the Deputy Secretary speak more to this, OCD historically has pursued plugging authority only for operators who have a large number of inactive wells. So, if you have one or two inactive wells which may be out of compliance with the Oil and Gas Act, OCD has historically not pursued the authority to plug those wells. So those wells are sitting there, which is how there are some wells on the inactive well list, as you can see here in table nine, that have been inactive for more than 40 years.

(01:01:41):

The third section of this chapter, which looks at extremely low producing wells, wells producing less than two barrels of oil equivalent a day. Those wells are not orphaned. They're not inactive. The state has taken no action against them. This report is recommending that there be additional regulatory oversight of wells once they reach that point. That is the 0.2 barrels of oil a day when industry appears to be plugging most of its wells. Chart two of the report shows that industry tends to plug wells when they have reached about 750 barrels of oil equivalent a year. And, so, we're recommending that wells that produce less than that are subject to additional regulatory oversight in this report. Currently, they're not subject to that.

Lanier: (01:02:31):

Okay, thank you. I think that was a good explanation. And, Mr. Chair, so Deputy, you talked about the difference between Texas and New Mexico which, I'm like you, I hate getting compared all the time to such a small state. But they plug at the bottom and they plug at the top. And in New Mexico we plug whatever the distance is, we plug it, fill it with, not concrete, but cement, and then we plug it again, and

then we retest it and retest it. So that drives that cost up. So, if it works in Texas as a much more economical way, why aren't we adopting that here?

Shelton: (01:03:23):

Mr. Chairman. Senator. It's set in the statute. That's what we're required to do.

Lanier: (01:03:27):

So, is that something you would recommend us looking at?

Shelton: (01:03:31):

Mr. Chairman, Senator. I don't believe that's in the recommendations for the report.

Lanier: (01:03:34):

Okay. So, Mr. Chair, so you don't think that would help get more of these orphan wells plugged?

Shelton: (01:03:44):

Mr. Chairman. Those are policy determinations that were made around preserving resources, protecting freshwater resources, those kinds of things. That's just the statute that we abide by. We don't think about it on that level.

Lanier: (01:03:55):

Okay. And, Mr. Chair, how do you make a plan? So, let's say we have a well and it needs to be plugged. What's the process of making a plan? Do you work with the industry? Do we work with the federal government, the industry, the state of New Mexico, your office and set a plan and go, okay, this one needs to be taken care of and this is how we need to do it? Or is it just, it's zero? Plug it.

Shelton: (01:04:21):

Mr. Chairman, Senator. Once we have that plugging authority, we go out and basically issue a purchase order under our statewide price agreement to one of our contractors. We kind of itemize out the work

that we expect for that well, and we set them to it. The use of the statewide price agreement is that it is, compared to the rest of the procurement code, a relatively nimble tool so it lets us get teams out there relatively expediently and working.

Lanier: (01:04:49):

Alright. And then, thank you for that. So, when we set up this fund, right, so I hate to go back to the financial part, but that's what we're about here. So, we set this fund up so that we can start plugging these wells. Yet we're asking industry to plug their own wells. I don't understand how, if we're taxing them and we're also asking them to pay to plug their own well, why are we taxing them if they're plugging anyway? Does it get lost in the paperwork? Do we not know who the owner is? Do we not know who's responsible for it? Is it federal government stepping in? I don't understand. When we get a well plugged, we see all the prices, we know what it costs. I don't understand how we're putting money back and then they're plugging their own wells anyway.

Joyce: (01:06:03):

Mr. Chair, Senator. If I can direct you to page 11. I think it would help to maybe just go over again a bit of the history of the Oil and Gas Reclamation Fund. The legislature established the fund in 1977, enumerated some of the purposes of the fund as ensuring the proper plugging and reclamation of abandoned oil and gas wells and associated facilities. The statute doesn't define abandoned historically. The fund has primarily been used for plugging and reclaiming wells and associated infrastructure that don't have a locatable or financially viable operator. So, for bankrupt or defunct companies, so, historically, the Oil and Gas Reclamation Fund was intended to take care of those wells that were not being plugged by industry. Over time, the Fund has been used to plug, in some cases, wells for active operators. That was not, in

reading the statute, the original intent of the Fund. Primarily, it was used as a stop gap. And, as I said, that was created in 1977 after the oil conservation tax was created in 1959.

Lanier: (01:07:35):

Okay. So, Mr. Chairman, so I guess my question is, so we're all on finance committees up here and capital outlay is a big, huge part of our job. So, when we send out capital outlay, we expect it to get spent. We expect it to get used on the road we put it on, the bridge we put it on, whatever swimming pool, whatever it is, that's what we expect. So, my question is, in capital outlay, we can reauthorize it, but there's a big movement again in the House and the Senate. There's a big movement to stop doing all these reauthorizations because we have over six, I don't even know the figure. Charles probably has a figure over $6 billion of unspent capital outlay. So, my question is, if you're going to have the industry use their money to plug these wells, then we need to be pulling back this fund and we can use that money somewhere else, whether we keep it in the Environment Department, whatever, it doesn't matter. But why do we just have $60 million sitting there not getting used? I understand we're fearful that the federal government might start pulling money or whatever, I mean, obviously you use a lot of federal grants and things like that, but we still have all that money sitting there doing nothing. It's no good for us. So how can we resolve that?

Shelton: (01:09:30):

Mr. Chair and Senator. We're just spending the federal money first. We are not going to have any trouble spending down the balance of the rec fund if and when we get to the bottom of the barrel on the federal dollars. Ideally, we'd like to be spending them both down at the same time. It's a capacity concern that we're trying to resolve by getting some more contractors on the price agreement and getting the wheels

spinning faster. But we have plenty of work to spend down the existing balance of state dollars in the rec fund. We've just been prioritizing spending the federal dollars first.

Lanier: (01:10:01):

Okay, so Mr. Chairman, and that's a good answer. And that's exactly what I'm getting to is, I want you to spend the federal money first. Do it. Spend it all the way down. But why are we keep taxing, and we're talking about increasing the taxes to our industry that feeds so many different programs in this state, and we're going to keep taxing them when we hadn't started spending the money that we've already taxed 'em on? Do you see what I'm saying? I don't know that it's a fair and a level playing field when we're playing on the unknown. If we need to come up with $300 million to plug every well in New Mexico, then why aren't we working towards that? I don't understand why we're breaking it down in so many different ways, other than to confuse the world out of me. So, any response

Chair: (01:11:05):

And thank you, Senator. I think a lot of, there's a very meaty policy conversation for us here as elected members, particularly on LFC. And, so, a lot of those questions, I think, will end up being very fair once that we will be debating and again, particularly with staff. Yeah, they're sort of given their best expertise and if we want to ask them at some point to sort of bring back policy recommendations, then maybe that's something we as a committee can discuss.

Lanier: (01:11:39):

Alright, thank you, Mr. Chair. Thank you panel.

Chair: (01:11:42):

Thank you very much, Senator. We have Representative Dow and then Senator Woods next. Representative Dow, please.

Dow: (01:11:48):

Thank you, Mr. Chairman. And a lot of the questions I had were answered, but created more questions. So, I'm on page 11 and looking at this and it, it's saying that this fund was established in 1977 as non-reverting to be used for Oil Conservation Division to carry out the provisions of the Act. And it's for plugging of the abandoned wells where you can't locate the operator or they're not financially viable. And that was at the time of the creation. But now am I understanding that, in addition to this, the producers are paying a fee and to go into this fund, but they're also responsible for plugging their own wells today?

Joyce: (01:12:35):

Mr. Chair, Representative. Industry has always been expected to plug their own wells. It is in statute that industry must plug their own wells at the end of the well's life. In 1977, the legislature, I don't want to speak for the legislature then, but presumably saw a need for there to be additional funds available for wells that did not have a locatable operator. The history of this, Elizabeth went into the books of statutes and it's a little hard to parse, but at the time the legislature enumerated the purposes of the Reclamation Fund as plugging abandoned wells. It did not define abandoned wells in statute. So, conventionally, the Fund has been used for plugging wells that don't have a locatable or financially viable operator. The expectation has been and remains that operators plug their own wells at the end of the well's life.

Dow: Speaker 11 (01:13:47):

Thank you. Thank you, Mr. Chair. And thank you for that. So, since the seventies, the producers have been plugging their own wells if they're viable producers. They've been plugging their own wells and contributing to this fund. And, at some point, we started diverting the Fund and now we want more money for the Fund, but not by recapturing the dollars that are being diverted to the general fund from increased fees?

Joyce: (01:14:18):

Mr. Chair, Representative. There's a very detailed history of the oil and gas conservation tax and the Reclamation Fund in Appendix C of the report. Since the creation of the Reclamation Fund in 1977, the portion of the conservation tax that has been diverted to the Fund has increased a thousand fold. So, since the creation of the fund, the amount of the conservation tax that goes to the fund has increased from 0.01% to as high as 19.7% today. So that's not an additional tax on industry. That is a percentage of the conservation tax that is being diverted to the Reclamation Fund has grown significantly over time. So, what that means is that, over time, the Reclamation Fund has expanded. There's more money available to plug orphaned or, as the statute calls them, abandoned wells. Thank you, Mr. Chair.

Dow: (01:15:31):

And maybe this is for the Deputy Secretary. You're talking about federal dollars that you're spending. Is the federal government paying you to plug wells on federal land, or they're paying you to plug wells on federal and state land?

Shelton: (01:15:42):

Mr. Chairman and Representative. All three. I would say most of the B-I-L-I-J funds we're using on state and private.

Dow: (01:15:53):

Okay, thank you, Mr. Chair. And these dollars are used for state land only, or are we also using, because the federal government pays for plugging on federal land, is this fund only being used to plug wells on state land?

Shelton: (01:16:11):

By this fund? You're referring to the Reclamation Fund specifically because, remember, the BIL, the federal money we've been spending, is kind of over here, right? So, the rec fund, so yes, the rec fund is used for state and private land plugging, primarily.

Dow: (01:16:24):

Primarily? Okay. And Mr. Chairman, I think what I am not understanding is if this is a tax or if it's a fee? Is this a tax or is this a fee on the industry?

Shelton: (01:16:38):

Mr. Chair, Representative. It's a tax. It's the conservation tax.

Dow: (01:16:42):

It's a constitution tax?

Shelton: (01:16:44):

Conservation tax.

Dow: (01:16:44):

Conservation tax.

Shelton: (01:16:45):

Conservation.

Dow: (01:16:46):

Tax. Okay. And, Mr. Chairman, what differentiates, we had a lot of debate on the House side anyways, on the difference of something as a tax or something of fee? What makes the distinction between a tax and a fee?

Shelton: (01:17:02):

Mr. Chair, Representative. That's a good question. I can repeat something that I heard in committee last year because I happened to have the opportunity to sit at the table during a lot of that debate. What I heard, that seemed to make sense to me, is a tax that is collected by one person is spent by somebody else. A fee would be more like OCD collects a filing fee, but then OCD spends the money on administration of the filing system. A tax is more something that TRD collects and then is spent by you all.

Dow: (01:17:29):

Thank you, Mr. Chair. I mean, I think that's where I'm getting lost here, because it's an industry fee. It's an amount that we take from the industry that was designated for a specific purpose, plugging orphaned wells. And, along the way we've decided as a body to change those purposes. It's not a fee, it's tax. I'm just thinking about that dog food thing that came up where it was determined that we had to spend the money for the purpose intended. So, I'm just wondering the distinction between when we decide we're going to, this is an industry that's paying into something for this purpose, and somewhere along the way we decide to divert money, why we had that right to do that, why we had the right to divert the money away from the intended purpose and statute, and why that was legal? I guess this

Joyce: (01:18:31):

Mr. Chair, Representative. If I can again refer you to Appendix C. The oil conservation tax was created in 1959 at a rate of 0.14% on oil and gas products severed and sold in the state. The revenue went originally to the oil conservation fund, which was used by the Oil Conservation Commission to enforce the Oil and Gas Act. In 1977 the legislature chose to create the Reclamation Fund and a reclamation fund receives a portion of the conservation tax.

Dow: (01:19:07):

So, Mr. Chairman, and I guess the question would be, when that money was restored or, why didn't that money just start going to the Reclamation Fund? I mean, did we make a mistake as a body when we said we're going to create the Reclamation Fund to plug wells and didn't put all the money we were collecting from industry for plugging wells into the Reclamation Fund but, instead, we said this had this purpose, but we're going to only leave a little bit of it in reclamation and the rest of it, we're going to put in the general fund? Has anybody asked that question? And what was the answer? I mean, I know we're we're on time

Chair: (01:19:48):

No, and again, totally fair questions. I think many of those may end up sort of things we may need to wrestle with in our roles. I don't know that the staff would sort of have necessarily a perspective. Super fair questions. Maybe we'll wrestle with those and, yeah. Okay, then we will go next to, sorry. Oh no, we lost our list! We have Representative Herrera and then Senator Woods. Representative Herrera?

Herrera: (01:20:23):

Thank you, Mr. Chair. I actually was following up on Rebecca, on Representative Dow's question. Looking at this chart, so we spent in, let's just say FY 19, $3,529,000 went into the Reclamation Fund. How much went into the General Fund that year? I guess that's a question I want to know.

Joyce: (01:20:53):

Mr. Chair, with your permission, I'll have our Chief Economist come up to answer that question.

Chair: (01:20:56):

Please. Mr. Torres, great to see you.

Torres:

Mr. Chair and Representative. In FY 24, the general fund received about $106 million from the conservation tax. And then the Reclamation Fund, I think we have $26 million. That's also in the report. So, a total of about $132 million of that tax collected and then $106 million General Fund 26 to the Reclamation Fund.

Herrera: (01:21:18):

So, I think that's the question that we're all struggling with and the questions Rebecca was leading up to. If we're putting in, paying in a hundred and what was it, $120 more million in '23 into the General Fund.

Torres: (01:21:36):

Mr. Chair and Representative Herrera. Yeah. And at risk of overstepping here, I think maybe it's helpful from the outside perspective to clarify that when the tax was created, the tax was not dedicated towards plugging wells. And I think that might be missing in this conversation. So, the tax was created to help run the agency. And so over time, the legislature began to pull more and more of that tax away for the reclamation for the purpose of plugging those wells, as Stephanie pointed out, increasing that amount over time. And, so, there is still an amount in the general fund which is, theoretically in statute, the purpose is to help fund the agency. And hopefully that helps clarify some of that confusion maybe.

Herrera: (01:22:15):

Well, I think I'm agreeing with a lot of representatives and senators on this panel that we really need to look at the distribution of those monies, make sure that we use most of it for plugging the wells and running the agency. It seems like there's a lot, but I am sure there is others on this panel that we'll talk about well, we need that for the general fund. So, I think we need to look at this formula all over again. So, thank you. That's all I have, Mr. Chair.

Chair: (01:22:41):

That's great. Thank you very much, Representative Herrera. And thank you, Mr. Torres, for the additional context. Next is Senator Woods, then Senator Shendo, then Senator Tobiason.

Woods: (01:22:54):

Thank you, Mr. Chair. If you guys will turn to page 38 on the report, put 38 up there. It's a very interesting process here that we've gone through through the years that we're blaming the oil producers, but I can see most definitely why the Finance Committee cut money, didn't put money in OCD for abandoned wells, because it looks like it was kind of hit and miss a lot. And we even required them to set a goal on how many wells they's going to plug. It says, if y'all read this deal, it says in here, well, the contractor was busy with someone else and didn't get to our stuff. It says that GSA picked the contractors. Is that true? Does GSA, Mr. Chairman, anybody? Does GSA pick the contractors?

Joyce: (01:24:17):

Mr. Chair, Senator. No. OCD today, in the present day, selects the plugging and reclamation and remediation contractors. There are currently 31 vendors on the statewide price agreement.

Woods: (01:24:34):

Did you say there were 31 vendors, contractors? That's on the list to plug wells?

Shelton: (01:24:43):

Mr. Chair. My understanding, again, these statewide price agreements, and the reason that we may be getting our numbers crosswise, is because they bid on different components. So, when we do an offer, there's, we offer for, I think GSD puts it out for many, many different task sort of items. And people bid on different components of them up to and including supervising the environmental remediation, but not actually doing any of it. So, there's all sorts of different things that you do. I think that we, from OCD's

perspective, have five down hole owners. The trucks will show up on the day and pour the cement contractors. So, the total number may be larger than five but, from our perspective, we see it as five San Juan based contractors who will actually do the plugging work and lay the cement in.

Woods: (01:25:33):

Is there, so there's no other contractors in the state that do that kind of work?

Shelton: (01:25:40):

Mr. Chair and Senator. Yes, there are many. Those are who bid when we first opened our statewide price agreement. We have another one open right now, and we are getting more. So, there's a lot more that are doing it. But at that time, that's who bid on the GSD open procurement.

Woods: (01:25:58):

So, this procurement contracts that we let, Mr. Chair, these procurement, they're competitive bid contractors open, wide open if you meet these qualifications as a down hole operator?

Shelton: (01:26:15):

Mr. Chair, yes. They bid into the open process that GSD had, and I believe it was 2023, and they were accepted. We said yes to everyone who showed up and bid for actual plugging work. And that was those five.

Woods: (01:26:30):

Well, it's funny because in this literature that I have in front of me on page 38, it doesn't sound like that. It sounded like they approved five contractors at one time. It sounded like they didn't plug any one quarter because they said the contractors said it was too wet. And, they talked about, they anticipate plugging 60 wells in 2018. And then in 2019, they said well, in 2018 we plugged 41, and the agency only targeted 27 in '19. And yet they knew there was 208 abandoned wells and orphaned wells. And then in the first quarter

of '21, timing conflicts with the well plugging contractor was not met in 2020. And then a new procurement agreement in '21 allowed for additional approved well contractors. So it sounded like maybe that was the first time additional contractors was considered, just in this narrative. I mean, just what I read here, I have a hard time. All I can do is read what I see in front of me. And I know this is a particular section of what you oversee. You don't know all the details in the deal. You probably don't work with it daily.

Chair: (01:28:38):

Senator, we're going to have

Shelton: (01:28:43):

Thank you Mr. Chair, Senator. So, this is a compendium. You get your quarterly report cards for agencies. And this is just a compilation that this has been a chronic performance challenge in this particular area. And we went back to 2007 when we started these; we're not plugging very many of them. The cost is variable. There's stop and start with contracts and it sort of provides context for why did we do this report? Because sometimes that performance data doesn't tell you why or what to do about it or provide more information than what you've got in front of you. So that was the purpose of this report. It's like, let's get a better handle on understanding the scope of this performance challenge that's faced the state, and how other states are trying to tackle it if they have similar issues.

Woods: (01:29:37):

Well, I'm sorry. Am I cutting you off, sir? Mr. Chair, with that said, that's exactly what I read in this, that yeah, this plugging goes up and down with the oil market. So why wouldn't you use the money as the oil is being produced to put in a fund so that you could keep this steady? And I know because of the

performance of this OCD, you're saying those some bucks ain't using the money anyway, so I'm not going to put money in there. I can just see John Arthur Smith saying that.

Shelton: (01:30:24):

Mr. Chair, Senator. I think the fund balance has grown exponentially as oil production and the price of oil grew exponentially, which happened at the same time that we got a huge influx of federal funds for the same exact purpose. And then it's what we're experiencing across government. We've talked about this just in schools as organizationally as state government, as well as the private sector in this particular area. We've run up against capacity constraints. And, so, the challenge is how to figure out how to manage through those capacity strengths. But the challenge is that industry, they take care of the vast majority of their wells as required by statute. There's a very small number that we're very challenged to do anything about, and how do we work through that to prevent more of those coming online as abandoned, and state responsibility and work with industry in order to do that?

Woods: (01:31:23):

And I agree with that. I mean, I agree that we probably haven't discovered all the abandoned wells yet, and we can't figure out who those operators were so, you can, and they may be bankrupt as it says in this narrative, but if you collect the money as they're producing well, as they produce the oil, then you don't have to worry about 'em going bankrupt because you've got the money to take care of the abandoned well, no matter.

Shelton: (01:32:00):

And that is something that the report alludes to of coming up with an alternative way to plan for the cost of plugging it. Currently there's bond requirements, financial surety that is very difficult for OCD to work

through. And this is an alternative mechanism that should be explored based on the staff report in a way that hasn't been an option up until this report came out.

Woods: (01:32:34):

Well, I won't keep going. I understand a little more of the problem now. The main problem is old, abandoned wells and you have nobody to tie to that. But what you're saying in the report is we need to collect more money from a producer today to take care of somebody else's mistake. And I think most of the committee is saying, we're collecting money, if we would direct it to this particular fund. But then again, I am worried as long as there's plenty of contractors out there and we do this at a competitive bid so that we know we get as cheap a job as we can get. I think that's what we all want if we want 'em plugged, but we don't want to pay extra to plug them.

Shelton: (01:33:31):

And I think the question, there's not a recommendation in here to increase general industry tax to put even more money in the reclamation. There's a recognition that there are certain types of wells that exist out there, about 3,000 of 'em that are only producing about a barrel a day, when your common stripper well would be producing ten, and are those financially viable? What do we do with the 3,000 if they stop pumping and turn over and say, it's your problem OCD. Is there a novel solution to dealing with that potential liability so that the Reclamation Fund or the general taxpayer doesn't have to take on that responsibility? Are there other alternatives and how can we explore that with industry?

Woods: (01:34:26):

Okay. And under that circumstance, you've got a producer who has a well producing one barrel a day. Do we know who the operator is?

Shelton: (01:34:35):

Yes.

Woods: (01:34:36):

And you can't tie the obligation to him?

Shelton: (01:34:39):

Well, by law, they're obligated to fill it and plug it.

Woods: (01:34:45):

And, so, what do they do? Use LLCs, LLPs and just bankrupt that LLC and no longer an operator?

Shelton: (01:34:54):

Well, there's a worry that it's not economically viable, but it still meets the operational definition. And does there need to be enhanced regulatory oversight so that doesn't happen? That's what the report is raising a question about.

Woods: (01:35:10):

What's the industry saying about that?

Shelton: (01:35:13):

We will be finding out.

Woods: (01:35:14):

Yeah, and that’s a great opportunity.

Chair: (01:35:15):

(01:35:23):

Sorry. No, no, that was great and good to go through the questions. We always want to make sure folks have that opportunity. We are going pretty late. We may have to delay dinner or at least our appearance

at the dinner a little bit. We will have an opportunity, it'll need to be brief, to hear from Mr. Winchester and Ms. Wagner. We will go back to you, Senator Woods, if there's additional questions. Okay. And thanks very much, Director. So, let's see, next we have Senator Shendo, Senator Tobiason, Vice Chairman Munoz, and then we'll conclude with Representative Dixon. Senator Shendo?

Shendo: Speaker 16 (01:36:01):

Thank you, Mr. Chairman. Thank you for the presentation. Just had a quick question. On page 18 where you have the chart on the right hand side where inactive wells, you have 336 identified as tribal. Are those mainly on Navajo allotted lands? I'm just curious. I know because on page 39, on that last section on 2025, it's also written on there that the Division has been requested by the Federal Indian Minerals to help plug wells on Navajo and other land. So, I'm just curious, are those are one and the same or are they different? I'm not sure.

Joyce: (01:36:47):

Mr. Chair, Senator. I don't have the exact answer for you about exactly where those wells are located. If you go to page 15 of the report, there is a QR code that you can scan with the camera on your cell phone. It will take you to a webpage that has an interactive map showing where all of the currently orphaned, inactive, and low producing wells, as we've identified them in this report, are located. So, you can see where all three categories of those wells are located here in New Mexico on that interactive map.

Shendo: (01:37:34):

Okay. Alright. And then another question is, it says that the OCD or has begun plugging the Navajo allotted land wells. So, is that from the 55 or whatever million federal dollars, or is that a different source of reimbursement to the state that comes in? I'm not sure.

Shelton: (01:37:57):

Mr. Chair. Senator. That's a good question. I don't have the answer to that right now and I'll get that information to you.

Shendo: (01:38:01):

Alright, that's fine. And the other questions I had have been answered by other questions. So, that's it, Mr. Chairman.

Chair: (01:38:06):

Great. Thank you very much Senator Shendo. Senator Tobiason?

Tobiason: (01:38:09):

Thank you, Mr. Chair. Of the wells that you've mentioned that are orphaned, how many of them are, let's say, 30, 40 years old or older?

Joyce: (01:38:19):

Mr. Chair, Senator. We do have a chart of that. If you'll just give me a minute to find it. I believe it's on page 17. Yeah, chart eight. You can see the age of the wells that are currently orphaned based on the year, decade that they were drilled.

Tobiason: (01:38:47):

Okay. So, it looks like by that chart, and thank you for that, that the vast majority were orphaned in the sixties. So, looking at other states like Texas, sorry Mr. Chair, who just passed a law, I believe this last legislative session, to be able to go back to those orphaned wells with today's technology and make those wells viable. As a state, are we looking at that so that we're not just focused on plugging? Maybe there is a way to make these active with today's technology?

Joyce: (01:39:19):

Mr. Chair, Senator. I just want to clarify that chart eight is showing not when the wells were orphaned, but when they were drilled.

Tobiason: (01:39:28):

Oh, I see.

Joyce: (01:39:28):

Okay. So, this is the year that they were spud, in the industry's terminology. When they were orphaned, Depends on when OCD pursued plugging authority because, as I have said, we define in this report orphan wells as wells for which OCD has pursued plugging authority. As to the question about whether these wells can be repurposed for other uses, I think there is a lot of interest in that. Our understanding, in speaking to experts as part of this report, is that that's often not possible because of the way the well was completed, was drilled originally, the way that the well was constructed originally was designed to target a specific formation, and targeting a different formation, a deeper formation. Doing something like horizontal drilling or hydraulic fracturing often requires a different well design. And so these older wells often are not able to be produced using modern technology. They do need to be plugged in order to facilitate, in some cases, those new wells coming online.

Tobiason: (01:40:39):

Okay. And Mr. Chair, so are they doing something remarkably different in Texas? Does their drilling look different than ours? Why would they have passed that in Texas? What's the difference?

Joyce: (01:40:54):

Mr. Chair, Senator. I'm not familiar with what you're discussing in Texas, so I wouldn't want to comment.

Tobiason: (01:41:00):

Okay, fair. And we're talking about increasing bonding amounts, and we just increased them in 2018. So, I'm really concerned about our small drillers. How does the tightening bond market really affect them in this scenario?

Joyce: (01:41:22):

Mr. Chair, Senator. So, I will direct you to, sorry, let me just get there, page 31 of the report, just so that we're all in the same place when it comes to financial assurance. You did mention that financial assurance was, you did increase the maximum amount of financial assurance that can be required for active wells from $50,000 to $250,000. You also introduced a separate financial assurance requirement for temporarily abandoned wells, which are not currently defined in THE statute. That translates to, for many operators, less than $1,000 per well. So, the amount of assurance held for a single well in some cases is $100. So that's the context. Obviously, the overall amount, when you look at it, looks large, $117 million, but OCD can only pursue financial assurance forfeiture from the operator whose wells it has to plug. So, if an operator only has $1,000 per well in financial assurance, that's all OCD can pursue if it has to plug that operator's wells. So, I just wanted to note that. I'm sorry, if you could repeat the rest of the question? I got a little lost there.

Tobiason: (01:42:57):

Well, so Mr. Chair, I'm just concerned, and maybe Mr. Winchester can help us when he comes up to speak, but I'm concerned with how the tightening bond markets will really affect small producers and are we pushing small producers out of an industry? I don't know if you want to elaborate.

Joyce: (01:43:18):

Mr. Chair, Senator. We did hear from NMOGA that members have been having trouble securing surety bonds, which are currently one of the many options for financial assurance that is allowed by statute. The surety bond market has gotten tighter, as we understand, in surveying surety companies as a result of increased perception of the risk of these wells being orphaned. So, as in the report, there is a recommendation that you, the legislature, look at an alternate financial assurance mechanism, which is a third party trust or a site specific escrow account which would allow operators to set aside money over the course of a well's life to ensure that the money is available when it does eventually need to be plugged and reclaimed.

Tobiason: (01:44:17):

Okay. And Mr. Chair, one more question? You mentioned that you only have five people that responded to the RFP here in New Mexico and that they're in San Juan County, all of them, which is kind of shocking to me since it looks like, based on the map from your QR code, that most of our wells are in the Permian Basin. So, are you also going out of state, in particular to Texas for responses?

Shelton: (01:44:48):

Mr. Chair and Senator. That's who responded. We do resource out of state resources. That really expensive plug that Stephanie mentioned earlier was because we had a unit that we had to bring in from Louisiana, had to bring a snubbing rig in from Louisiana to, that's not something that's necessarily on the statewide price agreement itself. That's more like our existing contractor will subcontract out for that and then bill us as an overage on that. So ,whether or not the statewide price agreement is open to out of state contractors? I don't know off the top of my head, Mr. Chair. I'm sorry. I can look that up.

Tobiason: (01:45:27):

Mr. Chair. Yes, if you could. Because it just seems to me, as just a business person, that it's not best practice for our state and even all the dollars, whether they're federal dollars that we're currently using or the tax from the oil and gas industry here in the state, it just doesn't seem practical to me that we would be paying top dollar when I'm sure there has to be other operators in the region at least, even if they aren't in Texas, which I would imagine Texas has quite a few. And I'd want to know why they aren't responding. Is there some situation here in New Mexico that precludes them from any desire to come here and expand their business? So, I'd like to know that answer. Thank you, Mr. Chair.

Chair: (01:46:12):

Great, thank you very much Senator Tobiason. We're going to go to Vice Chairman Munoz and then conclude with Representative Dixon.

Munoz: (01:46:22):

Thank you guys, and thanks for doing this report. Lemme ask you some questions. How many federal wells are unplugged right now, Mr. Shelton?

Shelton: (01:46:33):

Mr. Chair, Senator. I dunno if we keep that list. I can tell you that the process for the federal government for going about getting permission, basically getting the plugging orders, is a lot longer and a lot slower than ours.

Munoz: (01:46:51):

But we're not tracking the federal wells that need to be plugged too, because if the feds decide to come up, not fund us for the federal side, they'll probably become the state's responsibility. So, I'd like to know that. And then, why is not the land office abandoned wells listed in this also because they're part of the

abandoned well project, I think? I don't know how they do those. Do you know how the state land office pays for their well plugging?

Joyce: (01:47:22):

Mr. Chair, Vice Chair. State Land Office wells are included in this estimate of orphan wells. It is state and private land wells. The State Land Office, OCD plugs all wells in New Mexico, including the State Land Office wells. So, OCD does all of the plugging for wells in New Mexico, including on state lands.

Munoz: (01:47:50):

So, does the state land office have their own fund for well plugging? I believe they do.

Shelton: (01:47:57):

Mr. Chair. No. I will say that the State Land Office will compel their lease holders to go in and plug. So sometimes they'll have, the leaseholder will be one entity, and then they'll have the operator be somebody else. The state land office will frequently have the leaseholder go in and basically compel them to plug the well on state trust land which, that would kind of count towards the private or industry plugged wells.

Munoz: (01:48:21):

So, do you have any estimate on how many federal wells that will need to be plugged or how many in the last five years you plugged and what those numbers look like? How many federal wells have you plugged in the last five years and how many do you have on a two year spreadsheet to plug?

Joyce: (01:48:39):

Mr.

Munoz: (01:48:39):

Mr. Chair? I'm asking Mr. Sheldon there. He's in charge of OCD. You may not know that number.

Shelton: (01:48:44):

Mr. Chair. I don't know the exact number. The number is not huge. We basically will plug BLM wells with BLM funds. That's a separate fund. It's a separate project that we operate under, but it's not more than probably, I'd say, 300 in the last five years.

Munoz: (01:48:59):

So how many in the last four or five years?

Shelton: (01:49:01):

I would estimate not more than 300 in the last four or five years, but I'll get the exact number for you.

Munoz: (01:49:06):

But you can plug those 300 wells in the last five years. But in the last, how many wells did you plug on the state leases this last year?

Shelton: (01:49:17):

Mr. Chair and Senator. I think about 130.

Munoz: (01:49:20):

So, you have enough contractors to plug the federal wells, but you don't have enough contractors to plug the state wells? Are the BLM wells operating under, when you plug 'em, operating under the state price agreement?

Shelton: (01:49:36):

Mr. Chair, sorry,

Munoz: (01:49:38):

Just let me finish my question. So, if you're operating on the state pricing agreement and you're sending your contractors to plug BLM wells before you plug state wells because the federal money is there, you're

not balancing out the number of wells equally to balance those, even though you have the state funds to plug those wells, correct? Your priority is BLM wells to be plugged over state wells.

Shelton: (01:50:07):

Mr. Chair and Senator. I don't know that I would. I think that we prioritize plugging wells based on our criteria for what is a priority. The BLM project is significantly smaller. We get much less frequent orders, and we use a lot of different pot of money to go plug BLM wells. So, it's a little bit of an apples and oranges comparison, Mr. Chairman, based on just the volume of work.

Munoz: (01:50:31):

Well, how could it be different? I mean if you have a BLM well next to a state well a mile away, right, and you chose to prioritize, you said 300 wells over the last couple of years, and you've only done 120 wells for the state, you're prioritizing that state pricing agreement to do the federal wells and not do the state wells. Is that why the state money is not getting used?

Shelton: (01:50:58):

Mr. Chairman. No. No. That is not what we are talking about. We don't prioritize federal wells over state wells. When the BLM receives a plugging order under the contract that we have with them and they send to us, we will utilize our contractors under the statewide price agreement. But the actual order that we tackle the work on is based on the list, that is an appendix, I believe C. That is how we triage. It's based on a number of criteria. But the question, the difference is really just who does the plugging order come from, whether that is coming from OCD or coming from the BLM.

Munoz: (01:51:35):

So, does the OCD give the plugging orders or does the state land office give the plugging orders if the lease is expiring in the lessee? So, who gives the plugging orders?

Shelton: (01:51:43):

Mr. Chair. The OCD does all of the plugging orders. The land office can request them, but they will occasionally direct lessees, which is different from

Munoz: (01:51:50):

How many FTE do we have in OCD that are working on well plugging?

Shelton: (01:52:01):

Mr. Chairman. And that would be our engineering bureau. And that's about 30 to 40 staff that are doing well plugging in addition to all of the permitting for all of the active producing wells in the state.

Munoz: (01:52:15):

But you're not plugging active wells; you're just plugging abandoned or wells that have plugging orders through an agency, correct?

Shelton: (01:52:23):

Mr. Chair. Yes, that's correct.

Munoz: (01:52:25):

And are you required to get a permit to do plugging or, you issue the permit to the contractor, not just the order to do the plugging?

Joyce: (01:52:37):

Mr. Chair, Mr. Vice Chair. OCD does require a sundry notice for plugging. Operators have to submit that before they plug wells. The contractors who work for OCD also have to submit a sundry notice before plugging, which includes conditions of approval. OCD engineers review the plugging diagram, the plan, add additional conditions where necessary, so there is a permitting process for plugging a well.

Munoz: (01:53:13):

So, could you get me a copy of those orders, and I want to see the difference between the BLM and in the state and see what the difference in the orders are and see why, because there's an imbalance for a reason? I mean 300 to 120. There's an imbalance for a reason. I mean, if you have 120, how many orders do you currently have to plug wells right now?

Shelton: (01:53:35):

Mr. Chair? I believe the number is 702 on our list.

Munoz: (01:53:40):

I'm sorry. 702?

Shelton: (01:53:42):

702 wells.

Munoz: (01:53:43):

702. And how many do you expect to plug this year?

Shelton: (01:53:50):

Mr. Chairman. That's a bit of a moving target because we were recently advised that using BIL funds to plug wells requires us to satisfy some scoping requirements for the Endangered Species Act and the National Cultural Preservation Act as well, which has held up some of the expenditure of the federal funds. So, it's difficult to project right now. It kind of depends on what our contractors

(01:54:08):

get back to us with that final information that'll satisfy the federal government's requirements.

Munoz: (01:54:12):

But that's on the reclamation on the top side, not inside the well, right? To plug the well?

Shelton: (01:54:16):

No. That's to go in down hole, Mr. Chairman, and plug the well.

Munoz: (01:54:21):

What endangered species would be down the well? Give me an idea of some creature we have. Maybe Bigfoot's there since we haven't found him yet or any bones or anything.

Shelton: (01:54:32):

My understanding, Mr. Chairman, is that they're more concerned about the surface impacts associated with the plugging activity.

Munoz: (01:54:37):

That's what I just asked. I said that's more in the surface than within the well, and so you could plug the well and then do the reclamation later, right?

Shelton: (01:54:45):

Well, that's different from the environmental reclamation, which can frequently involve excavating soil and that kind of thing. This is more trucks, traffic, that kind of impact.

Munoz: (01:54:55):

And, so, when you did your statewide pricing agreement, how many contractors bid on plugging wells and, I don't know, how many they're scopes of work for each area, right? If it's going to take a plasticized cement, if it's going to take a 4,000 or 10,000 psi, how many contractors bid on well plugging in the state of New Mexico?

Shelton: (01:55:19):

And again, Mr. Chairman, not to get too lost in the sauce, but across,

Munoz: (01:55:23):

Well I want to get lost in the sauce. I want to understand how the sauce is made. And so how many contractors bid on the well plugging?

Shelton: (01:55:30):

On the actual well, plugging down hole work?

Munoz: (01:55:35):

So, on the state price agreement, how many contractors bid the statewide price agreement?

Shelton: (01:55:40):

Five.

Munoz: (01:55:41):

And that's five in total?

Shelton: (01:55:43):

On our last round for the statewide price agreement? Yes. Five.

Munoz: (01:55:46):

And then there's contractors in southeast New Mexico that plug wells, and they own well plugging deals, but they're not allowed to plug wells in New Mexico. I won't say their name, but you guys have told 'em, “No, you can't plug wells in New Mexico,” even though they plug wells in Texas. And even though they're well owners and can plug their own wells, you guys require them to go to the statewide pricing agreement to do that. And, so, if they got to plug their own well at a higher cost because of the statewide pricing agreement, then them plugging their own wells at a lower cost and meeting the same specs, why are you not allowing that?

Shelton: (01:56:29):

Mr. Chairman. I'm sorry. I'm not familiar with the process. You're talking about our contractors plug abandoned wells. So, if there's no operator who's seeking permission to plug their own well, they wouldn't be bound to use a contractor on our statewide price agreement. They can use whatever contractor that they, I think, need for their own well.

Munoz: (01:56:48):

Well, we'll get the names of the contractors, and we'll get the letters saying they have wells, and they want to plug their own wells, or they want to plug other wells, and you guys aren't allowing them to do that. I don't know if it's chicken in the hen coop or what the scenario is, but that's interesting. How many abandoned well owners has the state went after for well plugging costs?

Joyce: (01:57:15):

Mr. Chairman, Mr. Vice Chair. If you mean how many operators whose wells the state has plugged has OCD sued? The answer is none.

Munoz: (01:57:27):

And doing Mr. Shelton, why hasn't your agency sued or tried to reclaim the money and the cost of the state from those operators, owners, whatever you want to call ‘em.

Shelton: (01:57:39):

Mr. Chair. And just to be clear, there's two specific activities. There's suing and then there's actually pursuing financial assurance. And to be fair, we've barely pursued financial assurance, and the answer is because the juice isn't worth the squeeze. I have three attorneys to process a

(01:57:55):

hundred percent of the enforcements.

(01:57:57):

It's not worth the juice; is not worth the squeeze. I'm not going to send one of my three attorneys, who are doing a hundred percent of the enforcement for the entire state, on a two month goose chase for a $50,000 bond. It's just not worth the state's taxpayer's dollars for me to dispatch legal staff to go do that. Right now, that has been the case. We are adding another attorney. We're getting a little bit more active about doing this. But, to this point, the value proposition of the department of pursuing a lot of financial assurance and certainly suing under some of these things, the conditions have not been there for us to even pursue it. And then once the conditions are there, it's not an efficient use of taxpayer resources to go and try to get it.

Munoz: (01:58:36):

So, in the end, whoever it is, I'm going to use Senator Tobiason because she keeps losing it, looking at me. So, Senator Tobiason has a well and she says, ah, this well's not producing anymore. I don't want to spend the money and plug it. I'm just going to walk away. And she got a $50,000 bond. Maybe it was a thousand bucks or a $50,000 bond. And she knows the state's not going to come after her for plugging the well because the plugging the well costs I really couldn't see because I didn't have my glasses to see what it cost to plug a well from Drake Well Services in Farmington. Why would I not walk away knowing that I'm not going to get prosecuted even though that's the state's responsibility to chase the bad actors that leave and leave the abandoned wells? And that's a state's responsibility, then why even have a bond if we know that you're not going to chase the bond?

Shelton: (01:59:33):

Mr. Chairman. And this is, that's a great point, and this is why we're putting more of a priority and more of an emphasis on starting to retire and go after some of that financial assurance, in particular. But there

is a chicken and egg problem here, which is that we don't collect enough to make it worth our while. We don't collect enough to make it really hard for operators that we have to go get it, and they're not going to get it back. It's different in the mining space for instance, where we do full cost bonding. They really, really, really want to get their mines cleaned up because they really want their bond back. And that's just not the case in the oil and gas space because our amounts are low. And then, yeah, candidly, the capacity concerns have advised against pursuing it. But it's something that we're changing specific to that dynamic, we don't want to send that message.

Munoz: (02:00:14):

But you're allowing bad actors to continue their bad habits, knowing there's no recourse. I'm going to go get a thousand dollar bond and buy 20 wells and spend $20,000 getting a bond and maybe I make, I don't know what they make. I make money off that deal and then I'm just going walk away knowing that I committed a crime or a violation against the state of New Mexico, knowing that they're not going to even begin to chase me because we don't think we need to send a message for $50,000 to chase their bond. I mean that is kind of a dereliction of duty because the bond exists for a certain purpose, to clean up the wells, but you're just going to say no matter what happens, we don't think your bond's worth anything, and we're not going to chase it. And, so, go ahead and just keep doing the same thing over and over again.

(02:01:07):

And people are creatures of habit. There's good actors. There's bad actors, and they're creatures of habit. But if you don't prosecute or start chasing bonds and the bond companies say, we're not going to issue a bond because you're not creditworthy, that's the way they issue bonds. How are you on your credit worthiness? We're not going to issue a bond. We think you're going to bend this well and you don't have the wherewithal to plug the well, and they're going to come after us for $50,000. I mean, there's a process

and it was set in there in place for a reason, but if the state's determined that they're not going to chase the bonds, you could get a million dollar bond for a well and then the state would say, well, we're not going to chase a bond because it's not worth the juice. It doesn't quite make sense to me.

(02:01:56):

I mean, as a contractor, I have to have a bond. And anytime anything happens, they'll try to chase your bond if they can, but they will pursue it. But if the state's going to throw up their hands and say, go ahead and do whatever you want, abandon all the wells you want in New Mexico, because we're not going to have any recourse. We're not going to do anything to you. We're going to tax the industry or charge industry a fee or whatever it is, at a certain rate, and they're going to plug your well for you. Those guys that are buying those wells that are low producing, that they know are going to end up, that aren't credit worthy, that continue to leave abandoned wells in New Mexico and leave us to clean up the mess. That's not fair to everybody else. So, I want to see when the agency's going to start chasing bonds because they are tasked with chasing those bonds.

(02:02:45):

And I imagine that, in the statute, and the statute says the bond is in place because if you abandon the well and we have to plug it, then the state has a duty to proceed to chase that bond. Not just, I don't have the time or it's not worth the juice. It doesn't really help send a menta, l an issue to him saying, you better get to plugging this. So, if Senator Tobiason didn't plug her well and abandoned it and opened a new company, would she be allowed to issue a permit or get any other wells even though she abandoned that one?

Shelton: (02:03:26):

Mr. Chairman,

Munoz: (02:03:27):

OCD controls the permitting process. Do you guys control the permitting process? So, are you matching Senator Tobiason with a bad well actor, and then a new well actor, and saying, you didn't fix this well so we're not going to allow you to permit the next one, or take over the next one? Are you guys matching those up?

Shelton: (02:03:44):

Mr. Chairman. Our view of the Oil and Gas Act, and we proposed legislation I feel like, I'm going to say, in 2024. This may have been part of that bill, but the view right now is that we don't have the authority to do that sort of bad actor review on personal compliance. So, if you start a brand new company that's got a clean bill of health and a clean record, then no, we don't have the ability to come in and say, hey, one of your officers has outstanding liability on another company.

Munoz: (02:04:13):

Well, I think the state can do that. If the state would have filed or chased that bond, they would actually have a lien against somebody that's listed on a corporation that could now come back and say, well, we have this state lien and we're not going to allow anything else to happen until this other issue is resolved. I think they have that authority. I think they do it all the time. I mean, I think that Clay Bailey's agency can go to a contractor and say, you have a complaint and you have a lien and you have a claim and we're not going to renew your license or issue a permit. The former director's shaking her head at me and have recourse until that's done. Or if you owe your taxes in the state of New Mexico, I think there's a recourse that can happen too. But I mean the legislature is the legislature, but the agencies under the executive have to function. And if they're not functioning and they're not functioning correctly to plug wells, to make sure that you can't control the supply of contractors that are going to bid on well plugging. But you can

control how you prioritize wells, how you chase people that have a bond that abandon wells and leave us with this mess and spend us in a two or three hour discussion today and leave us holding the bag for how much money over the last 10 years, Charles? I don't have that. I mean, what did we spend last year? 40 million. What did we spend on abandoned wells last year? Over the last three years?

Joyce: (02:05:51):

Mr. Chairman, Mr. Vice Chair. Since FY 19, we've spent about $50 million on plugging. Yeah,

Munoz: (02:05:57):

I mean $50 million because we didn't want to chase 'em. I mean, that's a big number. I mean, there's places where we could put $50 million, probably going to be in the SNAP program as it comes forward in the cuts. But I mean, we all have to work together to get these problems resolved. I do want to bring one other issue that's really bothered me and that's in this report, and this is not going to the staff but to Charles, you agreed to meet with a legislator and then had him set up a meeting with the staff to talk about this, and this is a legislator I'm talking about. And then when the legislator showed up at the meeting, then there was no meeting and we're a nonpartisan committee, but if a legislator or someone has knowledge and a skillset, they should be allowed to talk about it in a nonpartisan way.

(02:06:56):

So, we have the best information that we can have and that's an issue for me when someone, if you don't want to have the meeting, then tell 'em you don't want to the meeting, but don't schedule a meeting and then schedule it with your staff and the analyst and then him show up at the meeting and drive from Roswell and then not have the meeting. I completely understand we're going to be nonpartisan. We're going to listen to industry. We're going to write your opinions and what you think the process is and give us a clear spotlight on what needs to happen. But if there's any outside influence, then it shouldn't be in

there, and that goes on every side. But when we schedule a meeting with legislators and agree to meetings and agree to do things in LFC, then we should do 'em. If we don't want to do 'em, don't agree to 'em, but when I got to get my email lit up and have conversations, I don't expect that to happen in LFC anymore. So, I think we got some responsibility and some that needs to happen. I think OCD and EMNRD has some work to do, so we don't spend $50 million when we could be ahead of this problem. If we have to change legislation, I guess we'll have to change legislation, but everybody should have an opportunity, especially industry, when they have knowledge and skillset. Thank you, Mr. Chairman.

Chair: (02:08:26):

Thank you. We're going to go to Representative Dixon and then Senator Padilla.

Dixon: (02:08:33):

Thank you, Mr. Chair, and thank you staff and Deputy Secretary for sitting here with us through a very long, but I think enlightening and thorough discussion, although I think we could discuss this for another three hours because there is actually a lot to unpack. I have three pages of questions, but since I am at the end of the list, I will not ask all of them and I will try to consolidate them so that I can just ask a question and get a quick answer. We answered why the state doesn't sue for financial assurances. It's because the agency, I think, has a valid perspective that it may not be worth the taxpayer dollars. I think that's useful information for us as we consider moving this forward. Why is the agency, sorry Mr. Chair and Deputy Secretary, is the reason that the state is not plugging more wells each year capacity or is it money?

Shelton: (02:09:49):

Mr. Chair. It's, I guess, capacity, but not agency capacity that we are limited by the contractors.

Dixon: (02:09:56):

Exactly. Okay. So, if you had more money or less money, that's not the issue right now? It's that there are five contractors on the price list that have signed up to do these pluggings, and when you do another bid for the state price agreement, hopefully operators in the Permian with this expertise will sign up. Is that correct?

Shelton: (02:10:25):

Mr. Chairman, Representative. Correct.

Dixon: (02:10:26):

And, so, Mr. Chairman, Secretary, Deputy Secretary. If you had ten contracted operators, theoretically the agency could plug twice as many wells, theoretically.

Shelton: (02:10:44):

Mr. Chairman. Sure.

Dixon: (02:10:45):

Thank you, Mr. Chair and team. I guess, do we monitor all of our inactive wells to see if there are methane emissions, things like that?

Joyce: (02:11:11):

Mr. Chair, Representative. As a condition of the funding through the I-I-J-A-B-I-L, OCD has begun monitoring methane from some of the orphaned wells. I believe it's in the report, but they've taken methane measurements at something about like 125 wells. But no,

Dixon: (02:11:36):

That is great. Mr. Chair, Deputy Secretary, is it possible that the state could implement measures? Could you work with contractors to monitor more wells because that's a significantly cheaper operation and would that potentially help prioritize more wells that should be plugged?

Shelton: (02:11:57):

Mr. Chairman, Representative. This question, from my mind, the first question I ask is that an acceptable use of just monitoring versus the actual plugging and reclamation work. So that'd be the threshold question I'd answer but, if the answer is yes, then certainly we could put a price agreement or put a ITB out for that kind of monitoring.

Dixon: (02:12:16):

Thank you, Mr. Chair. Thank you, Deputy Secretary. Because there are actually, there's a wide range of new technologies that are emerging that can actually help with the monitoring and plugging activities, that I think it would be great if this state could explore because it would also support the current energy industry, as well as some of the advanced energy startups here in New Mexico. TS Nano being a great example of a homegrown company. At some point I'd love to talk more about why there are 121 companies with 1,034 inactive wells just, and this is probably a question where I'd really like to talk to the industry to understand the calculations of what those wells are doing and why they wouldn't be plugged or would be plugged. Because I think that's just a business, because I'm not in the business. So, along those lines, I would love to hear, I don't think we're going to get to it tonight, but in the future, I'd love to hear what the industry recommends for steps that the state could take because I think that there's a valid, the question of raising financial assurances using more reclamation fund money gets to a philosophical debate about moral hazard, right?

(02:13:54):

I mean, I'm not an economist or a philosopher, but I think that this is not just an easy answer. And, so, I'd love to hear what industry suggests along those lines. Similarly, I was wondering for our team if you looked at Colorado's, their new legislation that rewards operators that plug their wells with a credit, because I certainly am a fan of incentives and carrots as opposed to sticks, particularly if the sticks aren't working the best. And, so, with that, Mr. Chair, I will conclude.

Chair: (02:14:37):

Great. Thank you very much. Representative Dixon. Senator Padilla informed me he's going to have some questions offline. I encourage everybody to do that. I'll wrap up a couple of quick things. First, we have a nationally recognized evaluations team. One of the reasons that they're nationally recognized in this work has gone on well, predating my time in the legislature, is because it's an independent group that is able to do their work that is very engaged with all of us, whether stakeholders or individual members. I think we can all agree that defending that independence is a core part of what keeps this evaluations team really functioning for our state. And we all know that more evaluation, particularly with the resources we're putting out, is very important at this time. So that's a long-winded way to say thank you to Ms. Joyce and Ms. Dodson. Really appreciate this work and the extensive amount of work that went into it, the evaluations team.

(02:15:47):

So, thank you guys. Whenever you can spark a lot of discussion, you know you're doing really good work. So, a big thank you Mr. Shelton. Thank you Deputy Secretary. From my own perspective, I think it's clear that there are things that need to change, and this has been sort of a start to that with an excellent report, a really good discussion, another part of that. So, we will let you guys step away from the table after that.

Thank you guys. I want to invite up Mr. Winchester and Ms. Wagner, communicating with them offline today. They made the request to be part of the presentation. This is, I think, the way that best uses the time we have today. Very grateful for them. Want to invite them. They're going to share brief thoughts and perspectives. There won't be any questions simply because we have a couple other presentations we've got to go to, but while this wasn't on the schedule, I did think was very important and appreciate them both being here and taking the time. With that, we'll go to you.

Winchester: (02:17:00):

Mr. Chair. Can you hear me? Okay? Thank you. First of all, I just want to introduce myself, Jim Winchester from the Independent Petroleum Association of New Mexico. We represent predominantly the smaller producers and, in this case, they are the ones that stand to be impacted quite a bit by some of the recommendations and some of the information that's being shared here. I want to start by saying that I really do appreciate the opportunity to comment and I'm concerned and want to offer context on the issue of abandoned wells a little bit from a higher perspective and, frankly, whatever specifics are in this report we only did get this afternoon so obviously I'm not going to get into the specifics of the report itself because we just don't know the context of that completely. But I want to offer context both as my eight years representing Independent Petroleum Association of New Mexico, but also four years working at EMNERD and directly interacting with OCD on many issues in seeing the pain of bureaucracy.

(02:18:09):

So, I want to stress that I'm empathetic of the challenges to that department. Industry has long been very concerned over plugging abandoned wells and, as you heard, so much so that in the seventies and then with further reforms over many, many years, we recognized that problem and want to fix it. As you heard, the most recent financial assurance increase took effect in 2019. Rulemaking was in 2018. But,

furthermore, I want to emphasize that it was industry that worked with the state that so many years ago to create what we were hoping was going to be adequate funding by industry to plug abandoned wells through this Reclamation Fund. We recognized that there are operators that abandoned wells, and the whole concept behind the Reclamation Fund was for industry to have the state hold and reserve money to take care of those wells by the bad actors.

(02:19:10):

We're not happy about the fact that this occurs and that there are bad actors that are out there. I want to stress that the Conservation Fund, the Reclamation Fund, these are not taxes paid for by private citizens. These are industry dollars on every barrel of production and, you've heard already in the discussion, had the funds remained whole, it's our estimation that at least $500 million, maybe more like a billion dollars of money paid by industry, would've been available to simply plug all the 1,700 wells that we have abandoned right now. Now, I don't have anything to back that up statistically, but I'm telling you that with the last 15 years, the way that money has been robbed from that fund, we're talking about millions and tens of millions of dollars.

(02:20:01):

We do want to make sure that the sites are cleaned up, that the environment is returned to its natural state, and I do want to stress that 98% of abandoned wells are already plugged by industry, and industry alone, without any of the additional funds that are put into the Reclamation Fund that operators already pay into. As you've heard, during the down years it is the legislature that has swept these funds and allocated them elsewhere and, essentially, in the perspective of my members, that's broken the trust with industry and it's tying up the hands of OCD. Again, with the legislator spending industry's reclamation funds money since 2010 elsewhere, it's become a very, very sensitive topic for the smaller members

because that money is dedicated from industry and earmarked for that very reason and it was robbed. So, understand that that is the starting point of view on this topic for IPANM members, hence the sensitivity, which I do believe is justified.

(02:21:10):

That's our first point. Obviously, legislature created this problem by choosing different priorities other than those intended by the industry and those industry dollars. I do want to note that even with that circumstance, industry has attempted to fix the thievery of the oil and gas funds with proposed Reclamation Fund Act bills the past two sessions that would redirect that industry money back into the Reclamation Fund, and I'm pleased to say it's had bipartisan support with many folks around this table, but we can't get it across the finish line for whatever reason. Sadly, I fear it's due to politics and, frankly, without the votes from you guys, that Fund will never be made whole. My second point is this. Industry has tried many times to work to create efficiencies with OCD to plug wells in a better manner with that industry money, and now with tens of millions of dollars from the federal money, and that money has to be spent or risk it being reverted back to the federal government. But the excuse we always hear from OCD is that there's not enough staff. Now, I am shocked to hear that there's 30 to 40 people working on plugging wells in OCD? That is not what at least my members tell me because maybe, it's just because they communicate with only one person and, at times when they're trying to get stuff through, there's delay after delay after delay.

(02:22:44):

But, frankly, in our estimation it's not necessarily just the staff situation. There's a systematic problem when OCD is only able to issue contracts to plug a small number of wells, a small finite number of wells. Industry does this job much more efficiently and at lower costs than OCD’s process. We've talked about

that and, in fact, to follow up on what Senator Munoz said, anecdotally, we've had some of our member companies create sub companies that have wanted to bid on large scale plugging projects a hundred at a time, at cheaper prices, but they've been told because of bureaucracy, that's not how we do it. I don't know what the number is, 25 at a time or the bids are separated by component jobs, which is inefficient and really just translates into bureaucracy getting in the way of cost savings and efficiencies. These member companies of IPANM have abandoned those projects because it was futile.

(02:23:50):

Now, again, I do sympathize with OCD, having worked there. In some respects, their hands are tied, but the fact of the matter is that the existing Reclamation Fund right now has tens of millions of dollars that remains unspent. Now, I commend them for working hard to prioritize those federal dollars before getting to the remainder of that which is contributed by the state and the state operators, excuse me, the state operators, but the fact of the matter is they can't spend the money that they have. I do want to add that we have high hopes and are excited about the newly appointed OCD director, Albert Chang, and we'll look forward to hopefully working with him collaboratively to address this and many other problems. Finally, I want to comment on the timing of this 43-page report.

Chair: (02:24:41):

And, go ahead, Mr. Winchester. I do want to say, and very much appreciate that sort of the hand on the scale idea from staff is one of the few things that will, so please continue. Just please know that sort of the independence of staff and the ability for folks to operate in a way that is separate from the politics that we have to work through, which is totally what we sign up for. It's an important place for me for sure.

Winchester: (02:25:19):

Okay, thank you. And regardless of the intent or why this report comes now, the fact of matter is, is that it's problematic because we know that LFC is a nonpartisan group. They do hard work, they do good work, but this report now comes three months before the Oil Conservation Division will be holding an extensive rulemaking hearing on new extremely high bonding rate proposals that will put smaller operators out of business. OCD. And, again, I haven't read the report, but what we are hearing suggests that one major answer to the abandoned well problem is to raise bonding. Folks, that is not the answer, at least not a sixfold increase proposed by OCD and the environmental groups who are driving this rulemaking. Now, IPANM intends to argue vigorously in rulemaking in October that raising bonds to this level would be catastrophic. Now, this nonpartisan report will be unfortunately flaunted as a dramatic reason as to why we need to increase those bonds regardless of what the conclusions are, instead of really addressing the problems that I just outlined.

(02:26:43):

Again, on the report itself, I paged through it. There are definitely some good points of analysis, but we strongly disagree with the financial assurance findings. The last thing I will mention, and I'm learning about this process even eight years into it with LFC, the report comes without any consultation to our group, the Independent Petroleum Association of New Mexico. For us to even talk with the analysts or explain the aforementioned problems. That's highly problematic to my members, and they're the ones that are on me to ask why. I find great irony in the fact that Mr. Shelton wrapped up his comments with It's good to be heard in this report. I counter by saying it sucks not to be heard. I think the members that I represent are highly justified in their concern. Had we been consulted, we would've pointed to Colorado and raised their financial rulemaking that occurred several years ago.

(02:27:45):

And the impact of that, which immediately added to the abandoned well problem, because the bonds they put in place were too high for smaller operators to continue to operate. We call that forced premature closing of wells due to overregulation. And the shame is that those wells would've generated revenue to the state, to Colorado, and we fear that that's coming our way. Again, I apologize, I'm wrapping up. I'll skip the final notes on the problematic stats that I saw in here, but if the state is paying $168,000 per well for plugging, they're getting taken to the cleaners. And there's more. I won't indulge. I appreciate all of you allowing IPANM to offer our serious concerns about the process. Again, we need to look at the content of this report, and there is a larger problem here about abandoned wells. I do want to stress, despite the fact that we are sensitive, as you can tell, that we do want to partner with the state to solve this problem, but to do so without making the problem worse and potentially taking down some of our good smaller operators in the process. Thanks.

Chair: (02:28:57):

Thank you. Ms. Wagner?

Wagner: (02:29:03):

Thank you, Chairman and members of the committee. I'm Ashley Wagner, the Vice President of Government Affairs for New Mexico Oil and Gas Association. We represent over 200 member companies. Jim did such an excellent and thorough job that my comments will be a lot shorter. In recent years, oil and gas operators plugged over 90% of the wells decommissioned in the state. For every well plugged using public funds, the oil and gas industry independently plugs 10 more without fanfare and without burdening New Mexico taxpayers. Only tax dollars paid by the oil and gas industry are used to plug orphan wells In New Mexico. Not a single cent comes from the pockets of New Mexico families. The millions spent by OCD

to plug wells came directly from federal funds and the Reclamation Fund funded entirely by industry paid taxes. But these funds are only effective if they're deployed efficiently. The oil and gas industry supports modernizing the Reclamation Fund to ensure it maintains a sustainable efficient tool for environmental remediation.

(02:30:07):

That means streamlining procurement, reducing administrative burdens, and preserving the fund's integrity for its intended purpose. The oil and gas industry is proud to carry the responsibility of plugging and remediating wells. During a well's lifetime, it provides energy for the world and contributes to our state's economy. At the end of its cycle, the land is returned to its native state. It's a responsibility we take seriously and one that we're already fulfilling. Let's work together to ensure that the systems in place support this important work now and for generations to come. NMOGA is committed to working with OCD and the legislature to find a solution to move forward. Thank you.

Chair: (02:30:47):

Great. Thank you both very much. Thank you. Okay, members, we have two more presentations. We're going to do our tax expenditure report and then Director Sali is going to go through the large appropriations, as he's informed me, and it's the large appropriations. Both of these pieces are important for the rest of the week as we go through it, and there's really no other time to reschedule, so we know we take our work seriously. So, we're going to invite up our analysts and work through tax expenditures.

Klug: (02:31:30):

Alright, good afternoon everyone, Chair, and members. My name is Maggie Klug. I'm one of your program evaluators at the LFC. On my right here is Brendan Gray, one of your economists at the LFC. If I could have you turn to Tab E in your binders, we'll be presenting the first tax expenditure assessment report or Tax E

report for short, and we'll try to keep our presentation short as well. Starting on slide two, we'll start with some background on tax expenditures, why these tax expenditure assessments are needed, what they contain, as well as some key terms and definitions to help you all in understanding the information you're going to hear today. Then we'll present our first two assessments on the rural job tax credit and high wage job tax credit.

(02:32:18):

Going to slide three, what is a tax expenditure? So, the name is actually a little bit maybe misleading. It's not necessarily an appropriation that the state is spending, but money that the state foregoes to incentivize businesses or individuals to act in a certain way. And, so, this can look like a credit or an exemption or a deduction. A credit is where a business or individual gets money back from their taxes, and a deduction or exemption is not having to pay something in the first place. Now moving to slide four, tax expenditures make up a large share of the state budget, around $3 billion or around 33% of our fiscal year '24 recurring appropriations, with the largest expenditures going towards citizen benefits, healthcare and economic development. However, despite this large share of the budget, monitoring of our tax expenditures has been limited thus far. Recurring appropriations track closely with performance measures.

(02:33:17):

We've recently begun non-recurring quarterly reports, but we don't really have a good idea of what we're getting for our money with these tax expenditures. So, now moving to slide five. As you can see, tax expenditures comprise most of economic development investments and you can see a list of these economic development tax expenditures on the right side of the slide. Once again, like I said, currently we don't have a good idea of what these expenditures and claims are getting or, we have an idea of the

expenditures and claims through the taxation and revenue departments annual tax expenditure report, but we don't know what we're really getting for our money. So, income, these monthly tax expenditure assessments or Tax E reports. So, we're starting today with the two that you see highlighted in blue, high wage jobs and rural jobs. And while these make up a small amount of the share of the total, we grouped these by topic and started with these because, as you'll hear, high wage jobs will be expiring shortly. And, so, we wanted to go ahead and get that information in front of you guys. I'll now hand it over to Brendan to further describe the report's focus and go over some key terms for you all.

Gray: (02:34:25):

Mr. Chair, committee members. My name is Brendan Gray. I'm an economist at LFC. Like Maggie said, my task is to orient you a little more towards the actual report itself, and to define some terms before we'll jump in, and we're going to keep flying through our slides. And, so, if you want to read ahead, you can. The actual Tax E reports are going to be after the slide deck. If you flip through your binder, they're going to look like this. The good news is they're very short one page front and back. That summarizes a lot of information very quickly.

(02:34:59):

Yeah, so if you, on slide six, this summarizes what these assessments contain and what they don't contain. So, we're hitting three sections. We're summarizing the history of these tax credits. Some of these are multi-decades old, and so we're going through that process. We're looking at the fiscal and economic impact. We ran these through a new economic modeling software that we have called REMI to understand how these are reverberating through the economy. And then, lastly, we're looking at the design of these tax credits. Are they designed well? Are there places of low hanging fruit that we can make improvements? What these assessments don't have, we're not comparing across states. We're not doing

a cost benefit analysis, so we're not at that point where we can compare apples to apples between these types of investments and other investments that you all as appropriators make. And then, lastly, we're not making recommendations.

(02:35:57):

All of that we can develop if you, Mr. Chair or the committee wants us to develop those things, we're happy to do that, but for now we're getting an inventory, getting our hands around that $600 million that we're spending on economic development tax expenditures to present to you all. Okay, on slide seven, two quick terms. First, these are kind of the key takeaways. The economic impact of these, the return in revenue, this is a measure that's measuring how much for every $1 we spend, how much more in taxes are we collecting? And, so, a negative return in revenue means that we're spending a dollar and we're getting less than a dollar back in increased tax revenue. And then you also have economic return on investment. This is moving away from just revenues and looking at the entire economy. For every $1 we spend on this tax expenditure, how much is the state economy growing?

(02:36:58):

That's what that measures and you're welcome to read more about those definitions and, if you have questions about our methodology, there's a whole long explainer on how those are defined on our website and I'm happy to talk about that if you'd like. And then slide eight, I want to pause, I've been going really quick here and talk a little bit about the cost benefit analysis and why it's important and notable that we are not including that here. So, cost benefit analysis helps you all as policymakers compare apples to apples across policy areas. So, you could think what's the cost benefit of investing in early childhood versus in K-12 education, apples to apples? And it's really the gold standard for answering what we call

normative questions. Is this thing worth it? Is this tax expenditure, the rural jobs tax credit, is it worth it or not?

(02:38:00):

And because we haven't done a cost benefit analysis, these tax expenditure assessments don't answer that question that may or may or may not be on your mind. Instead, what we're hoping to do is compare everything in this ecosystem to each other so you can get a sense of how you can prioritize best in this $600 million ecosystem that you're currently investing in. Alright, those are the terms and then last slide I'll cover on slide nine. This is the summary table that we're going to be presenting. I'll move relatively quickly through each of these, but if you have questions in the report or afterwards when you're reading, this is really the place you can come and get those answered. So, this is the summary table. First two, these are just reported by from TRD, jobs created, economic ROI, return and revenue. Those are all calculated using REMI usage trends.

(02:38:52):

Pretty self-evident. Purpose statement. We're looking at the purpose statement of these expenditures, whether they're being met or not. And then, lastly, the design of these credits, which I also think are relatively self-explanatory. Alright, Mr. Chair and committee, if you can now flip to the end of that slide deck. You should have the first actual Tax E report. Looks like this on the rural job tax credit. I've got one or two more minutes and then I'll turn it over Maggie, and then we will wrap it up. So, the rural job tax credit is companies eligible for JTIP, if you're familiar with that. Those are economic based companies in rural areas. A business can get a thousand dollars a year per job and they can either qualify for that for two years or for four years, based on the population that they're in. This credit is not refundable; it's transferable up to three years.

(02:39:56):

And I'll summarize the economic impact. On the top right hand corner of the page, you can see all those numbers. FY 24, the state spent $637,000 on the rural job tax credit. There was 45 claims. So, 40 businesses got this tax expenditure. This report estimates the economic ROI to be 35%. So that means for every $1 we spend on the rural job tax credit, the state economy grows by 35 cents. And this report estimates that the return in revenue for the rural job tax credit is negative 83 cents. That means for every $1 we spend, we're foregoing 83 cents and we're getting back 17 cents. So, we're not making our money back. We're making 17 cents back every dollar we spend. Alright, that's the economic impact analysis calculated using REMI software. And if you turn to the second page, quickly through the summary table, I'll go through the design elements and the usage trends.

(02:41:03):

Usage has dropped a lot recently for this credit. It does not have an expiration date. It does not have an expenditure cap. Those are both LFC tax policy principles that aren't being met. It targets rural areas, but maybe not distressed areas in particular. And it does target export based industry. And this report concludes by saying the credit partially satisfies its purpose of encouraging businesses to start or expand business to start or expand their operations. And it's partial because claims have come down so much and it's a relatively small expenditure, less than a million dollars a year. And, also, the value of that incentive has decreased a lot. It was created in 2000 at that $1,000 per year, and that has decreased in value by 45% over that period. So, you can imagine the relative size of that has decreased a lot. Mr. Chair, with that, I'll pass it back over to Maggie for high wage jobs.

Klug: (02:42:10):

Thanks, Brendan. Chair members, if you all could turn to your next page, you should have a brief that looks very similar, but says high wage jobs credit at the top. So, the high wage jobs credit, similar to rural jobs, provides a tax credit to businesses eligible for the job training incentive program or JTIP for the creation of new high wage jobs. Businesses can receive up to eight and 5% of wages up to around $12,700 for a new high wage job. And, so, a high wage job is defined as one with wages over $60,000 in urban communities and $40,000 in rural communities that are filled for at least 44 weeks of the year. So, for instance, if I'm a business owner that created a new job costing around $90,000, that would mean that I'd get around $7,500 back per year for that job. So, looking to the top right of the page, you can see that in fiscal year 24, businesses received around $11.2 million in state support through the credit, and 89 claims were made.

(02:43:09):

Also at the top right of the page, you can see that that economic return on investment is around 47%, meaning that for every dollar spent, the state economy grows by 47 cents and the return in revenue is negative 83%, meaning that for every $1 spent, the state foregoes 83 cents and gets back 17 cents in state tax revenue. If you could now turn to the back of the page for me, looking at the design elements of that summary box on the right that Brendan pointed you to, the credit does have a sunset date of July 1st, 2026. So, it does have an expiration date. However, it does not have an expenditure cap. Similarly, because of the urban rural divide, it does target rural areas, but it doesn't target other distressed areas. So, we said that it partially meets that criteria. And because of the JTIP requirements, it does target export based industries. Given the usage of the credit and the estimated jobs created, around 135 jobs per year, this

credit likely meets its purpose of providing an incentive for businesses to create and fill new high wage jobs. Thank you all for your time. And now if there's time for questions, we'd be happy to answer any.

Chair: (02:44:20):

Excellent. Thank you both. Fascinating information. We're going to jump right in starting with Representative Duncan. Representative Lujan know of course, Chair Lente, Representative Duncan to start.

Duncan: (02:44:33):

Thank you, Mr. Chair. Just one quick question for you. On page six, you had indicated that you didn't compare other states. Do you ever look, think there's a possibility that you will look back as you catch up and look at what other states are doing so we don't have to reinvent the wheel?

Gray: (02:44:49):

Mr. Chair, Representative? Absolutely. If that's something you would find valuable, we would be happy to do that.

Chair: (02:44:57):

Thank you.

Duncan: 7 (02:44:57):

Thank you, Mr. Chair.

Chair: (02:44:58):

Great, thank you very much, Representative Duncan. Representative LuJan, please?

Lujan: Speaker 8 (02:45:01):

Thank you, Mr. Chair. Just quickly in our for rural employers, do we know what counties are benefiting the most? Mr. Chair?

Gray: (02:45:15):

Mr. Chair, Representative. We don't have a breakdown of spending by county. I can give you the areas that are eligible if you'd like. Sure. So, it's everywhere in New Mexico that is defined as rural except for Albuquerque, Farmington, Las Cruces, Los Alamos, Roswell, Santa Fe, and then a 10 mile zone around all those cities. Everywhere else is rural.

Lujan: (02:45:44):

Thank you. And, so, as we're creating these, as we've created and amended this incentive and there's no cap, is that with the intention, because of inflation and growth of a need in housing as well? And if you don't have those answers, is that something you're going to be looking at as you're tying in accountability to what we're doing with this tax incentive? Mr. Chair?

Gray: (02:46:14):

Mr. Chair, Representative? What I'm hearing for your question is the reason this tax expenditure exists? I think it's an acknowledgement by the legislature that there are different costs in rural communities, self-evident but, to your point, there's a lot of other considerations like the indexing that haven't been made. And so yeah.

Lujan: (02:46:35):

Yeah. Will you be looking at those as you're doing further analysis, like how this is benefiting with the growth factor and the need for housing and those sorts of things? Because this would I mean, to my knowledge, and the reason why we have done these things is because of the cost of living in our state. And I represent Santa Fe, and so the highest cost of living areas and job creation. Is there's job creation around Santa Fe or in Santa Fe, but people don't necessarily live there? So, I'm wondering how we connect those things. Thank you, Mr. Chair.

Gray: (02:47:16):

Yeah, Mr. Chair, absolutely. I think that cost benefit analysis gets at exactly that point. It would be considering the value of that housing, the need of the housing, the cost, the benefit of that. So, we haven't gotten there yet, but it sounds like there's interest so we can definitely start that process.

Lujan: (02:47:34):

Thank you, Mr. Chair. Maybe a few other things, but really to that point and how much money we've really invested in the housing efforts for our state and tied to the tax incentives that we're doing, I think is very something I would, and I think the rest of us, would appreciate analysis on. Thank you.

Chair: (02:47:50):

Great. Thank you very much Representative Lujan. Chair Lente please?

Lente: (02:47:54):

Thank you, Mr. Chairman. Thank you Brendan for the presentation and thank you for the presentation. I forget your name, but I apologize. Nonetheless. Great work, fantastic new tool that we have at our disposal. And I'm also reminded by Chief Torres that the staff will be working on the other economic development investments that we have in this state so that, hopefully by the end of this year, we'll have a report card on all of these so that we can begin to see which ones are working and which ones are not. So, thank you Mr. Chairman.

Chair: (02:48:22):

Excellent. Thank you very much. Next we're going to go to Representative Herrera. Then we have Representative Dixon.

Herrera: (02:48:28):

Thank you, Mr. Chair. Thank you for the presentation. It was a very illuminating, I thought. I was very curious about how these things had worked. Do you think there are other or better cost effective alternatives to achieve these goals? Like just direct grant making or a direct investment? Have you thought about that?

Gray: (02:48:54):

Mr. Chair, Representative. And a really good question. It's a little outside of these Tax E reports, but I can give you my perspective. I would say the economic development literature tends to estimate the impacts as being higher when an incentive is more targeted and, so, when you can tip a business decision, you can say for sure that this business would not be open. But for this state investment, that's when it's going to be the most cost effective. And, in general, tax policy applies to all businesses. And, so, you might not have that level of specificity. So, I think to your point, I think the literature would say there are more effective ways to make these kinds of investments.

Herrera: 12 (02:49:46):

Mr. Chair, thank you. Thank you for that answer. And I'm curious, are these tax credits are just open to businesses? Are they open to nonprofits?

Gray: (02:50:03):

Mr. Chair, Representative? No, I don't think they would be open. These are JTIP eligible and I don't think a nonprofit would be JTIP eligible.

Herrera: (02:50:17):

Mr. Chair, and thank you for that answer. I just want you to know that in rural counties, most of the startup operations are really nonprofits. The only difference is they don't try to make a profit. They try to break

even, but it's really service to the community. And, most jobs probably aren't starting, I think a lot higher than $40,000, but they're probably starting at $40,000. Are they open to, are these tax credits open, these not tax credits, are these credits open to a health agency that would open?

Klug: (02:51:03):

Chair, Representative. Thank you for the question. Given the job training incentive program requirements, that eligibility can be found online. One of the business industries that is not eligible is healthcare.

Herrera: (02:51:22):

Mr. Chair, I'm also curious about the high quality jobs. I mean, how do you, is a high cost per job? Is it justified by the type or the quality of the job itself? That's what I'm curious about. Could you speak to that?

Gray: (02:51:42):

Mr. Chair, Representative? I think the economic development literature has looked at those questions, looking at quality of life of the job, retirement benefits, these kinds of things. These tax credits are just looking at wages and so, more narrow, not considering the quality of the job like you're mentioning. But, that said, that's an important consideration.

Chair: (02:52:12):

Thank you very much, Representative Herrera. Next. Representative Dixon?

Dixon: (02:52:18):

Thank you, Mr. Chair. Thank you Brendan and Maggie for this excellent report. I have several notes, but I just want to take a minute to express my appreciation for you guys for diving in and using REMI, so that we as a legislature can make informed decisions on tax expenditures and actually understand the return on investment and cost benefit. So, thank you, thank you, thank you.

Chair: (02:52:50):

Excellent. Okay. I don't see any other questions. I think really good questions beginning from the committee. We can clearly see that there's a great deal of opportunity here and are excited to know that LFC, as we understand other executive agencies, including economic development department, have this tool and we're excited to use it. And, yeah, appreciate both of you. Okay. We're going to ask Director Sallee to talk us through the large expenditures report. Again, sort of a look ahead. This is helpful as we go through the rest of the week. A lot, of some of these big expenditures are going to be very relevant to what we'll be dealing with. So, I'll turn over to the Director.

Dir. Soliz: (02:53:33):

So, thank you, Mr. Chairman. Just real quickly, on Tab F, I thought it was important to just bring it to your attention because it's going to, some of the information contained in this report is going to help answer questions you're going to have for the next two days on what the status of the $20 million is for child welfare and behavioral health at CYFD, or what's the status of the big investment in certificate training and higher education that's contained in this report? I think it's a snapshot in time of expenditures. We don't have higher ed expenditures and shares, so there's a bit of a limitation there. It's a point in time and we may not see encumbrances for personnel. So, it's something that's not going to answer all of your questions, but it will certainly help highlight things. The other thing I think is important for the committee to consider is, once we get to the closeout of some of these appropriations, agencies feel under a lot of pressure to not revert money and try to just spend all of it.

(02:54:38):

And I think we want to resist the temptation of spend what you need to get the job done, and if there's money that's left over, it goes back to the General Fund and we'll have to make kind of an informed

decision on a case by case basis on, are we over appropriating for something that creates an opportunity cost, or were you able to just be more efficient and should be congratulated for it as an agency? So, if you're reverting 4% of the appropriation, I really wouldn't sweat it. If it's like none of it's getting spent and you're in the legislative session and they're asking for an extension, that's going to raise some red flags, and you should have conversations with them about the viability of the appropriation or the special project. So, thank you, Mr. Chairman.

Chair: (02:55:22):

Great. Thank you very much, Director Sallee. That's very helpful. We can take these home if you want to. I'd just obviously bring 'em back tomorrow. That's going to wrap up. A quick note. Kelly reminded me for folks who are going on the Natural Resources tour tomorrow, please wear comfortable footwear because there's going to be some walking; not a ton, but it'll be some walking outside. These will be the subcommittees in the afternoon when we break up for that. With that, thank you members very much. Big thanks to the staff. We're adjourned for today. The Martyrs?

??: (02:55:59):

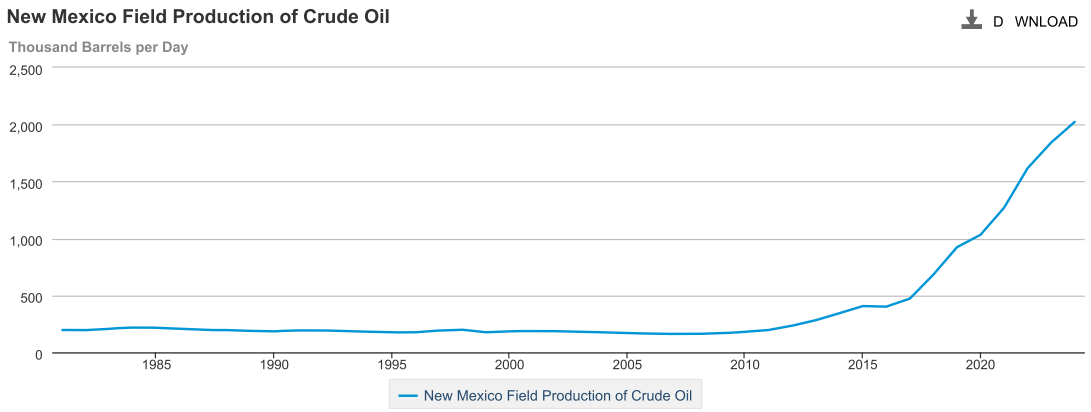
Martyr Steakhouse.

Chair: (02:56:01):

Martyr Steakhouse, and I'd drive safely, but head over there right away. We'll get started over there. Alright, thanks everybody. We're adjourned.

Petroleum & Other Liquids

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This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

New Mexico Field Production of Crude Oil (Thousand Barrels per Day)

Decade	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5	Year-6	Year-7	Year-8	Year-9
1980's		196	195	206	217	215	207	198	195	188
1990's	184	193	191	187	180	177	176	191	198	176
2000's	184	186	185	182	176	167	163	162	164	168
2010's	180	196	234	282	343	406	401	472	683	923
2020's	1,032	1,270	1,617	1,842	2,023					

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

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HOUSE BILL 133

56TH LEGISLATURE - STATE OF NEW MEXICO - SECOND SESSION, 2024

INTRODUCED BY

Kristina Ortez and Matthew McQueen and Cristina Parajón

and Mimi Stewart

AN ACT

RELATING TO THE ENVIRONMENT; AMENDING THE OIL AND GAS ACT; ALLOWING THE OIL CONSERVATION DIVISION OF THE ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT TO REGULATE CERTAIN TRANSFERS OF OIL AND GAS WELLS AND AUTHORIZE THE CONVERSION OF OIL AND GAS WELLS FOR ENERGY STORAGE AND GEOTHERMAL DEVELOPMENT; INCREASING THE AMOUNT OF FEES AND FINANCIAL ASSURANCE ASSOCIATED WITH OPERATING OIL AND GAS WELLS; INCREASING CIVIL PENALTIES; ALLOWING FEES TO BE ADJUSTED TO ACCOUNT FOR INFLATION; REQUIRING THE CAPTURE OF NINETY-EIGHT PERCENT OF NATURAL GAS PRODUCED BEGINNING IN 2027; PROVIDING FOR CERTAIN SETBACKS FROM OIL AND GAS FACILITIES.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF NEW MEXICO:

SECTION 1. Section 70-2-12 NMSA 1978 (being Laws 1978, Chapter 71, Section 1, as amended) is amended to read:

underscored material = new
[~~bracketed material~~] = delete

"70-2-12. ENUMERATION OF POWERS.--

A. The [~~oil conservation~~] division [~~of the energy, minerals and natural resources department~~] may:

(1) collect data;

(2) make investigations and inspections;

(3) examine properties, leases, papers, books and records;

(4) examine, check, test and gauge oil and gas wells, tanks, plants, refineries and all means and modes of transportation and equipment;

(5) hold hearings;

(6) provide for the keeping of records and the making of reports and for the checking of the accuracy of the records and reports;

(7) limit and prorate production of crude petroleum oil or natural gas or both as provided in the Oil and Gas Act; and

(8) require either generally or in particular areas certificates of clearance or tenders in connection with the transportation of crude petroleum oil or natural gas or any products of either or both oil and products or both natural gas and products.

B. The [~~oil conservation~~] division may make rules and orders [~~for the purposes and with respect to the subject matter stated in this subsection~~]:

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(1) to require dry or abandoned wells to be plugged in a way so as to confine the crude petroleum oil, natural gas or water in the strata in which it is found and to prevent it from escaping into other strata; pursuant to Section 70-2-14 NMSA 1978, the division shall require financial assurance conditioned for the performance of the rules;

(2) to prevent crude petroleum oil, natural gas or water from escaping from strata in which it is found into other strata;

(3) to require reports showing locations of all oil or gas wells and for the filing of logs and drilling records or reports;

(4) to prevent the drowning by water of any stratum or part thereof capable of producing oil or gas or both oil and gas in paying quantities and to prevent the premature and irregular encroachment of water or any other kind of water encroachment that reduces or tends to reduce the total ultimate recovery of crude petroleum oil or gas or both oil and gas from any pool;

(5) to prevent fires;

(6) to prevent "blow-ups" and "caving" in the sense that the conditions indicated by such terms are generally understood in the oil and gas business;

(7) to require wells to be drilled, operated and produced in such manner as to prevent injury to neighboring

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leases or properties;

(8) to identify the ownership of oil or gas producing leases, properties, wells, tanks, refineries, pipelines, plants, structures and all transportation equipment and facilities;

(9) to require the operation of wells with efficient gas-oil ratios and to fix such ratios;

(10) to fix the spacing of wells;

(11) to determine whether a particular well or pool is a gas or oil well or a gas or oil pool, as the case may be, and from time to time to classify and reclassify wells and pools accordingly;

(12) to determine the limits of any pool producing crude petroleum oil or natural gas or both and from time to time redetermine the limits;

(13) to regulate the methods and devices employed for storage in this state of oil or natural gas or any product of either, including subsurface storage;

(14) to permit the injection of natural gas or of any other substance into any pool in this state for the purpose of repressuring, cycling, pressure maintenance, secondary or any other enhanced recovery operations;

(15) to regulate the disposition, handling, transport, storage, recycling, treatment and disposal of produced water during, or for reuse in, the exploration,

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drilling, production, treatment or refinement of oil or gas, including disposal by injection pursuant to authority delegated under the federal Safe Drinking Water Act, in a manner that protects public health, the environment and fresh water resources;

(16) to determine the limits of any area containing commercial potash deposits and from time to time redetermine the limits;

(17) to regulate and, where necessary, prohibit drilling or producing operations for oil or gas within any area containing commercial deposits of potash where the operations would have the effect unduly to reduce the total quantity of the commercial deposits of potash that may reasonably be recovered in commercial quantities or where the operations would interfere unduly with the orderly commercial development of the potash deposits;

(18) to spend the oil and gas reclamation fund and do all acts necessary and proper to plug dry and abandoned oil and gas wells and to restore and remediate abandoned well sites and associated production facilities in accordance with the provisions of the Oil and Gas Act, the rules adopted under that act and the Procurement Code, including disposing of salvageable equipment and material removed from oil and gas wells being plugged by the state;

(19) to make well price category

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determinations pursuant to the provisions of the federal Natural Gas Policy Act of 1978 or any successor act and, by regulation, to adopt fees for such determinations, which fees shall not exceed twenty-five dollars ($25.00) per filing. Such fees shall be credited to the account of the [~~oil conservation~~] division by the state treasurer and may be expended as authorized by the legislature;

(20) to regulate the construction and operation of oil treating plants and to require the posting of bonds for the reclamation of treating plant sites after cessation of operations;

(21) to regulate the disposition of nondomestic wastes resulting from the exploration, development, production or storage of crude oil or natural gas to protect public health and the environment; [~~and~~]

(22) to regulate the disposition of nondomestic wastes resulting from the oil field service industry, the transportation of crude oil or natural gas, the treatment of natural gas or the refinement of crude oil to protect public health and the environment, including administering the Water Quality Act as provided in Subsection E of Section 74-6-4 NMSA 1978;

(23) to regulate the transfer of oil and gas wells or facilities, including limitations on transfers when:

(a) the transferor, the transferee or an

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entity that owns more than a twenty-five percent interest in a transferor or transferee has a significant history of noncompliance with the Oil and Gas Act or rules adopted pursuant to that act;

(b) the transferee fails to provide adequate financial assurance as required by the division;

(c) the transferee lacks sufficient financial capacity to manage liabilities associated with the oil and gas wells or facilities; or

(d) the division deems the limitations to be necessary for the purposes of mitigating risk to the state from potential inactive or abandoned oil and gas wells or facilities; and

(24) to authorize the conversion of an oil and gas well to a facility that supports energy storage or geothermal development, including establishing fees and financial assurance requirements specific to an energy storage or geothermal use."

SECTION 2. Section 70-2-14 NMSA 1978 (being Laws 1977, Chapter 237, Section 3, as amended) is amended to read:

"70-2-14. REQUIREMENT FOR FINANCIAL ASSURANCE.--

A. Each person, firm, corporation or association who operates [~~any~~] an oil, gas or service well within the state shall, as a condition precedent to drilling or producing the well, furnish financial assurance in the form of an irrevocable

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letter of credit, [~~or~~] a cash or surety bond or a [~~well-specific~~] plugging insurance policy pursuant to the provisions of this section to the [~~oil conservation~~] division [~~of the energy, minerals and natural resources department~~] running to the benefit of the state and conditioned that the covered well be plugged and abandoned in [~~compliance with the rules of the oil conservation~~] accordance with division rules. The [~~oil conservation~~] division shall establish categories of financial assurance by rule after notice and hearing. Such categories shall include, at a minimum, a blanket plugging financial assurance [~~which shall be set by rule~~] in an amount not to exceed [~~two hundred fifty thousand dollars ($250,000), a blanket plugging financial assurance for temporarily abandoned status wells, which shall be set by rule at amounts greater than fifty thousand dollars ($50,000)~~] ten million dollars ($10,000,000) [~~and~~] or a one-well plugging financial assurance in amounts determined sufficient to reasonably pay the cost of plugging the well or wells covered by the financial assurance. In establishing categories of financial assurance, the [~~oil conservation~~] division shall consider the depth of the well involved, the length of time since the well was produced, the cost of plugging similar wells and [~~such~~] other factors [~~as~~] the [~~oil conservation~~] division deems relevant. The [~~oil conservation~~] division shall require a one-well financial assurance on any well that has been held in a temporarily

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abandoned status for more than two years or, at the election of the operator, may allow an operator to increase its blanket plugging financial assurance to cover wells held in temporarily abandoned status. All financial assurance shall remain in force until released by the [~~oil conservation~~] division. The [~~oil conservation~~] division shall release financial assurance when [~~it~~] the division is satisfied that the conditions of the financial assurance have been fully performed.

B. If any of the requirements of the Oil and Gas Act or the rules promulgated pursuant to that act have not been complied with, the [~~oil conservation~~] division, after notice and hearing, may order any well plugged and abandoned by the operator or surety or both in accordance with division rules. If the order is not complied with in the time period set out in the order, the financial assurance shall be forfeited.

C. When any financial assurance is forfeited pursuant to the provisions of the Oil and Gas Act or rules promulgated pursuant to that act, the director of the [~~oil conservation~~] division shall [~~give notice to the attorney general, who shall~~] collect the forfeiture without delay.

D. All forfeitures shall be deposited in the state treasury in the oil and gas reclamation fund.

E. When the financial assurance proves insufficient to cover the cost of plugging oil and gas wells on land other than federal land and funds must be expended from the oil and

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gas reclamation fund to meet the additional expenses, the [~~oil conservation~~] division is authorized to bring suit against the operator in the district court of the county in which the well is located for indemnification for all costs incurred by the [~~oil conservation~~] division in plugging the well. All funds collected pursuant to a judgment in a suit for indemnification brought under the provisions of this section shall be deposited in the oil and gas reclamation fund.

F. An operator required to file financial assurance for a well pursuant to this section is considered to have met that requirement if the operator obtains a plugging insurance policy that includes the specific well and that:

(1) is approved by the office of superintendent of insurance;

(2) names the state of New Mexico as owner of the policy and contingent beneficiary;

(3) names a primary beneficiary who agrees to plug the specified wellbore;

(4) is fully prepaid and cannot be canceled or surrendered;

(5) provides that the policy continues in effect until the specified wellbore has been plugged;

(6) provides that benefits will be paid when, but not before, the specified wellbore has been plugged in accordance with rules of the [~~oil conservation~~] division in

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effect at the time of plugging; and

(7) provides benefits that are not less than an amount equal to the one-well financial assurance required by [~~oil conservation~~] division rules.

G. If, subsequent to an operator obtaining an insurance policy as provided in this section, the one-well financial assurance requirement applicable to the operator's well is increased, either because the well is deepened or [~~the rules of the oil conservation~~] division rules are amended, the operator is considered to have met the revised requirement if:

(1) the existing policy benefit equals or exceeds the revised requirement;

(2) the operator obtains an amendment increasing the policy benefit by the amount of the increase in the applicable financial assurance requirement; or

(3) the operator obtains financial assurance equal to the amount, if any, by which the revised requirement exceeds the policy benefit."

SECTION 3. Section 70-2-31 NMSA 1978 (being Laws 1981, Chapter 362, Section 1, as amended) is amended to read:

"70-2-31. VIOLATIONS OF THE OIL AND GAS ACT--PENALTIES.--

A. Whenever the division determines that a person violated or is violating the Oil and Gas Act or any provision of any rule, order, permit or authorization issued pursuant to that act, the division may seek compliance and civil penalties

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by:

(1) issuing a notice of violation;

(2) commencing a civil action in district court for appropriate relief, including injunctive relief; or

(3) issuing a temporary cessation order if the division determines that the violation is causing or will cause an imminent danger to public health or safety or a significant imminent environmental harm. The cessation order will remain in effect until the earlier of when the violation is abated or thirty days unless a hearing is held before the division and a new order is issued.

B. A notice of violation issued pursuant to Paragraph (1) of Subsection A of this section shall:

(1) state with reasonable specificity the nature of the violation; [~~shall~~]

(2) require compliance immediately or within a specified time period; [~~shall~~]

(3) provide notice of the availability of an informal review and the date of a hearing before the division; and [~~shall~~]

(4) provide notice of potential sanctions, including assessing a penalty, suspending, canceling or terminating a permit or authorization, shutting in a well and plugging and abandonment of a well and forfeiting financial assurance pursuant to Section 70-2-14 NMSA 1978.

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C. If the notice of violation is not resolved informally within thirty days after service of the notice, the division shall hold a hearing and determine whether the violation should be upheld and whether any sanctions, including civil penalties, shall be assessed. In assessing a penalty authorized by this section, the division shall take into account the seriousness of the violation, any good faith efforts to comply with the applicable requirements, any history of noncompliance under the Oil and Gas Act and other relevant factors. When a decision is rendered by the division after a hearing, any party of record adversely affected shall have the right to have the matter heard de novo before the commission pursuant to Section 70-2-13 NMSA 1978.

D. Any civil penalty assessed by a court or by the division or commission pursuant to this section may not exceed [~~two thousand five hundred dollars ($2,500)~~] ten thousand dollars ($10,000) per day of noncompliance for each violation unless the violation presents a risk either to the health or safety of the public or of causing significant environmental harm, or unless the noncompliance continues beyond a time specified in the notice of violation or order issued by the division, commission or court, whereupon the civil penalty may not exceed [~~ten thousand dollars ($10,000)~~] twenty-five thousand dollars ($25,000) per day of noncompliance for each violation. [~~No penalty assessed by the division or commission~~

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~~after a hearing may exceed two hundred thousand dollars ($200,000); provided that such limitation does not apply to penalties assessed by a court.~~]

E. The commission shall make rules, pursuant to Section 70-2-12.2 NMSA 1978, providing procedures for the issuance of notices of violations, the assessment of penalties and the conduct of informal proceedings and hearings pursuant to this section.

F. It is unlawful, subject to a criminal penalty of a fine of not more than five thousand dollars ($5,000) or imprisonment for a term not exceeding three years or both such fine and imprisonment, for any person to knowingly and willfully:

(1) violate any provision of the Oil and Gas Act or any rule, regulation or order of the commission or the division issued pursuant to that act; or

(2) do any of the following for the purpose of evading or violating the Oil and Gas Act or any rule, regulation or order of the commission or the division issued pursuant to that act:

(a) make any false entry or statement in a report required by the Oil and Gas Act or by any rule, regulation or order of the commission or division issued pursuant to that act;

(b) make or cause to be made any false entry

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in any record, account or memorandum required by the Oil and Gas Act or by any rule, regulation or order of the commission or division issued pursuant to that act;

(c) omit or cause to be omitted from any such record, account or memorandum full, true and correct entries; or

(d) remove from this state or destroy, mutilate, alter or falsify any such record, account or memorandum.

G. For the purposes of Subsection F of this section, each day of violation shall constitute a separate offense.

H. Any person who knowingly and willfully procures, counsels, aids or abets the commission of any act described in Subsection A or F of this section shall be subject to the same penalties as are prescribed in Subsection D or F of this section."

SECTION 4. Section 70-2-39 NMSA 1978 (being Laws 2019, Chapter 260, Section 1) is amended to read:

"70-2-39. FEES--[~~APPROPRIATION~~] FEE ADJUSTMENTS--OIL CONSERVATION DIVISION SYSTEMS AND HEARINGS FUND CREATED.--

A. Beginning January 1, 2027 and on January 1 of each successive year, the fees provided by this section may be adjusted for inflation as provided in Subsection B of this section. The following fees are required to be paid to the [~~oil conservation~~] division [~~of the energy, minerals and~~

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~~natural resources department~~] with each application for:

(1) [~~with each application for~~] a non-federal and non-Indian permit to drill, deepen, plug back or reenter a well, the applicant shall submit to the division a nonrefundable fee of [~~five hundred dollars ($500)~~] one thousand five hundred dollars ($1,500);

(2) [~~with each individual application for~~] administrative approval of a non-standard location, downhole commingle, surface commingle, off-lease measurement, release notification and corrective action, change of operator, application for modification to surface waste management facility, request for the creation of a new pool, proposed alternative method permit or closure plan application or authorization to move produced water, the applicant shall submit to the division a nonrefundable fee of [~~one hundred fifty dollars ($150)~~] four hundred fifty dollars ($450);

(3) [~~with each application for~~] a fluid injection well permit, the applicant shall submit to the division a nonrefundable fee of [~~five hundred dollars ($500)~~] one thousand five hundred dollars ($1,500) per well;

(4) [~~with each application for~~] a permit for a commercial surface waste management facility, landfill or landfarm, the applicant shall submit to the division a nonrefundable fee of ten thousand dollars ($10,000) per facility;

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(5) [~~with each application for~~] an administrative hearing, re-hearing or de novo hearing before the division or commission, the applicant shall submit to the division a nonrefundable fee of [~~five hundred dollars ($500)~~] one thousand five hundred dollars ($1,500) per application; and

(6) [~~with each application for~~] a continuance of an administrative hearing, re-hearing or de novo hearing before the division or commission, the applicant shall submit to the division a nonrefundable fee of [~~one hundred fifty dollars ($150)~~] four hundred fifty dollars ($450) per application.

B. On January 1, 2027 and on January 1 of each successive year, the division may adjust the fees provided by Subsection A of this section by multiplying the fee as of January 1, 2026 by a fraction, the numerator of which is the consumer price index ending in September of the previous year and the denominator of which is the consumer price index ending September 2025; provided that the fees shall not be adjusted below the minimum amounts provided in Subsection A of this section as a result of a decrease in the consumer price index. By November 1, 2026 and by November 1 of each successive year, the division shall post on its website the fees in Subsection A of this section for the next year.

[~~B.~~] C. An application for an administrative hearing, re-hearing or de novo hearing before the oil conservation division or commission will be considered to be materially

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amended if the amendment is made for a purpose other than to correct:

(1) typographical errors; or

(2) clerical errors.

[~~C.~~] D. The "oil conservation division systems and hearings fund" is created in the state treasury as a nonreverting fund. All funds received by the [~~oil conservation~~] division from fees imposed pursuant to Subsection A of this section shall be delivered to the state treasurer and deposited in the fund. Disbursements from the fund shall be made upon warrants drawn by the secretary of finance and administration pursuant to vouchers signed by the secretary of energy, minerals and natural resources or the secretary's authorized representative. Money in the fund is subject to appropriation by the legislature to the division to develop and modernize the division's online application processing system, online case management system, online data reporting and visualization systems and online case file system and for other technological and equipment upgrades necessary to support the efficient and transparent implementation and enforcement of the Oil and Gas Act, including hiring necessary information technology personnel, and for hearing administration costs. Any unexpended or unencumbered balance remaining in the fund at the end of a fiscal year shall not revert to the general fund. [~~Money in the fund in fiscal year 2020 may be expended by the~~

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~~division for the purposes of the fund.~~]

E. As used in this section, "consumer price index" means the consumer price index, not seasonally adjusted, for all urban consumers, United States city average for all items, or its successor index, as published by the United States department of labor for a twelve-month period ending September 30."

SECTION 5. A new section of the Oil and Gas Act is enacted to read:

"[NEW MATERIAL] NATURAL GAS CAPTURE REQUIREMENTS--RULES.--

A. Beginning January 1, 2027, an operator shall ensure that at least ninety-eight percent of the natural gas produced or gathered by the operator's facilities is captured in a calendar year; provided that natural gas released during an emergency or that is beneficially used by the operator does not count as gas released for the purpose of determining an operator's overall capture percentage.

B. The division shall adopt rules necessary to implement the provisions of this section and an application for a permit to drill shall be subject to the rules to be valid.

C. As used in this section, "operator" means a person that is duly authorized to construct, manage or operate an oil or gas well or associated facilities or a natural gas gathering system."

SECTION 6. A new section of the Oil and Gas Act is

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enacted to read:

"[NEW MATERIAL] SETBACKS FROM HUMAN AND ENVIRONMENTAL RECEPTORS--RULES.--

A. Beginning July 1, 2024, a new well pad, production facility, tank battery, compressor station or gas plant shall be at least:

(1) two thousand two hundred fifty feet from a health facility, correctional facility, multifamily residential structure, community college, public, private or charter school or state educational institution;

(2) two thousand two hundred fifty feet from a detached single-family occupied residence, including a manufactured home, unless the homeowner at the time a development is proposed provides consent in a manner provided by the division, in which case the setback in this paragraph may be reduced to seven hundred fifty feet without prior approval;

(3) six hundred sixty feet from a perennial or intermittent stream, lake, pond, delineated wetland or irrigation infrastructure that is in use; and

(4) three hundred feet from a surface water of the state not listed in Paragraph (3) of this subsection, a state park, state game commission land, a designated critical habitat for a federal or state endangered animal species or other environmental resource identified by commission rule.

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B. For purposes of determining whether a new well pad, production facility, tank battery, compressor station or gas plant complies with the requirements of this section, measurements shall be made from the outer edge of the human and environmental receptors listed in Subsection A of this section to the nearest operational equipment on a well pad, production facility, tank battery, compressor station or gas plant. For a building or structure, the outer edge shall be measured from the nearest portion of the building wall to the facilities covered by this section. For a water body, the outer edge shall be measured from the nearest ordinary high water mark or the transition between riparian and upland habitat to the facilities covered by this section.

C. The commission may approve deviations from the setbacks established in this section upon an application from the impacted operator demonstrating that:

(1) disallowing development within the setback is inconsistent with a directive or order from another state or federal agency;

(2) disallowing development will significantly impair correlative rights even after accounting for the division's or commission's ability to authorize variances from well spacing or other development requirements; or

(3) disallowing development will significantly contribute to underground waste.

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D. An oil and gas well or associated facility for which the commission approves a deviation pursuant to this section shall be inspected at least monthly by the operator to identify any spills or releases, unless more frequent inspections are required by law.

E. An application for a deviation from the setbacks established in this section may be denied for an operator that has received a notice of violation of the Oil and Gas Act from the division within twelve months of the application or is the subject of an unresolved notice of violation of the Oil and Gas Act issued by the division.

F. The commission may adopt rules:

(1) to increase the setback distances and identify additional resources subject to the setbacks established by Paragraphs (3) and (4) of Subsection A of this section when the commission determines that the proximity of an environmental resource to a new well pad, production facility, tank battery, compressor station or gas plant may significantly impair the environmental resource and increasing the distance between the resource and the facility would address such impairment;

(2) to increase the setback distances established by Paragraphs (1) and (2) of Subsection A of this section when the commission can demonstrate that the increases would result in direct reductions to exposures for individuals

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with elevated risk of adverse health impacts as a result of exposure;

(3) to provide for administrative proceedings before the division for the processing of requests to deviate from a setback established by this section or commission rule; and

(4) necessary to implement the provisions of this section.

G. This section does not apply to a new development on an existing well pad, production facility, tank battery, compressor station or gas plant, so long as the new development at an existing facility does not result in a one-time expansion of the external boundary of the existing facility of more than fifteen percent as determined by the boundaries in existence as of May 15, 2024, with the burden being on the operator to establish the boundaries, unless the operator demonstrates to the division that the one-time expansion will consolidate development and provide a demonstrable reduction of overall impacts to human health and the environment, in which case the division may approve an expansion of up to thirty percent.

H. The setbacks provided by this section shall not apply to a new well pad, production facility, tank battery, compressor station or gas plant if an operator demonstrates that:

(1) a deviation from the setback requirements is

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authorized by or necessary to effectuate the development of facilities pursuant to an application for a permit to drill, division order or commission order issued prior to May 15, 2024; or

(2) the facilities are located on the land or allotted lands of a federally recognized Indian nation, tribe or pueblo.

I. The burden to demonstrate the applicability of the provisions of Subsection H of this section rests solely on the operator.

J. The division shall provide an annual report by December 1 of each year to the appropriate interim legislative committee on any approved setback deviations, including setback deviations made pursuant to Subsection H of this section.

K. An oil and gas well in existence on July 1, 2024 within a setback provided by this section or established by commission rule that has been inactive for a period of greater than twenty-four months based on records maintained by the division shall be considered abandoned, and the division may order the plugging of the well after thirty days' notice to the registered operator of the well. An order issued pursuant to this subsection may be appealed to the commission.

L. As used in this section:

(1) "correctional facility" means a jail, prison or other detention facility that is used for the confinement of

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adult or juvenile persons, whether operated by the state or a political subdivision of the state or a private contractor on behalf of the state or a political subdivision of the state;

(2) "health facility" means a public hospital, profit or nonprofit private hospital, general or special hospital, outpatient facility, crisis triage center, freestanding birth center, adult daycare facility, nursing home, intermediate care facility, assisted living facility, boarding home not under the control of an institution of higher learning, child care facility, shelter care home, diagnostic and treatment center, rehabilitation center, infirmary, community mental health center that serves both children and adults or adults only, residential treatment center that serves persons up to twenty-one years of age, community mental health center that serves only persons up to twenty-one years of age, day treatment center that serves persons up to twenty-one years of age, health service organization operating as a freestanding hospice or a home health agency or facilities that, by federal regulation, are required to be licensed by the state to obtain or maintain full or partial, permanent or temporary federal funding, but does not include the offices and treatment rooms of licensed private practitioners; and

(3) "state educational institution" means an institution enumerated in Article 12, Section 11 of the constitution of New Mexico."

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HOUSE ENERGY, ENVIRONMENT AND NATURAL RESOURCES
COMMITTEE SUBSTITUTE FOR
HOUSE BILL 133

56TH LEGISLATURE - STATE OF NEW MEXICO - SECOND SESSION, 2024

AN ACT

RELATING TO THE ENVIRONMENT; AMENDING THE OIL AND GAS ACT; ALLOWING THE OIL CONSERVATION DIVISION OF THE ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT TO REGULATE CERTAIN TRANSFERS OF OIL AND GAS WELLS AND AUTHORIZE THE CONVERSION OF OIL AND GAS WELLS FOR ENERGY STORAGE AND GEOTHERMAL DEVELOPMENT; INCREASING THE AMOUNT OF FEES AND FINANCIAL ASSURANCE ASSOCIATED WITH OPERATING OIL AND GAS WELLS; INCREASING CIVIL PENALTIES; ALLOWING FEES TO BE ADJUSTED TO ACCOUNT FOR INFLATION; REQUIRING THE CAPTURE OF NINETY-EIGHT PERCENT OF NATURAL GAS PRODUCED BEGINNING IN 2027.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF NEW MEXICO:

SECTION 1. Section 70-2-12 NMSA 1978 (being Laws 1978, Chapter 71, Section 1, as amended) is amended to read:

"70-2-12. ENUMERATION OF POWERS.--

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A. The [~~oil conservation~~] division [~~of the energy, minerals and natural resources department~~] may:

(1) collect data;

(2) make investigations and inspections;

(3) examine properties, leases, papers, books and records;

(4) examine, check, test and gauge oil and gas wells, tanks, plants, refineries and all means and modes of transportation and equipment;

(5) hold hearings;

(6) provide for the keeping of records and the making of reports and for the checking of the accuracy of the records and reports;

(7) limit and prorate production of crude petroleum oil or natural gas or both as provided in the Oil and Gas Act; and

(8) require either generally or in particular areas certificates of clearance or tenders in connection with the transportation of crude petroleum oil or natural gas or any products of either or both oil and products or both natural gas and products.

B. The [~~oil conservation~~] division may make rules and orders [~~for the purposes and with respect to the subject matter stated in this subsection~~]:

(1) to require dry or abandoned wells to be

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plugged in a way so as to confine the crude petroleum oil, natural gas or water in the strata in which it is found and to prevent it from escaping into other strata; pursuant to Section 70-2-14 NMSA 1978, the division shall require financial assurance conditioned for the performance of the rules;

(2) to prevent crude petroleum oil, natural gas or water from escaping from strata in which it is found into other strata;

(3) to require reports showing locations of all oil or gas wells and for the filing of logs and drilling records or reports;

(4) to prevent the drowning by water of any stratum or part thereof capable of producing oil or gas or both oil and gas in paying quantities and to prevent the premature and irregular encroachment of water or any other kind of water encroachment that reduces or tends to reduce the total ultimate recovery of crude petroleum oil or gas or both oil and gas from any pool;

(5) to prevent fires;

(6) to prevent "blow-ups" and "caving" in the sense that the conditions indicated by such terms are generally understood in the oil and gas business;

(7) to require wells to be drilled, operated and produced in such manner as to prevent injury to neighboring leases or properties;

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(8) to identify the ownership of oil or gas producing leases, properties, wells, tanks, refineries, pipelines, plants, structures and all transportation equipment and facilities;

(9) to require the operation of wells with efficient gas-oil ratios and to fix such ratios;

(10) to fix the spacing of wells;

(11) to determine whether a particular well or pool is a gas or oil well or a gas or oil pool, as the case may be, and from time to time to classify and reclassify wells and pools accordingly;

(12) to determine the limits of any pool producing crude petroleum oil or natural gas or both and from time to time redetermine the limits;

(13) to regulate the methods and devices employed for storage in this state of oil or natural gas or any product of either, including subsurface storage;

(14) to permit the injection of natural gas or of any other substance into any pool in this state for the purpose of repressuring, cycling, pressure maintenance, secondary or any other enhanced recovery operations;

(15) to regulate the disposition, handling, transport, storage, recycling, treatment and disposal of produced water during, or for reuse in, the exploration, drilling, production, treatment or refinement of oil or gas,

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including disposal by injection pursuant to authority delegated under the federal Safe Drinking Water Act, in a manner that protects public health, the environment and fresh water resources;

(16) to determine the limits of any area containing commercial potash deposits and from time to time redetermine the limits;

(17) to regulate and, where necessary, prohibit drilling or producing operations for oil or gas within any area containing commercial deposits of potash where the operations would have the effect unduly to reduce the total quantity of the commercial deposits of potash that may reasonably be recovered in commercial quantities or where the operations would interfere unduly with the orderly commercial development of the potash deposits;

(18) to spend the oil and gas reclamation fund and do all acts necessary and proper to plug dry and abandoned oil and gas wells and to restore and remediate abandoned well sites and associated production facilities in accordance with the provisions of the Oil and Gas Act, the rules adopted under that act and the Procurement Code, including disposing of salvageable equipment and material removed from oil and gas wells being plugged by the state;

(19) to make well price category determinations pursuant to the provisions of the federal

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Natural Gas Policy Act of 1978 or any successor act and, by regulation, to adopt fees for such determinations, which fees shall not exceed twenty-five dollars ($25.00) per filing. Such fees shall be credited to the account of the [~~oil conservation~~] division by the state treasurer and may be expended as authorized by the legislature;

(20) to regulate the construction and operation of oil treating plants and to require the posting of bonds for the reclamation of treating plant sites after cessation of operations;

(21) to regulate the disposition of nondomestic wastes resulting from the exploration, development, production or storage of crude oil or natural gas to protect public health and the environment; [~~and~~]

(22) to regulate the disposition of nondomestic wastes resulting from the oil field service industry, the transportation of crude oil or natural gas, the treatment of natural gas or the refinement of crude oil to protect public health and the environment, including administering the Water Quality Act as provided in Subsection E of Section 74-6-4 NMSA 1978;

(23) to regulate the transfer of oil and gas wells, including limitations on transfers when:

(a) the transferor, the transferee or an entity that owns more than a twenty-five percent interest in a

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transferor or transferee has a significant history of noncompliance with the Oil and Gas Act or rules adopted pursuant to that act, including multiple notices of violations or spills or releases that are not in the process of being corrected or addressed;

(b) the transferee fails to provide adequate financial assurance as required by the division;

(c) the transferee lacks sufficient financial capacity based on known or projected production to manage liabilities associated with the oil and gas wells; or

(d) the division issues a written finding that the limitations on transfer are necessary for the purposes of mitigating risk to the state from potential inactive or abandoned oil and gas wells; and

(24) to authorize the conversion of an oil and gas well to a facility that supports energy storage or geothermal development, including establishing fees and financial assurance requirements specific to an energy storage or geothermal use."

SECTION 2. Section 70-2-14 NMSA 1978 (being Laws 1977, Chapter 237, Section 3, as amended) is amended to read:

"70-2-14. REQUIREMENT FOR FINANCIAL ASSURANCE.--

A. Each person, firm, corporation or association who operates [~~any~~] an oil, gas or service well within the state shall, as a condition precedent to drilling or producing the

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well, furnish financial assurance in the form of an irrevocable letter of credit, [~~or~~] a cash or surety bond, a well plugging risk pool fee or a [~~well-specific~~] plugging insurance policy pursuant to the provisions of this section to the [~~oil conservation~~] division [~~of the energy, minerals and natural resources department~~] running to the benefit of the state and conditioned that the covered well be plugged and abandoned in [~~compliance with the rules of the oil conservation~~] accordance with division rules. The [~~oil conservation~~] division shall establish categories of financial assurance by rule after notice and hearing. Such categories shall include a blanket plugging financial assurance [~~which shall be set by rule~~] tiered to reflect operator size and relative risk in an amount not to exceed [~~two hundred fifty thousand dollars ($250,000), a blanket plugging financial assurance for temporarily abandoned status wells, which shall be set by rule at amounts greater than fifty thousand dollars ($50,000) and~~] ten million dollars ($10,000,000), a well plugging risk pool fee or a one-well plugging financial assurance in amounts determined sufficient to reasonably pay the cost of plugging the well or wells covered by the financial assurance. In establishing categories of financial assurance, the [~~oil conservation~~] division shall consider the depth of the well involved, the length of time since the well was produced, the cost of plugging similar wells and [~~such~~] other factors [~~as~~] the [~~oil conservation~~] division

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deems relevant, such as operator size and relative risk. The [~~oil conservation~~] division shall require a one-well financial assurance on any well that has been held in a temporarily abandoned status for more than two years or, at the election of the operator, may allow an operator to increase its blanket plugging financial assurance to cover wells held in temporarily abandoned status. All financial assurance shall remain in force until released by the [~~oil conservation~~] division. The [~~oil conservation~~] division shall release financial assurance when [~~it~~] the division is satisfied that the conditions of the financial assurance have been fully performed.

B. The division may assess a non-refundable monthly well plugging risk pool fee on a per well basis on a subset of an operator's wells not to exceed five hundred dollars ($500) per well to offset bonding obligations. A well plugging risk pool fee collected by the division shall be deposited in the oil and gas reclamation fund.

[~~B.~~] C. If any of the requirements of the Oil and Gas Act or the rules promulgated pursuant to that act have not been complied with, the [~~oil conservation~~] division, after notice and hearing, may order any well plugged and abandoned by the operator or surety or both in accordance with division rules. If the order is not complied with in the time period set out in the order, the financial assurance shall be forfeited.

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[~~C.~~] D. When any financial assurance is forfeited pursuant to the provisions of the Oil and Gas Act or rules promulgated pursuant to that act, the director of the [~~oil conservation~~] division shall [~~give notice to the attorney general, who shall~~] collect the forfeiture without delay.

[~~D.~~] E. All forfeitures shall be deposited in the state treasury in the oil and gas reclamation fund.

[~~E.~~] F. When the financial assurance proves insufficient to cover the cost of plugging oil and gas wells on land other than federal land and funds must be expended from the oil and gas reclamation fund to meet the additional expenses, the [~~oil conservation~~] division is authorized to bring suit against the operator in the district court of the county in which the well is located for indemnification for all costs incurred by the [~~oil conservation~~] division in plugging the well. All funds collected pursuant to a judgment in a suit for indemnification brought under the provisions of this section shall be deposited in the oil and gas reclamation fund.

[~~F.~~] G. An operator required to file financial assurance for a well pursuant to this section is considered to have met that requirement if the operator obtains a plugging insurance policy that includes the specific well and that:

(1) is approved by the office of superintendent of insurance;

(2) names the state of New Mexico as owner of

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the policy and contingent beneficiary;

(3) names a primary beneficiary who agrees to plug the specified wellbore;

(4) is fully prepaid and cannot be canceled or surrendered;

(5) provides that the policy continues in effect until the specified wellbore has been plugged;

(6) provides that benefits will be paid when, but not before, the specified wellbore has been plugged in accordance with rules of the [~~oil conservation~~] division in effect at the time of plugging; and

(7) provides benefits that are not less than an amount equal to the one-well financial assurance required by [~~oil conservation~~] division rules.

[~~G.~~] H. If, subsequent to an operator obtaining an insurance policy as provided in this section, the one-well financial assurance requirement applicable to the operator's well is increased, either because the well is deepened or [~~the rules of the oil conservation~~] division rules are amended, the operator is considered to have met the revised requirement if:

(1) the existing policy benefit equals or exceeds the revised requirement;

(2) the operator obtains an amendment increasing the policy benefit by the amount of the increase in the applicable financial assurance requirement; or

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(3) the operator obtains financial assurance equal to the amount, if any, by which the revised requirement exceeds the policy benefit."

SECTION 3. Section 70-2-31 NMSA 1978 (being Laws 1981, Chapter 362, Section 1, as amended) is amended to read:

"70-2-31. VIOLATIONS OF THE OIL AND GAS ACT--PENALTIES.--

A. Whenever the division determines that a person violated or is violating the Oil and Gas Act or any provision of any rule, order, permit or authorization issued pursuant to that act, the division may seek compliance and civil penalties by:

(1) issuing a notice of violation;

(2) commencing a civil action in district court for appropriate relief, including injunctive relief; or

(3) issuing a temporary cessation order if the division determines that the violation is causing or will cause an imminent danger to public health or safety or a significant imminent environmental harm. The cessation order will remain in effect until the earlier of when the violation is abated or thirty days unless a hearing is held before the division and a new order is issued.

B. A notice of violation issued pursuant to Paragraph (1) of Subsection A of this section shall:

(1) state with reasonable specificity the nature of the violation; [~~shall~~]

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(2) require compliance immediately or within a specified time period; [~~shall~~]

(3) provide notice of the availability of an informal review and the date of a hearing before the division; and [~~shall~~]

(4) provide notice of potential sanctions, including assessing a penalty, suspending, canceling or terminating a permit or authorization, shutting in a well and plugging and abandonment of a well and forfeiting financial assurance pursuant to Section 70-2-14 NMSA 1978.

C. If the notice of violation is not resolved informally within thirty days after service of the notice, the division shall hold a hearing and determine whether the violation should be upheld and whether any sanctions, including civil penalties, shall be assessed. In assessing a penalty authorized by this section, the division shall take into account the seriousness of the violation, any good faith efforts to comply with the applicable requirements, any history of noncompliance under the Oil and Gas Act and other relevant factors. When a decision is rendered by the division after a hearing, any party of record adversely affected shall have the right to have the matter heard de novo before the commission pursuant to Section 70-2-13 NMSA 1978.

D. Any civil penalty assessed by a court or by the division or commission pursuant to this section may not exceed

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[~~two thousand five hundred dollars ($2,500)~~] ten thousand dollars ($10,000) per day of noncompliance for each violation unless the violation presents a risk either to the health or safety of the public or of causing significant environmental harm, or unless the noncompliance continues beyond a time specified in the notice of violation or order issued by the division, commission or court, whereupon the civil penalty may not exceed [~~ten thousand dollars ($10,000)~~] twenty-five thousand dollars ($25,000) per day of noncompliance for each violation. [~~No penalty assessed by the division or commission after a hearing may exceed two hundred thousand dollars ($200,000); provided that such limitation does not apply to penalties assessed by a court.~~]

E. The commission shall make rules, pursuant to Section 70-2-12.2 NMSA 1978, providing procedures for the issuance of notices of violations, the assessment of penalties and the conduct of informal proceedings and hearings pursuant to this section.

F. It is unlawful, subject to a criminal penalty of a fine of not more than five thousand dollars ($5,000) or imprisonment for a term not exceeding three years or both such fine and imprisonment, for any person to knowingly and willfully:

(1) violate any provision of the Oil and Gas Act or any rule, regulation or order of the commission or the

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division issued pursuant to that act; or

(2) do any of the following for the purpose of evading or violating the Oil and Gas Act or any rule, regulation or order of the commission or the division issued pursuant to that act:

(a) make any false entry or statement in a report required by the Oil and Gas Act or by any rule, regulation or order of the commission or division issued pursuant to that act;

(b) make or cause to be made any false entry in any record, account or memorandum required by the Oil and Gas Act or by any rule, regulation or order of the commission or division issued pursuant to that act;

(c) omit or cause to be omitted from any such record, account or memorandum full, true and correct entries; or

(d) remove from this state or destroy, mutilate, alter or falsify any such record, account or memorandum.

G. For the purposes of Subsection F of this section, each day of violation shall constitute a separate offense.

H. Any person who knowingly and willfully procures, counsels, aids or abets the commission of any act described in Subsection A or F of this section shall be subject to the same

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penalties as are prescribed in Subsection D or F of this section."

SECTION 4. Section 70-2-39 NMSA 1978 (being Laws 2019, Chapter 260, Section 1) is amended to read:

"70-2-39. FEES--[~~APPROPRIATION~~] FEE ADJUSTMENTS--OIL CONSERVATION DIVISION SYSTEMS AND HEARINGS FUND CREATED.--

A. Beginning January 1, 2027 and on January 1 of each successive year, the fees provided by this section may be adjusted for inflation as provided in Subsection B of this section. The following fees are required to be paid to the [~~oil conservation~~] division [~~of the energy, minerals and natural resources department~~] with each application for:

(1) [~~with each application for~~] a non-federal and non-Indian permit to drill, deepen, plug back or reenter a well, the applicant shall submit to the division a nonrefundable fee of [~~five hundred dollars ($500)~~] one thousand five hundred dollars ($1,500);

(2) [~~with each individual application for~~] administrative approval of a non-standard location, downhole commingle, surface commingle, off-lease measurement, release notification and corrective action, change of operator, application for modification to surface waste management facility, request for the creation of a new pool, proposed alternative method permit or closure plan application or authorization to move produced water, the applicant shall

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submit to the division a nonrefundable fee of [~~one hundred fifty dollars ($150)~~] four hundred fifty dollars ($450);

(3) [~~with each application for~~] a fluid injection well permit, the applicant shall submit to the division a nonrefundable fee of [~~five hundred dollars ($500)~~] one thousand five hundred dollars ($1,500) per well;

(4) [~~with each application for~~] a permit for a commercial surface waste management facility, landfill or landfarm, the applicant shall submit to the division a nonrefundable fee of ten thousand dollars ($10,000) per facility;

(5) [~~with each application for~~] an administrative hearing, re-hearing or de novo hearing before the division or commission, the applicant shall submit to the division a nonrefundable fee of [~~five hundred dollars ($500)~~] one thousand five hundred dollars ($1,500) per application; and

(6) [~~with each application for~~] a continuance of an administrative hearing, re-hearing or de novo hearing before the division or commission, the applicant shall submit to the division a nonrefundable fee of [~~one hundred fifty dollars ($150)~~] four hundred fifty dollars ($450) per application.

B. On January 1, 2027 and on January 1 of each successive year, the division may adjust the fees provided by Subsection A of this section by multiplying the fee as of

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January 1, 2026 by a fraction, the numerator of which is the consumer price index ending in September of the previous year and the denominator of which is the consumer price index ending September 2025; provided that the fees shall not be adjusted below the minimum amounts provided in Subsection A of this section as a result of a decrease in the consumer price index. By November 1, 2026 and by November 1 of each successive year, the division shall post on its website the fees in Subsection A of this section for the next year.

[~~B.~~] C. An application for an administrative hearing, re-hearing or de novo hearing before the oil conservation division or commission will be considered to be materially amended if the amendment is made for a purpose other than to correct:

(1) typographical errors; or

(2) clerical errors.

[~~C.~~] D. The "oil conservation division systems and hearings fund" is created in the state treasury as a nonreverting fund. All funds received by the [~~oil conservation~~] division from fees imposed pursuant to Subsection A of this section shall be delivered to the state treasurer and deposited in the fund. Disbursements from the fund shall be made upon warrants drawn by the secretary of finance and administration pursuant to vouchers signed by the secretary of energy, minerals and natural resources or the secretary's

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authorized representative. Money in the fund is subject to appropriation by the legislature to the division to develop and modernize the division's online application processing system, online case management system, online data reporting and visualization systems and online case file system and for other technological and equipment upgrades necessary to support the efficient and transparent implementation and enforcement of the Oil and Gas Act, including hiring necessary information technology personnel, and for hearing administration costs. Any unexpended or unencumbered balance remaining in the fund at the end of a fiscal year shall not revert to the general fund. [~~Money in the fund in fiscal year 2020 may be expended by the division for the purposes of the fund.~~]

E. As used in this section, "consumer price index" means the consumer price index, not seasonally adjusted, for all urban consumers, United States city average for all items, or its successor index, as published by the United States department of labor for a twelve-month period ending September 30."

SECTION 5. A new section of the Oil and Gas Act is enacted to read:

"[NEW MATERIAL] NATURAL GAS CAPTURE REQUIREMENTS--RULES.--

A. Beginning January 1, 2027, an operator shall ensure that at least ninety-eight percent of the natural gas produced or gathered by the operator's facilities is captured

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in a calendar year; provided that natural gas released during an emergency or that is beneficially used by the operator or is essential for drilling, completion, recompletion, gas gathering or production operations does not count as gas released for the purpose of determining an operator's overall capture percentage.

B. The division shall adopt rules necessary to implement the provisions of this section and an application for a permit to drill shall be subject to the rules to be valid.

C. As used in this section, "operator" means a person that is duly authorized to construct, manage or operate an oil or gas well or associated facilities or a natural gas gathering system."

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HOUSE JUDICIARY COMMITTEE SUBSTITUTE FOR HOUSE ENERGY, ENVIRONMENT AND NATURAL RESOURCES COMMITTEE SUBSTITUTE FOR HOUSE BILL 133

56TH LEGISLATURE - STATE OF NEW MEXICO - SECOND SESSION, 2024

AN ACT

RELATING TO THE ENVIRONMENT; AMENDING THE OIL AND GAS ACT; ALLOWING THE OIL CONSERVATION DIVISION OF THE ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT TO REGULATE CERTAIN TRANSFERS OF OIL AND GAS WELLS AND AUTHORIZE THE CONVERSION OF OIL AND GAS WELLS FOR ENERGY STORAGE AND GEOTHERMAL DEVELOPMENT; INCREASING THE AMOUNT OF FEES AND FINANCIAL ASSURANCE ASSOCIATED WITH OPERATING OIL AND GAS WELLS; INCREASING CIVIL PENALTIES; ALLOWING FEES TO BE ADJUSTED TO ACCOUNT FOR INFLATION; REQUIRING THE CAPTURE OF NINETY-EIGHT PERCENT OF NATURAL GAS PRODUCED BEGINNING IN 2027.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF NEW MEXICO:

SECTION 1. Section 70-2-12 NMSA 1978 (being Laws 1978, Chapter 71, Section 1, as amended) is amended to read:

"70-2-12. ENUMERATION OF POWERS.--

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A. The [~~oil conservation~~] division [~~of the energy, minerals and natural resources department~~] may:

(1) collect data;

(2) make investigations and inspections;

(3) examine properties, leases, papers, books and records;

(4) examine, check, test and gauge oil and gas wells, tanks, plants, refineries and all means and modes of transportation and equipment;

(5) hold hearings;

(6) provide for the keeping of records and the making of reports and for the checking of the accuracy of the records and reports;

(7) limit and prorate production of crude petroleum oil or natural gas or both as provided in the Oil and Gas Act; and

(8) require either generally or in particular areas certificates of clearance or tenders in connection with the transportation of crude petroleum oil or natural gas or any products of either or both oil and products or both natural gas and products.

B. The [~~oil conservation~~] division may make rules and orders [~~for the purposes and with respect to the subject matter stated in this subsection~~]:

(1) to require dry or abandoned wells to be

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plugged in a way so as to confine the crude petroleum oil, natural gas or water in the strata in which it is found and to prevent it from escaping into other strata; pursuant to Section 70-2-14 NMSA 1978, the division shall require financial assurance conditioned for the performance of the rules;

(2) to prevent crude petroleum oil, natural gas or water from escaping from strata in which it is found into other strata;

(3) to require reports showing locations of all oil or gas wells and for the filing of logs and drilling records or reports;

(4) to prevent the drowning by water of any stratum or part thereof capable of producing oil or gas or both oil and gas in paying quantities and to prevent the premature and irregular encroachment of water or any other kind of water encroachment that reduces or tends to reduce the total ultimate recovery of crude petroleum oil or gas or both oil and gas from any pool;

(5) to prevent fires;

(6) to prevent "blow-ups" and "caving" in the sense that the conditions indicated by such terms are generally understood in the oil and gas business;

(7) to require wells to be drilled, operated and produced in such manner as to prevent injury to neighboring leases or properties;

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(8) to identify the ownership of oil or gas producing leases, properties, wells, tanks, refineries, pipelines, plants, structures and all transportation equipment and facilities;

(9) to require the operation of wells with efficient gas-oil ratios and to fix such ratios;

(10) to fix the spacing of wells;

(11) to determine whether a particular well or pool is a gas or oil well or a gas or oil pool, as the case may be, and from time to time to classify and reclassify wells and pools accordingly;

(12) to determine the limits of any pool producing crude petroleum oil or natural gas or both and from time to time redetermine the limits;

(13) to regulate the methods and devices employed for storage in this state of oil or natural gas or any product of either, including subsurface storage;

(14) to permit the injection of natural gas or of any other substance into any pool in this state for the purpose of repressuring, cycling, pressure maintenance, secondary or any other enhanced recovery operations;

(15) to regulate the disposition, handling, transport, storage, recycling, treatment and disposal of produced water during, or for reuse in, the exploration, drilling, production, treatment or refinement of oil or gas,

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including disposal by injection pursuant to authority delegated under the federal Safe Drinking Water Act, in a manner that protects public health, the environment and fresh water resources;

(16) to determine the limits of any area containing commercial potash deposits and from time to time redetermine the limits;

(17) to regulate and, where necessary, prohibit drilling or producing operations for oil or gas within any area containing commercial deposits of potash where the operations would have the effect unduly to reduce the total quantity of the commercial deposits of potash that may reasonably be recovered in commercial quantities or where the operations would interfere unduly with the orderly commercial development of the potash deposits;

(18) to spend the oil and gas reclamation fund and do all acts necessary and proper to plug dry and abandoned oil and gas wells and to restore and remediate abandoned well sites and associated production facilities in accordance with the provisions of the Oil and Gas Act, the rules adopted under that act and the Procurement Code, including disposing of salvageable equipment and material removed from oil and gas wells being plugged by the state;

(19) to make well price category determinations pursuant to the provisions of the federal

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Natural Gas Policy Act of 1978 or any successor act and, by regulation, to adopt fees for such determinations, which fees shall not exceed twenty-five dollars ($25.00) per filing. Such fees shall be credited to the account of the [~~oil conservation~~] division by the state treasurer and may be expended as authorized by the legislature;

(20) to regulate the construction and operation of oil treating plants and to require the posting of bonds for the reclamation of treating plant sites after cessation of operations;

(21) to regulate the disposition of nondomestic wastes resulting from the exploration, development, production or storage of crude oil or natural gas to protect public health and the environment; [~~and~~]

(22) to regulate the disposition of nondomestic wastes resulting from the oil field service industry, the transportation of crude oil or natural gas, the treatment of natural gas or the refinement of crude oil to protect public health and the environment, including administering the Water Quality Act as provided in Subsection E of Section 74-6-4 NMSA 1978;

(23) to regulate the transfer of oil and gas wells, including limitations on transfers when:

(a) the transferor, the transferee or an entity that owns more than a twenty-five percent interest in a

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transferor or transferee has a significant history of noncompliance with the Oil and Gas Act or rules adopted pursuant to that act, including multiple notices of violations or spills or releases that are not in the process of being corrected or addressed;

(b) the transferee fails to provide adequate financial assurance as required by the division;

(c) the transferee lacks sufficient financial capacity based on known or projected production to manage liabilities associated with the oil and gas wells; or

(d) the division issues a written finding that the limitations on transfer are necessary for the purposes of mitigating risk to the state from potential inactive or abandoned oil and gas wells; and

(24) to authorize the conversion of an oil and gas well to a facility that supports energy storage or geothermal development, including establishing fees and financial assurance requirements specific to an energy storage or geothermal use."

SECTION 2. Section 70-2-14 NMSA 1978 (being Laws 1977, Chapter 237, Section 3, as amended) is amended to read:

"70-2-14. REQUIREMENT FOR FINANCIAL ASSURANCE.--

A. Each person, firm, corporation or association who operates [~~any~~] an oil, gas or service well within the state shall, as a condition precedent to drilling or producing the

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well, furnish financial assurance in the form of an irrevocable letter of credit, [~~or~~] a cash or surety bond, a well plugging risk pool fee or a [~~well-specific~~] plugging insurance policy pursuant to the provisions of this section to the [~~oil conservation~~] division [~~of the energy, minerals and natural resources department~~] running to the benefit of the state and conditioned that the covered well be plugged and abandoned in [~~compliance with the rules of the oil conservation~~] accordance with division rules. The [~~oil conservation~~] division shall establish categories of financial assurance by rule after notice and hearing. Such categories shall include: [~~a blanket plugging financial assurance, which shall be set by rule in an amount not to exceed two hundred fifty thousand dollars ($250,000), a blanket plugging financial assurance for temporarily abandoned status wells, which shall be set by rule at amounts greater than fifty thousand dollars ($50,000), and one-well plugging financial assurance in amounts determined sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance~~]

(1) blanket plugging financial assurance for an operator's active wells in an amount not to exceed:

(a) two hundred fifty thousand dollars ($250,000) for an operator with fewer than fifty wells and total oil and gas production of fewer than one hundred thousand barrels of oil equivalent per year;

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(b) three hundred fifty thousand dollars ($350,000) for an operator not covered by Subparagraph (a) of this paragraph with fewer than one hundred wells and total oil and gas production of fewer than two hundred thousand barrels of oil equivalent per year;

(c) five hundred thousand dollars ($500,000) for an operator not covered by Subparagraph (a) or (b) of this paragraph with fewer than one hundred fifty wells and total oil and gas production of fewer than five hundred thousand barrels of oil equivalent per year;

(d) seven hundred fifty thousand dollars ($750,000) for an operator not covered by Subparagraph (a), (b) or (c) of this paragraph with fewer than three hundred wells or total oil and gas production of fewer than seven hundred fifty thousand barrels of oil equivalent per year;

(e) five million dollars ($5,000,000) for an operator with between three hundred and five hundred wells or total oil and gas production of fewer than one million two hundred fifty thousand barrels of oil equivalent per year; or

(f) ten million dollars ($10,000,000) for an operator with greater than five hundred wells and total oil and gas production of greater than one million two hundred fifty thousand barrels of oil equivalent per year;

(2) a well plugging risk pool fee; or

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(3) a one-well plugging financial assurance in an amount determined sufficient to reasonably pay the cost of plugging the well or wells covered by the financial assurance.

B. The division may determine blanket plugging financial assurance requirements for an operator based on well count and oil and gas production from wholly owned subsidiaries of the same corporate parent.

C. In establishing categories of financial assurance, the [~~oil conservation~~] division shall consider the depth of the well involved, the length of time since the well was produced, the cost of plugging similar wells and [~~such~~] other factors [~~as~~] the [~~oil conservation~~] division deems relevant, such as operator size and relative risk. The [~~oil conservation~~] division shall require a one-well financial assurance on any well that has been held in a temporarily abandoned status for more than two years or, at the election of the operator, may allow an operator to increase its blanket plugging financial assurance to cover wells held in temporarily abandoned status. All financial assurance shall remain in force until released by the [~~oil conservation~~] division. The [~~oil conservation~~] division shall release financial assurance when [~~it~~] the division is satisfied that the conditions of the financial assurance have been fully performed.

D. The division may assess a non-refundable monthly well plugging risk pool fee on a per well basis on a subset of

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an operator's wells not to exceed five hundred dollars ($500) per well to offset bonding obligations. A well plugging risk pool fee collected by the division shall be deposited in the oil and gas reclamation fund.

[~~B.~~] E. If any of the requirements of the Oil and Gas Act or the rules promulgated pursuant to that act have not been complied with, the [~~oil conservation~~] division, after notice and hearing, may order any well plugged and abandoned by the operator or surety or both in accordance with division rules. If the order is not complied with in the time period set out in the order, the financial assurance shall be forfeited.

[~~C.~~] F. When any financial assurance is forfeited pursuant to the provisions of the Oil and Gas Act or rules promulgated pursuant to that act, the director of the [~~oil conservation~~] division shall [~~give notice to the attorney general, who shall~~] collect the forfeiture without delay.

[~~D.~~] G. All forfeitures shall be deposited in the state treasury in the oil and gas reclamation fund.

[~~E.~~] H. When the financial assurance proves insufficient to cover the cost of plugging oil and gas wells on land other than federal land and funds must be expended from the oil and gas reclamation fund to meet the additional expenses, the [~~oil conservation~~] division is authorized to bring suit against the operator in the district court of the

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county in which the well is located for indemnification for all costs incurred by the [~~oil conservation~~] division in plugging the well. All funds collected pursuant to a judgment in a suit for indemnification brought under the provisions of this section shall be deposited in the oil and gas reclamation fund.

[~~F.~~] I. An operator required to file financial assurance for a well pursuant to this section is considered to have met that requirement if the operator obtains a plugging insurance policy that includes the specific well and that:

(1) is approved by the office of superintendent of insurance;

(2) names the state of New Mexico as owner of the policy and contingent beneficiary;

(3) names a primary beneficiary who agrees to plug the specified wellbore;

(4) is fully prepaid and cannot be canceled or surrendered;

(5) provides that the policy continues in effect until the specified wellbore has been plugged;

(6) provides that benefits will be paid when, but not before, the specified wellbore has been plugged in accordance with rules of the [~~oil conservation~~] division in effect at the time of plugging; and

(7) provides benefits that are not less than an amount equal to the one-well financial assurance required by

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[~~oil conservation~~] division rules.

[~~C.~~] J. If, subsequent to an operator obtaining an insurance policy as provided in this section, the one-well financial assurance requirement applicable to the operator's well is increased, either because the well is deepened or [~~the rules of the oil conservation~~] division rules are amended, the operator is considered to have met the revised requirement if:

(1) the existing policy benefit equals or exceeds the revised requirement;

(2) the operator obtains an amendment increasing the policy benefit by the amount of the increase in the applicable financial assurance requirement; or

(3) the operator obtains financial assurance equal to the amount, if any, by which the revised requirement exceeds the policy benefit."

SECTION 3. Section 70-2-31 NMSA 1978 (being Laws 1981, Chapter 362, Section 1, as amended) is amended to read:

"70-2-31. VIOLATIONS OF THE OIL AND GAS ACT--PENALTIES.--

A. Whenever the division determines that a person violated or is violating the Oil and Gas Act or any provision of any rule, order, permit or authorization issued pursuant to that act, the division may seek compliance and civil penalties by:

(1) issuing a notice of violation;

(2) commencing a civil action in district

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court for appropriate relief, including injunctive relief; or

(3) issuing a temporary cessation order if the division determines that the violation is causing or will cause an imminent danger to public health or safety or a significant imminent environmental harm. The cessation order will remain in effect until the earlier of when the violation is abated or thirty days unless a hearing is held before the division and a new order is issued.

B. A notice of violation issued pursuant to Paragraph (1) of Subsection A of this section shall:

(1) state with reasonable specificity the nature of the violation; [~~shall~~]

(2) require compliance immediately or within a specified time period; [~~shall~~]

(3) provide notice of the availability of an informal review and the date of a hearing before the division; and [~~shall~~]

(4) provide notice of potential sanctions, including assessing a penalty, suspending, canceling or terminating a permit or authorization, shutting in a well and plugging and abandonment of a well and forfeiting financial assurance pursuant to Section 70-2-14 NMSA 1978.

C. If the notice of violation is not resolved informally within thirty days after service of the notice, the division shall hold a hearing and determine whether the

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violation should be upheld and whether any sanctions, including civil penalties, shall be assessed. In assessing a penalty authorized by this section, the division shall take into account the seriousness of the violation, any good faith efforts to comply with the applicable requirements, any history of noncompliance under the Oil and Gas Act and other relevant factors. When a decision is rendered by the division after a hearing, any party of record adversely affected shall have the right to have the matter heard de novo before the commission pursuant to Section 70-2-13 NMSA 1978.

D. Any civil penalty assessed by a court or by the division or commission pursuant to this section may not exceed [~~two thousand five hundred dollars ($2,500)~~] ten thousand dollars ($10,000) per day of noncompliance for each violation unless the violation presents a risk either to the health or safety of the public or of causing significant environmental harm, or unless the noncompliance continues beyond a time specified in the notice of violation or order issued by the division, commission or court, whereupon the civil penalty may not exceed [~~ten thousand dollars ($10,000)~~] twenty-five thousand dollars ($25,000) per day of noncompliance for each violation. No penalty assessed by the division or commission after a hearing may exceed [~~two hundred thousand dollars ($200,000)~~] three million six hundred fifty thousand dollars ($3,650,000); provided that such limitation does not apply to

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penalties assessed by a court.

E. The commission shall make rules, pursuant to Section 70-2-12.2 NMSA 1978, providing procedures for the issuance of notices of violations, the assessment of penalties and the conduct of informal proceedings and hearings pursuant to this section.

F. It is unlawful, subject to a criminal penalty of a fine of not more than five thousand dollars ($5,000) or imprisonment for a term not exceeding three years or both such fine and imprisonment, for any person to knowingly and willfully:

(1) violate any provision of the Oil and Gas Act or any rule, regulation or order of the commission or the division issued pursuant to that act; or

(2) do any of the following for the purpose of evading or violating the Oil and Gas Act or any rule, regulation or order of the commission or the division issued pursuant to that act:

(a) make any false entry or statement in a report required by the Oil and Gas Act or by any rule, regulation or order of the commission or division issued pursuant to that act;

(b) make or cause to be made any false entry in any record, account or memorandum required by the Oil and Gas Act or by any rule, regulation or order of the

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commission or division issued pursuant to that act;

(c) omit or cause to be omitted from any such record, account or memorandum full, true and correct entries; or

(d) remove from this state or destroy, mutilate, alter or falsify any such record, account or memorandum.

G. For the purposes of Subsection F of this section, each day of violation shall constitute a separate offense.

H. Any person who knowingly and willfully procures, counsels, aids or abets the commission of any act described in Subsection A or F of this section shall be subject to the same penalties as are prescribed in Subsection D or F of this section."

SECTION 4. Section 70-2-39 NMSA 1978 (being Laws 2019, Chapter 260, Section 1) is amended to read:

"70-2-39. FEES--[~~APPROPRIATION~~] FEE ADJUSTMENTS--OIL CONSERVATION DIVISION SYSTEMS AND HEARINGS FUND CREATED.--

A. Beginning January 1, 2027 and on January 1 of each successive year, the fees provided by this section may be adjusted for inflation as provided in Subsection B of this section. The following fees are required to be paid to the [~~oil conservation~~] division [~~of the energy, minerals and natural resources department~~] with each application for:

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(1) [~~with each application for~~] a non-federal and non-Indian permit to drill, deepen, plug back or reenter a well, the applicant shall submit to the division a nonrefundable fee of [~~five hundred dollars ($500)~~] one thousand five hundred dollars ($1,500);

(2) [~~with each individual application for~~] administrative approval of a non-standard location, downhole commingle, surface commingle, off-lease measurement, release notification and corrective action, change of operator, application for modification to surface waste management facility, request for the creation of a new pool, proposed alternative method permit or closure plan application or authorization to move produced water, the applicant shall submit to the division a nonrefundable fee of [~~one hundred fifty dollars ($150)~~] four hundred fifty dollars ($450);

(3) [~~with each application for~~] a fluid injection well permit, the applicant shall submit to the division a nonrefundable fee of [~~five hundred dollars ($500)~~] one thousand five hundred dollars ($1,500) per well;

(4) [~~with each application for~~] a permit for a commercial surface waste management facility, landfill or landfarm, the applicant shall submit to the division a nonrefundable fee of ten thousand dollars ($10,000) per facility;

(5) [~~with each application for~~] an

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administrative hearing, re-hearing or de novo hearing before the division or commission, the applicant shall submit to the division a nonrefundable fee of [~~five hundred dollars ($500)~~] one thousand five hundred dollars ($1,500) per application; and

(6) [~~with each application for~~] a continuance of an administrative hearing, re-hearing or de novo hearing before the division or commission, the applicant shall submit to the division a nonrefundable fee of [~~one hundred fifty dollars ($150)~~] four hundred fifty dollars ($450) per application.

B. On January 1, 2027 and on January 1 of each successive year, the division may adjust the fees provided by Subsection A of this section by multiplying the fee as of January 1, 2026 by a fraction, the numerator of which is the consumer price index ending in September of the previous year and the denominator of which is the consumer price index ending September 2025; provided that the fees shall not be adjusted below the minimum amounts provided in Subsection A of this section as a result of a decrease in the consumer price index. By November 1, 2026 and by November 1 of each successive year, the division shall post on its website the fees in Subsection A of this section for the next year.

[~~B.~~] C. An application for an administrative hearing, re-hearing or de novo hearing before the [~~oil conservation~~] division or commission will be considered to be

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materially amended if the amendment is made for a purpose other than to correct:

(1) typographical errors; or

(2) clerical errors.

[~~C.~~] D. The "oil conservation division systems and hearings fund" is created in the state treasury as a nonreverting fund. All funds received by the [~~oil conservation~~] division from fees imposed pursuant to Subsection A of this section shall be delivered to the state treasurer and deposited in the fund. Disbursements from the fund shall be made upon warrants drawn by the secretary of finance and administration pursuant to vouchers signed by the secretary of energy, minerals and natural resources or the secretary's authorized representative. Money in the fund is subject to appropriation by the legislature to the division to develop and modernize the division's online application processing system, online case management system, online data reporting and visualization systems and online case file system and for other technological and equipment upgrades necessary to support the efficient and transparent implementation and enforcement of the Oil and Gas Act, including hiring necessary information technology personnel, and for hearing administration costs. Any unexpended or unencumbered balance remaining in the fund at the end of a fiscal year shall not revert to the general fund. [~~Money in the fund in fiscal year 2020 may be expended by the~~

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~~division for the purposes of the fund.~~]

E. As used in this section, "consumer price index" means the consumer price index, not seasonally adjusted, for all urban consumers, United States city average for all items, or its successor index, as published by the United States department of labor for a twelve-month period ending September 30."

SECTION 5. A new section of the Oil and Gas Act is enacted to read:

"[NEW MATERIAL] NATURAL GAS CAPTURE REQUIREMENTS--RULES.--

A. Beginning January 1, 2027, an operator shall ensure that at least ninety-eight percent of the natural gas produced or gathered by the operator's facilities is captured in a calendar year; provided that natural gas does not count as gas released for the purpose of determining an operator's overall capture percentage if that gas is:

(1) released during an emergency;

(2) beneficially used by the operator;

(3) not suitable for transportation or processing due to nitrogen, hydrogen sulfide or carbon dioxide concentrations;

(4) vented as a result of normal operation of pneumatic controllers and pumps; or

(5) vented or flared from an exploratory well.

B. The division shall adopt rules necessary to

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implement the provisions of this section and an application for a permit to drill shall be subject to the rules to be valid.

C. As used in this section, "operator" means a person that is duly authorized to construct, manage or operate an oil or gas well or associated facilities or a natural gas gathering system."

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EXHIBIT 26

Fiscal impact reports (FIRs) are prepared by the Legislative Finance Committee (LFC) for standing finance committees of the Legislature. LFC does not assume responsibility for the accuracy of these reports if they are used for other purposes.

F I S C A L I M P A C T R E P O R T

SPONSOR HJC

SHORT TITLE Oil & Gas Act Changes

LAST UPDATED 02/02/24
ORIGINAL DATE 01/22/24
BILL NUMBER CS/CS/House Bill 133/HENRCS/HJCS
ANALYST Torres, Ismael/ Wan Smith

REVENUE*
(dollars in thousands)

Type	FY24	FY25	FY26	FY27	FY28	Recurring or Nonrecurring	Fund Affected
Application Fees	$393.5 to $455.2	$3,148.3 to $3,641.6	$3,148.3 to $3,641.6	$3,148.3 to $3,641.6	$3,148.3 to $3,641.6	Recurring	OCD Systems and Hearings Fund
Oil and Gas Severance Tax**		($530.0)	($4,150.0)	($14,280.0)	($21,380.0)	Recurring	Severance Tax Bonding Fund
Severance Tax Bonding Capacity**		Dependent upon bonding, negative	Dependent upon bonding, negative	Dependent upon bonding, negative	Dependent upon bonding, negative	Recurring	Capital Outlay
Oil and Gas Emergency School Tax**		($510.0)	($3,500.0)			Recurring	Early Childhood Trust Fund
Oil and Gas Emergency School Tax**			$3,400.0	($12,420.0)	($18,630.0)	Recurring	Severance Tax Permanent Fund
Oil and Gas Conservation Tax**		($10.0)	($40.0)	($140.0)	($210.0)	Recurring	Oil and Gas Reclamation Fund
Oil and Gas Conservation Tax**		($20.0)	($170.0)	($580.0)	($870.0)	Recurring	General Fund
Oil and Gas Ad Valorem Production Tax**		Dependent on local property tax rates	Dependent on local property tax rates	Dependent on local property tax rates	Dependent on local property tax rates	Recurring	Local govs/ GOBs
Oil and Gas Ad Valorem Equipment Tax**		Dependent on local property tax rates	Dependent on local property tax rates	Dependent on local property tax rates	Dependent on local property tax rates	Recurring	Local govs/ GOBs
State Land Office Rental and Bonus Income**		Negative	Negative	Negative	Negative	Recurring	General Fund
State Land Office Royalty Payments**		($620.0)	($4,530.0)	($15,640.0)	($23,440.0)	Recurring	Land Grant Permanent Fund

Federal Land Rental and Bonus Income**		Negative	Negative	Negative	Negative	Recurring	General Fund
Federal Land Royalty Payments**		($1,000.0)	($6,860.0)			Recurring	Early Childhood Trust Fund
Federal Land Royalty Payments**			($200.0)	($24,370.0)	($36,550.0)	Recurring	Severance Tax Permanent Fund
Investment Income Distributions from Permanent Funds**					($20.0)	Recurring	General Fund
Gross Receipts Tax**		($150.0)	($2,400.0)	($8,180.0)	($12,150.0)	Recurring	General Fund
Gross Receipts Tax**		($10.0)	($180.0)	($630.0)	($930.0)	Recurring	Local Gov.
Well Plugging Risk Pool Fee		Indeterminate but minimal gain	Indeterminate but minimal gain	Indeterminate but minimal gain	Indeterminate but minimal gain	Recurring	Oil and Gas Reclamation Fund

Parentheses ( ) indicate revenue decreases.
*Estimates on the impacts of this bill are particularly difficult to discern. Numbers provided are intended to illustrate a potential magnitude of impact and not an exact amount. Please see *Fiscal Implications* for more information.
****Values for revenue types are the upper limits for the revenue impacts.**

Relates to House Bills 30, House Bill 31, and House Bill 32

Sources of Information

LFC Files

Because of the short timeframe between the introduction of this bill and its first hearing, LFC has yet to receive analysis from state, education, or judicial agencies. This analysis could be updated if that analysis is received.

SUMMARY

Synopsis of HJC Substitute for House Bill 133

The House Judiciary Committee Substitute for House Bill 133 makes several changes to the Oil and Gas Act (Chapter 70 Article 2 NMSA 1978). First, the bill amends Section 70-2-12 NMSA 1978 to give the Oil Conservation Division (OCD) of the Energy, Minerals and Natural Resources Department (EMNRD) additional authority.

Specifically, OCD would be authorized to:

- Regulate the transfer of oil and gas wells or facilities, including placing limitations on transfers to mitigate risk to the state or when an entity has a significant history of noncompliance, fails to provide adequate financial assurance, or lacks sufficient financial capacity to cover facility liabilities; and
- Permit the conversion of an oil and gas well to a facility for energy storage or geothermal development and establish fees and financial assurance requirements for these purposes.

The substitute bill amends the financial assurance requirements of the Oil and Gas Act (Section 70-2-14 NMSA 1978) to establish tiers of blanket plugging financial assurance based on an operator's quantity of active wells and to increase the maximum blanket bond from $250 thousand to $10 million. Maximum amounts for each tier are set as follows:

1. $250 thousand for an operator with fewer than 50 wells and total oil and gas production of fewer than 100 thousand barrels of oil equivalent per year
2. $350 thousand for an operator with between 50 and 99 wells and total oil and gas production of 100 thousand to 199 thousand barrels of oil equivalent per year
3. $500 thousand for an operator with between 99 and 149 wells and total oil and gas production of 200 thousand to 499 thousand barrels of oil equivalent per year
4. $750 thousand for an operator with between 150 and 299 wells or total oil and gas production of 500 thousand to 749 thousand barrels of oil equivalent per year
5. $5 million for an operator with between 300 and 500 wells or total oil and gas production of fewer than 1.25 million barrels of oil equivalent per year
6. $10 million for an operator with more than 500 wells and total oil and gas production of greater than 1.25 million barrels of oil equivalent per year

The HJC substitute also adds to the categories of financial assurance the option of a well plugging risk pool fee, not to exceed $500 per well, that OCD may assess on a subset of an operator's wells to offset bonding obligations. The monthly risk pool fee is nonrefundable and would be deposited in the oil reclamation fund. The bill adds a third category of one-well plugging financial assurance in an amount determined sufficient to reasonably pay the cost of plugging the well or wells covered by the financial assurance.

The bill specifies that, in establishing categories of financial assurance, OCD shall consider operator size and relative risk among the factors already named in statute. In addition, the bill moves the responsibility for collecting a forfeiture of financial assurance from the Office of the Attorney General (NMAG) to OCD.

The remaining amendments to existing statute made by the committee substitute relate to penalties and fees. The bill increases the maximum daily civil penalty for noncompliance with the Oil and Gas Act from $2,500 to $10 thousand per violation; in cases where a risk to public health and safety or the environment exists, the penalty is increased from $10 thousand to $25 thousand. Additionally, the existing $200 thousand cap on administrative penalties is increased to $3.65 million.

The substitute bill increases all but one[1] of OCD's application fees by a factor of three and gives OCD authority, beginning in 2027, to annually adjust fees for inflation. The bill also expands the allowable uses of the OCD systems and hearings fund, where application fees are deposited. Currently, money in that fund is appropriated to OCD "to develop and modernize the division's online application processing system, online case management system and online case file system and for other technological upgrades and hearing administration costs." The bill adds "data reporting and visualization systems" to the list of items the fund should be used to develop and specifies that appropriations may also be used for equipment upgrades and information technology personnel "necessary to support the efficient and transparent implementation and enforcement of the Oil and Gas Act."

[1] The fee for commercial surface waste facility permitting is not increased by the legislation.

The committee substitute creates a new section of the Oil and Gas Act that requires operators to ensure at least 98 percent of natural gas produced or gathered by the operator's facilities is captured in a calendar year, beginning in 2027. The new language states that natural gas meeting any of the following conditions does not count as uncaptured gas:

- Released during an emergency;
- Beneficially used by the operator:
- Not suitable for transportation or processing due to nitrogen, hydrogen sulfide, or carbon dioxide concentrations:
- Vented as a result of normal operation of pneumatic controllers and pumps:
- Vented or flared from an exploratory well

The bill requires OCD to adopt rules for implementing the new provisions.

This bill does not contain an effective date and, as a result, would go into effect 90 days after the Legislature adjourns, or May 15, 2024, if enacted.

FISCAL IMPLICATIONS

Potential Impacts to Production of Oil and Gas

The table on page one presents an estimate of potential impacts intended to illustrate a magnitude rather than an exact amount. To gauge potential impacts on production, LFC staff utilized data from Rystad Energy, an energy analytics firm.

Firstly, future oil and gas production was estimated by considering completed wells, wells currently in progress, wells in the drilling phase, legacy wells, drilled but uncompleted wells, and already permitted wells. This analysis focused only on the remaining estimated future production attributed to not-yet-permitted wells, which, on average, accounts for approximately 16 percent of the projected future production. Fiscal implications for already permitted wells were not considered in this bill's analysis. As a result, fiscal impacts are delayed until production begins for not-yet-permitted wells. If this legislation negatively impacts production from already permitted wells, the financial costs estimated on page one could increase significantly and commence earlier than indicated.

Secondly, staff further refined the production impacts from not-yet-permitted wells by applying the share of oil and gas produced by smaller, private producers as a proxy for the wells most likely affected by increased financial assurances, capture requirements, and other regulatory costs. Producers with less than 1 million barrels of production a year in 2023 were chosen for this proxy and represent less than 2.3 percent of New Mexico's total production. This amount was chosen from cash flow analysis based on LFC analysis; however, costs vary greatly by producer and producers with half the production may still be able to produce profitably under these methodological assumptions. Therefore, the actual number of impacted producers is likely to be less than what is estimated here. This share of smaller producers was applied to the not-yet-permitted oil production. Larger producers, presumed more capable of handling increased regulatory costs, were not expected to be significantly impacted. However, if this legislation does substantially and negatively affect production from these larger sources beyond the estimated impact, the financial costs projected on page one could increase significantly.

Finally, the first and second estimates of impacts were applied to production representing a potential impact of less than 1 percent of future production that could be affected. The resulting fiscal impact analysis applied production impacts to the consensus revenue estimating group forecast for prices and taxable deductions, published in December 2023. Revenue impacts were then calculated by the affected fund. Similarly, for gross receipts tax impacts, a regression on Eddy County and Lea County matched taxable gross receipts and oil production was used to convert the possible impact to those collections. The lowest possible tax rate was used to determine losses. If losses occur in higher tax districts, oil prices rise, or deductions fall, costs represented on page one could increase significantly. Similarly, if oil prices fall or deductions rise, costs represented on page one could decrease significantly.

Other General Fund Revenues

Civil penalties assessed by OCD are reverted to the general fund. Raising the penalty caps may therefore increase general fund revenue, but by an indeterminate or negligible amount due to the unknown effect increased penalties will have on deterrence. Additionally, most notices of violation are resolved in settlement, so the impact of penalty limits on the eventual amount assessed on an operator is minimal, according to the agency. In FY23, violations of the Oil and Gas Act resulted in $2.15 million in civil penalties reverted to the general fund.

Agency Revenues

Application fees collected by OCD are deposited in the OCD systems and hearings fund. The committee substitute increases the fees for four of the five application types by a factor of three. In FY23, revenue from the application fees amended by the legislation was $1.82 million. EMNRD therefore estimates annual revenue to the systems and hearings fund would be three times that amount, or approximately $5.46 million, in the first full fiscal year after the bill's fee increases take effect. This would be a revenue increase of $3.64 million beginning in FY25. Using the FY20-FY23 average OCD fee revenue instead of the FY23 total to estimate the revenue impact, the projected FY25 increase is $3.15 million.

Because the legislation would go into effect on May 15, 2024, if enacted, the estimated revenue increase for FY24 is between $393.5 thousand and $455.2 thousand, which is the estimated range of the annual revenue increase prorated for one and a half months.

The bill's increase to OCD's blanket financial assurance requirement has no estimable direct revenue impact, since the state only receives bonds that are forfeited. It may, however, eventually affect the balance of the oil reclamation fund, which is OCD's source of funding for plugging orphan wells beyond the costs covered by operators' financial assurance. An orphan well is an inactive well that has no viable operator of record, meaning the well's owner is bankrupt or no longer exists and therefore cannot carry out its well-plugging responsibilities. The current average cost to plug an orphan well, according to OCD, is $125 thousand. Remediation costs vary much more widely: The division uses an estimate of $110 thousand for projection purposes, but an individual remediation could cost millions of dollars if the site had a significant leak.

The oil reclamation fund derives most of its revenue (typically 90-100 percent) from a portion of oil and gas conservation tax proceeds. Other revenue comes from forfeited financial assurance: when an operator forfeits a bond, the proceeds are deposited in the oil reclamation fund. Bond

forfeitures, however, are rare and only cover a small portion of OCD spending on well remediation. For example, in the last five fiscal years, only $250.3 thousand in forfeited bonds has been collected, while OCD has spent over $9 million on orphan well plugging. Therefore, although raising the blanket bond limit would have an impact of uncertain magnitude on the oil reclamation fund, it would undoubtedly increase the proportion of well remediation expenditures funded by operators' financial assurance.

The committee substitute's addition of a well plugging risk pool fee would generate new revenue for the oil reclamation fund. Because the bill language leaves the assessment of the risk pool fee to the discretion of OCD, the amount of revenue generated will depend on how the division decides to implement the new policy. Without analysis from EMNRD on this provision of the committee substitute, an estimate of additional revenue is not known.

Oil and gas conservation tax revenue is projected to take a hit due to the potential production impacts discussed previously. As this is the main source of revenue for the oil reclamation fund, in a typical year, declines could negatively affect OCD's ability to remediate orphan wells. However, in FY22, conservation tax revenue increased by 377 percent, bringing the balance of the fund to $27 million. Therefore, the projected decrease in conservation tax revenue would have a negligible effect on the oil reclamation fund.

SIGNIFICANT ISSUES

OCD Authority

The changes made by Section 1 of the substitute bill to OCD's authority regarding well transfers allow the division to consider operator compliance and other risk factors when evaluating applications. This primarily has relevance to potential transfers from large operators to small operators that buy wells when average production volume is lower. According to EMNRD, these small operators have less capacity to provide adequate financial assurance and fewer resources to comply with OCD requirements. Consequently, well transfers of this nature frequently result in an orphaned well that the state must assume responsibility for and remediate using funds from OCD's oil reclamation fund. Taking into account the likelihood that a well transfer would increase the state's liability would give OCD more opportunities to prevent abandoned well occurrences that consume state resources.

The other piece of the expanded authority granted to OCD by Section 1 relates to repurposing abandoned wells for uses outside of oil and gas development or wastewater reinjection. As the state and the energy industry continue to move away from fossil fuel extraction, interest in converting wells to kinetic energy storage or geothermal development site, for example, is rising. Authorizing OCD to create a regulatory framework for such conversions would allow for continued economic activity at former well sites outside of the oil and gas industry.

Gas Capture Requirement

In Section 5, the bill requires operators capture at least 98 percent of natural gas produced or gathered by the operator's facilities in a calendar year. However, NMAG points out that OCD regulations already require a 98 percent natural gas capture rate by December 31, 2026 (see NMAC 19.15.27.9), making the proposed statutory amendments redundant. NMAG further notes that the bill's language is more general than the existing regulations, and it is thus unclear "whether the bill is intended to impose any requirements not already in place." This creates a

potential interpretation of Section 5 of the bill that the existing natural gas capture rule does not comport with legislative intent.

ADMINISTRATIVE IMPLICATIONS

If this bill is enacted, EMNRD will need to promulgate rules to update NMAC 19.15.7., 19.1.58, 19.15.15, 19.15.25, and 19.15.107.

Eliminating the requirement for NMAG to collect forfeited financial assurance would reduce the administrative burden on that agency and streamline forfeiture collections by keeping the entire process in OCD.

CONFLICT, DUPLICATION, COMPANIONSHIP, RELATIONSHIP

House Bill 133 duplicates, in part, House Bill 30, House Bill 31, and House Bill 32. House Bill 133 also conflicts, in part, with House Bill 30, House Bill 31, and House Bill 32.

CW/IT/rl/ne/al/rl/ne/al/hg

EXHIBIT 26

State of New Mexico
Energy, Minerals and Natural Resources Department

Michelle Lujan Grisham
Governor

Melanie A. Kenderdine
Cabinet Secretary

Ben Shelton
Deputy Secretary

Erin Taylor
Deputy Secretary

Albert Chang
Division Director
Oil Conservation Division

July 1, 2025

Governor Michele Lujan Grisham
State Capitol
Santa Fe, NM 87503

Representative Nathan Small
Chair, House Appropriations and Finance Committee
PO Box 697
Dona Aña, NM 88032

Senator George Muñoz
Chair, Senate Finance Committee
Box 2679
Gallup, NM 87305

Cabinet Secretary Melanie Kenderdine
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, NM 87505

Re: FY 2024 Annual Report on Use of the Oil Reclamation Fund

Attached is the Oil and Gas Reclamation Fund Report for Fiscal Year 2024. If you have any questions or desire additional information, please feel free to contact me via email at *albert.chang@emnrd.nm.gov*.

Respectfully,

Albert Chang
Director, Oil Conservation Division

attachment

cc: Charles Sallee, Director, Legislative Finance Committee
Wayne Propst, Cabinet Secretary, Department of Finance and Administration

EXHIBIT 26

OIL AND GAS RECLAMATION REPORT FOR FISCAL YEAR 2024

(July 1, 2023 - June 30, 2024)

The Oil and gas Act requires the Director of the New Mexico Oil Conservation Division (OCD) to make an annual report to the Secretary of the Energy, Minerals and Natural Resources Department, the Governor and the Legislature on the use of the Oil and Gas Reclamation Fund. The OCD Director makes this report for the fiscal year 2024, ending the preceding June 30.

The OCD is authorized by the Oil and Gas Act to plug and abandon oil and gas wells to prevent the migration of fluids, gases and other contaminants to other strata or to fresh water, and to restore and remediate abandoned well sites and associated production facilities.

See NMSA 1978 Section 70-2-12.B. (1) and (18) and 70-2-38.

That same authority allows OCD to require oil and gas operators to post plugging bonds conditioned upon performance of their plugging obligations. A well operator may furnish a single-well bond for each of its wells or a blanket bond covering all wells.

Additional single-well bonds are required for wells on state and private land that have been inactive for two years or more. Bonds for other production facilities range from $25,000 to$250,000. If a bond covers a well, site or facility that the OCD has plugged or remediated, the OCD forecloses on the bond and places the proceeds in the Oil and Gas Reclamation Fund.

NMSA 1978, Sections 70-2-37 and 70-2-38 create the Oil and Gas Reclamation Fund ("Fund") and provide for administration of the Fund. Expenditures may be used to plug abandoned wells and to restore and remediate abandoned well sites and associated production facilities. In addition, up to $150,000 of the Fund may be spent annually to promote energy education in the State. The Fund is supported principally by the oil and gas conservation tax.

Effective on July 1, 2011, NMSA 1978 Section 7-1-6.21, as amended, provides for monthly distribution of proceeds of the Oil and Gas Conservation Tax to the Fund, as follows:

A. With respect to any period for which the rate of the tax imposed by Section 7-30-4 NMSA 1978 is nineteen-hundredths percent, a distribution pursuant to Section 7-1-6.20 NMSA 1978 shall be made to the oil and gas reclamation fund in an amount equal to two-nineteenths of the net receipts attributable to the tax imposed under the Oil and Gas Conservation Tax Act [Chapter 7, Article 30 NMSA 1978].

B. With respect to any period for which the total rate of the tax imposed on oil by Section 7-30-4 NMSA 1978 is twenty-four hundredths percent, a distribution pursuant to Section 7-1-6.20 NMSA 1978 shall be made to the oil and gas reclamation fund in an amount equal to nineteen and seven-tenths percent of the net receipts attributable to the tax imposed under the Oil and Gas Conservation Tax Act.

During all of FY 2024, the higher conservation tax applied, such that the monthly distribution to the Fund was computed pursuant to Subsection B of Section 7-1-6.21.

The OCD employs independent contractors to perform the plugging, restoration and remediation work. The contracts are Purchase Orders pursuant to the Procurement Code. Contractors awarded contracts are oil field service companies specializing in plugging oil and gas wells or firms specializing in environmental cleanups.

EXHIBIT 26

WELL PLUGGING, SITE REMEDIATION, PRE- AND POST METHANE EMISSIONS TESTING, BOND REQUIREMENTS

The following pages provide details on the Oil and Gas Reclamation fund and its uses. These details include an FY 24 balance sheet for the fund and information on the procurement of well plugging, emergency services and site remediation during the year.

The Oil Conservation Division used Reclamation funds in FY 2024 to plug 46 wells, conduct eight (8) site assessments followed by remediation and reclamation work, continues to monitor one (1) project, conducted 257 pre- and post-plug methane tests on wells, and reimbursed contractors for performance bonds. For continued funding from the Bipartisan Infrastructure Law, the Federal Phase One Formula Grant, requires States to provide on-site research information regarding the Federal Endangered Species Act of 1973 (ESA) and the National Historic Preservation Act of 1966 (NHPA). Two consultants were hired to conduct on site research, compile the data and prepare the reports covering areas in southeast New Mexico. Once the reports are approved by the appropriate Federal agency, OCD can begin working on plugging wells using the Federal Grant funds.

OCD staff and contractors were challenged with remediation and reclamation efforts on four sites found to be highly contaminated. While most of the sites have been approved for reseeding, one site, the Cano San Andres #6 Tank Battery, requires further remediation work.

Regarding the former I&W Brine well in Carlsbad, surface subsidence and cavern pressure monitoring including an early warning system along with indirect geophysical characterization continued to progress through the fiscal year.

The division did not use funds to pay the OCD staff salaries and benefits.

The OCD entered into a settlement agreement with Ridgeway Arizona Oil Corporation on December 13, 2023. The agreement contemplates OCD plugging 299 of Ridgeway's 337 wells. OCD entered the settlement after review of financial disclosures indicating that Ridgeway was incapable of plugging the wells. In consideration of OCD plugging activity, Ridgeway was required to perform site assessments for all inactive wells and to make monthly reimbursement payments to the state at the rate of $2.00 per gross barrel of oil sold or $30,000 per month, whichever is greater. Ridgeway is prohibited from transferring wells without OCD approval and may not continue operating within New Mexico if it fails to make any necessary reimbursement payment.

EXHIBIT 26

OIL RECLAMATION FUND

Beginning Cash Balance @ July 1, 2023	**$50,898,058.05**
Oil & Gas Conservation Tax Revenue	**$25,986,480.04**
Bond Forfeitures, Salvage and Reimbursement Recoveries	**$ 0.00**
Total Revenues:	**$25,986,480.04**
Balance:	**$64,401,673.23**
Subtotal expenditures for plugging, remediation, and reclamation, methane testing, bond reimbursement, and Endangered Species Act reports:	**($11,349,842.82)**
Subtotal Other Expenses:	**($922,105.16)**
TOTAL EXPENSES FY 2024	**(12,330,131.66)**
Ending Cash Balance June 30, 2024	**$52,071,541.57**

IPANM Exhibit #43

EXHIBIT 26

FY24 EXPENDITURE AND USAGE DETAIL

PLUGGED ORPHANED WELLS SERVICES (46)

1. Elks #1, well owned by the Office of the State Engineer, in Chavez County.
   Paid $127,495.16, Contractor: JA Drake Well Service Inc, Invoice #21804.
2. Lansford #002, operator Energy Acumen, in Lea County.
   Paid $89,429.66. Contractor: JA Drake Well Service, Inc, Invoice #22169.
3. Alves #004, operator Energy Acumen, in Lea County.
   Paid $144,820.79. Contractor JA Drake Well Service, Inc, Invoice #22122.
4. Alves #002, operator Energy Acumen, in Lea County.
   Paid $194,690.23, Contractor: JA Drake Well Service, Inc, Invoice #22121.
5. Mike #002, operator Energy Acumen LLC, Lea County.
   Paid $92,623.43, Contractor: A-Plus P&A Holdings LLC, Invoice #1983.
6. Double L Queen #001Y, operator Canyon E&P Company, Chaves County.
   Paid $11,703.83, Contractor: A-Plus P&A Holdings LLC, Invoice #1882 (remainder of invoice paid using federal funds).
7. Double L Queen #001H, operator Canyon E&P Company, Chaves County.
   Paid $8,792.46, Contractor: A-Plus P&A Holdings LLC, Invoice #1858 (remainder of invoice paid using federal funds).
8. Lansford #001, operator Energy Acumen LLC, Lea County.
   Paid $145,075.74, Contractor: JA Drake Well Service, Inc, Invoice #22157.
9. Lansford #004, operator Energy Acumen LLC, Lea County.
   Paid: $122,744.92, Contractor: JA Drake Well Service, Inc, Invoice #22181.
10. Pruitt #001, operator Energy Acumen LLC, Lea County.
    Paid: $137,015.56, Contractor: JA Drake Well Service, Inc, Invoice #22245.
11. GW Shahan #002, operator Unified Operating, LLC, Lea County.
    Paid: $31,456.46, Contractor: JA Drake Well Service, Inc., Invoice #22198.
12. Mike #004, operator Energy Acumen LLC, Lea County.
    Paid $128,328.19, A-Plus P&A Holdings, LLC, Invoice #1989.
13. Lansford #003, operator Energy Acumen LLC, Lea County.
    Paid $135,115.27, JA Drake Well Service Inc, Invoice #22180.
14. Alves #003, Operator Energy Acumen LLC, Lea County.
    Paid $214,185.83, JA Drake Well Service Inc, Invoice #22197.
15. Lansford #005, Operator Energy Acumen LLC, Lea County.
    Paid $197,772.25, JA Drake Well Service Inc, Invoice #22199.
16. Lansford #006, Operator Energy Acumen LLC, Lea County.
    Paid $166,599.96, JA Drake Well Service Inc, Invoice #22223.
17. Double L Queen #003, Operator Canyon E & P Company, Chaves County.
    Paid $69,279.31, A-Plus P&A Holdings LLC., Invoice #1860.
18. Double L Queen #003G, Operator Canyon E & P Company, Chaves County.
    Paid $69,148.62, A-Plus P&A Holdings LLC, Invoice #1862.
19. Double L Queen #003Q, Operator Canyon E & P Company, Chaves County.
    Paid $90,128.62, A-Plus P&A Holdings LLC, Invoice #1865.
20. Mike #001, operator Energy Acumen LLC, Lea County.
    Paid $86,416.72, A-Plus P&A Holdings LLC, Invoice #1962.
21. Miller Comm #001, operator Energy Acumen LLC, Lea County.
    Paid $204,077.39, A-Plus P&A Holdings LLC, Invoice #1972.
22. Mike #003, operator Energy Acumen LLC, Lea County.
    Paid $147,724.34, A-Plus P&A Holdings LLC, Invoice #1955.
23. Schwalbe #001, operator Robinson Oil Inc., Lea County.
    Paid $336,762.47, JA Drake Well Service, Invoice #21755.
24. Bagley #002, operator Lease Holders Acquisitions, Inc., Lea County.
    Paid $523,725.26, JA Drake Well Service, Invoice #22090.
25. Buckskin Federal #002, operator Energy Acumen, LLC., Lea County.
    Paid $49,579.19, JA Drake Well Service, Invoice #22260.
26. JP Collier #001, operator Lease Holders Acquisitions, Inc., Lea County.
    Paid $476,334.72, JA Drake Well Service, Invoice #22107.

EXHIBIT 26

PLUGGED ORPHANED WELL SERVICES, continued (46)

27. Alves A #001, operator Energy Acumen, LLC., Lea County.
    Paid $454,014.69, JA Drake Well Service, Invoice #22226.
28. Robert #001, operator Energy Acumen, LLC., Lea County.
    Paid $183,222.16, JA Drake Well Service, Invoice #22243.
29. Seanna #002 cut off, operator Canyon E & P Company, Chaves County.
    Union Happy #001 cut off, operator Canyon E & P Company, Chaves County.
    Union Happy #002 cut off, operator Canyon E & P Company, Chaves County.
    Paid $5,481.66, JA Drake Well Service, Invoice #22167.
30. Robert #002, operator Energy Acumen, LLC., Lea County.
    Paid $143,401.02, JA Drake Well Service, Invoice #22244.
31. Twin Lakes San Andres #109, operator Blue Sky NM, Inc., Chaves County.
    Paid $12,744.93, JA Drake Well Service Inc., Invoice #21510.
32. Twin Lakes San Andres #065, operator Blue Sky NM, Inc., Chaves County.
    Paid $5,480.93, JA Drake Well Service Inc, Invoice #21265.
33. Miller Comm #001, operator Energy Acumen LLC, Lea County.
    Paid $76,382.70, A-Plus P&A Holdings LLC, Invoice #2227.
34. Miller Comm #001, operator Energy Acumen LLC, Lea County.
    Paid $149,142.11, A-Plus P&A Holdings LLC, Invoice #2226.
35. Brown 93 #001, operator Ridgeway Arizona Oil Corporation, Lea County.
    Paid $189,275.69, JA Drake Well Service LLC, Invoice #22586.
36. Double L Queen #001R, operator Canyon E & P Company, Chaves County.
    Paid $115,772.09, A-Plus P&A Holdings, LLC., Invoice #1884.
37. Na Dzis Pah #002, operator Biya Operators Inc., Sandoval County.
    Paid $121,722.05, Aztec Well Servicing Co., Invoice #2024-00865
38. Na Dzis Pah #001, operator Biya Operators Inc., Sandoval County.
    Paid $104,801.86, Aztec Well Servicing Co, Invoice #2024-00866.
39. State Senate #002, operator Biya Operators Inc., Sandoval County.
    Paid $72,572.08, Aztec Well Servicing Co, Invoice #2024-00867.
40. Indian #002, operator Biya Operators Inc., Sandoval County.
    Paid $107,681.62, Aztec Well Servicing Co, Invoice #2024-00868.
41. Chaveroo San Andres Unit #004, operator Ridgeway Arizona Oil Corporation, Roosevelt County.
    Paid $161,592.64, A-Plus P&A Holdings LLC, Invoice #2414.
42. Chaveroo San Andres Unit #004, operator Ridgeway Arizona Oil Corporation, Roosevelt County.
    Paid $14,852.07, A-Plus P&A Holdings LLC, Invoice #DR-02815.
43. Chaveroo San Andres Unit #006, operator Ridgeway Arizona Oil Corporation, Roosevelt County.
    Paid $159,524.24, A-Plus P&A Holdings LLC, Invoice #2284
44. Chaveroo San Andres Unit #003, operator Ridgeway Arizona Oil Corp, Roosevelt County.
    Paid $168,526.06, A-Plus P&A Holdings LLC, Invoice #2426.
45. Brown 84 #002, Lea County, Arizona Ridgeway Oil Corporation, Lea County.
    Paid $274,383.81, JA Drake Well Service Inc, Invoice #22516.
46. Brown 84 #001, operator Arizona Ridgeway Oil Corporation, Lea County.
    Paid $276,444.71, JA Drake Well Service Inc, Invoice #22597.

Subtotal $6,798,045.50

EXHIBIT 26

SALVAGE, REMEDIATION, RECLAMATION AND REVEGETATION SERVICES (8)

1. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County
   Paid: $337,068.19, Contractor: Young Environmental Services, dba Envirotech, Invoice #63351.
2. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
   Paid: $418,495.10, Contractor: Young Environmental Services, dba Envirotech, Invoice #63245.
3. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
   Paid $19,519.28, Intera Incorporated, Invoice #03-24-01.
4. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
   Paid $40,675.41, Intera Incorporated, Invoice #03-24-18.
5. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County
   Paid: $298,678.93, Contractor: Young Environmental Services, dba Envirotech, Invoice #63564.
6. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County
   Paid: $87,001.78, Contractor: Young Environmental Services, dba Envirotech, Invoice #63697.
7. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
   Paid $65,852.09, Unlimited Construction 2 LLC, Invoice #5328.
8. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
   Paid $127,657.73, Unlimited Construction 2 LLC, Invoice #5317.
9. Cano San Andres Unit Tank Battery #006, operator Cano Petro of New Mexico Inc.
   Paid $66,682.27, Ensolum LLC, Invoice #28774.
10. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $32,881.03, Intera Incorporated, Invoice #03-24-101 REV.
11. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
    Paid: $42,082.08, Contractor: Young Environmental Services, dba Envirotech, Invoice #63840.
12. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $425,216.13, Unlimited Construction 2 LLC, Invoice #5342.
13. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $69,900.74, Intera Incorporated, Invoice #5346.
14. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $47,682.91, Intera Incorporated, Invoice #04-24-01.
15. Artesia Metex Unit #005, operator Cannon E & P Company., Eddy County.
    Paid $11,073.47, Miller Engineers, Inc, Invoice #5E3179601Revise.
16. Artesia Metex Unit #006, operator Cannon E & P Company., Eddy County.
    Paid $9,541.80, Miller Engineers, Inc. , Invoice #5E3179602
17. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $9,333.62, Miller Engineers, Inc, Invoice #5E3179603.
18. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $27,362.95, Miller Engineers, Inc, Invoice #5E3179608.
19. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $27,662.07, Miller Engineers, Inc, Invoice #5E3179609
20. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $26,080.90, Miller Engineers, Inc, Invoice #5E3179610.
21. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $11,880.73, Miller Engineers, Inc, Invoice #5E3179611.
22. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $12,174.60, Miller Engineers, Inc, Invoice #5E3179612.
23. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
    Paid: $4,613.22, Contractor: Young Environmental Services, dba Envirotech, Invoice #64599.
24. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $60,327.99, Intera Incorporated, Invoice #05-24-68.
25. Artesia Metex Unit #018, operator Cannon E & P Company., Eddy County.
    Paid $10,929.29, Miller Engineers, Inc, Invoice #5E31779604.

26. Artesia Metex Unit #019, operator Cannon E & P Company., Eddy County.
    Paid $6,623.47, Miller Engineers, Inc, Invoice #5E3179605.
27. Artesia Metex Unit #019, operator Cannon E & P Company., Eddy County.
    Paid $42,760.42, Miller Engineers, Inc, Invoice #5E3179606.
28. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
    Paid: $5,932.04, Contractor: Young Environmental Services, dba Envirotech, Invoice #64191.
29. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $407,412.23, Unlimited Construction 2 LLC, Invoice #5374.
30. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $45,657.67, Intera Incorporated, Invoice #04-24-21.
31. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $609,716.93, Unlimited Construction 2 LLC, Invoice #5358.
32. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $60,327.99, Intera Incorporated, Invoice #05-24-68.
33. Artesia Metex Unit #005, operator Cannon E & P Company., Eddy County.
    Paid $26,027.45, Miller Engineers, Inc, Invoice #5E3179607.
34. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $94,890.63, Intera Incorporated, Invoice #05-24-70 Rev.
35. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $31,736.13, Intera Incorporated, Invoice #06-24-02.
36. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $425,035.29, Unlimited Construction 2 LLC, Invoice #5380.
37. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
    Paid $17,458.49, Young Environmental Services, dba Envirotech, Invoice #64482.

Subtotal $4,003,625.06

PRE- AND POST-PLUG METHANE TESTING (257 Sites):

1. Double L Queen Unit #s 001D, 001H, 001K, 001P, 001Q, 001R, 001Y, 002, 002G, 002P, 002Q, 002X, 002Z, 003, 003G, 003L, 003Q, 003Y, 004, 004G, 004Q, 005, 005Q, 006, 007, operator Canyon E & P Company, in Chaves County.
   Paid: $51,173.00. Contractor: Well Done New Mexico, LLC, Invoice #1081.
2. INBE 12 #001, INBE 13 #001, Bagley #002, J P Collier #001, JP Collier #004Y, operator Lease Holders Acquisitions, Inc. and Schwalbe #001, #002, operator, Robinson Oil Inc., Chaves County.
   Paid: $16,911.28, Well Done New Mexico, LLC, Invoice #1090.
3. Cato San Andres Units #097, #098, #100, #119, #127, #515, #517, #518, #520, #531, #532, #533, #535, #544, #558, #559, #560, #561, #573. #574, #586, #587, #588, #822, #827, operator Cano Petro of New Mexico, Inc., Chaves County
   Paid $63,455.54, Well Done New Mexico LLC, Invoice #1083.
4. Barkeht #001, Elizabeth #001, #002, #003, #004, Elizabeth C #005, Graves #001, Lewis Neff #003, McDermott #001, Nancy #001, Seanna #001, #002, #003, Union Happy #001, #002, operator Canyon E & P Company, Chaves County.
   Paid $31,680.00, Well Done New Mexico LL, Invoice #1089.
5. EF King #003, operator Roca Production Inc, Lea County.
   Paid $2,085.82, Well Done New Mexico LLC, Invoice #1088.
6. Twin Lakes San Andres #081, operator Blue Sky NM, Inc., Chaves County.
   Paid $1,474.10 Well Done New Mexico LLC, Invoice #1079.
7. Twin Lakes San Andres #078, operator Blue Sky NM, Inc., Chaves County.
   Paid $1,474.10 Well Done New Mexico LLC, Invoice #1078.
8. Twin Lakes San Andres #065, operator Blue Sky NM, Inc., Chaves County.
   Paid $1,474.10 Well Done New Mexico LLC, Invoice #1077.

9. Cato San Andres #545, 557Y, #558, #559, #560, #561, #573, #574, #586, #587, #588, Chaves County, Cano Petro of New Mexico, Inc., and South Lucky Lake Queen #001, #002, operator Bar V Barb LLC, Chaves County.
   Paid $27,662.91 A-Plus P&A LLC for subcontractor, Well Done New Mexico, LLC, Invoice #1441.
10. Elizabeth #001, #002, #003, #004, operator Canyon E & P Company, Chaves County.
    Paid $8,511.66 A-Plus P&A LLC for subcontractor, Well Done New Mexico, LLC, Invoice #1440.
11. Alves A #001, Alves #002, #004, Lansford #001, Lansford #002, Lansford #003, Lansford #004, Lansford #005, Lansford #006, Mike #001, Mike #002, Mike #003, Mike #004, Milller Com #001, Pruitt #001, Robert #001, Robert #002, operator Energy Acumen LLC, Lea County.
    Paid $62,594.14, Well Done New Mexico, LLC, Invoice #1093.
12. Chaveroo San Andres Unit #003, #004, #005, #006, #007, Farrell Federal #002, Haley Chaveroo SA Unit #010, Jennifer Chaveroo SA Unit #028, Roosevelt County, KM Chaveroo SA Unit #012, #016, #018, #021, #032, #035, #049, #110, #111, #112, #113, KMS,#001, #002, #003, #004, #005, Levic 1 State #001, operator Ridgeway Arizona County, Chaves County
    Paid $25,391.28, Well Done New Mexico LLC, Invoice #1105.
13. Indian #003, State Senate #002, Na Dzis Pah #001, #002, Natani #014, #017, #018, #032, #033, #034, operator M &M Production & Operation, San Juan County.
    Paid $21,159.36, Well Done New Mexico LLC, Invoice #1106.
14. Allied 93 #004, Bilbrey 23 #004, #005, Bilbrey 51 #002, #003, Brown 84 #001, #002, Brown 93 #001, Lea County, operator Ridgeway Arizona Oil Corp., Lea County.
    Paid $16,748.97, Well Done New Mexico LLC, Invoice #1094.
15. Anderson State #005, operator Ridgeway Arizona Oil Corp., Roosevelt County.
    Paid $2,117.93, Well Done New Mexico LLC, Invoice #1095.
16. Chaveroo San Andres Unit #003, #004, #005, #006, KMS #001, operator Ridgeway Arizona Oil Corp, Roosevelt County
    Paid $10,589.63, Well Done New Mexico LLC, Invoice #1096.
17. Humble Tucker #001, #003, #004, James McFarland A #001, #002, #003, #004, James McFarland #001, #002, #003, #004, operator Ridgeway Arizona Oil Corp, Roosevelt County.
    Paid $17,552.28, TS Nano, Invoice #10029OCD.

Subtotal $362,056.10

PERFORMANCE BOND REIMBURSEMENT:

1. Elks #001, operator, Wayne J. Spears, in Lea County.
   Paid $2,987.06 Contractor: JA Drake Well Service Inc, Invoice #21775.
2. Alves #002, #003, #004, Alves A #001, Lansford #001, #002, #003, #004, #005, #006, Pruitt #001, Robert #001, Robert #002, operator, Energy Acumen Wells, Lea County.
   Paid $64,683.14, Contractor: JA Drake Well Service Inc, Invoice #22088.
3. Cano San Andre's Unit Tank Battery #006, operator Cano Petro of New Mexico, Inc., Chaves County.
   Paid $2,924.00, Contractor: Ensolum LLC, Invoice #Performance.
4. Reed Estate #001, operator Hal J. Rasmussen Operator, Inc., Lea County.
   Paid $8,099.90, Contractor: Intera Incorporated, Invoice #02-24-03.
5. Chaveroo San Andres Unit #003, #004, #005, #006, #007, Farrell Federal #002, Haley Chaveroo SA Unit #010, Jennifer Chaveroo SA Unit #028, KM Chaveroo SA Unit #012, #016, #018, #021, #032, #035, #049, #110, #111, #112, #113, KMS #001, #002, #003, #004, #005, Levick 1 State #001, Chavaroo A State #001, #002, Chaveroo B #001, #002, Chaveroo San Andres Unit #001, #002, former operator Ridgeway Arizona Oil Corp, Roosevelt County.
   Paid $1,441.16, Well Done New Mexico, LLC, Invoice #1092.
6. Allie Partin Et Al #001, #002, Allied 93 #004, Anderson State #001, #002, #003, #004, #005, #007, #008, #009, Bilbrey 23 #003, #004, #005, Bilbrey 51 #002, #003, Brown 84 #001, #002, Brown 93 #001, Lea County, Chavaroo A State #001, #002, Chaveroo B #001, #002, Chaveroo San Andres Unit #001, #002, operator Ridgeway Arizona Oil Corp., Roosevelt County.
   Paid $2,882.32, Well Done New Mexico LLC, Invoice #1091.

7. Barkneht #001, Elizabeth #001, #002, #003, #004, Elizabeth C #005, Graves #001, Lewis Neff #003, McDermott #001, Nancy #001, Seanna #001, #002, #003, Union Happy #001, #002, operator Canyon E & P Company, Chaves County.
   Paid $965.02, Well Done New Mexico LLC, Invoice #1099.
8. Mike #001, # 002, #003, #004 and Miller Com #001, operator Energy Acumen LLC, Lea County.
   Paid $22,175.12, A-Plus P&A Holdings LLC, Invoice #2421.
9. Brown 84 #001, operator Arizona Ridgeway Oil Corporation, Lea County.
   Paid $14,182.30, JA Drake Well Service Inc, Invoice #22524.
10. Double L Queen Units #001D, #001H, #001K, #001P, #001Q, #001R, #001Y, #002, #002G, #002P, #002Q, #002X, #002Z, #003, #003G, #003L, #003Q, #003Y, #004, #004G, #004Q, #005, #005Q, #006, #007, operator Canyon E & P Company, Chaves County
    Paid $3,188.40, Well Done New Mexico LLC, Invoice #1097.
11. Cato San Andres Unit #097, #098, #100, #119, #127, #516, #517, #518, #520, #531, #532, #533, #535, #544, #545, #558, #559, #560, #561, #573, #574, #586, #587, #588, #822, #827, Cano Petro of New Mexico LLC, Chaves County.
    Paid $3,315.94, Well Done New Mexico LLC, Invoice #1098.
12. INBE 12 #001, INBE 13 #001, Bagley #002, JP Collier #001, JP Collier #004Y, operator Lease Holders Acquisitions, Inc., Schwalbe #001, #002, operator Robinson Oil Inc. Cano Petro of New Mexico LLC, Lea County.
    Paid $59,271.80, JA Drake Well Service Inc, Invoice #22635.

Subtotal: $186,116.16

Endangered Species Act (ESA) and National Historic Preservation Act (NHPA) Reports

The payments made below are partial payments. During the fiscal year 2024, no NHPA progress reports were received.

1. ESA services located in Lea, Chaves, and Eddy counties in Southeastern New Mexico. The services include biological surveys, biological assessments and evaluations and finally consultation.
   Paid $16,518.82, Daniel B Stephens & Associates, Invoice #268961R.
2. ESA services located in Lea, Chaves, and Eddy counties in Southeastern New Mexico. The services include biological surveys, biological assessments and evaluations and finally consultation.
   Paid $7,154.91, Daniel B Stephens & Associates, Invoice #0270194.
3. ESA services located in Lea, Chaves, and Eddy counties in Southeastern New Mexico. The services include biological surveys, biological assessments and evaluations and finally consultation.
   Paid $34,509.95, Daniel B Stephens & Associates, Invoice #269765R.

Subtotal: $58,183.68

OTHER EXPENSES:

Below are categories with vendors associated and cumulative charges by category.

1. **Vehicle Maintenance and Replacement:**
   - O&S Quik Change Inc. ($2,448.89)
   - Wex Bank ($34,834.93)
   - Chalmers Ford Inc. ($408,660.00)
   - Farmington Tire ($10,380.29)
   - Advantage Dodge CPJ ($1,394.82)
   - Forrest Tire Company Inc. ($3,732.00)
   - Bob Turners Ford Country Inc. ($40,498.00)
   - Jose Alvarez ($533.35)
   - Mesa Tire ($1,180.00)
   - Ziems Ford Corners ($150.00)

   Subtotal: $503,812.28

2. **OCD Field Technician Work Clothing**
   - Boot Barn Inc. ($11,930.87)
   - The Graphic Designer LLC ($235.01)

Subtotal $12,165.88

3. **OCD Staff Training**
   - National Environmental Management Academy LLC. ($5,000.00)
   - Leigh Barr, OCD Staff Travel ($494.92)
   - Bank of America NA: Lodging for OCD Staff ($1,879.70)
   - Rosa Romero, OCD Staff Travel ($184.30)
   - Michael Buchanan, OCD Staff Travel ($120.41)
   - Brittany Hall, OCD Staff Travel ($116.74)

Subtotal $7,796.07

4. **Legal Services (OCD Hearings)**
   - Pfeifer Hanson Mullins & Baker PA

Subtotal $105,020.60

5. **Professional Memberships**
   - State Bar of New Mexico ($925.00)
   - Ground Water Protection Council ($12,000.00)

Subtotal $12,925.00

6. **EMNRD IT Division (Software and Hardware)**
   - Carahsoft Technology Corporation ($7,974.33)
   - SHI International Corporation ($613.11)
   - Advanced Network Management ($42,350.68)
   - PC Specialist Inc. ($49,342.98)
   - ABBA Technologies Inc. ($58,456.13)
   - APIC Solutions Inc. ($77,378.47)

Subtotal $236,115.60

7. **Expert Investigator (Critical, technical data and experts regarding seismicity)**
   - New Mexico Institute of Mining and Technology

Subtotal $36,620.13

8. **Carlsbad Brine Well Project (continued monitoring)**
   - WSP USA Environment & Infrastructure

Subtotal $7,649.60

Subtotal: $922,105.16

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN RE: RIDGEWAY ARIZONA OIL CORP **NMOCD-ACO-** 201929

AGREED COMPLIANCE ORDER

Pursuant to the New Mexico Oil and Gas Act ("Act"), NMSA 1978, Section 70-2-1, *et seq.*,and 19.15.5.10(E) NMAC, the Director of the Oil Conservation Division ("OCD") and RIDGEWAY ARIZONA OIL CORP ("Operator") enter into this Agreed Compliance Order ("Order").

I. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. OCD is charged with the administration and enforcement of the Act and the rules adopted thereunder, and has jurisdiction over Operator and its wells in the state of New Mexico.

2. Operator is the operator of record for 304 wells under OGRID # 164557.

3. Operator has or will shut-in each of the wells listed on **Exhibit "A"** ("Well" or "Wells") due to reasons outlined on exhibit "A", and each Well is or will become inactive under 19.15.25 NMAC on the specified date:

4. Operator has sufficient financial assurance for the Wells under 19.15.8.9(C) NMAC.

5. Operator intends to restore production from the Wells before the applicability of the requirement for inactive well financial assurance under 19.15.8.9(D) NMAC.

6. OCD is authorized to impose sanctions for violations of the Oil and Gas Act and the rules adopted thereunder, including denial or revocation of registrations, applications, permits, authorizations and transfers, and the assessment of civil penalties. *See* 19.15.5.10NMAC.

7. Operator requests the Order in order to avoid sanctions for violating the Oil and Gas Act and 19.15.25 NMAC with respect to the Wells.

8. Operator admits the findings of fact and waives any right to appeal from the Order.

II. ORDER

9. No later than the date listed on Exhibit A, Operator shall take one of the following actions for each well

   (a) restore the Well to production and file a C-115;

   (b) place the Well on approved temporary abandonment status in accordance with 19.15.25 NMAC; and

   (c) plug the Well in accordance with 19.15.25 NMAC and file a C-105.

10. No later than the 15th day of each month following the entry of this Order, Operator shall file a report describing the action taken for each Well, and such other information as OCD may request for time to time. The report shall be sent by electronic mail to OCD's Administrative and Compliance Bureau, at OCDAdminComp@state.nm.us

11. Operator shall maintain sufficient financial assurance for the Wells under 19.15.8.9(C) NMAC.

12. If Operator fails to comply with a requirement of this Order for a Well, the Well shall be deemed to be out of compliance with the Oil and Gas Act the Oil and Gas Act and the rules adopted thereunder, and not subject to an agreed compliance order setting a schedule for bringing the Well into compliance.

13. If Operator fails to comply with a requirement of this Order, no later than thirty (30) days after receipt of a written demand from OCD, in addition to any other sanction imposed by OCD pursuant to the Oil and Gas Act and the rules adopted thereunder, Operator shall pay a stipulated penalty of $500.00 for each day until it complies with each separate requirement ("Stipulated Penalty"). Each failure to comply with a requirement of this Order shall be subject to a separate Stipulated Penalty.

14. If Operator fails to pay the Stipulated Penalty or portion thereof within thirty (30) days after receipt of a written demand from OCD, it shall pay interest on the Stipulated Penalty or unpaid portion thereof until paid in full at the interest rate of 8.75 percent.

15. Operator shall not transfer a Well to another operator unless approved in writing by OCD.

16. Notwithstanding the foregoing provisions, OCD reserves the right to apply for authorization to plug a Well and to forfeit the financial assurance if the Well poses an imminent threat to the public health or environment.

17. OCD reserves the right to sanction Operator for any alleged violation not addressed in this Order.

NEW MEXICO OIL CONSERVATION DIVISION

Date: 10/07/2021

Adrienne Sandoval
Director

Date: 10/4/2021

J. Douglas
Schick
President

Ridgeway
Arizona Oil Corporation

October 1, 2021

New Mexico Oil Conservation Division
Attn: Karen Collins
1200 South St. Francis Drive
Santa Fe, NM 87505

Re: Request to Enter Inactive Well Compliance Order
Ridgeway Arizona Oil Company
OGRID #164557

Dear Ms. Collins:

With this letter and its attachments Ridgeway Arizona Oil Company (hereinafter "Ridgeway") respectfully requests to enter into an Inactive Well Compliance Order. This letter will provide responses to the informational requirements outlined in your letter dated September 13, 2021 and provide a brief narrative describing our company background, operations, and future plans.

Attached to this letter and labeled Exhibit "A" is a comprehensive spreadsheet in response to your request for inactive well data. Exhibit "A" contains data on each inactive well (304 in total) including average production of oil, gas and water from the final production year, bonding information for each well, and a timeline for proposed action for each well. Presently our wells are covered by our blanket plugging bond in the amount of $1,000,000.00 (SUR0013452) with Argo Surety.

Ridgeway has been engaged in revitalizing and cleaning up a legacy oil field that had been largely neglected for more than two decades. As requested, we provide the following brief on compliance work that has been performed over the last four year period. A concise recapitulation of said work is provided in the attached Exhibit "B". During the calendar year 2020 we experienced the same difficulties that affected all of our industry. Due to crashing commodity prices Ridgeway was forced to delay compliance efforts until commodity prices rebounded. Now that we are operating in a more stable industry environment, compliance efforts have fully resumed.

To the question of how many wells per month we will bring into compliance we provide the following response more specifically described in Exhibit "C":

- For the remainder of 2021 we plan to plug four wells. Plugging sundries have been approved by the Bureau of Land Management and when NMOCD approval is received plugging operations shall commence.
- Five wells will be properly temporarily abandoned beginning in March of 2022.
- Two wells have been returned to production and will qualify for appropriate C-115 filings in October 2021.

- Three wells will be returned to production by December of 2021.
- Five wells have been plugged and abandoned and the C-105 final abandonment notices will be filed in October 2021.

Please note that the information contained herein and in the exhibits is accurate to the best of my knowledge and ability. Much of the production data is unavailable to Ridgeway outside what is publicly available through the NMOCD.

In light of the significant effort Ridgeway is making to clean-up and revitalize the Chaveroo Field, we respectfully request that the New Mexico Oil Conservation Commission grant a one-year Inactive Well Agreed Compliance order.

Sincerely,

William Boyd
Land & Regulatory Manager
Ridgeway Arizona Oil Corporation

EXHIBIT A

Ridgeway Arizona Oil Corp

API #	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/I*	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-005-10236	STATE I #001	S	O	4	0	0	32	12/2007	0.125	0.000	0.000	1	Y	NFE
30-005-10240	STATE 5-8-33 #001	S	O	12	0	20	31	1/2008	0.387	0.000	0.645	1	Y	FO 2022
30-005-10409	STATE 5-8-33 #002	S	O	75	0	30	31	2/2008	2.419	0.000	0.968	1	Y	FO 2022
30-005-10433	HALEY CHAVEROO SA UNIT #032	S	O	20	0	1842	29	11/2015	0.690	0.000	63.517	1	Y	NFE
30-005-10434	STATE 5 A #001	S	O	16	0	1	1	4/2016	16.000	0.000	1.000	1	Y	FO 2022
30-005-10435	STATE 5 A #002	S	O	16	0	1	1	4/2016	16.000	0.000	1.000	2	Y	FO 2022
30-005-10438	SIGNAL STATE #001	S	O	63		3064	47	3/2010	1.340	#VALUE!	65.191	1	Y	FO 2022
30-005-10439	STATE I #002	S	O	31	0	0	92	10/2006	0.337	0.000	0.000	3	Y	NFE
30-005-10440	HALEY CHAVEROO SA UNIT #033	S	I	0	0	6926	UNK	5/2008	UNK	UNK	UNK	1	Y	TA 3-2022
30-005-10444	STATE 6 #001	S	O	1	20	0	31	1/2008	0.032	0.645	0.000	1	Y	FO 2022
30-005-10447	KM CHAVEROO SA UNIT #012	S	O	75	0	1753	73	7/2019	1.027	0.000	24.014	3	Y	NFE
30-005-10448	HALEY CHAVEROO SA UNIT #034	S	O	6	0	703	182	10/2006	0.033	0.000	3.863	1	Y	NFE
30-005-10451	STATE 6 #002	S	O	1	19	0	31	12/2007	0.032	0.613	0.000	1	Y	FO 2022
30-005-10457	STATE 6 #004	S	O	1	19	0	31	1/2008	0.032	0.613	0.000	1	Y	FO 2022
30-005-10458	KM CHAVEROO SA UNIT #032	S	O	24	0	2325	91	7/2019	0.264	0.000	25.549	3	Y	NFE
30-005-10467	HALEY CHAVEROO SA UNIT #037	S	O	6	0	729	151	7/2007	0.040	0.000	4.828	1	Y	NFE
30-005-10470	STATE 6 #006	S	O	33	387	651	31	1/1996	1.065	12.484	21.000	1	Y	FO 2022
30-005-10476	KM CHAVEROO SA UNIT #035	S	I	0	0	1469	151	4/2019	0.000	0.000	9.728	3	Y	TA 2022
30-005-10481	STATE 6 #007	S	O	45	0	1112	72	10/2011	0.625	0.000	15.444	1	Y	NFE
30-005-10485	KM CHAVEROO SA UNIT #021	S	O	39	0	892	76	7/2019	0.513	0.000	11.737	3	Y	NFE
30-005-10486	HALEY CHAVEROO SA UNIT #036	S	O	6	0	0	2	7/2007	3.000	0.000	0.000	1	Y	NFE
30-005-10490	HALEY CHAVEROO SA UNIT #035	S	I	0	0	1478	UNK	1/2011	UNK	UNK	UNK	2	Y	TA 2022
30-005-10493	LEVICK 1 STATE #001	S	O	420	0	11745	316	11/2014	1.329	0.000	37.168	1	Y	FO 2022
30-005-10494	SIGNAL STATE #002	S	O	73	0	19152	276	10/2010	0.264	0.000	69.391	1	Y	FO 2022
30-005-10495	SIGNAL STATE #003	S	O	116	0	21434	287	12/2010	0.404	0.000	74.683	1	Y	FO 2022

EXHIBIT 26

IPANM Exhibit #46
IPANM001097

EXHIBIT 26

API #	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/P*	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-005-10496	SIGNAL STATE #004	S	O	68	0	5249	73	4/2019	0.932	0.000	71.904	1	Y	FO 2022
30-005-10497	KM CHAVEROO SA UNIT #016	S	O	336	0	4084	217	12/2019	1.558	0.000	18.820	2	Y	NFE
30-005-10508	I STATE A #001	S	O	131	0	1	1	4/2016	131.000	0.000	1.000	2	Y	NFE
30-005-10509	KM CHAVEROO SA UNIT #049	S	O	23	0	464	87	7/2019	0.343	0.000	6.925	3	Y	NFE
30-005-10524	KM CHAVEROO SA UNIT #110	S	I	0	0	399	UNK	3/2020	UNK	UNK	UNK	2	Y	NFE
30-005-10529	KM CHAVEROO SA UNIT #111	S	O	400	0	4786	155	7/2019	2.581	0.000	30.877	3	Y	NFE
30-005-10530	KM CHAVEROO SA UNIT #112	S	O	72	0	932	97	7/2019	0.742	0.000	9.608	3	Y	NFE
30-005-10531	KM CHAVEROO SA UNIT #113	S	I	0	0	401	UNK	3/2020	UNK	UNK	UNK	2	Y	TA 2024
30-005-10541	HALEY CHAVEROO SA UNIT #039	S	O	3	0	100	2	4/2007	1.500	0.000	50.000	1	Y	NFE
30-005-10551	HALEY CHAVEROO SA UNIT #042	S	I	8	0	100	10	9/2007	0.800	0.000	10.000	1	Y	TA 2024
30-005-10582	CHAVES STATE #001	S	O	23	0	0	32	9/2007	0.719	0.000	0.000	1	Y	FO 2022
30-005-20026	HALEY CHAVEROO SA UNIT #041	S	O	14	0	100	10	12/2007	1.400	0.000	10.000	1	Y	NFE
30-005-20052	HALEY CHAVEROO SA UNIT #038	S	O	1	0	100	1	4/2007	1.000	0.000	100.000	1	Y	NFE
30-005-20063	I STATE A #002	S	O	131	0	1	1	4/2016	131.000	0.000	1.000	2	Y	FO 2022
30-005-20285	STATE I #003	S	O	21	0	0	24	9/2007	0.875	0.000	0.000	1	Y	NFE
30-005-20311	MWJ STATE #001	S	O	643	0	308	345	12/2000	1.864	0.000	0.893	1	Y	FO 2022
30-005-20487	CHAVEROO STATE #001	S	O	17	0	953	206	8/2016	0.063	0.000	4.626	3	Y	NFE
30-005-20470	CHAVES A STATE #001	S	O	297	0	4877	186	9/2019	1.597	0.000	26.220	2	Y	NFE
30-005-20512	CHAVEROO STATE #002	S	O	17	0	953	206	8/2016	0.063	0.000	4.626	3	Y	NFE
30-005-20516	SIGNAL STATE #005	S	O	0	96	50	31	12/2007	0.000	3.097	1.613	1	Y	FO 2022
30-005-20517	LEVICK 1 STATE #002	S	O	729	0	30713	302	12/2019	2.414	0.000	101.699	3	Y	NFE
30-005-20518	LEVICK 6 STATE #001	S	O	0	83	0	28	2/2007	0.000	2.964	0.000	1	Y	NFE
30-005-20533	SIGNAL STATE #006	S	O	74	80	370	165	12/2007	0.490	0.432	2.000	1	Y	FO 2022
30-005-20535	STATE 5-8-33 #006	S	O	11	0	30	31	1/2008	0.355	0.000	0.968	1	Y	NFE
30-005-20536	STATE 5-8-33 #007	S	O	132	0	1177	81	3/2020	1.630	0.000	14.531	3	Y	RTP 10-2021
30-005-20537	STATE 5-8-33 #009	S	O	11	0	20	31	1/2008	0.355	0.000	0.645	1	Y	FO 2022
30-005-20547	STATE 5-8-33 #004	S	O	11	0	30	31	1/2008	0.355	0.000	0.968	1	Y	NFE

RAOC 2021 ACOI Exhibit "A"

API #	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/I*	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-005-20548	STATE S-8-33 #005	S	O	11	0	30	31	1/2008	0.355	0.000	0.968	1	Y	NFE
30-005-20550	STATE S-8-33 #003	S	O	57	0	642	56	2/2013	1.018	0.000	11.464	2	Y	NFE
30-005-20551	STATE S-8-33 #008	S	O	248	0	4673	290	9/2014	0.855	0.000	16.114	2	Y	NFE
30-005-20552	STATE S-8-33 #010	S	O	12	0	30	31	1/2008	0.387	0.000	0.968	1	Y	FO 2022
30-005-20562	STATE S-8-33 #014	S	O	107	0	2229	59	3/2020	1.814	0.000	37.780	3	Y	RTP 10-2021
30-005-20563	STATE S-8-33 #011	S	O	12	0	30	31	1/2008	0.387	0.000	0.968	1	Y	NFE
30-005-20565	STATE S-8-33 #013	S	O	113	0	3296	37	2/2020	3.054	0.000	89.081	3	Y	NFE
30-005-20567	STATE 6 #011	S	O	1	20	0	31	1/2008	0.032	0.645	0.000	1	Y	NFE
30-005-20568	SIGNAL STATE #007	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-005-20570	STATE 6 #012	S	O	373	3219	5840	361	1/1/2008	1.033	8.917	16.177	1	Y	NFE
30-005-20589	STATE 6 #014	S	O	1	20	0	31	1/1/2008	0.032	0.645	0.000	1	Y	FO 2022
30-005-20590	STATE I #004	S	O	16	0	0	24	9/2007	0.667	0.000	0.000	1	Y	FO 2022
30-005-20648	CHAVEROO SAN ANDRES UNIT #013	P	O	62	111	100	60	2/2008	1.033	1.850	1.667	1	Y	NFE
30-005-20653	CHAVEROO STATE #004	S	O	53	0	953	206	9/2016	0.257	0.000	4.626	3	Y	NFE
30-005-20654	CHAVEROO STATE #005	S	O	25	0	953	206	9/2016	0.121	0.000	4.626	3	Y	NFE
30-005-20688	CHAVEROO SAN ANDRES UNIT #012	F	O	64	101	838	61	4/2008	1.049	1.656	13.738	1	Y	NFE
30-005-20697	CHAVEROO SAN ANDRES UNIT #021	P	O	53	0	779	63	3/2020	0.841	0.000	12.365	2	Y	RTP 12-2021
30-005-20701	CHAVEROO SAN ANDRES UNIT #017	F	O	31	82	100	31	1/2008	1.000	2.645	3.226	1	Y	NFE
30-005-20723	CHAVEROO SAN ANDRES UNIT #022	P	O	31	81	100	31	1/2008	1.000	2.613	3.226	1	Y	NFE
30-005-20749	CHAVEROO STATE #006	S	O	450	0	2731	115	4/2018	3.913	0.000	23.748	3	Y	NFE
30-005-20750	CHAVEROO STATE #007	S	O	237	0	1820	75	11/2018	3.160	0.000	24.267	3	Y	NFE
30-005-20751	CHAVEROO STATE #008	S	O	60	0	50	48	1/2019	1.250	0.000	1.042	3	Y	NFE
30-005-20753	CHAVEROO SAN ANDRES UNIT #023	P	O	60	0	73	54	2/2019	1.111	0.000	1.352	2	Y	RTP 12-2021
30-005-20758	CHAVEROO SAN ANDRES UNIT #025	F	O	326	148	4941	318	12/2013	1.025	0.465	15.538	1	Y	NFE
30-005-20764	CHAVEROO SAN ANDRES UNIT #019	F	O	329	0	2515	282	10/2018	1.167	0.000	8.918	3	Y	NFE
30-005-20765	CHAVEROO SAN ANDRES UNIT #018	F	O	146	119	1414	365	12/2006	0.400	0.326	3.874	1	Y	NFE
30-005-20766	CHAVEROO SAN ANDRES UNIT #026	F	O	26	0	370	41	3/2020	0.634	0.000	9.024	2	Y	RTP 12-2021

EXHIBIT 26

IPANM Exhibit #46

IPANM001099

API #	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/I*	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-005-20792	HALEY CHAVEROO SA UNIT #040	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-005-20899	CHAVEROO SAN ANDRES UNIT #028	P	O	140	150	892	121	4/2008	1.157	1.240	7.372	1	Y	NFE
30-005-20907	CHAVEROO SAN ANDRES UNIT #027	P	O	24	0	259	91	1/2008	0.264	0.000	2.846	1	Y	NFE
30-025-23681	BROWN 84 #001	F	O	53	0	446	100	7/2019	0.530	0.000	4.460	2	Y	NFE
30-025-23975	BROWN 93 #001	F	O	13	0	297	66	9/2018	0.191	0.000	4.368	3	Y	NFE
30-025-24369	YATES 69 FEDERAL #001	F	O	2	0	0	2	6/2019	1.000	0.000	0.000	2	Y	NFE
30-025-24684	BILBREY 23 #003	P	O	10	0	24	6	3/2019	1.667	0.000	4.000	3	Y	NFE
30-025-24783	ALLIED 93 #004	F	O	289	0	695	192	6/2019	1.505	0.000	3.620	2	Y	NFE
30-025-24784	BILBREY 23 #004	P	O	43	0	252	76	4/2019	0.566	0.000	3.316	2	Y	NFE
30-025-24900	BILBREY 51 #002	F	O	222	0	148	139	9/2019	1.597	0.000	1.065	2	Y	NFE
30-025-24965	BILBREY 23 #005	P	O	69	0	515	87	4/2019	0.793	0.000	5.920	2	Y	NFE
30-025-25075	BILBREY 51 #003	F	O	196	0	38	50	4/2020	3.920	0.000	0.760	2	Y	NFE
30-025-25076	YATES 69 FEDERAL #002	F	O	1	0	0	1	3/2019	1.000	0.000	0.000	3	Y	NFE
30-025-25297	BROWN 84 #002	F	O	46	0	112	56	7/2019	0.821	0.000	2.000	2	Y	NFE
30-041-10023	STATE 32-7-33 UNIT #010	S	O	5	0	0	31	12/2007	0.161	0.000	0.000	1	Y	NFE
30-041-10024	STATE 32-7-33 UNIT #011	S	O	11	0	0	42	12/2007	0.262	0.000	0.000	1	Y	NFE
30-041-10025	STATE 32-7-33 UNIT #012	S	O	5	0	0	31	12/2007	0.161	0.000	0.000	1	Y	NFE
30-041-10031	STATE 32-7-33 UNIT #003	S	O	41	0	0	31	3/2008	1.323	0.000	0.000	1	Y	NFE
30-041-10033	STATE 32-7-33 UNIT #005	S	O	7	0	0	20	9/2007	0.350	0.000	0.000	1	Y	NFE
30-041-10035	STATE 32-7-33 UNIT #006	S	O	1	0	0	1	6/2007	1.000	0.000	0.000	1	Y	NFE
30-041-10125	FARRELL FEDERAL #001	F	O	25	0	0	31	6/2006	0.806	0.000	0.000	1	Y	PA Q4 2021
30-041-10137	HALEY CHAVEROO SA UNIT #014	S	I	7	0	100	3	7/2007	2.333	0.000	33.333	1	Y	TA 3-2022
30-041-10138	HALEY CHAVEROO SA UNIT #018	S	I	8	0	1104	243	12/2006	0.033	0.000	4.543	1	Y	TA 2023
30-041-10139	HALEY CHAVEROO SA UNIT #026	S	O	6	0	1237	182	10/2006	0.033	0.000	6.797	1	Y	NFE
30-041-10140	HALEY CHAVEROO SA UNIT #012H	S	O	8	0	778	151	8/2006	0.053	0.000	5.152	1	Y	NFE
30-041-10141	HALEY CHAVEROO SA UNIT #004	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10142	HALEY CHAVEROO SA UNIT #009	S	O	0	0	3155	27	1/1996	0.000	0.000	116.852	1	Y	NFE

EXHIBIT 26

IPANM Exhibit #46

IPANM001100

EXHIBIT 26

API#	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS PIP	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN**	COVERED BY BLANKET BOND	TIMELINE***
30-045-10143	HALEY CHAVEROO SA UNIT #013	S	O	650	449	17331	359	12/1993	1.811	1.251	48.278	1	Y	NFE
30-045-10146	HALEY CHAVEROO SA UNIT #016	S	I	6	0	200	61	12/2006	0.098	0.000	3.279	1	Y	TA 2023
30-045-10164	HALEY CHAVEROO SA UNIT #023	S	I	0	0	20561	UNK	5/2001	UNK	UNK	UNK	1	Y	TA 2024
30-045-10165	HALEY CHAVEROO SA UNIT #010	S	O	5	0	488	151	8/2006	0.033	0.000	3.232	1	Y	NFE
30-045-10170	HALEY CHAVEROO SA UNIT #015	S	O	7	0	100	3	7/2007	2.333	0.000	33.333	1	Y	NFE
30-045-10171	HALEY CHAVEROO SA UNIT #017	S	O	7	0	100	3	7/2007	2.333	0.000	33.333	1	Y	NFE
30-045-10172	HALEY CHAVEROO SA UNIT #002	S	O	6	0	582	182	10/2006	0.033	0.000	3.198	1	Y	NFE
30-045-10173	HALEY CHAVEROO SA UNIT #024	S	O	4	0	100	30	11/2006	0.133	0.000	3.333	1	Y	NFE
30-045-10174	HALEY CHAVEROO SA UNIT #001	S	I	0	0	1606	UNK	UNK	UNK	UNK	UNK	1	Y	TA 3-2022
30-045-10175	HALEY CHAVEROO SA UNIT #019	S	O	5	0	698	151	8/2006	0.033	0.000	4.623	1	Y	NFE
30-045-10176	HALEY CHAVEROO SA UNIT #011	S	O	3	0	100	30	11/2006	0.100	0.000	3.333	1	Y	NFE
30-045-10212	FARRELL FEDERAL #002	F	O	1	0	0	1	7/2003	1.000	0.000	0.000	1	Y	PA Q4 2019
30-045-10213	HALEY CHAVEROO SA UNIT #012	S	I	0	0	94836	UNK	1997	UNK	UNK	UNK	1	Y	TA 2023
30-045-10214	HALEY CHAVEROO SA UNIT #021	S	O	8	0	1824	243	12/2005	0.033	0.000	7.506	1	Y	NFE
30-045-10216	HALEY CHAVEROO SA UNIT #025	S	I	0	0	10053	UNK	5/2001	UNK	UNK	UNK	1	Y	TA Q4 2022
30-045-10232	HALEY CHAVEROO SA UNIT #022	S	I	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	TA 2024
30-045-10240	FARRELL FEDERAL #005	F	O	1	0	0	1	7/2003	1.000	0.000	0.000	1	Y	PA Q4 2021
30-045-10242	HALEY CHAVEROO SA UNIT #006	S	O	1	0	100	1	4/2007	1.000	0.000	100.000	1	Y	NFE
30-045-10243	HALEY CHAVEROO SA UNIT #007	S	I	17	0	0	32	11/2007	0.531	0.000	0.000	1	Y	TA Q4 2022
30-045-10252	FARRELL FEDERAL #003	F	O	1	0	0	1	7/2003	1.000	0.000	0.000	1	Y	PA Q4 2019
30-045-10253	FARRELL FEDERAL #004	F	O	33	0	0	31	7/2006	1.065	0.000	0.000	1	Y	PA Q2 2021
30-045-10403	JAMES MCFARLAND A #001	P	O	20	0	842	120	4/2007	0.167	0.000	7.017	1	Y	NFE
30-045-10405	JENNIFER CHAVEROO SA UNIT #013	S	O	2	0	319	154	6/2006	0.013	0.000	2.071	1	Y	NFE
30-045-10407	JAMES MCFARLAND #002	P	O	11	0	35	31	3/2008	0.355	0.000	1.226	1	Y	NFE
30-045-10408	JENNIFER CHAVEROO SA UNIT #046	F	O	4	0	456	212	6/2006	0.019	0.000	2.151	1	Y	NFE
30-045-10409	JENNIFER CHAVEROO SA UNIT #061	S	O	4	0	939	212	6/2006	0.019	0.000	4.429	1	Y	NFE
30-045-10411	FARRELL FEDERAL #006	F	O	27	0	0	31	7/2006	0.871	0.000	0.000	1	Y	PA Q2 2021

RAOC 2021 ACOI Exhibit "A"

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EXHIBIT 26

API#	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/F	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-041-10413	HALEY CHAVEROO SA UNIT #006	S	I	0	0	2332	UNK	5/2001	UNK	UNK	UNK	1	Y	TA Q4 2022
30-041-10415	MORGAN A FEDERAL #004	F	O	8	0	0	4	6/2006	2.000	0.000	0.000	1	Y	NFE
30-041-10416	MORGAN A FEDERAL #005	F	O	6	0	0	4	7/2006	2.000	0.000	0.000	1	Y	NFE
30-041-10417	MORGAN A FEDERAL #006	F	O	5	0	0	2	11/2007	2.500	0.000	0.000	1	Y	NFE
30-041-10419	MORGAN A FEDERAL #001	F	G	11	0	0	5	12/2007	2.200	0.000	0.000	1	Y	NFE
30-041-10420	MORGAN A FEDERAL #002	F	O	8	0	0	4	11/2007	2.000	0.000	0.000	1	Y	NFE
30-041-10421	HALEY CHAVEROO SA UNIT #031	S	I	0	0	12101	UNK	3/2010	UNK	UNK	UNK	1	Y	TA 2023
30-041-10423	FARRELL FEDERAL #007	F	O	1	0	0	1	7/2003	1.000	0.000	0.000	1	Y	PA Q4 2021
30-041-10426	JENNIFER CHAVEROO SA UNIT #060	S	O	4	0	628	212	6/2006	0.019	0.000	2.962	1	Y	NFE
30-041-10439	JENNIFER CHAVEROO SA UNIT #015	S	O	14	19	72	16	1/1996	0.875	1.188	4.500	1	Y	NFE
30-041-10442	STATE 32-7-33 UNIT #007	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10445	MORGAN A FEDERAL #003	F	G	3	0	0	3	11/2007	1.000	0.000	0.000	1	Y	NFE
30-041-10447	JAMES MCFARLAND A #002	P	O	26	0	804	120	4/2007	0.217	0.000	5.033	1	Y	NFE
30-041-10448	MORGAN B FEDERAL #001	F	O	7	0	11442	85	1/2014	0.082	0.000	134.612	2	Y	NFE
30-041-10449	MORGAN B FEDERAL #002	F	O	7	0	0	9	9/2007	0.778	0.000	0.000	1	Y	NFE
30-041-10450	HALEY CHAVEROO SA UNIT #029	S	I	0	0	7472	UNK	5/2008	UNK	UNK	UNK	1	Y	TA 3-2022
30-041-10451	JENNIFER CHAVEROO SA UNIT #070	S	O	4	0	479	212	6/2006	0.019	0.000	2.259	1	Y	NFE
30-041-10454	HONDO STATE B #001	S	O	10	0	0	5	10/2003	2.000	0.000	0.000	1	Y	NFE
30-041-10456	MORGAN B FEDERAL #004	F	O	9	0	55	9	6/2020	1.000	0.000	6.111	2	Y	NFE
30-041-10457	MORGAN B FEDERAL #005	F	O	34	0	0	61	7/2001	0.557	0.000	0.000	1	Y	NFE
30-041-10458	MORGAN B FEDERAL #006	F	O	3	0	0	1	11/2007	3.000	0.000	0.000	1	Y	NFE
30-041-10467	JENNIFER CHAVEROO SA UNIT #049	S	O	2	0	337	154	6/2006	0.013	0.000	2.188	1	Y	NFE
30-041-10468	JENNIFER CHAVEROO SA UNIT #062	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10474	JAMES MCFARLAND #001	P	O	12	0	107	39	4/2008	0.308	0.000	2.744	1	Y	NFE
30-041-10477	JENNIFER CHAVEROO SA UNIT #058	S	O	2	0	496	154	6/2006	0.013	0.000	3.221	1	Y	NFE
30-041-10478	JENNIFER CHAVEROO SA UNIT #063	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10479	MORGAN B FEDERAL #003	F	O	19	1444	593	181	6/1994	0.105	7.978	3.276	1	Y	NFE

RAOC 2021 ACOI Exhibit "A"

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IPANM Exhibit #46

IPANM001102

API #	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/I*	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-041-10480	HALEY CHAVEROO SA UNIT #030	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	2	Y	NFE
30-041-10484	JAMES MCFARLAMD A #003	P	O	34	0	1217	120	4/2007	0.283	0.000	10.142	1	Y	NFE
30-041-10485	JENNIFER CHAVEROO SA UNIT #030	S	O	2	0	430	154	6/2006	0.013	0.000	2.792	1	Y	NFE
30-041-10488	JENNIFER CHAVEROO SA UNIT #057	S	O	7	0	600	4	9/2007	1.750	0.000	150.000	1	Y	NFE
30-041-10489	JENNIFER CHAVEROO SA UNIT #048	S	O	2	0	299	154	6/2006	0.013	0.000	1.942	1	Y	NFE
30-041-10490	JENNIFER CHAVEROO SA UNIT #017	S	O	3	0	467	184	6/2006	0.016	0.000	2.538	1	Y	NFE
30-041-10492	JAMES MCFARLAMD A #004	P	O	30	0	1269	120	4/2007	0.250	0.000	10.575	1	Y	NFE
30-041-10493	JENNIFER CHAVEROO SA UNIT #016	S	O	2	0	303	154	6/2006	0.013	0.000	1.968	1	Y	NFE
30-041-10494	JENNIFER CHAVEROO SA UNIT #069	S	O	3	0	423	184	6/2006	0.016	0.000	2.299	1	Y	NFE
30-041-10495	HALEY CHAVEROO SA UNIT #028	S	O	6	0	605	182	10/2006	0.033	0.000	3.324	1	Y	NFE
30-041-10496	JENNIFER CHAVEROO SA UNIT #050	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10510	FEDERAL 24 #006	F	O	1	0	0	1	11/2007	1.000	0.000	0.000	1	Y	NFE
30-041-10511	FEDERAL 24 #007	F	O	10	0	0	13	11/2007	0.769	0.000	0.000	1	Y	NFE
30-041-10512	FEDERAL 24 #008	F	O	1	0	0	1	11/2007	1.000	0.000	0.000	1	Y	NFE
30-041-10520	JENNIFER CHAVEROO SA UNIT #031	F	O	4	0	460	212	6/2006	0.019	0.000	2.170	1	Y	NFE
30-041-10521	JENNIFER CHAVEROO SA UNIT #032	F	O	4	0	401	212	6/2006	0.019	0.000	1.892	1	Y	NFE
30-041-10522	JENNIFER CHAVEROO SA UNIT #045	F	O	4	0	469	212	6/2006	0.019	0.000	2.212	1	Y	NFE
30-041-10523	JENNIFER CHAVEROO SA UNIT #033	F	O	4	0	527	212	6/2006	0.019	0.000	2.486	1	Y	NFE
30-041-10524	JENNIFER CHAVEROO SA UNIT #044	F	O	3	0	417	184	9/2007	0.016	0.000	2.266	1	Y	NFE
30-041-10525	JENNIFER CHAVEROO SA UNIT #034	F	O	4	0	300	4	9/2007	1.000	0.000	75.000	1	Y	NFE
30-041-10526	JENNIFER CHAVEROO SA UNIT #043	F	O	7	10	36	16	12/1995	0.438	0.625	2.250	1	Y	NFE
30-041-10545	JENNIFER CHAVEROO SA UNIT #047	S	O	3	0	555	182	8/2006	0.016	0.000	3.049	1	Y	NFE
30-041-10552	JENNIFER CHAVEROO SA UNIT #029	S	O	13	0	278	29	2/2008	0.448	0.000	9.586	1	Y	NFE
30-041-10553	JENNIFER CHAVEROO SA UNIT #042	S	I	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	TA 2023
30-041-10554	JENNIFER CHAVEROO SA UNIT #035	S	O	4	0	550	212	8/2006	0.019	0.000	2.594	1	Y	NFE
30-041-10556	JENNIFER CHAVEROO SA UNIT #056	S	O	4	0	150	4	9/2007	1.000	0.000	37.500	1	Y	NFE
30-041-10557	JENNIFER CHAVEROO SA UNIT #068	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE

EXHIBIT 26

IPANM Exhibit #46

IPANM001103

EXHIBIT 26

API#	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/F*	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-041-10558	JENNIFER CHAVEROO SA UNIT #051	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10567	JAMES MCFARLAND #004	P	O	11	0	38	31	3/2008	0.355	0.000	1.226	1	Y	NFE
30-041-10568	JENNIFER CHAVEROO SA UNIT #067	S	O	327	1194	23405	270	12/1993	1.211	4.422	86.685	1	Y	NFE
30-041-10569	JENNIFER CHAVEROO SA UNIT #018	S	O	70	0	371	361	12/2019	0.194	0.000	1.028	3	Y	NFE
30-041-10570	JENNIFER CHAVEROO SA UNIT #055	S	O	70	0	371	361	12/2019	0.194	0.000	1.028	3	Y	NFE
30-041-10571	JENNIFER CHAVEROO SA UNIT #071	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10575	JENNIFER CHAVEROO SA UNIT #014	S	O	13	0	378	29	2/2008	0.448	0.000	13.034	1	Y	NFE
30-041-10578	JENNIFER CHAVEROO SA UNIT #038	F	O	2	0	321	154	6/2006	0.013	0.000	2.084	1	Y	NFE
30-041-10580	STATE CVB #001	S	O	29	0	0	214	7/2006	0.136	0.000	0.000	1	Y	FO 2022
30-041-10581	JENNIFER CHAVEROO SA UNIT #052	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10588	MIDWEST MORGAN FEDERAL #001	F	I	0	0	5690	UNK	12/2007	UNK	UNK	UNK	1	Y	TA 2022
30-041-10589	JENNIFER CHAVEROO SA UNIT #036	S	O	4	0	369	212	8/2006	0.019	0.000	2.684	1	Y	NFE
30-041-10591	JENNIFER CHAVEROO SA UNIT #041	S	O	3	0	417	184	6/2006	0.016	0.000	2.266	1	Y	NFE
30-041-10595	JENNIFER CHAVEROO SA UNIT #009	S	O	49	0	315	287	11/2019	0.171	0.000	1.098	2	Y	NFE
30-041-10596	JENNIFER CHAVEROO SA UNIT #013	S	O	13	0	278	29	2/2008	0.448	0.000	9.586	1	Y	NFE
30-041-10604	STATE CVB #002	S	O	29	0	0	214	7/2006	0.136	0.000	0.000	1	Y	NFE
30-041-10607	JENNIFER CHAVEROO SA UNIT #019	S	O	14	0	1398	46	3/2010	0.304	0.000	30.391	2	Y	NFE
30-041-10611	JENNIFER CHAVEROO SA UNIT #010	S	O	18	0	357	29	2/2008	0.621	0.000	12.310	1	Y	NFE
30-041-10612	JENNIFER CHAVEROO SA UNIT #012	S	O	13	0	278	29	2/2008	0.448	0.000	9.586	1	Y	NFE
30-041-10613	JENNIFER CHAVEROO SA UNIT #002	F	O	3	0	432	184	6/2008	0.016	0.000	2.348	1	Y	NFE
30-041-10614	JENNIFER CHAVEROO SA UNIT #020	S	O	25	0	1983	65	7/2008	0.385	0.000	30.508	1	Y	NFE
30-041-10615	E B BURGLAND #001	P	G	0	64	0	122	8/2011	0.000	0.525	0.000	1	Y	NFE
30-041-10617	JENNIFER CHAVEROO SA UNIT #028	S	O	55	0	2549	220	10/2014	0.250	0.000	11.586	3	Y	NFE
30-041-10623	STATE CVB #003	S	O	29	0	0	90	3/2006	0.322	0.000	0.000	1	Y	NFE
30-041-10624	JENNIFER CHAVEROO SA UNIT #027	S	O	37	0	4999	323	11/2019	0.115	0.000	15.477	3	Y	NFE
30-041-10625	JENNIFER CHAVEROO SA UNIT #064	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10626	JENNIFER CHAVEROO SA UNIT #066	S	O	4	0	447	212	8/2006	0.019	0.000	2.108	1	Y	NFE

RAOC 2021 ACOI Exhibit "A"

IPANM Exhibit #46

IPANM001104

EXHIBIT 26

API #	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/P*	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-041-10627	JENNIFER CHAVEROO SA UNIT #004	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10630	JENNIFER CHAVEROO SA UNIT #005	F	O	7	10	36	16	1/1996	0.438	0.625	2.250	1	Y	NFE
30-041-10633	CHAVEROO A STATE #001	S	O	6	0	0	UNK	5/2008	UNK	UNK	UNK	1	Y	FO 2022
30-041-10634	JENNIFER CHAVEROO SA UNIT #026	S	O	18	0	278	29	2/2008	0.621	0.000	9.586	1	Y	NFE
30-041-10635	JENNIFER CHAVEROO SA UNIT #037	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10636	JENNIFER CHAVEROO SA UNIT #021	S	O	41	0	4600	92	5/2008	0.446	0.000	50.000	1	Y	NFE
30-041-10639	JENNIFER CHAVEROO SA UNIT #031	F	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10640	JENNIFER CHAVEROO SA UNIT #038	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10645	JENNIFER CHAVEROO SA UNIT #011	F	O	2	0	277	154	6/2006	0.013	0.000	1.799	1	Y	NFE
30-041-10646	JENNIFER CHAVEROO SA UNIT #022	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10647	MORGAN C FEDERAL #001	F	O	14	0	0	16	11/2007	0.875	0.000	0.000	1	Y	NFE
30-041-10648	MORGAN C FEDERAL #002	F	O	12	0	0	16	11/2007	0.750	0.000	0.000	1	Y	NFE
30-041-10652	JENNIFER CHAVEROO SA UNIT #003	F	O	4	0	1120	212	8/2006	0.019	0.000	5.283	1	Y	NFE
30-041-10653	JENNIFER CHAVEROO SA UNIT #007	F	O	4	0	180	4	9/2007	1.000	0.000	45.000	1	Y	NFE
30-041-10655	JENNIFER CHAVEROO SA UNIT #025	S	O	51	0	3918	177	8/2011	0.288	0.000	22.136	2	Y	NFE
30-041-10660	JENNIFER CHAVEROO SA UNIT #023	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-10661	JENNIFER CHAVEROO SA UNIT #039	S	O	9	0	300	4	9/2007	2.250	0.000	75.000	1	Y	NFE
30-041-10666	CHAVEROO B #001	S	O	67	0	0	126	7/2005	0.532	0.000	0.000	1	Y	NFE
30-041-10667	JENNIFER CHAVEROO SA UNIT #005F	F	O	8	0	1423	215	8/2006	0.037	0.000	6.619	1	Y	NFE
30-041-10668	CHAVEROO A STATE #002	S	O	25	0	0	UNK	7/2006	UNK	UNK	UNK	1	Y	FO 2022
30-041-10669	CHAVEROO B #002	S	O	83	0	0	126	6/2006	0.500	0.000	0.000	1	Y	NFE
30-041-20002	STATE D #001	S	O	228	0	0	203	12/2007	1.123	0.000	0.000	1	Y	NFE
30-041-20005	JENNIFER CHAVEROO SA UNIT #040	S	O	13	0	278	29	2/2008	0.448	0.000	9.586	1	Y	NFE
30-041-20024	ANDERSON STATE #001	S	O	66	0	71	120	6/2007	0.550	0.000	0.592	1	Y	NFE
30-041-20033	KMS #001	S	O	113	0	38	120	6/2007	0.942	0.000	0.317	1	Y	NFE
30-041-20035	ANDERSON STATE #002	S	O	69	0	76	120	6/2007	0.575	0.000	0.650	1	Y	NFE
30-041-20041	KMS #002	S	O	132	0	24	120	6/2007	1.100	0.000	0.200	1	Y	NFE

IPANM Exhibit #46

IPANM001105

API #	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/I*	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-041-20042	ANDERSON STATE #003	S	O	6	0	4300	127	9/2015	0.047	0.000	33.858	1	Y	NFE
30-041-20043	ANDERSON STATE #004	S	O	58	0	93	120	6/2007	0.483	0.000	0.775	1	Y	NFE
30-041-20044	JENNIFER CHAVEROO SA UNIT #065	S	O	7	10	36	16	1/1996	0.438	0.625	2.250	1	Y	NFE
30-041-20045	KMS #003	S	O	28	0	3113	130	5/2014	0.215	0.000	23.946	1	Y	NFE
30-041-20046	ANDERSON STATE #005	S	O	159	0	4128	138	7/2010	1.152	0.000	29.913	1	Y	NFE
30-041-20051	ANDERSON STATE #007	S	O	65	0	81	120	6/2007	0.542	0.000	0.675	1	Y	NFE
30-041-20052	ANDERSON STATE #008	S	O	82	0	51	120	6/2007	0.683	0.000	0.425	1	Y	NFE
30-041-20053	KMS #004	S	O	8	0	100	7	8/2021	1.143	0.000	14.286	2	Y	NFE
30-041-20054	KMS #005	S	O	3	0	380	14	1/2015	0.214	0.000	27.143	2	Y	NFE
30-041-20058	HUMBLE TUCKER #001	P	O	39	0	0	214	3/2006	0.182	0.000	0.000	1	Y	FO 2022
30-041-20077	HONDO STATE #005	S	O	15	0	0	54	9/2007	0.278	0.000	0.000	1	Y	NFE
30-041-20082	HONDO STATE #006	S	O	10	0	0	2	5/2008	5.000	0.000	0.000	1	Y	NFE
30-041-20084	ANDERSON STATE #009	S	O	18	0	757	22	4/2008	0.818	0.000	34.409	1	Y	NFE
30-041-20090	CWS #001	S	O	137	0	0	147	8/2008	0.932	0.000	0.000	1	Y	FO 2022
30-041-20091	CWS #002	S	O	86	0	690	100	8/2009	0.860	0.000	6.900	1	Y	NFE
30-041-20095	HUMBLE TUCKER #003	P	O	39	0	0	214	7/2006	0.182	0.000	0.000	1	Y	FO 2022
30-041-20096	HUMBLE TUCKER #004	P	O	39	0	0	214	3/2006	0.182	0.000	0.000	1	Y	NFE
30-041-20100	JENNIFER CHAVEROO SA UNIT #053	S	I	17	0	0	28	2/2007	0.607	0.000	0.000	1	Y	TA 2023
30-041-20105	JENNIFER CHAVEROO SA UNIT #024	S	I	0	0	13526	UNK	12/2006	UNK	UNK	UNK	1	Y	NFE
30-041-20109	HUMBLE FEDERAL #001	F	O	0	0	5665	UNK	11/2019	UNK	UNK	UNK	3	Y	FO 2022
30-041-20113	HUMBLE FEDERAL #002	F	O	331	0	704	182	6/2007	1.819	0.000	3.868	1	Y	FO 2022
30-041-20118	HUMBLE FEDERAL #007	F	O	334	0	1544	182	6/2007	1.835	0.000	8.484	1	Y	NFE
30-041-20119	HUMBLE FEDERAL #008	F	O	208	0	1241	220	10/2019	0.945	0.000	5.641	3	Y	FO 2022
30-041-20139	PARTIN 35 #001	P	O	33	0	370	90	3/2018	0.367	0.000	4.111	3	Y	NFE
30-041-20141	TUCKER #001	P	O	250	0	329	139	7/2008	1.799	0.000	2.367	1	Y	NFE
30-041-20145	TUCKER #002	P	O	40	0	0	UNK	7/2006	UNK	UNK	UNK	1	Y	NFE
30-041-20152	TUCKER HALL #001	P	O	17	0	0	59	3/2007	0.288	0.000	0.000	1	Y	NFE

EXHIBIT 26

IPANM Exhibit #46

IPANM001106

API #	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/I*	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-041-20160	TUCKER HALL #002	P	O	37	0	0	155	7/2006	0.239	0.000	0.000	1	Y	FO 2022
30-041-20162	TUCKER HALL #003	P	O	50	0	182	11	09/2008	4.545	0.000	16.545	1	Y	FO 2022
30-041-20166	TUCKER HALL #004	P	O	33	0	137	165	6/2013	0.200	0.000	0.830	2	Y	NFE
30-041-20215	SHELL CONE PARTIN #001	P	O	32	0	136	165	6/2013	0.194	0.000	0.824	1	Y	NFE
30-041-20247	SHELL CONE PARTIN #002	P	O	41	0	0	215	5/2006	0.191	0.000	0.000	1	Y	NFE
30-041-20309	CHAVEROO SAN ANDRES UNIT #005	P	O	40	0	0	214	5/2006	0.187	0.000	0.000	1	Y	NFE
30-041-20344	ALLIE PARTIN ET AL #001	P	O	32	82	100	31	1/2008	1.032	2.645	3.226	1	Y	NFE
30-041-20347	ALLIE PARTIN ET AL #002	P	O	107	0	0	117	8/2008	0.915	0.000	0.000	1	Y	NFE
30-041-20386	CHAVEROO SAN ANDRES UNIT #006	P	O	106	0	0	117	8/2008	0.906	0.000	0.000	1	Y	NFE
30-041-20399	CHAVEROO SAN ANDRES UNIT #007	P	O	31	81	100	31	1/2008	1.000	2.613	3.226	1	Y	NFE
30-041-20417	CHAVEROO SAN ANDRES UNIT #004	P	O	134	162	1553	366	12/2006	0.366	0.443	4.243	1	Y	NFE
30-041-20418	STATE 32-7-33 UNIT #014	S	O	146	131	1872	365	12/2006	0.400	0.359	5.129	1	Y	NFE
30-041-20426	STATE 32-7-33 UNIT #015	S	O	0	0	0	UNK	UNK	UNK	UNK	UNK	1	Y	NFE
30-041-20444	HONDO A STATE #001	S	O	78	0	10712	113	11/2012	0.690	0.000	94.796	1	Y	NFE
30-041-20453	CHAVEROO SAN ANDRES UNIT #009	P	O	61	0	0	60	2/2008	1.017	0.000	0.000	1	Y	NFE
30-041-20472	CHAVEROO SAN ANDRES UNIT #008	P	O	17	0	25	20	11/2018	0.850	0.000	1.250	3	Y	NFE
30-041-20473	CHAVEROO SAN ANDRES UNIT #002	P	O	32	82	100	31	1/2008	1.032	2.645	3.226	1	Y	NFE
30-041-20480	CHAVEROO SAN ANDRES UNIT #010	F	O	31	81	100	31	1/2008	1.000	2.613	3.226	1	Y	NFE
30-041-20490	CHAVEROO SAN ANDRES UNIT #001	F	O	240	0	2695	351	10/2018	0.684	0.000	7.678	3	Y	NFE
30-041-20680	SIEBER #001	P	O	88	129	838	90	4/2008	0.978	1.433	9.311	1	Y	NFE
30-041-20685	METZGER #002	P	O	58	0	114	90	2/2013	0.644	0.000	1.267	1	Y	NFE
30-041-20688	FARRELL FEDERAL #023	F	O	1	0	0	1	2/2008	1.000	0.000	0.000	1	Y	PA Q2 2021
30-041-20699	FARRELL FEDERAL #024	F	O	5	0	0	UNK	7/2006	UNK	UNK	UNK	1	Y	PA Q4 2021
30-041-20701	METZGER #003	P	O	4	0	0	UNK	7/2006	UNK	UNK	UNK	1	Y	NFE
30-041-20707	STATE S #001	S	O	33	0	0	123	10/2007	0.268	0.000	0.000	1	Y	NFE
30-041-20709	HEFFLEFINGER #001	P	O	83	0	165	121	11/2007	0.686	0.000	1.364	1	Y	NFE
30-041-20720	METZGER #004	P	O	72	0	0	UNK	7/2006	UNK	UNK	UNK	1	Y	NFE

EXHIBIT 26

IPANM Exhibit #46

IPANM001107

EXHIBIT 26

API#	WELL NAME / #	LEASE TYPE	WELL TYPE	LAST PRODUCTION OIL	LAST PRODUCTION GAS	LAST PRODUCTION WATER	DAYS P/P	LAST PRODUCTION MONTH	AVG LAST OIL	AVG LAST GAS	AVG LAST WATER	REASON FOR SHUT-IN **	COVERED BY BLANKET BOND	TIMELINE***
30-041-20730	METZGER #006	P	O	123	0	981	272	9/2005	0.452	0.000	3.607	1	Y	NFE
30-041-20759	TUCKER HALL #008	P	O	130	0	1089	272	9/2005	0.478	0.000	4.004	1	Y	NFE
30-041-20760	TUCKER HALL #007	P	O	31	0	0	UNK	7/2006	UNK	UNK	UNK	1	Y	NFE
30-041-20761	TUCKER HALL #008	P	O	28	0	0	152	7/2003	0.184	0.000	0.000	1	Y	NFE
30-041-20763	METZGER #006	P	O	171	0	28	347	12/2018	0.493	0.000	0.081	2	Y	NFE
30-041-20769	TUCKER #005	P	I	1	0	0	1	2/2008	1.000	0.000	0.000	1	Y	TA 2022
30-041-20803	HASELOFF FEDERAL #001	F	O	0	0	48400	UNK	11/2006	UNK	UNK	UNK	1	Y	NFE
30-041-20952	ROCKIN ROBIN #001	P	O	49	0	0	59	11/2007	0.678	0.000	0.000	1	Y	NFE
30-041-20971	TUPELO HONEY 27 COM #006H	P	O	98	0	0	2	1/2019	49.000	0.000	0.000	3	Y	NFE

* Data represented as "UNK" is an unkown number of days producing in the last year of production. Calculated averages are also represented as such due to insufficient data to make calculation.

** Reason for Shut-In Codes	
1	Historically shut-in, no surface equipment
2	Needs additional facility or infrastructure to produce i.e. tankage, flowline, electricity
3	Needs surface mechanical repair i.e. pumping unit, rod string, tubing stuck in hole or other

** Codes for well timelines below	
TA (Date)	Anticipated TA date/year
PA	Plugged and abandoned
FO (date)	Ridgeway engaged in finalizing a Farmout Agreement wherein a third party will either return wells to production or plug and abandon
NFE	Well needs further evaluation to determine status

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

NMOCD – ACOI-266

IN THE MATTER OF DOMINION PRODUCTION COMPANY LLC,

Respondent.

INACTIVE WELL
AGREED COMPLIANCE ORDER

Pursuant to the New Mexico Oil and Gas Act, NMSA 1978, Sections 70-2-1 through 70-2-38, as amended ("Act") and OCD Rule 19.15.5.10(E) NMAC, the Director of the Oil Conservation Division ("OCD") and Dominion Production Company LLC ("Operator") enter into this Inactive Well Agreed Compliance Order ("Order" or "ACOI") under which Operator agrees to plug, place on approved temporary abandonment status or restore to production or other beneficial use the wells identified herein pursuant to the Act and OCD Rule 19.15.25.8 NMAC in accordance with the following agreed schedule and procedures, and understands that the OCD may decide not to enter into any further agreed compliance orders with Operator if Operator fails to meet the schedule set out in this Order.

FINDINGS

1. The OCD is the state division charged with administration and enforcement of the Act, and rules and orders adopted pursuant to the Act.

2. Operator is a limited liability company doing business in the state of New Mexico under OGRID 291567.

3. Operator is seeking to become the operator of record of the wells identified in Exhibit "A" attached.

4. Nacogdoches Oil and Gas, Inc. (OGRID 256689) is the current operator of record of the wells identified in Exhibit "A".

5. The wells identified in Exhibit "A"

   (a) have been continuously inactive for a period of one year plus 90 days (or within the next six months will become continuously inactive for a period of one year plus 90 days if no action is taken on the wells);
   (b) are not plugged or abandoned in accordance with OCD Rule 19.15.25.9 NMAC through 19.15.25.11 NMAC; and

(c) are not on approved temporary abandonment status in accordance with OCD Rule 19.15.25.12 NMAC through 19.15.25.14 NMAC.

6. OCD Rule 19.15.25.8 NMAC states, in relevant part:

"A. The operator of wells drilled for oil or gas or services wells including seismic, core, exploration or injection wells, whether cased or uncased, shall plug the wells as Subsection B of 19.15.25.8 NMAC requires.
B. The operator shall either properly plug and abandon a well or place the well in approved temporary abandonment in accordance with 19.15.25 NMAC within 90 days after:
....
....
(3) a period of one year in which a well has been continuously inactive."

7. Some of the wells identified in Exhibit "A" are also under a compliance order (Order R-13166).

8. Paragraph 2 of Subsection C of OCD Rule 19.15.5.9 NMAC provides that the director or her designee may deny a change of operator if the new operator is acquiring wells, facilities or sites subject to a compliance order requiring compliance with 19.15.25.8 NMAC and the new operator has not entered into an agreed compliance order setting a schedule for compliance with the existing order.

9. The OCD and Operator are entering into this agreed compliance order which sets a schedule for compliance to allow Operator to become the operator of record of the wells identified in Exhibit "A."

CONCLUSIONS

1. The OCD has jurisdiction over the parties and subject matter in this proceeding.

2. The wells identified in Exhibit "A" are either out of compliance with OCD Rule 19.15.25.8 NMAC or will fall out of compliance with OCD Rule 19.15.25.8 NMAC in the next six months if they are not returned to production or other beneficial use, plugged and abandoned, or placed on approved temporary abandonment status.

3. The OCD and Operator are entering into this agreed compliance order which sets a schedule for compliance to allow Operator to become the operator of record of the wells identified in Exhibit "A."

4. As operator of the wells identified in Exhibit "A," Operator will be responsible for bringing those wells into compliance with OCD Rule 19.15.25.8 NMAC once it becomes the operator of record of the wells.

ORDER

1. Operator agrees to bring 12 wells identified in Exhibit "A" into compliance with OCD Rule 19.15.25.8 NMAC by April 18, 2013 by

   (a) restoring the well to production or other OCD-approved beneficial use **and filing a C-115 documenting such production or use**;
   (b) causing the wellbore to be plugged in accordance with OCD Rule 19.15.25.10(B) NMAC **and filing a C-103 describing the completed work**; or
   (c) placing the well on approved temporary abandonment status in accordance with OCD Rule 19.15.25.12 NMAC through 19.15.25.14 NMAC.

2. Oil and gas produced during swabbing does not count as production for purposes of this Order.

3. Operator shall file a compliance report identifying each well returned to compliance, stating the date it was returned to compliance and describing how the well was returned to compliance (restored to production or other approved beneficial use, plugged wellbore, approved temporary abandonment status.) Transfer of a well identified on Exhibit "A" to another operator does not count towards Operator's obligation to return wells to compliance under the terms of this Order, but does reduce the total number of wells for which Operator is responsible under the terms of this Order. The written compliance report must be mailed or e-mailed to the OCD's Enforcement and Compliance Manager and to the OCD attorney in charge of inactive well agreed compliance orders so that it is **received by** the compliance deadline of April 18, 2013. The total length of this Agreed Compliance Order is six months.

4. Operator understands that if it fails to meet the terms of this Order, the OCD may decide not to enter into any further agreed compliance orders with Operator.

5. Thirty days after the compliance deadline set by this Order, any wells on Exhibit "A" not in compliance with OCD Rule 19.15.25.8 NMAC will appear on the inactive well list kept pursuant to OCD Rule 19.15.5.9(F) NMAC.

6. By signing this Order, Operator expressly:

   (a) acknowledges the correctness of the Findings and Conclusions set forth in this Order;
   (b) agrees to return to compliance 12 wells identified in Exhibit "A" by April 18, 2013;

(c) agrees to submit a compliance report as required in Ordering Paragraph 3 by the April 18, 2013 compliance deadline set by this Order;

(d) waives any right, pursuant to the Oil and Gas Act or otherwise, to an appeal from this Order, or to a hearing either prior to or subsequent to the entry of this Order; and

(e) agrees that the Order may be enforced by OCD or Oil Conservation Commission Order, by suit or otherwise to the same extent and with the same effect as a final Order of the OCD or Oil Conservation Commission entered after notice and hearing in accordance with all terms and provisions of the Oil and Gas Act.

7. This Order applies only to the enforcement of OCD Rule 19.15.25.8 NMAC against those wells identified in Exhibit "A." Other wells operated by Operator out of compliance with OCD Rule 19.15.25.8 NMAC may be subject to immediate enforcement action under the Oil and Gas Act and OCD Rules. Wells identified in Exhibit "A" that are out of compliance with the Oil and Gas Act or OCD Rules other than OCD Rule 19.15.25.8 NMAC may be subject to immediate enforcement action under the Oil and Gas Act and OCD Rules.

8. The OCD reserves the right to file an application for hearing to obtain authority to plug any well identified in Exhibit "A" and forfeit the applicable financial assurance if the well poses an immediate environmental threat.

Done at Santa Fe, New Mexico this 4th day of October, 2012

By: _____
Jami Bailey
Director, Oil Conservation Division

ACCEPTANCE

Dominion Production Company LLC hereby accepts the foregoing Order, and agrees to all of the terms and provisions set forth in that Order.

Dominion Production Company LLC

By: _____
(Please print name) DAVID BURNS
Title: PRESIDENT
Date: 10/1/2012

Exhibit A to Agreed Compliance Order for Dominion Production Company LLC

30-031-20419 HANSON #026

30-031-20725	HANSON #038
30-031-20338	HOSPAH SAND UNIT #001Y
30-031-05205	HOSPAH SAND UNIT #003
30-031-05176	HOSPAH SAND UNIT #009
30-031-05189	HOSPAH SAND UNIT #012
30-031-05207	HOSPAH SAND UNIT #015
30-031-05211	HOSPAH SAND UNIT #016
30-031-05213	HOSPAH SAND UNIT #017
30-031-05203	HOSPAH SAND UNIT #019
30-031-05195	HOSPAH SAND UNIT #022
30-031-05192	HOSPAH SAND UNIT #023
30-031-05186	HOSPAH SAND UNIT #024
30-031-05214	HOSPAH SAND UNIT #027
30-031-05225	HOSPAH SAND UNIT #029
30-031-05224	HOSPAH SAND UNIT #032
30-031-05223	HOSPAH SAND UNIT #034
30-031-05222	HOSPAH SAND UNIT #035
30-031-05219	HOSPAH SAND UNIT #037
30-031-05171	HOSPAH SAND UNIT #039
30-031-05194	HOSPAH SAND UNIT #051
30-031-20115	HOSPAH SAND UNIT #058
30-031-20116	HOSPAH SAND UNIT #059
30-031-07025	HOSPAH SAND UNIT #061
30-031-05559	HOSPAH SAND UNIT #063
30-031-05577	HOSPAH SAND UNIT #066
30-031-20247	HOSPAH SAND UNIT #070
30-031-20608	HOSPAH SAND UNIT #095
30-031-20831	HOSPAH SAND UNIT #100
30-031-20183	LONE PINE DAKOTA D UNIT #012
30-031-20174	LONE PINE DAKOTA D UNIT #014
30-031-20201	LONE PINE DAKOTA D UNIT #023
30-031-20086	SANTA FE #016
30-031-20102	SANTA FE #017
30-031-20341	SANTA FE #029
30-031-20165	SANTA FE PACIFIC RAILROAD #002

30-031-20181	SANTA FE PACIFIC RAILROAD #008
30-031-20182	SANTA FE PACIFIC RAILROAD #009
30-031-05531	SANTA FE RAILROAD #009
30-031-20038	SANTA FE RAILROAD #013
30-031-20037	SANTA FE RAILROAD #014
30-031-20036	SANTA FE RAILROAD #015
30-031-20138	SANTA FE RAILROAD #018
30-031-20140	SANTA FE RAILROAD #020
30-031-20150	SANTA FE RAILROAD #023
30-031-20594	SANTA FE RAILROAD #041
30-031-20712	SANTA FE RAILROAD #043
30-031-20713	SANTA FE RAILROAD #044
30-031-20836	SANTA FE RAILROAD #047
30-031-20837	SANTA FE RAILROAD #048
30-031-20854	SANTA FE RAILROAD #050
30-031-05570	SANTA FE RAILROAD A #072
30-031-20021	SANTA FE RAILROAD A #074
30-031-20147	SANTA FE RAILROAD A #083
30-031-20372	SANTA FE RAILROAD A #084
30-031-20413	SANTA FE RAILROAD A #087
30-031-20855	SANTA FE RAILROAD A #097
30-031-20303	SANTA FE RR B #032
30-031-20369	SANTA FE RR B #033
30-031-20390	SANTA FE RR B #034
30-031-20416	SANTA FE RR B #036
30-031-20415	SANTA FE RR B #037
30-031-05146	SOUTH HOSPAH UNIT #005
30-031-20012	SOUTH HOSPAH UNIT #007
30-031-20016	SOUTH HOSPAH UNIT #011
30-031-20054	SOUTH HOSPAH UNIT #013
30-031-20056	SOUTH HOSPAH UNIT #016
30-031-20094	SOUTH HOSPAH UNIT #027
30-031-20124	SOUTH HOSPAH UNIT #033
30-031-20118	SOUTH HOSPAH UNIT #036
30-031-20135	SOUTH HOSPAH UNIT #037X

30-031-20152	SOUTH HOSPAH UNIT #039
30-031-20360	SOUTH HOSPAH UNIT #046
30-031-20362	SOUTH HOSPAH UNIT #048
30-031-20242	SOUTH HOSPAH UNIT #051
30-031-20243	SOUTH HOSPAH UNIT #052
30-031-20411	SOUTH HOSPAH UNIT #060
30-031-20546	SOUTH HOSPAH UNIT #061
30-031-20544	SOUTH HOSPAH UNIT #063

Dominion Production Company LLC
By: _____
Title: PRESIDENT

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

NMOCD – ACO- 285

IN THE MATTER OF DOMINION PRODUCTION COMPANY LLC,

AGREED COMPLIANCE ORDER

Pursuant to the New Mexico Oil and Gas Act, NMSA 1978, Sections 70-2-1 through 70-2-38, as amended, and the Water Quality Act, NMSA 1978, Sections 74-6-1 through 74-6-17 as amended, the Director of the Oil Conservation Division ("OCD") and Dominion Production Company LLC ("Operator") enter into this Agreed Compliance Order ("Order" or "ACO") under which Operator agrees to perform maintenance on the subject injection wells as established in this order, and pay a monetary fine pursuant to Section 74-6-10 of the Water Quality Act. Operator agrees to perform the requirements established in this order in accordance with OCD rules, the following agreed schedule and procedures, and understands that the OCD will seek further sanctions if Operator fails to meet the schedule set out in this ACO.

FINDINGS

1. The OCD is the state division charged with administration and enforcement of the New Mexico Oil and Gas Act and the Water Quality Act, and rules and orders adopted pursuant to each Act.

2. Operator is a limited liability company doing business in the State of New Mexico and is registered with the Division under Oil and Gas Reporting Identification ("OGRID") No. 291567.

3. On October 2, 2013, the OCD met with Operator to discuss ACOI-266-0. During that meeting several other compliance issues were discussed including twenty two injection wells which were out of compliance.

4. The OCD contends that Operator did not comply with ACOI-266-0. This ACOI expired on April 18, 2013 and at that time the operator had not complied with all conditions. The Operator had also allowed additional wells to also be placed on the inactive well list. This ACO deals specifically with the violations detailed herein and does not affect ACOI-260-0.

5. OCD Rule 19.15.16.11 NMAC (Defective Casing Or Cementing) states in relevant part: If a well appears to have a defective casing program or faultily cemented or corroded casing that will permit or may create underground waste or contamination of fresh waters, the operator shall give written notice to the division within five working days and proceed with diligence to use the appropriate method and means to eliminate the hazard. If the hazard of waste or

contamination of fresh water cannot be eliminated, the operator shall properly plug and abandon the well.

6. Operator violated OCD Rule 19.15.16.11 NMAC by not proceeding with diligence to identify the cause of the Mechanical Integrity Test ("MIT") failures and proceed with diligence to repair any issues identified and properly report them to the OCD for the two wells below.
   a. South Hospah Unit #39- Failed MIT on October 21, 2008.
   b. South Hospah Unit #17- Failed MITs on November 21, 2013, and on January 8, 2014.

7. OCD Rule 19.15.5.11 NMAC (Enforceability Of Permits And Administrative Orders) states in relevant part: A person who conducts an activity pursuant to a permit, administrative order or other written authorization or approval from the division shall comply with every term, condition and provision of the permit, administrative order, authorization or approval.

8. Operator violated OCD Rule 19.15.5.11 NMAC by not complying with all of the OCD's conditions of approval on the following wells:
   a. South Hospah Unit #36- An OCD inspection on August 14, 2013, identified this well as producing. To date Dominion has not complied with the conditions of their approval.
   b. South Hospah Unit #39- Dominion has not complied with the 30 day MIT requirement for this well as required on August 21, 2013.

9. OCD Rule 19.15.26.11(A)(2) NMAC (Testing, Monitoring, Step-Rate Tests, Notice to the Division, Requests for Pressure Increases) states in relevant part: At least once every five years thereafter, the operator shall test an injection well to assure its continued mechanical integrity...

10. Operator violated OCD Rule 19.15.26.11(A)(2) NMAC by not proceeding with diligence to perform an MIT as required by rule on the following wells from the time it assumed operations:
    a. Hospah Sand Unit #61- Last MIT performed 9-27-06
    b. Hospah Sand Unit #66- Last MIT performed 8-27-04
    c. Hospah Sand Unit #100- Last MIT performed 4-27-06
    d. Hospah Sand Unit #58- Last MIT performed 4-19-06
    e. Santa Fe Rail Road #23- Last MIT performed 9-27-06
    f. Santa Fe Rail Road #87- Last MIT performed 9-15-00
    g. Santa Fe Rail Road #97- Last MIT performed 9-15-00
    h. Santa Fe Rail Road #83- Last MIT performed 9-15-00
    i. South Hospah Unit #51- Last MIT performed 10-20-08 (A pretest was performed on 7-21-14 and the casing would not hold pressure.)
    j. South Hospah Unit #39- Last MIT performed 10-21-08
    k. South Hospah Unit #52- Last MIT performed 9-14-00
    l. South Hospah Unit #36- Last MIT performed 9-14-00

m. South Hospah Unit #60- Last MIT performed 7-31-01
n. Lone Pine Dakota D Unit #14- Last MIT performed 7-23-02

11. OCD Rule 19.15.7.14 (Sundry Notices And Reports On Wells) (Form C-103): Form C-103 is a dual purpose form the operator files with the appropriate division district office to obtain division approval prior to commencing certain operations and to report various completed operations, including:

OCD Rule 19.15.7.14(A)(1)(a) NMAC effecting a change of plans from those the division previously approved on form C-101 or form C-103;

OCD Rule 19.15.7.14(B)(2)(h) NMAC installation of artificial lifting equipment;

12. Operator violated OCD Rule 19.15.7.14(A)(1)(a) NMAC by placing the South Hospah Unit #36 on production prior to having OCD's approval of a Notice of Intent.

13. Operator violated OCD Rule 19.15.7.14(B)(2)(h) NMAC by installing artificial lifting equipment on the South Hospah Unit #36 without filing a subsequent report with OCD. An OCD inspection on August 14th, 2013, identified lifting equipment.

14. OCD Rule 19.15.7.14.G(4) report of installation of pumping equipment or gas lift facilities.

15. Operator violated OCD Rule 19.15.7.14(G)(4) NMAC by not filing subsequent reports of installation of pumping equipment within 30 days on the South Hospah Unit #36. An OCD inspection on August 14th, 2013, identified this well had a pump install and was producing. It has been over 10 months since this well was identified as producing and a subsequent report has not been received.

16. OCD Rule 19.15.16.8 (Sign On Wells) states in relevant part:

A. An operator shall identify wells and related facilities the division regulates by a sign, which shall remain in place until the operator plugs and abandons the well and closes the related facilities…

C. The sign shall be of durable construction and the lettering shall be legible and large enough to be read under normal conditions at a distance of 50 feet…

E. An operator shall have 90 days from the effective date of an operator name change to change the operator name on the well sign unless the division grants an extension of time, for good cause shown along with a schedule for making the changes…

17. Operator violated OCD Rule 19.15.16.8 NMAC by not having a sign in compliance with the rule on the following locations:

a. Santa Fe Rail Road #23- Current operator not listed and sign is illegible.
b. Hospah Sand Unit #61- Current operator not listed and incorrect API number.
c. Hospah Sand Unit #66- No well sign.
d. Lone Pine Dakota D Unit #14- No well sign.
e. Hospah Sand Unit #58- No well sign.
f. Santa Fe Rail Road #87- No well sign.
g. Santa Fe Rail Road #97- Current operator not listed.
h. South Hospah Unit #54- Current operator not listed.

18. OCD Rule 19.15.26.10(E) states that the division may restrict the injected volume and pressure for, or shut-in, injection wells or projects that have exhibited failure to confine injected fluids to the authorized injection zone or zones, until the operator has identified and corrected the failure.

19. Operator violated OCD Rule 19.15.26.10(E) NMAC by injecting into the South Hospah Unit #17 after it failed MITs on November 21st, 2013 and January 8th, 2014, and was required to be shut-in. This violation is also considered a Significant Non-Compliance (SNC) violation in accordance with United States Environmental Protection Agency ("USEPA"). A SNC violation requires the OCD to directly notify the USEPA.

20. NMSA 1978, § 74-6-5 states that the Water Quality Control Commission may require a person to obtain from a constituent agency designated by the commission a permit for the discharge of any water contaminant.

21. NMSA 1978, § 74-6-2(K)(4) identifies the oil conservation commission as a constituent agency of the Water Quality Control Commission.

22. The South Hospah Unit #17 was shut in and therefore Operator lacked authority to inject into the South Hospah Unit #17 well. The OCD considers this a discharge of a water contaminant without a permit in violation of NMSA 1978, § 74-6-5.

OPERATOR INFORMATION SUBMITTED SUBSEQUENT TO THE ADMINISTRATIVE CONFERENCE

1. The 16 injection wells identified in Exhibit "A", below, were not in compliance with certain of the OCD's rules when Operator acquired them in 2012. Authorization to assume operations and accrual of Operator's responsibility to correct incidents of non-compliance and prevent future violations commenced when OCD approved the C-145 Change of Operator forms on October 12, 2012.

2. The Operator disputes that it had not complied with ACOI-266-0 and noted that by correspondence dated April 11, 2013 it provided OCD with documentation of compliance.

3. Operator has corrected earlier incidents of non-compliance with OCD Rule 19.15.16.8 NMAC by placing new well signs on the following locations:
   a. Santa Fe Rail Road #23
   b. Hospah Sand Unit #61
   c. Hospah Sand Unit #66
   d. Lone Pine Dakota D Unit #14
   e. Hospah Sand Unit #58
   f. Santa Fe Rail Road #87
   g. Santa Fe Rail Road #97
   h. South Hospah Unit #54

4. Operator had obtained BLM approval of sundry notices for the work on the following wells:
   a. South Hospah Unit #36
   b. South Hospah Unit #39

5. Operator had obtained BLM approval of a sundry notice for the work on the South Hospah Unit #36 on production prior to having OCD's approval of a Notice of Intent.

6. Operator has subsequently corrected the violation of OCD Rule 19.15.7.14(G)(4) NMAC on the South Hospah Unit #36.

7. Operator has subsequently plugged and abandoned the following wells in accordance with the terms agreed upon at the September 3, 2014 administrative conference with the OCD:
   a. Hospah Sand Unit #61, API 30-031-07025, UL E, Sec. 1, Township 17N, Range 9W
   b. Hospah Sand Unit #66, API 30-031-05577, UL A, Sec. 1, Township 17N, Range 9W
   c. Santa Fe Rail Road #23, API 30-031-20150, UL C, Sec. 7, Township 17N, Range 8W
   d. Santa Fe Rail Road #83, API 30-031-20147, UL I, Sec. 1, Township 17N, Range 9W

CONCLUSIONS

1. The OCD has jurisdiction over the parties and subject matter in this proceeding.

2. The OCD and Operator are entering into this agreed compliance order which sets a schedule for Operator to return the wells identified in Exhibit "A" to compliance with OCD rules.

3. Some of the violations existed prior to Dominion assuming responsibility of the wells and some of the violations occurred after Dominion acquired the wells. However, Dominion acquired the wells on October 12, 2012 and as the current

operator Dominion is responsible to ensure compliance with the rules and regulations.

ORDER

1. Pursuant to the Water Quality Act, Section 74-6-10 NMSA 1978, Operator agrees to pay a fine of $10,000 for violation of the Water Quality Act, Section 74-6-5 NMSA 1978 to be paid to the State of New Mexico general fund. This violation is determined to be Significant Non-Compliance by injecting into the South Hospah Unit #017, API No. 30-031-20057, a shut–in well that failed MIT Testing.

2. Operator agrees to plug and abandon four of the following injection wells by October 31, 2014, and the remaining five injection wells by March 1, 2015:

   a. Hospah Sand Unit #61, API 30-031-07025, UL E, Sec. 1, Township 17N, Range 9W
   b. Hospah Sand Unit #66, API 30-031-05577, UL A, Sec. 1, Township 17N, Range 9W
   c. Hospah Sand Unit #100, API 30-031-20831, UL H, Sec. 36, Township 18N, Range 9W
   d. Santa Fe Rail Road #23, API 30-031-20150, UL C, Sec. 7, Township 17N, Range 8W
   e. Santa Fe Rail Road #87, API 30-031-20413, UL P, Sec. 1, Township 17N, Range 9W
   f. Santa Fe Rail Road #97, API 30-031-20855, UL O, Sec. 1, Township 17N, Range 9W
   g. Santa Fe Rail Road #83, API 30-031-20147, UL I, Sec. 1, Township 17N, Range 9W
   h. South Hospah Unit #52, API 30-031-20243, UL C, Sec. 12, Township 17N, Range 9W
   i. South Hospah Unit #60, API 30-031-20411, UL H, Sec. 12, Township 17N, Range 9W

3. Operator will place a well sign on the South Hospah Unit #54 by November 3, 2014.

4. Operator will perform MIT and in the event of an unsuccessful test shall run a liner or otherwise repair the South Hospah Unit #36 with work to be completed on or before by January 31, 2015.

5. Well work will be performed on the South Hospah Unit #17 and South Hospah Unit #39 to run liners, subject to approval of the OCD, to repair the wells and perform MITs by January 15, 2015 or immediately after the rig work at South Hospah 10.

6. MIT's will be performed on the South Hospah Unit #51, Hospah Sand Unit #58 and Lone Pine Dakota D Unit #14 by January 31, 2015.

7. Operator shall file a compliance report identifying each well returned to compliance, stating the date it was returned to compliance, and describing the work performed to return the well to compliance, in addition to any other forms or documentation required by OCD rules for the work performed. The written compliance report must be mailed or e-mailed to the OCD's Enforcement and Compliance Manager and to the OCD attorney in charge of agreed compliance orders so that it is **received within 10 (ten) business days** after each of the above stated deadlines.

8. Operator understands that if it fails to meet the terms of this Order, the OCD may seek additional penalties pursuant to the New Mexico Oil and Gas and Water Quality Acts.

9. Operator shall complete the work on or before those dates referenced in paragraphs 2, 3, 4, 5, and 6 hereof, or as soon as reasonably practicable thereafter if prevented from doing so by the occurrence of force majeure events, including inclement weather, or inaccessibility of locations. Operator will promptly provide OCD with e-mail notification of the occurrence of such events before the respective deadline has expired. OCD may extend the time for completion of the work for good cause shown.

10. By signing this Order, Operator expressly:

    a. acknowledges the correctness of the Findings and Conclusions set forth in this Order;

    b. agrees to pay the fine of $10,000 within 30 (thirty) days of the execution of this order by check, made payable to the State of New Mexico.

    c. agrees to meet the compliance deadlines established in this order;

    d. agrees to submit a compliance report as required in Ordering Paragraph 7;

    e. waives any right, pursuant to the Oil and Gas Act, Water Quality Act, or otherwise, to an appeal from this Order, or to a hearing either prior to or subsequent to the entry of this Order regarding the matters resolved hereby; and

    f. agrees that the Order may be enforced by OCD or Oil Conservation Commission Order, by suit or otherwise to the same extent and with the same effect as a final Order of the OCD or Oil Conservation Commission entered after notice and hearing in accordance with all terms and provisions of the Oil and Gas Act.

11. The OCD reserves the right to file an application for hearing to obtain authority to plug any well identified in Exhibit "A" and forfeit the applicable financial assurance if the well poses an immediate environmental threat.

Done at Santa Fe, New Mexico this 21st day of January, 2015

By: David Catanach
David Catanach
Director, Oil Conservation Division

ACCEPTANCE

Dominion Production Company LLC hereby accepts the foregoing Order, and agrees to all of the terms and provisions set forth in that Order.

Dominion Production Company LLC

By: _____
(Please print name) David Ross
Title: President
Date: 1/12/2015

Exhibit A to Agreed Compliance Order for Dominion Production Company LLC

Dominion Production Company LLC, Injection Wells in McKinley County:

1. Hospah Sand Unit #61, API 30-031-07025, UL E, Sec. 1, Township 17N, Range 9W
2. Hospah Sand Unit #66, API 30-031-05577, UL A, Sec. 1, Township 17N, Range 9W
3. Hospah Sand Unit #100, API 30-031-20831, UL H, Sec. 36, Township 18N, Range 9W
4. Hospah Sand Unit #58, API 30-031-20115, UL O, Sec. 36, Township 18N, Range 9W
5. Santa Fe Rail Road #23, API 30-031-20150, UL C, Sec. 7, Township 17N, Range 8W
6. Santa Fe Rail Road #87, API 30-031-20413, UL P, Sec. 1, Township 17N, Range 9W
7. Santa Fe Rail Road #97, API 30-031-20855, UL O, Sec. 1, Township 17N, Range 9W
8. Santa Fe Rail Road #83, API 30-031-20147, UL I, Sec. 1, Township 17N, Range 9W
9. South Hospah Unit #17, API 30-031-20057, UL G, Sec. 12, Township 17N, Range 9W
10. South Hospah Unit #51, API 30-031-20242, UL E, Sec. 12, Township 17N, Range 9W

11. South Hospah Unit #39, API 30-031-20152, UL H, Sec. 3, Township 17N, Range 9W
12. South Hospah Unit #52, API 30-031-20243, UL C, Sec. 12, Township 17N, Range 9W
13. South Hospah Unit #36, API 30-031-20118, UL B, Sec. 12, Township 17N, Range 9W
14. South Hospah Unit #60, API 30-031-20411, UL H, Sec. 12, Township 17N, Range 9W
15. Lone Pine Dakota D Unit #14, API 30-031-20174, UL H, Sec. 13, Township 17N, Range 9W
16. South Hospah Unit #54, API 30-031-20407, UL A, Sec. 12, Township 17N, Range 9W

Dominion Production Company LLC
By: _____
Title: PRESIDENT

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE APPLICATION OF THE NEW MEXICO OIL CONSERVATION DIVISION ("OCD") COMPLIANCE AND ENFORCEMENT MANAGER FOR A COMPLIANCE ORDER AGAINST DOMINION PRODUCTION COMPANY, LLC

CASE NO. 15379

SETTLEMENT AGREEMENT

NMOCD-ACOI-2016-312

Pursuant to the New Mexico Oil and Gas Act, NMSA 1978, §§ 70-2-1 through 70-2-38, as amended ("Act"), and the rules promulgated in accordance with the Act, the Director of the Oil Conservation Division ("Division" or "OCD"), and Dominion Production Company, LLC, ("Operator" or "Dominion") enter into this Settlement Agreement ("Agreement"). Dominion agrees to comply with the following settlement for the specified violations of the Act and the rules promulgated in accordance with the Act, and in the event of non-compliance, the remedies detailed herein.

I. FINDINGS

1. The Oil Conservation Division is charged with the authority to enforce Act and the rules promulgated in accordance with the Act. NMSA 1978, Section 70-2-6(A).

2. The New Mexico Attorney General is charged with collecting penalties issued pursuant to NMSA 1978, Section 70-2-31.

3. Dominion Production Company, LLC ("Operator") is the operator of record of one hundred sixty-five (165) wells in McKinley County, New Mexico, under OGRID No. 291567.

4. Operator's address of record is: 1414 W. Swann Ave., Suite 100, Tampa FL 33606.

5. The New Mexico Secretary of State has Operator registered under corporation number 4541596. It identifies David Burns and W. Andrew Krusen, Jr. as the officers of record.

6. Operator has one blanket letter of credit filed with the OCD, letter of credit no. 26943-SA, from Frost Bank, for the amount of $50,000.

7. Operator has additionally furnished the OCD with thirty-two (32) single well bonds on file with the OCD from West Texas National Bank for a total amount of $222,317.

Inactive Well and Financial Assurance Violations

8. 19.15.25.8 NMAC requires an operator to plug and abandon or temporarily abandon a well within 90 days after: (1) a 60 day period following the suspension of drilling operations; (2) a determination that a well is no longer usable for beneficial purposes; or (3) a period of one year in which a well has been continuous inactive.

9. 19.15.5.9(A)(4) NMAC states that an operator is compliant with 19.15.5.9 NMAC if it has no more than the following number of wells out of compliance with

19.15.25.8 NMAC that are not subject to an agreed compliance order setting a schedule for bringing the wells into compliance with 19.15.25.8 NMAC and imposing sanctions if the schedule is not met:

(a) two wells or 50 percent of the wells the operator operates, whichever is less, if the operator operates 100 wells or less;

(b) five wells if the operator operates between 101 and 500 wells;

(c) seven wells if the operator operates between 501 and 1000 wells; and

(d) 10 wells if the operator operates more than 1000 wells.

10. Operator currently has eighty-one (81) wells out of a total of one hundred sixty-five (165) wells out of compliance with 19.15.25.8 NMAC, exceeding the amount allowed under 19.15.5.9(A)(4) NMAC. See *Exhibit 1: Inactive Well List.*

11. 19.15.8.9(C) NMAC requires that an operator to cover a well that has been in temporary abandonment status for more than two years with a one-well financial assurance or a blanket plugging financial assurance for wells in temporary abandoned status.

12. Operator currently has forty-four (44) wells that require additional bonding, in violation of 19.15.8.9 NMAC. See *Exhibit 2: Inactive Well Additional Financial Assurance Report.*

13. Seventy-nine (79) of the wells identified in Exhibits 1 and 2 were not in compliance with certain of the OCD's rules when Operator acquired them in 2012. Authorization to assume operations and accrual of Operator's responsibility to correct incidents of non-compliance and prevent future violations commenced when OCD approved the C-145 Change of Operator forms on October 12, 2012.

Violations of Agreed Compliance Order 285

14. On January 21, 2015, Operator entered into Agreed Compliance Order ("ACO") 285 to resolve outstanding compliance issues regarding Dominion's injection wells.

15. ACO 285 was limited in scope to resolve violations regarding Dominion's injection wells as part of a stepped approach for Dominion to work with the OCD in order to return to overall compliance with OCD rules.

16. ACO 285 Order paragraph 2, required Operator to plug and abandon nine (9) wells by March 1, 2015.

17. Operator failed to comply with ACO 285 Order paragraph 2 by only plugging four (4) of the nine (9) wells. The following five (5) require plugging as agreed to:

(a) Hospah Sand Unit No. 100, API No. 30-31-20831

(b) Santa Fe Rail Road A No. 87, API No. 30-31-20413

(c) Santa Fe Rail Road A No. 97, API No. 30-31-20855

(d) South Hospah Unit No. 52, API No. 30-31-20243

(e) South Hospah Unit No. 60, API No. 30-31-20411

18. ACO 285 Order paragraph 5 required Operator perform remedial work and mechanical integrity tests ("MITs") on two (2) wells by January 15, 2015.

19. Dominion failed to comply with Order paragraph 5 by completing the required work on one (1) well. Dominion did not repair the well so it could pass an MIT and therefore could not install a new liner subject to the OCD's approval in the South

Hospah Unit No. 39, API No. 30-31-20152, by January 15, 2015, as required by ACO 285 Order paragraph 5.

20. 19.15.26.11(A) NMAC requires an MIT to be performed at least once every five (5) years after injection is commenced on an injection well.

21. ACO 285 Order paragraph 6 required MITs to be performed on the following wells, which were in violation of the testing requirement in 19.15.26.11 NMAC by January 31, 2015:

(a) South Hospah Unit No. 51, API No. 30-31-20242

(b) Hospah Sand Unit No. 58, API No. 30-31-20115

(c) Lone Pine Dakota D Unit No. 14, API No. 30-31-20174

22. Dominion has not fulfilled its obligation as required by ACO 285 Order paragraph 6.

Additional MIT Violations

23. The Santa Fe RR B No. 39, API No. 30-31-20749, which was not included in ACO 285, is in violation of 19.15.26.11 NMAC, requiring an MIT to be performed every 5 years. The Santa Fe RR B No. 39 last had an MIT performed on July 30, 2010.

II. CONCLUSIONS

1. The OCD has jurisdiction over the parties and subject matter in this proceeding.

2. Dominion is a person as defined by NMSA 1978, § 70-2-33(A) that may be subject to civil penalties under NMSA 1978, § 70-2-31(A).

3. Dominion disputes that it caused certain of the instances of non-compliance referenced above, but does not dispute it is responsible for correcting the matters of non-compliance and wishes to settle this matter with the OCD.

III. SETTLEMENT AGREEMENT

WHEREFORE, the parties agree to the following:

1. Compliance Schedule

   a. Dominion will continue to file Monthly Production Reports as required by 19.15.7.24 NMAC. If no production occurs, Dominion must still report zero production to the OCD;

   b. Dominion will obtain acceptable blanket plugging financial assurance for wells in temporarily abandoned status as permitted by 19.15.8.9 Subsections (C) and (D)(5) in the amount of $1,000,000 by October 31, 2016

   c. Dominion will plug and abandon the following wells pursuant to 19.15.25.10 NMAC by December 31, 2016:

      i. Hospah Sand Unit No. 100, API No. 30-31-20831

      ii. Santa Fe Rail Road A No. 87, API No. 30-31-20413

      iii. Santa Fe Rail Road A No. 97, API No. 30-31-20855

      iv. South Hospah Unit No. 52, API No. 30-31-20243

      v. South Hospah Unit No. 60, API No. 30-31-20411

   d. Dominion will perform MITs pursuant to 19.15.26.11 NMAC on following wells by December 31, 2016:

      i. South Hospah Unit No. 51, API No. 30-31-20242

ii. Hospah Sand Unit No. 58, API No. 30-31-20115

iii. Lone Pine Dakota D Unit No. 14, API No. 30-31-20174

iv. Santa Fe RR B No. 39, API No. 30-31-20749

e. If any well(s) listed in Paragraph III.1.d hereof fails the MIT(s), Dominion will give written notice to the OCD within five (5) calendar days of the failed test and proceed within thirty (30) days to eliminate the cause of failure. If a well cannot be repaired, Dominion will file a sundry notice within sixty (60) days of the failed MIT to perform the plugging procedure, and commence work pursuant to 19.15.25.10 NMAC no later than ninety (90) days after Dominion files the sundry notice, or other such later date as may be agreed between the parties for good cause shown.;

f. Dominion will install a new liner or cement squeeze subject to OCD's approval, to repair the well, and perform an MIT, in the South Hospah Unit No. 39, API No. 30-31-20152, by December 31, 2016. If the well cannot be repaired, Dominion will plug the well by March 31st, 2017;

g. Production by swabbing, oil hound, or other alternative to traditional means of oil recovery will be allowed on Dominion's wells as identified in *Exhibit 1*, so long as:

i. Dominion performs production activities at a rate of four (4) wells per week;

ii. Each well will have attempted production every eighteen (18) weeks; or

iii. If Dominion is unable to restore a well to production after two (2) consecutive monthly attempts to produce or it determines that the well is no longer capable of producing due to inadequate or failed casing or for other reasons, Dominion will plug the well within six (6) months.

h. Unless the OCD grants an extension in writing prior to the expiration of the deadline; should Dominion miss any deadlines identified in paragraphs III.1.c-g above, the OCD may plug and abandon the well for which the deadline was missed and recoup the associated costs from Dominion's financial assurance;

i. The OCD will notify Dominion and Dominion's surety pursuant to 19.15.8.13 NMAC if OCD intends to plug and abandon a well that has missed its plugging date as established by this Agreement. Dominion expressly waives its right to oppose any application of the Division for an order authorizing the Division to plug a well that has not been plugged pursuant to this Agreement;

j. Once any portion of Dominion's financial assurance is used to fulfill a term of this Agreement, the OCD will review Dominion's financial assurance and, if found inadequate, Dominion will be out of compliance with 19.15.5.9 and 19.15.8.9 NMAC and will be subject to additional compliance actions. Dominion does not waive its right to notice and hearing for adjudication regarding additional compliance actions except as expressly waived herein;

k. OCD will not withhold approval of reasonable extensions, for good cause shown, provided Dominion requests extensions prior to the expiration of the deadlines, and remains in compliance with the other terms of the Agreement, the Act, and the rules promulgated in accordance with the Act;

l. Dominion shall bear the costs to comply with the terms of this Agreement;

m. OCD will dismiss, pursuant to this Agreement, the claims in OCD Case No. 15379 for violating 19.15.5.9, 19.15.8.9, 19.15.25.8 NMAC, and the terms of ACO 285 so long as Dominion complies with this Agreement. OCD agrees that Order No. R-14132 shall be vacated. Dominion will withdraw its Application for Hearing De Novo

n. For purposes of determining compliance with 19.15.5.9(A) NMAC, this Agreement will also serve as an Agreed Compliance Order covering the wells identified in *Exhibits 1* and *2* so long as Dominion remains in compliance with the terms of this Agreement, the Act, and the rules promulgated in accordance with the Act.

2. Civil Penalties

a. Should Dominion fail to place acceptable financial assurance on file with the OCD as provided by Paragraph III.1.b, Dominion shall pay a civil penalty of $1,000 per day until compliance is achieved, unless the OCD grants an extension in writing prior to the expiration of the deadline. OCD will not withhold approval of reasonable extensions

for good cause shown, provided Dominion requests extensions prior to the expiration of the deadlines, and remains in compliance with the other terms of the Agreement, the Act, and the rules promulgated in accordance with the Act. For purposes of this Section, lack of financial resources does not constitute good cause;

b. Dominion shall pay any civil penalty in Paragraph III.2.a. within 45 days of Dominion receiving a demand from the OCD. OCD shall make demand to Dominion for penalties to the following address:

1414 W. Swann Ave.
Suite 100
Tampa, FL 33606

c. Payment shall be made to the State of New Mexico General Fund by certified or corporate check and sent to the following address:

Director, Oil Conservation Division
New Mexico Energy, Minerals & Natural Resources Department
1220 South St. Francis Drive Santa Fe, NM 87505
Re: Dominion Production Co., ACOI-2016-312

IV. OTHER TERMS AND CONDITIONS

1. By signing this Agreement, Dominion expressly:

a. acknowledges the authority of the Director to render the above Findings, Conclusions, and Agreement;

b. agrees to comply with the Agreement;

c. as to the Agreement, waives any right, pursuant to the Act or otherwise, to a hearing either prior or subsequent to the entry of this Agreement or to an appeal from this Agreement; and

d. agrees that if it fails to comply with this Agreement, OCD may enforce the Agreement by suit or otherwise to the same extent and with the same effect as a final OCD Order entered after notice and hearing or civil suit in accordance with all terms and provisions of the Oil and Gas Act.

2. Nothing in this Agreement relieves Dominion of its liability should its operations create waste and/or pose additional threats to the environment or correlative rights, or commits other violations of the Act or rules promulgated in accordance with the Act.

3. Should Dominion's financial assurance prove insufficient to cover the costs associated with plugging and abandoning the wells subject to this Agreement, the OCD reserves its rights under the Oil and Gas Act for indemnification and costs pursuant to NMSA 1978, § 70-2-14.

4. Dominion and the OCD have the right to modify or terminate this Agreement by written instrument signed by both parties. Once Dominion complies with all the terms of this Agreement, this Agreement will terminate.

Done at Santa Fe, New Mexico this 8th day of September, 2016.

By: David Catanach

David Catanach
Director, Oil Conservation Division

ACCEPTANCE

DOMINION OPERATING, LLC (OGRID No. 291567), operator of record of the wells identified in *Exhibits 1 and 2*, hereby accepts the foregoing Agreement, and agrees to all of the terms and provisions as set forth in the Agreement.

DOMINION OPERATING, LLC By: _____

Print Name: DAVID RUAS

Title: PRESIDENT

Date: 8/24/2016

NEW MEXICO SPECIAL ASSISTANT ATTORNEY GENERAL, representing the Oil Conservation Division of the Energy, Minerals and Natural Resources Department, hereby accepts the foregoing Agreement, and agrees to all of the terms and provisions as set forth in the Agreement, and retains jurisdiction to enforce this Agreement should the provisions not be complied with.

NEW MEXICO SPECIAL ASSISTANT ATTORNEY GENERAL By: _____

Print Name: Keith Herrmann

Title: Special Assistant Attorney General

Date: 9/9/2016

Exhibit 1: Inactive Well List

EXHIBIT 26

Inactive Well List

Total Well Count: 165 Inactive Well Count: 88
Printed On: Wednesday, September 07 2016

District	API	Well	ULSTR	OCD Unit	OGRID	Operator	Lease Type	Well Type	Last Production	Formation/Notes	Status	TA Exp Date
3	30-031-20338	HOSPAH SAND UNIT #001Y	2-01-17N-09W	A	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	07/2009	HOSPAH UPPER SAND		
3	30-031-05185	HOSPAH SAND UNIT #002	L-01-17N-09W	L	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	12/2012			
3	30-031-20339	HOSPAH SAND UNIT #004Y	4-01-17N-09W	C	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	01/2015			
3	30-031-05158	HOSPAH SAND UNIT #005	4-01-17N-09W	C	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	07/2013	RTP 10-15-11		
3	30-031-05176	HOSPAH SAND UNIT #009	J-01-17N-09W	J	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	01/2010			
3	30-031-20340	HOSPAH SAND UNIT #011Y	F-01-17N-09W	F	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	01/2015			
3	30-031-05189	HOSPAH SAND UNIT #012	3-01-17N-09W	B	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	02/2010	HOSPAH UPPER SAND		
3	30-031-05207	HOSPAH SAND UNIT #015	N-36-18N-09W	N	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	08/2011			
3	30-031-05211	HOSPAH SAND UNIT #016	N-36-18N-09W	N	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	02/2010			
3	30-031-05213	HOSPAH SAND UNIT #017	N-36-18N-09W	N	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	08/2011			
3	30-031-05203	HOSPAH SAND UNIT #019	O-36-18N-09W	O	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	08/2011	HOSPAH UPPER SAND		
3	30-031-05195	HOSPAH SAND UNIT #022	2-01-17N-09W	A	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	12/2009	HOSPAH UPPER SAND		
3	30-031-05192	HOSPAH SAND UNIT #023	5-01-17N-09W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	HOSPAH UPPER SAND		
3	30-031-05186	HOSPAH SAND UNIT #024	G-01-17N-09W	G	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011			
3	30-031-05214	HOSPAH SAND UNIT #027	P-36-18N-09W	P	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	08/2011	HOSPAH UPPER SAND		
3	30-031-05225	HOSPAH SAND UNIT #029	G-36-18N-09W	G	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	08/2011	HOSPAH UPPER SAND		
3	30-031-05224	HOSPAH SAND UNIT #032	I-36-18N-09W	I	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	08/2011	HOSPAH UPPER SAND		
3	30-031-05223	HOSPAH SAND UNIT #034	J-36-18N-09W	J	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	08/2011			
3	30-031-05222	HOSPAH SAND UNIT #035	K-36-18N-09W	K	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	08/2011	HOSPAH UPPER SAND		
3	30-031-05217	HOSPAH SAND UNIT #036	J-36-18N-09W	J	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	07/2012			
3	30-031-05219	HOSPAH SAND UNIT #037	I-36-18N-09W	I	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	07/2009	HOSPAH UPPER SAND		
3	30-031-05171	HOSPAH SAND UNIT #039	K-01-17N-09W	K	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	07/2004	HOSPAH UPPER SAND		
3	30-031-20269	HOSPAH SAND UNIT #048Y	O-36-18N-09W	O	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	01/2015			
3	30-031-05201	HOSPAH SAND UNIT #050	P-36-18N-09W	P	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	02/2012			
3	30-031-05194	HOSPAH SAND UNIT #051	3-01-17N-09W	B	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	11/2004			
3	30-031-05182	HOSPAH SAND UNIT #052	G-01-17N-09W	G	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	01/2014	RTP 11-14-11		

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3	30-031-60022	HOSPAH SAND UNIT #053	O-35-18N-09W	O	291567	DOMINION PRODUCTION COMPANY, LLC	S	O	04/2015			
3	30-031-05220	HOSPAH SAND UNIT #054	3-31-18N-08W	L	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	12/2012	HOSPAH UPPER SAND		
3	30-031-05594	HOSPAH SAND UNIT #055	G-01-17N-09W	G	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	02/2012	HOSPAH UPPER SAND/ RET TO PROD 7-12-10		
3	30-031-20115	HOSPAH SAND UNIT #058	O-36-18N-09W	O	291567	DOMINION PRODUCTION COMPANY, LLC	P	I	12/2005			
3	30-031-20116	HOSPAH SAND UNIT #059	J-36-18N-09W	J	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	05/2015	HOSPAH UPPER SAND		
3	30-031-05193	HOSPAH SAND UNIT #089	3-01-17N-09W	B	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	09/2013			
3	30-031-20608	HOSPAH SAND UNIT #095	3-01-17N-09W	B	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	HOSPAH UPR SND		
3	30-031-20717	HOSPAH SAND UNIT #096	K-36-18N-09W	K	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	07/2012			
3	30-031-20831	HOSPAH SAND UNIT #100	H-36-18N-09W	H	291567	DOMINION PRODUCTION COMPANY, LLC	S	I	11/2009	INT TO P&A/OCD 3-11-14		
3	30-031-20183	LONE PINE DAKOTA D UNIT #012	B-13-17N-09W	B	291567	DOMINION PRODUCTION COMPANY, LLC	P	G	12/1992	LONE PINE DAK D		
3	30-031-20174	LONE PINE DAKOTA D UNIT #014	3-13-17N-09W	H	291567	DOMINION PRODUCTION COMPANY, LLC	P	I	12/1992		T	7/23/2007
3	30-031-20201	LONE PINE DAKOTA D UNIT #023	K-13-17N-09W	K	291567	DOMINION PRODUCTION COMPANY, LLC	P	G	06/2005	LONE PINE DAK D		
3	30-031-20086	SANTA FE #016	C-07-17N-08W	C	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011			
3	30-031-20102	SANTA FE #017	F-07-17N-08W	F	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	HOSPAH DAKOTA		
3	30-031-20341	SANTA FE #029	B-07-17N-08W	B	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	HOSPAH DAKOTA		
3	30-031-20165	SANTA FE PACIFIC RAILROAD #002	L-13-17N-09W	L	291567	DOMINION PRODUCTION COMPANY, LLC	P	G	06/2009	LONE PINE DAKOTA A	T	7/28/2007
3	30-031-20181	SANTA FE PACIFIC RAILROAD #008	D-24-17N-09W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	G	12/2010	LONE PINE DAKOTA A	T	7/26/2007
3	30-031-20182	SANTA FE PACIFIC RAILROAD #009	F-13-17N-09W	F	291567	DOMINION PRODUCTION COMPANY, LLC	P	G	06/2005			
3	30-031-05147	SANTA FE RAILROAD #003	1-07-17N-08W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	04/2015	S HOSPAH LOWER SAND/ RTP 11-10-11		
3	30-031-05151	SANTA FE RAILROAD #004	C-07-17N-08W	C	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	04/2015	S LOWER HOSPAH SAND/ RTP 11-18-11		
3	30-031-05531	SANTA FE RAILROAD #009	F-07-17N-08W	F	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	S HOSPAH UPPER SAND		
3	30-031-20032	SANTA FE RAILROAD #012	1-07-17N-08W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	04/2015	S HOSPAH LOWER SAND/ RTP 11-10-11		
3	30-031-20038	SANTA FE RAILROAD #013	1-07-17N-08W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	S HOSPAH LOWER SAND		
3	30-031-20037	SANTA FE RAILROAD #014	1-07-17N-08W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	S HOSPAH LOWER SAND		
3	30-031-20036	SANTA FE RAILROAD #015	2-07-17N-08W	E	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	S HOSPAH LOWER SAND		
3	30-031-20138	SANTA FE RAILROAD #018	1-07-17N-08W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	S HOSPAH UPPER SAND		
3	30-031-20139	SANTA FE RAILROAD #019	2-07-17N-08W	E	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	07/2014	S HOSPAH UPPER SAND		
3	30-031-20140	SANTA FE RAILROAD #020	F-07-17N-08W	F	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	04/2015	S HOSPAH LOWER SAND		
3	30-031-20452	SANTA FE RAILROAD #039	1-07-17N-08W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	04/2015	S HOSPAH LOWER SAND		
3	30-031-20451	SANTA FE RAILROAD #040	2-07-17N-08W	E	291567	DOMINION PRODUCTION	P	O	08/2012	S HOSPAH LOWER SAND/RTP 11-18-11		

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						COMPANY, LLC							
3	30-031-20594	SANTA FE RAILROAD #041	1-07-17N-08W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	S HOSPAH LOWER SAND		
3	30-031-20804	SANTA FE RAILROAD #045	F-07-17N-08W	F	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	12/2014	S HOSPAH LOWER SAND		
3	30-031-20836	SANTA FE RAILROAD #047	1-07-17N-08W	D	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	S HOSPAH LOWER SAND		
3	30-031-20837	SANTA FE RAILROAD #048	2-07-17N-08W	E	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	S HOSPAH LOWER SAND		
3	30-031-20854	SANTA FE RAILROAD #050	2-07-17N-08W	E	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2011	S HOSPAH LOWER SAND		
3	30-031-20019	SANTA FE RAILROAD A #073	O-01-17N-09W	O	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	09/2013			
3	30-031-20021	SANTA FE RAILROAD A #074	9-01-17N-09W	I	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	07/2009			
3	30-031-20072	SANTA FE RAILROAD A #075	10-01-17N-09W	P	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	12/2013			
3	30-031-20100	SANTA FE RAILROAD A #077	11-01-17N-09W	P	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	05/2015	S HOSPAH UPPER SAND		
3	30-031-20134	SANTA FE RAILROAD A #081	O-01-17N-09W	O	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	05/2015			
3	30-031-20372	SANTA FE RAILROAD A #084	O-01-17N-09W	O	291567	DOMINION PRODUCTION COMPANY, LLC	P	I	05/2014	S HOSPAH LOWER SAND		
3	30-031-20413	SANTA FE RAILROAD A #087	10-01-17N-09W	P	291567	DOMINION PRODUCTION COMPANY, LLC	P	I	03/2005	NOI TO P&A/OCD 09-19-15		
3	30-031-20442	SANTA FE RAILROAD A #089	O-01-17N-09W	O	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	11/2013			
3	30-031-20441	SANTA FE RAILROAD A #090	10-01-17N-09W	P	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	05/2012	RTP 11-18-11		
3	30-031-20722	SANTA FE RAILROAD A #094	11-01-17N-09W	P	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	05/2015			
3	30-031-20855	SANTA FE RAILROAD A #097	O-01-17N-09W	O	291567	DOMINION PRODUCTION COMPANY, LLC	P	I	03/2005	NOI TO P&A/OCO 6-19-15		
3	30-031-20303	SANTA FE RR B #032	M-05-17N-08W	M	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	04/1980		T	3/25/2007
3	30-031-20369	SANTA FE RR B #033	L-05-17N-08W	L	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	12/2010	HOSPAH UPPER SAND, SOUTH	T	3/26/2008
3	30-031-20390	SANTA FE RR B #034	M-05-17N-08W	M	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	06/2009	S HOSPAH UPR SAND		
3	30-031-20391	SANTA FE RR B #035	E-05-17N-08W	E	291567	DOMINION PRODUCTION COMPANY, LLC	P	I	03/2014	RET TO INJ 11-4-11		
3	30-031-20416	SANTA FE RR B #036	L-05-17N-08W	L	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	12/2010	SOUTH HOSPAH UPPER SAND	T	3/25/2008
3	30-031-20415	SANTA FE RR B #037	M-05-17N-08W	M	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	12/2010	HOSPAH UPPER SAND, SOUTH	T	3/26/2008
3	30-031-20749	SANTA FE RR B #039	M-05-17N-08W	M	291567	DOMINION PRODUCTION COMPANY, LLC	P	I	02/2012	S HOSPAH SAND/NEED MIT BEFORE TA		
3	30-031-05145	SOUTH HOSPAH UNIT #004	C-12-17N-09W	C	291567	DOMINION PRODUCTION COMPANY, LLC	F	O	08/2014	RET TO PROD 7-12-10		
3	30-031-05146	SOUTH HOSPAH UNIT #005	B-12-17N-09W	B	291567	DOMINION PRODUCTION COMPANY, LLC	F	O	05/2005	S HOSPAH UPPER SND/RTP FR INJ 2013		
3	30-031-20094	SOUTH HOSPAH UNIT #027	4-12-17N-09W	H	291567	DOMINION PRODUCTION COMPANY, LLC	F	O	08/2014	S HOSPAH UPR SND		
3	30-031-20118	SOUTH HOSPAH UNIT #038	B-12-17N-09W	B	291567	DOMINION PRODUCTION COMPANY, LLC	F	I	10/2005	S HOSPAH LOWER SAND		
3	30-031-20152	SOUTH HOSPAH UNIT #039	3-12-17N-09W	H	291567	DOMINION PRODUCTION COMPANY, LLC	F	I	10/2005	S HOSPAH LOWER SAND		
3	30-031-20242	SOUTH HOSPAH UNIT #051	E-12-17N-09W	E	291567	DOMINION PRODUCTION COMPANY, LLC	F	I	11/2011	S HOSPAH UPPER SND		

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3	30-031-20243	SOUTH HOSPAH UNIT #052	C-12-17N-09W	C	291567	DOMINION PRODUCTION COMPANY, LLC	F	I	05/2005	NOI TO P&A/BLM 6-9-15
3	30-031-20411	SOUTH HOSPAH UNIT #060	3-12-17N-09W	H	291567	DOMINION PRODUCTION COMPANY, LLC	F	I	10/2005	NOI TO P&A/BLM 6-9-15
3	30-031-20129	WHIGHAM #003	H-11-17N-09W	H	291567	DOMINION PRODUCTION COMPANY, LLC	P	O	08/2013	HOSPAH DK

WHERE Ogrid:291567, County:All, District:All, Township:All, Range:All, Section:All, Production(months):15, Excludes Wells Under ACOI, Excludes Wells in Approved TA Period

Exhibit 2: Inactive Well Additional Financial Assurance Report

EXHIBIT 26

Inactive Well Additional Financial Assurance Report

291567 DOMINION PRODUCTION COMPANY, LLC
Total Well Count: 165
Printed On: Wednesday, June 29 2016

Property	Well Name	Lease Type	ULSTR	OCD Unit Letter	API	Well Type	Last Prodctn	Inactive Additional Bond Due	Measured Depth	Required Bond Amount	Bond Required Now	Covered By Blanket TA Bond	Bond In Place	In Violation
311752	HANSON #026	N	D-08-17N-08W	D	30-031-20419	O	10/2015		1654				0	
311753	HOSPAH SAND UNIT #001Y	P	2-01-17N-09W	A	30-031-20338	O	07/2009	08/01/2011	1613	6613	Y		6613	
	HOSPAH SAND UNIT #002	P	L-01-17N-09W	L	30-031-05185	O	12/2012	01/01/2015	3282	8282	Y		8282	
	HOSPAH SAND UNIT #003	S	N-36-18N-09W	N	30-031-05205	O	12/2015	01/01/2018	1631	6631			6631	
	HOSPAH SAND UNIT #004Y	P	4-01-17N-09W	C	30-031-20339	O	01/2015	02/01/2017	1581	6581			0	
	HOSPAH SAND UNIT #005	P	C-01-17N-09W	C	30-031-05158	O	07/2013	08/01/2015	1675	6675	Y		0	Y
	HOSPAH SAND UNIT #006	P	4-01-17N-09W	C	30-031-05190	O	12/2015	01/01/2018	1590	6590			0	
	HOSPAH SAND UNIT #007	S	N-36-18N-09W	N	30-031-05204	O	12/2015	01/01/2018	1615	6615			0	
	HOSPAH SAND UNIT #009	P	J-01-17N-09W	J	30-031-05176	O	01/2010	02/01/2012	1570	6570	Y		6570	
	HOSPAH SAND UNIT #010	S	N-36-18N-09W	N	30-031-05208	O	08/2015	09/01/2017	1665	6665			0	
	HOSPAH SAND UNIT #011Y	P	F-01-17N-09W	F	30-031-20340	O	01/2015	02/01/2017	1563	6563			0	
	HOSPAH SAND UNIT #012	P	3-01-17N-09W	B	30-031-05189	O	02/2010	03/01/2012	1610	6610	Y		6610	
	HOSPAH SAND UNIT #013	P	F-01-17N-09W	F	30-031-05178	O	12/2015	01/01/2018	1561	6561			0	
	HOSPAH SAND UNIT #015	S	N-36-18N-09W	N	30-031-05207	O	08/2011	09/01/2013	1677	6677	Y		0	Y
	HOSPAH SAND UNIT #016	S	N-36-18N-09W	N	30-031-05211	O	02/2010	03/01/2012	1663	6663	Y		6663	
	HOSPAH SAND UNIT #017	S	N-36-18N-09W	N	30-031-05213	O	08/2011	09/01/2013	1689	6689	Y		0	Y
	HOSPAH SAND UNIT #019	S	O-36-18N-09W	O	30-031-05203	O	08/2011	09/01/2013	1600	6600	Y		0	Y
	HOSPAH SAND UNIT #020	P	3-01-17N-09W	B	30-031-05196	O	12/2015	01/01/2018	1587	6587			0	
	HOSPAH SAND UNIT #021	P	F-01-17N-09W	F	30-031-05184	O	12/2015	01/01/2018	1570	6570			0	
	HOSPAH SAND UNIT #022	P	2-01-17N-09W	A	30-031-05195	O	12/2009	01/01/2012	1596	6596	Y		6596	
	HOSPAH SAND UNIT #023	P	5-01-17N-09W	D	30-031-05192	O	08/2011	09/01/2013	1570	6570	Y		0	Y
	HOSPAH SAND UNIT #024	P	G-01-17N-09W	G	30-031-05186	O	08/2011	09/01/2013	1552	6552	Y		0	Y
	HOSPAH SAND UNIT #025	S	O-36-18N-09W	O	30-031-05212	O	12/2015	01/01/2018	1646	6646			0	
	HOSPAH SAND UNIT #027	S	P-36-18N-09W	P	30-031-05214	O	08/2011	09/01/2013	1630	6630	Y		0	Y
	HOSPAH SAND UNIT #028	S	J-36-18N-09W	J	30-031-05216	O	12/2015	01/01/2018	1733	6733			0	
	HOSPAH SAND UNIT #029	S	G-36-18N-09W	G	30-031-05225	O	08/2011	09/01/2013	1792	6792	Y		0	Y
	HOSPAH SAND UNIT #032	S	I-36-18N-09W	I	30-031-05224	O	08/2011	09/01/2013	1783	6783	Y		0	Y
	HOSPAH SAND UNIT #034	S	J-36-18N-09W	J	30-031-05223	O	08/2011	09/01/2013	1769	6769	Y		0	Y
	HOSPAH SAND UNIT #035	S	K-36-18N-09W	K	30-031-05222	O	08/2011	09/01/2013	1724	6724	Y		0	Y
	HOSPAH SAND UNIT #036	S	J-36-18N-09W	J	30-031-05217	O	07/2012	08/01/2014	1704	6704	Y		0	Y
	HOSPAH SAND UNIT #037	S	I-36-18N-09W	I	30-031-05219	O	07/2009	08/01/2011	1730	6730	Y		6730	
	HOSPAH SAND UNIT #038	P	F-01-17N-09W	F	30-031-05179	O	12/2015	01/01/2018	1665	6665			0	
	HOSPAH SAND UNIT #039	P	K-01-17N-09W	K	30-031-05171	O	07/2004	08/01/2006	1557	6557	Y		6557	
	HOSPAH SAND UNIT #048Y	S	O-36-18N-09W	O	30-031-20269	O	01/2015	02/01/2017	1625	6625			0	
	HOSPAH SAND UNIT #050	S	P-36-18N-09W	P	30-031-05201	O	02/2012	03/01/2014	1614	6614	Y		0	Y
	HOSPAH SAND UNIT #051	P	3-01-17N-09W	B	30-031-05194	O	11/2004	12/01/2006	1550	6550	Y		6550	
	HOSPAH SAND UNIT #052	P	G-01-17N-09W	G	30-031-05182	O	01/2014	02/01/2016	1529	6529	Y		0	Y
	HOSPAH SAND UNIT #053	S	O-36-18N-09W	O	30-031-60022	O	04/2015	05/01/2017	3105	8105			0	
	HOSPAH SAND UNIT #054	P	3-31-18N-08W	L	30-031-05220	O	12/2012	01/01/2015	1720	6720	Y		0	Y
	HOSPAH SAND UNIT #055	P	G-01-17N-09W	G	30-031-05594	O	02/2012	03/01/2014	455	5455	Y		0	Y
	HOSPAH SAND UNIT #056	P	G-01-17N-09W	G	30-031-20104	O	12/2015	01/01/2018	2730	7730			0	
	HOSPAH SAND UNIT #058	P	O-36-18N-09W	O	30-031-20115	I	12/2005	01/01/2008	1631	6631	Y		6631	
	HOSPAH SAND UNIT #059	P	J-36-18N-09W	J	30-031-20116	O	05/2015	06/01/2017	1744	6744			6744	
	HOSPAH SAND UNIT #060	P	L-01-17N-09W	L	30-031-07024	I	12/2015	01/01/2018	1640	6640			0	
	HOSPAH SAND UNIT #085	P	G-01-17N-09W	G	30-031-20371	O	12/2015	01/01/2018	1580	6580			0	
	HOSPAH SAND UNIT #088	P	O-36-18N-09W	O	30-031-20596	O	12/2015	01/01/2018	1720	6720			0	
	HOSPAH SAND UNIT #089	P	3-01-17N-09W	B	30-031-05193	O	09/2013	10/01/2015	7850	12850	Y		0	Y
	HOSPAH SAND UNIT #094	P	K-01-17N-09W	K	30-031-20609	I	06/2015	07/01/2017	1635	6635			0	
	HOSPAH SAND UNIT #095	P	3-01-17N-09W	B	30-031-20608	O	08/2011	09/01/2013	1650	6650	Y		0	Y
	HOSPAH SAND UNIT #096	P	K-36-18N-09W	K	30-031-20717	O	07/2012	08/01/2014	1790	6790	Y		0	Y
	HOSPAH SAND UNIT #098	P	2-01-17N-09W	A	30-031-20798	O	12/2015	01/01/2018	1602	6602			0	
	HOSPAH SAND UNIT #100	S	H-36-18N-09W	H	30-031-20831	I	11/2009	12/01/2011	1835	6835	Y		6835	
	HOSPAH SAND UNIT #102	S	I-36-18N-09W	I	30-031-20833	O	12/2015	01/01/2018	1695	6695			0	
	HOSPAH SAND UNIT #105	P	N-36-18N-09W	N	30-031-20944	O	12/2015	01/01/2018	1701	6701			0	
311754	LONE PINE DAKOTA D UNIT #012	P	B-13-17N-09W	B	30-031-20183	G	12/1992	01/01/1995	3926	8926	Y		8926	
	LONE PINE DAKOTA D UNIT #014	P	3-13-17N-09W	H	30-031-20174	I	12/1992	01/01/1995	2793	7793	Y		7793	

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	LONE PINE DAKOTA D UNIT #023	P	K-13-17N-09W	K	30-031-20201	G	06/2005	07/01/2007	2775	7775	Y	7775		
311755	SANTA FE #016	P	C-07-17N-06W	C	30-031-20086	O	08/2011	09/01/2013	2708	7708	Y	0	Y	
	SANTA FE #017	P	F-07-17N-06W	F	30-031-20102	O	08/2011	09/01/2013	2794	7794	Y	0	Y	
	SANTA FE #029	P	B-07-17N-06W	B	30-031-20341	O	08/2011	09/01/2013	2705	7705	Y	0	Y	
311756	SANTA FE PACIFIC RAILROAD #002	P	L-13-17N-09W	L	30-031-20165	G	06/2009	07/01/2011	2811	7811	Y	7811		
	SANTA FE PACIFIC RAILROAD #008	P	D-24-17N-09W	D	30-031-20181	G	12/2010	01/01/2013	2930	7930	Y	0	Y	
	SANTA FE PACIFIC RAILROAD #009	P	F-13-17N-09W	F	30-031-20182	G	06/2005	07/01/2007	2810	7810	Y	7810		
311757	SANTA FE RAILROAD #003	P	1-07-17N-08W	D	30-031-05147	O	04/2015	05/01/2017	1584	6584		0		
	SANTA FE RAILROAD #004	P	C-07-17N-08W	C	30-031-05151	O	04/2015	05/01/2017	1567	6567		0		
	SANTA FE RAILROAD #007	P	2-07-17N-08W	E	30-031-05141	O	12/2015	01/01/2018	1614	6614		0		
	SANTA FE RAILROAD #008	P	3-07-17N-08W	L	30-031-05496	O	12/2015	01/01/2018	1665	6665		0		
	SANTA FE RAILROAD #009	P	F-07-17N-08W	F	30-031-05531	O	08/2011	09/01/2013	1670	6670	Y	0	Y	
	SANTA FE RAILROAD #012	P	1-07-17N-08W	D	30-031-20032	O	04/2015	05/01/2017	1585	6585		0		
	SANTA FE RAILROAD #013	P	1-07-17N-08W	D	30-031-20038	O	08/2011	09/01/2013	1606	6606	Y	0	Y	
	SANTA FE RAILROAD #014	P	1-07-17N-08W	D	30-031-20037	O	08/2011	09/01/2013	1576	6576	Y	0	Y	
	SANTA FE RAILROAD #015	P	2-07-17N-08W	E	30-031-20036	O	08/2011	09/01/2013	1642	6642	Y	0	Y	
	SANTA FE RAILROAD #018	P	1-07-17N-08W	D	30-031-20138	O	08/2011	09/01/2013	1551	6551	Y	0	Y	
	SANTA FE RAILROAD #019	P	2-07-17N-08W	E	30-031-20139	O	07/2014	08/01/2016	1622	6622		0		
	SANTA FE RAILROAD #020	P	F-07-17N-08W	F	30-031-20140	O	04/2015	05/01/2017	1655	6655		0		
	SANTA FE RAILROAD #021	P	C-07-17N-08W	C	30-031-20141	O	12/2015	01/01/2018	1609	6609		0		
	SANTA FE RAILROAD #039	P	1-07-17N-08W	D	30-031-20452	O	04/2015	05/01/2017	1650	6650		0		
	SANTA FE RAILROAD #040	P	2-07-17N-08W	E	30-031-20451	O	08/2012	09/01/2014	1655	6655	Y	0	Y	
	SANTA FE RAILROAD #041	P	1-07-17N-08W	D	30-031-20594	O	08/2011	09/01/2013	1650	6650	Y	0	Y	
	SANTA FE RAILROAD #042	P	F-07-17N-08W	F	30-031-20745	O	12/2015	01/01/2018	4029	9029		0		
	SANTA FE RAILROAD #043	P	C-07-17N-08W	C	30-031-20712	O	12/2015	01/01/2018	1715	6715		0		
	SANTA FE RAILROAD #044	P	C-07-17N-08W	C	30-031-20713	O	12/2015	01/01/2018	1715	6715		6715		
	SANTA FE RAILROAD #045	P	F-07-17N-08W	F	30-031-20804	O	12/2014	01/01/2017	1676	6676		0		
	SANTA FE RAILROAD #047	P	1-07-17N-08W	D	30-031-20836	O	08/2011	09/01/2013	1625	6625	Y	0	Y	
	SANTA FE RAILROAD #048	P	2-07-17N-08W	E	30-031-20837	O	08/2011	09/01/2013	1665	6665	Y	0	Y	
	SANTA FE RAILROAD #049	P	2-07-17N-08W	E	30-031-20838	O	12/2015	01/01/2018	1740	6740		0		
	SANTA FE RAILROAD #050	P	2-07-17N-08W	E	30-031-20854	O	08/2011	09/01/2013	1650	6650	Y	0	Y	
311758	SANTA FE RAILROAD A #072	P	11-01-17N-09W	P	30-031-05570	O	06/2013	07/01/2015	1631	6631	Y	0	Y	
	SANTA FE RAILROAD A #073	P	O-01-17N-09W	O	30-031-20019	O	09/2013	10/01/2015	1665	6665	Y	0	Y	
	SANTA FE RAILROAD A #074	P	9-01-17N-09W	I	30-031-20021	O	07/2009	08/01/2011	1592	6592	Y	6592		
	SANTA FE RAILROAD A #075	P	10-01-17N-09W	P	30-031-20072	O	12/2013	01/01/2016	1608	6608	Y	0	Y	
	SANTA FE RAILROAD A #076	P	11-01-17N-09W	P	30-031-20073	O	12/2015	01/01/2018	1591	6591		0		
	SANTA FE RAILROAD A #077	P	11-01-17N-09W	P	30-031-20100	O	05/2015	06/01/2017	1609	6609		0		
	SANTA FE RAILROAD A #079	P	O-01-17N-09W	O	30-031-20099	O	05/2015	06/01/2017	1665	6665		0		
	SANTA FE RAILROAD A #080	P	11-01-17N-09W	P	30-031-20133	O	12/2015	01/01/2018	1635	6635		0		
	SANTA FE RAILROAD A #081	P	O-01-17N-09W	O	30-031-20134	O	05/2015	06/01/2017	1655	6655		0		
	SANTA FE RAILROAD A #082	P	11-01-17N-09W	P	30-031-20137	O	12/2015	01/01/2018	1605	6605		0		
	SANTA FE RAILROAD A #084	P	O-01-17N-09W	O	30-031-20372	I	05/2014	06/01/2016	1656	6656	Y	6656		
	SANTA FE RAILROAD A #087	P	10-01-17N-09W	P	30-031-20413	I	03/2005	04/01/2007	1598	6598	Y	6598		
	SANTA FE RAILROAD A #088	P	11-01-17N-09W	P	30-031-20440	O	12/2015	01/01/2018	1670	6670		0		
	SANTA FE RAILROAD A #089	P	O-01-17N-09W	O	30-031-20442	O	11/2013	12/01/2015	1769	6769	Y	0	Y	
	SANTA FE RAILROAD A #090	P	10-01-17N-09W	P	30-031-20441	O	05/2012	06/01/2014	1670	6670	Y	0	Y	
	SANTA FE RAILROAD A #091	P	11-01-17N-09W	P	30-031-20714	O	01/2015	02/01/2017	1682	6682		0		
	SANTA FE RAILROAD A #093	P	10-01-17N-09W	P	30-031-20716	O	01/2015	02/01/2017	1620	6620		0		
	SANTA FE RAILROAD A #094	P	11-01-17N-09W	P	30-031-20722	O	05/2015	06/01/2017	1700	6700		0		
	SANTA FE RAILROAD A #095	P	9-01-17N-09W	I	30-031-20746	O	12/2015	01/01/2018	1640	6640		0		
	SANTA FE RAILROAD A #096	P	O-01-17N-09W	O	30-031-20800	O	12/2015	01/01/2018	1682	6682		0		
	SANTA FE RAILROAD A #097	P	O-01-17N-09W	O	30-031-20855	I	03/2005	04/01/2007	1690	6690	Y	6690		
311759	SANTA FE RR B #032	P	M-05-17N-08W	M	30-031-20303	O	04/1980	05/01/1982	2648	7648	Y	7648		
	SANTA FE RR B #033	P	L-05-17N-08W	L	30-031-20369	O	12/2010	01/01/2013	2652	7652	Y	0	Y	
	SANTA FE RR B #034	P	M-05-17N-08W	M	30-031-20390	O	06/2009	07/01/2011	1638	6638	Y	6638		
	SANTA FE RR B #035	P	E-05-17N-08W	E	30-031-20391	I	03/2014	04/01/2016	1644	6644	Y	0	Y	
	SANTA FE RR B #036	P	L-05-17N-08W	L	30-031-20416	O	12/2010	01/01/2013	1600	6600	Y	0	Y	
	SANTA FE RR B #037	P	M-05-17N-08W	M	30-031-20415	O	12/2010	01/01/2013	1614	6614	Y	0	Y	
	SANTA FE RR B #039	P	M-05-17N-08W	M	30-031-20749	I	02/2012	03/01/2014	1650	6650	Y	0	Y	
311760	SOUTH HOSPAH UNIT #001	F	G-12-17N-09W	G	30-031-05142	O	12/2015		1585			0		
	SOUTH HOSPAH UNIT #002	F	F-12-17N-09W	F	30-031-05139	O	12/2015		1637			0		
	SOUTH HOSPAH UNIT #003	F	3-12-17N-09W	H	30-031-05140	O	12/2015		1603			0		
	SOUTH HOSPAH UNIT #004	F	C-12-17N-09W	C	30-031-05145	O	08/2014		1640			0		

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	SOUTH HOSPAH UNIT #005	F	B-12-17N-09W	B	30-031-05146	O	05/2005		1645				0	
	SOUTH HOSPAH UNIT #006	F	1-12-17N-09W	A	30-031-20009	O	12/2015		1710				0	
	SOUTH HOSPAH UNIT #007	F	4-12-17N-09W	H	30-031-20012	O	12/2015		1750				0	
	SOUTH HOSPAH UNIT #008	F	G-12-17N-09W	G	30-031-20015	O	12/2015		1709				0	
	SOUTH HOSPAH UNIT #009	F	B-12-17N-09W	B	30-031-20013	S	12/2015		6945				0	
	SOUTH HOSPAH UNIT #010	F	C-12-17N-09W	C	30-031-60017	O	12/2015		2827				0	
	SOUTH HOSPAH UNIT #011	F	F-12-17N-09W	F	30-031-20016	O	12/2015		1774				0	
	SOUTH HOSPAH UNIT #012	F	E-12-17N-09W	E	30-031-20020	O	12/2015		1840				0	
	SOUTH HOSPAH UNIT #013	F	F-12-17N-09W	F	30-031-20054	O	12/2015		1720				0	
	SOUTH HOSPAH UNIT #014	F	E-12-17N-09W	E	30-031-20053	O	12/2015		1758				0	
	SOUTH HOSPAH UNIT #015	F	E-12-17N-09W	E	30-031-20055	O	12/2015		1790				0	
	SOUTH HOSPAH UNIT #016	F	F-12-17N-09W	F	30-031-20056	O	12/2015		1710				0	
	SOUTH HOSPAH UNIT #017	F	G-12-17N-09W	G	30-031-20057	I	12/2015		1787				0	
	SOUTH HOSPAH UNIT #024	F	B-12-17N-09W	B	30-031-20091	O	12/2015		1711				0	
	SOUTH HOSPAH UNIT #025	F	2-12-17N-09W	A	30-031-20092	O	12/2015		1702				0	
	SOUTH HOSPAH UNIT #026	F	1-12-17N-09W	A	30-031-20093	O	12/2015		1660				0	
	SOUTH HOSPAH UNIT #027	F	4-12-17N-09W	H	30-031-20094	O	08/2014		1669				0	
	SOUTH HOSPAH UNIT #028	F	2-12-17N-09W	A	30-031-20095	O	12/2015		1675				0	
	SOUTH HOSPAH UNIT #029	F	B-12-17N-09W	B	30-031-20120	O	12/2015		1625				0	
	SOUTH HOSPAH UNIT #030	F	B-12-17N-09W	B	30-031-20121	O	12/2015		1622				0	
	SOUTH HOSPAH UNIT #031	F	B-12-17N-09W	B	30-031-20122	O	12/2015		1651				0	
	SOUTH HOSPAH UNIT #032	F	C-12-17N-09W	C	30-031-20125	O	12/2015		1647				0	
	SOUTH HOSPAH UNIT #033	F	F-12-17N-09W	F	30-031-20124	I	12/2015		3930				0	
	SOUTH HOSPAH UNIT #035	F	2-12-17N-09W	A	30-031-20119	O	12/2015		1596				0	
	SOUTH HOSPAH UNIT #036	F	B-12-17N-09W	B	30-031-20118	I	10/2005		1635				0	
	SOUTH HOSPAH UNIT #037X	F	D-12-17N-09W	D	30-031-20135	O	12/2015		1666				0	
	SOUTH HOSPAH UNIT #038	F	2-12-17N-09W	A	30-031-20151	O	12/2015		1595				0	
	SOUTH HOSPAH UNIT #039	F	3-12-17N-09W	H	30-031-20152	I	10/2005		1687				0	
	SOUTH HOSPAH UNIT #046	F	E-12-17N-09W	E	30-031-20360	O	12/2015		1696				0	
	SOUTH HOSPAH UNIT #047	F	3-12-17N-09W	C	30-031-20361	O	12/2015		1780				0	
	SOUTH HOSPAH UNIT #048	F	G-12-17N-09W	G	30-031-20362	O	12/2015		1635				0	
	SOUTH HOSPAH UNIT #049	F	B-12-17N-09W	B	30-031-20363	O	12/2015		1639				0	
	SOUTH HOSPAH UNIT #050	F	2-12-17N-09W	A	30-031-20364	O	12/2015		1601				0	
	SOUTH HOSPAH UNIT #051	F	E-12-17N-09W	E	30-031-20242	I	11/2011		1662				0	
	SOUTH HOSPAH UNIT #052	F	C-12-17N-09W	C	30-031-20243	I	05/2005		1622				0	
	SOUTH HOSPAH UNIT #053	F	1-12-17N-09W	A	30-031-20278	O	12/2015		1678				0	
	SOUTH HOSPAH UNIT #054	F	1-12-17N-09W	A	30-031-20407	I	12/2015		1624				0	
	SOUTH HOSPAH UNIT #057	F	E-12-17N-09W	E	30-031-20408	I	12/2015		1746				0	
	SOUTH HOSPAH UNIT #058	F	F-12-17N-09W	F	30-031-20409	I	12/2015		1679				0	
	SOUTH HOSPAH UNIT #059	F	G-12-17N-09W	G	30-031-20410	I	12/2015		1657				0	
	SOUTH HOSPAH UNIT #060	F	3-12-17N-09W	H	30-031-20411	I	10/2005		1648				0	
	SOUTH HOSPAH UNIT #061	F	B-12-17N-09W	B	30-031-20546	O	12/2015		1715				0	
	SOUTH HOSPAH UNIT #062	F	B-12-17N-09W	B	30-031-20545	O	12/2015		1710				0	
	SOUTH HOSPAH UNIT #063	F	1-12-17N-09W	A	30-031-20544	O	12/2015		1695				0	
	SOUTH HOSPAH UNIT #064	F	3-12-17N-09W	H	30-031-20547	O	12/2015		1685				0	
311761	WHIGHAM #003	P	H-11-17N-09W	H	30-031-20129	O	06/2013	07/01/2015	2885	7885	Y		0	Y

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EXHIBIT 26

State of New Mexico
Energy, Minerals and Natural Resources Department

Susana Martinez
Governor

Ken McQueen
Cabinet Secretary

Matthias Sayer
Deputy Cabinet Secretary

Heather Riley, Division Director
Oil Conservation Division

March 26, 2018

CFM Oil, LLC
OGRID #280554
P.O. Box 1176
Artesia, NM 88210

Re: ACOI No. 344
CFM Oil, LLC; OGRID No. 280554

Dear Operator:

Thank you for returning the signed agreed compliance order regarding inactive wells operated by CFM Oil, LLC (CFM). Enclosed is a copy of the fully executed order.

The Order requires CFM to bring **18** of the wells identified in the Order into compliance with Rule 19.15.25.8 NMAC by **September 23, 2018**. Please remember that to bring a well into compliance under the order, CFM must not only plug the wellbore, place the well on approved temporary abandonment, or return it to production or other beneficial use, CFM must also file the appropriate paperwork. For example, if CFM plugs the wellbore of a well, it must also file a C-103 subsequent report on the plugging. You may wish to confirm the status of each well on the list with the appropriate district office prior to the expiration of the Order.

The Order also requires CFM to file a compliance report with the Oil Conservation Division (OCD) Compliance and Enforcement Manager, Daniel Sanchez, by **September 23, 2018**. This means **the compliance report must be received by the OCD by September 23, 2018**. I will review the report to determine whether the wells have been returned to compliance. If you have questions about how to file a compliance report, please contact me at (505) 476-3493.

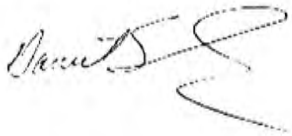
As CFM works to fulfill its obligations under the order, it should also monitor the status of its other wells to ensure that wells do not remain inactive for a period exceeding 15 months. Remember that you can search the OCD's Inactive Well List for wells that are inactive, but not yet out of compliance.

1220 South St. Francis Drive • Santa Fe, New Mexico 87505
Phone (505) 476-3460 • Fax (505) 476-3462 • www.emnrd.state.nm.us/ocd

EXHIBIT 26

The OCD appreciates CFM's commitment to bringing its inactive wells into compliance. If you have any questions, or if I can help you in any way, please do not hesitate to call. My email address is daniel.sanchez@state.nm.us.

Sincerely yours,



Daniel Sanchez
NMOCD Compliance & Enforcement Manager

Encl. ACOI No. 344

CC: Maxey Brown, OCD District I Supervisor
Michael Bratcher, OCD District II Supervisor
Charlie Perrin, OCD District III Supervisor
Will Jones, OCD District IV Supervisor

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

NMOCD – ACOI- 344

IN THE MATTER OF CFM OIL, LLC

Respondent.

INACTIVE WELL AGREED COMPLIANCE ORDER

Pursuant to the New Mexico Oil and Gas Act, NMSA 1978, Sections 70-2-1 through 70-2-38, as amended ("Act") and OCD Rule 19.15.5.10(E) NMAC, the Director of the Oil Conservation Division ("OCD") and **CFM Oil, LLC** ("Operator") enter into this Inactive Well Agreed Compliance Order ("Order" or "ACOI"). Operator agrees to plug, place on approved temporary abandonment status, or restore to production or other beneficial use the wells identified herein in accordance with the following agreed schedule and procedures, or face the possibility of no further agreed compliance orders. See 19.15.25.8 NMAC

FINDINGS

1. The OCD is the state division charged with administration and enforcement of the Act, and rules and orders adopted pursuant to the Act.

2. Operator is a Limited Liability Company doing business in the state of New Mexico.

3. Operator is the operator of record under OGRID **280554** for the wells identified in Exhibit "A," attached.

4. OCD Rule 19.15.25.8 NMAC states, in relevant part:

> "A. The operator of wells drilled for oil or gas or services wells including seismic, core, exploration or injection wells, whether cased or uncased, shall plug the wells as Subsection B of 19.15.25.8 NMAC requires.
> B. The operator shall either properly plug and abandon a well or place the well in approved temporary abandonment in accordance with 19.15.25 NMAC within 90 days after:
> ....
> ....
> (3) a period of one year in which a well has been continuously inactive."

5. The wells identified in Exhibit "A"

   (a) have been continuously inactive for a period of one year plus 90 days;
   (b) are not plugged or abandoned in accordance with OCD Rule 19.15.25.9 NMAC through 19.15.25.11 NMAC; and
   (c) are not on approved temporary abandonment status in accordance with OCD Rule 19.15.25.12 NMAC through 19.15.25.14 NMAC.

6. An operator faces sanctions if it is out of compliance with OCD Rule 19.15.5.9 NMAC. Sanctions include possible denial of registration by operator or certain related entities (OCD Rule 19.15.9.8B NMAC), possible denial of change of operator that would transfer wells to the noncompliant operator (OCD Rule 19.15.9.9C.1 NMAC), mandatory denial of injection permits (OCD Rule 19.15.26.8A NMAC), possible revocation of injection permits after notice and hearing (OCD Rule 19.15.26.8A NMAC), possible denial of applications for a drilling permit (OCD Rule 19.15.14.10A NMAC), and mandatory denial of allowable and authorization to transport (OCD Rule 19.15.16.19A NMAC).

7. Operator is currently out of compliance with OCD Rule 19.15.5.9.A(4) NMAC because it has too many wells out of compliance with OCD Rule 19.15.25.8 NMAC (the inactive well rule) that are not subject to an agreed compliance order setting a schedule for bringing the wells into compliance with the inactive well rule and imposing sanctions if the schedule is not met. See OCD Rule 19.15.5.9(A)(4) NMAC.

8. As the operator of record of **146** wells, to be in compliance with OCD Rule 19.15.5.9.A(4) NMAC, Operator may have no more than **5** wells out of compliance with OCD Rule 19.15.25.8 NMAC (inactive well rule). See OCD Rule 19.15.5.9A(4)(b) NMAC. According to the inactive well list kept pursuant to OCD Rule 19.15.5.9(F) NMAC, Operator has **31** wells out of compliance as of **March 16, 2018**. The Operator's inactive well list, dated **March 16, 2018** is attached as Exhibit "A." Operator faces sanctions for being out of compliance with OCD Rule 19.15.5.9 NMAC.

9. Operator intends to seek privileges from the OCD that would be subject to sanction due to Operator being out of compliance with OCD Rule 19.15.5.9 NMAC. By placing the wells identified in Exhibit "A" under this Order, Operator will not face sanctions for being out of compliance with OCD Rule 19.15.5.9 NMAC.

CONCLUSIONS

1. The OCD has jurisdiction over the parties and subject matter in this proceeding.

2. The wells identified in Exhibit "A" are out of compliance or will be out of compliance with OCD Rule 19.15.25.8 NMAC.

3. As operator of the wells identified in Exhibit "A," Operator is responsible for bringing those wells into compliance with OCD Rule 19.15.25.8 NMAC.

4. The OCD and Operator enter into this Order to remove the wells identified in Exhibit "A" from the inactive well list kept pursuant to OCD Rule 19.15.5.9(F) NMAC and consideration of Operator's compliance with the inactive well rule for purposes of Operator's compliance with OCD Rule 19.15.5.9 NMAC. Operator remains subject to sanctions for being out of compliance with OCD Rule 19.15.5.9 NMAC ***IF*** Operator becomes out of compliance with OCD Rule 19.15.5.9 NMAC for any reason other than the inactive wells identified in Exhibit "A."

ORDER

1. Operator agrees to bring **18** wells identified in Exhibit "A" into compliance with OCD Rule 19.15.25.8 NMAC by **September 23, 2018** via

   (a) restoring the well to production or other OCD-approved beneficial use **and filing a C-115 documenting such production or use**;
   (b) causing the wellbore to be plugged in accordance with OCD Rule 19.15.25.10(B) NMAC **and filing a C-103 describing the completed work**; or
   (c) placing the well on approved temporary abandonment status in accordance with OCD Rule 19.15.25.12 NMAC through 19.15.25.14 NMAC.

2. **Prior to completing the term of this agreement, the operator agrees to provide a comprehensive plan, acceptable to the division, as to how it will address the remaining inactive wells on Exhibit "A". Failure to provide such a plan may result in the division denying future amendments to this agreement.** Oil and gas produced during swabbing does not count as production for purposes of this Order.

3. Operator shall file a **monthly** compliance report, **due on the last day of each month**, identifying each well returned to compliance, stating the date it was returned to compliance and describing how the well was returned to compliance (restored to production or other approved beneficial use, plugged wellbore, approved temporary abandonment status.) Transfer of a well identified on Exhibit "A" to another operator does not count towards Operator's obligation to return wells to compliance under the terms of this Order, but does reduce the total number of wells for which Operator is responsible under the terms of this Order. The final written compliance report must be mailed or e-mailed to the OCD's Enforcement and Compliance Manager and to the OCD attorney in charge of inactive well agreed

compliance orders so that it is **received by** the compliance deadline of **September 23, 2018**. The total length of this Agreed Compliance Order is six months.

4. Operator understands that if it fails to meet the terms of this Order, the OCD may decide not to enter into any further agreed compliance orders with Operator. **If any more wells become inactive during the duration of this ACOI or the operator is in any other way in violation of OCD Rule 19.15.5.9 NMAC, this ACOI may terminate, at the sole discretion of the Division.**

5. This Order shall expire on **October 23, 2018**. At that time, any wells on Exhibit "A" not in compliance with OCD Rule 19.15.25.8 NMAC will appear on the inactive well list kept pursuant to OCD Rule 19.15.5.9(F) NMAC, and will be considered when determining Operator's compliance with OCD Rule 19.15.5.9 NMAC.

6. By signing this Order, Operator expressly:

   (a) acknowledges the correctness of the Findings and Conclusions set forth in this Order;
   (b) agrees to return to compliance **18** wells identified in Exhibit "A" by **September 23, 2018**;
   (c) agrees to submit a compliance report as required in Ordering Paragraph 3 by the **September 23, 2018** compliance deadline set by this Order;
   (d) waives any right, pursuant to the Oil and Gas Act or otherwise, to an appeal from this Order, or to a hearing either prior to or subsequent to the entry of this Order other than a hearing on a request for waiver; and
   (e) agrees that the Order may be enforced by OCD or Oil Conservation Commission Order, by suit or otherwise to the same extent and with the same effect as a final Order of the OCD or Oil Conservation Commission entered after notice and hearing in accordance with all terms and provisions of the Oil and Gas Act.

7. This Order applies only to the enforcement of OCD Rule 19.15.25.8 NMAC against those wells identified in Exhibit "A." Other wells operated by Operator out of compliance with OCD Rule 19.15.25.8 NMAC may be subject to immediate enforcement action under the Oil and Gas Act and OCD Rules. Wells identified in Exhibit "A" that are out of compliance with the Oil and Gas Act or OCD Rules other than OCD Rule 19.15.25.8 NMAC may be subject to immediate enforcement action under the Oil and Gas Act and OCD Rules.

8. The OCD reserves the right to file an application for hearing to obtain authority to plug any well identified in Exhibit "A" and forfeit the applicable financial assurance if the well poses an immediate environmental threat.

Done at Santa Fe, New Mexico this 28th day of March, 2018

By: Heather Riley
Heather Riley
Director, Oil Conservation Division

ACCEPTANCE

CFM Oil, LLC hereby accepts the foregoing Order, and agrees to all of the terms and provisions set forth in that Order.

CFM Oil, LLC

By: Lee F Fulton
(Please print name) Lee F Fulton
Title: Owner
Date: 3-21-18

Exhibit "A" to Agreed Compliance Order for CFM Oil, LLC

Total Well Count: 146 Inactive Well Count: 31
Printed On: Friday, March 16 2018

District	API	Well	ULSTR	OCD Unit	Ogrid	Operator	Lease Type	Well Type	Last Production	Formation/Notes	Status	TA Exp Date
1	30-025-01584	CONOCO FEDERAL #001	K-06-18S-33E	K	280551	CFM OIL, LLC	F	O	06/2015	QUEEN		
1	30-025-01585	CONOCO FEDERAL #002	J-06-18S-33E	M	280554	CFM OIL, LLC	F	O	08/2015	QUEEN		
2	30-015-21823	GILLESPIE STATE #002	C-27-17S-28E	C	280554	CFM OIL, LLC	S	O	08/2012			
2	30-015-22410	KINDLE #003	B-26-18S-26E	B	280551	CFM OIL, LLC	P	G	04/2010			
2	30-015-10247	STATE B 1111 #001	F-22-17S-28E	F	280554	CFM OIL, LLC	S	O	03/2015			
2	30-015-23138	STATE B 1111 #008	H-22-17S-28E	H	280554	CFM OIL, LLC	S	O	06/2016			
2	30-015-23139	STATE B 1111 #009	H-22-17S-28E	H	280554	CFM OIL, LLC	S	O	05/2016			
2	30-015-23231	STATE B 1111 #010	H-22-17S-28E	H	280554	CFM OIL, LLC	S	O	03/2016			
2	30-015-23140	STATE B 1111 #011	H-22-17S-28E	H	280554	CFM OIL, LLC	S	O	03/2016			
2	30-015-23451	STATE B 1111 #012	F-22-17S-28E	F	280554	CFM OIL, LLC	S	O	03/2015			
2	30-015-23452	STATE B 1111 #013	G-22-17S-28E	G	280554	CFM OIL, LLC	S	O	09/2014			
2	30-015-23453	STATE B 1111 #014	G-22-17S-28E	G	280554	CFM OIL, LLC	S	O	05/2014			
2	30-015-23454	STATE B 1111 #015A	G-22-17S-28E	G	280554	CFM OIL, LLC	S	O	12/2013			
2	30-015-23455	STATE B 1111 #016	F-22-17S-28E	F	280554	CFM OIL, LLC	S	O	03/2013			
2	30-015-23456	STATE B 1111 #017	F-22-17S-28E	F	280554	CFM OIL, LLC	S	O	05/2013			
2	30-015-23569	STATE B 1111 #018	A-22-17S-28E	A	280554	CFM OIL, LLC	S	O	01/2013			
2	30-015-23570	STATE B 1111 #019	A-22-17S-28E	A	280554	CFM OIL, LLC	S	O	03/2016			
2	30-015-23571	STATE B 1111 #020	A-22-17S-28E	A	280554	CFM OIL, LLC	S	O	12/2014			
2	30-015-23572	STATE B 1111 #021	A-22-17S-28E	A	280554	CFM OIL, LLC	S	O	08/2015			
2	30-015-21661	STATE B 1111 #022	G-22-17S-28E	G	280554	CFM OIL, LLC	S	O	08/2015			
2	30-015-22813	STATE B 1969 #010	O-22-17S-28E	O	280554	CFM OIL, LLC	S	O	01/2016			
2	30-015-22827	STATE B 1969 #011	O-22-17S-28E	O	280554	CFM OIL, LLC	S	O	04/2014	SEVEN RIVERS INT TO PA 03/11/10		
2	30-015-22828	STATE B 1969 #012	O-22-17S-28E	O	280554	CFM OIL, LLC	S	O	01/2016			
2	30-015-22829	STATE B 1969 #013	O-22-17S-28E	O	280554	CFM OIL, LLC	S	O	01/2016			
2	30-015-23141	STATE B 1969 #014	J-22-17S-28E	J	280554	CFM OIL, LLC	S	O	06/2016			
2	30-015-23142	STATE B 1969 #015	J-22-17S-28E	J	280554	CFM OIL, LLC	S	O	06/2016			
2	30-015-23232	STATE B 1969 #016	J-22-17S-28E	J	280554	CFM OIL, LLC	S	O	01/2016			
2	30-015-23143	STATE B 1969 #017	J-22-17S-28E	J	280554	CFM OIL, LLC	S	O	03/2015			
2	30-005-62761	VALLEY B ST #001	H-27-10S-26E	H	280554	CFM OIL, LLC	S	O	04/2011			
2	30-015-00318	WILLIAMS #003	B-25-18S-26E	B	280554	CFM OIL, LLC	P	O	04/2014			
2	30-005-62250	YATES BROWN ST #001	I-27-10S-26E	I	280554	CFM OIL, LLC	S	O	04/2011			

WHERE Operator:280554, County:All, District:All, Township:All, Range:All, Section:All, Production(months):15, Excludes Wells Under ACOI, Excludes Wells in Approved TA Period

CFM Oil, LLC

By: [signature]

Title: OWNER

ACOI

EXHIBIT 26

State of New Mexico
Energy, Minerals and Natural Resources Department

Susana Martinez
Governor

Ken McQueen
Cabinet Secretary

Matthias Sayer
Deputy Cabinet Secretary

David R. Catanach, Division Director
Oil Conservation Division

August 1, 2017

CFM Oil, LLC
OGRID #280554
P.O. Box 1176
Artesia, NM 88210

Re: 19.15.5.9 NMAC Compliance

Dear Operator:

The Oil Conservation Division (OCD) is conducting ongoing review of all operators' compliance status with Subsection A of 19.15.5.9 NMAC. According to OCD records, your company is not in compliance with Subsection A of 19.15.5.9 NMAC for the following reason:

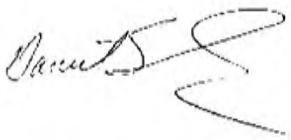
__X__ Inactive wells. According to the attached inactive well list, your company has too many wells in violation of 19.15.25.8 NMAC (the inactive well rule) that are not subject to an inactive well agreed compliance order. As an operator of __146__ wells, your company may have no more than __5__ wells in violation of the inactive well rule. Your company has __26__ wells in violation of the inactive well rule.

Non-compliance with 19.15.5.9 NMAC will prevent your company from acquiring any new wells, acquiring approval of exploration and development plans, receiving new allowables, and obtaining drilling, injection, and other OCD issued permits, and potentially expose your company to additional compliance actions including an OCD order requiring compliance, and revocation of injection permits. As the operator of a non 19.15.5.9 NMAC compliant company, you will not be permitted to register any additional companies to operate in New Mexico or have any interest exceeding 25 percent in any other companies in New Mexico.

The OCD is requesting that you review the OCD's online database for your specific Oil and Gas Registration Identification (OGRID) number and notify the OCD how your company plans to return to compliance with 19.15.5.9 NMAC. This is an opportunity for your company to work with the OCD toward achieving its goal of maintaining compliance with the rules of the State of New Mexico. Please respond to the OCD within 30 days of receipt of this letter. If no response is received the OCD may begin formal compliance action.

1220 South St. Francis Drive • Santa Fe, New Mexico 87505
Phone (505) 476-3460 • Fax (505) 476-3462 • www.emnrd.state.nm.us/ocd

Respectfully yours,



Daniel Sanchez,
Compliance and Enforcement Manager
(505)476-3493
Daniel.sanchez@state.nm.us

Ec: David R. Catanach, Division Director
Maxey Brown, District 1 Supervisor
Raymond Podany, District 2 Geologist
Charlie Perrin, District 3 Supervisor
Will Jones, District 4 Supervisor
Keith Herrmann, Attorney, Santa Fe

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN RE CFM OIL, LLC **CASE NO. ACOI-201946**

STIPULATED FINAL ORDER

Pursuant to the New Mexico Oil and Gas Act ("Act"), NMSA 1978, Section 70-2-1, *et seq.*, and 19.15.5.10(C) NMAC, the Director of the Oil Conservation Division ("OCD") and CFM Oil, LLC, OGRID #280554 ("CFM") enter into this Stipulated Final Order ("Order") to resolve the above-referenced matter.

1. OCD is charged with the administration and enforcement of the Act and the implementing rules, and has jurisdiction to regulate CFM's wells in the state of New Mexico.

2. CFM is the operator of record for the wells identified in Exhibit A.

3. On March 25, 2021, OCD issued a Notice of Violation ("NOV") to CFM alleging:

(a) CFM exceeded the number of inactive wells allowed by 19.15.5.9(A)(4)(b) NMAC;

(b) CFM failed to provide financial assurance in the required amount required by 19.15.8.9(C) NMAC; and

(c) CFM failed to provide financial assurance in the required amount required by 19.15.8.9(D) NMAC.

4. OCD subsequently identified additional inactive wells, which CFM agreed to address as part of this Order.

5. On April 23, 2021, CFM requested informal resolution of the NOV.

6. CFM admitted the alleged violations.

7. CFM resolved the alleged violation of 19.15.8.9(C) NMAC by providing the

required financial assurance.

8. To resolve the remaining alleged violations, CFM agrees that:

(a) No later than the specified date, unless extended upon request of CFM for good cause shown, CFM shall return to production each well identified in the column "Return to Production By" in Exhibit A and give OCD and SLO written notice by electronic mail.

(b) No later than the specified date, unless extended upon request of CFM for good cause shown, CFM shall submit to OCD Permitting an approvable C-103Q for each well identified in the column "P&A and Release By" in Exhibit A, which shall be reviewed in accordance with OCD's rules and for which approval shall not be unreasonably withheld, and give OCD and SLO written notice by electronic mail.

9. Written notice required by paragraph 8 shall be given to OCD at the following electronic mail address: Rob.Jackson@state.nm.us, and to SLO at the following electronic mail address: ABiernoff@slo.state.nm.us.

10. If CFM complies with this Stipulated Final Order, OCD shall abate all of the civil penalties.

11. If CFM fails to complete an action specified in paragraph 8, then CFM shall pay a stipulated penalty of $100.00 for each day until it completes the action.

12. If CFM fails to pay the stipulated penalty or portion thereof no later than 30 days after service of OCD's written demand, it shall pay interest on the stipulated penalty or unpaid portion thereof until paid in full at the interest rate of 8.75 percent as provided in NMSA 1978, § 56-8-4(A).

13. OCD reserves the right to revoke the authorization to transport and require a well to be plugged and abandoned if CFM fails to complete an action specified in paragraph 8 more

than 90 days after the specified date in Exhibit A or, for the Maljamar wells, after the date as extended by OCD for good cause shown.

14. CFM admit OCD's jurisdiction to file the NOV, consent to the relief specified herein, and waive the right of review by the Oil Conservation Commission.

15. The persons executing this Order represent that they have the requisite authority to bind their respective parties and such representation shall be legally sufficient evidence of their actual or apparent authority.

OIL CONSERVATION DIVISION

_____ Date: _____
Adrienne Sandoval
Director

CFM OIL, LLC

_____ Date: _____
Louis F. Fulton

than 90 days after the specified date in Exhibit A or, for the Maljamar wells, after the date as extended by OCD for good cause shown.

14. CFM admit OCD's jurisdiction to file the NOV, consent to the relief specified herein, and waive the right of review by the Oil Conservation Commission.

15. The persons executing this Order represent that they have the requisite authority to bind their respective parties and such representation shall be legally sufficient evidence of their actual or apparent authority.

OIL CONSERVATION DIVISION

Adrienne Sandoval
Director

Date: 1/27/2022

CFM OIL, LLC

Louis F. Fulton

Date: 1/27/2022

EXHIBIT A

API	WELL	RETURN TO PRODUCTION BY:	PLUG & ABANDON BY:
RED LAKE			
30-015-21823	GILLESPIE STATE #002		10/31/2022
30-015-21903	GILLESPIE STATE #003		10/31/2022
30-015-21928	GILLESPIE STATE #004		10/31/2022
30-015-01588	GILLESPIE STATE #005		10/31/2022
30-015-22393	GILLESPIE STATE #006		10/31/2022
30-015-22497	GILLESPIE STATE #007		10/31/2022
30-015-22498	GILLESPIE STATE #008		10/31/2022
30-015-22550	GILLESPIE STATE #009		10/31/2022
30-015-22580	GILLESPIE STATE #011		12/31/2022
30-015-22616	GILLESPIE STATE #012		12/31/2022
30-015-22762	GILLESPIE STATE #013		12/31/2022
30-015-22860	GILLESPIE STATE #014		12/31/2022
30-015-01589	GILLESPIE STATE #015		12/31/2022
30-015-01587	GILLESPIE STATE #016		12/31/2022
30-015-24064	SRC STATE #001		3/31/2021
30-015-23138	STATE B 1111 #008		3/31/2021
30-015-23139	STATE B 1111 #009		3/31/2021
30-015-23231	STATE B 1111 #010		3/31/2021
30-015-23140	STATE B 1111 #011		3/31/2021
30-015-23452	STATE B 1111 #013		3/31/2021
30-015-23455	STATE B 1111 #016		3/31/2021
30-015-23569	STATE B 1111 #018		3/31/2022
30-015-23570	STATE B 1111 #019		3/31/2022
30-015-23571	STATE B 1111 #020		3/31/2022
30-015-23572	STATE B 1111 #021		3/31/2021
30-015-23474	STATE B 1111 #022		3/31/2022
30-015-22813	STATE B 1969 #010		3/31/2022
30-015-22827	STATE B 1969 #011		3/31/2022

EXHIBIT 26

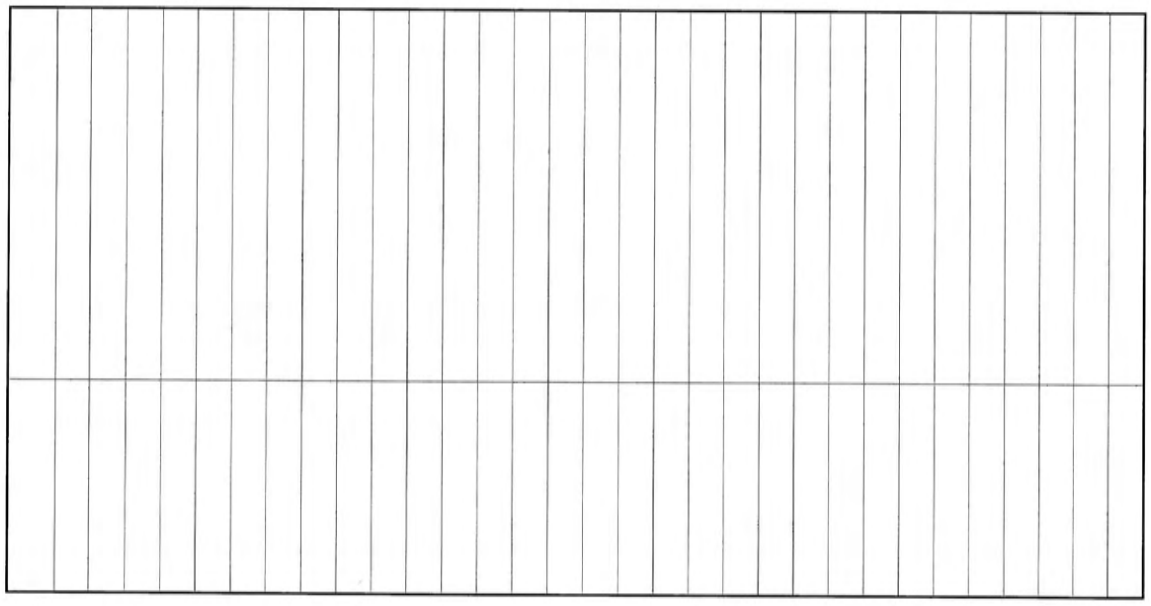
30-015-22828	STATE B 1969 #012			3/31/2022	
30-015-22829	STATE B 1969 #013			3/31/2022	
30-015-23141	STATE B 1969 #014			3/31/2022	
30-015-23142	STATE B 1969 #015			3/31/2022	
30-015-23232	STATE B 1969 #016			7/31/2022	
30-015-23143	STATE B 1969 #017			7/31/2022	
30-015-23244	STATE B 1969 #018			7/31/2022	
30-015-23395	STATE B 1969 #019Y			7/31/2022	
30-015-23246	STATE B 1969 #020			7/31/2022	
30-015-23573	STATE B 1969 #020Z		7/31/2022		
30-015-23475	STATE B 1969 #023		7/31/2022		
30-015-23476	STATE B 1969 #024		7/31/2022		
30-015-23477	STATE B 1969 #025		7/31/2022		
30-015-23478	STATE B 1969 #026		7/31/2022		
30-015-22166	WOLF #001		7/31/2022		
30-015-22362	WOLF #002		7/31/2022		
30-015-23082	WOLF #003		10/31/2022		
30-015-23310	WOLF #004		10/31/2022		
DAYTON					
30-015-00243	KINDLE #002			12/31/2022	
30-015-22410	KINDLE #003			12/31/2022	
30-015-00318	WILLIAMS #003		12/31/2022		
BARNSVILLE DRAW					
30-015-03959	DEKALB FEDERAL #002		12/31/2022		
30-015-03953	DEKALB FEDERAL #004		12/31/2022		
30-015-03954	ETZ FEDERAL #001		12/31/2022		
30-015-03956	ETZ FEDERAL #002		12/31/2022		
30-015-03955	ETZ FEDERAL #003		3/31/2023		
30-015-03957	ETZ FEDERAL #004		3/31/2023		
30-015-03958	FEDERAL E #001		3/31/2023		
30-015-03951	FEDERAL E #002		3/31/2023		
30-015-03960	FEDERAL E #003		3/31/2023		

EXHIBIT 26

30-015-02821	LEONARD #002	3/31/2023	
30-015-02865	STATE B #001	3/31/2023	
POTASH MINES			
30-015-04548	GATES FEDERAL #004	3/31/2023	
30-015-23050	GATES FEDERAL #005	3/31/2023	
30-015-27070	SPIKE FEDERAL #001	3/31/2023	
MILLIMAN			
30-015-02281	FRYMAN STATE #001	3/31/2023	
30-015-24159	FRYMAN STATE #002	3/31/2023	
30-015-23359	GULF STATE #001	3/31/2023	
30-015-23366	GULF STATE #003	3/31/2023	
ROSWELL			
30-005-62761	VALLEY B ST #001		3/31/2023*
30-005-62250	YATES BROWN ST #001		3/31/2023*
MALJAMAR			
30-025-01584	CONOCO FEDERAL #001	3/31/2023	3/31/2023
30-025-01585	CONOCO FEDERAL #002	3/31/2023	3/31/2023

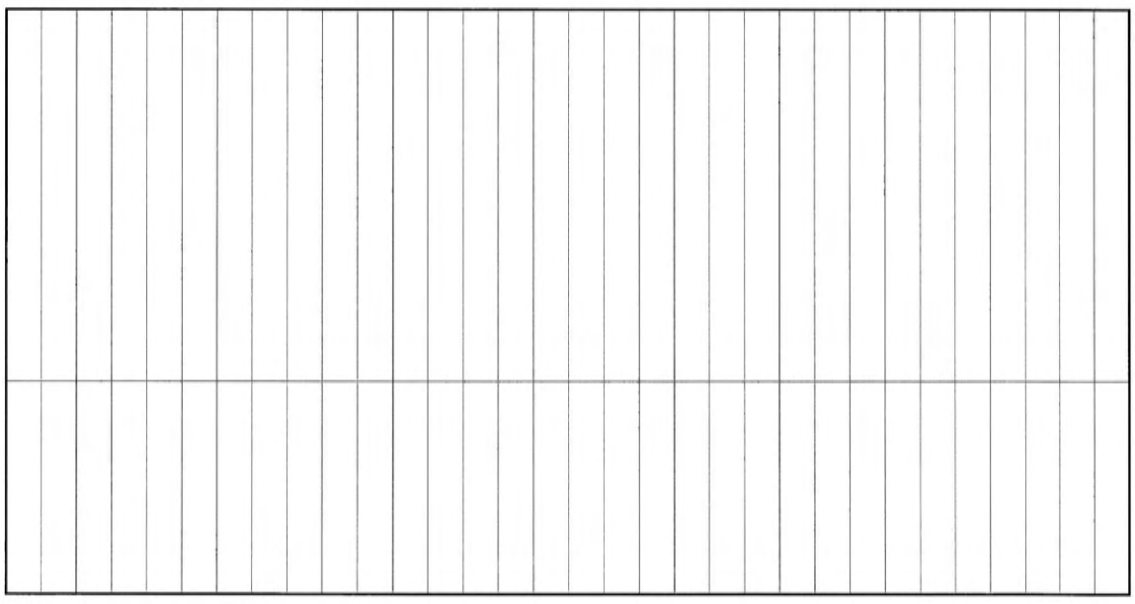
* OCD may extend this date for good cause shown, including a showing that the surface owner will not allow access to the wellsite.

EXHIBIT 26



IPANM Exhibit #51

EXHIBIT 26



IPANM Exhibit #51

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN RE: NMOCD-ACOI-201959

AGREED COMPLIANCE ORDER FOR INACTIVE WELLS

Pursuant to the New Mexico Oil and Gas Act ("Act"), NMSA 1978, Section 70-2-1, *et seq.*,and 19.15.5.10(E) NMAC, the Director of the Oil Conservation Division ("OCD") and Maverick Permian, LLC (331199) ("Operator") enter into this Agreed Compliance Order for Inactive Wells ("ACOI").

I. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. OCD is charged with the administration and enforcement of the Oil and Gas Act and the rules and has jurisdiction over Operator and its wells in the state of New Mexico.

2. Operator is the operator of record for 868 wells of which 27 are inactive.

3. Operator is under OGRID # 331199.

4. Operator will address each well listed on **Exhibit "A"** ("Well" or "Wells") due to Acquisition of Wells.

5. Operator has sufficient financial assurance for the Wells under 19.15.8.9(C) NMAC.

6. Operator intends to restore production from the Wells before the applicability of the requirement for inactive well financial assurance under 19.15.8.9(D) NMAC.

7. OCD is authorized to impose sanctions for violations of the Oil and Gas Act and the rules, including denial or revocation of registrations, applications, permits, authorizations and transfers, and the assessment of civil penalties. *See* 19.15.5.10NMAC.

8. Operator requests this ACOI to avoid sanctions for violating the Oil and Gas Act and 19.15.25 NMAC with respect to the Wells.

9. Operator admits the findings of fact and waives any right to appeal from this ACOI.

II. ORDER

9. No later than the dates listed on Exhibit A, Operator shall take one of the following actions for each well

   (a) restore the Well to production and file a C-115;

   (b) place the Well on approved temporary abandonment status in accordance with 19.15.25 NMAC; and

   (c) plug the Well in accordance with 19.15.25 NMAC and file a C-103.

10. No later than the 15th day of each month following the entry of this ACOI, Operator shall file a report describing the action taken for each Well, and such other information as OCD may request for time to time. The report shall be sent by electronic mail to OCD's Administrative and Compliance Bureau, at OCDAdminComp@state.nm.us

11. Operator shall maintain sufficient financial assurance for the Wells under 19.15.8.9(C) NMAC.

12. If Operator fails to comply with a requirement of this ACOI for a Well, the Well shall be deemed to be out of compliance with the Oil and Gas Act and rules.

13. If Operator fails to comply with a requirement of this ACOI, no later than thirty (30) days after receipt of a written demand from OCD, in addition to any other sanction imposed by OCD pursuant to the Oil and Gas Act and the rules adopted thereunder, Operator shall pay a stipulated penalty of $500.00 for each day until it complies with each separate requirement ("Stipulated Penalty"). Each failure to comply with a requirement of this ACOI shall be subject to a separate Stipulated Penalty.

14. If Operator fails to pay the Stipulated Penalty or portion thereof within thirty (30) days after receipt of a written demand from OCD, it shall pay interest on the Stipulated Penalty or unpaid portion thereof until paid in full at the interest rate of 8.75 percent.

15. Operator shall not transfer a Well to another operator unless approved by OCD.

16. Notwithstanding the foregoing provisions, OCD reserves the right to apply for authorization to plug a Well and to forfeit the financial assurance if the Well poses an imminent threat to the public health or environment.

17. OCD reserves the right to sanction Operator for any alleged violation not addressed in this Order.

NEW MEXICO OIL CONSERVATION DIVISION

Adrienne Sandoval

6/30/2022
Date

Lauri Stanfield
Name of Authorized Representative

June 27, 2022
Date

EXHIBIT 26

Exhibit A

Operator Name:	Maverick Permian LLC
Operator OGRID:	331199
ACOI sumbital Date:	6/23/2022
ACOI Approval Date:	
Total Number of Non-Compliant Wells:	27
Number of Wells per month brought into production or plugged:	4.5
ACOI # : *(Assigned by OCD)*	201959

List of Noncompliant Wells

API	Well Name/Number	Plug or Produce?
		Example
30-025-12345	Anywhere 31	Produce
30-025-00636	BAISH B #003	Produce
30-025-01566	COCKBURN B STATE #002	Plug
30-025-02836	EAST VACUUM (GSA) UNIT #002	Produce
30-025-26929	EAST VACUUM (GSA) UNIT #002	Produce
30-025-02973	EAST VACUUM (GSA) UNIT #002H	Produce
30-025-26381	EAST VACUUM (GSA) UNIT #006	Plug
30-025-26865	EAST VACUUM (GSA) UNIT #008	Produce
30-025-21651	EAST VACUUM (GSA) UNIT #112	Plug
30-025-25539	PEARL B #005	Produce
30-025-00690	PEARL B #017	Produce
30-025-07846	SEMU BTD #011	Produce
30-025-01425	STATE F TG #004	Produce
30-025-08541	VACUUM ABO UNIT #067	Plug
30-025-08547	VACUUM ABO UNIT #072	Produce
30-025-42070	VACUUM ABO UNIT #687	Produce
30-025-42072	VACUUM ABO UNIT #707	Produce
30-025-20854	VACUUM GLORIETA EAST UNIT #001	Produce
30-025-20866	VACUUM GLORIETA EAST UNIT #001	Produce
30-025-20846	VACUUM GLORIETA EAST UNIT #001	Plug
30-025-20826	VACUUM GLORIETA EAST UNIT #001	Plug
30-025-20797	VACUUM GLORIETA EAST UNIT #001K	Produce
30-025-20855	VACUUM GLORIETA EAST UNIT #002	Produce
30-025-38386	VACUUM GLORIETA EAST UNIT #029	Produce
30-025-42104	VACUUM GLORIETA EAST UNIT #114H	Produce
30-025-42103	VACUUM GLORIETA EAST UNIT #123H	Produce
30-025-42691	VACUUM GLORIETA EAST UNIT #224H	Produce

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30-025-44141	ZEPPO 5 FEDERAL COM #025H	Produce

EXHIBIT 26

Date of plugging or production	Date of Last Production	Financal Assurance Single well or Blanket bond?	Amount of Financial Assurance	TA Exp Date
10/31/2021 (End of month it happens in)		single well	$45,600.00	
Aug-22	Jul-19	Blanket	$250,000	
Nov-22	Jun-14	Blanket	$250,000	6/11/2021
Aug-22	Aug-19	Blanket	$250,000	10/20/2024
Aug-22	Feb-21	Blanket	$250,000	
Aug-22	Mar-19	Blanket	$250,000	3/8/2024
Nov-22	Nov-20	Blanket	$250,000	
Aug-22	Jul-20	Blanket	$250,000	
Nov-22	Dec-20	Blanket	$250,000	
Aug-22	Feb-20	Blanket	$250,000	
Sep-22	Oct-19	Blanket	$250,000	
Sep-22	Jan-21	Blanket	$250,000	
Sep-22	Sep-19	Blanket	$250,000	
Nov-22	Nov-19	Blanket	$250,000	
Sep-22	Jan-19	Blanket	$250,000	9/3/2026
Oct-22	Oct-17	Blanket	$250,000	1/4/2023
Oct-22	Nov-19	Blanket	$250,000	1/14/2024
Oct-22	Nov-19	Blanket	$250,000	3/6/2026
Oct-22	Dec-20	Blanket	$250,000	
Nov-22	Aug-19	Blanket	$250,000	
Nov-22	Mar-20	Blanket	$250,000	
Nov-22	May-16	Blanket	$250,000	5/1/2026
Nov-22	Sep-20	Blanket	$250,000	
Nov-22	Sep-17	Blanket	$250,000	8/20/2026
Dec-22	Jul-17	Blanket	$250,000	9/3/2026
Dec-22	Jan-18	Blanket	$250,000	10/16/2022
Dec-22	Apr-16	Blanket	$250,000	4/1/2026

EXHIBIT 26

Dec-22	Dec-19	Blanket	$250,000	

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

APPLICATION OF THE NEW MEXICO OIL CONSERVATION DIVISION COMPLIANCE AND ENFORCEMENT BUREAU FOR A COMPLIANCE ORDER AGAINST CANO PETRO OF NEW MEXICO, INC., FOR WELLS OPERATED IN CHAVES AND ROOSEVELT COUNTIES, NEW MEXICO.

CASE NO. 16040
CASE NO. 16359
ORDER NO. R-14795-A

ORDER OF THE COMMISSION

THIS MATTER came before the New Mexico Oil Conservation Commission ("Commission") on two consolidated applications. In the first application for Case 16040, Cano Petro of New Mexico Inc. ("Cano") applied for a *de novo* review of a compliance order, Order No. R-14663, issued by the Oil Conservation Division after a hearing. In the second application, the Oil Conservation Division of the Energy, Minerals and Natural Resources Department Compliance and Enforcement Bureau ("OCD") applied for a hearing to obtain a compliance order against Cano for violations of 19.15.8, 19.15.17, 19.15.29, and 19.15.36 NMAC in Case 16359. Upon request by the OCD, the Commission Chair, noting the similar subject matter against the same operator, directed Case 16359 to be heard by the Commission and joined the two cases.

The Commission, having conducted a public hearing on August 20, 2018, and having considered the testimony and the record in this case, and being otherwise fully advised, enters the following findings, conclusions and order:

THE COMMISSION FINDS THAT:

1. Notice has been given of *de novo* hearing in Case 16040 and the Commission has jurisdiction over the parties and the subject matter herein.

2. Notice has been given of Case 16359 hearing as required by 19.15.4 NMAC and the Commission has jurisdiction over the parties and the subject matter herein.

3. In Case 16040, OCD seeks an order finding Cano in violation of the provisions of 19.15.5.9(A)(4) and 19.15.25.8 NMAC, directing Cano to return to compliance with 19.15.5.9(A)(4) and 19.15.25.8 NMAC within forty-five (45) days, and in the event of non-compliance, declaring the wells abandoned and authorizing OCD to plug the violating wells in accordance with a Division-approved plugging program to restore and remediate the location, recover costs from Cano's financial assurance as

permitted by 19.15.8.13 NMAC, and seek indemnification and costs as permitted by NMSA 1978, § 70-2-14(E).

4. In Case 16359, OCD seeks an order finding Cano in violation of the provisions of 19.15.8, 19.15.17, 19.15.29, and 19.15.36 NMAC, and directing Cano to return to compliance with 19.15.8, 19.15.17, 19.15.29, and 19.15.36 NMAC by a date certain.

5. Cano is a foreign profit corporation that operates three hundred twenty-three (323) wells in Chaves and Roosevelt Counties, New Mexico, under OGRID No. 248802. Cano is registered with the New Mexico Secretary of State under entity number 2851087. OCD identified Richard Nichols, President, Orville Nichols, Secretary, Phillip Burch, Chief Financial Officer, and John Archer, President, as officers of record. Rick Harris, E&P Director, is listed as the point of contact in internal OCD records.

6. U.S. Specialty Insurance, which is a surety on bonds held by Cano, was notified of the proceeding in Case 16040 as required by 19.15.8.13(A) NMAC and entered an appearance but did not appear at the August 20, 2018 Commission hearing. U.S. Specialty Insurance requested a continuance on behalf of Cano, which was opposed by OCD, and the Commission declined to grant the request.

7. OCD presented testimony on violations of 19.15.5.9(A)(4), 19.15.25.8, and 19.15.8 NMAC from OCD Compliance and Enforcement Manager, Daniel Sanchez, who had personally reviewed relevant Division records and visited numerous Cano sites, most recently on July 9, 2018. Mr. Sanchez testified that:

a. Cano currently has two hundred ninety-one (291) wells out of compliance with 19.15.25.8 NMAC, which requires wells to be properly plugged and abandoned within ninety (90) days after a period of one year in which a well has been continually inactive. *See Exhibit 1: Inactive Well List;*

b. As an operator of three hundred twenty-three (323) wells, Cano is permitted to have no more than five (5) wells out of compliance with 19.15.25.8 NMAC to remain in compliance with 19.15.5.9 NMAC;

c. On June 20, 2017, OCD sent Cano notice that it was out of compliance with 19.15.5.9 NMAC and that OCD would seek formal compliance proceedings in accordance with the notice provisions of 19.15.5.9(B) NMAC;

d. Cano's inactive well total has steadily increased since 2012, including increasing from two hundred sixty-nine (269) to two hundred ninety-one (291) between April 5, 2018 and August 20, 2018;

e. During his site visit on July 9, 2018, Mr. Sanchez visited twenty-one (21) well sites and noted only one (1) had equipment that would make it capable of production;

f. Cano has furnished OCD with eighty (80) single well bonds on file with OCD for a total amount of $688,617.00 and one blanket bond filed with OCD, bond no. B003422, for the amount of $50,000.00, from U.S. Specialty Insurance. *See Exhibit 2: Cano Bonding Status;* and

g. Cano requires additional financial assurance for fourteen (14) wells, requiring a total of $120,200.00.

8. The Commission took administrative notice of Commission Order No. R-9210, where the Commission adopted the current rule on plugging and abandonment. In Order No. R-9210 finding paragraph 5, the Commission found that "[t]he proposed rules on abandonment will prevent migration of fluids, prevent waste, protect correlative rights and protect fresh water."

9. OCD presented testimony on violations of 19.15.17, 19.15.29, and 19.15.36 NMAC from its Environmental Bureau Chief, Jim Griswold, who reviewed Division records and visited numerous Cano sites, most recently on July 9, 2018. Mr. Griswold testified that:

a. Cano had eight (8) open remediation permits as follows:

Remediation Permit No.	Site Identification	API No.
1R-1396	Cato San Andres Unit #18	30-05-20173
1R-1980	Cato #6 Tank Battery	30-05-10455
1R-2062	Cato San Andres Unit #507	30-05-28022
1R-2184	Cato San Andres Unit #544	30-05-27986
1R-2518	Cato #6 Tank Battery	30-05-10455
1R-2579	Cato San Andres Unit #561	30-05-28029
1R-4363	Cato #6 Tank Battery	30-05-10455
1R-4779	Cato San Andes Unit Injection Line, Well #19	30-05-10484

b. Upon personal inspection, the Cato #6 Tank battery has multiple reported and un-reported releases that were existing and on-going at the site and required immediate corrective action because groundwater

was within one hundred (100) feet below ground surface, and given the volume and duration of the releases, could be impacted;

c. To address the release at the Cato #6 Tank Battery, Cano will need to perform the following actions based on 19.15.29 NMAC and best management practices in the field:

   i. Drain and properly dispose of all liquids from the tanks;

   ii. Remove and relocate the tanks, piping, and other infrastructure;

   iii. Remove and properly dispose all liner(s);

   iv. Investigate the vadose zone beneath the battery for adsorbed contamination by crude oil and produced water;

   v. If the soils beneath the battery are contaminated, excavate and backfill with clean soils; and

   vi. If soil contamination has impacted groundwater, perform a hydrogeologic investigation of the extents of that contamination and develop an appropriate abatement program;

d. Upon review of aerial photographs, there are eight (8) open pits that exist on sites operated by Cano. Mr. Griswold was able to visit four (4) but did not have sufficient time to visit all of Cano's sites;

e. To address the unclosed pits, Cano will need to perform the follow actions based on 19.15.17 NMAC and best management practices in the field:

   i. Remove and properly dispose pit contents;

   ii. Remove and properly dispose pit liners;

   iii. Sample and analyze soils beneath the pit for concentrations of adsorbed chloride, total petroleum hydrocarbons, benzene, toluene, ethylbenzene, and total xylenes;

   iv. If the soils are found to be contaminated in excess of the pertinent standards, the extents of the soil contamination must be determined and contaminated soil must be excavated;

   v. Properly backfill the pit area, even if the soils are not adversely impacted; and

vi. If soil contamination has impacted groundwater, perform a hydrogeologic investigation of the extents of that contamination so an appropriate abatement program can be developed;

f. Upon inspection, Mr. Griswold identified two (2) stockpiles of contaminated soil on sites operated by Cano. The stockpiles were in violation of the provisions of 19.15.36 NMAC governing the operation of surface waste management facilities;

g. To address the stockpiles of waste, Cano will need to perform the following actions based on 19.15.36 NMAC and best management practices in the field:

i. Remove and properly dispose contaminated soil;

ii. Remove and properly dispose any liners;

iii. Investigate the vadose zone beneath the stockpiles for adsorbed contamination by crude oil and produced water;

iv. If the soils beneath the stockpiles are contaminated, excavate and backfill with clean soils; and

v. If soil contamination has impacted groundwater, perform a hydrogeologic investigation of the extents of that contamination so an appropriate abatement program can be developed;

10. The Commission adopted the closure requirements, as well as the other requirements of 19.15.17 NMAC (commonly known as the "pit rule") to ensure that the design, operation, closure, and revegetation standards for pits are protective of groundwater, public health, and the environment. OCC Order No. R-13506-D pg. 44, para. S. Pits that are not in compliance with 19.15.17 NMAC pose a threat to groundwater.

11. OCD presented testimony from the New Mexico State Land Office Units and Commingling Manager, Marilyn Gruebel, who presented the unit agreement between Cano, the State Land Office, and the Bureau of Land Management for operations on the Cato Unit. The Cato Unit is comprised of a large number of Cano's wells. The unit agreement contains provisions requiring the operator to submit a plan of development, which Cano has not submitted to the State Land Office. The unit agreement also contains language relating to how the operations in the field must eliminate waste. The State Land Office does not believe Cano is operating within the parameters of the unit agreement.

THE COMMISSION CONCLUDES THAT:

1. Based on the evidence presented, the Commission finds that Cano is in violation of:

a. 19.15.25 NMAC (failure to properly plug and abandon two hundred ninety-one (291) wells);

b. 19.15.5.9 NMAC (having too many wells that are out of compliance with 19.15.25.8 NMAC);

c. 19.15.8 NMAC (not providing the Division with adequate financial assurance);

d. 19.15.17 NMAC (having eight (8) pits that are not closed);

e. 19.15.29 NMAC (having major releases of oil, produced water, and other oilfield waste that are not reported, nor cleaned up pursuant to a Division-approved remediation or abatement plan); and

f. 19.15.36 (having stockpiles of waste improperly stored in an unpermitted surface waste management facility).

2. The violations threaten public safety, the environment, and fresh water.

3. The violations, particularly the environmental violations that were reported years ago and not remediated, are knowing and willful.

IT IS THEREFORE ORDERED THAT:

1. Cano has forty-five (45) days to resolve its violations of 19.15.25.8 and 19.15.5.9 NMAC. Compliance can include entering into an agreed compliance order that includes a schedule to return to compliance and a plan of development.

2. Cano has forty-five (45) days to provide the division with the requisite financial assurance as required by 19.15.8 NMAC.

3. Cano has forty-five (45) days to submit a delineation plan for environmental contamination at the Cato #6 Tank Battery and associated well sites.

4. Cano has forty-five (45) days to submit delineation plans, including a schedule for remediation, for the following sites with reported releases:

Remediation Permit No.	Site Identification	API No.
1R-1396	Cato San Andres Unit #18	30-05-20173
1R-1980	Cato #6 Tank Battery	30-05-10455
1R-2062	Cato San Andres Unit #507	30-05-28022

1R-2184	Cato San Andres Unit #544	30-05-27986
1R-2518	Cato #6 Tank Battery	30-05-10455
1R-2579	Cato San Andres Unit #561	30-05-28029
1R-4363	Cato #6 Tank Battery	30-05-10455
1R-4779	Cato San Andes Unit Injection Line, Well #19	30-05-10484

5. Cano has forty-five (45) days to resolve its violations of 19.15.17 NMAC regarding the eight (8) unclosed pits identified by OCD.

6. Cano has forty-five (45) days to resolve its violations of 19.15.36 NMAC regarding the two (2) stockpiles of contaminated soil identified by OCD.

7. Cano has forty-five (45) days to assess all remaining sites for other releases, and if discovered, perform remedial actions as required by 19.15.29 and 19.15.30 NMAC.

8. If after forty-five (45) days, Cano has not performed the work described in Ordering Paragraph (1), Cano shall be in violation of this Order and the Commission authorizes the Division to:

a. plug and abandon the well or wells operated by Cano that are out of compliance with Commission rules in accordance with Division-approved plugging programs;

b. restore and remediate the well locations;

c. direct forfeiture of the applicable financial assurance of Cano;

d. recover plugging, restoration, and remediation costs from Cano's financial assurance as permitted by 19.15.8.13 NMAC; and

e. seek indemnification and costs from Cano as provided in Subsection E of NMSA 1978, § 70-2-14 if there are not sufficient funds recovered from financial assurance to cover all costs the Division incurs while plugging and abandoning the wells and restoring and remediating the well locations.

9. If after forty-five (45) days, Cano has not performed the work described in Ordering Paragraph (2)-(7), Cano shall be in violation of this Order and the Commission shall authorize the Division to pursue its own cleanup in accordance with 19.15.29 and 19.15.30 NMAC and seek to recoup expenses from a court of competent jurisdiction.

10. If Cano is found to be in violation of this Order, the OCD with the Attorney General's Office may pursue penalties as provided in the Oil and Gas Act, NMSA 1978 §70-2-31.

11. Jurisdiction of this case is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on September 13, 2018.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

ROBERT BALCH, Member

ED MARTIN, Member

HEATHER RILEY, Chair

SEAL

Exhibit 1: Inactive Well List

EXHIBIT 26

API	Well	ULSTR	Operator	Lease Type	Well Type	Last Production	Formation/Notes
30-005-20588	AMOCO FEDERAL #001	H-01-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-98	SAN ANDRES
30-005-20610	AMOCO FEDERAL #002	G-01-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-99	
30-005-10584	CATO SAN ANDRES UNIT #001	H-03-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Nov-14	SAN ANDRES
30-005-20932	CATO SAN ANDRES UNIT #002	G-03-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Mar-15	SAN ANDRES
30-005-20678	CATO SAN ANDRES UNIT #003	E-04-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jan-17	SAN ANDRES
30-005-20271	CATO SAN ANDRES UNIT #005	L-02-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Nov-14	SAN ANDRES
30-005-20001	CATO SAN ANDRES UNIT #006	N-02-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	SAN ANDRES
30-005-10536	CATO SAN ANDRES UNIT #007	M-02-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Apr-15	SAN ANDRES
30-005-20160	CATO SAN ANDRES UNIT #008	P-03-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Nov-14	SAN ANDRES
30-005-10537	CATO SAN ANDRES UNIT #009	O-03-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-16	SAN ANDRES
30-005-20161	CATO SAN ANDRES UNIT #010	M-04-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Mar-17	SAN ANDRES
30-005-20164	CATO SAN ANDRES UNIT #011	B-08-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-17	SAN ANDRES
30-005-20127	CATO SAN ANDRES UNIT #012	A-08-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SA BLM DENIED INT TO RWTP 07/21/10
30-005-20142	CATO SAN ANDRES UNIT #013	D-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Mar-17	SAN ANDRES
30-005-20066	CATO SAN ANDRES UNIT #014	C-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Mar-17	SAN ANDRES
30-005-20156	CATO SAN ANDRES UNIT #015	B-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-09	SA BLM DENIED INT TO RWTP 07/21/10
30-005-20067	CATO SAN ANDRES UNIT #016	A-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	I	Nov-14	SAN ANDRES
30-005-10501	CATO SAN ANDRES UNIT #017	C-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Sep-09	SAN ANDRES
30-005-10504	CATO SAN ANDRES UNIT #020	D-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	I	Aug-16	SA CONVRT TO INJ 09/06/09
30-005-20069	CATO SAN ANDRES UNIT #021	C-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	I	Aug-16	SAN ANDRES
30-005-10523	CATO SAN ANDRES UNIT #023	A-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	I	Aug-16	SAN ANDRES R9029 IPI 315
30-005-20294	CATO SAN ANDRES UNIT #025	H-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	SAN ANDRES
30-005-10491	CATO SAN ANDRES UNIT #027	F-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	May-09	SAN ANDRES SWAB 05/14/09
30-005-10503	CATO SAN ANDRES UNIT #028	E-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	I	Aug-16	SA CONVRT TO INJ 06/25/09 LH
30-005-10473	CATO SAN ANDRES UNIT #029	H-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-09	SAN ANDRES INT CONV INJ 07/12/10 BLM
30-005-10483	CATO SAN ANDRES UNIT #030	G-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-15	SAN ANDRES
30-005-20170	CATO SAN ANDRES UNIT #031	F-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Sep-09	SAN ANDRES SHUT IN TIL 07/01/09 BLM
30-005-10522	CATO SAN ANDRES UNIT #032	E-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Sep-09	SA RETURN TO PROD 11/17/08
30-005-20006	CATO SAN ANDRES UNIT #033	H-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	SAN ANDRES
30-005-20027	CATO SAN ANDRES UNIT #034	G-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SA BLM DENIED INT TO RWTP 07/21/10

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30-005-20046	CATO SAN ANDRES UNIT #035	F-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Mar-17	SAN ANDRES
30-005-20065	CATO SAN ANDRES UNIT #036	E-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Dec-06	SAN ANDRES/ INT TO PA 11/05/08
30-005-20073	CATO SAN ANDRES UNIT #037	H-08-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-16	SAN ANDRES
30-005-20099	CATO SAN ANDRES UNIT #038	G-08-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	SAN ANDRES
30-005-20098	CATO SAN ANDRES UNIT #039	J-08-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-17	SAN ANDRES
30-005-20047	CATO SAN ANDRES UNIT #041	L-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	SAN ANDRES
30-005-20089	CATO SAN ANDRES UNIT #042	K-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	SAN ANDRES
30-005-20095	CATO SAN ANDRES UNIT #043	J-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	SAN ANDRES
30-005-20004	CATO SAN ANDRES UNIT #044	I-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	May-09	SAN ANDRES
30-005-20130	CATO SAN ANDRES UNIT #045	L-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jun-09	
30-005-10538	CATO SAN ANDRES UNIT #046	K-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	May-09	SAN ANDRES SWAB 05/20/09
30-005-10578	CATO SAN ANDRES UNIT #047	J-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	SAN ANDRES
30-005-10455	CATO SAN ANDRES UNIT #049	L-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	I	Aug-16	CONVERT TO INJ 12/4/2008
30-005-29021	CATO SAN ANDRES UNIT #050	J-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	I	Oct-16	SAN ANDRES 09/17/10 BLM DENIED TUBING FI
30-005-10539	CATO SAN ANDRES UNIT #051	I-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	I	Aug-16	SAN ANDRES 03/10/10 R 9029 MIT
30-005-20009	CATO SAN ANDRES UNIT #052	M-12-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	SAN ANDRES BLM RECORD TIL 10/19/10 R9029
30-005-20293	CATO SAN ANDRES UNIT #053	P-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-04	
30-005-10560	CATO SAN ANDRES UNIT #055	N-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	May-09	SWAB 05/22/09
30-005-10579	CATO SAN ANDRES UNIT #056	M-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	I	Sep-16	CONVERT TO INJ 09/13/08 R9029A
30-005-10500	CATO SAN ANDRES UNIT #058	O-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Oct-04	
30-005-10570	CATO SAN ANDRES UNIT #059	N-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	May-09	SWAB 05/22/09
30-005-10571	CATO SAN ANDRES UNIT #060	M-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	
30-005-20005	CATO SAN ANDRES UNIT #061	P-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	May-09	SWAB 05/24/09
30-005-20038	CATO SAN ANDRES UNIT #062	O-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20049	CATO SAN ANDRES UNIT #063	N-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-16	
30-005-20028	CATO SAN ANDRES UNIT #064	M-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-16	
30-005-20037	CATO SAN ANDRES UNIT #066	O-08-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Dec-06	BLM DENIED INT TO RWTP 07/21/10
30-005-20054	CATO SAN ANDRES UNIT #067	C-17-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	
30-005-20236	CATO SAN ANDRES UNIT #068	B-17-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-16	SAN ANDRES
30-005-10586	CATO SAN ANDRES UNIT #069	A-17-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-16	
30-005-20019	CATO SAN ANDRES UNIT #070	D-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	
30-005-20020	CATO SAN ANDRES UNIT #071	C-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	04/01/09 RET TO PROD

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30-005-20021	CATO SAN ANDRES UNIT #072	B-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Mar-17	
30-005-20017	CATO SAN ANDRES UNIT #073	A-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	10/04/08 HOOKED UP GAS
30-005-10573	CATO SAN ANDRES UNIT #074	D-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-16	RET TO PROD 07/16/2007
30-005-10562	CATO SAN ANDRES UNIT #075	C-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-16	
30-005-10566	CATO SAN ANDRES UNIT #076	B-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Dec-09	INT TO CONVERT TO INJ 02/24/2010
30-005-10572	CATO SAN ANDRES UNIT #081	A-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	I	Feb-08	SAN ANDRES
30-005-10525	CATO SAN ANDRES UNIT #082	D-13-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-03	BLM RECORD TIL 10/19/10 R-9028A
30-005-20144	CATO SAN ANDRES UNIT #083	E-13-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-03	
30-005-10563	CATO SAN ANDRES UNIT #089	G-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Nov-14	10/06/08 RET TO PROD
30-005-20088	CATO SAN ANDRES UNIT #090	F-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Mar-17	07/30/07 RET TO PROD
30-005-10574	CATO SAN ANDRES UNIT #091	E-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-16	07/30/07 RET TO PROD
30-005-20018	CATO SAN ANDRES UNIT #092	H-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jun-09	
30-005-20022	CATO SAN ANDRES UNIT #093	G-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	10/10/08 HOOKED UP GAS
30-005-20677	CATO SAN ANDRES UNIT #094	G-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	I	Jun-15	
30-005-20023	CATO SAN ANDRES UNIT #095	F-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	10/11/08 HOOKED UP GAS
30-005-20002	CATO SAN ANDRES UNIT #096	E-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	10/11/08 HOOKED UP GAS
30-005-10567	CATO SAN ANDRES UNIT #097	H-17-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jun-09	RET TO PROD 10/09/08 HOOKED UP GAS
30-005-10474	CATO SAN ANDRES UNIT #098	G-17-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	10/03/08 HOOKED UP GAS
30-005-20007	CATO SAN ANDRES UNIT #100	J-17-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	May-09	SWAB 05/27/09
30-005-20010	CATO SAN ANDRES UNIT #101	I-17-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	
30-005-20039	CATO SAN ANDRES UNIT #102	L-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	10/19/08 HOOKED UP GAS
30-005-20032	CATO SAN ANDRES UNIT #103	K-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	May-09	SWAB 03/04/09
30-005-20040	CATO SAN ANDRES UNIT #104	J-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	10/03/08 HOOKED UP GAS
30-005-20033	CATO SAN ANDRES UNIT #105	I-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	10/06/2008 HOOKED UP GAS
30-005-20056	CATO SAN ANDRES UNIT #106	L-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-16	
30-005-20008	CATO SAN ANDRES UNIT #107	K-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-03	
30-005-20015	CATO SAN ANDRES UNIT #110	L-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	INT TO CONVERT INJ R9029A 07/02/10
30-005-20115	CATO SAN ANDRES UNIT #111	K-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	
30-005-20016	CATO SAN ANDRES UNIT #112	J-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-14	
30-005-20211	CATO SAN ANDRES UNIT #113	I-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Aug-16	
30-005-20292	CATO SAN ANDRES UNIT #114	P-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-09	07/02/10 INT TO CONV TO INJ R9029A
30-005-20031	CATO SAN ANDRES UNIT #116	N-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-09	BLM RECORD TIL 10/19/10 R-9029A

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30-005-20094	CATO SAN ANDRES UNIT #117	M-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Sep-99	BLM DENIED INT RWTP 07/21/10
30-005-20077	CATO SAN ANDRES UNIT #118	P-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Nov-14	
30-005-20103	CATO SAN ANDRES UNIT #119	O-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	10/06/08 HOOKED UP GAS
30-005-20137	CATO SAN ANDRES UNIT #120	N-15-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-16	
30-005-20041	CATO SAN ANDRES UNIT #121	P-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	G	Nov-14	SA 10/06/8 HOOKED UP GAS
30-005-20034	CATO SAN ANDRES UNIT #122	O-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	May-09	SWAB 03/08/2009
30-005-20042	CATO SAN ANDRES UNIT #123	N-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	May-09	RET TO PROD 03/10/2009
30-005-20035	CATO SAN ANDRES UNIT #124	M-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	May-09	RET TO PROD 03/12/09
30-005-20146	CATO SAN ANDRES UNIT #125	C-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SWAB 03/13/09
30-005-20083	CATO SAN ANDRES UNIT #126	B-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Oct-13	10/06/08 HOOKED UP GAS
30-005-20071	CATO SAN ANDRES UNIT #127	A-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	
30-005-20045	CATO SAN ANDRES UNIT #128	D-23-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-02	
30-005-20116	CATO SAN ANDRES UNIT #129	C-23-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-14	
30-005-20058	CATO SAN ANDRES UNIT #130	B-23-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/08/08 HOOKED UP GAS
30-005-20297	CATO SAN ANDRES UNIT #131	A-23-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-14	
30-005-20129	CATO SAN ANDRES UNIT #132	G-23-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20096	CATO SAN ANDRES UNIT #134	E-23-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20082	CATO SAN ANDRES UNIT #135	H-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-11	
30-005-20084	CATO SAN ANDRES UNIT #136	G-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-16	
30-005-20117	CATO SAN ANDRES UNIT #137	F-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	
30-005-20267	CATO SAN ANDRES UNIT #138	L-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20131	CATO SAN ANDRES UNIT #139	K-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jan-15	
30-005-20087	CATO SAN ANDRES UNIT #140	J-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-14	BLM DENIED INT TO RWTP 07/21/10
30-005-20105	CATO SAN ANDRES UNIT #142	K-23-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	
30-005-20260	CATO SAN ANDRES UNIT #143	J-23-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/8/08 HOOKED UP GAS
30-005-20215	CATO SAN ANDRES UNIT #144	M-22-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	
30-005-20191	CATO SAN ANDRES UNIT #145	A-29-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/18/08 HOOKED UP GAS
30-005-20192	CATO SAN ANDRES UNIT #146	D-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-14	10/19/08 HOOKED UP GAS
30-005-20193	CATO SAN ANDRES UNIT #147	C-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/19/08 HOOKED UP GAS
30-005-20204	CATO SAN ANDRES UNIT #148	D-27-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SWAB 03/18/09 BLM RECORD TIL 10/19/10
30-005-20257	CATO SAN ANDRES UNIT #149	A-27-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/09/08 HOOKED UP GAS SWAB 03/20/09

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30-005-20119	CATO SAN ANDRES UNIT #150	D-26-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/09/08 HOOKED GAS AND STARTED SELLING
30-005-20282	CATO SAN ANDRES UNIT #151	H-27-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Dec-04	BLM DENIED INT TO RWTP 07/21/10
30-005-20314	CATO SAN ANDRES UNIT #152	G-27-08S-30E	CANO PETRO OF NEW MEXICO, INC	F	O	May-09	SWAB BLM DENIED INT TO RWTP 07/21/10
30-005-20167	CATO SAN ANDRES UNIT #153	F-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	BLM DENIED INT TO RWTP 07/21/10
30-005-20172	CATO SAN ANDRES UNIT #154	E-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	SA 10/18/08 HOOKED UP GAS
30-005-20182	CATO SAN ANDRES UNIT #155	H-29-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/06/08 HOOKED UP GAS
30-005-20187	CATO SAN ANDRES UNIT #156	G-29-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/06/08 HOOKED UP GAS
30-005-20162	CATO SAN ANDRES UNIT #157	J-29-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/06/08 HOOKED UP GAS
30-005-20153	CATO SAN ANDRES UNIT #158	I-29-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Aug-11	10/06/08 HOOKED UP GAS
30-005-20152	CATO SAN ANDRES UNIT #159	L-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/07/08 HOOKED UP GAS
30-005-20151	CATO SAN ANDRES UNIT #160	K-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20150	CATO SAN ANDRES UNIT #161	J-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20180	CATO SAN ANDRES UNIT #162	I-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/09/08 HOOKED UP GAS
30-005-20101	CATO SAN ANDRES UNIT #163	K-27-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SWAB 03/27/09 BLM RECORD TIL 10/19/10
30-005-20100	CATO SAN ANDRES UNIT #164	M-27-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Aug-03	BLM DENIED INT TO RWTP 07/21/10
30-005-20139	CATO SAN ANDRES UNIT #165	O-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20140	CATO SAN ANDRES UNIT #166	N-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20141	CATO SAN ANDRES UNIT #167	M-28-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/07/08 HOOKED UP GAS
30-005-20126	CATO SAN ANDRES UNIT #168	P-29-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/07/08 HOOKED UP GAS
30-005-20190	CATO SAN ANDRES UNIT #169	O-29-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/07/08 HOOKED UP GAS
30-005-20133	CATO SAN ANDRES UNIT #170	D-34-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	10/9/08 HOOKED UP GAS
30-005-20188	CATO SAN ANDRES UNIT #174	G-32-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20189	CATO SAN ANDRES UNIT #175	F-32-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20197	CATO SAN ANDRES UNIT #176	I-33-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	
30-005-20179	CATO SAN ANDRES UNIT #177	I-33-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20224	CATO SAN ANDRES UNIT #178	M-34-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SA BLM DENIED INT RWTP 07/21/10
30-005-20207	CATO SAN ANDRES UNIT #179	P-33-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INT TO RWTP 07/21/10
30-005-20169	CATO SAN ANDRES UNIT #180	O-33-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	I	Jul-98	
30-005-20178	CATO SAN ANDRES UNIT #181	M-33-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	I	Oct-94	BLM DENIED INT TO RWTP 07/21/10
30-005-20305	CATO SAN ANDRES UNIT #182	4-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	
30-005-20545	CATO SAN ANDRES UNIT #183	3-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	May-09	

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30-005-20243	CATO SAN ANDRES UNIT #184	4-03-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	BLM DENIED INTO TO RWTP 07/21/10
30-005-20186	CATO SAN ANDRES UNIT #185	G-04-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	
30-005-20217	CATO SAN ANDRES UNIT #186	E-04-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	
30-005-20596	CATO SAN ANDRES UNIT #187	H-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	
30-005-20273	CATO SAN ANDRES UNIT #188	G-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jan-05	
30-005-20261	CATO SAN ANDRES UNIT #189	F-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jun-01	
30-005-20544	CATO SAN ANDRES UNIT #190	E-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jan-05	SAN ANDRES
30-005-20526	CATO SAN ANDRES UNIT #191	H-06-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jan-05	
30-005-20482	CATO SAN ANDRES UNIT #193	I-06-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-02	
30-005-20546	CATO SAN ANDRES UNIT #194	L-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Oct-03	
30-005-20272	CATO SAN ANDRES UNIT #195	K-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Apr-99	
30-005-20598	CATO SAN ANDRES UNIT #196	J-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-02	
30-005-20230	CATO SAN ANDRES UNIT #197	I-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-02	
30-005-20599	CATO SAN ANDRES UNIT #198	L-04-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-03	
30-005-20597	CATO SAN ANDRES UNIT #199	M-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Apr-99	
30-005-20472	CATO SAN ANDRES UNIT #201	D-08-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Apr-99	
30-005-20524	CATO SAN ANDRES UNIT #202	C-08-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Apr-99	
30-005-20241	CATO SAN ANDRES UNIT #203	A-08-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jun-03	
30-005-20556	CATO SAN ANDRES UNIT #204	H-07-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-03	
30-005-21163	CATO SAN ANDRES UNIT #302	C-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-16	SAN ANDRES
30-005-21164	CATO SAN ANDRES UNIT #328	M-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-16	SAN ANDRES PLRK TO QN 08/03/10 SEE PP
30-005-21165	CATO SAN ANDRES UNIT #330	I-09-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Mar-17	SAN ANDRES
30-005-21167	CATO SAN ANDRES UNIT #355	E-16-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-16	SAN ANDRES 08/26/07 RET TO PROD
30-005-27969	CATO SAN ANDRES UNIT #404	C-27-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	SAN ANDRES
30-005-27970	CATO SAN ANDRES UNIT #407	J-27-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-11	SAN ANDRES 10/23/2007 SPUD
30-005-27980	CATO SAN ANDRES UNIT #505	N-02-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jul-11	SAN ANDRES 12/12/07 SPUD
30-005-27973	CATO SAN ANDRES UNIT #516	D-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	May-15	San Andres
30-005-27962	CATO SAN ANDRES UNIT #517	E-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-16	San Andres
30-005-27963	CATO SAN ANDRES UNIT #518	F-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-16	SAN ANDRES 12/7/07 SPUD
30-005-28027	CATO SAN ANDRES UNIT #520	H-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jan-12	San Andres
30-005-27974	CATO SAN ANDRES UNIT #531	L-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-16	San Andres
30-005-27964	CATO SAN ANDRES UNIT #532	L-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-16	San Andres

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30-005-27961	CATO SAN ANDRES UNIT #534	J-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-16	San Andres
30-005-27984	CATO SAN ANDRES UNIT #545	M-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Dec-16	San Andres
30-005-29051	CATO SAN ANDRES UNIT #557Y	O-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Apr-17	SAN ANDRES
30-005-28010	CATO SAN ANDRES UNIT #558	M-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Nov-14	SAN ANDRES
30-005-28011	CATO SAN ANDRES UNIT #559	N-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Nov-14	San Andres
30-005-28012	CATO SAN ANDRES UNIT #560	O-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Nov-14	SAN ANDRES
30-005-28029	CATO SAN ANDRES UNIT #561	O-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Apr-15	SAN ANDRES 11/13/09 INSTALL PUMP
30-005-28017	CATO SAN ANDRES UNIT #574	H-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Dec-16	San Andres
30-005-29025	CATO SAN ANDRES UNIT #586	E-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jan-17	San Andres
30-005-29024	CATO SAN ANDRES UNIT #587	G-14-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-16	San Andres
30-041-20431	CONE FEDERAL #001	A-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Dec-10	SA 05/12/08 RET WELL TO PROD/FED
30-041-20440	CONE FEDERAL #002	C-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-14	SA 05/12/08 RET WELL TO PROD/FED
30-041-20441	CONE FEDERAL #003	G-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-14	SA 05/12/08 RET WELL TO PROD/FED
30-041-20450	CONE FEDERAL #004	I-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Dec-14	SA 05/12/08 RET WELL TO PROD/FED
30-041-20464	CONE FEDERAL #005	2-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-16	SAN ANDRES
30-041-20458	CONE FEDERAL #006	4-30-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-16	SAN ANDRES
30-041-20468	CONE FEDERAL #007	H-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-16	SAN ANDRES
30-041-20477	CONE FEDERAL #008	P-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	S	May-16	
30-041-20485	CONE FEDERAL #009	K-30-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SAN ANDRES SWAB 05/25/09
30-041-20486	CONE FEDERAL #010	N-30-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SAN ANDRES
30-041-20487	CONE FEDERAL #011	B-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-16	SAN ANDRES
30-041-20488	CONE FEDERAL #012	F-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-16	SAN ANDRES
30-041-20049	CONE FEDERAL #013	3-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-05	SAN ANDRES
30-041-20495	CONE FEDERAL #014	K-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jan-15	SAN ANDRES 05/12/08 RET WELL TO PROD/FED
30-041-20496	CONE FEDERAL #015	J-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-16	SAN ANDRES
30-041-20497	CONE FEDERAL #016	O-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-15	SAN ANDRES
30-041-20498	CONE FEDERAL #017	3-30-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-16	SAN ANDRES SWAB 05/27/09
30-041-20499	CONE FEDERAL #018	2-30-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-16	SAN ANDRES
30-041-20510	CONE FEDERAL #019	1-30-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-14	SAN ANDRES
30-041-20509	CONE FEDERAL #020	1-31-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-03	SAN ANDRES
30-041-20549	CONE FEDERAL #021	4-19-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SAN ANDRES RET TO PROD 05/29/09
30-041-20566	CONE FEDERAL #027	3-19-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Apr-15	SAN ANDRES

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30-041-20567	CONE FEDERAL #028	2-19-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-05	SAN ANDRES
30-041-20585	CONE FEDERAL #031Y	C-19-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	May-09	SAN ANDRES SWAB 05/23/09
30-005-20557	EXXON FEDERAL #001	G-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-09	SAN ANDRES RET TO PROD 09/28/09
30-005-20584	EXXON FEDERAL #002	J-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-09	SAN ANDRES RET TO PROD 09/24/09
30-005-20585	EXXON FEDERAL #003	5-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-09	SAN ANDRES 10/01/09 RET TO PROD
30-005-20611	EXXON FEDERAL #004	1-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-09	SAN ANDRES RET TO PROD 10/06/09
30-005-20541	GRAVES #001	J-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	P	O	Nov-09	SAN ANDRES 11/2/09 RET TO PROD
30-005-20549	GRAVES #002	K-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	P	O	Aug-04	SAN ANDRES
30-005-20577	GRAVES #003	6-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	P	O	Sep-04	SAN ANDRES
30-005-20579	GRAVES #005	N 06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	P	O	Sep-04	SAN ANDRES
30-005-20580	GRAVES #006	O-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	P	O	Jul-03	SAN ANDRES
30-005-20607	GRAVES #007	I-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	P	O	Nov-09	SAN ANDRES 11/03/09 RET TO PROD
30-005-20621	GRAVES #008	P-06-08S-31E	CANO PETRO OF NEW MEXICO, INC.	P	O	Oct-03	SAN ANDRES
30-005-20646	INGRAM FEDERAL #001Y	1-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES
30-005-20488	INGRAM FEDERAL #002	1-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	S	Dec-94	SAN ANDRES
30-005-20605	INGRAM FEDERAL #006	F-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-09	SA RET TO PROD 11/05/09
30-005-20639	INGRAM FEDERAL #007	L-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-09	SAN ANDRES RET TO PROD 11/7/09
30-005-20702	INGRAM FEDERAL #009	4-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES
30-005-20703	INGRAM FEDERAL #010	3-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES
30-005-20704	INGRAM FEDERAL #011	2-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES
30-005-20705	INGRAM FEDERAL #012	1-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES
30-005-20743	INGRAM FEDERAL #013	G-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES
30-005-20744	INGRAM FEDERAL #014	F-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES
30-005-20745	INGRAM FEDERAL #015	K-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES INT TO PROD 08/10/10 BLM
30-005-20782	INGRAM FEDERAL #016	N-05-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES
30-005-20783	INGRAM FEDERAL #017	C-08-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES 09/01/09 INT TO TA
30-005-21025	INGRAM FEDERAL #019	M-09-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-06	SAN ANDRES
30-041-20469	LANGLEY FEDERAL #001	J-30-07S-32E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-05	INT TO PROD 08/10/2010 BLM
30-005-20838	MILLER 33 FEDERAL #002	J-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Aug-03	SAN ANDRES
30-005-20886	MILLER 33 FEDERAL #003	H-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Apr-99	SAN ANDRES

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30-005-20890	MILLER 33 FEDERAL #004	P-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jan-02	SAN ANDRES
30-005-20606	MILLER FEDERAL #001	O-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-02	SAN ANDRES
30-005-20613	MILLER FEDERAL #002	I-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-03	SAN ANDRES
30-005-20622	MILLER FEDERAL #003	G-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-03	SAN ANDRES
30-005-20617	OAKSON A FEDERAL #002	N-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-01	SAN ANDRES
30-005-20633	OAKSON A FEDERAL #003	M-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-01	SAN ANDRES
30-005-20635	OAKSON A FEDERAL #004	K-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-01	SAN ANDRES INT TO PROD 08/10/10 BLM
30-005-20647	OAKSON A FEDERAL #005	L-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Aug-01	SAN ANDRES
30-005-20640	OAKSON B FEDERAL #001	F-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Sep-04	SA 09/30/09 ACCEPTED FOR RECORD SWAB
30-005-20652	OAKSON B FEDERAL #002	E-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jun-02	SA 09/30/09 BLM EVALUATE WELL
30-005-20682	OAKSON B FEDERAL #003	C-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-09	SA RET TO PROD 02/26/2010
30-005-20671	OAKSON B FEDERAL #004	D-33-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-09	SA 07/02/09 RET TO PROD
30-005-20698	OAKSON FEDERAL #001	M-28-07S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Nov-03	SAN ANDRES
30-005-20458	PAYE FEDERAL #001	I-04-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-03	SAN ANDRES
30-005-20484	PAYE FEDERAL #002	J-04-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-03	
30-005-20492	PAYE FEDERAL #004	J-04-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-03	INT TO PROD 08/10/10 BLM
30-005-20493	PAYE FEDERAL #005	G-04-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Aug-04	
30-005-20494	PAYE FEDERAL #006	F-04-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jul-03	
30-005-20500	PAYE FEDERAL #008	H-04-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-04	
30-005-20501	PAYE FEDERAL #009	I-04-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-04	
30-005-20502	PAYE FEDERAL #010	J-04-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-02	
30-005-20904	SIETE FEDERAL #002Y	H-17-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Apr-97	SAN ANDRES
30-005-20910	SIETE FEDERAL #003	G-17-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Jan-00	SAN ANDRES
30-005-20947	SIETE FEDERAL #004	A-17-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Apr-97	SAN ANDRES
30-005-20974	SIETE FEDERAL #005	I-17-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Apr-97	SAN ANDRES
30-005-21031	SIETE FEDERAL #006	K-17-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Apr-97	SAN ANDRES INT TO PROD 08/10/10 BLM
30-005-20945	SIETE FEDERAL WEST #001	H-18-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-98	SAN ANDRES
30-041-20445	STATE #001	E-32-07S-32E	CANO PETRO OF NEW MEXICO, INC.	S	O	Jan-92	
30-041-20542	STATE #002	D-32-07S-32E	CANO PETRO OF NEW MEXICO, INC.	S	O	May-00	
30-005-20455	STRANGE FEDERAL #001	E-09-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Mar-02	INT TO PROD 08/10/10 BLM
30-005-20486	STRANGE FEDERAL #002	C-09-08S-31E	CANO PETRO OF NEW MEXICO, INC.	F	O	Oct-03	

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30-005-29028	CATO SAN ANDRES UNIT #557	O-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O	Dec-09	Plugged, Not Released
30-005-28013	CATO SAN ANDRES UNIT #562	M-12-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O		Plugged, Not Released
30-005-29030	CATO SAN ANDRES UNIT #827	F-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O		Zones Temporarily Plugged
30-005-20165	CATO SAN ANDRES UNIT #171	G-33-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	I		Well Never Reported Production
30-005-20177	CATO SAN ANDRES UNIT #172	E-33-08S-30E	CANO PETRO OF NEW MEXICO, INC.	F	I		Well Never Reported Production
30-005-20529	CATO SAN ANDRES UNIT #200	P-6-09S-30E	CANO PETRO OF NEW MEXICO, INC.	F	I		Well Never Reported Production
30-005-27982	CATO SAN ANDRES UNIT #400D	D-10-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O		Cancelled APD
30-005-27998	CATO SAN ANDRES UNIT #410O	O-05-09S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O		Cancelled APD
30-005-29128	CATO SAN ANDRES UNIT #548	P-11-08S-30E	CANO PETRO OF NEW MEXICO, INC.	P	O		Cancelled APD
30-005-28033	CATO SAN ANDRES UNIT #852	M-12-08S-30E	CANO PETRO OF NEW MEXICO, INC.	S	O		Cancelled APD

EXHIBIT 26

Exhibit 2: Cano Bonding Status

EXHIBIT 26

Well Name	Lease Type	ULSTR	API	Last Prod/Inj	Inactive Additional Bond Due	Measured Depth (ft)	Required Bond Amount	Bond Required Now	Bond In Place	In Violation
CATO SAN ANDRES UNIT #001	P	H-03-08S-30E	30-005-10584	Nov-14	12/1/2016	3505	$8,505	Y	$8,505	
CATO SAN ANDRES UNIT #002	P	G-03-08S-30E	30-005-20932	Mar-15	4/1/2017	3445	$8,445	Y	$8,445	
CATO SAN ANDRES UNIT #003	P	E-04-08S-30E	30-005-20678	Jan-17	2/1/2019	3350	$8,350		$0	
CATO SAN ANDRES UNIT #005	S	L-02-08S-30E	30-005-20271	Nov-14	12/1/2016	3492	$8,492	Y	$8,492	
CATO SAN ANDRES UNIT #006	S	N-02-08S-30E	30-005-20001	Jul-11	8/1/2013	3540	$8,540	Y	$8,540	
CATO SAN ANDRES UNIT #007	S	M-02-08S-30E	30-005-10536	Apr-15	5/1/2017	3498	$8,498	Y	$0	Y
CATO SAN ANDRES UNIT #008	P	P-03-08S-30E	30-005-20160	Nov-14	12/1/2016	3498	$8,498	Y	$8,498	
CATO SAN ANDRES UNIT #009	P	O-03-08S-30E	30-005-10537	Aug-16	9/1/2018	3600	$8,600	Y	$0	Y
CATO SAN ANDRES UNIT #010	P	M-04-08S-30E	30-005-20161	Mar-17	4/1/2019	3387	$8,387		$0	
CATO SAN ANDRES UNIT #013	P	D-09-08S-30E	30-005-20142	Mar-17	4/1/2019	3384	$8,384		$0	
CATO SAN ANDRES UNIT #014	P	C-09-08S-30E	30-005-20066	Mar-17	4/1/2019	3500	$8,500		$0	
CATO SAN ANDRES UNIT #017	P	C-10-08S-30E	30-005-10501	Sep-09	10/1/2011	3420	$8,420	Y	$8,420	
CATO SAN ANDRES UNIT #020	P	D-11-08S-30E	30-005-10504	Aug-16	9/1/2018	3650	$8,650	Y	$0	Y
CATO SAN ANDRES UNIT #021	P	C-11-08S-30E	30-005-20069	Aug-16	9/1/2018	3532	$8,532	Y	$0	Y
CATO SAN ANDRES UNIT #023	P	A-11-08S-30E	30-005-10523	Aug-16	9/1/2018	3576	$8,576	Y	$0	Y
CATO SAN ANDRES UNIT #025	P	H-11-08S-30E	30-005-20294	Jul-11	8/1/2013	3642	$8,642	Y	$8,642	
CATO SAN ANDRES UNIT #027	P	F-11-08S-30E	30-005-10491	May-09	6/1/2011	3562	$8,562	Y	$8,562	
CATO SAN ANDRES UNIT #028	P	E-11-08S-30E	30-005-10503	Aug-16	9/1/2018	3618	$8,518	Y	$0	Y
CATO SAN ANDRES UNIT #031	P	F-10-08S-30E	30-005-20170	Sep-09	10/1/2011	3453	$8,453	Y	$8,453	
CATO SAN ANDRES UNIT #032	P	E-10-08S-30E	30-005-10522	Sep-09	10/1/2011	3410	$8,410	Y	$8,410	
CATO SAN ANDRES UNIT #035	P	F-09-08S-30E	30-005-20046	Mar-17	4/1/2019	3500	$8,500		$0	
CATO SAN ANDRES UNIT #036	P	E-09-08S-30E	30-005-20065	Dec-06	1/1/2009	3350	$8,350	Y	$8,350	
CATO SAN ANDRES UNIT #041	P	L-09-08S-30E	30-005-20047	Jul-11	8/1/2013	3500	$8,500	Y	$8,500	
CATO SAN ANDRES UNIT #042	P	K-09-08S-30E	30-005-20089	Jul-11	8/1/2013	3403	$8,403	Y	$8,403	
CATO SAN ANDRES UNIT #044	P	I-09-08S-30E	30-005-20004	May-09	6/1/2011	3500	$8,500	Y	$8,500	

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CATO SAN ANDRES UNIT #045	P	L-10-08S-30E	30-005-20130	Jun-09	7/1/2011	3445	$8,445	Y	$8,445	
CATO SAN ANDRES UNIT #046	P	K-10-08S-30E	30-005-10538	May-09	6/1/2011	3600	$8,600	Y	$8,600	
CATO SAN ANDRES UNIT #047	P	J-10-08S-30E	30-005-10578	Jul-11	8/1/2013	3480	$8,480	Y	$8,480	
CATO SAN ANDRES UNIT #048	P	I-10-08S-30E	30-005-10484	Mar-18	4/1/2020	3620	$8,620		$0	
CATO SAN ANDRES UNIT #049	P	L-11-08S-30E	30-005-10455	Aug-16	9/1/2018	3561	$8,561	Y	$0	Y
CATO SAN ANDRES UNIT #050	P	J-11-08S-30E	30-005-29021	Oct-16	11/1/2018	4055	$9,055		$0	
CATO SAN ANDRES UNIT #051	P	I-11-08S-30E	30-005-10539	Aug-16	9/1/2018	3682	$8,682	Y	$0	Y
CATO SAN ANDRES UNIT #052	P	M-12-08S-30E	30-005-20009	Jul-11	8/1/2013	3714	$8,714	Y	$8,714	
CATO SAN ANDRES UNIT #053	P	P-11-08S-30E	30-005-20293	Jul-04	8/1/2006	3665	$8,665	Y	$8,665	
CATO SAN ANDRES UNIT #055	P	N-11-08S-30E	30-005-10560	May-09	6/1/2011	3600	$8,600	Y	$8,600	
CATO SAN ANDRES UNIT #056	P	M-11-08S-30E	30-005-10579	Sep-16	10/1/2018	3523	$8,523		$0	
CATO SAN ANDRES UNIT #057	P	P-10-08S-30E	30-005-10502	Mar-18	4/1/2020	3600	$8,600		$0	
CATO SAN ANDRES UNIT #058	P	O-10-08S-30E	30-005-10500	Oct-04	11/1/2006	3515	$8,515	Y	$8,515	
CATO SAN ANDRES UNIT #059	P	N-10-08S-30E	30-005-10570	May-09	6/1/2011	3600	$8,600	Y	$8,600	
CATO SAN ANDRES UNIT #060	P	M-10-08S-30E	30-005-10571	Jul-11	8/1/2013	3492	$8,492	Y	$8,492	
CATO SAN ANDRES UNIT #061	P	P-09-08S-30E	30-005-20005	May-09	6/1/2011	3450	$8,450	Y	$8,450	
CATO SAN ANDRES UNIT #063	P	N-09-08S-30E	30-005-20049	Jul-16	8/1/2018	3490	$8,490	Y	$0	Y
CATO SAN ANDRES UNIT #064	P	M-09-08S-30E	30-005-20028	Jul-16	8/1/2018	3450	$8,450	Y	$0	Y
CATO SAN ANDRES UNIT #068	P	B-17-08S-30E	30-005-20236	Jul-16	8/1/2018	3450	$8,450	Y	$0	Y
CATO SAN ANDRES UNIT #069	P	A-17-08S-30E	30-005-10586	Jul-16	8/1/2018	3605	$8,605	Y	$0	Y
CATO SAN ANDRES UNIT #070	S	D-16-08S-30E	30-005-20019	Jul-11	8/1/2013	3450	$8,450	Y	$8,450	
CATO SAN ANDRES UNIT #071	S	C-16-08S-30E	30-005-20020	Jul-11	8/1/2013	3480	$8,480	Y	$8,480	
CATO SAN ANDRES UNIT #072	S	B-16-08S-30E	30-005-20021	Mar-17	4/1/2019	3460	$8,460		$0	
CATO SAN ANDRES UNIT #073	S	A-16-08S-30E	30-005-20017	Jul-11	8/1/2013	3450	$8,450	Y	$8,450	
CATO SAN ANDRES UNIT #074	P	D-15-08S-30E	30-005-10573	Jul-16	8/1/2018	3541	$8,541	Y	$0	Y
CATO SAN ANDRES UNIT #075	P	C-15-08S-30E	30-005-10562	Jul-16	8/1/2018	3530	$8,530	Y	$0	Y

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CATO SAN ANDRES UNIT #076	P	B-15-08S-30E	30-005-10566	Dec-09	1/1/2012	3600	$8,600	Y	$8,600	
CATO SAN ANDRES UNIT #077	P	A-15-08S-30E	30-005-10532	Mar-18	4/1/2020	3560	$8,560		$0	
CATO SAN ANDRES UNIT #081	P	A-14-08S-30E	30-005-10572	Feb-08	3/1/2010	3680	$8,680	Y	$8,680	
CATO SAN ANDRES UNIT #084	P	H-14-08S-30E	30-005-20174	Mar-18	4/1/2020	3674	$8,674		$0	
CATO SAN ANDRES UNIT #085	P	G-14-08S-30E	30-005-10588	Mar-18	4/1/2020	3654	$8,654		$0	
CATO SAN ANDRES UNIT #086	P	F-14-08S-30E	30-005-20109	Mar-18	4/1/2020	3610	$8,610		$0	
CATO SAN ANDRES UNIT #087	P	E-14-08S-30E	30-005-10561	Mar-18	4/1/2020	3570	$8,570		$0	
CATO SAN ANDRES UNIT #088	P	H-15-08S-30E	30-005-20090	Mar-18	4/1/2020	3558	$8,558		$0	
CATO SAN ANDRES UNIT #089	P	G-15-08S-30E	30-005-10563	Nov-14	12/1/2016	3558	$8,558	Y	$8,600	
CATO SAN ANDRES UNIT #090	P	F-15-08S-30E	30-005-20088	Mar-17	4/1/2019	3531	$8,531		$0	
CATO SAN ANDRES UNIT #091	P	E-15-08S-30E	30-005-10574	Jul-16	8/1/2018	3533	$8,533	Y	$0	Y
CATO SAN ANDRES UNIT #092	S	H-16-08S-30E	30-005-20018	Jun-09	7/1/2011	3510	$8,510	Y	$8,510	
CATO SAN ANDRES UNIT #093	S	G-16-08S-30E	30-005-20022	Jul-11	8/1/2013	3540	$8,540	Y	$8,540	
CATO SAN ANDRES UNIT #094	S	G-16-08S-30E	30-005-20677	Jun-15	7/1/2017	3550	$8,550	Y	$0	Y
CATO SAN ANDRES UNIT #095	S	F-16-08S-30E	30-005-20023	Jul-11	8/1/2013	3506	$8,506	Y	$8,506	
CATO SAN ANDRES UNIT #096	S	E-16-08S-30E	30-005-20002	Jul-11	8/1/2013	3598	$8,598	Y	$8,598	
CATO SAN ANDRES UNIT #097	P	H-17-08S-30E	30-005-10567	Jun-09	7/1/2011	3600	$8,600	Y	$8,600	
CATO SAN ANDRES UNIT #098	P	G-17-08S-30E	30-005-10474	Jul-11	8/1/2013	3682	$8,682	Y	$8,682	
CATO SAN ANDRES UNIT #100	P	J-17-08S-30E	30-005-20007	May-09	6/1/2011	3450	$8,450	Y	$8,450	
CATO SAN ANDRES UNIT #101	P	I-17-08S-30E	30-005-20010	Jul-11	8/1/2013	3488	$8,488	Y	$8,488	
CATO SAN ANDRES UNIT #102	S	L-16-08S-30E	30-005-20039	Jul-11	8/1/2013	3500	$8,500	Y	$8,500	
CATO SAN ANDRES UNIT #103	S	K-16-08S-30E	30-005-20032	May-09	6/1/2011	3497	$8,497	Y	$8,497	
CATO SAN ANDRES UNIT #104	S	J-16-08S-30E	30-005-20040	Jul-11	8/1/2013	3540	$8,540	Y	$8,540	
CATO SAN ANDRES UNIT #105	S	I-16-08S-30E	30-005-20033	Jul-11	8/1/2013	3560	$8,560	Y	$8,560	
CATO SAN ANDRES UNIT #108	P	J-15-08S-30E	30-005-20078	Sep-17	10/1/2019	3600	$8,600		$0	
CATO SAN ANDRES UNIT #109	P	I-15-08S-30E	30-005-20068	Jan-18	2/1/2020	3700	$8,700		$0	

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CATO SAN ANDRES UNIT #118	P	P-15-08S-30E	30-005-20077	Nov-14	12/1/2016	3650	$8,650	Y	$8,650	
CATO SAN ANDRES UNIT #119	P	O-15-08S-30E	30-005-20103	Jul-11	8/1/2013	3650	$8,650	Y	$8,650	
CATO SAN ANDRES UNIT #121	S	P-16-08S-30E	30-005-20041	Nov-14	12/1/2016	3598	$8,598	Y	$8,598	
CATO SAN ANDRES UNIT #122	S	O-16-08S-30E	30-005-20034	May-09	6/1/2011	3550	$8,550	Y	$8,550	
CATO SAN ANDRES UNIT #123	S	N-16-08S-30E	30-005-20042	May-09	6/1/2011	3520	$8,520	Y	$8,520	
CATO SAN ANDRES UNIT #124	S	M-16-08S-30E	30-005-20035	May-09	6/1/2011	3500	$8,500	Y	$8,500	
CATO SAN ANDRES UNIT #126	P	B-22-08S-30E	30-005-20083	Oct-13	11/1/2015	3648	$8,648	Y	$8,650	
CATO SAN ANDRES UNIT #127	P	A-22-08S-30E	30-005-20071	Jul-11	8/1/2013	3700	$8,700	Y	$8,700	
CATO SAN ANDRES UNIT #135	P	H-22-08S-30E	30-005-20082	Jul-11	8/1/2013	3700	$8,700	Y	$8,700	
CATO SAN ANDRES UNIT #136	P	G-22-08S-30E	30-005-20084	Aug-16	9/1/2018	3650	$8,650	Y	$0	Y
CATO SAN ANDRES UNIT #183	P	J-05-09S-30E	30-005-20545	May-09	6/1/2011	3415	$8,415	Y	$8,415	
CATO SAN ANDRES UNIT #189	P	F-05-09S-30E	30-005-20261	Jun-01	7/1/2003	3480	$8,480	Y	$8,480	
CATO SAN ANDRES UNIT #190	P	E-05-09S-30E	30-005-20544	Jan-05	2/1/2007	3475	$8,475	Y	$8,475	
CATO SAN ANDRES UNIT #191	P	H-06-09S-30E	30-005-20526	Jan-05	2/1/2007	3360	$8,360	Y	$8,360	
CATO SAN ANDRES UNIT #194	P	L-05-09S-30E	30-005-20546	Oct-03	11/1/2005	3370	$8,370	Y	$8,370	
CATO SAN ANDRES UNIT #195	P	K-05-09S-30E	30-005-20272	Apr-99	5/1/2001	3329	$8,329	Y	$8,329	
CATO SAN ANDRES UNIT #196	P	J-05-09S-30E	30-005-20598	Aug-02	9/1/2004	3492	$8,450	Y	$8,450	
CATO SAN ANDRES UNIT #197	P	I-05-09S-30E	30-005-20230	Jul-02	8/1/2004	3507	$8,507	Y	$8,507	
CATO SAN ANDRES UNIT #199	P	M-05-09S-30E	30-005-20597	Apr-99	5/1/2001	3450	$8,450	Y	$8,450	
CATO SAN ANDRES UNIT #201	P	D-08-09S-30E	30-005-20472	Apr-99	5/1/2001	3364	$8,364	Y	$8,364	
CATO SAN ANDRES UNIT #203	P	A-08-09S-30E	30-005-20241	Jun-03	7/1/2005	3413	$8,413	Y	$8,413	
CATO SAN ANDRES UNIT #302	P	C-09-08S-30E	30-005-21163	Jul-16	8/1/2018	3447	$8,447	Y	$0	Y
CATO SAN ANDRES UNIT #328	P	M-09-08S-30E	30-005-21164	Jul-16	8/1/2018	3448	$8,448	Y	$0	Y
CATO SAN ANDRES UNIT #330	P	I-09-08S-30E	30-005-21165	Mar-17	4/1/2019	3560	$8,560		$0	
CATO SAN ANDRES UNIT #334	P	J-10-08S-30E	30-005-21166	Mar-19	4/1/2020	3600	$8,600		$0	
CATO SAN ANDRES UNIT #355	S	E-16-08S-30E	30-005-21167	Jul-16	8/1/2018	3552	$8,552	Y	$0	Y

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CATO SAN ANDRES UNIT #504	S	M-02-08S-30E	30-005-27971	Feb-18	3/1/2020	3860	$8,860		$0	
CATO SAN ANDRES UNIT #505	S	N-02-08S-30E	30-005-27980	Jul-11	8/1/2013	3863	$8,863	Y	$8,863	
CATO SAN ANDRES UNIT #506	S	O-02-08S-30E	30-005-27981	Feb-18	3/1/2020	3935	$8,935		$0	
CATO SAN ANDRES UNIT #507	S	O-02-08S-30E	30-005-28022	Mar-18	4/1/2020	3956	$8,956		$8,956	
CATO SAN ANDRES UNIT #516	P	D-11-08S-30E	30-005-27973	May-15	6/1/2017	4006	$9,006	Y	$0	Y
CATO SAN ANDRES UNIT #517	P	E-11-08S-30E	30-005-27962	Aug-16	9/1/2018	4015	$9,015	Y	$0	Y
CATO SAN ANDRES UNIT #518	P	F-11-08S-30E	30-005-27963	Aug-16	9/1/2018	4081	$9,081	Y	$0	Y
CATO SAN ANDRES UNIT #519	P	A-11-08S-30E	30-005-27989	Feb-18	3/1/2020	4055	$9,055		$0	
CATO SAN ANDRES UNIT #520	P	H-11-08S-30E	30-005-28027	Jan-12	2/1/2014	4500	$9,500	Y	$9,500	
CATO SAN ANDRES UNIT #531	P	L-11-08S-30E	30-005-27974	Aug-16	9/1/2018	4030	$9,030	Y	$0	Y
CATO SAN ANDRES UNIT #532	P	L-11-08S-30E	30-005-27964	Aug-16	9/1/2018	4062	$9,062	Y	$0	Y
CATO SAN ANDRES UNIT #533	P	K-11-08S-30E	30-005-27985	Mar-18	4/1/2020	4005	$9,005		$0	
CATO SAN ANDRES UNIT #534	P	J-11-08S-30E	30-005-27961	Aug-16	9/1/2018	4010	$9,010	Y	$0	Y
CATO SAN ANDRES UNIT #535	P	I-11-08S-30E	30-005-27983	Jan-18	2/1/2020	4020	$9,020		$0	
CATO SAN ANDRES UNIT #544	P	M-11-08S-30E	30-005-27986	Sep-17	10/1/2019	3940	$8,940		$0	
CATO SAN ANDRES UNIT #545	P	M-11-08S-30E	30-005-27984	Dec-16	1/1/2019	3990	$8,990		$0	
CATO SAN ANDRES UNIT #546	S	O-11-08S-30E	30-005-27987	Sep-17	10/1/2019	4015	$9,015		$0	
CATO SAN ANDRES UNIT #547	S	P-11-08S-30E	30-005-27988	Oct-17	11/1/2019	4080	$9,080		$0	
CATO SAN ANDRES UNIT #557	P	O-10-08S-30E	30-005-28028	Dec-09	1/1/2012	3484	$8,484	Y	$8,484	
CATO SAN ANDRES UNIT #557Y	P	O-10-08S-30E	30-005-29051	Apr-17	5/1/2019	4022	$9,022		$0	
CATO SAN ANDRES UNIT #558	P	M-11-08S-30E	30-005-28010	Nov-14	12/1/2016	3960	$8,960	Y	$8,960	
CATO SAN ANDRES UNIT #559	P	N-11-08S-30E	30-005-28011	Nov-14	12/1/2016	3960	$8,960	Y	$8,960	
CATO SAN ANDRES UNIT #560	P	O-11-08S-30E	30-005-28012	Nov-14	12/1/2016	4000	$9,000	Y	$9,000	
CATO SAN ANDRES UNIT #561	P	O-11-08S-30E	30-005-28029	Apr-15	5/1/2017	4100	$9,100	Y	$0	Y
CATO SAN ANDRES UNIT #562	P	M-12-08S-30E	30-005-28013			3370			$0	
CATO SAN ANDRES UNIT #570	P	G-15-08S-30E	30-005-28030	Feb-18	3/1/2020	4010	$9,010		$0	

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CATO SAN ANDRES UNIT #571	P	E-14-08S-30E	30-005-28014	Feb-18	3/1/2020	3960	$8,960		$0	
CATO SAN ANDRES UNIT #573	P	G-14-08S-30E	30-005-28016	Feb-18	3/1/2020	4010	$9,010		$0	
CATO SAN ANDRES UNIT #574	P	H-14-08S-30E	30-005-28017	Dec-16	1/1/2019	4045	$9,045		$0	
CATO SAN ANDRES UNIT #584	P	G-15-08S-30E	30-005-28031	Mar-18	4/1/2020	4500	$9,500		$0	
CATO SAN ANDRES UNIT #585	P	E-14-08S-30E	30-005-29026	Feb-18	3/1/2020	3990	$8,990		$0	
CATO SAN ANDRES UNIT #586	P	E-14-08S-30E	30-005-29025	Jan-17	2/1/2019	3995	$8,995		$0	
CATO SAN ANDRES UNIT #587	P	G-14-08S-30E	30-005-29024	Aug-16	9/1/2018	3995	$8,995	Y	$0	Y
CATO SAN ANDRES UNIT #588	P	H-14-08S-30E	30-005-29027	Dec-17	1/1/2020	4050	$9,050		$0	
CATO SAN ANDRES UNIT #822	P	B-11-08S-30E	30-005-29028	Mar-18	4/1/2020	4000	$9,000		$0	
CATO SAN ANDRES UNIT #826	P	G-11-08S-30E	30-005-29029	Mar-18	4/1/2020	4000	$9,000		$0	
CATO SAN ANDRES UNIT #827	P	F-11-08S-30E	30-005-29030			1155			$0	
CATO SAN ANDRES UNIT #854	P	O-11-08S-30E	30-005-29031	Mar-18	4/1/2020	4030	$9,030		$0	
GRAVES #001	P	J-06-08S-31E	30-005-20541	Nov-09	12/1/2011	3860	$8,860	Y	$8,860	
GRAVES #002	P	K-06-08S-31E	30-005-20549	Aug-04	9/1/2006	3810	$8,810	Y	$8,810	
GRAVES #003	P	6-06-08S-31E	30-005-20577	Sep-04	10/1/2006	3778	$8,778	Y	$8,778	
GRAVES #005	P	N-06-08S-31E	30-005-20579	Sep-04	10/1/2006	3860	$8,860	Y	$8,860	
GRAVES #006	P	O-06-08S-31E	30-005-20580	Jul-03	8/1/2005	3850	$8,850	Y	$8,850	
GRAVES #007	P	I-06-08S-31E	30-005-20607	Nov-09	12/1/2011	3873	$8,873	Y	$8,873	
GRAVES #008	P	P-06-08S-31E	30-005-20621	Oct-03	11/1/2005	3907	$8,907	Y	$8,907	
STATE #001	S	E-32-07S-32E	30-041-20445	Jan-92	2/1/1994	4405	$9,405	Y	$9,405	
STATE #002	S	D-32-07S-32E	30-041-20542	May-00	6/1/2002	4390	$9,390	Y	$9,390	

EXHIBIT 26

Testimonial Summary



JAMES WINCHESTER

Our members plug wells.

INDUSTRY PLUGS 95% OF WELLS PLUGGED. NUMEROUS MEMBERS TESTIFIED ABOUT PLUGGING PROGRAMS.

The Death Penalty Proposal

RULE 19.15.5.9(A)(4) PROPOSAL (APPS. EX. 72-B, P. 964)

Adds to List of Things Mandated of Operator for Good Standing.

To be in good standing, the operator needs to meet the waste prevention requirements of 19.14.25.8 (plugging) and 19.15.27.8.A (venting & flaring prohibited) NMAC

One violation means operator cannot operate any of its wells.

- Danger to environment
- Waste?

Civil Penalties Rulemaking—added to the OCD's "toolbox" of "enforcement tools"

- Why limit to the tools to the death penalty
- Leave out and let OCD decide how to proceed and preserve Operator's right to challenge

Despite being "prohibited" in 8.A, flaring and venting are permitted in certain circumstances in 8.B

- Lose operator status even if in 8.B exception?

In a rulemaking supposedly designed to prevent orphan wells, why propose a "death penalty" rule that will orphan all an operator's well for a single violation?

OCD DISCRETION TO PURSUE IS APPROPRIATE. AUTOMATIC REVOCATION OF STATUS BAD POLICY

Evidence Shows Bonding Ineffective

INFORMATION OCD REPORTS, OCD EX. 17 (MASTER ORPHAN SPREADSHEET) & EX. 29 (FINANCIAL ASSURANCE REPORT)

Bond Collections Rarely Occur

From 7 Most Recent OCD Annual Reclamation Fund Reports

WELLS PLUGGED	COST	BONDS RECOVERED
39	$976,278.20	$88,472
25	$790,090	$0
49	$2,359,698	$0
27	$1,788,940	$161,250
13	$2,235,242	$0
46	$6,798,045.50	$0
37	$4,003,625.06	$0
193		**$249,722**
$1,294 in recovered bonds per Well		
1.67% of total P&A costs		

EXHIBIT 26

OPERATOR	# of Wells on Ex.17	% of Total
Cano Petro of New Mexico Inc.	329 wells	18.13%
Ridgeway Arizona Oil Corp	299 wells	16.47%
Canyon E&P Company	235 wells	12.95%
LLJ Ventures LLC DBA Marker Oil & Gas	149 wells	8.21%
Northern Pacific Oil and Gas Inc	83 wells	4.57%
Xeric Oil and Gas Corp	69 wells	3.8%
Marks and Garner Production Ltd Co	64 wells	3.53%
Remnant Oil Operating LLC	52 wells	2.87%
Energy Acumen LLC	50 wells	2.75%
Blue Sky NM Inc.	41 wells	2.26%
TOTAL	**1,371 wells**	**74.54%**

The Population of Ex. 17 is Concentrated in a Few Operators

IPANM
INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO

Cano Petroleum

Isolated all Cano Petroleum which are "Plugged, Site Released" Ex. 17

Isolated all Cano Petroleum bonds on OCD Ex. 29

Cano Plugged Orphans #1 (29 wells)

Cato SA Unit #033 through Cato SA Unit #052 from OCD Ex. 17

30-005-20006	CATO SAN ANDRES UNIT #033	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20098	CATO SAN ANDRES UNIT #039	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20054	CATO SAN ANDRES UNIT #067	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20067	CATO SAN ANDRES UNIT #016	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20224	CATO SAN ANDRES UNIT #178	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20100	CATO SAN ANDRES UNIT #164	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20101	CATO SAN ANDRES UNIT #163	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20133	CATO SAN ANDRES UNIT #170	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20529	CATO SAN ANDRES UNIT #200	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20556	CATO SAN ANDRES UNIT #204	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-041-20585	CONE FEDERAL #031Y	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20482	CATO SAN ANDRES UNIT #193	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20243	CATO SAN ANDRES UNIT #184	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20127	CATO SAN ANDRES UNIT #012	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20117	CATO SAN ANDRES UNIT #137	Plugged, site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20180	CATO SAN ANDRES UNIT #162	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-041-20496	CONE FEDERAL #015	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20179	CATO SAN ANDRES UNIT #177	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20599	CATO SAN ANDRES UNIT #198	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20144	CATO SAN ANDRES UNIT #083	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20186	CATO SAN ANDRES UNIT #185	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20273	CATO SAN ANDRES UNIT #188	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-27969	CATO SAN ANDRES UNIT #404	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-27970	CATO SAN ANDRES UNIT #407	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20073	CATO SAN ANDRES UNIT #037	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20087	CATO SAN ANDRES UNIT #140	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20217	CATO SAN ANDRES UNIT #186	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20596	CATO SAN ANDRES UNIT #187	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20947	SIETE FEDERAL #004	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20009	CATO SAN ANDRES UNIT #052	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,

Cano Plugged #2 (25 new wells)

Cato SA Unit #052 through Cato SA Unit #160 from OCD Ex. 17 (Cato SA Unit #52 not counted on this slide)

30-005-20009	CATO SAN ANDRES UNIT #052	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20191	CATO SAN ANDRES UNIT #145	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20193	CATO SAN ANDRES UNIT #147	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20172	CATO SAN ANDRES UNIT #154	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20187	CATO SAN ANDRES UNIT #156	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20008	CATO SAN ANDRES UNIT #107	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20015	CATO SAN ANDRES UNIT #110	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20192	CATO SAN ANDRES UNIT #146	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20167	CATO SAN ANDRES UNIT #153	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20182	CATO SAN ANDRES UNIT #155	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20094	CATO SAN ANDRES UNIT #117	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20095	CATO SAN ANDRES UNIT #043	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20056	CATO SAN ANDRES UNIT #106	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20038	CATO SAN ANDRES UNIT #062	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20146	CATO SAN ANDRES UNIT #125	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20137	CATO SAN ANDRES UNIT #120	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20096	CATO SAN ANDRES UNIT #134	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20116	CATO SAN ANDRES UNIT #129	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20292	CATO SAN ANDRES UNIT #114	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20045	CATO SAN ANDRES UNIT #128	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20058	CATO SAN ANDRES UNIT #130	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20031	CATO SAN ANDRES UNIT #116	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20115	CATO SAN ANDRES UNIT #111	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20016	CATO SAN ANDRES UNIT #112	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20129	CATO SAN ANDRES UNIT #132	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20151	CATO SAN ANDRES UNIT #160	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,

Cato Plugged #3 (19 new wells)

Cato SA Unit #160 to Cato SA Unit #202 from OCD Ex. 17 (Cato SA Unit #160 not counted here)

30-005-20151	CATO SAN ANDRES UNIT #160	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20297	CATO SAN ANDRES UNIT #131	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20211	CATO SAN ANDRES UNIT #113	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-10525	CATO SAN ANDRES UNIT #082	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20152	CATO SAN ANDRES UNIT #159	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-10473	CATO SAN ANDRES UNIT #029	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20153	CATO SAN ANDRES UNIT #158	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-10483	CATO SAN ANDRES UNIT #030	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20610	AMOCO FEDERAL #002	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20588	AMOCO FEDERAL #001	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20002	CATO SAN ANDRES UNIT #096	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20492	PAYE FEDERAL #004	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20494	PAYE FEDERAL #006	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20500	PAYE FEDERAL #008	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20493	PAYE FEDERAL #005	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20501	PAYE FEDERAL #009	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20502	PAYE FEDERAL #010	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20605	INGRAM FEDERAL #006	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20639	INGRAM FEDERAL #007	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,
30-005-20524	CATO SAN ANDRES UNIT #202	Plugged, Site Released	Yes	[248802] CANO PETRO OF NEW MEXICO,

Cano Bonds #1 from OCD Ex. 29

(1 BB & 24 SWBs lns. 8133-8158)

8124	WESTERN REFINING COMPANY, L.P.	3963	FIDELITY & DEPOSIT CO OF MARYLAND	8973637	SWB	32440	0
8133	CANO PETRO OF NEW MEXICO, INC.	3877	U.S. SPECIALTY INSURANCE COMPANY	B003422	BB	50000	0
8134	CANO PETRO OF NEW MEXICO, INC.	3944	U.S. SPECIALTY INSURANCE COMPANY	B003482	SWB	9390	0
8135	CANO PETRO OF NEW MEXICO, INC.	5512	U.S. SPECIALTY INSURANCE COMPANY	B004246	SWB	8500	0
8136	CANO PETRO OF NEW MEXICO, INC.	3938	U.S. SPECIALTY INSURANCE COMPANY	B003480	SWB	8450	0
8137	CANO PETRO OF NEW MEXICO, INC.	8987	U.S. SPECIALTY INSURANCE COMPANY	B010527	SWB	8960	0
8138	CANO PETRO OF NEW MEXICO, INC.	8008	U.S. SPECIALTY INSURANCE COMPANY	B007817	SWB	8410	0
8139	CANO PETRO OF NEW MEXICO, INC.	3891	U.S. SPECIALTY INSURANCE COMPANY	B003487	SWB	8600	0
8140	CANO PETRO OF NEW MEXICO, INC.	3897	U.S. SPECIALTY INSURANCE COMPANY	B003491	SWB	8492	0
8141	CANO PETRO OF NEW MEXICO, INC.	6324	U.S. SPECIALTY INSURANCE COMPANY	B004899	SWB	8480	0
8142	CANO PETRO OF NEW MEXICO, INC.	3928	U.S. SPECIALTY INSURANCE COMPANY	B003511	SWB	8642	0
8143	CANO PETRO OF NEW MEXICO, INC.	3931	U.S. SPECIALTY INSURANCE COMPANY	B003473	SWB	8360	0
8144	CANO PETRO OF NEW MEXICO, INC.	3886	U.S. SPECIALTY INSURANCE COMPANY	B003484	SWB	8515	0
8145	CANO PETRO OF NEW MEXICO, INC.	3937	U.S. SPECIALTY INSURANCE COMPANY	B003514	SWB	8850	0
8146	CANO PETRO OF NEW MEXICO, INC.	5508	U.S. SPECIALTY INSURANCE COMPANY	B004242	SWB	8600	0
8147	CANO PETRO OF NEW MEXICO, INC.	8909	U.S. SPECIALTY INSURANCE COMPANY	B010044	SWB	8863	0
8148	CANO PETRO OF NEW MEXICO, INC.	3906	U.S. SPECIALTY INSURANCE COMPANY	B003496	SWB	8450	0
8149	CANO PETRO OF NEW MEXICO, INC.	3894	U.S. SPECIALTY INSURANCE COMPANY	B003488	SWB	8600	0
8150	CANO PETRO OF NEW MEXICO, INC.	3932	U.S. SPECIALTY INSURANCE COMPANY	B003474	SWB	8860	0
8151	CANO PETRO OF NEW MEXICO, INC.	4067	U.S. SPECIALTY INSURANCE COMPANY	B003775	SWB	8505	0
8152	CANO PETRO OF NEW MEXICO, INC.	3908	U.S. SPECIALTY INSURANCE COMPANY	B003498	SWB	8450	0
8153	CANO PETRO OF NEW MEXICO, INC.	3910	U.S. SPECIALTY INSURANCE COMPANY	B003500	SWB	8540	0
8154	CANO PETRO OF NEW MEXICO, INC.	6323	U.S. SPECIALTY INSURANCE COMPANY	B004897	SWB	8350	0
8155	CANO PETRO OF NEW MEXICO, INC.	3911	U.S. SPECIALTY INSURANCE COMPANY	B003501	SWB	8497	0
8156	CANO PETRO OF NEW MEXICO, INC.	1114	U.S. SPECIALTY INSURANCE COMPANY	B010041	SWB	8450	0
8157	CANO PETRO OF NEW MEXICO, INC.	3917	U.S. SPECIALTY INSURANCE COMPANY	B003466	SWB	8700	0
8158	CANO PETRO OF NEW MEXICO. INC.	8988	U.S. SPECIALTY INSURANCE COMPANY	B010523	SWB	8650	0

Cano Bonds #2 from OCD Ex. 29

(27 SWBs lns. 8159-8185)

8159	CANO PETRO OF NEW MEXICO, INC.	3923 U.S. SPECIALTY INSURANCE COMPANY	B003468	SWB	8507	0
8160	CANO PETRO OF NEW MEXICO, INC.	3925 U.S. SPECIALTY INSURANCE COMPANY	B003470	SWB	8480	0
8161	CANO PETRO OF NEW MEXICO, INC.	5510 U.S. SPECIALTY INSURANCE COMPANY	B004244	SWB	8560	0
8162	CANO PETRO OF NEW MEXICO, INC.	8911 U.S. SPECIALTY INSURANCE COMPANY	B010039	SWB	8480	0
8163	CANO PETRO OF NEW MEXICO, INC.	3924 U.S. SPECIALTY INSURANCE COMPANY	B003469	SWB	8413	0
8164	CANO PETRO OF NEW MEXICO, INC.	3946 U.S. SPECIALTY INSURANCE COMPANY	B003476	SWB	8415	0
8165	CANO PETRO OF NEW MEXICO, INC.	3885 U.S. SPECIALTY INSURANCE COMPANY	B003483	SWB	8562	0
8166	CANO PETRO OF NEW MEXICO, INC.	8913 U.S. SPECIALTY INSURANCE COMPANY	B010042	SWB	8488	0
8167	CANO PETRO OF NEW MEXICO, INC.	8908 U.S. SPECIALTY INSURANCE COMPANY	B010038	SWB	8403	0
8168	CANO PETRO OF NEW MEXICO, INC.	9087 U.S. SPECIALTY INSURANCE COMPANY	B010524	SWB	8598	0
8169	CANO PETRO OF NEW MEXICO, INC.	3935 U.S. SPECIALTY INSURANCE COMPANY	B003478	SWB	8778	0
8170	CANO PETRO OF NEW MEXICO, INC.	3926 U.S. SPECIALTY INSURANCE COMPANY	B003471	SWB	8329	0
8171	CANO PETRO OF NEW MEXICO, INC.	3918 U.S. SPECIALTY INSURANCE COMPANY	B003467	SWB	8650	0
8172	CANO PETRO OF NEW MEXICO, INC.	8912 U.S. SPECIALTY INSURANCE COMPANY	B010040	SWB	8714	0
8173	CANO PETRO OF NEW MEXICO, INC.	3943 U.S. SPECIALTY INSURANCE COMPANY	B003518	SWB	9405	0
8174	CANO PETRO OF NEW MEXICO, INC.	3883 U.S. SPECIALTY INSURANCE COMPANY	B003454	SWB	8682	0
8175	CANO PETRO OF NEW MEXICO, INC.	8009 U.S. SPECIALTY INSURANCE COMPANY	B007818	SWB	8484	0
8176	CANO PETRO OF NEW MEXICO, INC.	3915 U.S. SPECIALTY INSURANCE COMPANY	B003505	SWB	8500	0
8177	CANO PETRO OF NEW MEXICO, INC.	3904 U.S. SPECIALTY INSURANCE COMPANY	B003494	SWB	8598	0
8178	CANO PETRO OF NEW MEXICO, INC.	3896 U.S. SPECIALTY INSURANCE COMPANY	B003490	SWB	8600	0
8179	CANO PETRO OF NEW MEXICO, INC.	9088 U.S. SPECIALTY INSURANCE COMPANY	B010522	SWB	8498	0
8180	CANO PETRO OF NEW MEXICO, INC.	3920 U.S. SPECIALTY INSURANCE COMPANY	B003507	SWB	8650	0
8181	CANO PETRO OF NEW MEXICO, INC.	3927 U.S. SPECIALTY INSURANCE COMPANY	B003510	SWB	8665	0
8182	CANO PETRO OF NEW MEXICO, INC.	3941 U.S. SPECIALTY INSURANCE COMPANY	B003516	SWB	8907	0
8183	CANO PETRO OF NEW MEXICO, INC.	3905 U.S. SPECIALTY INSURANCE COMPANY	B003495	SWB	8500	0
8184	CANO PETRO OF NEW MEXICO, INC.	3909 U.S. SPECIALTY INSURANCE COMPANY	B003499	SWB	8510	0
8185	CANO PETRO OF NEW MEXICO, INC.	3942 U.S. SPECIALTY INSURANCE COMPANY	B003517	SWB	8445	0

Cano Bonds #3 from OCD Ex. 29

(25 SWBs lns. 8186-8211)

8186	CANO PETRO OF NEW MEXICO, INC.	6124 U.S. SPECIALTY INSURANCE COMPANY	B004586	SWB	8644	0
8187	CANO PETRO OF NEW MEXICO, INC.	3895 U.S. SPECIALTY INSURANCE COMPANY	B003489	SWB	8600	0
8188	CANO PETRO OF NEW MEXICO, INC.	3907 U.S. SPECIALTY INSURANCE COMPANY	B003497	SWB	8450	0
8189	CANO PETRO OF NEW MEXICO, INC.	3914 U.S. SPECIALTY INSURANCE COMPANY	B003504	SWB	8520	0
8190	CANO PETRO OF NEW MEXICO, INC.	8007 U.S. SPECIALTY INSURANCE COMPANY	B007816	SWB	8453	0
8191	CANO PETRO OF NEW MEXICO, INC.	1112 U.S. SPECIALTY INSURANCE COMPANY	B010045	SWB	9500	0
8192	CANO PETRO OF NEW MEXICO, INC.	9086 U.S. SPECIALTY INSURANCE COMPANY	B010525	SWB	8956	0
8193	CANO PETRO OF NEW MEXICO, INC.	3940 U.S. SPECIALTY INSURANCE COMPANY	B003515	SWB	8873	0
8194	CANO PETRO OF NEW MEXICO, INC.	3913 U.S. SPECIALTY INSURANCE COMPANY	B003503	SWB	8540	0
8195	CANO PETRO OF NEW MEXICO, INC.	3939 U.S. SPECIALTY INSURANCE COMPANY	B003481	SWB	8450	0
8196	CANO PETRO OF NEW MEXICO, INC.	3930 U.S. SPECIALTY INSURANCE COMPANY	B003472	SWB	8364	0
8197	CANO PETRO OF NEW MEXICO, INC.	3934 U.S. SPECIALTY INSURANCE COMPANY	B003513	SWB	8810	0
8198	CANO PETRO OF NEW MEXICO, INC.	5511 U.S. SPECIALTY INSURANCE COMPANY	B004245	SWB	8550	0
8199	CANO PETRO OF NEW MEXICO, INC.	8986 U.S. SPECIALTY INSURANCE COMPANY	B010528	SWB	9000	0
8200	CANO PETRO OF NEW MEXICO, INC.	5509 U.S. SPECIALTY INSURANCE COMPANY	B004243	SWB	8506	0
8201	CANO PETRO OF NEW MEXICO, INC.	8006 U.S. SPECIALTY INSURANCE COMPANY	B007815	SWB	8420	0
8202	CANO PETRO OF NEW MEXICO, INC.	9085 U.S. SPECIALTY INSURANCE COMPANY	B010526	SWB	8960	0
8203	CANO PETRO OF NEW MEXICO, INC.	1113 U.S. SPECIALTY INSURANCE COMPANY	B010037	SWB	8540	0
8204	CANO PETRO OF NEW MEXICO, INC.	3936 U.S. SPECIALTY INSURANCE COMPANY	B003479	SWB	8860	0
8205	CANO PETRO OF NEW MEXICO, INC.	3889 U.S. SPECIALTY INSURANCE COMPANY	B003457	SWB	8600	0
8206	CANO PETRO OF NEW MEXICO, INC.	3912 U.S. SPECIALTY INSURANCE COMPANY	B003502	SWB	8500	0
8207	CANO PETRO OF NEW MEXICO, INC.	1201 U.S. SPECIALTY INSURANCE COMPANY	B010521	SWB	8492	0
8208	CANO PETRO OF NEW MEXICO, INC.	3929 U.S. SPECIALTY INSURANCE COMPANY	B003512	SWB	8374	0
8209	CANO PETRO OF NEW MEXICO, INC.	3933 U.S. SPECIALTY INSURANCE COMPANY	B003477	SWB	8370	0
8210	CANO PETRO OF NEW MEXICO, INC.	3898 U.S. SPECIALTY INSURANCE COMPANY	B003461	SWB	8680	0
8211	CANO PETRO OF NEW MEXICO, INC.	8910 U.S. SPECIALTY INSURANCE COMPANY	B010043	SWB	8700	0

Cano Bonds #4 from OCD Ex. 29

(2 SWBs lns. 8212-8213) TOTAL = 1 Blanket Bond & 78 Single Well Bonds

8212	CANO PETRO OF NEW MEXICO, INC.	3947	U.S. SPECIALTY INSURANCE COMPANY	B003475	SWB	8475	0
8213	CANO PETRO OF NEW MEXICO, INC.	3922	U.S. SPECIALTY INSURANCE COMPANY	B003509	SWB	8445	0
8233	CAZA OPERATING, LLC	3881	RLI INSURANCE COMPANY	RLB0010287	BB	125000	0

Cato San Andres Unit #052

API #30-05-20009

OCD EX.17

Appears on line 189 of Master Orphan Well List

Cell C189 “Plugged, Site Released”

Cells E189 & G189 (Past & Current Owner) are Cano Petroleum of New Mexico, Inc.

OCD EX. 29

$50,000 blanket bond appears on line 8133

- Column H (SumOfRedemption) shows $0 on line 8133 (cell H8133)

SWB of $8,714 single well bond appears on line 8172

- Column H (Cell H8172) shows $0

“The juice is not worth the squeeze.”

Secretary Shelton’s answer to a question as to why Division not pursuing bonds at June LFC Meeting

Cano is one example.

Don’t doubt Secretary Shelton.

In fact, aligns with IPANM’s belief that increased FA, especially at these levels, does not afford State meaningful protection but is a huge burden on industry.

Comparisons of OCD Exhibits 17 & 23

EXHIBIT 23 IS A PDF OF THE INACTIVE WELL LIST COMBINED WITH THE TA WELLS—A PROXY FOR POTENTIAL ORPHAN WELLS?

IPA NM
INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO

Caveat: Unlike Ex. 17, Ex. 23 is not in native format so there may be some errors.

For some of my testimony, we converted Ex. 23 to text to get information. That process is not foolproof in my experience.

For some of my testimony, we performed manual counts from sequential portions of the Exhibit. I strived for accuracy but obtaining a count in native format may result in differences (which I think, if existing, should be small).

Top 10 Operators on OCD Exhibit 23

WITH SOME NOTES, POSITIVE OR NEGATIVE

EXHIBIT 26

OPERATOR	#Wells on Ex. 23	Extra Bond	Notes
Ridgeway Arizona	287	$43,050,000	Subject to ACOI--OCD will P&A 304 wells and Ridgeway pays $2/bbl. sold, $30,000/month minimum.[1] 299 Wells on OCD Ex. 17 ten.
Acacia Operating	231	$34,650,000	One well on OCD Ex. 17
LLJ Ventures (Marker)	134	$20,100,000	149 wells on OCD Ex. 17.
LH Operating	131	$19,650,000	Acquired by EON Resources, Inc. 11/2023. Waterfloods planned.[2]
Dominion Production	124	$18,600,000	Three Agreed Compliance Orders with two regarding financial assurances violations.[3]
Cano Petro	118	$17,700,000	Filed bankruptcy in March 2012. Abandoned its NM wells. 329 wells on OCD Ex. 17. Order R-14795-A.[4]
Hilcorp Energy	102	$15,300,000	Active plugging and reworking programs. Not on OCD Ex.17
OLEUM Energy	92	$13,800,000	At least 2 wells on OCD Ex. 17
Empire NM LLC	80	$12,000,000	Not on OCD Ex. 17; $1M blanket TA Bond in place 8/3/2022 on all 80 TA wells.
Maverick Permian	76	$11,400,000	Not on OCD Ex.17; $1M blanket TA Bond in place 4/15/2024 on all 76 TA wells. ACOI-201959.[5]
Northern Pacific	65	$9,750,000	83 wells on OCD Ex. 17
Total	1440	$216,000,000	39.41% of Exhibit 23 Wells

[1] IPANM Ex. 46.
[2] https://www.morningstar.com/news/accesswire/1056003msn/eon-resources-inc-announces-funding-design-for-the-settlement-of-the-seller-agreement-and-debt-payoff-and-the-grayburg-jackson-field-development
[3] ACOI-266 (IPANM Ex. 47); ACOI-285 (IPANM Ex. 48); and ACOI-2016-312 (IPANM Ex. 49).
[4] IPANM Ex. 53.
[5] IPANM Ex. 52.

Summary of Top 10

I do not know these 9 of these companies. The one I know, Hilcorp, has an active plugging program & no wells on Ex. 17.

LH Operating issued a press release indicating it was going use at least some of these wells for a secondary recovery (waterflood) project.

Two of operators, Empire NM & Maverick, have posted $1,000,000 blanket TA bonds per OCD Ex. 29, and do not have a well on Ex. 17.

Cano &, perhaps, Ridgeway are not bonding any more.

The other 4 have known information that makes their capacity to bond questionable.

There are other operators on Exhibit 23 who are on Exhibit 17

AND/OR THERE IS INFORMATION PUBLICLY AVAILABLE THAT MAY SUGGEST LACK OF ADDITIONAL BONDING ABILITY.

EXHIBIT 26

Operator	# of Ex. 23 wells	Extra Bond	Notes
Northern Pacific	65 wells	$9,750,000	83 wells on OCD Ex. 17
Sellers & Fulton	36 wells	$5,400,000	36 wells on OCD Ex. 17
Canyon E&P Co.	36 wells	$5,400,000	235 wells on OCD Ex. 17
M&M Production	34 wells	$5,100,000	Owner plead guilty to federal fraud charges.[7] 9 wells on OCD Ex. 17.
CFM Oil	25 wells	$3,750,000	Two Stipulated Final Orders resolving no financial assurances: ACOI-344 3/26/18; and ACOI-201946 1/27/22.[8] 2 wells on OCD Ex. 17.
Energy Acumen	20 wells	$3,000,000	50 wells on OCD Ex. 17.
G&G Operating	6 wells	$900,000	Filed Ch. 7 Bankruptcy 8/6/25 in Bankr. D.N.M. Case No. 25-10975-j7
Marks & Garner Prod. Ltd. Co.	4 wells	$600,000	64 wells on OCD Ex. 17
Blue Sky NM Inc.	1 well	$150,000	41 wells on OCD. Ex. 17
Total	227 wells	$34,050,000	6.21% of wells on Ex. 23

Summary of Comparisons of Ex. 17 & 23

Don’t have a crystal ball and not here to throw stones at any company.

However, the 19 companies on the two tables would apparently need to post about $250MM in marginal well bonds under the rulemaking proposal if Ex. 23 is, at it appears, wells that need to be bonded or plugged.

There is information available to all parties and the Commission that ought to call into question at least a very material portion of these 19 operators having little to no bonding capacity.

Member Survey about Wrinkle's Lease Operating Costs Testimony

AFTER REVIEWING MR. WRINKLE'S WELL COSTS TESTIMONY, WE ASKED FOR MEMBER COMMENTS.

What our members told me

Expenditures at time for first production. Not recurring, unlikely incurred again except repair.

- tanks
- meters
- piping
- shut-off valves
- SCADA and remote monitoring equipment
- flare stacks
- infrastructure costs

Ongoing Lease Operating Expenses for Older Wells (some are not monthly and/or not universal)

- Compression
- Road/access costs
- Field Operator (Pumper)
- Hot oil/treatments
- Energy costs
  - Common for oil wells only
- Marketing
- Water removal
  - 1 of 3 categories common for oil

What members said about specific expenses that may be incurred on a recurring basis

Compression—becomes less prevalent the lower the producing capacity of well

Road/access—most just blade roads every 1-2 years, spread among multiple wells & (sometimes) operators. Nobody had ever heard of anything like Mr. Wrinkle's high figure.

Field Operator—every well. Use contractors and cost is 1/3 or less than that Mr. Wrinkle experienced at Marathon. They have their own 4 gas monitors.

Hot oil & chem treatments—no more than once per year, often less or none.

Marketing—taken out of price paid. Runs about 2%. Marketer getting better prices than operator. New meters are rare.

Water removal—common for oil wells only. A well would only use one way (pipe or truck)

Conclusions about Lease Operating Expenses

When capital expenditures are eliminated from Mr. Wrinkle's testimony, his cost figures are in the range of $1,925/month

Our members report marginal well LOEs falling in a range of $600 - $1,300/month

Maybe a difference between Mr. Wrinkle's big company experience and our members who testify that they can operate wells more efficiently than big companies.

Even if you accept Mr. Wrinkle's figure, at a price of $65.00/bbl. less a $1.35 marketing fee, a 1.01 bbl./day is at a breakeven point $63.65 x 1.01 x 30 = $1,928.60

IPANM's Position on Financial Assurances

Ineffective & Expensive

Evidence from Division and its past results show bonding can be in place but not pursued.

Surety industry seems to make it tough to recover --“not worth the squeeze.”

Most of the problems with orphan wells are concentrated in a discrete subset of operators.

Wish I knew the “warning signs” to assist Division

IPANM is pursuing legislation to get the Conservation Tax to be used for its original purpose—enforce Oil & Gas Act including properly funding the Reclamation Fund.

If Commission Believes It Can & Should Adopt a FA Bond Rule, It Should Wait

COMMISSIONER/SLO JUST ANNOUNCED A RULEMAKING TO SUBSTANTIALLY INCREASE STATE BONDS.

Allegations of Bad Faith

Not true

Don’t want to engage on a rulemaking where the primary objects are outside Commission’s authority

Don’t want to engage on a rulemaking where the primary objects are so bad for our membership—probably existential for some

HB 133 Experience

EXHIBIT 26

PUBLIC HEARING
STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

Pecos Hall, 1st Floor, Wendell Chino Building
1220 S. Saint Francis Drive
Santa Fe, New Mexico

IN THE MATTER OF:
PROPOSED AMENDMENTS TO 19.15.2, 19.15.5 19.15.8, 19.15.9 and 19.15.25 NMAC

TRANSCRIPT OF PROCEEDINGS

November 3, 2025

HEARD BEFORE:

HEARING OFFICER FELICIA ORTH

COMMISSION MEMBERS:
ALBERT CHANG, Chair
GREGORY BLOOM, Member (virtual)
DR. WILLIAM AMPOMAH, Member

COUNSEL TO THE COMMISSION:

MR. ZACHARY SHANDLER, ESQ.

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(On the record at 9:00 a.m.)

TRANSCRIPT OF PROCEEDINGS

HEARING OFFICER ORTH: Good morning. My name is Felicia Orth, hearing officer appointed by the Oil Conservation Commission to conduct a hearing on OCC 24683 relating to well plugging and financial assurance.

We are on day 11 of the hearing and have reached another public comment session. I don't believe I see anyone in the room here to offer public comment, but I believe we have several folks online.

Here in the room, we have Commissioner Ampomah and Commissioner Bloom. The Chair is online, Chair Chang is online.

So let's see, Sheila, who are we going to pull up first? This is Karen Kilpatrick.

Just a couple of things about public comment. I will ask you to spell your first and last name for the transcript. I will ask you, pursuant to Commission rules, to swear or affirm to tell the truth.

And I will ask you to keep your comments to three minutes. In the event you have a lot more to say, please submit your public comment and rating to the Commission administrator, Sheila Apodaca.

Ms. Kilpatrick, can you unmute yourself.

MS. KILPATRICK: My name is Karen Kilpatrick. It's K-A-R-E-N, K-I-L-P-A-T-R-I-C-K.

HEARING OFFICER ORTH: Thank you. Do you swear or affirm to tell the truth?

MS. KILPATRICK: Yes, ma'am, I do.

HEARING OFFICER ORTH: I'll start your time.

MS. KILPATRICK: Thank you for your time today. I was born in Gallup while my father was working at the Prewitt refinery in 1954. In 1956, my father took a job at the Conoco refinery in Artesia just before I turned two years old. He worked there in the lab for 25 years before his health forced him to retire.

My older brother went to work there shortly after my father's retirement and worked in the lab for 40 years before he retired. This brother also worked in a jewelry store or owned one from 1966 until he closed it and retired in 2011.

My younger brother graduated high school in 1977 and started at the refinery a year afterwards as a pot mechanic. He worked his way up to managing the asphalt plant. He was laid off after 32 years of work when he was 61 or 62 years old.

I have spent 60 years in Artesia with ten years in Texas and Virginia at different times. Most of the time, Artesia is self-sustainable, but there is a lot that would make it better. Our biggest and oldest oil drilling company, Yates Drilling and Production Company, sold out to EOG a few years back. EOG went through a reorganization and moved their offices from here to Midland, Texas.

We have the largest oil pool under our county that we cannot access due to drilling regulations already on the books. Why try to place more on companies that would leave the state? There are too many regulations on the state and federal lands where drilling could be done and was done in the past.

The new proposed regulations may cause the companies currently doing business in Eddy and Lea County to withdraw. This could lessen the influx of oil and gas money. This would mean less funds for schools.

I would really recommend the Commission to vote these new proposals down. Thank you very much for your time and listening to me.

HEARING OFFICER ORTH: Sheila, who do we have next?

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Andrew Klooster, can you unmute yourself?

MR. KLOOSTER: Can you hear me all right?

HEARING OFFICER ORTH: Yes. Thank you. If you would spell your first and last name.

MR. KLOOSTER: Perfect. Thank you. My name is Andrew Klooster. It's A-N-D-R-E-W, K-L-O-O-S-T-E-R.

HEARING OFFICER ORTH: Do swear or affirm to tell the truth?

MR. KLOOSTER: I do.

HEARING OFFICER ORTH: I'll start your time.

MR. KLOOSTER: Thank you. I am the Colorado field advocate and an optical gas imaging thermographer with Earthworks, and I'm thankful for the opportunity today to lend my voice in support of stronger bonding and cleanup rules.

For over ten years, Earthworks has deployed optical gas imaging cameras here in New Mexico and in other states, both nationally and internationally, to document emissions from facilities throughout the oil and gas supply chain and at each stage in the lifecycle of an oil and gas well path.

We have used this experience to advocate

for new rules and regulations to mitigate emissions from facilities that pose a risk to public health and the environment. I personally served as a thermographer for Earthworks for the past five years, and in those five years I have conducted over 2,000 surveys of roughly a thousand different oil and gas facilities throughout the Mountain West, including Colorado, Idaho, Montana, Utah, and here in New Mexico in the San Juan Basin.

I've made multiple trips to San Juan and Rio Arriba counties, and what I've observed at marginal wells in New Mexico is not surprisingly, but unfortunately, no different than what I've observed at similar wells in Colorado or elsewhere.

Let me elaborate on that point. When you spend as much time as I have looking at low-producing and abandoned wells with an optical gas imaging camera, you will likely observe over and over again emissions from loose fittings and valves, cracked or unsealed stuffing boxes, broken gauges and controllers, improperly maintained storage tanks, malfunctioning flares and separators, and even as in the case of a facility in San Juan County a few years back, emissions wafting directly out of the ground itself due to a cracked flowline on a well pad.

These emissions are not just a sign of aging and perhaps in some instances poorly maintained equipment, they pose a threat to public health and the environment. I worked with a rural community here in Colorado where the emissions from just a single leaking tank battery on a low-producing well pad made multiple people from various households sick with nausea and headaches and potentially exposed them to a particularly dangerous pollutant, hydrogen sulfide.

Now that well pad is shut down, but the public will be footing the bill to clean up the mess because the operator was, for all intents and purposes, financially insolvent long before their equipment started leaking and impacting public health.

This should never happen. The public, particularly those who may have already suffered negative consequences from nearby oil and gas facilities, should never have to pay to clean up a mess they did not create, a mess that they may have already had to pay for in the form of bills for doctor's visits, laboratory tests, or air purifiers.

This really is a very common-sense proposition. The operators that drill the wells and

make a profit from the wells, should pay the cost to clean up those wells after their productive life cycle has ended.

New Mexicans have lived on and cared for this land for centuries. To honor that legacy, the state must adopt rules that ensure that New Mexico's people and land do not pay the price for a mess they did not create. Thank you.

HEARING OFFICER ORTH: Thank you, Mr. Klooster.

Next we have Matt Strickler.

Mr. Strickler, can you unmute yourself?

MR. STRICKLER: Yes.

HEARING OFFICER ORTH: Hello. Would you spell your first and last name, please?

MR. STRICKLER: Yes. My name is Matt Strickler. Matt, M-A-T-T, Strickler, S-T-R-I-C-K-L-E-R.

HEARING OFFICER ORTH: Do you swear or affirm to tell the truth?

MR. STRICKLER: Yes.

HEARING OFFICER ORTH: Thank you. I'll start your time.

MR. STRICKLER: Hello. My name is Matt Strickler. I'm a native New Mexican and a graduate

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of Farmington High School. I chose a degree and career in the energy sector and have over 20-plus years experience in the industry.

The start of my energy career began in Texas and expanded to work in Colorado, Oklahoma, New Mexico, and internationally. I chose to return to the state in 2011 and hope to remain in New Mexico. My family and I love the climate and the people here in Northwest New Mexico. I would very much like to remain optimistic about our family and future generations having a life here.

Unfortunately, over the last 14 years, I've seen my focus shift from 100 percent progress in investments based in New Mexico to a de minimis amount of consideration in new investments in New Mexico. Aside from legacy assets in New Mexico, we have turned almost all of our efforts to investments in Oklahoma and Texas. The regulatory and energy policy environment in New Mexico has been the primary reason for our shift outside of the state as risk and returns are rarely competitive.

I do not believe my experience is unique, as policymakers have taken an increasingly hostile approach to small independent producers in favor of large corporate interests. I am concerned

that as the shale production, particularly in the southeastern New Mexico peaks, the budget level of Santa Fe has increased since the pandemic and will eventually lead to a cascade of insolvencies for the small producers in the state in favor of the larger oil and gas interests.

Policy measures like the proposed marginal well bonding will lead to a cascade of insolvencies if energy prices ever take a downturn. And I strongly urge the rulemaking bodies to stress test these measures before triggering a cascade of liabilities to the State of New Mexico as they take solvent companies and drive them into insolvency.

I thank you for your time and consideration and I hope this committee makes the right decision.

HEARING OFFICER ORTH: Thank you, Mr. Strickler.

If you're on the platform and would like to offer comment, please raise your virtual hand. If you have dialed in using a telephone, you can press star 5 to raise your hand. Is there anyone else at all who would like to offer comment at this time?

The next opportunity for public comment will be this afternoon at 4:00 p.m. And during that

comment session, there will be available an interpreter between English and Spanish, Spanish and English.

All right. If there's no one else, we will return to the technical case.

Thank you, Mr. Cloutier, for sending an updated lineup this weekend. Are we still on that path?

MR. CLOUTIER: Yes, Madam Hearing Officer. I were uncertain when Mr. Gilstrap is available this morning before noon. If he is, and we're done, we can put him on. If not, he's ready to go at 1:00.

Mr. Ezzell will be here to follow up on that. And we are well on our way unless, Mr. Tremaine and Mr. Hall try and ask more questions than they're entitled to, to finish on Tuesday.

HEARING OFFICER ORTH: Okay.

MR. CLOUTIER: I am obviously just teasing, since Mr. Tremaine's smiling. And Mr. Hall may be glaring.

HEARING OFFICER ORTH: Thank you very much, Mr. Cloutier.

MR. CLOUTIER: And then we will have the two witnesses available on Thursday, as outlined in my e-mail to you and all counsel.

HEARING OFFICER ORTH: All right. So we may have Commissioner Ampomah and others -- we may have a break, if you will, between today and Thursday or tomorrow and Thursday due to witness availability.

MR. CLOUTIER: I think we're just going to convene versus Microsoft Teams. Commissioner Ampomah's, the hearing officer's reference. But I have one witness who is out of the country until sometime tomorrow afternoon; another witness who's not available today, but is available tomorrow.

Since they're both available Thursday morning after conferring with the hearing officer and counsel, we thought it might be best if we just reconvene for those two witnesses virtually on Thursday morning.

HEARING OFFICER ORTH: It's something that's in discussion, but we don't have that discussion official yet.

MR. CLOUTIER: Yes.

HEARING OFFICER ORTH: Commissioner Ampomah.

COMMISSIONER AMPOMAH: Yeah, so if I can know the time, because I've already booked my hotel and I need to know that, and if I need to go back home or not.

HEARING OFFICER ORTH: Okay. Thank you.

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MR. CLOUTIER: Thank you.
HEARING OFFICER ORTH: Commissioner Bloom.
COMMISSIONER BLOOM: That would certainly work for me. I'm glad you're discussing this with respect to Thursday. And just to note, tomorrow I will not be able to be in Santa Fe, but I will participate virtually. I don't think I'll miss any portion of the meeting, but I'll be virtual tomorrow.
HEARING OFFICER ORTH: Thank you.
Mr. Winchester, would you join us up here at the front, please. Thank you. If you would spell your first and last name, please.
THE WITNESS: All right. Is that better? Jim Winchester, last name is W-I-N-C-H-E-S-T-E-R.
HEARING OFFICER ORTH: Thank you. Do you swear or affirm to tell the truth?
THE WITNESS: I do.
HEARING OFFICER ORTH: Thank you. Go ahead, Mr. Cloutier.

JIM WINCHESTER,
having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. CLOUTIER:

Q. Mr. Winchester, good morning. Would you please introduce yourself to the Commission?

A. Certainly. Good morning. Jim Winchester, director of the Independent Petroleum Association of New Mexico. We're a volunteer trade association, oil and gas producers who explore and produce E&P oil and gas in New Mexico. And we're made up of predominantly those independent producers, along with businesses and professions who support those producers.

Q. Thank you. Have you been in attendance in person or virtually throughout these proceedings?

A. On and off. I've been in the room for some parts of the proceeding. I've also been listening on the virtual platform. And at times I've been able to catch up a little bit on the department's YouTube channel. I have certainly not caught up on everything. And sometimes when I was listening, I was multitasking. So I'm not sure that I've caught everything.

Q. Okay, thank you. And you submitted direct and rebuttal testimony in these proceedings, Mr. Winchester?

A. Yes, that's correct.

Q. Do you have any corrections or clarifications to the testimony you submitted?

A. Yes. Thank you. Based on what occurred in the proceeding, I do have a couple of clarifications.

First, in my rebuttal, I testified concerning reaction from multiple members of my association to a form that was issued by the Division in August or September that interpreted as implementing -- as though this rulemaking had been adapted.

My testimony from the members at the time was truthful. My clarification is that after Mr. Hall questioned an earlier witness, and I apologize, I don't remember who that was, I discussed Mr. Hall's questions with members, and I wish to clarify that I think the initial form's reactions was misplaced.

Q. Anything else?

A. Yes. I spent a lot of time in my direct testimony talking about what was and what was not represented by the master orphaned well spreadsheet. Again, I do not think what I testified to in direct is inaccurate, however, in listening to the applicants and to the Division, I do not think that they are trying to use each entry on that spreadsheet as the scope of the current orphan well issue in New Mexico, which is something that I heard prior to the hearing.

Since both the Division and the applicants seem to be using the number of roughly 700

for the number of orphaned wells that the Division has the responsibility to plug, I think it's a number that is roughly accurate. So I don't think that my testimony about the spreadsheet has much relevance.

IPANM agrees with the applicants and the Division about the scope of the current orphan well problem. And to be clear, IPANM agrees that it is a problem that does need a solution.

MR. CLOUTIER: With that, Madam Hearing Officer, I'D move the admission of Mr. Winchester's direct and rebuttal testimony as demonstrative IPANM Exhibits 10 through 13, 27, 28, 40, 43, 44 and 46 through 53.

HEARING OFFICER ORTH: I'll pause for a moment in the event there are objections. Those exhibits are admitted.

(Admitted: IPANM Winchester Direct and Rebuttal Exhibits 10 through 13, 27, 28, 40, 43, 44 and 46 through 53.)

BY MR. CLOUTIER:

Q. You've already touched on this, Mr. Winchester, but would you describe your role in the oil and gas industry?

A. Yes, certainly. I am, as I mentioned, executive director of IPANM, again, a trade

association. And as a trade association, I do a number of administrative functions, everything from preparing a budget, membership trainings, industry events, communications, general operations, staff, including myself, and a part-time operations manager.

My primary duty, though, in this role, is to really listen to my board and the membership and communicate their collective views to the legislature, to the general public, and today to this Commission.

Q. Do you hold yourself out as an expert in things like day-to-day oil and gas operations, running an oil and gas company, or implementing the regulations that affect oil and gas companies.

A. Not at all. I did work here at EMNRD and NMED from 2011 to 2015. In my role with those departments, I learned about some of the issues at the time from the regulatory perspective. But safe to say I'm not an expert in those regulatory issues.

I'm also not a lawyer. I know that non-lawyers can contribute to drafting and interpreting regulations, but I don't hold myself as having a skill in that area.

In my role at IPANM, I learn things every day from members about the industry and their companies. But I've never been active or employed

directly for an oil and gas company.

So I guess that's a long way of saying that I have some knowledge about a number of industry matters, but not always in any great depth.

Q. Please explain to the Commission the purpose of your testimony here today.

A. Yeah, there's three things. First, we have a number of members who volunteered and even asked to tell the Commission about their company and how they would be affected by the rulemaking. In fact, some of those members initially submitted written testimony, but we have now submitted their comments in writing, as you and Ms. Tripp thought it best to pare down our presentation. I do think that those individual members have and will provide valuable insight.

However, there are other members that we represent that don't want to be in the limelight, which is certainly understandable. So in my capacity as their representative, where I heard some basic concerns multiple times, I'm here to tell the Commission about those concerns. So that's really my first purpose for being here and testifying.

Second, there were occasions in the rulemaking where we thought the Commission needed more information from industry than the testifying

operators could provide. So we did survey our members, and I'm presenting the results of those surveys.

And then the third thing is, we have been criticized for not engaging on this rulemaking. And I'm here to tell the Commission as to why that is.

Q. Let's move to specific areas of your direct testimony.

MR. CLOUTIER: If we could move to slide 3, please, Mr. Everhart.

BY MR. CLOUTIER:

Q. And there are changes to 19.15.5.9 proposed by the applicant. The first is a change to A(4). What's the purpose of your testimony today regarding that issue?

A. Okay. Certainly, I think in general IPANM members are concerned about two rule changes sort of related to what we're considering an operator in good standing. So 19.15.5.9A(4), so based on the current rule, the member feedback that I've received is that I'm told that the current regulations allow an operator to be maybe 1 or 2 percent out of compliance with the existing rule to plug. In other words, the rule, as it's written now, forces operators to plug, but it's a rule that recognizes the reality that there

may be some lag time between the need to plug in an actual plugging.

My understanding is that this has to do with any number of reasons, including but not limited, for example, like the availability of plugging crews, service companies to plug within a certain time frame.

I think the concern with the new 19.15.5.4A(4), and I think that starts at slide 3 as you mentioned, is what referring to as "the death penalty," that the new proposal seems to eliminate any tolerance for even being one well out of compliance.

Now my members read that as such, that if you are one day out of compliance with plugging one well, you're not eligible to operate any wells.

Q. And there is a new provision suggested at A(5) of that same rule. Can you tell the Commission what members' concerns are?

A. Okay. So just to clarify, this is 19.15.5.9A(5), correct?

Q. Correct.

A. So this, to my understanding, adds that one violation of the venting and flaring rule and the operator is deemed not in good standing. So I think it's the same deal where you're no longer eligible to operate any of your wells.

And in addition to that, my members have brought to me further concerns that by referencing Part A of the venting and flaring rule, even permissible venting and flaring under Subparts B, C, and D of that rule is not allowed. And again, I want to emphasize this is how it reads to our operators.

Q. And could you articulate the concerns that you've been told about that operators have expressed to you about these two changes?

A. Okay, sure. There's three things. First, if we go back, you and I, Mr. Cloutier, participated for IPANM in a civil penalties rulemaking a couple years ago. And we heard a number of times that the OCD has a toolbox, various tools at its disposal, when it finds an operator in non-compliance. This includes the civil penalty matrix, that waste factors and circumstances to come up with appropriate penalty. But here, there's no such discretion or penalty matrix available. I think that's why it's been dubbed the death penalty, one strike and you're out.

Second, and I think it needs to be asked both for the stated mission of the Oil Conservation Commission and the Division in terms of preventing resource waste and for the public, how is it good for the state to withdraw an operator's ability to

operate, say, you know, an additional hundred wells for one violation of one well.

Third, and this is really a central theme here throughout the rule, and this is the thinking, if the collective goal of these rules is to prevent orphan wells under this one strike and you're out provision, the proposed rule effectively orphans a lot of wells.

Q. Thank you, Mr. Winchester.

The next area of your testimony I want to talk about is concerns you expressed on the issue of bonding. Can you tell us, on an overall basis, what the concern is that IPANM had with it?

A. Okay. Thanks. And I think this is a slide 7. Adding the new bonding requirements is effectively a sledgehammer. And that gets to what I'm bringing up here and showing here on the slides moving forward.

In my direct written testimony, I testified that how bonding has historically been ineffective in New Mexico. And this is supported in slide 7 by the most recent seven annual reclamation reports showing that bonds were only drawn on to -- total two in the past seven years, amounting to less than $250,000 after plugging 193 wells.

Now, this is upsetting to IPANM members

first because the Division is asking for essentially a 600 percent increase for their individual bond, with no blanket option. And I'm not sure that any industry could survive a sudden 600 percent cost in its holdings.

And the industry is being asked this, when the state collects virtually none or very little of his existing bonds. It's just not good policy or practice, as it's been relayed to me.

And I think to sort of put a circle on this one, this was asked back in June at the LFC meeting, legislative finance committee meeting, in Taos. Assistant Deputy Secretary Sheldon testified in front of the legislative finance committee that this is the equivalent of that "The juice is, is not worth the squeeze." Should I go on?

I mean, I've noticed since then that there's been a slight change of approach, again, at the June LFC hearing, when that reference was made. You know, there was bipartisan pushback. And I know that I brought that up as a concern in my written testimony submitted on August 8th.

Now, in this rulemaking, I found out for the first time that in the last half of August, the OCD made bond demands of three of the largest

offenders on its orphan well list. And whether the timing suggests OCD got the message, it really doesn't matter. We just want to be on the record now as saying that we're glad to see that the Division is doing this.

But the argument remains, the bonding system right now offers us no evidence that it protects the taxpayer. And our members who are coming forward in this hearing are demonstrating that bonds only succeed in creating hardships for the good operators and, therefore, really risk increasing orphaned wells.

Q. Thank you, Mr. Winchester.

I'd like to move to your testimony concerning Exhibits 17 and 23. I think that's around slide 18 or so. These are two of the Division's exhibits. They're Exhibits 17 and 23. Tell the Commission what you did at a high level.

A. Sure. So I want to first give some context related to this. It's come up before in this rulemaking but most operators plug their wells. The Division or somebody else may wish that some of these wells get plugged sooner and there may be disagreements about when wells need plugging, but I want to make it clear good operators take care of

business, including the plugging of wells and reclaiming of property.

Now Exhibit 17, it's been clarified as I've been told, and it seems like the Division and the applicants agree, that there are a number of wells on the spreadsheet that have been plugged.

Exhibit 23 is one of the TA well exhibits submitted by the Division.

Q. So in addition to having talked about the number of wells that have already been plugged, does your testimony on these exhibits have any other relevance to the Commission in your mind?

A. Okay, sure. A couple of things. First, on Exhibit 17, when we analyze it, as we do on slide 8, I believe that's our slide, but correct me if I'm wrong --

Q. It's not on there?

A. -- it demonstrates that the population of those orphan wells is concentrated into a smaller number of operators; ten, to be exact.

And again, on that slide 8, this shows that the problem in scope is involved in ten operators that account for 75 percent of the total orphan wells.

Second, and most important, if we look at Exhibit 23, that is the basis, to my understanding,

of at least a good chunk of legislative finance committee's concerns about another 4,300 wells being orphaned in addition to the 700 unplugged. I think there ought to be real doubt as to whether these wells unfortunately will ever get bonded.

Q. Let's look at the next slide, please, and then the next one after that.

A. That's slide 22, I think.

Q. Tell us what's depicted here. This is taken from your testimony?

A. Okay, this is the number that we did and ran based on Exhibit 23, and you can see it again on page 22 of the slides. As you can see there, it indicates that almost 40 percent of the wells in Exhibit 23, the TA list, are concentrated into ten operators.

Based on the well count of those operators in Exhibit 23, we've calculated the amount of their extra bond under the new rule proposals. And under notes, there is publicly available information about those operators which we've compiled.

And if I may, I want to briefly walk through that list.

MR. CLOUTIER: If we could go to the next slide, please, slide 22.

A. Yeah, back to slide 22. I'm going to

briefly walk through this list just to illustrate something.

First you know we look at the top. There's Ridgeway in Arizona. It has 287 wells, it's under a compliance order. And the question I ask is and what members have asked me: Do we think that the state will come up with $43 million in extra bonding.

The next one, Acacia Operating, I believe it's pronounced, it has 231 wells in Exhibit 23. Only one well shows up on the orphaned well spreadsheet, Exhibit 17. But essentially, under the new bonding, they will owe an extra $34 million. And I think we are pretty uncertain regarding their bonding capacity.

The next one LLJ Ventures shows 149 orphaned, and I think we can conclude it's very unlikely that they will be able to post $40 million in bonds.

LH Operating has 131 wells, but recently sold to EON Resources, and they are planning secondary recovery through waterflooding. So that's substantial.

Q. Excuse me. Let me interrupt. Do you know that personally or was that the result of some other information that was provided to you?

A. No, I do not know that personally. But that is information that is publicly available, to my understanding.

Okay. Dominion Production holds various compliance orders, but with those -- regarding compliance orders on financial assurance violations, I think it's obvious that they will not meet the new bonding requirements. So that's another $18 million.

Cano Petro we know very well filed for bankruptcy, they're gone. So we know there's an additional 17 million in bonding coming there.

Hilcorp is on this list. And as we know, they have submitted information to the Commission. They have a very robust well program. They are successfully reworking wells, and that's transformed old wells into individual success stories. So they're responsible. They're actively plugging wells. They should be considered low risk and yet, this rule would cost them $15 million of bonding, which doesn't make sense because their plugging and repurposing track record is there.

They are concerned, however, that, you know, their ability to continue to grow through acquisitions in their business model is under tremendous threat with the uncertainty of the OCD

authority to reject acquisitions. So they're out there like that and they're not alone.

I'm moving on. The smaller operators, like OEM, they'll be asked to increase bonding, $13 million. I think it's unlikely given their portfolio.

Empire, Maverick, they're each being asked to increase 12, $11 million respectively. They're less known, but with uncertain bonding capacity.

And then at the bottom, Northern Pacific has 65 wells on the inactive list and 83 wells on the orphaned well spreadsheet.

So overall, I think the pattern we see here is that most of these operators, outside of Hilcorp, on the orphaned well list lack the financial ability to provide bonds.

Q. Thank you. Did members and you notice anything else about the population of Exhibit 23?

MR. CLOUTIER: Next slide, please.

A. Yeah, we noticed that there were other operators on 23, Exhibit 23, who we would describe as problem operators, again, publicly available information, that suggests they are no longer capable of plugging or bonding.

I think this is slide 25, is that

correct?

Q. That's one.

A. Okay. Slide 25, that is a list that we've compiled of those operators.

Q. And what's over there in the notes, just for a summary? I don't think we need to walk through it.

A. Yeah, I think what we're showing here is we're identifying the operators, we're showing how many wells we counted in Exhibit 23 for that operator. Then we multiplied that number by 150,000, and then that summarizes the information based on what we knew about that operator.

Now, this is a technicality I want to make clear. Exhibit 23 itself was presented as a PDF. It was not in Excel format. So you can't do a direct conversion of the data we're sorting through on a PDF as you could on an Excel. So we manually counted entries for each operator. And it's possible that our counts were a little off.

But they are as close to be expected, you know, when you're looking down at a PDF document like that. So point being is that they may be slightly off, but they're represented to make the same point.

Q. Could you summarize for the Commission what

you and membership would like the Commission to understand about the analysis done on 17 and 23, OCD Exhibits 17 and 23?

A. So on 26, that shows the summary, same as, you know, our previous analysis. You know, we've identified a total of 19 companies that are going to be asked to come up with a combined quarter billion dollars of bonding. And the information is clear that the capacity is simply not there.

But here's what we do know. The companies not showing up on this list, they're overall responsible. Their track record is such that they are not in a risky category because they plug their wells. And yet in this rule, it will saddle them, the good operators, with excessive bonding costs. And I think this is the fundamental argument with this bonding rule proposal.

I mean, in the minds of the members who I've talked to, it's clearly and unfairly putting an enormous burden on good actors. And that is going to be, you know, essentially 600 percent bonding increases per well thrust upon these less risky operators.

I think the conclusion based on the perspective of our members, is that with this rule,

the Division risks creating more orphan wells now from good companies. But the problem that this rule is supposed to be fixing is orphan wells.

Q. You've mentioned that 600 percent figure a couple of times. Is that going to be the cost for every operator?

A. Well, depending on the scope of the rule. And I believe there's a threshold analysis related to marginal wells that's being talked about or proposed. If that threshold is what falls under those marginal wells, then all those marginal wells will be bonded at 150,000, which is a 600 percent increase from the 25,000 that is on the rule now. And I hope I state that correctly, but it's a little confusing.

Q. It's a number that you've derived from listening to members overall, correct?

A. Yes, correct.

MR. CLOUTIER: Madam Hearing Officer, that concludes the direct testimony of Mr. Winchester, and we'd like to move to his rebuttal.

HEARING OFFICER ORTH: Thank you.

BY MR. CLOUTIER:

Q. First slide of the rebuttal will be --

A. 27?

Q. Yes, sir. So OCD employee Mr. Justin

Wrinkle submitted written testimony about lease operating expenses. Did you see that testimony?

A. Yes. And as a result of that, that was one of the surveys we ran internally with our association to get information, on some of which our members are testifying.

Q. And you ran a survey to get even more information than just the members who are testifying, as I appreciate it?

A. Yes, of course. Exactly. Some of the members are testifying.

Q. Okay. And what would you like to tell the Commission on an overall basis about what you found out from members?

A. Okay. As I understand Mr. Wrinkle's testimony, we may not have much disagreement.

Q. You're talking about his live testing to the Commission, correct?

A. Correct. And I'm talking about what we are presenting and finding in slide 23 -- or excuse me, 28. So this is slide 28, and Mr. Wrinkle identified cost of equipment that members in that first column generally referred to as "camp X." But what needs to be clear here, coming from my members, is that these expenses are almost always incurred at the beginning

of the life the well itself, not when it gets into so-called marginal status.

The second thing I want to point out here is that Mr. Wrinkle seem to agree that every well is different cost-wise. For the costs he identified and my members agreed with were true lease operating expenses. Many of them, my members report, are not common to every well. And those are the ones denoted in red in that second column on slide 28.

Q. We could go to the next slide. And could you briefly tell the Commission, on those items in that second column what your summary of member feedback revealed about those particular costs?

A. Okay, certainly. I'll be brief. Slide 29. The point here is to show the Commission that our members disagree with the high-cost assessments that Mr. Wrinkle is presenting, depending upon how members in the real world come up with those cost numbers.

So I just want to point out these in particular. Compression in itself as a cost becomes less prevalent the lower the capacity of the well in terms of production.

Road/access, most just blade roads every one or two years. It's often that these roads are spread across multiple wells and sometimes multiple

operators. Nobody that we had talked to within the Independent Petroleum Association had heard of numbers related to high figures related to road/access like that.

The field operator, every well, you know, they use contractors and cost is one-third or less than what Mr. Wrinkle experienced at Marathon.

Hot oil chem treatments, you know, no more than once per year; often less or none.

Marketing is taken out of the price paid, runs about 2 percent. The marketer is getting better prices than the operator.

And then water removal is common for oil wells only. A well would only use, you know, that one way.

So again, just to reemphasize that there is disagreement on those costs and we believe, based on what was presented by Mr. Wrinkle and then what was discussed within the membership, it's high.

Q. And we've got a couple of surrebuttals. Let's walk through your conclusions about the lease operating expenses that you and the members were able to come to. Tell the Commission kind of bullet point fashion.

A. So these were some just quick number

comparisons that members had discussed and come up with. So when the capital expenditures are eliminated from Mr. Wrinkle's testimony, his cost figures are in the range of about $1,925 per month.

Our members are reporting that the marginal well falls in the range of $600 to $300 -- or, excuse me, $1,300 per month.

The difference, perhaps, Mr. Wrinkle is coming from a big company versus our members, who testify that they can operate wells more efficiently than those larger companies.

And then even if you run a calculation accepting Mr. Wrinkle's figure at the price of $65 per barrel, less $1.35 marketing fee, essentially one barrel per day is a break-even point at 63.65 times 1 times 30 is $1,928.60. So I think that shows what we're talking about.

MR. CLOUTIER: That concludes Mr. Winchester's rebuttal testimony, Madam Hearing Officer. We have a couple of items in surrebuttal.

BY MR. CLOUTIER:

Q. First, Mr. Winchester, some new information's come to you and membership. And would you raise that?

MR. CLOUTIER: I think next slide, please.

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BY MR. CLOUTIER:

Q. All right. Tell us about the new information and what you would request the Commission do with it.

A. Okay, sure. This one caught us by surprise. And by "us," I mean membership. I think it late on a Friday in early October that the State Land commissioner announced that rulemaking will be forthcoming to substantially increase bondings on leases.

And they are in the early stages of that. They have announced a number of discussions, open discussions regionally, to gather and talk a little bit more and share information about that. So that is on top of obviously what we're talking about here.

Q. And the concern is what, double bonding or excess bonding?

A. Yeah, I think that's a --

MR. NYKIEL: Madam Hearing Officer.

HEARING OFFICER ORTH: Yes.

MR. NYKIEL: I'm going to object. This is Matt Nykiel with applicants. I'm not clear what he's surrebutting. He hasn't identified rebuttal testimony or page number, so I'm not sure what he's

surrebutting here.

MR. CLOUTIER: This is a concern, Madam Hearing Officer, that came up after all rebuttal testimony was submitted and public information. This is my last question on the point and just wanted to express the industry's concern. But if you deem fit, we'll move on.

HEARING OFFICER ORTH: All right. Yeah, let's move on.

Thank you, Mr. Nykiel.

BY MR. CLOUTIER:

Q. Mr. Winchester, have you heard that in these proceedings, IPANM has been accused of not having a solution?

A. Yes, I've heard that and I disagree. And I think for some context, my observation from memory personally is that industry expressed major concerns about what turned in to be HB133 and that was a significant stakeholder discussion that occurred in 2023 before the 2024 session.

And we met up to about ten exhaustive meetings with industry participants that included NMOGA, it included the Division, it included the applicants. And the concerns that we had then are the same basic concerns that we have about this proposal.

And there was never any material movement on the issues about how to address those concerns in that stakeholder process in the first go-around.

Independent operators in those meetings and I felt that the smaller operator concerns specifically were never given -- were not addressed. And in many instances, the proposals came back a week later even worse for industry as the weeks progressed.

So I viewed the entire process as very frustrating. It was a waste of time. And my members who invested time expressed a feeling of futility, especially when HB133 was filed and it did not address our fundamental concerns.

So HB133 died in the legislature back in 2024 as we brought our valid concerns to them.

Now, as far as this hearing, it was within months after that bill died that the Western Environmental Law Center gave industry notice that it was proposing rulemaking and that was forthcoming.

Now, I'll be honest, I can't remember the sequence of e-mails, I can't remember necessarily if NMOGA brought this to our attention or if Ms. Fox reached out to us directly. Regardless, we were on those e-mails.

But when that happened, the question

from my members immediately to me were, "Well, the bill died, right?" The second question was, "Has there been any discussion since that session a couple months ago on how to best address orphaned wells, how to best anticipate orphaned wells or any of the big issues that the applicants in the Division say that they're now seeking to address?" The answer is no.

And days later, just like that, the new proposals were filed for rulemaking. Now, after the filing our members took time to digest the rulemaking proposals. We were aware that overtures were being made to further discuss this. But it was after the fact, without prior scoping to see if anything had changed in the views of the Division or the applicants.

Thus, after reviewing those rules, the consensus with my members was these already filed rules had shifted even further away from workability for small operators. And IPANM members simply can't invest time, people, resources and money on another long stakeholder process based on what had happened the first time around.

And I just want to illustrate this for everybody involved. The undertaking that took place for all of those months, those ten sessions in '23,

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was massive. Keep in mind, everyone is in the same position. But smaller operators don't have government affairs people. Our owners and operators' staffs had and would have to again sacrifice time from the field to attend to these meetings, and they already proved fruitless and a waste of their time and their resources.

And filed rules, in its entirety, represents, in the minds of my members, an existential threat to their operations.

Now, I want to be clear, we do feel that there are solutions that are out there. And we want to and can and would be willing to continue to explore those. But in the paradigm and in terms under which this rule is proposed, membership from IPANM got the message that real changes in the rulemaking proposal were not going to come. So here we are today here making our case.

Industry did not ask for this rule. Members have varying opinions about the extent of the orphaned well problem. But I think all acknowledge there are orphaned wells that need to be attended to and there are ways to plug them. But my members have expressed to me, bonding is not that answer. It's punishing the good members, the ones, as far as we

know, who are plugging wells that need plugging.

The real question to IPANM is how to pay and plug the remaining orphan wells and those that might get into that situation. So that's why we've been proposing and pushing for a fix of the oil and gas conservation tax to go to the reclamation fund to get this done.

MR. CLOUTIER: Thank you, Mr Winchester.

That concludes Mr Winchester's surrebuttal testimony, Madam Hearing Officer.

HEARING OFFICER ORTH: Thank you very much, Mr. Cloutier.

Mr. Nykiel, will you be doing the cross-examination?

MR. NYKIEL: Yes, that's right. It sounds like you can hear me loud and clear.

HEARING OFFICER ORTH: Yes. Thank you.

CROSS-EXAMINATION

BY MR. NYKIEL:

Q. Good morning, Mr. Winchester. My name is Matt Nykiel. I'm an attorney with the Western Environmental Law Center, and I represent applicants. Thank you for your testimony.

Would you let me know, as we go on, if there's any trouble understanding me through the

virtual platform?

A. Certainly.

Q. Okay. Thank you. And it looks like you have a copy of your direct and rebuttal testimony in front of you?

A. Yes.

MR. NYKIEL: And, Madam Hearing Officer, may I have permission to share my screen? It looks like I do. Okay. Is that presenting?

HEARING OFFICER ORTH: Yes. It could be a little bigger for ease of reading. There we go. All right. Thank you.

BY MR. NYKIEL:

Q. All right. Mr. Winchester, I'm pulling up your direct testimony at page 6. At line 14, you testified that virtually all of applicant's proposal comes from parties that have little to zero understanding or experience, be it in government or industry; is that right?

A. Right.

Q. And you're aware, though, that Oxy USA, Inc. supports or doesn't object to several of the applicant's proposed rules; is that right?

A. Yes. With the clarifier that Oxy is in a different position than the membership of IPANM.

BY MR. NYKIEL:

Q. And among those proposed rules that Oxy has supported or not objected to, those include applicant's proposal to increase financial assurance for active and inactive wells?

A. If they said so, is that what you're saying? Oxy did? Mm-hmm. Okay, sure.

Q. And Oxy has also not objected to applicant's proposal to establish a presumption of no beneficial use?

A. Sure.

Q. Would you like me to bring up their demonstrative that they used in their slides to confirm that, or would you accept that as true?

A. Oh, no, I accept that.

Q. Okay. And lastly, just that Oxy is not objected to applicant's proposal to require that operators certify on registration or transfer that they are not subject to any forfeiture demands in any domestic jurisdiction; is that right? Or is that your understanding?

A. I will take that as your understanding, which I believe -- I'm sure I have no reason to believe why that's not the case.

Q. Okay. And you're also aware that the

New Mexico State Land Office strongly supports applicant's proposed rulemaking?

A. I just want to backtrack on that last line of questioning.

I think I've raised the point, but Oxy is not representative of small producers and is not a member of IPANM. So I just want to make that clear.

Q. Yeah, but they haven't objected to applicant's proposed rules that operators certify that they're not subject to any forfeiture demands in any other jurisdiction, though?

A. Yeah, that's -- I mean, that's from their position, certainly.

Q. And so, you're also aware that the New Mexico State Land Office strongly supports applicant's proposed rulemaking. I think I heard you testify that you're aware of that. Yes, very much so?

Okay. And you're also aware that the New Mexico Oil Conservation Division supports applicant's proposed rulemaking?

A. Right.

Q. And, in fact, some of the rules that applicants have adopted and proposed were first recommended by the Division? Is that your understanding?

A. I can't speak to that. In fact, we're starting to go back into the talks that took place for HB133, and there were so many regulation proposals that were bouncing around. I don't know if it came from the applicants or if it came from OCD.

Q. Okay. I'm just going to pull up here just very quickly, this is applicants Exhibit 15?

This is the testimony of Mr. Alexander. Would you please read lines 18 through 20 that are highlighted here.

A. "OCD initially proposed a definition for 'marginal well' in its February 12, 2025, Redline proposals to all parties in the proceeding and proposed increased financial assurance for these wells in 19.15.8 NMAC. Applicants adopted OCD proposals."

But again, that doesn't give context to what was going on before then. But regardless, I had no problem with this.

Q. Okay.

A. As I said, they were being bounced around between the two parties, the regulations and the proposals.

Q. In your preparation for your testimony, you reviewed the testimony of OCD's witnesses; is that correct?

A. Not line by line. I was more paying attention specifically to what was being said in oral testimony, and when I could. So I can speak to whatever questions you have, and if I have knowledge, I certainly will answer. If not, I definitely will say that I am not aware of that.

Q. Sure. Are you aware that both Mr. Wrinkle and Mr. Diede worked in the oil and gas industry prior to their employment with the OCD?

A. Yes. With larger companies.

Q. And are you aware that between the two of them, they have nearly 40 years of combined industry experience?

A. Sure. Certainly.

Q. And did you review the testimony of applicant's witnesses as well in your preparation for this hearing?

A. Same question. Hit or miss.

Q. Okay. Are you aware that --

MR. CLOUTIER: Sorry, Mr. Nykiel.

Mr. Winchester, because of the virtual platform, please try not to step on Mr. Nykiel's question when you answer. You're answering very quickly.

Apologize, Madam Hearing Officer.

MR. NYKIEL: Thanks, Mr. Cloutier.

MR. CLOUTIER: Apologies.

MR. NYKIEL: Oh, no worries.

BY MR. NYKIEL:

Q. So, are you aware that Mr. Alexander, applicant's first witness, worked in the oil and gas industry?

A. Yes. I saw his testimony and listened to it.

Q. Okay. And he had worked in the industry for over three decades, correct?

A. Correct. But again, to be clear, industry is a broad definition, representative of a wide spectre of companies in different positions financially, in terms of their place, in terms of their various producing basins that they're working in.

Q. And you're aware that Mr. Purvis, also applicant's second witness, also worked in the oil and gas industry and works in the oil and gas industry?

A. Yes, yes. For sure.

Q. And he has over three decades of experience at this point?

A. That, I can't attest to. But I take it as your word, as no reason to believe it's not true.

Q. Okay. I'm going to pull up your direct testimony again and bring us to page 1. At line 14, you testified that all the matters to which you testify were also raised by IPANM members, correct?
A. Correct.
Q. And on line 5, you testified that IPANM, quote, solicited and got a lot of member comments about applicant's proposed rulemaking, correct?
A. Correct.
Q. Now, neither you nor IPANM provided written copies of those comments that you received from your members?
A. Correct. That's information that is within the confines of private operating companies who are disclosing that internally, but who did not wish to be in the limelight.
Q. And your testimony doesn't provide the identity of the members you received comments from, correct?
A. Correct, with the same stated reason.
Q. And how many members does IPANM have?
A. Last count, 107 different companies; total members represented over those, in the range of 350.
Q. Okay. And I'm back at your direct testimony on the same page, line 7. You testified that of the

member comments you received, different members commented on different parts of the proposed rule, correct?
A. Correct.
Q. I'm going to jump to your rebuttal testimony. And just as an example, there on page 11, at line 12, you state that after you circulated the testimony of OCD expert Mr. Wrinkle, you received comments from seven companies, correct?
A. Right.
Q. And at line 13, I'm looking at the statement you made here when you state, "All those responses indicate that even if Mr. Wrinkle's testimony reflects his experience at Marathon, no member believed those costs were accurate for low-producing wells," correct?
A. Correct.
Q. Now when you say "no member," you're referring to the seven companies you received responses from, correct?
A. Correct. In that particular survey.
Q. Okay.
A. There were additional discussion with members who, you know, would make same comments.
Q. Okay. And --
A. But I didn't -- I didn't chart those or --

I'm sorry, I didn't mean to walk over you. I didn't chart those or log those.
Q. Okay. And I just scrolled to page 12 of your rebuttal testimony. At line 2, you state that members thought that Mr. Wrinkle's testimony was not accurate.
And the same question here. When you refer to "members," you're referring to the seven companies you received responses from?
A. I think it's the same response, the seven, and then those based on conversations anecdotally.
Q. And approximately, how many oil and gas companies would you estimate operate in New Mexico offhand?
A. Well, I think if you look at the number of entities that are currently on OCD's reporting list, I think it's in the neighborhood of 450, something like that.
Q. Now, Mr. Winchester, I want to ask about your personal testimony in this. And just to reiterate, your testimony is as a fact witness today, correct?
A. Yes, sir.
Q. And not as an expert?
A. Correct.

Q. And as you said, the summary of your experience indicates that you're the executive director of IPANM, right?
A. Right.
Q. And the summary of your experience also states that you're a former EMNRD employee, right?
A. Correct.
Q. What was your job title at EMNRD?
A. Communications director for both EMNRD and the New Mexico Environment Department. So I split time between those two divisions.
Q. So you haven't been qualified as a corporate finance or risk expert, right?
A. Certainly not.
Q. I'm going to direct us to your direct testimony again at page 4. At lines 6 through 22, you discuss applicant's proposed rules for operator transfer at 19.15.9.9B NMAC; is that right?
A. I apologize. Can you please reference again the page of the testimony in which one, if it's direct or the rebuttal?
Q. Yes. Direct testimony and page 4.
A. Okay, which lines?
Q. Lines 6 through 22. It's this paragraph that begins with the question, "What's your next

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comment about the change of operator proposal?"
A. Correct.
Q. Okay. So, as you understand it, among other things, the proposed rule here would require a new operator to provide OCD a plugging and abandonment plan, correct?
A. Yes.
Q. And specifically at line 20, you opine that reviewing an operator's plugging and abandonment plan would do little to nothing to assure the state that an operator will have the funds available in the future to plug and abandon; is that right?
A. Correct.
Q. Okay. I'm going to pull up applicant's Exhibit 72-D, which is that rule we're talking about.
MR. CLOUTIER: And I'm going object, Madam Hearing Officer. This exhibit was admitted after the direct testimony that Mr. Nykiel is referencing and represents a change to the rulemaking that Mr. Winchester did not have available to him at the time of his direct.
HEARING OFFICER ORTH: Mr. Nykiel.
MR. NYKIEL: Yeah, my line of questions isn't -- it doesn't go to the changes that were made here. It goes to what was already existing in the

proposed rule at the time of his direct.
HEARING OFFICER ORTH: All right. Go ahead.
BY MR. NYKIEL:
Q. So I was trying not to introduce too many additional colors, to avoid a rainbow here. But there are colors, and I'd like you to focus on the light blue, please. Would you please read the first two sections that are highlighted in light blue, just to -- I just want to confirm that this is the plugging and abandonment plan you were talking about here.
A. What am I reading again?
Q. Just in light blue at the top, that one, and the second one. And then we'll follow up with the third light blue paragraph below.
A. Okay. Well, first of all, it's blocked because there's a thing that's in front of it. Okay. Good:
A new operator shall make such applications in writing and provide...a plugging and abandonment plan.
Q. Okay. So that's what you were talking about in your direct. Would you please read the final paragraph highlighted in blue.
A. The plugging and abandonment plan shall be certified by an authorized representative of the new

operator and shall demonstrate that the new operator has and will have financial ability to meet the plugging and abandonment requirements of 19.15.25 for the well or wells to be transferred in light of all operator's assets and liabilities. The Division may request the operator to provide additional information, including corporate credit rating, corporate financial statements, long-term liabilities, reserves and economics reports, records and historical records for documentation, decommissioning activities, estimated operators, Commission applications, and history of inactive wells.
So I read this, but I'm not sure if this was added or if this is initial, and really where we're going. I know that we have members who have concerns about this.
MR. CLOUTIER: Madam Hearing Officer, I think we're a little past 15 minutes, even accounting for the couple times I interrupted.
HEARING OFFICER ORTH: No, it just hit 15 -- 16 minutes.
Mr. Nykiel, are you done with your examination?
MR. NYKIEL: Have one final line of questions.

HEARING OFFICER ORTH: Okay.
MR. CLOUTIER: Line?
MR. NYKIEL: I'll conclude on this line.
BY MR. NYKIEL:
Q. So, Mr. Winchester, when you testified that the plugging and abandonment plan would serve no utility to the Division, that was not based on any expert experience you have in corporate finance analysis or risk assessment, was it?
A. I think I've made it clear that it's based on what we hear collectively from operators.
HEARING OFFICER ORTH: Yeah, I think he did make that clear, Mr. Nykiel.
All right. Thank you very much, Mr. Nykiel.
Mr. Tremaine or Mr. Hall.
MR. TREMAINE: Mr. Tremaine. Thank you, Madam Hearing Officer.
CROSS-EXAMINATION
BY MR. TREMAINE:
Q. Good morning, Mr. Winchester. We've had the opportunity to meet virtually before. I think this is maybe the first time in person, or online now. So, if that's the case, nice to meet you officially.
I'm Jesse Tremaine, I'm the legal

director for the Oil Conservation Division. I have a couple kind of general questions.

A lot of your testimony we've really kind of gone over quite a bit in hearings, so I'm going to try to be quick.

So, I just want to reiterate, you've already answered this, make sure you agree for foundation, that your testimony summarizes the concerns expressed by some of IPANM's membership, correct?

A. Correct.

Q. At the beginning of your testimony, which I very much appreciate, I believe that you had identified that some or two specifically of those concerns raised in your direct were alleviated after you clarified some of the information and discussed those issues with your membership. Is that fair?

A. Sure. Yes. Correct.

Q. Thank you for that. And you are a fact witness here, so you did not perform or provide any of your own analysis or expertise?

A. Correct. As a fact witness, to my understanding, yes, of course.

Q. So all of your testimony is presenting undocumented hearsay to the Commission?

A. I don't agree with that at all. I think that what we are presenting is the positions of operators who do not want to seek the limelight. And I think they're very justified in having concerns if they do step forward. So I think we're providing a summation, and I am representative of what those concerns are.

Q. Well, I'm not going to ask you to testify to the definition of hearsay, so I'll be move on.

I want to ask you some questions about financial assurance timing and forfeiture. So specifically and not to get into -- are you familiar with the provision of 19.15.9.8, operator registration provisions?

A. Um, no, if you bring it up, I could review it and maybe it will ring a bell. I just don't know the provisions by number.

Q. I still have share authorization. All right. So, Mr. Winchester, I want to point you to -- so this is -- again, this New Mexico OneSource. It's Compilation Commission, official legal publisher of the State of New Mexico. And I like to use these because there's no -- there's no reading rainbow.

So in 9.8A, operator registration, would you be so kind as to read that please, A.

A. "Prior to commencing operations, an operator of a well or wells in New Mexico shall register with the Division as an operator. Applicants shall provide the following to the financial assurance administrator in the division's Santa Fe office."

Q. All right. So before you begin operations as a new operator, you have to provide these three things listed under A. And do you agree with me that the third thing that you have to provide before beginning operations is the financial assurance that's required?

A. As it says here. Again, I'm not sure referring to 19.15.8 in particular is something that I have knowledge of by name.

Q. Right. But, I mean, you would agree it says the "financial assurance" and then provides another section of the rule?

A. Correct.

Q. And I'll represent and actually I'll show you here, just to make sure there's no trickery here, 19 Part A is the financial assurance requirements.

So 9.8 stands for the proposition that when you register as a new operator, you have to provide the financial assurance before you begin Operating. That's that reference.

So with that in mind, I want to ask you about your awareness of OCD's current practices in this regard. Are you aware that OCD currently requires financial assurance before well transfers?

A. I'm not sure of what the procedure is in the particulars.

Q. Okay. So you don't know?

A. I don't know off the top of my head.

Q. Well, I thought it was implied from your testimony that you were suggesting that the requirement to -- that OCD require and review financial assurance prior to a transfer was a new thing.

A. So, I'm confused I guess. Can you restate the question?

Q. Well, was it your testimony that it was going to be a problem for OCD to require financial assurance prior to approving a transfer of a well?

MR. CLOUTIER: Mr. Winchester did not testify to that here today, Madam Hearing Officer. Can I ask Mr. Winchester -- Mr. Tremaine to pull up --

MR. TREMAINE: I will rephrase.

BY MR. TREMAINE:

Q. Let me direct you to your testimony. So, on

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page 2, line 6, you're referring to --
A. I'm sorry, which document?
Q. I have it up on the screen.
A. Rebuttal or direct?
Q. This is your direct.
A. Okay. Thank you.
Q. This is your direct?
A. Page 6.
Q. So, page 2, line 6, you stated the proposal for amending rule 19.15.8.9, which is financial assurance provision, is vague and very broad, it would not allow an operator to proceed with any proposed acquisition until the operator has furnished the required financial assurance.
You later state, starting on line 10, that obviously this is absurd and will not happen.
So, I'm just asking you, you seem to directly state or imply there that that's not already the practice. I'm just trying to clarify that that's your testimony.
A. That, I'm still a little confused in terms of I think we're getting bogged down in procedural order.
Q. Well, sir, your testimony is, which is on the screen, that it would be absurd and impractical

for an operator to provide financial assurance for a well that they do not yet have registered with the OCD and operate. Is that your testimony?
A. I think I'm pointing out the problems that operators would face if, upon acquisition, they had to take upon, under this rule, new financial assurance individually for each well, as opposed to what's currently in rule with a blanket fund.
And if I'm confused, it's because I am confused.
Q. So just to put a bow on this, it was not your understanding that OCD already requires financial assurance prior to transfer of wells.
A. As we sit here today, I will just stand by what I've put down in the document, because I'm actually not quite certain what your question is.
Q. Are you aware that it's OCD's practice that if a well transfer would cause the receiving operator to fall out of compliance with the financial assurance for the well plugging and inactive well requirements in OCD's rules, that OCD requires, on a case-by-case basis, agreed compliance orders for inactive wells prior to approving a transfer?
A. Are you asking me about an existing rule or are you asking me about information submitted in my

testimony?
Q. I'm asking you if you are aware of OCD's practice. Because you are stating in your testimony that this is impractical, it doesn't work, it won't happen. And I'm challenging that because OCD already does it.
A. Okay. So what's the question again, please?
Q. The question was, were you aware of the fact that OCD requires agreed compliance orders for inactive wells if the transfer would cause the receiving operator to fall out of compliance with existing OCD rules?
A. Again, we're getting into procedure and process and timing.
Q. Well, Mr. Winchester, we're getting into your knowledge of OCD's rules and practices, which is what you are testifying about and the implications of the new rules.
A. In regards to what I've been informed by members.
Q. So those statements are not based on any personal experience?
A. I think there's a combination, but based on predominantly the input from members.
Q. Okay. Thank you. I want to ask you about a

few things here with share screen again. You spent some time on this slide 22, just a demonstrative aid, and talked about some of these operators and the financial assurance implications for each of those.
You walk through here. Ridgway, Arizona, that's been the source of some discussion at the hearing. If OCD had not entered into the settlement agreement with Ridgway, Arizona, to your knowledge, what would have been OCD's other enforcement options regarding those 287 wells?
A. I can't answer that. I don't know --
Q. Okay.
A. -- the regs number by number.
HEARING OFFICER ORTH: Mr. Tremaine, five minutes.
MR. TREMAINE: Okay. Thank you.
BY MR. TREMAINE:
Q. So when we talk about this slide -- well, first of all, are you aware that Acacia Operating is one of the remaining interests from Remnant?
A. I am not aware beyond what is presented here.
Q. Okay. And are you aware that OCD brought at least two separate enforcement actions related to the LLJ Ventures wells?

A. Are we talking about Acacia or are we talking about the previous --
Q. No. I just referred to LLJ Ventures.
A. Oh, LLJ. Okay, I'm sorry. Could you restate the question? I thought we were still on Acacia.
Q. So, LLJ Ventures, there were two inactive well NOVs related to that. Were you aware?
A. No, sir.
Q. Okay. Were you aware that there is an NOV pending against LH Operating for inactive wells?
A. There is an NOV, is that what you're saying?
Q. Notice of violation, yes, for inactive wells.
A. My information here, you know, indicates that they've been acquired by Ian, so I'm not sure semantically. No, I'm not aware.
Q. Okay. Were you aware that OCD is engaged in extensive discussions with energy related to Dominion Production?
A. Three agreed compliance orders, correct. Two regarding financial assurance violations.
Q. Aside from the agreed compliance orders. I'll move on.
So, Mr. Winchester, do you agree -- I

mean, because the point of this slide is that we're not going to recover additional financial assurance from the operators that are already out of compliance, and I would very much agree with that.
Is it your testimony that there is not a concern that other currently solvent operators could end up in a similar posture?
A. I think the demonstration with this exhibit --
Q. That's not what I'm asking you about. I'm asking you if you are testifying as to the potential for other operators to end up in a situation.
A. No, sir. I'm testifying from the standpoint that the good operators that are out there are going to be saddled with excessive extra bonding that jumps in scale, that is unreasonable for a good operator to continue their operations.
Q. According to your own testimony, Cano Petro was a good operator until they were not, right?
A. I don't know if I ever said Cano Petro was a good operator.
MR. CLOUTIER: Objection. He never said that.
BY MR. TREMAINE:
Q. You said that they were solvent and they

were compliant with OCD rule until they filed bankruptcy.
A. I don't think I even said that either.
Q. Okay. I'll let the record stand.
I want to point out -- Mr. Winchester, there's been a lot of talk about the 66 million in the reclamation fund. And in your testimony on page 8, direct testimony on page 8, line 14, you're stating that the state is now under pressure to spend initial and follow-on federal sums awarded under the IIJA?
So first of all, under the IIJA funds, are you able to articulate for the Commission which phase of the federal grant? We are currently operating under?
A. No, sir.
Q. Okay. So you don't really know the terms or the conditions of the federal grant?
A. Based on conversations that were brought up specifically by former OCD Director Dylan Fuge, in which we were in those conversations in those extensive stakeholder meetings, it was made very clear, even with numbers that I don't recall, 25 million, 50 million, whatever, that there was pressure in statements that he had said that we need to spend that money first.

Q. Is it consistent with your understanding that --
MR. CLOUTIER: Madam Hearing Officer, we're well beyond 15 minutes. I didn't start my clock until after Mr. Tremaine's pleasantries to Mr. Winchester.
HEARING OFFICER ORTH: All righty. So I had that we started at 10:16 and it's just now turning 10:32, so this is 15 minutes.
MR. TREMAINE: Thank you, Madam Hearing Officer.
HEARING OFFICER ORTH: Thank you, Mr. Tremaine.
MR. CLOUTIER: Thank you.
HEARING OFFICER ORTH: Let's see. Mr. Moore or Mr. Biernoff or Mr. Grazer? Who do we have here?
MR. MOORE: Good morning, Madam Hearing Officer. I'll be representing the Commissioner this morning.
HEARING OFFICER ORTH: Terrific, thank you.
CROSS-EXAMINATION
BY MR. MOORE:
Q. Good afternoon, Mr. Winchester. My name is Richard Moore. I represent the Commissioner of Public Lands and the New Mexico State Land Office. Thank you

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for your testimony this morning.

I just had a few questions concerning some of the things you testified about this morning. In your testimony, and I will share my screen here, you testified to what you referred to as the death penalty proposal.

In testifying to that, you referenced the current rule 19.15.5.9A(4), and I believe testified that the current rule allows an operator to be out of compliance with plugging obligations for 1 to 2 percent of its wells; is that correct?

A. I did. And I won't purport to be an expert on the specifics of that rule, but I will say that that was as, you know, indicated to me. And that's why I sort of used the approximation when describing that existing rule.

Q. Okay. And I'm just going to look and bring that rule up quickly. As I believe Mr. Tremaine already explained, this is the New Mexico OneSource and the administrative code as reflected on New Mexico OneSource. This is the current rule.

If you could read 19.15.5.9A(4) and how many wells that allows an operator to be out of compliance with.

A. So are you talking about A, B, C, D

specifically, two wells or 50 percent --

Q. Yes. 19.15.5.9A(4)(a), under that regulation as currently written, if a company operates four wells, how many wells under this regulation, as currently written, may it be out of compliance with?

A. Well, I mean, that's interpreting the rule. I can only read the rule. Two wells or 50 percent of the wells that the operator operates, whichever is less, if the operator operates 100 wells or less. Five wells if the operator operates between 101 and 500 wells. Seven wells if the operator operates between 501 and 1,000 wells. And then ten wells if the operator operates more than 1,000 wells.

Q. And so would you agree that under (4)(a), as written, an operator can be out of compliance for more than 1-2 percent of wells? Is that correct?

A. They can be out, as it reads, two wells or 50 percent of the wells the operator operates, whichever is less, if the operator operates 100 or less.

Q. And looking at subpart (b), five wells, if an operator operates between 105 and 500 wells. If an operator has 101 wells and five are out of compliance, that's more than 1 to 2 percent. Would you agree?

A. Five wells if the operator operates between

101 and 500 miles. That's how it reads.

Q. So, would you agree that it's only the larger operators that, as the rule currently reads, may be out of compliance with only 1 or 2 percent of their wells?

A. I think you are getting into semantics and interpretation of the rule. So I would say when you're talking about large operators, that's a very vague term. So I guess I can't answer that with the context in which the question is coming from.

I'm not trying to be difficult, Richard. I'm trying to further understand and not necessarily agree with your conclusion. Because I think large operators is a different definition to different people.

Q. I suppose, just to reframe the question, it's only if an operator is operating -- if they have ten wells that are inactive and they operate 1,000, that's in the 1 to 2 percent range. But if an operator is operating with fewer than 500 wells, has 5 wells out of compliance, that is a larger percentage than 1 to 2 percent?

A. If that is the correct math, then yes.

Q. All right. And then I'm going to turn to, you also testified to the operation of 19.15.25.8. So

I turn to that. This is also the rule as currently written and reflected on New Mexico OneSource.

So under 19.15.25.8B, the rule requires that an operator shell either properly plug and abandon a well or place that well into approved temporary abandonment, in accordance with 19.15.25, within 90 days after first a 60-day period following suspension of drilling operations, correct?

A. Correct. As the rule reads, yes.

Q. And then B(2), a determination that the well is no longer useful for beneficial purposes, or B(3), a period of one year in which the well has been continuously inactive; is that correct?

A. That is the rule, correct.

Q. So just to be clear, under 19.15.25.8, as currently written, the rule does not allow an operator to be out -- the rule doesn't allow 1 to 2 percent of an operator's well or really any percentage of an operator's wells to be out of compliance with this rule?

A. I don't know what you're stating essentially. I think the rule speaks for itself.

Q. And you don't see any language -- I guess, just to be clear, you don't see any language in 19.15.25.8, as currently written, that provides leeway

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for when a well has to be plugged under B(1), (2), or (3)?

MR. CLOUTIER: Madam Hearing Officer, Mr. Winchester stated clearly at the beginning he's not an expert on rule interpretations, and we're asking him to interpret rules that he's never held himself out to the Commission as having any expertise on that.

HEARING OFFICER ORTH: Yeah, Mr. Moore. I think he has offered up his limits.

MR. MOORE: Fair enough. I'll move on from this specific language.

BY MR. MOORE:

Q. But given the two rules we just discussed, and what you did discuss in your direct testimony, would you say that there is currently a conflict between 19.15.25.8 and 19.15.5.9, as currently written?

MR. CLOUTIER: Same objection.

HEARING OFFICER ORTH: Mr. Winchester, if you can answer the question.

A. I don't know.

Q. And leaving the specific language of the four members, would you agree that clarity in the regulations that apply to your members is beneficial?

A. I'm sorry, Mr. Moore, you were cutting out. Can you repeat the question, please.

Q. I apologize. I was just wondering if you would agree that for your members, that clarity in the in the regulations that apply is useful?

A. Yes.

Q. And same with regulators, clarity in the rules concerning when a well must be plugged is beneficial for that regulators of your industry?

A. Yes, certainly.

Q. And now you mentioned briefly in discussing upcoming state land office bonding rule changes, that it would be best for these rulemaking proceedings to wait for the State Land Office proceedings to continue or even conclude; is that correct?

A. I don't know if I stated that. I think the discussion point there is the introduction of a State Land Office rule proposal, and the timing of that coming in the midst of this. And the process, again, by which prior to, there was rumors that something was forthcoming, but that there was no prior input. And, again, the rule just was posted.

Q. And just one question on that. Are you aware that the State Land Office does not require bonds for wells on any private land?

A. I am not an expert on State Land Office rules and regulations.

HEARING OFFICER ORTH: Mr. Moore, five minutes.

MR. MOORE: Thank you, Madam Hearing Officer. I just have one final line of questioning.

BY MR. MOORE:

Q. So I'll share my screen again with the slides from your direct testimony. In that testimony, you discussed a number of companies seen on the screen that account for around 1,300 wells on the inactive list, roughly 74 percent of the total list; is that correct?

A. As presented, correct.

Q. Now, if these companies, such as Cano Petro or Ridgeway Arizona, if they had been required to provide higher bonding while they still had assets and some of their wells were still producing, would you agree that the OCD would be in a better position to address the plumbing expenses for these companies?

A. But I can't agree, only because I think you're asking a speculative question. So I just don't know. I don't think anyone really knows if so and so had been with this. Well, they weren't.

MR. MOORE: Fair enough. And I believe that

those are all the questions that I have. Thank you for your testimony today.

HEARING OFFICER ORTH: Thank you, Mr. Moore and Mr. Winchester. Let's take a break at this point and come back at 11:00.

THE WITNESS: I have a quick question. Was there any redirect, or are we done?

HEARING OFFICER ORTH: No, there's still more people to come along.

MR. CLOUTIER: She's giving you a break before Miguel breaks you over the coals.

THE WITNESS: Okay. Thank you. I wasn't sure if I was dismissed or not.

(Recess held from 10:44 to 11:00 a.m.)

HEARING OFFICER ORTH: We have Ms. Nanasi with us. Who would be next?

Mr. Maxwell, do you have questions?

MR. MAXWELL: No questions. Thank you.

HEARING OFFICER ORTH: Thank you.

Mr. Rankin, do you have questions?

MR. RANKIN: None. Thank you, Madam Hearing Officer.

HEARING OFFICER ORTH: Thank you.

EOG is monitoring.

Mr. Suazo, do you have questions?

MR. SUAZO: Just a few questions, Madam Hearing Officer.

CROSS-EXAMINATION

BY MR. SUAZO:

Q. Mr. Winchester, good morning?

A. Good morning.

Q. I'm Miguel Suazo. I'm representing NMOGA in these proceedings?

And Mr. Tremaine asked you about financial assurances the operators must have in place before they're operating, under the current rules, and what the changes would be under the proposed rules.

Is it your understanding of the current rules that they require operators to have financial assurance in place before they operate and produce wells?

A. I think we're getting back into the timing of when that procedure takes place. But based on what you are presenting, yes.

Q. Okay. And so is it your understanding that applicants are essentially proposing requiring operators to have financial assurance in place before they even acquire the rights to operate or own those wells?

A. Yes. And I think, to my understanding, the

analogy is you're buying a car and you have to put the payment down before you even kick the tires or check it out. Is that the correct analogy?

Q. Well, I mean, I think it's one analogy. I think, really, to your point, though, what I'm just trying to understand is that IPANM opposes these proposed changes primarily because of the timing associated with the acquisition of financial assurances in relation to the actual acquisition of the wells themselves, correct?

A. Yes. And I hope that that was what I was trying to illustrate with the car acquisition analogy.

MR. SUAZO: Thank you, Mr. Winchester. No further questions.

HEARING OFFICER ORTH: Thank you.

Mr. Cloutier, do you have redirect?

MR. CLOUTIER: Just one question, if I could have Mr. Everhart share a slide, please.

REDIRECT EXAMINATION

BY MR. CLOUTIER:

Q. Mr. Winchester, I don't remember exactly this table, but Mr. Tremaine put up a table like this, and there are a few of them in your testimony. A couple of questions?

Were you intending by presenting these

tables for the information in them to imply or actually make any criticism of the Division for their enforcement actions against any of these operators?

A. Absolutely not.

Q. And do you intend, do you purport that on your notes column that every single enforcement action that the Division has taken is described there and that there can't be any others?

A. No. This is all, as far as I know, in terms of the knowledge that we have.

MR. CLOUTIER: Okay. That's all.

HEARING OFFICER ORTH: Thank you.

Commissioner Ampomah, do you have question?

EXAMINATION

BY COMMISSIONER AMPOMAH:

Q. Good morning, sir. I'm William Ampomah, a professional engineer from New Mexico Tech. Nice to meeting you, sir?

A. Nice to meet you, sir.

Q. So I do have just probably two or three questions for you. So if we can bring up your testimony, direct testimony. I want to start with Page 10 of the direct testimony?

A. Yes sir, I have that.

Q. So you were asked a question about can you go into more detail why increasing the FA levels impact small operators. And you said -- you answered: The surety market is not just tighter or more difficult for small operators. It is unavailable?

Can you explain a little bit on that to the Commission?

A. Certainly. And I will do this to the best of my understanding, based on education that I've received from my membership.

The surety market, again, to my understanding, is essentially not available for the smaller operators because they have made concerted decisions not to get involved in those companies for whatever reasons of their analysis.

And from that standpoint, what I hear from operators is that our options are cash. And to expound upon that a little bit more, it's daunting when a $25,000 bond for one well is to be increased 600 percent.

We're doing a paradigm shift to essentially a very high number bonding level, which I believe our members don't agree with in terms of that number. I think it's been clear and we wanted to be clear from the get-go, even in our prior negotiations,

that we don't agree with the $150,000 amount.
Q. Thank you, sir. Now, so based on your testimony, you did a lot of surveying, you know, to get your members' thoughts about these proposed rules? I want to know, is there any bonding options that your members really recommend to the Commission for a consideration?
A. I'm sorry, you're asking for are there any other options, is what you're saying?
Q. Yeah. So you said that your members totally disagree with the $150,000?
A. Yeah.
Q. So based on the survey, did you ask your members the type of bonding levels that they will be comfortable with? Especially we all agree that this is a problem.
A. I think that I would have to defer back to my board in order to get direction to put out any sort of a number. But that being said, I don't think we in any way want to close the door about talking about it. Does that make sense?
Q. Yeah, that makes sense. So, you know, the commissioners have tried very hard to more or less push for some consensus between all the parties. And definitely NMOGA is open to more or less discuss more

with the Division and also with the applicant?
I want to ask if IPANM is also on board to discuss and see if there could be any consensus between all the parties.
A. Certainly. But I want to be very clear and nuanced because of what we are talking about in our direct testimony. I think the willingness is to definitely talk, but there are still some fundamental differences. And there's also still the question looming out there of whether or not the Commission has the authority.
So I don't want to say that we're going to come into it and be able to necessarily reach a number. However, I think that discussion is helpful for everyone. I don't know what the outcome would be, but I certainly want to make sure that that is something that we are involved with, but also, you know, not in any way -- making clear that our fundamental arguments still are in play. Does that make sense?
COMMISSIONER AMPOMAH: Yeah, that makes sense. Thank you so much for your time. No further question.
THE WITNESS: Okay. Thank you.
HEARING OFFICER ORTH: Thank you.

Commissioner Bloom, do you have a question?
COMMISSIONER BLOOM: Yes. Thank you, Madam Hearing Officer.
EXAMINATION
BY COMMISSIONER BLOOM:
Q. Mr. Winchester, good morning?
A. Good morning, sir.
Q. Just a couple questions for you. At the outset here today, did Mr. Cloutier state that you would reply to OCC criticism that IPANM hasn't engaged with applicants?
A. Would I agree that we haven't engaged in conversation with the applicants?
Q. I can repeat that. So at the outset here today, did Mr. Cloutier state that you would reply to OCC criticism that IPANM hasn't engaged with applicants?
A. Yes. I believe we talked about that.
Q. Okay. Do you know who made that criticism?
MR. CLOUTIER: Criticizing the Commission? I said that before the OCC -- I meant to say that IPANM had been criticized before this Commission. And if I misspoke, that is my sincere apology. Because I have not heard any criticism from the

Commission. And if anybody deserves the wrath for my misstatement, it's me, not Mr. Winchester.
But I wish to be excruciatingly clear, there has been criticism in these proceedings, but it has not come from any of the three commissioners.
COMMISSIONER BLOOM: Okay. Thank you, Mr. Cloutier. And I may have misheard, too, so the record would certainly clear that up.
BY COMMISSIONER BLOOM:
Q. I think if anything, I expressed frustrations, and I think it was that NMOGA's witnesses made recommendations that weren't backed with implementable solutions or there was no redline for at least some of them, and that witnesses did not provide, in some cases, data or evidence to back their recommendations. Does that sound right to you?
A. I think the question is whether or not financial assurance works. And I think what we are saying is that, based on the history and base that we know who predominantly are the bad actors, the only outcome going down this particular road is going to be punishing good actors, and we're not going to be able to collect on the bad actors.
It's, I think, the foundation of what we are representing, you know, from my IPANM's

perspective.
Q. Okay. Thank you for clarifying your position. Yeah, just in general, and I won't speak for the other commissioners, but I've been through a number of rulemakings, and I think sometimes we're put in an uncomfortable position to have to draft new material from things like a loose recommendation, without suggested language, and perhaps more importantly, without the data or other material to back up those provisions. Does that make sense?
A. Correct. And I will say that the discussions since the beginning of this rulemaking have been clear from the Commission to focus on some of those potential changes or recommendations. And I think we're very much open to that discussion, which gets us into more specifics.
That being said, if there is agreement, I still think that fundamentally, you know, IPANM reserves some serious questions about the entire process. Does that make sense?
Q. Yeah, absolutely. Thank you. And just lastly, my position at least is that parties don't have to engage prior to coming here. I mean, there might be times when that makes things easier for us if there's some commonalities that you've found. I

understand that sometimes it makes sense for parties to talk, but not always. Ultimately, that's up to you. Is that clear?
A. It's up to the applicant. It's up to whoever is submitting the rulemaking under those rules. But certainly, given the extensive potential impacts of this rule, you know, coming out with essentially something that's this drastic, it's probably better, I don't know, to talk about paradigm shifts to the rule itself before we even present a proposal that is just, you know, devastating to our members.
COMMISSIONER BLOOM: Okay. I certainly understand that as your position as well.
Mr. Winchester, thank you for your time. No further questions.
THE WITNESS: Thank you.
HEARING OFFICER ORTH: Thank you. Chair Chang, do you have questions?

EXAMINATION

BY CHAIR CHANG:
Q. Forgive me. I think I just missed this. But were you saying that -- you had said something about members needing to put up cash instead of bonds; is that correct? Or something --

A. Yes, sir. I think, you know, when the surety market is not there, the requirement is a cash bond, to my understanding. So, yeah, $150,000 per well marginal.
Q. And I can certainly understand how that would be an alarming or at least a concerning change for your members?
We explored the rule there that said insurance was also available as an option. Have members considered or explored what insurance policies may look like?
A. I can't speak for the members directly, but I know that that is an avenue that anecdotally is something that some are considering or looking into if it's permissible.
I also do think there is confusion whether or not the bond in this case is essentially insurance. I think there is a difference, but I think the members would agree with that. I'm sorry if I created more confusion in answering that question.
Q. No, that's okay. Well, I certainly understand that there is some concern about whether or not the surety market and/or the insurance market will be robust enough to facilitate the type of bonding that we're asking for here. And I certainly

understand that if you had to put this amount of financial insurance up in cash up front, that that would be a recognizable burden?
But presuming that the financial markets, whether through insurance policies or whether through bonds, come up with a way to service this market that will now exist if the rules are adopted, typically the cost to bond and/or the cost to insure the premiums are only a fraction, right, of the overall cost?
And so this is where I'm struggling a little bit. Because if you're telling me that an operator can't afford the fractional premiums, isn't that operator also by definition then going to struggle to find the cash to actually plug the well when the well is ready to be plugged?
A. I think, Mr. Commissioner, the -- and, again, I'm not an operator, so I can't speak for them. I think the financials based on cash flow for companies vary. And I don't know if some of those are based off of future returns. I don't know if some of that money otherwise would be used in operations as opposed to be hanging out there. You know, that's -- I think therein lies the question.
Q. So let me explore a different idea, and this

is going to be less -- sort of more directed at something hopefully the attorneys can address at some point. But I wanted to sort of use this format to try to get a thought out there?

It seems to me that there has been a lot of discussion around who -- you know, whether there are good actors or bad actors. And I wanted to explore whether or not there are perfectly good faith operators, who, for misfortunes outside of their control, whether it's a serious personal health crisis, whether it's something else -- aren't there good operators who, with absolutely good faith intention, who end up, for some misfortune outside of their control, being unable to plug a well, whether it's through -- let me just start with, isn't that a possibility, that there are good actors out there who intended to do the right thing, but for reasons outside of their control just simply couldn't?

A. Again, speaking on behalf of the members, I don't know the scenarios that are out there that impact all of this. And I'm not trying to in any way be disrespectful or not answer the question. I just -- I can't speak again when it comes to that.

Q. Sure. And I'm going to just raise a hypothetical that you probably won't be able to

answer, but hopefully we'll get the attorneys to think a little bit about how to address some of at least where I'm coming from?

I certainly don't think that the intent of any of this bonding is to punish anybody, but to protect from misfortunes that can happen to both good and bad actors. We've talked a little bit earlier in the proceedings around drivers, how regardless of how careful or not, or skillful a driver is, the state requires everybody to bond to protect against -- or not bond, but insure, against liabilities and risks, regardless of how -- I mean, I don't think the state is making any sort of judgment that drivers are driving in either good or bad faith.

And similarly, in my capacity, and you're welcome to take this as a hypothetical, so I'm not introducing facts, not in evidence here. But in my experience as the director of the Mining and Minerals Division, I knew of an operator who, I'm sure, there's absolutely no reason for me to believe that he didn't intend to do the absolute right thing of reclaiming his mine, but the man had a heart attack, and so left the state with no choice but to go after a bond as a way to reclaim that mine. Not because he was -- I'm sure not because he was a bad

actor, but because life happens to all of us.

So, you know, I'm not even going to ask you to answer -- well, you're more than welcome to comment back. But I just want to leave that as a thought that hopefully attorneys can address. I certainly don't want the -- or I think it's -- from my perspective, I don't know that the good actor/bad actor helps me in making this decision. Because I do think -- because it seems like what is important here is how do we protect from risk that sometimes befalls all of us even when we're doing absolutely all the all the best. Right?

And so all I'm asking here to try to form this into the form of a question is, isn't it plausible that there are perfectly good actors acting in perfectly good faith, but who, in the oil and gas context, but for some misfortune outside of their control, end up being unable to plug a well?

A. Mr. Commissioner, thank you. I appreciate that insight. The only response I will say is that as we move forward, as IPANM moves forward, I think some of the witnesses will get further into the role that the reclamation fund pays -- plays in this, both pays and plays in this. And I think that that's something just to draw attention to. And it's a piece of this,

whether we want to acknowledge that or not.

CHAIR CHANG: No, fair enough, fair enough. That's okay. Thank you, sir. Very, very valid point. That's all I have.

HEARING OFFICER ORTH: All right. Thank you, Chair Chang.

Any reason not to excuse Mr. Winchester?

MR. CLOUTIER: No, Madam Hearing Officer.

HEARING OFFICER ORTH: Thank you, Mr. Winchester.

THE WITNESS: Thank you all.

MR. CLOUTIER: Madam Hearing Officer, Ms. Tripp will handle the examination, but IPANM calls Kyle Armstrong next. We've set aside 30 minutes for his direct. I believe he'll have some surrebuttal that will probably take us right up to the lunch hour.

HEARING OFFICER ORTH: Terrific. Thank you.

Would you spell your first and last name, please.

THE WITNESS: Yes. Kyle Armstrong, K-Y-L-E, A-R-M-S-T-R-O-N-G.

UNIDENTIFIED FEMALE: Do you swear on affirm to tell the truth?

THE WITNESS: I do.

EXHIBIT 26

HEARING OFFICER ORTH: Thank you.

Go ahead, Ms. Tripp.

MS. TRIPP? All right. Thank you, Madam Hearing Officer.

KYLE ARMSTRONG,

having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. TRIPP:

Q. Mr. Armstrong, can you hear me okay?

A. Yes, I can.

Q. Okay. Great. And we have a couple slides that we've prepared to kind of guide your direct testimony here. So I'll share those this for the COMMISSION'S benefit?

But can you introduce yourself to the Commission in terms of your education, your employment experience.

A. Sure. I'm the president and CEO of Armstrong Energy Corporation, based in Roswell, New Mexico. It's a small, primarily family-owned company. I hold a JD. I practiced law for a very brief period of time, but decided that was not the direction I wanted to continue in my life. So I certainly can't speak as a legal expert or should not be relied on for that.

I have been in the industry, exposed to it my entire life; been with Armstrong Energy directly for about 12 years. I took over as president and CEO in 2020. I've held various functions within the industry. I'm the past president of IPANM. I'm on the board of directors for NMOGA. I served on Governor Lujan Grisham's energy transition team, as well as very briefly on the State Land Office energy advisory council.

And over the last six years, I think I have been a participant in every single negotiation rulemaking task force, however you want to phrase it, up until this one. So I've had some experience with these.

Q. Thank you. And can you tell us a little bit more about Armstrong Energy?

A. Sure. As I said, we're a small, independent operator, primarily family-owned, based in Roswell. All of our employees, geologists, engineers, pumpers, are based in or around Roswell.

We operate currently about 70 wells. And principally, those have been in southeast New Mexico. We have operated in Texas for brief periods of time in the past.

Q. And then in addition to operating wells,

does Armstrong Energy have any experience in plugging wells?

A. Yes, we do.

Q. Can you expand on that a little bit?

A. Certainly. So we have, in the last -- trying to find a number here real quick. In the past six years, we've plugged and abandoned about 16 wells, and in the last two years, we've plugged four wells. And I believe the cost of those four wells was approximately $120,000 each, inclusive of remediation costs.

Q. So you mentioned Armstrong is a small operator. If you had to describe sort of your business model or how you've grown or acquired wells, what process do you all follow?

A. Certainly. So I guess I should establish the company was founded by my father in 1976, and we have operated wells Since approximately 1981. So we have quite a bit of experience.

We currently employ about 23 full-time employees, a handful of part-time employees. We engage with service companies throughout southeast New Mexico, primarily local; some of the larger national companies as well. But we primarily utilize local law firms, local CPAs, local tech folks. So we

are pretty ingrained within our communities.

In terms of what we do, historically, we have drilled vertical wells. We have drilled and operated a waterflood. About seven, eight years ago, we acquired a couple of packages of wells from much larger operators and undertook various operations to maximize the productivity of those wells, in addition to drilling some new wells there.

We hold interest in about 350 non-op well, which is certainly another big part of our business. And in the last 18, 24 months, we have been actively pursuing opportunities outside of New Mexico. We're participating in a non-op fashion in Louisiana, Texas, Kansas, Oklahoma, are looking for prospects that we can drill and/or operate outside of New Mexico.

Q. And so the wells that you acquired in packages, do those typically come from larger operators?

A. Typically. An operator will put a package of wells up for either a private sale or on various online auction houses. And we have successfully bid on at least two of those packages, two larger packages in the last seven years. That was a major component of our business for several years.

STATE OF NEW MEXICO
ENERGY MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO THE COMMISSION'S RULES ON FINANCIAL ASSURANCE AND PLUGGING AND ABANDONMENT OF WELLS, 19.15.2, 19.15.8 AND 19.15.25 NMAC; STATEWIDE

CASE NO. 16078
ORDER NO. R-14834

ORDER OF THE COMMISSION

THIS MATTER came before the New Mexico Oil Conservation Commission ("Commission") on the application of the Oil Conservation Division of the Energy, Minerals and Natural Resources Department ("OCD") to amend Rules 19.15.2, 19.15.8 and 19.15.25 NMAC. The Commission, having conducted a hearing on July 19 and 20, 2018 and deliberated in open session following the hearing, and having considered the testimony, the record, and the arguments of the parties, and being otherwise fully advised, enters the following findings, conclusions, and order.

THE COMMISSION FINDS THAT:

1. Statutory Authority. The Commission is authorized to adopt rules, after a hearing, under the Oil and Gas Act, NMSA 1978, §§ 70-2-1 to -38 (1935, as amended through 2018) ("Act"). NMSA 1978, § 70-2-12.2 (2015). The Commission and OCD are given the duty to prevent waste and protect correlative rights and to make and enforce rules to carry out the purpose of the Act, NMSA 1978, § 70-2-11, and are specifically authorized to make rules to require abandoned wells to be plugged and to require financial assurance for the performance of such rules. NMSA 1978, § 70-2-12(B)(1). The Act also specifies the requirements for types and amounts of acceptable financial assurance and requires the adoption of rules to establish amounts. NMSA 1978, § 70-2-14 (2018). In 2018, the Legislature amended Section 70-2-14 to increase the cap for a blanket financial assurance and required that the amounts for a blanket plugging financial assurance be set by rule. Laws 2018, ch. 16.

2. Application and Notice. OCD filed an Application on March 28, 2018, to amend 19.15.2, 19.15.8 and 19.15.25 NMAC, which rules relate to financial assurance and plugging and abandonment of wells ("proposed rule change"). The Application included a draft of the proposed rule change and a proposed legal notice. 19.15.3.8(A) NMAC.

3. At a public meeting on April 12, 2018, the Commission determined to hold a hearing on the proposed rule change and scheduled the hearing to begin on May 24, 2018. 19.15.3.8(C) NMAC. The Commission continued the hearing to July 19, 2018.

4. Notice of the rulemaking and of the date, time, and place of the hearing was provided as required by NMSA 1978, § 14-4-5.2 (2017) and 19.15.3.9 NMAC, including publication in the New Mexico Register on April 24, 2018. (OCD exh. 2).

5. Pre-hearing statements were submitted by OCD and the Independent Petroleum Association of New Mexico ("IPANM"). OCD proposed technical witnesses for the hearing; IPANM did not propose any technical witnesses. In its pre-hearing statement, IPANM offered modifications to the proposed rule changes. The OCC did not receive any written submittals, other than those submitted in the hearing process.

6. Proposed Rule Change. The applicant, OCD, proposed to amend rules 19.15.2, 19.15.8 and 19.15.25 NMAC. The proposed rule change adds the following provisions:

(a) Blanket Financial Assurance: To implement the higher cap enacted by the Legislature, OCD proposed a ladder of blanket bond amounts with steps at $50,000, $75,000, $125,000 and $250,000 depending on the total number of wells operated by the company on the bond. The amounts of blanket plugging financial assurance for wells in temporarily abandoned status are not changed.

(b) Single Well Financial Assurance: OCD proposed to increase the financial assurance amount for a single well. The current formula of $5000 or $10,000 per well plus $1 per foot is increased to $25,000 per well and $2 per foot. The current system of two formulas based on the location within the state is replaced by a single formula. In 19.15.2, OCD proposes to add definitions for the terms "measured depth" and "true vertical depth", which terms are employed in the formulas.

(c) Approved Temporary Abandonment: OCD proposes to amend 19.15.25 to limit the percentage of wells that an operator can place in approved temporary abandonment. An operator will not be permitted to place more than one-third of all its wells in approved temporary abandonment. The proposal also requires that an operator must comply with the financial assurance requirements for temporarily abandoned wells under 19.15.8 NMAC before the well can receive a permit for approved temporary abandonment.

(d) Transition Provision: OCD proposes that the new financial assurance requirements will apply immediately to all permit applications to drill, deepen or plug back a well or for approved temporary abandonment. For all other wells, the effective date of the new requirements is delayed approximately 3 months.

7. Public hearing. The Commission commenced a public hearing on the proposed rule changes that began on July 19, 2018 and continued until July 20, 2018. The Commission completed deliberations on July 20, 2018.

8. OCD presented Allison Marks and Philip Goetze as technical witnesses. No other technical witnesses were presented by the parties. Each technical witness was subject to cross-examination by the other parties and by the Commissioners and Commission Counsel.

9. Allison Marks explained the purposes of the proposed rule change. The primary purpose is to implement changes to the Act enacted in 2018, to amend financial assurance requirements to reflect the goals of the Act and to prevent the overuse of approved temporary abandonment. The Act was amended in 2018 to increase the cap on blanket financial assurance for active wells from $50,000 to $250,000. Laws 2018, ch. 16. The amendments to the Act require that the amounts be set by rule. Laws 2018, ch. 16, §2. The proposed rule change also amends the formula for a one well financial assurance to meet the requirement in the Act that a one well plugging financial assurance be "in amounts determined sufficient to reasonably pay the costs of plugging the wells." NMSA 1978, §70-2-14(A). Finally, the proposed amendments to the temporary abandonment rules are designed to limit the percentage of wells that an operator can place in approved temporary abandonment and to link the approval with the requirements for financial assurance. (Marks testimony).

10. Allison Marks went through each of the provisions to explain the changes. The proposal to implement the Legislative change to blanket plugging financial assurance provides for a tiered approach with blanket bonds at $50,000 for operators with one to ten wells, $75,000 for operators with eleven to fifty wells, $125,000 for operators with fifty-one to one hundred wells and $250,000 for operators with more than one hundred wells. The tiered approach follows what the Commission had adopted in 2015 for blanket plugging financial assurance for temporarily abandoned status wells. 19.15.8.9(D) NMAC. The proposal increases the amount of financial assurance available to the State if an operator fails to comply with the requirements to plug and abandon their wells. (Marks testimony).

11. The proposal to increase the amount of the one well financial assurance is based on data from the last 4 years of actual plugging costs incurred by OCD. (OCD exh. 6). The current formula in the rule does not accurately reflect the actual costs. OCD provided data and charts demonstrating how the proposed formula ($25,000 plus two dollars per foot of the depth of the well) fit the actual costs of plugging wells at various depths. OCD also proposed to eliminate the use of two different formulas for different areas of the State. (Marks testimony; OCD exh. 3-5, 9, 10).

12. The proposal adds new definitions of "measured depth" and "true vertical depth" that are used in the calculation of the one well financial assurance amount. Given the variation in the types of wells now employed by operators, different calculations of depth are used for vertical and horizontal wells (true vertical depth) and for deviated and directional wells (measured depth). OCD explained the methods and the reasoning for using each in different situations. (Goetze testimony; OCD exh. 8). In response to questions from the Commission, OCD offered a slightly revised definition of "true vertical depth". (OCD exh. 12).

13. The OCD proposal amends 19.15.25 ("Plugging and Abandonment of Wells") to (a) limit the percentage of wells that an operator can place into approved temporary abandonment status and (b) link the approval of temporary abandonment with the change in financial assurance required by the Act and Rules. Under the Rules, OCD can permit a well to be in approved temporary abandonment if the well has been inactive for fifteen months and the well meets certain requirements. This status allows the well to

remain inactive without being permanently plugged. OCD presented evidence on operators that are currently out of compliance with the inactive well rules and the risks those operators pose. (Marks testimony; OCD exh. 7). Operators with a high percentage of inactive wells pose the greatest threats. The OCD proposal would limit the number the number of wells that could receive approved temporary abandonment to one-third of the total number of wells. OCD provided amended language for this proposal. (OCD exh. 12)

14. OCD proposed to add a financial assurance requirement to the standards for approved temporary abandonment. 19.15.25.13(F) NMAC. The Act requires operators to have increased financial assurance for wells in "temporary abandonment status". NMSA 1978, §70-2-14(A). This proposal is intended to simplify the process for both operators and the agency by having the operator provide the new financial assurance at the same time they would apply for approved temporary abandonment. (Marks testimony).

15. IPANM participated in the hearing through the submittal of amendments to the proposed rule change and through cross examination of witnesses. IPANM proposed to lower the tiers for blanket financial assurance by beginning at $25,000. In cross-examination, IPANM raised several concerns with the proposed rule change including whether it is fair to include the numbers of federal wells in the calculating the tier levels. The financial assurance requirements only cover wells on state and private land. 19.15.8.9(A) NMAC. Federal wells have separate financial assurance through the federal government.

16. Public comment was provided at the hearing by Larry Marker and Rory McMinn. Mr. Marker also offered written comments, which included proposed changes to the proposal. Mr. Marker and Mr. McMinn both testified as operators of low volume wells, sometimes referred to as "stripper wells". Both testified on the costs to comply with financial assurance requirements, and that the OCD proposal would increase those costs. Both supported the IPANM proposal for blanket plugging financial assurance. Mr. Marker also proposed changes to the one well financial assurance formulas; Mr. McMinn supported Mr. Marker's changes.

17. Changes to Published Rule. During the rulemaking proceeding, modifications to the proposed rule were offered. IPANM proposed modifications in its pre-hearing submittal. Larry Marker submitted written modifications at the hearing that were untimely under Commission rules, 19.15.3.11.B NMAC, but no party objected and the Commission considered the proposals during deliberations. In response to requests and questions from the Commissioners, additional changes were submitted by OCD at the hearing prior to deliberation by the Commission (OCD exh. 11, 12, 15).

18. Deliberations and Actions. The Commission commenced deliberation on July 19. During deliberation, the Commission reviewed the proposed rule changes, the modifications submitted by other parties, the further modifications submitted by OCD, and the evidence presented during the hearing. The Commission reviewed each section of the proposed rule and made some changes to the proposal. The Commission directed Commission counsel to prepare a clean version of the proposed rule changes based on the deliberation, and a draft Order. On August 20, 2018, the Commission reviewed the final draft of the proposed rule changes, completed deliberations and adopted this Order. The

Commission adopted the attached rule changes which consist of the proposed rule changes with modifications.

19. Reasons for Adopting the Rule Changes. The Commission finds that the 2018 amendments to the Act require changes to the Commission's financial assurance rules. The proposed rule changes are a reasonable implementation of the statutory changes and are supported by substantial evidence. The changes are necessary to bring the rules into compliance with the statutory mandates, which require financial assurance to assure that operators meet the requirements to properly plug and abandon wells. The Commission finds that the proposed rule change, as modified, increases the requirements for financial assurance, as required by the Act, without unnecessarily burdening small operators. The proposed rule change provides a clear and detailed process for when and how to provide financial assurance, and brings greater consistency to the rules.

20. Blanket plugging financial assurance. The Commission finds that the proposal from OCD, as amended, is a reasonable implementation of the Legislative change to the Act. The Commission reviewed the impacts of the OCD and IPANM proposals, and the impacts with and without including federal wells in the totals. (OCD exh. 9, 13. 14). The Commission finds that the proposed rule changes provide for the statutory increase in blanket financial assurance without unreasonably burdening small operators. Under the OCD proposal, over 50% of the operators would not be subject to a blanket bond greater than is currently required. By not unreasonably burdening small operators who could be forced to plug low volume wells, the proposal avoids potential waste. NMSA 1978, §§ 70-2-3, 70-2-6, and 70-2-11. The Commission finds that the IPANM proposal, which would allow over 50% of the operators to be eligible for reduced blanket financial assurance and increase the amount for less than 12% of the operators, is not consistent with the intent of the legislation which authorized a 400% increase in the maximum blanket financial assurance.

21. The Commission finds that the IPANM concern about potential double bonding when the number of wells covered by the state blanket bond includes federal wells which are covered by separate financial assurance is valid. The Commission modified the proposed rule change to provide that if the number of federal wells held by an operator causes the operator to move into a higher tier under 19.15.8.9(C)(2) NMAC, then the state blanket bond can be reduced by the amount of the federal statewide blanket bond. 10.15.8.9(C)(3) NMAC.

22. One Well Financial Assurance. The Commission finds that the new formula for one well financial assurance more accurately reflects the actual costs of plugging wells at various depths. The evidence clearly shows that the current formulas for one well financial assurance do not accurately reflect the actual costs, and that it is not necessary to prescribe different formulas for different areas of the State. The new formula will bring the rule into compliance with the statutory mandate that the one well financial assurance must be in "amounts determined sufficient to reasonably pay the costs of plugging the wells". NMSA 1978, §70-2-14(A). The Commission finds that the formulas offered by Mr. Marker do not reflect the actual costs nearly as well as the OCD proposal. The Commission also finds that the new definitions of "measured depth" and "true vertical depth", as amended, are reasonable and necessary to implement the one well financial assurance.

23. Temporary Abandonment. The Commission finds that the OCD proposal to limit the percentage of approved temporary abandonment wells reasonable. Wells that are inactive for a significant period pose threats to the environment and fresh water. Operators with large percentages of inactive wells present an increased risk of improperly abandoning the wells and leaving the plugging and cleanup costs to the State. The Commission also finds that coordinating the requirements to permit temporary abandoned wells and to provide increased financial assurance is reasonable and will simplify the process for both the operators and the agency.

24. Transition provisions. The Commission finds that the proposal to have the new financial assurance requirements be effective immediately for new applications but be delayed for other wells is reasonable. The Commission modified the dates to comply with the actual effective date of the rule change.

25. The Commission finds that the proposed rule changes, as modified by the Commission, are supported by substantial evidence in the record. The Commission reviewed the amendments to the proposed rule changes submitted by the parties. The changes approved by the Commission are within the scope of the rulemaking as provided in the notice.

THE COMMISSION CONCLUDES THAT:

1. The Commission has jurisdiction, under the Oil and Gas Act, NMSA 1978, §§ 70-2-1 to -38, over the parties and subject matter of this case.

2. The Commission has legal authority, under the Oil and Gas Act, to enact the proposed rule changes.

3. The Commission provided due public notice and an opportunity for the public to provide comments regarding the proposed rule change. A public hearing was held and reasonable opportunity was provided for all persons present to provide testimony, evidence and exhibits.

4. All Commissioners were present at the public hearing and considered all the evidence presented during the hearing including the proposed modifications submitted by the parties. The Commission deliberated after the hearing and adopted the rule changes.

5. The amendments to the proposed rule changes adopted by the Commission were a logical outgrowth of the original proposal.

6. The Commission concludes that there is substantial evidence in the record to support the proposed rule changes, as amended by the Commission, that these rule changes are within the authority of the Commission under the Oil and Gas Act and that these rule changes are reasonable and further the goals of the Oil and Gas Act.

IT IS THEREFORE ORDERED THAT:

1. The proposed changes to 19.15.2, 19.15.8 and 19.15.25 NMAC, as submitted to the Commission by the OCD and as amended by the Commission during

deliberation, are hereby approved by the Commission. The adoption of the rule changes will be final upon the later of (a) the action, or deemed action, of the Commission on a rehearing application filed pursuant to NMSA 1978, § 70-2-25, or (b) 20 days from the date of this order if no rehearing application is filed. The rule change shall not be filed with the state records administrator until the rule change is adopted and then must be filed within 15 days after the adoption. If no rehearing is required by the Commission, this Order shall serve as the "concise explanatory statement" required by NMSA 1978, § 14-4-5.5 (2017).

2. Commission counsel shall review the text of the final rule and make any necessary non-substantive corrections prior to filing.

DONE at Santa Fe, New Mexico, on August 20, 2018.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

HEATHER RILEY, Chair

ROBERT BALCH, Member

ED MARTIN, Member

SEAL

EXHIBIT 27

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

IN THE MATTER OF THE:

PROPOSED AMENDMENTS TO THE COMMISSION'S RULES ON FINANCIAL ASSURANCE AND PLUGGING AND ABANDONMENT OF WELLS, 19.15.2, 19.15.8, AND 19.15.25 NMAC.

CASE NO. 16078

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSIONER HEARING

July 19, 2018

Volume 1 of 2

Santa Fe, New Mexico

BEFORE: HEATHER RILEY, CHAIRWOMAN
ED MARTIN, COMMISSIONER
DR. ROBERT S. BALCH, COMMISSIONER
BILL BRANCARD, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Thursday, July 19, 2018, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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(9:05 a.m.)

CHAIRWOMAN RILEY: So the first case we're going to hear today is 16078. It is a rulemaking. It's been continued from the May 24th hearing date, and it's In the Matter of Proposed Amendments to the Commission's Rules on Financial Assurance and Plugging and Abandonment of Wells, 19.15.2, 19.15.8 and 19.15.25 NMAC.

It looks like we have two parties to this. We have the OCD represented by Mr. Brooks.

MR. BROOKS: David Brooks, with the Energy, Minerals and Natural Resources Department, general counsel for the Oil Conservation Division.

CHAIRWOMAN RILEY: Thank you.

And then we have a second party.

MR. LARSON: Good morning, Madam Chair, Commissioners.

Gary Larson for the Independent Petroleum Association of New Mexico. I do not have any witnesses.

CHAIRWOMAN RILEY: Okay. Thank you.

MR. BROOKS: I have two witnesses.

CHAIRWOMAN RILEY: Two witnesses. All right. All right.

Mr. Brooks, do you want to --

MR. BROOKS: I think we should swear in the

witnesses first.

(Ms. Marks and Mr. Goetze sworn.)

CHAIRWOMAN RILEY: Thank you.

Mr. Brooks.

MR. BROOKS: These are very simple rule changes, and my witness will explain them. So I think in the interest of time, I will defer -- I will not make any opening statement and begin by calling Ms. Marks.

Do you want to make an opening statement?

MR. LARSON: I do not have an opening statement.

I would like to point out to the Commission on IPANM's proposed modifications of the Division's proposed rules -- and Ms. Marks was kind enough to point this out to me -- in Subparagraph D, we have a category of 149 to 199 wells. That should be 150 to 199 wells.

MR. BROOKS: Very well. I'll call Allison Marks.

ALLISON MARKS,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BROOKS:

Q. Good morning, Ms. Marks.

A. Good morning, Mr. Brooks.

Q. State your name, please, for the record.

A. Allison Marks.

Q. And what position do you hold at the Oil Conservation Division?

A. I am the deputy director.

Q. And how long have you been in that office?

A. A little over two years, I believe.

Q. Very good.

Were you involved in directing the proposed amendments being submitted for adoption at this hearing?

A. I was.

Q. Rather than doing a detailed Q and A, since this is a rulemaking proceeding, I'm going to ask you to go through the rule section by section, explain the changes and state for each one the reasons which the Division came in and offered these amendments for the Commission's consideration.

A. Very well. It will be my pleasure.

So in 19.15.2.7, in (6), we have added a definition of "measured depth," with that definition being "means the total length of the wellbore."

Since Phil Goetze prepared a nice diagram, I believe Exhibit 8 in your packets, to explain the proposed changes to "measured depth" and "true vertical depth," I will let him testify as to both of those

definitions. Both are new definitions that are used in the proposed 19.15.8.9E.

Finally, the only other new definition is under 19.15.2.7.T.(3). The words "or temporarily abandoned status" have been added after "temporary abandonment." And this serves as a means to simply clean up this definition, as the Division uses this term regularly.

And also the phrasing has been incorporated into the proposed amendments to 19.15.8.9.D, and the term "temporarily abandoned status" is also used in statute. So defining it in our rule is helpful and consistent with the new rulemaking statute, I believe, as well.

Q. Ms. Marks, for a considerable time, we have had a situation where a well -- where we had a requirement and I believe we still do under the present rules that will change under this amendment.

Under the present rules, if a well is abandoned temporarily but is not permitted for temporary abandonment by the Division, it is -- it is required -- the operator of that well is required to supply additional financial assurance of that well, correct? Under present rules, if a well is temporarily abandoned, it's not being used, but it is not -- has not been

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approved by the Division for temporary abandonment, then, in that event, the operator is currently required to supply financial assurance -- to provide the Division with additional financial assurance for the plugging of that well, correct?

A. Correct.

Under -- under 19.15.2, "temporarily abandoned" is synonymous with the term "inactive."

Under the proposed rule, "approved temporarily" -- "approved temporary abandoned" and "approved temporarily abandoned status" is a different term. And under this proposed amendment, it puts the well in approved temporary abandoned status. They still have to place additional financial assurance.

Q. But under the present rule, that is not the case, right?

A. Correct. If you want -- wish to -- a condition to get an approved temporary abandoned permit, it's not a condition precedent to place additional financial assurance.

Q. Okay. So this change in definition, to make the terms synonymous of -- temporary abandonment and approved temporary abandonment are synonymous or will be under the new rule if it's adopted and, therefore -- that goes along with the substantive change that both --

either one will require the filing and maintenance of additional financial assurance?

A. No, that's not correct.

Approved temporary abandonment and -- approved temporary abandonment will still be a term of art under 19.15.25.12. "Temporary abandonment" and "temporarily abandoned status," the Division is proposing just to simply modify those terms, but the word "approved" has a different meaning under 19.15.25.12.

Q. Okay. But "temporary abandonment" includes both a generic temporary abandonment, that is: This well is abandoned with the new intention that it will be restored in the future, but it's not being used currently, and it also includes approved temporary abandonment status. Either way, it's temporarily abandoned, right?

A. "Temporary abandonment" and "temporarily abandoned status" simply means that the well is inactive.

Q. Whether it's proved that they're inactive status -- whether it's approved temporary abandonment or not? Doesn't make any difference about it being temporarily abandoned status?

A. I think we should just address if they're

"temporary abandoned" later on in the section on "Approved Temporary Abandonment."

Q. Well, you will agree with me that it makes no difference as a matter of requiring additional bonding under the new rules that it is approved to be temporary abandonment status, right?

A. I'm sorry. Can you restate your question?

Q. You will agree with me, will you not, that under the proposed changes, it will make no difference for the purpose of -- the requirement of additional funding whether a well is in temporary abandonment status generically or whether it is approved for temporary abandonment -- well, no. I put it -- it does make a difference whether it's one or the other. It doesn't make a difference which category it's in.

A. That's not correct. If a well is seeking to be in approved temporary abandonment, which I will discuss later on, to get that permit, you will need to place additional financial assurance. Just for a well to be temporarily abandoned or in temporarily abandoned status or temporary abandonment, which is at the two-year mark, the existing financial assurance requirements remain in place.

Q. I don't understand, but go ahead.

A. Okay. Should I continue?

Q. Yes.

A. Okay. The Division is also proposing modifications to 19.15.8.9 here. And the title to this section, we added the words "categories and amounts of" before the words "financial assurance for well plugging."

And then before I go into specific changes, I'd like to just give a bit of an overview of what prompted some of the proposed changes and what we as the Division have seen over the last several years.

First, during the last legislative session, the legislature passed and the governor signed Senate Bill 189. While the bill cleaned up a few matters not relevant to this rulemaking, the bill also raised the amount of blanket plugging financial assurance to $250,000 from $50,000 and instructed the blanket plugging amount to be set by rule before this Commission. For reference, the blanket plugging amount has not been increased since 1977.

In addition and in contemplating the Division's proposed amendments, there is some statutory language I'd like point out to the Commission. Namely, 70-2-14(a) states in part that "one well plugging financial assurance amounts determined to be" -- "to reasonably pay the cost of plugging the wells covered by

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the financial assurance. In establishing categories of financial assurance, the Oil Conservation Division shall consider the depth of the well involved, the length of time since the well has produced, the cost of plugging similar wells, and such other factors as the Oil Conservation Division seems relevant."

In drafting a rule before the Commission, the statutory requirements are really taken to heart, and we have tried to develop the most fair and equitable proposal while also considering the Division's actual plugging costs in conjunction with the Division's compliance efforts and potential risk exposure.

With the above in mind and having undertaken over the past several years an analysis of the Division's expenditures due to underbonding of well plugging, we worked to develop new appropriate financial assurance levels. On that note and before diving into the proposed changes, it may be helpful to look at Exhibits 3 through 7 at this time, which I believe are in the packets before the Commission.

So if we could start with Exhibit 6, what I did here is I pulled from fiscal year '14 all the wells that the Division has plugged since fiscal year '14 until a certain time in fiscal year '18. And I can't tell you exactly when I stopped in fiscal year '18. I

believe it was sometime in February or March. And you'll see all wells listed by API, depth and the total plugging costs and the price per foot and the fiscal year the well was plugged.

Then this data was plotted in Exhibits 3 and 4 in your packet. Exhibit 4 excluded some of the unusually high outlier well plugging the Division saw. You'll see one for $140,000, $146,023, and some of the really shallow wells of 45 feet, which cost $50.89 per foot. I didn't think it was really fair, in contemplating a rule change, to include those very high outliers.

Then if you turn to Exhibit 5, I wanted to see what our fixed costs, plus price per foot looked like with different fixed costs. And since we have mobilization costs and other expected costs in every plugging job, bearing those minimum costs in minds and in consideration of our statutory duty, I wanted to develop an appropriate cost -- an appropriate single-well bond amount, and that's how we came up with $25,000, plus $2 per foot.

Then if you turn to Exhibit 7 in your packets, this is a list of operators as of June 28th, 2018 who are not compliant with our inactive well rule. There are 136 operators on this list, with a total of

1,738 wells out of compliance.

As a matter of reference, when an operator continues to be out of compliance with the Division's inactive well rule and fails to come into compliance, whether it be by plugging the well, bringing the well back in production or entering into an agreed compliance order with the Division, the Division pursues a compliance case against the operator, and we seek a plugging order. When the operator fails to plug the well, the Division plugs the well, and then if the operator has financial assurance, the Division first seeks to recover under the financial assurance, which the Division is the beneficiary of. And then as the Oil and Gas Act under 70-2-14(e) allows, the Division will bring suit for indemnification for all costs incurred by the Division in plugging the well.

So I'll just point out some of these operators in Exhibit 7 because I think that could be helpful. Some Commissioners may not be familiar with some of these operators. So Canyon E & P on this list, they have 271 inactive wells showing up, and we have a plugging order against this company. And they went through bankruptcy, and we aren't going to recover anything further from this company.

Then the same can be said about DC Energy,

LLC. So there is a broad range of small operators to larger operators. DC Energy, they also went through bankruptcy, and the Division recovered $50,000. Again, we're not going to recover any other funds from this operator, and we still have six wells to plug, along with any reclamation.

Giant Operating, LLC is yet another operator -- operator the Division is left with recovering -- covering plugging costs. The operator went through a receivership, and the Division received $37,000 from the receiver. Giant still has five wells to plug.

Then we have a number of operators on this list with 100 percent of their wells inactive and have plugging orders or have a very high number of noncompliance rates with our Legal Bureau. And I can anticipate, based on history with the Division, the Division will have to plug these wells, and the cost will be paid out of the oil reclamation fund.

For instance, Dominion Production Company, LLC, the Division has a pending district court case against the operator for inactive well violations and for violations of financial assurance rules, amongst other violations. Dominion has 126 noncompliant wells and requires additional financial assurance on 62 wells.

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Blue Sky NM is another operator we filed suit against in district court. They have 32 wells in need of additional financial assurance and 38 inactive wells.

So just Blue Sky and Dominion alone, we're looking at millions of dollars in plugging costs that will come out of the reclamation fund. So by illustration, there are several noncompliant operators for which we turn to the reclamation fund to fill the gap when financial assurance isn't enough. And we have really stepped up our compliance efforts, and, therefore, we will have a lot of operators whose wells will be added to the plugging list. Since February of this year alone, we have added hundreds of wells onto the plugging list, and at present, we have about 500 or so wells on our plugging list with only a million and a half or $2 million in bonding to cover our anticipated plugging jobs.

So with that said, I'll go back to the rule before you. If you turn to 8.9C. and D., I have attempted to add a lot of clarity for operators, as the existing language is confusing. Our bond administrator was just back from maternity leave, and I filled in for her for several months. And I had the pleasure of interacting with a number of operators during this time,

and I saw a lot of the confusion and frustration that they faced, so I think this does a nice job of cleaning up the rule for them.

So Subsection C sets forth the financial assurance requirements just for wells that have been producing within the last two years or which is in new, not in approved temporary abandoned status. Consistent with statute, an operator can either post a single-well bond or a blanket bond for the wells produced within the last two years.

Thus, we propose striking the existing Subsection C and replacing it with the words "the division accepts the following categories of financial assurance for wells that are not required to provide financial assurance under Subsection D of 19.15.8.9 NMAC: (1) a one well financial assurance in the amount of $25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well";

Or "(2) a blanket plugging financial assurance in the following amounts covering all oil, gas or service wells drilled, acquired or operated in this state by the principal on the bond: $50,000 for one to 10 wells; $75,000 for 11 to 50 wells; $125,000 for 51 to 100 wells; $250,000 for more than 100 wells."

I did an analysis of the 613 operators in

OCD's database, and for reference, there are 348 operators in the one-to-ten operator range. That's 56.7 percent of all of our operators. There are 145 operators in the 11-to-50 range, which is 23.6 percent of all of our operators. Forty-eight operators in the 51-to-100 range, which is 7.8 of all of our operators, and 72 operators in the greater-than-100 range, which is 11.7 percent of all of our operators.

Of those operators, I further determined how many operators as of July 16th are currently out of compliance with our existing financial assurance requirements. In the one-to-ten well range, 40 operators are out of compliance with our financial assurance requirement, which is 50 percent of all of our operators who are out of compliance with our financial assurance requirements. Twenty-eight operators in the 51-to-100 well range are out of compliance. That's 35 percent of all of our noncompliant operators. Two operators in the 51-to-100 range are out of compliance with our financial assurance requirements. That's 2.5 of all noncompliance operators. And ten operators in the over-100 range, and that's 12.5 percent of all noncompliance operators.

And I will point out, too, you know, when I ran those numbers -- and this was done after we filed

this application -- it was kind of striking to see such a small number of operators, 7.8 percent, in that 51-to-100 range. And from an administrative perspective, initially I had contemplated three tiers in C.(2). And I thought, you know, we want to be fair and equitable. That's always a consideration of the Division in developing tiers. So we did come up with a fourth tier in consideration of the broad range of operators that do operate in this state. So we did add a fourth tier. But from an administrative standpoint, we can't have -- it would just be way too burdensome, and there would be too many operators coming in and out of compliance, and we do have so many compliance problems from a bonding perspective, so too many tiers would be problematic, but we did add that fourth tier in.

I did also review IPANM's proposed breakdown for 8.9C.(2), and for reference, what their proposed range is, the breakdown of operators would be as follows: The one-to-ten range, that would stay the same because it's consistent with what the OCD has proposed. In the 11-to-99 range, there are 193 operators, which is 31.2 percent of all of our operators. In the 100-to-149 range, there are 13 operators, which would be 2.1 percent of all of our

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operators. In the 150-to-199 range, there are ten operators, which is 1.6 percent of all operators. And in the over-200 well operator range, there are 49 operators, 8 percent of all operators.

So with IPANM's proposed breakdown, 56.6 of operators would see a reduction in their financial assurance with the Division. 31.5 percent of operators would see no change in their blanket bond. And that's -- just under 12 percent of operators would see an increase in their blanket bonding. And despite the number of noncompliant operators in our statutory mandate, 56.6 percent of operators would see a decrease in their financial assurance with that proposal, which caused me a little bit of heartburn with the plugging costs that the Division has seen and the out-of -- out-of-pocket expenses out of the rec fund that I have seen.

So moving on to 8.9D., we strike the existing Subsection D and add clarity to this section. We eliminate the distinction based on most producing -- on the most producing counties, since this is not relevant, and actually can be more expensive to get a plugging range out to areas like the Bravo Dome and eliminate the administrative headache of allowing up to a 500-foot variance in well depth.

This subsection then sets forth the financial assurance requirements for wells that have been inactive for more than two years and keeps the same plugging financial assurance for temporarily abandoned wells that the Commission adopted in rulemaking about three years ago, I believe. The only addition to this section is the proposed rule requires that any well the Division places in approved temporary abandoned status, pursuant to 19.15.25.13 NMAC, must also place the normally required additional financial assurance required after two years.

Then we have added a Subsection E, which clarifies how depth is measured, and Phil can answer any table questions regarding this subsection, since he will be discussing those two terms.

Then in 19.15.8.14 -- it's the "Effective Dates" provision -- the Division proposes the following language: "The 2018 amendments to 19.15.8.9 NMAC apply to applications for permit to drill, deepen or plug back and applications for approved temporary abandonment filed on or after July 24th, 2018, and for all other wells on October 31st, 2018." This will allow operators with existing financial assurance a grace period to come into compliance and work with the banks or surety companies to provide the Division with correct financial

assurance.

Then if we move on to 19.15.25.12, in this section the Division proposes to limit the number of wells an operator can place in approved temporary abandonment. After this application was filed, I noticed we just need to clean up the proposed sentence a little. I'd suggest a little language change here. I propose the following: "The operator is limited to the number of wells it can place in approved temporary abandonment status as follows: (A) one well for one to five wells; (B) 33-and-three-tenths percent for more than five wells."

In the language before you, the third percent would be difficult from an administrative perspective because a third is obviously an unknown number, and the introductory prepositional phrase causes a bit of confusion, and the proposed language to adjust it would make it a bit easier and clearer, I think, for operators. So --

MR. BRANCARD: Could you go over that language again?

THE WITNESS: Sure. "The operator is limited to the number of wells it can place in approved temporary abandonment status as follows: (A) one well for one to five wells; (B), 33-and-three-tenths percent

for more than five wells." The actual meaning and intent doesn't change. It just adds some clarity.

Then if we move on to 19.15.25.13, here in Subsection B, we've added the words "a permit for approved" before the words "temporary abandonment," since we are, in fact, granting a permit. And this provides clarity to the subsection.

Then in Subsection E, we have clarified that "no permit shall be approved until an operator has complied with Subsection D of 19.15.8.9 NMAC, which requires the financial assurance to be posted before approval of the approved temporary abandonment permit." And this really protects the Division in a lot of ways. From a compliance perspective, I see a lot of cases where we bring plugging cases against an operator who have no additional financial assurance, and the well is in expired temporary abandonment status. And a well can be placed in approved temporary abandonment status for five years, and an operator can encounter financial difficulties during this time. Since the status allows an operator to allow the well -- since this says allows an operator to allow the well to not produce, this gives the Division more protection from the onset so we don't have to chase down additional financial assurance in seven months when the well hits the two-year mark, which

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statutorily requires additional financial assurance at this time.

Certainly when a well is producing, there is less likelihood of a wellbore deteriorating, and an operator knows if there are any problems with the well -- with a producing well.

When a well is inactive, the risk of something happening to the wellbore increases, and the risk of damage to a producing zone or the migration of hydrocarbons or other leaks increases. During a five-year cycle, there is no way to monitor the wells if anything is happening with the wells, so this provides more protection to the Division.

These are all of our proposed changes.

Q. (BY MR. BROOKS) Well, I need to ask you some questions about them because I don't understand it very well myself. The test of whether a presentation is sufficient is whether the dullest person in the audience understands. So assuming I am in that category, I do need to understand.

One thing this -- this rule has not specifically discussed is it increases the amount of certain financial assurances, right?

A. Correct.

Q. It increases the amount pursuant to legislative

authorization --

A. Correct.

Q. -- at the last regular session of the legislature?

This rule would increase the amount of the blanket plugging bond required of an operator who has no wells in temporary abandonment status, correct, from 25,000 to 250,000?

A. I'm sorry?

Q. I'm sorry. Yeah. It increases the amount of the blanket bond required of an operator that has no wells in temporary abandonment status, correct?

A. If an operator has a well in approved temporary abandonment status --

Q. No. That's not what I asked you. I'm sorry.

Suppose an operator has no wells in temporary abandonment status. Under present law, what is the required blanket bond of that operator if the operator chooses to use a blanket bond instead of single-well bonds?

A. $50,000.

Q. And what would it be under this new rule?

A. It would depend on the number of wells that an operator has.

Q. Okay. Let's assume the operator had 15 wells.

What would it be?

A. $75,000.

Q. And that schedule is found in 8.9C.(2) of the proposed new rule, correct?

A. Correct.

Q. And depending -- and if you want to know what the blanket bond is required of an operator regardless of the existence of temporary abandoned wells, supposing he has none, you go to 18 -- you go to 8.9C.(2) of the proposed rule and look at how many wells does the operator have. You've got to figure that's the amount of blanket bond that will be required to provide under this new rule, correct?

A. That's correct. And just to clarify -- I just want to bring clarity to the term "temporary abandoned." It simply means an inactive well.

Q. Correct.

A. So an inactive well, regardless, will be included in this well count. But I don't think -- I don't think we need to make any distinction over whether a well is temporary abandoned or not.

Q. Well, not -- I assume they were not temporarily abandoned. Merely to clarify what purpose, but your point is very -- what is the -- the bonding requirement in that situation, but your point is well taken.

The existing $50,000 bond and the -- under the existing rule and the revised -- the amended $50,000 bond required under 8.9C.(2) would apply based on the number of wells regardless of how many of them may be in inactive temporary abandonment, correct?

A. Correct.

Even if they're in approved temporary abandonment, the blanket bond -- if an operator chooses to place all of their wells under a blanket bond, if they are in approved temporary abandonment, that just requires additional bonding.

Q. Yeah. Well, I'm going to get to that in a minute. I'm trying to go through this step-by-step.

Now, an operator under present law and under the proposed rules has the option of putting a single-well bond on each well that he has --

A. Correct.

Q. -- instead of using a blanket bond, right?

A. Correct.

Q. But it's seldom to the operator's advantage to do that, correct? Most operators have a blanket, don't they?

A. Most operators have a blanket bond.

Q. Okay. Now, when it comes time to -- when an operator has wells that go inactive and they stay

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inactive for two years, they are deemed to be in temporary abandonment status for two years, correct?

A. Correct.

Q. At that point, whether or not the operator has applied -- well, if the operator had applied for temporary abandonment previously under the existing rule, no bonding would have been required at the time of that application for temporary abandonment, correct?

A. For approved temporary abandonment, we have not previously required financial assurance at the time of application.

Q. Right.

Now, if a well -- this is perhaps where I'm missing -- where I need clarification, maybe where I'm misunderstanding.

If a well is placed in approved temporary abandonment, under the present rule, without regard to these amendments, and then the two years passes and that well has been in temporary abandonment status for two years, it's been approved maybe for two months but the approval is still current, is the operator then required under the present rules to provide additional financial assurance?

A. All operators, whether a well is in approved temporary abandonment status or temporary abandonment

status, which is just synonymous with inactive, are required to post additional financial assurance after two years.

Q. Even if a well is in approved temporary abandonment status at that point?

A. Correct.

Q. Okay. That was a misunderstanding. And because I was dealt with this some time ago and there have been several amendments to the rule, that's probably the source of my misunderstanding.

A. That's okay.

Q. So additional bonding is required for wells that have been in temporarily abandonment status for two years under the present rule and under the new rule regardless of whether they are approved for temporary abandonment or not?

A. Yes, with the caveat that any well under the proposed rule to be in approved temporary abandonment status will require additional financial assurance in order to get that approval. But yes. Any well in the state of New Mexico that is on private or state land will require -- does require financial assurance after two years, and if it is to be an approved temporary abandonment status, will require additional financial assurance under the Division's proposal in order to get

approval.

Q. Well, but you said two different things there. And I'm trying to get this clear, and I'm still not clear. And I thought I was until you answered the last question.

Let's say well X is inactive. Two years passes. It's still inactive. No application for temporary abandonment has been filed. Then when the clock hits two years, the additional financial assurance requirement kicks in, correct?

A. Correct.

Q. But that's not because the operator doesn't have financial assurance because the operator does have financial assurance. They have to have additional financial assurance because that well is in temporary abandonment status, correct?

A. Correct.

Q. Okay. And that's true under the old rule, and it's true under the new rule?

A. Correct.

Q. Now let's say the well was completed on November the 1st, 2016. Well, no. Let's go back so we're under the old rule. The well was completed on November the 1st, 2015. On November the 1st, 2017, it would have required additional financial assurance?

A. It's over two years, so it would be November 2nd, 2017. Yes.

Q. Okay. November 2nd. I stand corrected.

That is still true under the new rule if the operator has not applied for temporary abandonment status before November 2nd, 2017 for that well, correct?

A. That's correct.

And I will amend my answer to say I did not consider whether this is a leap year or not of any other years, so that's not a consideration. And I don't know if our I.T. people consider leap years or not.

Q. I don't either. We'll assume they don't for purposes of these illustrative questions.

A. And I --

Q. Okay. Now, under the new rule, if, on October the 1st -- let's say instead of 2017 -- 2015 and 2017, it's 2016 and 2018. The well was completed November 1st, 2016. On October 1st, 2018, after this rule has presumably gone into effect, the operator files for temporary abandonment status. At that point, under this rule, the operator would be required to file additional bonding, correct?

A. If the operator applied for approved temporary abandonment status.

Q. That is what I asked.

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A. Yes.
Q. Okay. But if he files that additional financial assurance with his application, then November the 2nd comes around. The operator is -- and the well has been, then, in temporary abandonment status for two years, he is not required to file -- I do not understand if he is required to file further additional financial assurance, is that correct --
A. Correct.
Q. -- or he has additional financial assurance in effect?
Now, let's go back and get the thing that I was mixed up about in the first place and get it straightened out.
On November the 1st, 2015, while I was up in Durango, this operator completed a well. On October the 1st, 2017, the second year after I had come back from Durango, this is the third, the operator filed an application for temporary abandonment, but the well was not at that time in temporary abandonment for two years because it only been temporary abandonment for 23 months. Under the old rule, he was not -- he or she was not required to file an application for -- an additional bonding with the application for temporary abandonment, right?

A. That's correct.
Q. But 30 days later, when November 2nd -- 32 days later, when November 2nd rolls around, then the operator was required -- it would have been required by the existing rule to file temporary -- to file additional bonding on that well?
A. Correct.
Q. Okay. That was what I was confused about, because there was one stage in the sequence of amendments in this rule when that was not the case, but I lost track of what was happening with this rule between then and the adoption of the present rule apparently.
So the only thing -- the only thing the present rule changes in regard to the requirement for additional financial assurance, other than the amounts, is that if you file an application for temporary abandonment before you are required to file -- that is the two-year time -- or before you have, in fact, filed a temporary -- a required temporary assurance -- a required additional bonding for temporary assurance -- for additional financial assurance for temporary abandonment -- I'm sorry. I've got to get my wording right. If you request approval of temporary abandonment, at the time you make that request, either

you're not yet required to have additional bonding on that well, or, two, you are required, but you haven't done it, in either of those situations, you have to file an additional bonding at the time that you apply for temporary abandonment, correct?
A. At the time you apply for approved temporary abandonment permit, you'd have to submit additional financial assurance. And under 5.9, when an operator does not want the well on the inactive well list, there would be incentive to place it into approved temporary abandonment to reduce its non -- potential for noncompliance with the inactive well violations.
Q. Okay. And that is the reason why we want to make it a condition precedent rather than simply a condition to get that additional bonding in place because that's the best time to get him to -- that's when the operator has the best incentive to file -- to comply?
A. That's correct.
Q. Now, we have a lot of operators who do not comply with that additional financial assurance requirements when their well's been inactive for two years?
A. That's correct.
And that's where I did a breakdown earlier

in my testimony. In the one-to-ten operator range, 50 percent of our noncompliant financial assurance operators -- of our noncompliant financial assurance operators, 50 of those operators are in the one-to-ten operator range. And I can go back to my numbers if desired. But yes.
Q. Well, you don't need to go back through the numbers. But if that's the case, the well is inactive, the operator has not complied with the additional financial assurance, and either it is in temporary abandonment status or the operator is not approved for temporary abandoned status or the operator has not applied for that status, then the only way to enforce the requirement is to file an enforcement action, correct?
A. That's correct.
And oftentimes we bring -- we'll bring compliance actions and whether -- we either will bring a financial assurance compliance case or a plugging case, and we still won't get compliance from those operators. We won't get them to post the additional financial assurance. Sometimes we do. Sometimes we don't. We have had a lot of success with the Division's internal efforts to get -- get operators to come into compliance.
But once we have to refer it over to Legal,

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we'll have orders for operators to post their required financial assurance. But if they don't, we'll be left with operators who need to post the additional financial assurance, but then the wells are also inactive. So we are left with insufficient financial assurance and a plugging order for those wells.

Q. Okay. Now, the amounts for -- well, if an operator has more than one inactive well, it would be kind of a moot point for only one. But if it's more than one inactive well, the operator has a choice, does he not, under the present rule and under the new rule to file a blanket plugging bond for temporarily abandoned wells under 8.9D.(2) or to file an individual bond -- a one-well bond for each temporarily abandoned well, correct?

A. That's correct.

Q. And have the amounts of the required blanket bonds for -- for corresponding to the number of temporarily abandoned wells been changed by the new rule?

A. The amounts for the blanket plugging financial assurance for temporarily abandoned status wells under D.(2) have not changed since my testimony before the Commission about three years ago. I think they are still sufficient.

Q. So the proposed rule would make no change in the present rule for that particular -- those particular amounts?

A. Correct.

Q. And, of course, the schedule in C.(2) for blanket bonds for all wells is a new schedule because we had a plat amount before by statute?

A. That's correct.

Q. Okay. Now, the amounts of a one-well bond have been changed -- or are proposed to change; are they not?

A. That's correct.

Q. And what will be the new amounts for one-well bonds? Well, before you answer that question, let me clarify. The amount for one-well bond, is that the same amount if you choose to use one-well bonds for all your wells as it is for a temporarily abandoned well?

A. For one-well bonds, that's correct. Yes.

Q. And what is that amount?

A. $25,000, plus $2 per foot. And that's based off of our statutory duty to determine the appropriate well plugging costs.

Q. And you have already testified to the fact that we have made a study of well-plugging costs and that those figures are justified pursuant to that study?

A. Yes, based off of our downhole plugging costs,

and those are reflected in Exhibit 6.

Q. Again, you'll have to pardon me because I'm a Texan and I speak very slowly, and when someone speaks very fast, I'm not sure if I'm covering everything or not because I lose track. I haven't developed the talent to speak both Texan and American --

A. I'll try to speak Texan.

Q. Well, I'm not sure there's much hope for you (laughter). But New Mexico is not Texas. Somebody around here used to have a sign that said, "I know how you do it in Texas. Now let's talk about how we do it in New Mexico."

Okay. I think I've covered all the questions that I have, and I think I now understand what you're doing. So I will move on to a couple of other things.

You did cover, specifically, the fact of the 500-foot tolerance on the depth bracket. In other words, it used to be if you have -- if a well goes 500 feet below the depth bracket for which -- waiver for additional bonding is required when going into the next depth category, correct?

A. The district office had that ability and we -- it was very difficult from an administrative perspective to manage that.

Q. And you propose to eliminate that?

A. Correct.

Q. Okay. Now, you also -- also, the district office had discretionary authority to waive the additional bonding requirement for inactive wells if a well was inactive because of the lack of a pipeline connection? That's a part of the existing rule, right?

A. Let me see. We've actually never had that request. I don't -- I mean, I don't know if it's the district office or if it's Santa Fe, but --

Q. That's in existing 9.C, I believe, but I don't have my rule book with me.

A. It says "the division," but it's not specific to a district office.

Q. Well, it doesn't matter.

A. But yeah, we propose to eliminate that.

Q. But you propose to repeal that entirely?

A. Correct.

Q. And if it's inactive for any reason, it's inactive under the proposed rule?

A. Correct.

Q. Okay.

MR. BROOKS: I believe I've covered all the things except those I'm supposed to cover with Mr. Goetze, so pass -- I will pass the witness.

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Oh, I need to get the exhibits tendered. I would tender Exhibits 1, 2, 3, 4, 5, 6 and 7.

Q. (BY MR. BROOKS) Before I do that, were these exhibits prepared by you or under your direction from OCD records?

A. They were.

MR. BROOKS: I tender Exhibits 1 through 7.

CHAIRWOMAN RILEY: Exhibits 1 through 7 can be accepted into the record.

(NMOCD Exhibit Numbers 1 through 7 are offered and admitted into evidence.)

MR. BROOKS: And I will pass the witness.

MR. LARSON: No objection (laughter).

(Laughter.)

MR. BROOKS: To the exhibits or me passing the witness?

MR. LARSON: No objection to the exhibits.

CHAIRWOMAN RILEY: Thank you, Mr. Larson.

CROSS-EXAMINATION

BY MR. LARSON:

Q. Good morning, Ms. Marks.

A. Good morning, Mr. Larson. I don't think you could be any more difficult than my own attorney (laughter).

Q. You mentioned a number of operators in the

one-to-ten well category. I'm afraid I didn't catch that number, 300 something.

A. Sure. 348.

Q. And what was the percentage of the total number of approved operators?

A. 56.7.

Q. Would you agree with me that the reclamation fund is the primary source of funds for the Division to plug wells?

A. For the Division to plug the wells, generally the reclamation fund is the primary source. During fiscal year '18, I believe, the Division does not have sufficient funds to plug wells out of the reclamation fund, so we relied on a federal grant and plugged -- I believe Commissioner Martin would know this. We've only plugged, I believe, four or five wells that were nonfederal wells because of unfortunate gross deficiencies in the reclamation fund. So we plugged significant federal wells under that grant.

Of course, statutorily -- and I have the -- I have the statute in front of me. The funds should come out of -- should be coming out of an operator's financial assurance.

Q. And during fiscal year '18, were any redeemed bonds used to plug wells by the Division?

A. I'd have to look, of the four wells that we did plug, if we -- if there was any financial assurance on file, we would have redeemed those bonds. I don't believe we've plugged any in the northwest. But at $5,000, plus $1 per foot, that's not much financial assurance. We would have maybe redeemed $28,000, at max, assuming every operator would have had financial assurance in place.

Again, with the number of operators who fail to comply with our financial assurance requirements, unfortunately -- and I've been -- we've been plugging a number of Canyon wells. Unfortunately, we've plugged a number of wells where the operator does not have bonding in place. So we plug out of the reclamation fund 100 percent as the plugging costs come out of the reclamation fund, and we don't have any financial assurance to offset any of the plugging costs. So even with the increase -- proposed increase in financial assurance, a lot of the expenses will still come out of the reclamation fund.

Q. Does the Division have an enforcement mechanism to prevent an operator from being out of compliance with financial assurance?

A. Sure. Of course. And we -- we -- our dockets are very full. I believe we have 102 cases on our

docket. Poor Florene over there. And we take -- we take compliance very seriously, and we've really stepped up our financial assurance compliance and our inactive well compliance, which it's a double-edged sword.

When we increase our inactive well compliance, our inactive well -- our plugging list continues to grow. We didn't have much of a remedy before and now -- but we have to do our -- take over our statutory duty to protect human health, the environment and safety. And so in doing so, our plugging list continues to grow, and that will inevitably lead to more expenditures out of the reclamation fund to cover those plugging costs. And despite the best efforts of our legal department and our internal OCD efforts to bring operators into compliance, there will always be operators who are out of compliance.

We see oil prices. They go up. They go down. And when oil prices go down, unfortunately, we have a lot of operators who just walk away. The best operators will go through a formal bankruptcy or a formal process to wrap up their businesses, but a lot of times, the Division will be left holding the bag to plug those wells or the operators are noncompliant. We have operators that aren't formal business entities. They're just sole proprietors. They, unfortunately, pass away;

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They haven't done the -- with probate estates or don't have the most formal probate processes, and so we don't file a claim in their estate. So in those cases, we don't receive the financial assurance, and we have to plug those wells as well.

So yes, despite phenomenal efforts, I believe by the Division and our Legal Bureau, unfortunately, we can't have 100 percent success rate, and the reclamation fund is used for its intended purpose, to offset those costs.

Q. And who contributes to the reclamation fund?

A. Oil and gas operators in the state.

Q. And what's the formula for those contributions, off the top of your head?

A. If you give me a minute, I can go pull the statutes. If you have the statutes with you, I can --

Q. I don't.

A. Or I'd ask the Commission to take notice of whatever is in the statute under -- it's based off the price of oil. When the price of oil is over $70 a barrel, it's one factor, and under, it's another.

Q. So it's a certain fraction per dollar of oil produced, generally speaking?

A. Yes.

Q. And would I be correct to say the same

operators who are required to post blanket and/or single-well bonds are also contributing to the reclamation fund?

A. That's correct.

Q. And exactly what wells does the Division plug with reclamation fund money?

A. Are you asking for a priority of wells or wells on state lease land, private land?

Q. Type of well.

A. Oil and gas wells, generally.

Q. And are they orphaned wells?

A. Yes, and any well that an operator -- that we received a plugging order for.

Q. Okay. When you say a plugging order, that's going to Division hearing, getting an order requiring the operator to plug the well?

A. Correct. And if an operator is noncompliant with said order, then we would go and plug the well.

Q. You mentioned priority. Could you go into some detail on that?

A. Sure. If there's -- if there's a well that would affect human health, safety, the environment, water, those are certainly our top priorities. We take those statutory duties very seriously, and we do everything -- everything within our power to make sure

we do protect any -- any water zones and any -- we make those wells the absolute most priority -- highest operator priority.

After that, we would look to see about old wells in certain areas. We try to keep our costs down. We'll go into a certain unit and plug a number of wells within that unit all at once. It wouldn't make sense to go just jump all around to different units. So we look to see if an operator does have bonding, especially with -- I have our numbers from the reclamation fund. But when our reclamation fund was down to, you know, $3 million -- presuming we're paying salaries out of there -- we couldn't -- we tried to maximize the amount of plugging we could do with -- at our lowest cost for an operator who did have bonding in place. We would try to plug wells that had financial assurance in place and use as little of the reclamation fund as possible.

Q. And for these plugging orders that you mentioned, do you redeem those operators' single-well or blanket bonds if they have them?

A. Of course.

Q. And do you know roughly the current balance of the reclamation fund?

A. I have -- let's see. As of June 30th -- I think as of June 30th, 2018, I believe it is $5,774,700.

Q. And that money is earmarked for plugging costs?

A. No. That's the total balance of the reclamation fund. In fiscal year 2019, I believe we have $2,181,000 earmarked in contractual services, which plugging costs would fall under.

Q. What about the remainder of the balance?

A. Actually, this probably does not -- let's see. The balance -- in general -- in general, we don't -- we don't earmark the entire -- that would be my quick math here. We do have some operating costs as well that comes out of there. We only had 100-and-something-thousand dollars this year. We did a -- it was great this year of only having about $145,000 per month come out of the reclamation fund for salaries this year.

We never earmark the entire reclamation fund. We never spend down the entire reclamation fund every year. That would -- that would be ill-advised from a budgetary standpoint. We also -- and, again, that's just for the downhole plugging. Usually we do earmark some monies, and we set aside some monies for reclamation efforts.

So, again, we talked about prioritizing wells based off of public health, safety and the environment. We do have -- we do use money from the reclamation fund for cleanup and environmental matters

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as well. So we've been very fortunate not to have any matters in need of environmental cleanup, but we do set aside funds in the reclamation funds to address environmental matters that may come up that can be very expensive. And so it's nice to keep money set aside in the reclamation fund to clean up sites. And we have plugged and not released a number of sites. And if the fund balance were to continue to grow in the reclamation fund, we could certainly clean up a number of additional sites and then release those sites and continue to clean up a lot more sites from the reclamation fund, which is an additional purpose which the fund is allowed to use as opposed to just downhole plugging.

Q. And does the legislature allow the Division to carry forward the balance from the previous fiscal year?

A. Yes, it does. It's nonrecurring funds.

Q. And does the Division have access to the Office of Natural Resources trustee for environmental and surface-location issues?

A. I would have to get back to you on that.

Q. You mentioned, in looking at particular operators in one of your exhibits, that several of them declared bankruptcy or had gone into receivership, and you mentioned funds received. Are those based on proofs of the claim, for instance, in the bankruptcy?

A. Yes.

Since I've -- before becoming deputy director, I worked in the Legal Bureau with EMNRD and was in charge of a lot of bankruptcy matters, and in the deputy director position, I have worked in conjunction with the Attorney General's Office on bankruptcy matters. And we've done a great job of being much more proactive in filing claims in bankruptcy matters. So we will certainly file a proof of claim in all bankruptcy matters and have been diligent in converting claims to administrative claims when applicable. So an unsecured claim -- for example, in Vanguard, we filed an unsecured claim. Obviously, there is no need to convert that claim to an administrative claim, but --

Q. Are those claims to cover plugging costs?

A. It depends on the nature of the claim, but yes. If it's an administrative claim, certainly.

Q. And do you have a sense of the Division's success rate in terms of proof of claims that are filed in bankruptcy?

A. Could you clarify success rate?

Q. How many times do you receive funds from a bankruptcy estate?

A. If it's -- it depends on the amount of monies in the bankruptcy estate and how well funded the

bankruptcy estate is. A lot of times, unfortunately, some operators aren't well funded in their bankruptcy estates.

In the DC Energy case, unfortunately, when we received $50,000, that certainly wasn't enough to cover our very large claim that we filed in that case, and we were in the administrative claim in that case. Administrative claims, obviously, are paid before even a priority claim. We got paid before -- before Tax and Rev. So I think we've done a great job in getting paid. It's a matter of what per- -- what percent on every dollar we are getting paid. But our success rate -- I think we're batting 100 on our success rate in getting paid, if we get a penny for every dollar, but I don't know if I'd say that's successful.

Q. You and a lot of other unsecured creditors.

Does the Division track the number of its blanket and/or single-well bonds that are redeemed for plugging costs?

A. Historically -- historically, I don't believe we had. We have -- we have now started to track the number of bonds that aren't redeemed. We have developed -- about a year and a half ago, we worked with our I.T. department to develop a new bonding module, which develops bonding compliance reports and also

tracks every bond that comes in -- into our system. It's readily available for the public to see, and also any redemptions to any bond are also available. So if you look up any well, you will see -- say it's a $50,000 bond. You'll see the remaining balance on that bond.

Q. And what's the Division's process for retaining plugging contractors?

A. We go through our mandate through the State. The contract goes out to bid, and we receive bids from any -- any and all contractors that are interested. Unfortunately, during the last -- the last offer about a year ago, we -- we had two interested pluggers. We tried to get a second plugger in the southeast even to bid on the contract, and we were unsuccessful in doing so. So it's very difficult to compete with industry. We go through -- you have to do a purchase order, and then you wait for payment, and I think industry pays a lot faster than we do. And to bid on the right -- purchase order and a lot the paper associated with working with the State sometimes can be a lot more difficult than working directly with a company.

Q. Does the Division attempt to have a plugging contract to plug multiple wells and, therefore, get a discount on the per-well plugging costs?

A. We -- when we talked about prioritizing wells,

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we certainly looked into certain units, and that brings down our costs. And what we also do is we always try -- under the Oil and Gas Act, we are allowed to offset our plugging costs with salvage. And I actually have an invoice right here on a well.

So actually in Exhibit 6 before you, those costs actually reflect the salvage equipment offset. So the true -- true costs of plugging a well are actually more, but the -- the plugger automatically deducts all of its salvage -- salvage costs in the invoice. So those are reflected in Exhibit 6.

But in this last -- last invoice I received on April 23rd -- I just pulled the latest one from one of our budget people, when I talked -- to be honest, there was salvage -- let's see -- about $633 in salvage costs there. And sometimes it can be $2,000. Sometimes you show up to a site and all the tubing and everything has been stripped from the site. So there is no way to know until our plugger actually goes out to a site.

Q. And I'll direct your attention to your proposed tiers under 19.15.8.9.C.(2), tiers for blankets bonds. Do the well counts included in the Division's tiers have fee, state and federal wells?

A. Yes, they do.

Q. And aren't federal wells subject to BLM bonding

requirements?

A. They are. An operator is not required to post additional single-well bonds or post single-well bonds with the Division for any federal wells. And if an operator has all federal wells, then they would not be subject to place any blanket bond with the State.

Q. For an operator that has a mix of fee and federal wells, did the Division consider excluding the federal wells from that well count category?

A. No, it did not.

Q. Why is that?

A. Our total well count always has included federal wells. When we do our inactive well rule, all well counts consider the federal wells.

Q. And along those same lines, has the Division considered excluding wells with single-well bonds separate and apart from the blanket bond in the well counts, in the tiers you proposed?

A. I'm sorry. Can you repeat that?

Q. If an operator is submitting a blanket bond and also has, say, two single-well bonds, did the Division consider deducting those two wells with single-well bonds from the total well count?

A. No, it didn't. I think administratively -- I mean, we can go through a number of various scenarios,

but administratively, I don't know how difficult it would be.

If you'll just bear with me for a minute, I just want to confirm statutorily what's required on the blanket bond (reading).

I'm just not seeing it -- yeah. Okay. So if you turn to 70-2-14, to your earlier question, (A) to your excluding federal wells, we aren't required. And I think statutorily, the direction is: "Each person, firm, corporation or association that operates any oil, gas or service well within the state shall," and then it talks about financial assurance. So I don't think we are supposed to be excluding any operator's federal wells in our consideration of wells. But that was the intro to 70-2-14.

Q. Do you have a sense of the total number of current orphaned wells that the State intends to plug?

A. Our current plugging list is around 500, and we have, I want to say, about 30 cases pending with our Legal Bureau which -- we had prioritized our referrals over to our Legal Bureau of operators who were noncompliant with 19.15.9C, the inactive well rule, who were still operating in this state because we thought we could get them back into compliance and they would still be solvent and still operating within the state, but

they just haven't been responsive to the Division's compliance efforts.

And then after -- because it's problematic -- what's problematic for the OCD has been the fact that operators had inactive wells and then the wells had last produced since 1995, but likely we're not going to get any response from those operators. So in prioritizing those cases, because we can't -- we have one compliance attorney who can't bring 100 cases at once, the next tier of cases are going to be inactive well cases where they are 80 percent inactive, 90 percent, 100 percent inactive.

So I certainly imagine the inactive well plugging list is going to grow significantly from the 500 wells because the operators are perhaps deceased or, again, haven't produced since 2000 or the late '90s or substantially a long time and the wells are 100 percent inactive.

Q. Okay. What in your mind is the distinction between an inactive well and an orphaned well?

A. Inactive well is described in 19.15.2 as a well that's not producing. I don't believe an orphaned well is defined in 19.15.2. I don't have my rule book with me to confirm that, so I don't want to give any testimony of an undefined term.

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Q. Sure.

And out of the approximately 500 wells on the Division's plugging list, how many bonds have been redeemed for those wells?

A. I'm sorry?

Q. Of the approximately 500 wells that are currently on the Division's plugging list, how many bonds have been redeemed to cover plugging costs for those wells?

A. We don't redeem a bond until we actually plug a well. And what we do is we plug a well. We see what our actual costs are. We get an invoice, similar to this here. And we'll see that this was a well that was 3,326 feet, and the cost to plug the well was $34,000, $10.22 a foot. And the operator may have a $7,000 bond. If they -- if they had, say, a $50,000 bond, we would send -- our process is we usually send a copy of the hearing order, a copy of the invoice and a copy of the bond to the surety company, and we would make demand for the $34,00i to the surety company. So we would certainly not make demand on any of the bonds on the 500 wells until we knew what the actual cost expended by the Division would be.

MR. LARSON: Madam Chair, I still have more questions, but I would request a break at this time.

CHAIRWOMAN RILEY: That sounds good. Why don't we break for 15 minutes, come back at quarter till, a little less than 15 minutes.

(Recess, 10:31 a.m. to 10:46 a.m.)

CHAIRWOMAN RILEY: I believe we're all here. Let's get started again.

Mr. Larson, do you want do to continue with this witness?

MR. LARSON: Yes. Thank you, Madam Chair.

Q. (BY MR. LARSON) Ms. Marks, what is the increase for the amount of a single-well bond?

A. So if we -- if you refer to my earlier testimony, we have a statutory mandate. Let me pull our language from the statute. "In establishing categories of financial assurance, the Oil Conservation Division shall consider the depth of the well involved, the length of time since the well has produced, the cost of plugging similar wells and such other factors as the Oil Conservation Division seems relevant." So that's obviously a consideration.

There has been inflation, obviously, since 1977. And I don't know the last time that we really did an analysis of all of our expenditures from the reclamation fund. And if we turn to Exhibit 6 and we look at what our expenditures -- and, again, this is

just our downhole expenditures and no other -- no other costs associated with plugging, which if we consider those, they would be more. I believe this is very much fair and reasonable and sufficient to cover the downhole plugging costs.

Q. Again what is the Division's average of costs?

A. From FY '14 to present, around 33-, $35,000 per well for the downhole plugging cost.

Q. And what is the average in fiscal year '18?

A. If you would like me to do that calculation, I can do so. I can pull them up from Exhibit 6 and do an average (laughter.)

Q. Do you know off the top of your head?

A. No. It won't take me long to --

Q. Okay. Go for it.

A. We can all do it together. But I have a calculator.

It may be easier if we take a break, and they're on a spreadsheet in my office. These are all mixed by fiscal year here, so it would be easier to break and I just do it quickly as opposed to -- but -- unless we want to just wait, but it will probably take me about two minutes to run up there to do it.

Q. That's okay.

Would it be in the ballpark of 30,000 per

well?

A. Certainly no less. On average, it is about 33-, $35,000.

Q. And that's for '14 through '18 or just '18?

A. '14 through '18, it is around $33,000.

And, again -- and I misspoke earlier, because the four wells were for FY '17. In '18, we did plug more state and private wells. But when we worked off of the BLM grant, that was in FY '17, so we were very limited.

But when we have been very limited in our expenditures -- when we've been very limited in our expenditures, again, we've focused on -- you'll see a lot of these depths here. They're pretty shallow wells. And we have SWD wells or wells that are going deeper into the Devonian or deeper wells. The plugging costs are going to be more. So when we've had a lower balance in the reclamation fund, we need to -- we have an LNC [sic] mandate to plug a certain number of wells. We need to meet that. Plus, we also want to plug wells. We're not going to be -- with drilling, we're not going to be plugging a whole bunch of 2,800-deep wells. Wells are drilled much deeper, which means even if we had 30,000 -- you know, 30,000 plugging costs, you can't reasonably expect our costs to be that low going into

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the future because operators do drill deeper wells than that. But we've been limited in our expenditures from the reclamation fund.

Q. And am I correct to say the Division's also suggesting 100 percent increase in the per-foot cost?

A. I'll defer to your -- I'll defer to your math on that. But, again, I'll state that the per-foot cost and all of our proposed plugging costs are based off of our costs realized and seen by our invoices and what the State has spent from the reclamation fund. And we have a statutory duty to have appropriate financial assurance in place. And, again, those expenditures are just our downhole plugging costs and are not contemplating any other expenditure by the Division.

Q. Is the current rule based on a plus $1 per foot?

A. It is.

Q. And the new rule is $2 per foot?

A. A base amount, plus $2 per foot. And the current amount of either 5,000 or $10,000, plus a dollar per foot has been proven to be grossly insufficient.

Q. At $25,000 base price and $2 per foot, I'm not a math whiz, but it seems to me that you could easily have a single-well bond that exceeds your average plugging cost.

A. Well, I've actually run those numbers. And let me bring up my calculator here. And, again, we don't put a -- we would never make a claim on a bond for more than our actual plugging costs. But let's just go to the exhibit here. So I think there would be certain cases where it may be a couple hundred dollars more, but then there would be cases where it would be very insufficient. So I'm looking at all the 5,000 -- 5,040 [sic]. I'm running those numbers. That would be -- we'd be underbonded there by $3,980.42. And I think if we get to some of the deeper wells, we'll certainly have significant issues. And, again, we're seeing wells drilled deeper and deeper as technology continues to advance.

Q. From IPANM's perspective, the real issue here is how much of the operator's capital is tied up in bonds. So the point I'm trying to make is could you do a single-well bond based on the actual TD of the well, which would be a base amount, plus an amount per foot for those wells that basically overfinance the play?

A. We are proposing a base amount, plus a price per foot.

Q. Okay. But you admit there are some wells where that's going to exceed the Division's average plugging costs?

A. Not significantly. I mean, you're talking a few hundred dollars. But, I mean -- and then there is going to be a much greater -- many greater number of wells where they will be underfunded. So it's a -- it's a case in which a number of operators will continue to be underfunding their plugging costs potentially and, again, just their downhole plugging costs, which the balance would come out of the reclamation fund.

Q. On direct, you addressed the tiers of bonding requirements for blanket bonds, and I believe you testified that too many tiers would create an administrative problem --

A. Correct.

Q. -- is that correct?

And why would that create an administrative problem?

A. So what we do now -- and we've actually tried to do a lot more outreach with operators. We have a list -- and it probably would be -- it would be great if I actually brought this list down and I could just show -- show everybody here. We bring this global bonding compliance list, and this list is pages and pages and pages of noncompliant operators. And what we do as a matter of outreach and to try and work with operators, a lot of times we'll -- first, we'll send a

letter to an operator. We'll try to call the operator to get the operator back into compliance. And this is just a matter of an operator not having the required single-well bond in place.

With these different tiers, if an operator acquires the well, gets rid of the well, they'll move within those tiers. So they can easily fall out of compliance with the required bonding, which administratively would be very difficult to -- it would just add to the compliance aspect of getting operators back into compliance.

What we've also done in order to work with operators is we try to give operators the opportunity to enter into agreed compliance orders. You can't enter into an agreed compliance order if you're out of compliance with our financial assurance rules. So we would have operators out of compliance with financial assurance, and then they would -- it would invalidate their agreed compliance orders, which would then make them in violation of our inactive well rule, which would then increase exponentially the number of operators requiring legal action and then force them to get a plugging order against them because they are out of compliance with our financial assurance rules. To combat that on a single-well basis, we're working with

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operators to post the required financial assurance for the duration of their agreed compliance order.

If we have too many tiers on the blanket bond, it would -- it would kind of limit an operator's ability to transact business from a personal standpoint. I don't like to say, Hey, Operator, you can't buy and sell wells during this agreed compliance order, if they want to acquire wells, sell wells. I don't really want to tell an operator how to transact business in this state. That would be really difficult, and I can envision a ton of problems telling an operator, You can bring your wells into compliance -- we want to work with you to get your wells back into compliance, but now you're out of compliance, and your agreed compliance order is now invalid, and now we're going to have to take action against you. So from an administrative standpoint, that would be, again, very difficult.

And the -- and the percentages are very -- extremely low. So I don't know the utility in having 2 percent or 1 percent operators in certain tiers either.

Q. Doesn't the Division keep current listings of the number of wells that an operator has in the state?

A. Yes.

Q. How often is that updated?

A. Instantaneously. You can bring up how many wells an operator has in the state.

Q. So why would it be difficult to have five tiers? So how you determine, for instance, one to ten, 11 to 50, you could just look at the operator's current well list.

A. Sure. That's true. But then from an administrative standpoint, we would be doing that for all 613 operators on a daily basis, to see if their well count has changed. I mean, we have -- we have a certain full-time employee count, and with our FTE [sic] count, that we couldn't devote an employee to look at all 613 operators every single day to check what their well count is to see if they're in compliance with the bonding rules.

Q. How about at the point in time where a change-of-operator is approved? You or somebody else in the Division is notified there might be an adjustment in somebody's well count.

A. That could -- that could certainly be -- that could certainly be done, but we also have a number of change-of-operators that come in as well. Again, we have very limited resources under our employee count with a -- we are very fortunate to be the number three oil-producing state in the country and with limited

employees. Unfortunately, our employee count has not increased with well production increases. If we had increased employees, I think we could devote a full-time employee to this for sure.

Q. So it appears to me that even under the Division's proposed tiers, you have that same issue?

A. Like I said initially, we really wanted three tiers, but we were trying to be considerate of limited financial resources and not affect a tremendous number of people despite the legislative change. So, again, half of all operators will see no change in their blanket bonding. Again, it hasn't been changed in over 40 years.

Q. But the tiers are a new concept, aren't they?

A. I mean, we could just increase it to $250,000 and make it really easy. But I think the tiers are a very -- are an easier way to consider that not every operator could or maybe should be posting a $250,000 bond. I think the legislation allowed flexibility in setting the blanket bond. And so instead of us coming before the Division just asking to raise the blanket of bond from 50,000 to cover all wells in the state, we decided a tiered approach was better than just asking for the increase from 1977 to now, to 250.

MR. LARSON: I'll pass the witness, Madam

Chair.

CHAIRWOMAN RILEY: Do you have any redirect?

MR. BROOKS: Yes.

REDIRECT EXAMINATION

BY MR. BROOKS:

Q. Mr. Larson asked you a question about the primary source of the funds to pay for the plugging of inactive wells. Now, I am looking at Section 70-2-14 of the Oil and Gas Act, New Mexico statutes, and what I find there is that Subsection B of that section says, "If any of the requirements of the Oil and Gas Act or the rules promulgated pursuant to that act have not been complied with, the Oil Conservation Division, after notice and hearing, may order any well plugged and abandoned by the operator or surety or both in accordance with the Division rules. If the order is not complied with in the time period set out in the order, the financial assurance shall be forfeited."

In Subsection C, "If any financial assurance is forfeited pursuant to the division's Oil and Gas Act and the rules promulgated by the act, the director of the Oil Conservation Division shall give notice to the Attorney General who should collect the funds without delay."

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Now, I know interpretation of the statutes is somewhat subjective, but does not that suggest -- does not that indicate to you that the primary source to which the Oil Conservation Division should look to provide a source of funding for plugging of wells -- I'm not talking about a source of cash because I understand it's resorted to only after the plugging has been done in practice, and that's another issue. But the primary source that the Oil Conversation Division should look to is the financial assurance.

MR. LARSON: Objection. Calls for a legal conclusion.

MR. BRANCARD: I think the witness can answer. She's a lawyer.

CHAIRWOMAN RILEY: Go ahead.

THE WITNESS: It does. And actually -- in pointing that out, you actually raise another -- you made me think of something else as well. But to answer your question, yes, it does. And Mr. Larson had asked me earlier -- I brought down my rule book just to confirm that there was no definition of orphan, and there isn't. And I will say, when I think of orphan, we go through a whole hearing process, and a well is deemed orphaned after we go through a hearing process and we get a plugging order. And then the operator has its due

process before the Division or if appealed de novo before the Division or Commission. But yes.

Q. (BY MR. BROOKS) Okay. I have follow-up on that, and I also have follow-up on my last question. So I'll ask my follow-up on the orphaned well first.

Since there is no definition for orphaned wells, you can't say that anything is or is not an orphaned well unless you first tell us what you mean by orphaned well, right?

A. Right.

And, again, in my -- if I put on my attorney hat, I would say that if an operator -- if an application is filed before the Division and a plugging order is issued, then in that case, there is a whole due process opportunity for the operator. At that point -- there is a plugging order issued at that point. The well would be deemed orphaned.

Q. Okay. Then I have one further. On the primary source, I have one further question.

I read from 70-2-14(B) and (C) and then I go look at 70-14(E), it says, "When the financial assurance proves insufficient to cover the cost of plugging oil and gas wells on federal lands," et cetera, "and funds must be expended from the oil and gas reclamation fund to meet additional expenses," it goes

on to say, in that event, you can sue the operator.

Now, my question is: Does not that further reinforce that the legislature contemplated that the loss would fall on the -- would be reimbursed out of the financial assurance, and only then would it be necessary to charge the reclamation fund?

A. I can't speculate as to the intent of the legislature, but that seems like a reasonable conclusion.

Q. Okay.

MR. BROOKS: Pass the witness.

CHAIRWOMAN RILEY: All right. Commissioners?

Ed, would you like to go first?

COMMISSIONER MARTIN: Sure.

CROSS-EXAMINATION

BY COMMISSIONER MARTIN:

Q. Is there a cap on the reclamation fund --

A. No.

Q. -- of how much it can grow?

In your testimony, you mentioned operating cost of the fund. Going forward, what do you consider -- what does the Division consider proper operating costs, and what percentage of that of total expenditures for the year is it? Do you have an idea of

that?

A. I can find out what is budgeted in our operating costs budget out of the -- out of our 400 category in the reclamation fund, but there are various expenditures that come out of the operating costs. Usually, we like to have them tied to reclamation-fund activities.

Q. Directly tied?

A. I'll defer to the reclamation fund statutes and allow for legal interpretations, but they are -- the operating -- the budget is set by the legislature. And whatever the legislature and governor deem appropriate to be set aside for the operating costs is what we will use.

Q. Okay. Does the Division have even an informal definition of what is meant by "restoration and remediation on a well location"?

A. Yes. We do have an informal definition. And we do not follow what, for example, the BLM requires for on-site restoration, and I believe our requirements are -- we want the land to be contoured and the site cleaned up. But the site should be cleaned up, debris removed and the site contoured.

Q. And if there is subsurface contamination, that is excavated or otherwise dealt with, would you say, or

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is it just surface consideration?
A. If there is subsurface contamination, that would be -- are you talking about an abandoned well site?
Q. Uh-huh.
A. That would be an appropriate use of the reclamation fund to use to clean up the site. I believe the State Land Office can also use its restoration fund to clean those sites up as well.
Q. I'm sure it could.
To follow up on Mr. Larson's question --
A. Those sites are very -- can be very expensive.
Q. I understand.
To follow up on Mr. Larson's question, with the assumption that the federal government is not going to implode in the foreseeable future, would the Division object to excluding federal wells, since it remains remote that the State would be liable for plugging those wells?
A. I believe really under 70-2-14 -- again, it's not my position to speculate as to the legislature's intent, but I believe that federal wells are to be included in overall well counts. And we -- there is not a preclusion in using the reclamation fund to plug a federal well. There is bonding. I believe the federal

government, the BLM bonding -- I don't know if their bonding is sufficient necessarily at all. We -- we could certainly work with the BLM on plugging certain sites, but I believe it is their primary duty to plug federal sites.
But I wouldn't wanted to get in a position where we exclude federal wells from our well count and then we put an absolute ban on plugging a federal well, especially if that federal well were to be contaminating water within the state of New Mexico and then the BLM doesn't plug that well. I think that's a very dangerous avenue to go down, especially if we are -- if the well is causing harm to public health or the environment.
The reason that we are currently plugging wells on federal land is because the BLM hasn't acted maybe quick enough in plugging their own wells. So I don't know from a policy perspective -- I know our -- our biggest job is to protect public health, safety and the environment, that we'd want to exclude those federal wells and then put a ban on using the reclamation fund to plug the federal well. I think that's a dangerous avenue to go down.
Q. In the cases where the Division reclamation funds are used for federal wells, is the reclamation fund reimbursed by the federal government for those

costs?
A. If it's -- so we don't use the reclamation funds if it's under the BLM grant. If it's not under the grant, we would -- we would not be reimbursed by the federal government if it's an expenditure out of the reclamation fund. There could be a nationwide bond that an operator places with the federal government. And so we have had those discussions with the BLM on redeeming those bonds, but, unfortunately, I think from their administrative perspective, it's just too difficult to do in how they do their bonding.
Q. And the last question: In your example where the bond was attached or if it was collected or was redeemed for $34,001, where does that money go? Does it go back in the reclamation fund?
A. It does.
Q. That's all I've got.
CHAIRWOMAN RILEY: Dr. Balch?
CROSS-EXAMINATION
BY COMMISSIONER BALCH:
Q. Good morning.
A. Good morning.
Q. I still promise I won't treat you as a hostile witness.
A. Thank you.

Q. I actually have a number of questions, which is not very surprising.
A. Okay.
Q. The first thing is some of the language in 18.9C., and it's the --
A. I'm sorry. 18.9?
Q. 18.9C.(1), 19.15.18 --
A. 8.9?
Q. 8.9, yes. Sorry.
MR. BROOKS: The proposed rule, Mr. Commissioner?
COMMISSIONER BALCH: The proposed amendments to 19.15.8.9.
MR. BROOKS: Thank you.
Q. (BY COMMISSIONER BALCH) Under C.(1), you went through adding definitions for true vertical depth and measured depth, and that's very unclear what depths you're looking at there. I'm wondering if the language ought to read: "Plus $2 per foot of the projected length of the proposed well or the measured depth of an existing well."
A. So I am sympathetic to your concern. I think that is addressed in E, if you go to E, and that is applicable. Instead of restating it in D and C, that is where -- how depth is calculated.

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Q. Then in that case, I would move E above --
A. Into both C.(1) and D.(1).
Q. I would move it to C or something like that. I would put it above that.
A. It would then have to go into C.(1) and D.(1) if that move were to take place, because --
Q. Or it could become a new C, and C could become D.
A. That same language for -- in C.(1) that you're referring to is repeated in D.(1).
Q. So I tend to read these rules very linearly, so I don't like it when I find something that makes me have to go back and re-read something that I've already read. So I would really suggest changing the language in C.(1) or moving the language in E above that point in the document.
A. Yeah. I have no objections. I am a linear reader as well, so in drafting, I am sympathetic to your concerns. And I will defer to the Commission. I would just, again, suggest that if it is moved in C.(1), it would have to take place -- the change would take place in D.(1) as well.
Q. Yup, or you can put the language in front of both of them.
A. Yeah. But it's repeated twice, I just want to

point out.
Q. I'd like to look at Exhibit 6. And in response -- I'm thinking about one of Mr. Larson's questions. He was talking about deeper wells under bonding costs. So I just did a quick number, and for wells that are above 10,000 feet -- and there is a pretty small sample of that; there are six wells -- the average cost is 56,000 for plugging those wells, and the bonding cost would have been 45- to 46,000 for deeper wells. In this case, smaller sample statistics are more expensive. And what that made me wonder -- and I'm very appreciative of this table of data, but I think that it would be useful to make -- a picture is worth a thousand words. I think that there are two other things I'd like to see on this here.
I'd like to see another column. There is the bond cost under the new proposed scheme for each of those wells and then the difference in that bond cost from the actual cost.
Also, I think if you could plot the bond cost versus depth -- it would be a simple Excel plot. There are a couple of engineers in the back of the room who could help you with that, if you're not an Excel master. And then put the 25k, plus 2 foot per -- $2-per-foot line on that plot, and that will show you

how well the estimate works for different depth branches.
Can we get that exhibit to look at this afternoon?
A. Yes. I think that would not be a problem at all.
COMMISSIONER BALCH: I think Mr. Goetze can do it in two minutes.
MR. BROOKS: Mr. Goetze is very good at that type of thing. Could we ask that --
THE WITNESS: I have no problem getting that to you.
COMMISSIONER BALCH: I think that would be useful for the record.
THE WITNESS: Sure.
MR. BROOKS: Could we ask that the court reporter reproduce for us your request, just get that out of the -- not getting a transcript or anything under certificate. Just get what Dr. Balch said so we would know exactly that we're complying with, what he is requesting.
Q. (BY COMMISSIONER BALCH) Two lines to the table -- two columns to the table. The first column will be what the bond cost would have been with the new scheme, so the 25k, plus $2 per foot. Pretty easily

calculated. And then the difference between that number and the actual cost to plug the well would be the next column.
A. Okay.
Q. And then I would like a plot that shows bond cost versus depth, so basically just your shallowest well to your deepest well with the actual cost of the bond closure. And superimposed on that, a line representing the 25k, plus $2 per foot, the proposed change to the regulation.
A. Not a problem. I can get that for you.
MR. BRANCARD: So are you looking at Exhibit 4 then?
COMMISSIONER BALCH: 6.
MR. BRANCARD: No. I'm saying for the -- Exhibit 4 gives you cost per foot per depth, and then you just want to have --
COMMISSIONER BALCH: Yes, a line on top.
MR. BRANCARD: -- a line that would cover the actual bond cost?
COMMISSIONER BALCH: Keep it simpler. You already have an exhibit for it.
THE WITNESS: I understand what you want. I can do it for you. I have become an Excel master.
Q. (BY COMMISSIONER BALCH) Good.

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All right. I did the calculation for the 345 wells in Table 6 and the average cost of 32,400 --

A. 32,000?

Q. -- 32,400 and some change.

So if you look at a 5,000-foot well with the new scheme, that would be 35,000. So that's kind of in the middle of that range.

I think that line on Exhibit 4 would help clarify if there is a difference. As I noted for the deeper wells, is there something similar in the midrange or shallow wells that -- is there overpayment or underpayment based on the new scheme?

So when an operator fails, some percentage of those wells will go into -- maybe all of the wells will go into abandonment temporarily. But after that is resolved, their bankruptcy, I presume the properties will get sold off to other producers. What kind of percentage on an average basis of those wells would go into closure? How many of them would just go to another operator that would just -- operation.

A. That's a really -- that's a really difficult question, and let me -- let me have a discussion with you, if you don't mind, about that.

Q. Sure.

A. Unfortunately, we have not -- we've really

stepped up the notice -- during the last Commission hearing on financial assurance, we required operators to give us notice of their bankruptcies. So now we actually get notice of bankruptcies, so that has helped, to receive notice. Unfortunately, we have a great number of operators who actually don't go through bankruptcy. They just leave the state. They don't go through any formal wrap-up process. So I will put aside that large chunk of operators whose wells just are abandoned, and we'll go through the actual bankruptcies.

And maybe we've had -- I don't know. Maybe we have seven to ten -- seven to ten of those. They'll go through -- maybe they'll start out as a Chapter 11, and huge operators, D J Simmons, Vanguard, those big operators. And they'll sell off some of their assets. Some will emerge from bankruptcy as the same entity. Some of them will sell off their assets. And some will convert a Chapter 7 and not exist in the state anymore.

With the latter, those are the problems -- the problems that we see as a Division, the DC Energy, the Canyons, the Zerex (sic; phonetic), and they can have -- Marks and Garner. They can have very large well counts, and they won't sell off their assets. They will leave the State with 200, 300 wells that will be on our plugging list that we will ultimately be responsible

for, or you will have operators who will emerge and continue to operate. So it's not -- it's not a -- unfortunately, it's not a clear answer.

We have a case -- well, I don't know if it's appropriate to talk about. But there is a case that the Division brought before the Division. I think it's going to go up before the Commission -- appealed to the Commission.

MR. BRANCARD: So maybe not talk about that.

COMMISSIONER BALCH: Because it's coming before the Commission.

Q. (BY COMMISSIONER BALCH) Well, actually you brought a case -- an example that is going to illustrate my concern, and that is the operator leaves and there are 200 wells and they're all put onto the plug list. But some of those are probably viable producers. So plugging them actually produces waste. Is there a mechanism for passing orphan wells on or selling -- reselling orphan wells to other producers?

A. I mean, if another operator wants to come in and take over those wells, we certainly would work with that new operator. Under our change-of-operator provisions, the operator trying to get rid of the wells would sign off on it. It would be the future duty of

the trustee in the bankruptcy to do everything within his or her power to sell off those wells in order to get the most money for the bankruptcy estate. So I think if there was an operator trying to get those wells, the trustee would sell off those wells in order to do his or her duty as the trustee to the estate. But yes, after the close of the bankruptcy, if some operator came in, we would certainly prefer to sign off on a change-of-operator as opposed to just plugging a well.

Q. Are there any horizontal wells in Exhibit 6?

A. There are not. There are not.

Q. And why just from 2014?

A. As opposed to going back to FY '12 or '13?

Q. '10 or whatever.

A. I just went back to '14. I pulled a number of invoices, and I worked with our administrative services division to pull all those invoices from a record-keeping perspective.

Q. Do you think the four-year sample here is representative of costs present and going forward?

A. No, actually. I believe that our costs will likely increase. Our well drilling is deeper. As I said, our reclamation fund has been very strapped, and we plugged a lot of shallower wells. As you mentioned with the 10,000-foot deep wells, those would be more

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expensive. We see a lot of deeper wells. So I imagine those deeper wells would be more expensive, talking with certain -- certain other operators and plugging other types of wells.

We have operators in this one-to-ten range who just operate SWD wells, and it's not going to be -- it's not going to be an appropriate amount to plug an SWD well at $25,000, plus $2 per foot. So no. I think it's a gross under -- in certain cases. But, again, we find the difference in the reclamation fund, but we can't find an exact pinpoint amount for every single well, an individualized rule.

Q. And all of the concern about how the closure for horizontal wells -- deviated wells because really horizontal wells have become, starting in the early 2000s, more and more common. In fact, right now they're 90, 95 percent of all the wells that are drilled. So eventually these are going to start to come into the mix of wells that are being closed or abandoned. Maybe Mr. Goetze is the person to ask that question of.

A. Sure. I still believe we -- we plug the downhole part and wouldn't plug the --

Q. Wouldn't plug the horizontal?

A. -- horizontal. I had that concern a couple of years ago. And I reached out to some people in Texas,

and I wanted to see if they had done any horizontal well plugging. And my understanding is we would worry about the vertical part and set the plug there.

Q. That would be roughly --

A. Yes. I think contemplate horizontal plugging in determining appropriate plugging costs.

Q. This might be a little bit back into some of Mr. Larson's questions, but is it fair to say that as a whole, the problems we have are more with the smaller side of the operator scale than the larger side? There aren't many Conchos or Conocos closing up shop and leaving you with abandoned wells that are not bonded?

A. I mean, from a -- so I believe I gave the statistics of operators out of compliance with our financial assurance rule. They certainly are the smaller operators. As far as operators going through bankruptcy, we do not see operators with ten wells who are going through a -- who file bankruptcy, or even 25 wells. That would be -- from historical practices, yes, that is the operator that is more likely to either be a sole proprietor or a smaller operator who will just walk away.

Q. Okay. How does an operator end up out of compliance? When do you pay the bond?

A. When do you -- when does an operator have to

pay the bond?

Q. Yeah.

A. After a well is inactive for more than two years, they have to post additional --

Q. But there are two levels of bond, but everybody has to pay an initial bond?

A. Right.

Q. Right. And when is that collected?

A. In order to operate in the state of New Mexico, any private or --

Q. So how do you get out of compliance? You can't get out of compliance on that end?

A. Only after the two-year mark.

Q. So the two-year mark is when you have additional compliance?

A. Uh-huh.

Q. And that's when you have a hard time getting people to pay?

A. Correct.

Q. So my next question comes to the deadline for changes at the end of October 2018, so three months from now, basically, three-and-a-half months.

A. It would be like a Halloween trick or treat. I think it's a treat to us.

Q. There's a lot of operators, 600-plus operators.

A lot of oil wells, more than 100,000, right?

A. Active wells, I believe it's around 50,000.

Q. Okay. But total wells, it's a big number.

Is it possible, do you think, to rebond all those wells in that amount of time?

A. I do.

Q. I mean, are there a lot of bonding companies, or is it just one or two or three that show up over and over again?

A. We have usually about four, maybe sometimes five surety companies that we deal with routinely, and the average turnaround time is about -- no more than a few weeks dealing with the surety companies. There's also the opportunity to post a cash bond or a letter of credit, and that can be done very quickly with the bank.

Q. A letter of credit with the bank.

So that comes back to my other concern. The people that you're -- or the companies that you're going to have a large amount of problems with are the small companies, and they're the ones that may have a harder time dealing with the sudden change in their expenses for operating in just a three-month period. Is there a --

A. Well, again, it's 50 -- 56 percent or so of the operators would have -- if they're in the one-to-ten

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category range, they would have no change in financial assurance.

Q. No change from the previous?

A. Right.

Q. How does this work with drilled but uncompleted wells? So we sometimes run into this with shale development, which is a very big part of what we're doing in New Mexico right now. But if the price were to go down to $30 a barrel or something like that, there is a pretty good chance that a lot of wells would be drilled and not completed, and they could sit there until the price goes back up. Does this impact that type of a well, or is it only wells that are completed and are ready for production?

A. What do you mean as far as impact?

Q. So when the price dropped in 2014, 2015, we ended up with a surplus of wells that were already drilled but not completed in the shale plays in the back Penn and other places, thousands of them. And that inventory didn't start to drop until after the price had gone back up a couple of years later.

A. In order to drill -- for us to permit certain wells, you have to post the financial assurance before we permit the well.

Q. So it's before the permits?

A. Uh-huh.

Q. So those would be sitting there. But those are -- those are wells that could, very conceivably, wait a couple of years to be completed, but they're relatively low risk if they're not completed eventually. It just depends on the price of oil.

A. There would be no change, though, in our financial assurance rules.

Q. Except for the two years. Okay. So after two years, they would have to add additional assurance if they still haven't completed the well?

A. Uh-huh.

MR. BRANCARD: Is that a yes?

THE WITNESS: Yes.

MR. BRANCARD: Thank you.

Q. (BY COMMISSIONER BALCH) Going back to the issue of federal wells, I'm wondering if there is a way to not count the federal wells for your financial assurance numbers or levels on the table but still allow you to deal with them as necessary from the fund -- the reclamation fund. I'm not sure -- it seems like when Commissioner Martin was questioning you about that, that there was a tie between the count and then being able to -- and then excluding them from the reclamation fund altogether. Is that necessarily true, that you have to

have it that way?

A. So I think you could have a problem with an operator having, say, 99 federal wells. We often have one or two state or private wells. The remainder are federal wells. And then the operator is indeed not compliant with our 5.9 inactive well rule. If we were to not include those wells, then we would put them into that much lower bonding tier.

Q. Uh-huh.

A. And then if you're suggesting then we would then use the reclamation fund to plug their 100 wells, we would then take on, say, a $3.5 million liability out of the reclamation fund when there are only -- and there would be no single-well bonds for those either because we don't require single-well bonds for federal wells.

Q. Well, I think most of those 99 wells would be plugged under the federal bond, right?

A. No. They don't actually have single -- all single-well bonds with the BLM. And so there generally isn't all federal bonding, so they will give us a grant sometimes. But if we use the reclamation fund to then plug federal wells, I think we could be ultimately subsidizing --

Q. How often does that happen, that you use the reclamation fund to plug a federal well?

A. Well, that's --

Q. Does it happen?

A. It does happen. But I think part of the limitations that we have had is the very limited funds available in the reclamation fund. Again, we wouldn't want to be reliant on a federal grant. We haven't always had a federal grant, but we wouldn't want to be limited if we could reach out to the BLM and say, We'd like to go plug these wells, do you agree, and this is a matter of public health, safety or the environment; I think we would like to go do that. And if it is, say, a $145,000 plugging job or restoration --

Q. Or an emergency environmental issue is probably more expensive. However, does this happen? How many have happened in that four-year period, from 2014 to 2018?

A. That we've plugged out of the reclamation fund?

Q. Uh-huh.

A. I couldn't speak on '14 and '15 off the top of my head. I know we plugged one out of the reclamation fund certainly in the past two years.

Q. So it's not a common occurrence?

A. Well, we had the BLM grant until '17.

Q. And the BLM paid for it?

A. Right.

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Q. It's not a common occurrence, and then the BLM paid for it. So I guess I still don't see why you wouldn't be able to exclude the federal wells from the count for the purpose of establishing the bonding levels.

Here's the -- here's the other side of the coin. If you're that operator with the 99 federal wells and you have -- do you have to provide some assurance to the federal government that those wells are going to be plugged when they're abandoned?

A. I can't speak to the federal policies or procedures and what assurances they give. They post a minimal, in my mind, bond to the federal government.

Q. So they must have some kind of a bond with the federal government?

A. Right. I want to say maybe for -- if these were all wells in the entire -- I believe there is like a -- the Government Accountability Office came out with some report talking about the federal government's bonds and how they weren't sufficient to cover -- it'll be a good read during your lunch break.

Q. But if they are underbonded, then that's their problem when it comes to plugging the wells. It's not the State of New Mexico's problem.

A. Unless -- unless we wanted to protect the

citizens of the state of New Mexico.

Q. Which does happen, on one occasion at least in the last four years but not every month or even every year.

A. Well, in '17 -- FY '17, again, we plugged -- Commissioner Martin can probably speak to this. Basically all the wells we plugged are federal wells.

Q. Did you get any money back from the federal government fund for those wells, or will you get money back eventually?

A. We did, but that may not always be the case. So if there were limitations placed on a federal agency or if there wasn't any priority, we could, as a state agency, make that a priority to plug those wells. So if we don't want to be relying on the federal government for monies to plug a well, we could take it upon ourselves to plug a federal well that was a problem well.

Q. It does seem like the exception, though, right? It's not a common occurrence? It has not been a common occurrence?

A. I don't -- I don't know that it has been a common occurrence, to get a grant to plug wells from the BLM, and I believe they're quite backlogged in their plugging.

Q. How far is New Mexico backlogged? Quite a bit also, right?

A. We had been extremely backlogged, but we have actually done a phenomenal job this year. We are on target to double our LFC [phonetic] performance measure. So we were asked to plug maybe 30 wells. We're on target to maybe plug 60 wells this year. So we would like to clear up that backlog significantly.

Q. How big is the backlog?

A. Well, we had 200 or so wells. But like I said, we stepped up our compliance efforts significantly, so now we have about 500 wells on that plugging list. So we can -- if we continue the rate of 60 wells a year, we will do a phenomenal job.

Q. Basically, orphaned wells that nobody owns or nobody -- is there no way the Division could auction those out, see if anybody wants to buy them, put that money in the reclamation fund? I know that's a complete aside, but I'm just curious.

A. No.

Q. Because I think that that exposes the State to possible waste for a well plugged -- could be liable to the producers. That's a different issue.

A. I won't say that the State can't, but the Division can't.

Q. How many changes-of-operator on new wells completed and ready for operation do you get every day, just a ballpark?

A. How many change-of-operators?

Q. Yeah. There was a question from Mr. Larson about how dynamic could you be about selecting these number of wells that an operator has?

A. They're usually handled on a district basis, but -- and it varies every day. But there may be -- pending at any time, it could be eight pending at any time.

Q. So eight or so changes a day maybe?

A. There could be. And that could be for various number of wells.

Q. So my computer programming skills are woefully out of date, but even now I can write a script that would read the database and make that list without a human having to do it and as often as you'd like, very quickly.

A. We'll hire you in I.T.

(Laughter.)

Q. I suspect that Mr. Goetze could do that, too. I mean, it's not hard to automate those kind of processes. The difficulty would then be you have to notice the operator that you're above or below a

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threshold, and you need to change your bonding. Right?
A. Right. We would be denying change-of-operator. We deny a lot of change-of-operators already because of bonding compliance issues or out-of-bonding compliance issue already with our existing rules.
Q. Well, it seems like you would want to have that number on the fly as something to look at?
A. The number of --
Q. Wells per operator, so you know if they're in compliance or not.
A. Right. If we add an additional measure --
Q. So when I'm looking at IPANM's proposed changes -- I don't think they're going to have a witness, so we just have to go with what they've presented here. But they're adding one more category, and they're changing some of the numbers, particularly on the lower level, for the bonding requirements. And I think Mr. Larson was asking that why can't you have more categories than -- I guess originally the OCD wanted three categories, and that was for simplification of keeping track of these bonding level requirements.
A. Right.
Q. I don't think it's very hard to track how many wells an operator has, very quickly, very automated.
A. I don't know that the tracking necessarily -- I

mean, I guess we could automate it. But how many -- how much personnel time are we going to devote on a daily basis to tracking in and out of compliance? And I think the numbers that I had come up with, their ranges were 2.1 percent of operators in one category, 1.6 percent in another category. I'm not really sure -- I mean, we could come up with 15 categories if we wanted to.
Q. Sure.
A. But if we're managing that from an administrative standpoint, that would be really difficult for us. We are -- you guys just heard the spill rule. We are very extremely understaffed right now, and we just don't have the personnel to manage our existing duties facing the Division. So that's giving us more and more duties with less people.
Q. So how are -- how are these categories arrived at? I mean, were there some statistics done on the data set that you were examining to determine higher levels of this from different levels of wells?
A. Yeah. I mean -- well, we had to come up with what is -- what's the -- I mean, obviously $250,000 really isn't enough to cover all of an operator's wells. I mean, we have Hilcorp with 11,000 wells in the state. $250,000 is not going to be enough. If you have ten wells, $50,000 isn't enough to cover all your liability.

But that's kind of a risk that you're going take. An operator isn't going to necessarily post all of their additional single-well bonds that are required.
So even if -- you know, to your earlier point with Exhibit 6, you may have -- you may be overbonded by $800 or $1,000. But the Division may -- like with Jim Pierce in Exhibit 7, they have ten out of ten wells or nine of nine wells that are on a plugging list. So where does that difference come? And he has no additional financial assurance. That has to come from the blanket fund and our proposed $50,000 and IPANM's $25,000. So we'd be left with 25,000 or $50,000 to plug nine wells, grossly insufficient.
Fifty percent of all those operators are out of compliance are the ones -- the operators out of compliance with the financial assurance, those are in the one-to-ten category range, so we have to turn to the blanket bond for that difference. And then after we turn to the blanket bond, then we turn to the reclamation fund. And, again, that's just a downhole plugging.
Then to Commissioner Martin's point for any reclamation efforts, then we would then again turn to the reclamation fund to address those issues.
So when we looked at 56 percent of all

operators who would not be affected, we thought that was pretty reasonable, and we looked at how many -- how many operators -- how many operators have wells in the state and, again, those percentages that I kind of broke down earlier.
Q. So 56 percent would be included in A and B?
A. 56 percent would be -- 56.7 percent would be in A, and then in B, it's 23.6 percent.
Q. And for A, it's not changing from the previous?
A. Correct.
Q. And for B, it is going up 25,000?
A. Right.
Q. Okay. Thank you very much.
A. You're welcome.

CROSS-EXAMINATION

BY CHAIRWOMAN RILEY:
Q. Ms. Marks, I wanted to go over just a couple of definitions, really, with you, the new rule under "Temporary" -- under 19.15.2.7E.(3) that talks about temporary abandonment and the language was added of "temporarily abandoned status," for clarification. And you testified that was synonymous with a well being inactive; is that correct?
A. Correct.
Q. I know you have your book with you. Could you

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look over to 19.15.25.12 and 25.13? And just take a minute and kind of look at that, and then would you tell us what -- give us some clarification around the temporary abandonment status. And I think that might help us clear up some of this morning's discussion. In particular 13, what it takes to get a well to abandoned status.

A. Sorry. I was going back to the definitions and temporary abandonment.

Q. Oh, okay.

A. And then I looked at the definition of inactive well, yes, and then approved temporary abandonment in 19.15.25.

Q. 12, uh-huh. And 13 describes how you get that.

A. Okay. And, again, the key word here is -- which I think -- bless my attorney. The word is "approved temporary abandonment." And, unfortunately, the definitions in 19.15.2 are confusing, and that's rather unfortunate. But -- so approved temporary abandonment, the Division can place a well on approved temporary abandonment for up to five years. And procedurally an operator submits a Form C-103 and seeks approval for -- to place a well on approved temporary abandonment. The operator gives the district office notice that it would -- before working on a well. And

the operator then has to perform an MIT test on the well.

Sorry, Madam Chair. Do you want me to go through the rule or --

Q. Well, so the purpose of that, putting a well into an approved temporary abandonment status, would you say that is -- so read through B.(1) through (4).

A. Sure. So the Division and the district office "does not approve temporary abandonment until the operator furnishes evidence demonstrating that the well's casing and cementing are mechanically and physically sound and in such condition as to prevent: (1) damage to the producing zone; (2) migration of hydrocarbons or water; (3) the contamination of fresh water or other natural resources; and (4) the leakage of a substance at the surface."

Q. Okay. So the point of the approved temporary abandonment status is for the operator to have an inactive well but to also be sure that it is not damaging water or doesn't have anything -- any service, all that stuff, to make sure that the well is mechanically sound?

A. Correct.

Q. Okay. And so an operator can ask for approved temporary abandonment status really at any time,

correct?

A. Correct. It could be -- exactly.

Q. And so it's not really -- it doesn't have anything to do with the two-year time frame of an inactive well that's required. Extra bonding is required?

A. Absolutely correct.

Q. Okay. So what we are attempting to correct in the new rule is that in order for them to get that approved temporary abandonment status at any time, not to do with the two years, they have to get that additional bonding?

A. Exactly.

And I think it really addresses -- I was trying to -- maybe I wasn't as eloquent as I should have been. But it really addresses a concern, because we have, under Rule 5.9, that a well can become inactive and an operator may try to remedy that by placing it into approved temporary abandonment status. And in between that 15 months and two years, statutorily, we are prevented right now from requiring any additional bonding.

But if we're giving an operator a permit, basically, by telling them they can be in approved temporary abandonment status, that's good for five

years. So if we allow that well to be in approved temporary abandonment status for five years but then comes two years and three days or three years and the operator fails to provide us the additional financial assurance, we have no recourse against the operator to then yank that permit that we've given them or to go do anything about that approval that we've given them. So, again, it's a permit that we don't have to grant them. It's something that we're trying give guidance to our districts and to operators to say, Listen, if you want that permit, this is something you need to do to get that permit.

And then since the well will -- I mean, MIT tests are expensive to run. So if you're going to want to place a well in approved temporary abandonment status for up to five years, they're going to need that financial assurance. At that two-year mark, it makes sense to get it to close that gap if they're doing it before that two-year mark anyway.

Q. Okay. Thank you.

And then if you can flip backwards to 19.15.25B [sic], which is "Wells To Be Properly Abandoned," I think that will help address Dr. Balch's question about DUCs. So on B.(1), it talks about "the operator shall either properly plug and abandon the well

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or place it on temporary abandonment status in accordance with 19.15.25 within 90 days after," and then number one, "a 60-day period following suspension of drilling operations." So wouldn't that then indicate that a DUC really falls into the same category as any other wells, being that they have to be in approved temporary abandonment status or plugged or producing?

A. It does.

Q. Okay. I think that's all the clarifying questions I have.

COMMISSIONER MARTIN: I have two more.

MR. BRANCARD: Go ahead.

RECROSS EXAMINATION

BY COMMISSIONER MARTIN:

Q. In the wells that the Commissioner was just referencing, those would never get to your inactive well list. The drilled and completed wells have to have produced for some period of time to get --

A. That's correct.

Q. So you have different ways to track these wells?

A. We can query those wells.

Q. Pardon me?

A. We can query those wells.

Q. Okay. One more. In the event that you have to

plug a federal well because of the imminent threat to health and the environment, wouldn't you have -- this is a legal question. It may end up being rhetorical. I'm going to ask it anyway. Wouldn't the Division have a claim on the federal government for those costs, in theory, since they have a bond in place to cover that same cost, assuming they do?

A. I'll abstain from that right now.

Q. That's fine. That's all I've got. Sorry.

CHAIRWOMAN RILEY: No, that's fine.

Okay. Mr. Brancard?

MR. BRANCARD: Before the witness goes, before lunch, I have two requests of the Division.

MR. BROOKS: Okay.

MR. BRANCARD: First of all, your witness proposed new language for 25.12. Could we get that in writing so the Commissioners can see that?

And then the effective dates that are proposed for 8.14, those effective dates were in the original proposal submitted in March. Since we've delayed the hearing, I don't know if these effective dates are workable anymore. I was sort of running through calculations of if the Commission makes a decision today, issues an order next month and then the delay in filing for rehearing and the effective date for

the "New Mexico Register," this rule likely -- if it is adopted, will likely not be effective until probably sometime in September.

MR. BROOKS: Yes. Mr. Brancard, I looked --

MR. BRANCARD: So you may want to look at those effective dates in 8.14.

MR. BROOKS: I did look at those proposed dates in preparation for this hearing, and I would have proposed changes except for the time for filing alternative -- required to file changes with our pre-hearing statement and that was after our pre-hearing statement was filed that I looked at it. It goes without saying that we cannot make any provision -- the Commission cannot make any provision before publication of the rule in the "New Mexico Register." So I believe the first of those dates is before. It will likely be published, although it is -- if the Commission were to issue an order today and get a final rule today, then it could still be submitted for publication by the date in September that's on the proposal. But otherwise, not. And I think those dates will have to be adjusted.

MR. BRANCARD: Yeah, because the July 24th date is not going to work.

MR. BROOKS: That obviously could not be

met.

MR. BRANCARD: So if, over lunch, the Division can look at that section if you have proposals for -- if you recommend, I think the Commission will likely look at those dates anyway.

MR. BROOKS: I think so, too.

THE WITNESS: I just think that -- I know that compliance, I mean, in that October 31st would not be an issue to Commissioner Balch's question for us, but we can come up with some other dates.

COMMISSIONER BALCH: Well, if we end up giving them five weeks, that includes being noticed by the Division that they need.

THE WITNESS: We'll think -- I'll think of something.

And I will just say, Commissioner Martin, it just bothers me. Of course, if someone asks me a legal question, even though I do try and take that hat off, I do think -- I think that -- and, again, I won't speak for BLM. But I think the statewide bond for federal wells is $25,000, and I believe a nationwide bond is $150,000. So even if we did make a claim and we had limited resources, our amount to recover could be pretty limited, if, again, the operator had limited resources. So going into the reclamation fund may be

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our only possible --

COMMISSIONER BALCH: So we have the reclamation fund to catch the overages for the State of New Mexico. There has to be something equivalent for the federal government as well. If it costs more than the bond, they must have some mechanism.

MR. BRANCARD: Possibly whatever Congress appropriates.

THE WITNESS: Yeah. I think it's on a Congress -- Congressional appropriation. We reached out --

COMMISSIONER BALCH: Seems like you could get more from them than they can get from their bond.

THE WITNESS: And some of it -- I mean, there is a -- there is a well now out there that BLM has a funding issue on. So it's sitting out there right now, and they're saying they have no money to plug -- to plug a well. So while we would like to say that the federal government has unlimited resources, I don't know that that is necessarily true, and they are tied to their appropriations that they have. And we wouldn't want to be reliant as a state on an appropriation or go up to the federal government for an appropriation, especially for health or safety issues.

MR. BROOKS: If I may address that issue,

Honorable Commissioners. I don't know the answer either, but it seems highly unlikely to me that there are any circumstances in which the Division would have a claim against the United States for the cost of plugging a well in the absence of a specific contract --

COMMISSIONER BALCH: They can just ask nicely.

MR. BROOKS: -- contractual obligation on the part of the United States that was funded by an appropriation by Congress.

I would recommend that if the Commission feels it's necessary to have advice on that question, that they rely on Commission counsel because it is a legal question, and it's not one I'm prepared for address.

THE WITNESS: And I can see some immunity defenses being raised. I mean, I could see all kinds of problems being raised there if we tried to recover certain costs.

COMMISSIONER BALCH: Well, it still seems to be a pretty low percentage of the wells that you're closing that fall into that category, that we would not get paid back from the federal government, or you're closing federal wells overall.

COMMISSIONER MARTIN: Issue here, in

instances where a small operator has a disproportionate share of federal wells and has two state wells that remain federal wells and is penalized under this rule --

COMMISSIONER BALCH: He has to buy a $250,000 bond.

COMMISSIONER MARTIN: Right.

THE WITNESS: Well, we do have a number of operators who have a lot of federal wells.

COMMISSIONER MARTIN: Correct.

THE WITNESS: So that could have a significant -- I mean, it seems like a minor adjustment, but it would have significant impact to us.

CHAIRWOMAN RILEY: Do you have questions?

MR. BRANCARD: That's it for me. Thank you.

MR. BROOKS: I have nothing further of the witness. We have another witness.

THE WITNESS: I will say I believe Mr. Goetze will be quick, and I don't know if he is wanting to stay all day. He has been gracious enough to come in for this hearing. He has not been well. So I would kindly ask the Commission to hear his testimony now, as the deputy director and who truly cares about all of my people. I would ask that of the Commission.

MR. BROOKS: I would request that we ask

the witness what his preference would be.

EXAMINER GOETZE: I'm good for all day, folks. Choose as you see fit, but I appreciate the courtesy. But I do have an Excel file to look at.

MR. LARSON: You volunteered.

COMMISSIONER MARTIN: You were volunteered.

COMMISSIONER BALCH: I just looked at the most competent person I could find in the room.

MR. GOETZE: I will save that for my performance appraisal.

(Laughter.)

CHAIRWOMAN RILEY: Well, I can go either way. If you guys want to take a lunch break, we can.

COMMISSIONER BALCH: That's a preference for Mr. Goetze.

MR. GOETZE: I can do it either way. I have other duties assigned, so --

THE WITNESS: If he has no preference, it doesn't matter.

CHAIRWOMAN RILEY: Why don't we go ahead and take our lunch break. And you might want to confer with Secretary McQueen because he has a lot of that data already.

THE WITNESS: I'll be good to --

CHAIRWOMAN RILEY: All right. So let's

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break, do an hour and 15 and come back at 1:30.
Is that good for you, Ms. Larson?
MR. LARSON: It is, Madam Chair.
I assume Ms. Marks is going to come back and present an additional exhibit, because I have a couple of follow-up questions for her.
CHAIRWOMAN RILEY: You do. Okay. Yes. Then we will not release the witness.
COMMISSIONER BALCH: She's going to come back anyway and give us a new Exhibit 4 and a new Exhibit 6. So --
COMMISSIONER MARTIN: You were close.
THE WITNESS: Darn.
CHAIRWOMAN RILEY: We are adjourned for lunch.
(Recess, 12:13 p.m. to 1:37 p.m.)
CHAIRWOMAN RILEY: Let's go back on the record, please.
So we were just working on testimony from Allison Marks. She was asked to prepare some things and bring back, which looks like that's been done, and then we also have some additional questions, I think, by IPANM's attorney.
Is that where we are with this witness?
MR. BRANCARD: I assume the questions are

on the exhibits.
MR. BROOKS: Well, these exhibits have got to be numbered and marked. Does everyone have copies?
THE WITNESS: They do. I distributed them to everybody.
MR. BROOKS: My copies are not marked.
THE WITNESS: No, I didn't mark them.
And I will note that there is a -- just -- in the Excel spreadsheet, because I love Excel, in the Difference column, per Commissioner Balch's request, the G equals F minus A, it's not A. It's minus C, but I added the column. So you can ignore the G in that formula, but the difference is actually correct. So it is F minus C.

REDIRECT EXAMINATION

BY MR. BROOKS:
Q. Do you have any other comments on the exhibits before I number them?
A. I can discuss the exhibits if you would like.
Q. Let's number them first because then we can discuss them by number.
Now, unless I'm -- unless I am contradicting some exhibit number that has already been assigned, I want to call the exhibit spreadsheet Exhibit Number 9 and this chart, Exhibit Number 10, and the

proposed new language, Exhibit Number 11.
Can we proceed?
A. So on Exhibit 9, I was asked to add additional columns of what the proposed bond would be for each API and our plugging costs and what the difference would with each bond. I can recite that Commissioner Balch's language if necessary. So that is reflected in Exhibit 9.
And then I took the data from the Excel spreadsheet, and I believe I was asked to plot that similar to what was in Exhibit 4 in the packets, and that is reflected in Exhibit 10 to show the new bonding -- what the new bonding costs would be with our historical plugging costs. And that's the red line -- the red line here. And I think it demonstrates that the proposed $25- -- $25,000, plus $2 per foot is actually pretty dead-on point with the new --
COMMISSIONER BALCH: Are you sure you didn't curve it to get that 2-foot denominator?
(Laughter.)
THE WITNESS: I'm not that proficient in Excel.
COMMISSIONER MARTIN: It's pretty perfect.
COMMISSIONER BALCH: It's pretty good.
THE WITNESS: I think that this means that

I'm pretty perfect.
(Laughter.)
MR. BROOKS: May I ask the witness a qualifying question before I tender the exhibits?
CHAIRWOMAN RILEY: Mr. Brancard?
MR. BRANCARD: Go ahead.
COMMISSIONER BALCH: It's new exhibits so --
Q. (BY MR. BROOKS) Ms. Marks, were Exhibits 9, 10 and 11 prepared by you and, in the case of Exhibits 9 and 10, from information from Division records?
A. Yes, they were.
MR. BROOKS: And I will tender Exhibits 9, 10 and 11.
CHAIRWOMAN RILEY: Mr. Larson?
MR. LARSON: No objection.
CHAIRWOMAN RILEY: Okay. Those exhibits are accepted into the record.
(NMOCD Exhibit Numbers 9, 10 and 11 are offered and admitted into evidence.)
MR. BROOKS: Pass the witness.
CHAIRWOMAN RILEY: Mr. Brancard, is that appropriate?
MR. BRANCARD: Yes.

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RECROSS EXAMINATION

BY MR. LARSON:

Q. Ms. Marks, looking at your Exhibit Number 9, go maybe a third of the way down the list of wells on page 1 to API Number 30-005-6391 [sic]?

A. 63191, did you say?

Q. 63191, yes.

A. Okay.

Q. And if I'm reading this correctly, we have a natural cost of plugging of 18,201.39 and a bonding level, under the proposed new rules, at $30,400, for a difference of 12,198. Am I reading that correctly?

A. You are. I mean, obviously there are a number of black and a number of red, and that's one of the -- an outlier, and then there is the $119,000 deficiency. So it's not going to be a perfect fit, but Exhibit 10 will show that it's a pretty good fit.

Q. We'll just say I cherry-picked this one.

A. Yes. Good cherry-picking (laughter).

Q. Wouldn't this be an instance, to particularly a small operator, where it would make more sense to do the bonding for the total depth rather than the 25,000 and $2 per foot, because you're tying up, essentially, $12,200 of the operator's operating cash?

A. I guess you could say -- by total depth, I

guess you're going back to Exhibit --

Q. I'm just going off your numbering right there on Exhibit 9.

A. Right. I just want to clarify before I answer. So I presume that you would be looking at Exhibit 5. And which well is that? So you would be suggesting the zero dollars and then the $7.49 for total depth? Is that the question?

Q. No. I'm just looking at the numbers across your table there. It appears to me that at the new bonding level, it would have been $12,198.61 more than the actual plugging cost.

A. It is 12,000-or-so-dollars more, but I'm confused as to what -- how the calculation of total depth would be done, what the proposed bonding level is that you are suggesting.

Q. It would be whatever depth the well is.

A. Right. But there would still --

Q. That's in the Division's records.

A. But there would still have to be a cost allocated to that depth. We would still need a formula --

Q. That's true.

A. -- for that. And so what we did was determine an appropriate formula knowing that we have certain

costs. Like I said, I pulled that invoice from our plugger, but we have certain mobilization costs and certain costs that we would expect in every plugging job. So if we took that $7.49 and then we had a very, for example -- you know, we can also cherry-pick out a really shallow well, for example, that 1,003-foot-depth well. And if we took that times 7.49, that would be $7,512 in bonding, where the actual plugging -- with the actual plugging costs of $146,000. So that would be grossly underbonded for us as well.

So, again, we have to -- we run a risk analysis for the Division, and that's where -- I think when Commissioner Balch asked us to run the best fit for that line. There is always going to be wells above and below it, but we came up with an appropriate formula, I believe.

Q. And getting back to a point that Dr. Balch hit on in terms of having realtime data of changes in operator well counts, looking at the Division's proposed tiers, the second tier is for 11 to 50 wells; is that correct?

A. That's correct.

Q. And what if an operator with 49 wells purchases five wells? Doesn't that automatically raise the blanket bond by $50,000?

A. Under our proposed rule, that is correct.

MR. BROOKS: I would object to that question because he said automatically raise their blanket bond. It should -- I think he meant to say -- I would ask him to -- would request the Commission to ask him to rephrase as: Does it increase the blanket bond requirement.

THE WITNESS: That's correct.

MR. LARSON: I'm fine with that.

MR. BROOKS: That's just in the interest of accuracy.

THE WITNESS: And so yes, it would increase their blanket bond requirements.

And I actually -- since I was working on these exhibits during lunch, I've actually decided -- since the -- since the Commission started raising inquiries on the whole federal wells and exclusion, I started to look at some of those numbers and how many wells would be excluded and started to just kind of randomly pick some operators, and it could -- it would -- it could really decrease the number of operators in certain tiers if we excluded those wells.

And I don't think the intent of the legislature when we did the -- when we brought the bonding bill before the legislature, coming before the

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Commission, was to decrease the amount of bonding available to the Division given the deficiencies that we've had before -- when trying to recover funds from operators. We had noticed that there was significant decreases in blanket bonds available to the Division, and that testimony was provided to the legislature. And in response, we thought it was appropriate to bring that legislation before the legislature and, in turn, come before the Commission to increase the amount of -- in response to the Senate Bill and come before the Commission to increase our blanket bonds because we have had significant deficiencies when we try to recoup the amount of monies available to the Division. And the number of federal wells have always, historically, been included. I think that would have a significant net impact that was never contemplated. So I just wanted to point that out.

Q. (BY MR. LARSON) Does the Division have an approved list of plugging operators?

A. Of?

Q. Plugging operators.

A. There is an approved list of operators -- plugging operators that the Division can use pursuant to the price agreement that we go through under state law.

Q. So that grouping of potential plugging

operators is to be done through price points?

A. We go up for competitive bid and whoever goes and bids. During the last bid proposal, Jamie [phonetic] Well Service and A Plus pluggers were the only companies that bid. We again tried to get more people to bid and -- I think I said earlier -- we just weren't very successful in those efforts. We would love to have more pluggers, to be honest. It just hasn't been very successful.

Q. Have you ever seen any data comparing industry plugging costs versus Division plugging costs?

A. I have -- I have heard, actually, that -- I've heard various stories, and I don't know if it would be appropriate to go into hearsay. But I've heard that -- I've heard -- I've heard that various operators, their plugging costs are astronomically high, and they wonder how we are able to plug wells so cheaply. But, again, that's just the downhole plugging costs. And when we want a plugger, what we require of an operator to go plug, that's to plug and restore a site. We just plug. We would love to restore every site. But I have heard stories about downhole plugging costs.

And, again, with advances in technology and wells being drilled deeper in the future, to Commissioner Balch's question earlier about the 10,000

feet, I would assume that many wells will be drilled deeper with increasing horizontal wells, with many more laterals. So these are a lot shallower wells in the data provided.

Q. So basically you have some third-end stories and no hard data?

A. Well, I could also -- I believe -- I believe the Division worked on a case with the Hinkle Law Firm on a plugging and restoration case, so we can go into restoration costs if you would like.

Q. No. I'm keeping it to downhole.

A. So, again, I do know what it takes for an operator to plug and restore a site in compliance with our rules, and those costs are higher than what our costs provided to the Commission are. So I believe the Division does an excellent job in getting sites plugged. Again, if anybody wanted to bid on plugging costs at a lower rate, we would be happy to do so. We try and plug wells for the lowest cost possible. We can only -- we can only go with whatever pluggers have bid on contracts.

Q. You mentioned this morning a scenario where, say, an operator has nine, 12, 15 wells. They all have become inactive. They've all come out of compliance, and they all leave the state.

A. Uh-huh.

Q. Is there any way to go after the operator to try to retrieve plugging costs?

A. Definitely. That's where we've really stepped up our compliance efforts to get operators back into compliance or address those operators from the onset as opposed to letting those operators fall into noncompliance and then just leave -- leave the state or just leave operations with the Division. They don't all leave the state of New Mexico. But we will get a plugging order, plug the well, and then we will file suit in district court for indemnification of the cost expended by the Division.

Q. Let's address a scenario of an operator who had 15 wells, basically leaves the state but is still the operator of record for those wells. So you get your plugging order from a Division examiner. You then go to district court to get a judgment. Do you then go to whatever state that operator may still be operating in to try to recoup from them?

A. So if the operator is under the same business entity, we could -- this remedy would certainly be available to us that we could do so.

If we have a parent company and there are subsidiary companies, I think we may have -- if there is

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a piercing-the-corporate-veil type argument or certain types of arguments that may be applicable, we'd have to examine that. But if it's all under one type of business structure, that remedy would certainly be available to us.

Q. Would you say the Division aggressively pursues those remedies?

A. I believe under Secretary McQueen, we have aggressively taken on compliance, and it has been very much to the benefit of all good operators in the state of New Mexico. Yes.

Q. Thank you, Ms. Marks.

MR. LARSON: That's all I have.

COMMISSIONER BALCH: Thank you. No follow-up. Thank you.

THE WITNESS: I'm sorry. I do want to -- that is not to say that Secretary Martin wasn't a fantastic cabinet secretary who did not support the Division. I have worked under fabulous cabinet secretaries every time I have worked at EMNRD. Secretary McQueen has been very supportive of our compliance efforts, too.

RECROSS EXAMINATION

BY CHAIRWOMAN RILEY:

Q. So do you know ahead of time how much a well is

going to cost for plugging, and do you know ahead of time if you're going to have issues downhole?

A. We do not.

Q. Thank you.

CHAIRWOMAN RILEY: That is all I have.

Mr. Brancard?

MR. BRANCARD: No.

CHAIRWOMAN RILEY: So, Mr. Brooks, are you done with this witness?

MR. BROOKS: I am done with this witness, Madam Chair.

CHAIRWOMAN RILEY: All right. You may be released.

THE WITNESS: Thank you.

CHAIRWOMAN RILEY: Call your next witness, Mr. Brooks.

MR. BROOKS: Call Phillip Goetze.

PHILLIP GOETZE,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BROOKS:

Q. Good afternoon, Mr. Goetze.

A. Good afternoon, Mr. Brooks.

Q. I'm hopeful you are in satisfactory condition.

A. When you work with the Division, you're always satisfactory.

Q. I hadn't noticed. I mean I hadn't noticed myself. I don't mean that I hadn't noticed that you're not satisfactory with the Division.

Anyway, you are going to testify about the definition of the true vertical depth, correct?

A. That is correct.

Q. Is there anything else I need to ask you -- is there any other subject matter that you have been told you're to testify about?

A. No, strictly definitions and some colors (sic).

Q. Okay. Well, I'm going to ask you to look at Exhibit 1 -- OCD Exhibit 1, and that is the proposed rule. Do you have that in front of you?

A. Yes.

Q. Okay. On the first page, 19.15.2.7M.(6), that purports to be a definition of "measured depth." Is that a satisfactory definition of measured depth?

A. Yes. For its application and rule, it would be adequate.

Q. Okay. Then I will take you to the second page and ask you to look at 19.15.2.7(11), "true vertical depth," the definition. Is that a satisfactory definition of the term "true vertical depth" as used by

petroleum engineers for industry purposes?

A. I will elaborate if my attorney wishes.

Q. Well --

A. At this point, it really doesn't qualify for a definition.

Q. Okay. Then tell me what's wrong with it and what needs to be changed.

A. The concern was raised about using the description as provided here as to assess the true vertical depth by using "a straight line perpendicular to the surface." There are other sources of information available which the Division obtains on a well, especially with regards to wells that are deviated or horizontal wells.

Q. Let me interrupt you here and ask another question. I didn't get really beyond plane geometry in my studies in mathematics, but I did study plane geometry in the university.

Perpendicular refers to two lines. And while it can be perpendicular to another line, it can't be perpendicular to something that's not a straight line, right?

A. That's correct.

Q. Okay. Is the surface of the earth a straight line anywhere that you know of, even in eastern New

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Mexico?
A. No. There is some devi- -- some change in the surface elevation.
Q. So the term "perpendicular to the surface" -- not mathematically precise, correct?
A. That's correct.
Q. Go ahead and tell me how you would go about defining true vertical depth?
A. I went back and looked at what was proposed in the rule and what we have currently in rule, and I looked to modify the definition as we present it.
Q. Definition of?
A. True vertical depth.
Q. Okay. Proceed.
A. The definition I propose for 11: "True vertical depth means the distance from ground level of the surface location to a point in the wellbore which is the deepest subsurface depth drilled." True vertical depth for vertical wells is measured by using a straight line perpendicular to ground level to the deepest depth. Otherwise, true vertical depth is obtained for directional wells from the directional survey required under 19.15.16.14B or obtained from the directional survey for horizontal wells required under 19.15.16.15E."

Q. Well, conceptually, what true vertical depth is, is it not, is the vertical distance from the -- from the plane in which the surface of the well -- the surface location of the well exists to the plane -- to the parallel plane that intersects the deepest point in the well? Is that not a correct conceptual definition?
A. That is correct.
Q. Okay. And you're saying that that is properly measured and reported on the directional surveys required by the --
A. Yes. If I may refer to Exhibit 8, which I put together as a demonstration?
Q. You may. And I'm going to ask you to identify Exhibit 8.
A. Exhibit 8 is a generic figure showing the difference between a vertical well, a directional well and a horizontal well.
In the case of a vertical well, it is generally fairly easy to derive a true vertical depth with using the simplest information provided. We do get deviation surveys for our vertical wells. If it is such that it gets outside our standards, well, then we can ask for additional information. The big difference between true vertical depth and measured depth changes when you go to directional wells and very much the

horizontal wells.
Q. And measured depth in most all wells is going to be a greater figure than true vertical depth, correct?
A. Generally, yes, that's true.
Q. But that's much more exaggerated in the case of the horizontal well where it may have 5,000 feet vertical depth and 10,000 or more feet horizontal depth?
A. That is correct.
Q. Or no. Like, 15,000 feet measured depth if it's a mile deep and two miles long?
A. That's correct.
Q. Okay. Now, to be really mathematically precise in here, vertical, to the extent we can apply plane geometry to a sphere, vertical -- a vertical line in the case of ensuring things in the earth -- in or on the earth is a line -- a line is defined by two points in plane geometry, right?
A. Yes.
Q. So the two points that define a vertical line are the point you're looking -- you're looking from in the center of the earth because that's what makes it vertical -- center of the earth.
A. The projection would be to the core, yes.
Q. Yeah.

So the lines that are shown as vertical on here are theoretically projected to the center of the earth, right?
A. Correct.
Q. And the dashed horizontal line that you draw from the base of the dashed horizontal line with two arrows on it, those lines -- for each well, those lines are perpendicular to the vertical lines, right?
A. The dashed lines, which represent the deepest locations, the deepest depth?
Q. Yes.
A. Yes.
Q. So what you have is a vertical distance from the deepest depth in the wellbore to the plane of the kelly bushing in the well?
A. Or ground level.
Q. Or ground level.
Usually you measure ground level in the kelly bushing --
A. That's correct.
Q. -- in the oil and gas industry?
And you're saying that that is the same figure that will be shown as true vertical depth on a directional survey prepared as we require them to be prepared?

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A. That information will be available, yes.
Q. Okay.
MR. BROOKS: Now, I think the Commission is going to be asking us, as they did Ms. Marks, for some language that we're substituting, although we couldn't file it in advance because we were deadlined.
Is that a correct assumption, Madam Chair?
COMMISSIONER MARTIN: As far as I'm concerned.
CHAIRWOMAN RILEY: Yes.
MR. BRANCARD: Unless we come up with our own language.
MR. BROOKS: Pardon me?
MR. BRANCARD: Unless we come up with our own language.
MR. BROOKS: Well, I'd be very happy if you come up with your own language --
COMMISSIONER MARTIN: I'd rather see your suggestion.
MR. BROOKS: -- but I will supply my suggestion. My suggestion would be -- you want it in writing, I'm sure, so I'll get that.
But my suggestion would be that "the distance is the distance" -- "the true vertical depth is the vertical distance from the plane of the kelly

bushing to the" -- "from the horizontal plane of the kelly bushing to the horizontal plane in the deepest point in the well."
Q. (BY MR. BROOKS) Is that a correct definition -- theoretical definition, Mr. Goetze?
A. Well, the kelly bushing is going to disappear, so you're going to have the ground level.
Q. Okay.
A. So --
Q. Well, what would you say? How would you precisely define the ground level in a well that is not drilling? I'm talking about your zero point.
A. The datum would be supplied in the C-102 as the ground level.
Q. Okay. So if we say ground level, that would be an unambiguous term that everybody in the oil and gas industry would recognize?
A. I believe so.
Q. Okay. So we'll say: "Ground level to" -- "the vertical distance from ground level to the plane" -- "the ground level at the surface location to the plane of the deepest point in the well."
A. That would be sufficient.
Q. "In the wellbore."
A. "In the wellbore."

Q. We used to say well, but now we say wellbore. That's fine with me. Okay. I will supply that definition in writing at the next break.
MR. BRANCARD: Madam Chair?
CHAIRWOMAN RILEY: Yes.
MR. BRANCARD: May I ask a question or two?
CHAIRWOMAN RILEY: Yes.

CROSS-EXAMINATION

BY MR. BRANCARD:
Q. So in the documents that an operator provides, are they going to provide a depth in this -- are they going to provide the elevation --
A. Yes.
Q. -- of the ground level at where you're drilling from?
A. That's correct.
Q. That number, the elevation, will appear on which form?
A. The C-102.
Q. Okay. Are they then going to give you the elevation of their lowest depth?
A. You will get a survey that provides you a continuous measurement of both measured depth and true vertical depth usually done from a datum either selected by the drilling company or the client. So you get both

the kelly bushing and the ground level in the most recent surveys conducted.
Q. What are they going to provide in the C-102?
A. The C-102 will have a surveyed location at ground level. And the kelly bushing and other measurements typically are not provided. Those would appear in the application -- application and permit to drill, in which case you would have the proposed depth, which would give you both the proposed vertical depth and the proposed measured depth.
Q. Okay. So you would have the proposed vertical depth in the APD?
A. You should have it.
Q. Right.
And you would have it as an elevation number?
A. You would have it as a datum -- zero from ground level.

REDIRECT EXAMINATION

BY MR. BROOKS:
Q. So if I may clarify, because we discussed this during lunch. If -- on the directional survey, the ground level is zero, right, zero elevation in the True Vertical Depth column?
A. Yes.

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Q. And then the directional survey for each point that is included in the directional survey, each depth point, they would -- the survey would provide a datum, a number, which is the different -- the vertical distance, the difference in elevation, between the zero point, which is the ground level at the well site or the kelly bushing or whatever datum they use and the point that they're reporting for.

So if you drill down 100 feet, your true vertical depth is going to show 100 feet, but then if you drill horizontally, it's just going to stay -- it's going to go up and down, but it's going to stay basically the same. So when you get to the deepest point, wherever that is, it will show the maximum amount in that column, the difference between the elevation at the surface and the elevation at that point of maximum depth, correct?

A. Correct.

Q. Okay.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. That's in the directional survey?

A. Yes.

Q. That doesn't help us, because you have to provide financial assurance before you drill.

A. That's correct. And in most cases, you have to go back and correct because you may even have -- from the period of awarding of an APD, you may go back and change your design, which it happens. You may decide to go to a shallower zone, and you would have to have modify then also.

REDIRECT EXAMINATION

BY MR. BROOKS:

Q. And it may wander, right?

A. Well, yes.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. But I'm reading your proposed rule here.

A. Yeah, I know.

Q. And it focuses on projected depth for a single-well bond. So how do we find out the projected depth for true vertical depth?

A. It is available in the C-101 application permit to drill.

Q. And it would be listed as true vertical depth, or is it some number minus some other number?

A. No. It is listed as true vertical depth and measured depth.

MR. BROOKS: I take the witness' word for it. I don't have a copy of the form.

COMMISSIONER MARTIN: That's correct.

REDIRECT EXAMINATION

BY MR. BROOKS:

Q. Okay. Mr. Goetze, are there any other exhibits you prepared other than Exhibit 8?

A. No, there are no other exhibits.

Q. Very well. Was Exhibit 8 prepared by you using your expertise?

I didn't go into your credentials and get you qualified as an expert because somebody told me that wasn't necessary in a rulemaking proceeding. Plus, last time I did that, you testified to your credentials before -- in a proceeding before the Commission, and the Commissioners remarked that they had them memorized. And besides, Dr. Balch has already stated you're the smartest man in the room.

COMMISSIONER BALCH: In the audience.

(Laughter.)

MR. BROOKS: Thank you for that qualification, Dr. Balch.

But based on the testimony that the witness has given in previous proceedings, without prolonging this one, I would like to tender Mr. Goetze as an expert in the technical aspects of oil and gas drilling even though he's not a drilling engineer.

MR. LARSON: No objection.

MR. BRANCARD: As I said, Madam Chair, we have no experts in rulemaking. Everybody's entitled to their opinion.

MR. BROOKS: Well, that's what I was told you would say, so that's why I wasn't prepared to. But based on what I'm going to ask next, I wanted to establish that technicality.

Q. (BY MR. BROOKS) Now, Mr. Goetze, was Exhibit 8 prepared by you using your technical expertise and --

A. Yes, and referencing.

Q. Okay.

MR. BROOKS: I'll tender Exhibit 8.

CHAIRWOMAN RILEY: You tendered the exhibit?

MR. BROOKS: Yes, Madam Chair.

CHAIRWOMAN RILEY: Mr. Larson?

MR. LARSON: No objection.

CHAIRWOMAN RILEY: The exhibit can be accepted into the record.

(NMOCD Exhibit Number 8 is offered and admitted into evidence.)

MR. BROOKS: And I pass the witness.

Oh, before I do, let me say that at least from my perspective, I would be happy for the

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Commissioners to ask him any question that they feel is appropriate to ask him or opposing counsel to do so, without committing myself as to who is the smartest person in the room, as I think he is one of them.

With that, I pass the witness.

MR. LARSON: And I appreciate the invitation, but I have no questions for Mr. Goetze.

COMMISSIONER MARTIN: Nor do I.

COMMISSIONER BALCH: Actually, I have a couple of comments for the purpose of the recent discussion.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. The projected depth of the well versus the actual touchdown, you're probably caught in the 50 feet, 100 feet, couple hundred feet maybe in a very deep well?

A. Maybe, unless someone changes their mind.

Q. So we're talking a difference in bonding between 50 to $500?

A. Yeah. Yeah.

Q. I'm not sure if that's something that we really want to incorporate in the rule, that you have to necessarily modify, or maybe language that makes you modify if it's more than so many feet would be a little more appropriate or something like that.

A. But I have had compulsory poolings where we say Bone Spring. They come in and make the application for the second and then, mysteriously, it turns into the third, and that's the case where you would want to rebond (laughter).

Q. But in most cases, the projected depth is going to be pretty close to TVD?

A. Oh, yes. The controls nowadays are so much greater that these folks know where they're going, and really this is -- actually comes out as a product of measuring while drilling.

Q. Again, I would say that maybe we don't need to rebond necessarily unless it's a dramatic change. More than 500 feet or something like that would be more appropriate.

The other thing is I don't think it is really the intent of this rule to dictate how TVD is measured by drillers. And I'm not sure how much into detail in the definition of true vertical depth we really need to go. In fact, I think that the definition under 11 there is fine if you strike the second sentence.

A. (Indicating.)

Q. And that would be: "A true vertical depth means the distance from the surface to a point from the

wellbore which is the deepest subsurface depth drilled." And then you let best practices and industry tell you how that's done.

MR. BROOKS: Excuse me. May I make a point, or would you rather I wait until you finish your questions?

COMMISSIONER BALCH: I'm not ready to be cross-examined yet.

(Laughter.)

MR. BROOKS: Well, I was just going to make a suggestion. I wasn't going to -- I wasn't going to presume to cross-examine you, Dr. Balch.

Go ahead.

COMMISSIONER BALCH: Oh, that's all right. You were asking for clarification maybe.

MR. BROOKS: I think, in my point of view -- from our point of view, the definition would be sufficient if we struck the second sentence and put in the word "vertical" before "distance."

COMMISSIONER BALCH: So you don't like to define things with the word in the definition. So you don't want to define "true vertical depth" using the word "vertical." But I think that the understanding of "vertical" is pretty well known in the scientific community and --

MR. BROOKS: Well, the Commission can do whatever they want to do. I'm just making a suggestion.

COMMISSIONER BALCH: Generally, you don't want to define things using one of the words in your definition.

MR. BRANCARD: I would actually support Mr. Brooks' comments because if you don't include the word "vertical," the distance from the surface to the point in the well where the deepest subsurface drill is, you're just doing this and measuring that. You want to measure that (demonstrating).

COMMISSIONER BALCH: Part of the deepest depth. Depth is pretty well defined.

MR. BRANCARD: No. It just says "distance."

COMMISSIONER BALCH: Okay. Depth is probably the one that we need instead of "distance." "Deepest subsurface depth drilled." It says "depth" right there. I think depth is pretty well understood, also, as being measured in a line towards the center of the earth along the --

MR. BROOKS: Well, I would recommend to the Commission they use a more precise definition, but that is the Commission's prerogative.

COMMISSIONER BALCH: What's your opinion on

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it?

THE WITNESS: I like to keep it simple. When money gets involved and lawyers are attracted to it, there tends to be points of clarity.

COMMISSIONER BALCH: That is all I have. Thank you very much.

THE WITNESS: You're welcome.

CROSS-EXAMINATION

BY CHAIRWOMAN RILEY:

Q. Just to help clarify as to what goes into the original APD, definitely have -- if you wanted to adjust your plat, give you your ground elevation but also directional plans. And the directional plans call out at least what the proposed -- or your measured depth. And your vertical depth cannot be based on the eastings and -- what you're doing with your eastings, northings and get accurate measurement of that vertical depth.

So as to Mr. Brancard's concern about having that at the beginning, call out for or is required for that bond, we can look to the directional plan?

A. We don't always require a directional plan. Usually that's provided in more -- the BLM does have a predrilling directional plan requirement. Sometimes we do not get those. The tendency is now that the clients

are -- operators are offering them more -- more and more? So you do have historically a better presentation. Again, there may be someone -- when you have people putting in horizontal wells -- it's only one or two or three -- the tendency is they will not provide that information. But it should be in the APD.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. Okay. I'm looking at the C-101 form. Okay? Box 15 says "ground level elevation."

A. Uh-huh.

Q. Box 17 says "proposed depth."

A. Uh-huh.

Q. How would they write the proposed depth?

A. They will probably put in a true vertical depth.

Q. So in other words, distance below surface?

A. TVD -- designated TVD. And usually they'll give us both because typically for the C-102 to be complementary to the 101, you have to dedicate the acreage. And so your footages, which are surveyed in longitude and latitude, have to conform to what's coming in with your APD. Without the 102 and the 101 together, you don't have an approved drilling plan.

Q. Okay. But that proposed depth on this form,

does that equate to what this definition is asking for, which is the deepest subsurface depth?

COMMISSIONER MARTIN: Bill, do you have the C-101 and C-102 instructions?

MR. BRANCARD: I just have the form.

COMMISSIONER MARTIN: I think it maybe specifies it in there.

MR. BRANCARD: Okay.

Q. (BY MR. BRANCARD) It says, 17, "proposed total depth of this well." Is that what we're looking for?

A. No. That opens up the question, "total depth."

COMMISSIONER BALCH: Measures that depth?

THE WITNESS: Yup.

COMMISSIONER BALCH: Could be either.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I think in all cases, TVD is going to be measured from the location of the wellbore -- of the well at the surface, correct?

A. Correct.

Q. So if you have a situation where you're on a hill, the well is here, your TD is down here (demonstrating), it is measured from -- from the depth of -- from the point of the surface where the well --

A. Most of your references are back to the surface

location for elevation.

Q. And that, I think, is where the definition is fine, if we just strike the second sentence.

CONTINUED CROSS-EXAMINATION

BY CHAIRWOMAN RILEY:

Q. So then will we need to add any measurements to our C-101 or C-102?

A. I did not consider the remodification of any forms for this.

MR. BROOKS: That matter is being considered by the Division, by the new horizontal well rule because the rule -- when the rule went into effect, we found that the existing forms -- or the forms we had previously developed -- the rules were not adequate so now we're working on the revision.

CHAIRWOMAN RILEY: And that could be included in the revisions?

MR. BROOKS: It could be, Madam Chair.

COMMISSIONER BALCH: Actually, I have one more question.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Where in the proposed rule is "true vertical depth" used besides in the definition of "true vertical depth"?

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A. Only in the rule, I think. I don't know.

CHAIRWOMAN RILEY: Here it is right here. It's that same paragraph --

COMMISSIONER BALCH: Okay.

CHAIRWOMAN RILEY: -- that you wanted to move higher up.

I would tend to agree with moving it because I -- when I first read this, I thought there was a mistake, that we hadn't captured that. So I think putting it higher might help the reader.

COMMISSIONER BALCH: Thank you. I'm glad it's just used in one place.

CHAIRWOMAN RILEY: Mr. Brooks, do you have any redirect?

MR. BROOKS: No. Thank you, Madam Commissioner.

CHAIRWOMAN RILEY: We can excuse this witness.

MR. BROOKS: May I ask if it is still the desire of the Commission to have the Division submit a proposed alternative definition, or has the Commission reached conclusion and no longer needs it?

COMMISSIONER BALCH: We haven't debated it yet.

MR. BROOKS: Okay. I will submit it.

And I will add that I have been approached by someone requesting to make a public comment, and so I would ask that we take a recess before we ask for public comment in case this person actually does desire to make a public comment.

CHAIRWOMAN RILEY: Okay. Let me ask this question first: Mr. Larson, it would go to you next. Do you have anything more that you want to do?

MR. LARSON: I do not. The only thing I would have at this point is a closing statement.

CHAIRWOMAN RILEY: A closing. Okay.

So I think, Mr. Brancard, it's probably an appropriate point in this hearing to bring in public comment.

MR. BRANCARD: There are no more party witnesses, so I think it's a good point for any kind of public testimony.

CHAIRWOMAN RILEY: Okay. And you're asking for a break between --

MR. BROOKS: Yes.

CHAIRWOMAN RILEY: Okay. So let's take a break right now and come back at quarter till.

MR. BROOKS: That would be acceptable.

CHAIRWOMAN RILEY: Would that work for you, Mr. Brooks?

MR. BROOKS: Yes.

CHAIRWOMAN RILEY: We are off the record. Let's adjourn for 15 minutes.

(Recess, 2:31 p.m. to 2:52 p.m.)

MR. BROOKS: Madam Chair, Commissioners, I would like to make a brief closing statement at an appropriate time. I assume it would be after members of the public are given an opportunity to comment. However, that's all I have. I have no more witnesses and no more evidence to present.

CHAIRWOMAN RILEY: We're back on the record.

So I think at this point if we could do our public comments, public testimony. There are two that I see on the sheet that I find here. Larry Marker is the first one and Rory --

COMMISSIONER MARTIN: McMinn.

CHAIRWOMAN RILEY: -- McMinn. Okay. Thank you.

So let's start with --

MR. MARKER: Do I do it from here or at the table? Where do you want me to be?

CHAIRWOMAN RILEY: Well, probably where the court reporter can hear you best.

MR. MARKER: Will right here work?

CHAIRWOMAN RILEY: That's perfect.

MR. MARKER: What I'm going to do is I'm going to present some basic -- I'm going to read this prepared statement. But what I've done -- I'm a little bit nervous. I'm not the best communicator on the planet, so what I did -- I have it written.

CHAIRWOMAN RILEY: Could please state your name?

MR. MARKER: Oh. My name is Larry Marker.

Anyway, I'm out of Roswell, New Mexico. I'm representing myself, several other stripper wellers and then a little cooperative we just recently formed called the IPPC. That stands for Independent Petroleum Producers Cooperative. The main focus of our cooperative is to -- right now our main focus is to help with the administrative issues that smaller operators have.

Anyway, I've got these copies of what I'm going to say today. I've left spacing in them so you can make notes, and then I left a blank page on the back.

Do you want one, sir?

MR. BROOKS: Thank you.

MR. MARKER: Do you want one?

MR. LARSON: Sure. That's your last one?

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Is that your last one?

MR. MARKER: I've got my own copy. I've been scribbling on it all morning.

MR. BRANCARD: Would you like to swear in the witness?

LARRY MARKER,

after having been first duly sworn under oath, testified in narrative form as follows:

MR. MARKER: I'm going to go ahead and sit down.

Okay. You guys know all the other stuff and here we go.

In reference to the proposed amendments to the Commission rules of financial assurance, I am submitting these comments and request verbally and written to provide clarity and reference.

Number 1: Proposed amendment to Rule 19.15.8.9, Subsection C, Part 1. The OCD has proposed a single well financial assurance of active wells of $25,000, plus an additional $2 per foot of depth. We request the Commission to reconsider the amendment to require a single active financial assurance of $5,000, plus an additional $2 per foot.

(A) To require single active well assurance as proposed by the OCD will, for all practical purposes,

end the entry of new operators into the industry. The value of entry level position in any industry is vital to the future of that industry.

(B) New Mexico operators commonly will have wells on both federal and state land. This level of assurance proposed by the OCD would be prohibitive in the event that an operator has several federal wells and one or two state wells.

Number 2: Proposed amendment to Rule 19.15.8.9, Subsection C, Part 2. We endorse the proposal presented by counsel for IPANM for the amended ratios as we referenced in the following excerpt from the pre-hearing statement submitted: $25,000 for one to ten wells; $50,000 for 11 to 99 wells; 100,000 for 100 to 149 wells; 200,000 for 150 to 199 wells; $250,000 for more.

The ratios of assurance as proposed by the IPANM will serve to satisfy the implementation of the changes enacted by the 2018 Legislature.

Number 3: The Oil Conservation Division proposed ratios of assurance as they have submitted in their pre-hearing statement would be detrimental to every aspect of the oil and gas industry in New Mexico.

(A) The independent operators, small, medium and large, have had three of the toughest years

in the history of the industry and will be forced to commit already limited resources required for operations to comply with the massive increases in financial assurance as proposed by the OCD.

(B) Several methods of acquiring financial assurance are available. Each of these methods will require a substantial increase in operator investment under the OCD proposal.

Example -- and this is me -- I have on record 77 state wells. My existing blanket bond is $50,000. I am fortunate to have surety company participation. My conditions to have this bond is a 40 percent collateral and a 3 percent yearly premium. My actual cost is $20,000 cash held by the surety company and a $1,500-a-year premium charge. The OCD proposal would require I increase my blanket bond to $125,000. I would then have $50,000 cash held by the surety company -- it's a $30,000 increase -- and have a yearly premium of $3,750. That is a $2,250 increase. This is assuming that the surety company, after reviewing my financials, will be willing to accept the increased risk at the 40 percent -- excuse me -- 40 percent collateral or increase that as well. The surety company could also refuse an increased level of liability at any level of collateral.

(C) State statute allows for the use of an irrevocable letter of credit as financial assurance. This option is common. Lending institutions require cash or property to be encumbered as collateral. The encumbrance of assets, along with the reduction in the amount of credit now available to the operator, further restricts his operations.

(D) Cash is another form of assurance used to provide assurance. To increase the level of cash required to meet the OCD proposed ratios would be a challenge even for the most financially secure operators.

(E) Sale of assets to provide the additional resources would normally be an option. The dramatic increases of assurance proposed by the OCD has already seriously reduced the value of producing properties. Full implementation, if adopted, will further reduce the marketability of an operator's property.

The phenomenon of increasing regulation expense on operators can easily be examined right here in our own industry. The increased regulatory activity to include the latest round of bond reviews by federal agencies has depreciated the value of stripper wells on federal land to the point of making them nonmarketable.

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Even the most aggressive buyers are not interested in stripper wells on federal land.

The proposed OCD amendment could conceivably result in financially destroying many small, medium and even some larger operators by forcing them to divert cash or other resources to the most nonproductive part of their business. The reduced value of properties and the reduction of available credit from already worried lenders is an additional negative result.

(H) The proposed OCD amendment will most likely result in an increase of the number of properties abandoned, also reducing the OCD's ability to market any of those properties -- excuse me; let me start over -- reducing the OCD's ability to market its already full portfolio of abandoned properties.

Number 4: The OCD proposed amendment to Rule 19.15.8.9, Subsection D, Part 1 has proposed a single well financial assurance in the amount of $25,000, plus $2 per foot for wells categorized as temporarily abandoned.

We respectfully request that the Commission consider the alternative of financial assurance requirement of a $5,000 base, plus $4 per foot of depth.

(B) The level of assurance we are requesting will more accurately reflect a practical

level of assurance for the shallow wells abundant in southeastern New Mexico. The requested $5,000, plus $4 per foot will also provide the amount of assurance necessary for deeper wells.

(C) The more shallow wells are attractive to entry level operators, as well as small operators expanding their business. These wells also serve as a type of apprentice or incubation program for new operators. Shallow wells are traditionally less expensive to operate and have provided a foundation for some of the most successful operators in this region.

(D) The level of assurance as proposed by the OCD will be prohibitive to any operator attempting to purchase inactive wells with the intention of reworking them to bring them back into production further limiting potential.

Number 5: The evidence and exhibits provided by the OCD in the pre-hearing statement are informative and thorough. That material does not demonstrate that by implementing the ratios of assurance or the increasing -- or increasing the amount of assurance for the single-well bonds as proposed by the OCD will serve to produce any positive results. As a matter of practicality, the OCD amendment as proposed will further expose the OCD and taxpayers to even more

liability and less income from the affected properties and operators. The obvious detrimental conditions created by massive increases of financial assurance make the OCD proposed amendments counterproductive.

Number 6: The evidence and exhibits provided by the OCD expose facts that will not be remedied by raising the amount of financial assurance.

(A) Exhibit 6, "List of Wells Plugged" provides a list of wells plugged by the OCD over the last few years. I can find -- or I have no information that these wells were plugged using funds obtained from forfeited financial assurance provided by the operators. To properly demonstrate that a simple increase of financial assurance will benefit, we must examine where the funds to plugs these wells originated.

(B) Without all the information required, I am left to speculate that most, if not all, of the 145 abandoned wells were plugged using funds procured from the Oil and Gas Reclamation Act or litigation, neither of which would be avoided by increasing the amount of financial assurance provided by reputable operators.

(C) My research did allow me to conclude that over 80 percent of the wells listed in Exhibit 6 were operated by out-of-state operators.

(D) Further research revealed that of the

ten operators associated with these wells, two individual operators accounted for 100 of these wells, both out-of-state operators.

Number 7: Exhibit 7, "Rule 5.9 Compliance List" provides a list of wells in the category of inactive. Most of the wells listed are on the list because of reporting issues, waiting on repairs, et cetera.

I believe the OCD provided this compliance list to demonstrate the large amount of inactive wells and potential liability to the taxpayer. This list does serve that purpose.

Additionally, this list also provides more evidence that the majority of the wells that will eventually be plugged by the OCD will not be plugged using forfeited financial assurance funds. These wells, when plugged, will be plugged with money procured from the oil and gas reclamation fund. Again, the largest share of this future liability comes from out-of-state operators.

(B) The compliance list contains a list of wells owned by 136 individual operators or companies. These operators and companies have a total of 10,351 wells with 1,738 of these wells listed as inactive. Further investigation into this has led me to the

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conclusion that the number of inactive wells on state or private leases is actually 949. Most of these wells are classified as inactive because of late production reports, waiting on workover equipment, et cetera. These wells are normally inactive for a short period of time.

(C) The OCD requires financial assurance from the operator on wells that are on state or private leases. Of the 1,738 wells categorized as inactive, only 949 of these wells require OCD-administered bonds of any type.

(D) I do note that the OCD did plug nine wells shown as federal. These federal wells, by statute, could be plugged using the money procured from the oil and gas reclamation fund. This money is not relating to financial assurance provided by the operator.

The increase in financial assurance will not reduce the number of existing wells already abandoned by defunct operators.

The BLM -- I'm sorry.

(F) The BLM requires its own financial assurance for wells on federal property.

Number 8: These comments of conclusion are based on our perception of the issues of financial

assurance based on my own experiences in this industry, the information I researched for this hearing and input from at least a dozen experienced independent operators.

(A) The increase of financial assurance will not be of benefit to the operators, the OCD or the taxpayers. The only people that will benefit from increase in financial assurance is the people that provide that assurance. There is no evidence provided to prove that a massive increase in financial assurance will improve this situation.

(B) The increase in financial assurance will not increase the amount of funds available to the OCD to plug wells. The only practical method available is to increase the funds available via the oil and gas reclamation fund.

(C) The natural course of business is that some operators will go broke. Also, no amount of financial assurance will completely protect us from people with nefarious intentions. Considering current bankruptcy laws and the cost of litigation, we need to adjust our policies.

We would be willing to support the OCD and modifications required to better use the oil and gas reclamation fund.

To summarize, myself, the members of the

IPPC and nonmember independent operators consulted respectfully request the OCC to consider the facts of the case and implement the amendments as we have requested.

Thank you.

CHAIRWOMAN RILEY: Thank you, Mr. Marker.

MR. MARKER: Am I done?

COMMISSIONER BALCH: You can be cross-examined, if you'd like to answer questions.

MR. MARKER: It doesn't bother me. Go ahead.

MR. BROOKS: No questions.

MR. LARSON: No questions.

CHAIRWOMAN RILEY: Questions?

COMMISSIONER MARTIN: No.

CHAIRWOMAN RILEY: I don't.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I've got a couple of questions.

A. Okay. Go ahead.

Q. First of all, thanks for coming here today. It's very important, I think, to hear the perspective of the stripper-well operators.

A. Yes, sir.

Q. They're a lot of, I think, a big chunk of

production that doesn't get --

A. And I can promise you there is no place I'd rather not be (laughter), to be real honest.

Q. The individual bond --

A. Yes, sir.

Q. -- if you have a couple of individual bonds and then you end up with a few more wells, you can go to a bulk bond and pull back those individual bonds, right?

A. Yes, sir. You can do that. And my point is if a guy -- if a guy wants to get started in the oil and gas business, he'll pick up one or two wells, and if it goes pretty good, then he'll go buy -- you know, he'll go buy a blanket bond, which generally works. Typically, you have to be in the business quite a while to be able to get surety company participation. The only way I was able to accomplish that is at one point, I was actually at 100 percent collateral. Normally, a person wouldn't go through that process, but I went through it to build a relationship with the surety company because I knew -- down the road, I had intended on growing my business, and I could also see that eventually we're going to have to change the way we do business.

Q. Did you put up your wells as the collateral?

A. No, sir. The bank typically -- the banks I

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deal with won't --

Q. They know better?

A. They know better (laughter). I wasn't going to say it like that, but yeah.

Typically, on my surety -- my surety company requires cash. I'm still in the process of getting all of my federal bonds moved over to the surety company, but right now, the way I was having to do it, when I got started, I bought a couple of federal wells, and I thought life was wonderful. I went and put up a metal building. I got $25,000. I ran down and bought a CD and put my bonds up, and I was off and running.

It took me a little while longer to get a state bond of $50,000 collateral, but I was able to do that. And now my business has grown to the point where my balance sheet reflects enough that the surety company will ride with me. Most people don't have that option.

Q. So IPPC, that's your cooperative?

A. What we did --

Q. How many participants in there?

A. Right now we've got seven participants. We're probably going to max out at 20 participants.

Q. How many wells?

A. 5-, 600. Easily 5- or 600.

Q. So as a cooperative, you might be able to go

for the bonding at the 250,000 level, the blanket bond.

A. It's kind of funny that you mentioned that. Right now we sat down -- we all sat down -- actually, we don't sit down anywhere together. We're typically running all over the place. We might run by a rig when we're working or whatever. But what we've decided as a group is there is no way any one of us can provide a full office staff for anybody. It just can't happen. And we're sick to death of waking up at 3:00 in the morning because we're six months behind on our reporting; Daniel's probably trying to avoid the phone or whatever. No. You know, me and Daniel actually have a relationship.

But what we decided is what we want to do is we want to change the way we do business. We want to stay current on our reports. We want this co-op to address any of the issues that the small independent operators have. Right now the biggest issue, the one that was biting the most of us and not so much on the state reporting as on the federal reporting, the ONRR federal reporting is just a nightmare. Okay? We've got a girl in place now. She's got everybody caught up. We're gaining new members. That's why we're growing slowly, to get everybody caught up. We charge a fee for that to the member, plus the monthly investment capital

fee. Eventually, we will be able to roll that investment capital into retirement.

But my -- my personal goal -- and, of course, I'm not the full co-op. My personal goal and where we were headed for is I was researching the possibility of finding an underwriter so we can self-bond. That way all of the guys could get a surety company, because it made a massive difference in my life. And not everybody is going to be able to go through the struggles that I did to get a surety company relationship, especially now.

So our next -- our next idea -- and that actually is a good idea.

Our next idea is to figure out a way for bonding wells for the individual operators, you know, as well as everybody else. And I was talking to a couple of guys a while ago who are trying to do business differently than what we've done in the past. That's just the way it is. Things are different.

Q. So your group of stripper operators is averaging 70 to 80 wells apiece. So 600 wells --

A. I'm probably one of the more aggressive -- one of the more aggressive. I rolled into the industry about six years ago. I was tired of working in town. I wanted to get back in the oil industry and buying,

selling, trading, swapping. And a lot of opportunity presented itself when the market cratered that normally would not have been there. I made a couple of pretty good deals, some rougher deals, whatever, but that's basically how I survived, and that's how I've grown my business basically debt free. So, you know, my balance sheet looks pretty sweet to a bonding company. And you and I both know my balance sheet and cash position probably are pretty bad.

The average stripper weller -- and I'm stalling because I was hoping Buddy would slip me an answer. But I would say -- we've got Steve here.

How many wells you got, Steve?

MR. OLDFIELD: 20.

MR. MARKER: He's got 20 wells. Two of those are state wells.

MR. OLDFIELD: Three.

MR. MARKER: Three of those are state wells.

COMMISSIONER BALCH: 17 are Fed?

MR. MARKER: And 17 are Fed.

MR. OLDFIELD: I've got eight federal, eight state.

MR. MARKER: Eight federal, eight state. We've got -- we've got -- how many wells

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does Louis have?

MR. OLDFIELD: Probably similar to what I have.

MR. MARKER: Probably similar.

Q. (BY COMMISSIONER BALCH) So for your stripper wells -- just for your own 77 wells --

A. Yes, sir, my own state.

Q. -- what's your monthly production?

A. My wells are a little different because I have taken a bunch of properties that I continue to work on. And that's kind of my deal, is I take environmental issues that people normally wouldn't take. For whatever reason, my personality, I don't judge consequence real well, so I'm liable to jump into anything with both feet, which has made my dentist a lot of money over the years, but it hasn't served me too well all of the time.

But anyway, the average stripper well, I would say, is going to be somewhere between a half and a barrel a day.

Wouldn't you, Buddy?

MR. DeLONG: Uh-huh.

MR. MARKER: Realistically. I mean, we're all going to sit around and say, I've got 16 2-barrel-a-day wells. No, you don't.

Q. (BY COMMISSIONER BALCH) So what's your net out

of that?

A. Right now --

Q. Let's say 30 barrels a month for one well at -- I think it was 60 the other day. But that's not the price you're going to get.

A. Yeah. That's not the price you're going to get. It gets really, really complicated really, really easy.

You can have as many wells as I have and sell six loads in a month, and then the next load, you might sell 12 -- the next month, you might sell 12 loads. Or the issue with a stripper well is you might have one well here making you a half a barrel a day going into that tank. And then you've got three wells over here. Each one of these makes a half a barrel, but they all go into the same tank.

And then I guarantee you, 30 percent of the wells that you're operating will break. There are only two kinds of stripper wells in the world: broken and breaking. There is no in-between. It's a constant.

Q. Right.

So let me phrase it a little bit differently. What's your break-even point? Half a barrel a day, right now it sounds like you can run a stripper well.

A. I can operate a stripper well at a half a barrel a day. Now, I'm a little, again, unusual. I've got my own pulling unit, my own water truck. I do all my own work. I'm the one-man pulling unit crew. Steve's another example of that. We can't -- we can't really afford to -- practically to pay somebody to come pull our wells and stuff, so there is a challenge.

What I would say -- and then we recently just had an increase in our electric price, which is more of a challenge.

If we could keep oil at $60 a barrel -- the advertised price of 60 bucks a barrel, that gets me, for the oil that I sell -- we're taking a $10 hit in southeastern New Mexico right now because of the pipelines and the trains and that various thing. So if you've got -- let's just go 70. If you've got $70 crude WTI, you take that $10 hit when you're going to get your reduction. You're going to get your reduction for sour crude or whatever. So if it's $70 crude, I'm confident my best crude I'm going to sell for -- you've got ten. That's 60. I'm going to get 75 percent. My average net revenue is 75 percent of, let's say, $57. That's what I actually bring -- that's what I actually have to pay my bills with.

Any amount of money that we take out of our

cash flow, some months it's better than others. It's an ugly business, especially right now.

In February of 2013 -- I'm sorry. In February of 2016, I sold 22 loads of crude oil, and it did not pay my electric bill. That's ugly. It's gotten continually better. My best lease I sold -- when did I sell the -- like two years ago? About a year and a half ago. I sold my best lease about a year and a half ago. The down- -- the downturn lasted longer than what I had anticipated. I was a little too aggressive rolling in, so I ended up selling my best property to go ahead and get my debt taken care of. And I had some issues on some wells around Roswell that me and Daniel had worked on that I'm getting squared away.

Q. So you're 77 wells (indicating).

20 wells (indicating).

MR. DeLONG: 16.

COMMISSIONER BALCH: 16.

MR. MARKER: Those are -- his are federal and state.

Q. (BY COMMISSIONER BALCH) Federal and state.

And out of all the stripper-well operators, you know, what's a good average number, stripper wells?

A. Number of average -- average number of wells?

What's Daryl got?

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We actually had two other stripper wellers calling [sic] in today, but one was so nervous, he got sick and had to go home.

MR. McMINN: Your question was what, Commissioner?

MR. MARKER: The average number of wells --

COMMISSIONER BALCH: I'm trying to figure out how many -- how many stripper wells you have to have to make a viable operation. It sounds like at least 16 or 20.

MR. McMINN: Not necessarily. I mean, it's not just -- they're not all just a half a barrel a day. I've got some that are three barrels a day and one that's five. But I guess to cut to the chase on what Larry was saying, half a barrel a day will net you $12,000 a year, and you figure you may spend $1,500 over the year's time on electricity -- on electricity. If you have ten of those and it's not something where you're totally away at a desk every day for eight hours, you're going --

MR. MARKER: There's no doubt it's a rough life.

MR. BRANCARD: Excuse me. Can we just get your names for the record?

MR. DeLONG: Buddy DeLong.

MR. OLDFIELD: Oldfield, O-L-D-F-I-E-L-D.

Q. (BY COMMISSIONER BALCH) So it's pretty variable, but more than ten?

A. Yes, sir, I would say so. Yes, sir. Typically, ten wells. If a guy comes into the business and he picks up less than ten wells and he stays that way for very long, he's typically looking to sell those wells and get out of it because it's more work than what he had anticipated. Or -- or he typically goes past that point and decides, Hey, this is something I want to do. Unfortunately, we haven't had a whole lot of people saying, Hey, this is something I want to do, in the last few years, but things are improving.

That's another reason for the co-op. A guy can walk in and buy four or five wells. He's never -- he's never going to get behind on his reporting. He's never going to have the regulatory issues that I had when I started. You know, getting behind -- the first red flag that I see -- and I've been told by other operators. When the OCD sees you get behind on your reporting, the red flag goes up. Then you're on the radar. I actually got into this business trying to fly under the radar. I just didn't do a very good job.

Q. I think however this turns out, you ought to talk to the OCD about getting your cooperative to be an

entity for the purpose of bonding.

A. And I will say -- and I'm not -- believe me. I mean, I'm impressed with, you know, the evidence today and all that. I'm not knocking the OCD at all. I've worked with the BLM. I love the OCD.

(Laughter.)

A. I mean, maybe that's not a popular thing to say. But Daniel has -- truly, Daniel and Keith, both, have gone out of their way.

MR. BROOKS: That's a popular thing to say around here.

MR. MARKER: Sir?

MR. BROOKS: That's a popular thing to say around here.

MR. MARKER: Well, the last 33 wells that hit my -- and the reason I'm showing 21 inactive wells on my inactive well list is in February, we put 33 inactive wells on my list, some wells I brought from a buddy and it's a long story. But I'm just going to tell you. Had Daniel not worked with me, that was another 33 wells that the OCD was going to end up with. Instead, we worked it out. He said, you know, You do your seven years of reporting, you get Johnny's [sic] reports current, you get all that done, and we'll let you -- we'll let you continue on.

I'm going to drop three more of them off of the inactive well list this month. I'm waiting on the right-of-way stuff from the BLM, or I would have had nine more off this week. But I'm still waiting on rights-of-way on wells that are 40 years old, but that's another story. And then me and Steve, we're going to check six more on the way home, see if I can call CV and have the meters put in. That'll be another six that'll be off the inactive list.

But that tells you the inactive list is basically pretty fluid. Now, you've got EP, Canyon, Cano and those people who are headed for a wreck. But typically, stripper wells, that list -- like I said, 30 percent of them are going to be off anyway. Normally, they won't hit the inactive well list unless you don't report them for 60 days. And you try to stay off the list. The ultimate goal is to not have anything on the radar.

Q. (BY COMMISSIONER BALCH) I think I also encourage you to shop the list of orphaned wells, see if you can acquire some of those.

A. Actually, another thing Daniel has done -- a friend of mine, the guy that actually ended up throwing up and had to go home, he was working with Daniel to buy some of those wells. Daniel actually has been marketing

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those wells. Him and Daryl come to an agreement. And then the deep rights operator apparently didn't want the deal to go through. You'd have to ask him the particulars. But Daryl was upset or was pretty frustrated.

The OCD has been trying to sell those wells. I believe we need to give them some -- well, maybe some help somehow or another. But I agree with you. There's opportunity there. Right now I'm kind of hamstrung. I've got another deal. I'm kind of hamstrung with what I've got going, but, you know, at the end of the year, beginning of next year, we've got several guys from the co-op that would look to drill.

Plus, with our co-op, like I said, if a guy has been thinking about getting in the oil and gas business, if he wants to pick up 10 or 15 wells, gets ahold of Daniel, talks to Buddy, gets with Mr. Fulton or whatever, they go check these wells and yeah, you can make a go of it, then they can get set up with the co-op, stake themselves a well if everything's good.

The problem that we have with the increase in bonding, that's going to be a challenge. We understand that the taxpayer needs to be protected. We completely -- we understand that.

You know, I can't tell you how many wells

I've wanted to buy or how many units I wanted to buy, and some big out-of-state -- some big out-of-state operator ended up with it. And I knew what he was doing. Worked the thing for six months or a year, decided he couldn't make any money, strips all the pumper jacks, takes the tubing -- takes the tubing rods and leaves. That was the lease that I was trying to get bought, but I didn't have the money to get it done because the guy overbid me. Now he's gone.

MR. DeLONG: And we're still here.

MR. MARKER: And then we drive by those daily.

I don't understand exactly -- there must be -- it must cost more to litigate those cases. I wouldn't want the challenge of trying to figure that mess out. I believe the OCD is qualified to take care of the situation. The people that would we have on staff -- and I say "we." The people we have on staff with the OCD are more than qualified to take care of the situation. We just have to give them the right tools.

As far as the assurance goes -- and obviously this is just my humble opinion. As far as the assurance goes, just giving somebody a bigger hammer isn't always the answer. Believe me. I'm from the bigger-hammer crowd. You know, get a bigger hammer. I

really think that increasing the financial assurance to this amount is basically just saying, The state legislature told us to take it 250. And believe me. We appreciate the fact that you guys are considering -- I call them ratios. You call them -- we appreciate the effort that you guys are taking in this deal, but just to give -- just to put this into place, simply because the state legislature told us to, probably doesn't make a lot of sense because I really don't think the state legislature knows anything about the oil and gas business, for one. Just my opinion.

Q. (BY COMMISSIONER BALCH) Thank you, Mr. Marker.

A. Thank you.

CHAIRWOMAN RILEY: I don't have anything.

Mr. McMinn?

MR. McMINN: I don't know how I can follow that.

My name is Rory, R-O-R-Y, McMinn, M-C-M-I-N-N. I'm here representing an entity called Quatro Osos E&P, LLC. We are OGRID Number 372241.

We bought our first set of 17 wells in April of last year, operated those up until January, added enough more wells to get us a total count of 64. Our wells are located approximately 22 to 25 miles east of Roswell on a little San Andres trend. Our deepest

wells are just barely over 2,100 feet deep. And we have three inactive single-well bonds posted, and those were part of a sell package when we closed on the balance of our wells the first of January.

The principals of Quatro Osos are four couples. My wife and I primarily do the operating of Quatros Osos because of our proximity to the wells. Our goal has been to take wells that have been -- the best term would be a total lack of maintenance, and so what we've done -- we were fortunate enough to gain the services of a pumper who was involved in cable tooling many, if not most, of the wells that we bought. So his experience in the field is great for us and gives us the historical connection that we need.

The issues that we have, as Larry has pointed out, revolve around just the normal course of business and expenses that you have to deal with. And so when financial assurance came forward and was first brought to our attention, it really caused great concern on our part because of the fact that all of our bonds, including our single-well bonds, are cash bonds. So all of the cash that we have in the bank to cover those bonds are encumbered by the State Land Office or the OCD, and we have no access to those funds. So we've taken working capital and moved it into the bond arena.

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So out of the 64 wells that we have, 61 are producers, and we produce between 50 and 55 barrels a day. So we're averaging less than a barrel a day per well. Last month, we sold 1,417 barrels, and we've sold five loads so far this month. We rebuild four pumping units a month. A group out of Hobbs comes over. We just pulled a well yesterday, had to lay down a whole string of tubing and rods because of corrosion. And so our expenses at this moment are extremely high because of the fact that we're reworking these wells and trying to get these wells on a consistent basis.

Consistency -- Larry's right. They're either broken or they're breaking, and so consistency is a problem. And Mother Nature is no great help when it comes to electrical storms and that kind of thing. We've burned up several control boxes, you know, at 12-, $1,300 apiece. So we count our pennies.

In essence, what I'm representing is a mom-and-pop operation. And I've worked for family-owned companies. I've worked for a large Australian company here in the United States. And so my experience in dealing with the large operations and a very large budget was great, but the freedom that I have in being able to go out and do what I do on a daily basis in the field, I can't get that and could not get that with any

of the employment that I had prior. So at my age, I did not to want retire, and I wanted to continue to work. And so my partners agreed with that, and since I'm the one doing the daily work, it was real easy for them to agree to it.

And so the point that I would like to make to you is that we support the presentation as amended today by IPANM on the tier structure for the financial assuredness on the bonds. We also support the Independent Petroleum Producers Cooperative position in regards to the inactive well at $5,000 per well and $4 per foot.

The issue that I have is payback. So what is being proposed currently by the OCD to me takes a sixth of my annual income to recover that revenue. It's going to cost us out-of-pocket, in order to come up with the difference, just under $140,000 to post those additional cash bonds. That's my cash flow. You're taking cash flow for a couple of months out of our pockets. We amortize that, of course.

The other issue we have -- in addition to the fact that I'm not Devon, I'm not Concho, I'm not Marathon -- is I have no public money. Money that we put into the business, my wife writes a check out of a joint account. So any income that may come in, we're

turning around and putting it back, and every month we add a little more out of our bank account in order to make ends meet, as do my partners. So we split things four ways. I have one CPA in Artesia who has a quarter of 1 percent that was bequeathed to her by her mother, and she'll never sell it. So other than that, there are four working interest owners. We have a 75 percent net revenue, which in the state of the things makes it difficult. On those state wells that have already been applied for, we have a reduced royalty that the State Land Office allows us to apply for, and that differential is phenomenal in the amount of income that comes in.

And so the concerns that we have are that the things that we hear being spoken by the OCD and personnel indicate to us that there is a negative bias towards the small operator, and that's very concerning to us because -- because of the fact that we believe that we are part of what made this state what it is in regards to operations. We wouldn't be here in many instances if we hadn't been in a position to take the wells that the bigger operators didn't -- no longer wanted to have, because they could not operate it with their overhead.

So being able to do what Steve and Buddy

and Larry and others do keeps these things active.

We have depth limits on the wells that we have, so we're at the total depth of the wells. We can't improve our position any at all by drilling into the P3 or the P2, so we're producing what we have. We've accepted it as it is. We're -- we have the ability to generate a little cash flow on a monthly basis, but determining that we're going to have to come up with additional money is -- I mean, we've been -- everybody -- all my partners and I have been saving money since this first came through the legislature in order to try to be able to have it when the time comes in order to make the payment. We don't think it's a matter of whether this is going to get done. We think it's a matter of when it's going to become official. So we're trying to acclimate ourselves to that position.

One of the things that concerns me greatly about the presentation today, which was well done, by the way, and I failed to thank you-all for having this hearing. I mean, the legislature allowed you-all to have 250,000. You could have just gone 250,000 without having the hearing. But we appreciate the Secretary's position in wanting to consider a tiered approach. We appreciate that very much, and we are thankful to be able to participate in the hearing.

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But the FTE count, the administrative burden statements, the lack of statistical data that's available through the OCD is of a cause of great concern. The State Land Office and the OCD are the repositories of all of the knowledge of oil-and-gas income, sales, acreage sales and everything for the State. If we cannot come to you-all to get statistics such as how many bonds have been redeemed on operators that have gone out of business, if you can't even tell us that number, then there's a problem.

So I'd like to make a suggestion in closing and that is, Commissioner Balch, who works for New Mexico Tech, which is crawling with ants named students that are technically oriented, and I think the reclamation fund money, you need to make a long-term arrangement for analysis through those students and gather the statistics from the data that you already capture that you don't know how to put together, because you get -- you have that data. I have no doubt. But you just don't know how -- you haven't been able at this point in time to disseminate it.

So I would recommend that some of that money is used for that because I think that the manner in which these kind of things, like financial assuredness, could be done in the future would be done

upon accurate numbers rather than it costs an average of $33,000 to plug a well. Mine are between $8,200 and 10,000, what it costs to plug one of my wells. So $33,000 is ludicrous. I mean, paying the bonds, you know, the single-well bond -- I will plug three wells when this is implemented, if the single-well bond comes in, at $25,000 per well. It's cheaper for me to plug them than it is to pay $25,000 a well.

So we have wired two of the wells, put motors on two of the wells, are putting control boxes on two of the wells and stringing flow lines to two of the wells in order to try and activate them. But if it comes in at 25,000 and I don't have that done, I'll take all that equipment off and plug them because I can't afford to pay $25,000 per well.

So with that, I'll close and stand for any questions.

MR. BROOKS: No questions.

MR. LARSON: No questions.

COMMISSIONER MARTIN: No.

CHAIRWOMAN RILEY: I don't have any.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Do your number of wells and economic analysis fall pretty much in line with Mr. Marker?

A. It's all the same. Yeah.

Q. But you can do the same thing. If you have a $25,000 bond per well, after two wells, it makes more sense to have a blanket bond.

A. Forgive me?

Q. If you have two wells at 25,000, it makes more sense on your third well to have a blanket bond for 50,000?

A. Correct. Yeah.

Q. So I think you maybe understand that the quandary that we're facing here. You guys are -- you're the good guys. You're doing everything right. You're on the up-and-up and making sure you're responsible for your properties, and there are some people that don't do that. And, unfortunately, they make it harder for everybody else.

A. Right.

Q. That's why the OCD is asking for a regular surety. You guys aren't the problem. We want to make sure that we don't get rid of the good guys or the bad guys, right?

So is there maybe some compromise levels, somewhere in between the IPANM proposal and the OCD proposal that might bring a little more comfort to an operator like you?

A. Currently, we have about $7,200 on each well -- on each of the three wells that is held at the bank for bond. That's below our plugging cost, so it's easy for us to justify that. If we were to do the $5,000 and $4 a foot, we need -- "we" meaning the royal we in the room. It's your decision, not mine. But if that decision was made, it becomes -- it becomes a teeter-totter for us because it's just over that $10,000. It would be $13,000 or 13,5-, something like that, on a per-well basis we'd have to post. So if we did that, that would be -- each would be $30,000, still below the $50,000 blanket bond. But if -- if we do a $50,000 blanket bond, it's still cheaper for me to plug three wells than it is to --

Q. Now, is there a way that you could demonstrate to Daniel, for example, that your plugging cost is $10,000 -- 8- to $10,000?

A. That the plugging cost is --

Q. 8- to 10,000 and not 25,000.

A. Yeah. We can put an AFE together very easily.

Q. I don't know about you, but I haven't seen an AFE come in on target yet.

A. Well, we've -- we've -- you know, because of the way we operate, we don't AFE anything because, you know, what we're doing is maintenance -- maintenance,

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repair and operations.

Q. But you have a receipt from the same field for plugging a well, maybe, that shows that it's 8- to $10,000?

A. Yeah. You know, that can be done.

Q. So maybe the thing to do is for the individual bond, put a little language in there that allows for a variance if you can demonstrate that your cost is significantly lower.

A. We'd -- we would welcome that kind of change to it.

Q. Okay. Thank you.

A. Thank you.

CHAIRWOMAN RILEY: Are there others out there that would like to make a comment?

I don't have anybody else on the list.

So that concludes public comment time.

Any other matters of business we need to take care of before we close down and go into deliberation?

MR. BRANCARD: I believe the parties would like final closing statements.

CHAIRWOMAN RILEY: Okay.

MR. BROOKS: Do you want to proceed with those now?

CHAIRWOMAN RILEY: How are you doing?

(The court reporter responds.)

CLOSING ARGUMENT

MR. BROOKS: Madam Chair, Honorable Commissioners, I'm going to be brief here, just a couple of -- or just a few points I want to make.

One is that adequate bonding will prevent or will minimize the necessity to pursue litigation against operators in bankruptcy court or otherwise to recover costs of plugging. I led my witness through the provisions of the Oil and Gas Act on the subject of priority of funding plugging operations, and it's very clear that the -- to me and I would argue it should be clear to any reader that the legislature intended our primary resource to be financial assur- -- operator financial assurance that we're forfeiting.

First of all, we can't actually, in a practical manner, forfeit it until we plug the well because you have to prove damages to recover from the surety company, and we don't want to litigate with the surety companies. They usually pay up promptly.

So what we do is we plug the well, then we forget the bond, and then if the bond is not adequate, we've got to decide how we're going to get back the rest of the money, which we have a right to, from the

operators, but we have to file suit. And it may be in bankruptcy, and there may be costs involved in that. There definitely will be some costs, and they may be large. And there is an uncertainty of getting your money back, because if it's in bankruptcy, you may not get it all, and if it's not in bankruptcy, you may find you get a judgment that can't be collected. We avoid all those problems if we have adequate financial assurance to cover the cost of the plugging.

The next point I want to make is about federal wells. I believe it is very unlikely that the State of New Mexico would ever, under any circumstances, have a claim or cause of action that could be enforced against the United States for plugging any well unless we had an express contract with the United States to bring that claim in a court of United States Court of Claims. I just don't think it would ever happen.

Now, we have worked the BLM, as Ms. Marks testified, since she's been in charge of that and before that, when I was in charge of it. And Ed Martin was in between us there. He was in charge of plugging operations before he left -- before he defected to the State Land Office. But under everybody that's been under it, there's been an effort to work with the BLM. Sometimes we've worked with the BLM successfully.

Sometimes we've not.

But the point is the State of New Mexico has an interest in getting wells that need to be plugged. If they are not plugged, they may affect correlative rights by reducing the production available from wells that are producing, and they may cause environmental damage from subsurface conditions. So the State of New Mexico has a responsibility to our citizens to see that wells are plugged when they need to be plugged, even if they happen to be on federal land and we are not able to make satisfactory arrangements with the United States Bureau of Land Management or if they're on tribal land and we're not able to make satisfactory arrangements with the tribe.

Now, contrary to what was suggested by the public commenters, I want to assure them that I don't know anybody at the OCD who has any bias against small operators. It is true that we have more noncompliant small operators than we have noncompliant big operators, but it's also true that the police pick up more poor people for vagrancy, back when that used to be allowed, than they do rich people for some obvious reasons.

We are sympathetic to the small operator, and the OCD staff would not oppose making some accommodations, including those suggested by Dr. Balch

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just a few minutes ago. But we do believe that the legislature has directed this agency, and we believe that the Commission should make it our general objective to get every well adequately bonded to the extent it's within our power to do so and it can be done without causing waste. For instance, in some situations where an operator could not bond a well, there might be waste issues, we would not object to adjustments for that. But to the extent it could be done so without waste, it should be, because the legislature has told us that and because it's to the interest of the citizens of the state of New Mexico.

Thank you.

CHAIRWOMAN RILEY: Mr. Larson.

CLOSING ARGUMENT

MR. LARSON: Madam Chair, Commissioners, IPANM acknowledges that the legislature has given the Commission a mandate to increase the blanket of single-well bonding requirements and also acknowledges the need to update bonding levels, which Ms. Marks has testified hasn't been changed since 1977. Nevertheless, the Commission afforded considerable discretion in establishing the tiers of blanket bonding maxed out to the cap of $250,000.

A significant number of IPANM's members are

small independents who operate marginal wells on very tight operating budgets. Given that requiring IPANM's members to tie up significant amounts of what would otherwise be operating capital in Division cash bonds would place a substantial financial burden on them. Consequently, IPANM has proposed blanket bonding amounts that are different from those proposed by the Division, including a fifth tier intended to provide relief for the smallest operators, independent operators who have ten wells or less, as well as reduced bonding amounts for other tiers.

The first tier which IPANM proposes, which is $25,000, for an operator with one to ten wells would significantly reduce the financial burden on these operators and help them to maintain their financial viability. IPANM's proposed reduction would also make the bonding requirement less of a barrier to entering for entrepreneurial independents who would like to conduct oil-and-gas operations in New Mexico, particularly in the Permian Basin.

IPANM also requests reduction in the three tiers for the very same reasons. The reduced bonding amounts free up cash that the operators can utilize for operative costs and other expenses. Again, these bonding amounts will directly impact the financial

viability of these operators to provide jobs and contribute millions of dollars of revenue yearly to the State of New Mexico. The amount of cash tied up in a blanket bond could potentially be a significant factor in the prospects for a small independent operator staying in or going out of business.

The bonding amounts in the proposed rules are insufficient to cover the Division's average plugging costs for the number of wells in any of the tiers. And, thus, the respective bonding amounts are not grounded to any plugging costs equivalency. Given that, IPANM believes that the Commission, in the exercise of discretion, should take into account the significant financial burdens that the bonding requirements would place on small independent operators and weigh those burdens against the regulatory issues raised by Ms. Marks.

And in sum, IPANM requests that the Commission adopt its proposed changes to the plugging financial assurance amounts proposed by the Division.

CHAIRWOMAN RILEY: Thank you.

Anything else we need to take care of?

MR. BRANCARD: No.

CHAIRWOMAN RILEY: Is there anything else before we close and go into deliberation?

MR. BRANCARD: You can't close the meeting. You deliberate in public.

COMMISSIONER BALCH: No matter how much you want to.

CHAIRWOMAN RILEY: Yeah, I know.

MR. BRANCARD: I think we're done, and I think the record is -- the Commission can always re-open the record if necessary.

CHAIRWOMAN RILEY: Okay.

MR. BRANCARD: At this point, you'll begin your deliberations today and tomorrow for the Commission meeting. So you can start the discussion and see how far you can get on this so far today.

CHAIRWOMAN RILEY: Okay. Is that okay with the Commissioners?

COMMISSIONER BALCH: Works for me.

CHAIRWOMAN RILEY: Are you okay with that?

COMMISSIONER MARTIN: I'm good.

CHAIRWOMAN RILEY: All right. Let's begin deliberations.

MR. BRANCARD: Mr. Feldewert?

MR. FELDEWERT: Madam Chair, members of the Commission, I'm sorry to interrupt. There are some other matters on the docket. Is it safe to assume you'll get to those in the morning?

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CHAIRWOMAN RILEY: I believe you are safe in assuming that.

MR. FELDEWERT: Appreciate that. Thank you.

MR. BRANCARD: Mr. Brooks, did you submit another exhibit?

MR. BROOKS: I did. I think I handed copies to everyone, Exhibit Number 12, which is the proposed change in definition of the --

MR. LARSON: I don't think it was admitted into the record.

MR. BROOKS: Okay. I will then offer it as an exhibit.

CHAIRWOMAN RILEY: Do you have any objections?

MR. LARSON: No objection.

CHAIRWOMAN RILEY: Okay. So Exhibit Number 12 is admitted into the record.

(NMOCD Exhibit Number 12 is offered and admitted into evidence.)

MR. BROOKS: Okay. Thank you.

CHAIRWOMAN RILEY: Thank you.

(Open-session deliberations, 3:58 p.m.)

CHAIRWOMAN RILEY: Do you guys want to start this from the beginning, tackle the definitions

first --

COMMISSIONER BALCH: Sure.

CHAIRWOMAN RILEY: -- because those ought to be fairly easy?

The first change is measured depth. Everybody comfortable with that change?

COMMISSIONER MARTIN: Yup.

COMMISSIONER BALCH: Yup.

CHAIRWOMAN RILEY: As am I.

Everybody okay with "temporary abandonment," adding "or temporarily abandonment status" for clarification?

COMMISSIONER BALCH: Is that additional language because of another OCD form?

MR. BRANCARD: I believe the phrase is used in the financial assurance rule because it's a phrase that's in the statute. So normally throughout the rules, we use the phrase "temporary abandonment." But in the financial assurance provision in the Oil and Gas Act, it uses the phrase "temporary abandoned status." So the attempt here is to try to make it clear that those two phrases mean the same thing. So it's used several times in the financial assurance rule because that's the phrase that's used in the statute.

COMMISSIONER MARTIN: I'm not sure that

they're the same thing in reality. I don't think all the temporarily abandoned wells have a temporary abandonment status.

COMMISSIONER BALCH: Status has -- notated as temporarily abandoned.

COMMISSIONER MARTIN: OCD has approved the temporary abandoned status.

MR. BRANCARD: But if I may, Commissioner Martin, these two phrases are different from the phrase "approved temporary abandonment," which is an entirely different concept under Rule 25. So, basically, "temporary abandonment" is another word for "inactive."

COMMISSIONER MARTIN: Yes. I agree with that.

MR. BRANCARD: So once you're inactive, not producing, the clock starts ticking. And then at a certain point, you have to get into temporary -- approved temporary abandoned status. Otherwise, you're not in compliance with Rule 25. So this definition has nothing to do with approved temporary abandoned. It's just "temporary."

CHAIRWOMAN RILEY: I think it's just a point of clarification. I'm good with it.

COMMISSIONER BALCH: I'm okay with it. I was just curious why we had to have it.

COMMISSIONER MARTIN: I'm good, too.

CHAIRWOMAN RILEY: Cleanup.

And the last one would be true vertical depth.

COMMISSIONER BALCH: I'm comfortable with the definition as long as you strike the second sentence.

CHAIRWOMAN RILEY: Did he keep the same --

MR. BRANCARD: OCD Exhibit 12?

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: Which is the same thing, I believe.

MR. BRANCARD: No. There is a difference in elevation.

COMMISSIONER BALCH: Ah, I see. "At the well's surface location." I actually like that. That's better. It matches my little diagram that I made.

CHAIRWOMAN RILEY: Wait a minute.

COMMISSIONER BALCH: The well could -- the touchdown point of the well could be at a higher elevation -- could have a higher elevation than the well, so it specifies it measuring from the well.

CHAIRWOMAN RILEY: Uh-huh. Okay.

COMMISSIONER BALCH: It's my job, of trying to find the exception to everything.

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CHAIRWOMAN RILEY: Uh-huh.
COMMISSIONER BALCH: Actually, I would move to adopt this language.
COMMISSIONER MARTIN: I agree. I second.
CHAIRWOMAN RILEY: So moved.
Okay. That was easy.
That gets us to 19.15.8.9.
COMMISSIONER BALCH: I'm wondering if perhaps we -- that's going to be the main part of the discussion.
CHAIRWOMAN RILEY: Uh-huh.
COMMISSIONER BALCH: But we could clean up some of the other parts of it probably rather quickly.
CHAIRWOMAN RILEY: Are you saying you don't want to go in a linear fashion?
COMMISSIONER BALCH: I'm saying I want to skip ahead. I don't know. Well, there's the effective dates, but I think those are going to be driven by when we can get this processed. We can go linear.
CHAIRWOMAN RILEY: Okay.
COMMISSIONER MARTIN: Inclusion of federal wells may be a shorter discussion. Do you want to talk about that?
COMMISSIONER BALCH: I would like to talk about inclusion of federal wells.

CHAIRWOMAN RILEY: I don't know how short it will be.
COMMISSIONER MARTIN: Shorter than this one.
COMMISSIONER BALCH: It's how do you count the number of wells, right?
CHAIRWOMAN RILEY: Uh-huh.
COMMISSIONER BALCH: One example was from the public commenter, with 18 or 19 wells, and two of them are state and the rest of them are federal. It puts them into a whole different category of compliance.
COMMISSIONER MARTIN: Right. I don't think we should include federal wells in the well count. It seems unfair and illogical to me.
Your turn.
CHAIRWOMAN RILEY: Wait. Who wants to go next (laughter)? Maybe I'll be the tiebreaker.
COMMISSIONER BALCH: No. Actually, I tend to agree with Mr. Martin. I'm just not sure how we -- how we address the other comments from testimony, that we may -- we will have to close up a federal well, plug it with no real guarantee that we'll get the money back. I think in general that's not the case. So I'm not sure how to address that, but I think it's a little bit unfair, and particularly unfair to this gentleman

(indicating) on what he's doing.
COMMISSIONER MARTIN: I don't think he's the only one. I don't think it happens -- I'm not saying it doesn't happen. Okay? And so far it hasn't happened enough to justify penalizing all the operators that have a predominant number of federal wells, I don't think.
CHAIRWOMAN RILEY: I think our problem is we don't -- I don't know whether we have enough statistical data, really, to do that.
COMMISSIONER MARTIN: That's possibly true.
CHAIRWOMAN RILEY: I haven't been here very long, but I've done a lot of looking at those operators that are having issues with compliance and looking at their financial assurance situation, and it's fairly dire. And I don't -- the federal bonding at $25 for a statewide blanket bond --
COMMISSIONER BALCH: 25,000.
CHAIRWOMAN RILEY: -- 25,000 and 150,000 for a nationwide. Say you've got an operator who has operations across the nation, $150,000 is not very much money.
COMMISSIONER MARTIN: No.
CHAIRWOMAN RILEY: And so the reality is that the burden could truly come back to the State for

federal wells if that's all there is to cover that.
COMMISSIONER BALCH: I think it actually could. When I was cross-examining Ms. Marks, I could not get a feel that that was a very common occurrence.
CHAIRWOMAN RILEY: Okay. But you also have to look, too, that the federal government has a different way in which they deal with inactive wells, idle wells, all that stuff. They do require permission to have a well shut in. It can require you to do MITs, but it doesn't require they do that very often. They have a temporary abandonment program as well, but what they call an idle well -- and I'm just -- I haven't worked in it in a while, but my recollection is it's a seven-year scenario, where it's not even considered idle until seven years.
COMMISSIONER MARTIN: That's right.
CHAIRWOMAN RILEY: So if you've had last production, you know, at some point and then you get an additional seven years before they're even coming to knock on your door. So they have a much less stringent procedure in dealing with these. And I don't know how active they're really being on that. In fact, I think they're getting a lot of criticism nationwide for lack of pursuing these idle wells.
COMMISSIONER BALCH: Still, if do you have

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to close -- if you do have to plug a federal well, you're not completely without recourse. You can take them to court and sue them. You can, Hey, we really need to close this, and then reimbursement is this for later on. And I think that that's -- the sense that I got was in most cases, that is what occurs and they did get the money back.

MR. BRANCARD: Well, I don't think that's what the testimony was. I think the testimony was that the agency was able to obtain a grant from the federal government probably for specific wells that the federal government wanted plugged. Basically, the State is basically acting as a contractor --

COMMISSIONER BALCH: Right.

MR. BRANCARD: -- to do these wells and using the State's contractor as a subcontractor.

CHAIRWOMAN RILEY: Correct. Bank.

MR. BRANCARD: Right? Because that was more efficient for the federal government to do it that way. So my sense from the testimony is they had to apply for that funding to get it in order to even do that. It wasn't, Oh, we went out and plugged your well; can you pay us? I don't know that that would work.

And, you know, legally, I agree with, you know, with Mr. Brooks, that I don't think the State

really has much recourse. I mean, I can tell you, you know, on the mining side, there is a prohibition for duplicating federal financial assurance. So what the State has done is to get financial assurance that is payable to both the State and the federal government so both parties are covered by one bond. That's not what's happening here. You have federal BLM financial assurance and you have OCD financial assurance with two groups of wells.

COMMISSIONER BALCH: But I think that's part of what I'm wrestling with, is it -- it is two groups of wells.

MR. BRANCARD: Right. And here's the problem that, you know, the testimony brought up, is that we have a conflict -- maybe I shouldn't use it that way. We have a disconnect, perhaps, between what the Oil and Gas Act requires and what the reality is of the rules and what's happening on the ground. And what the Oil and Gas Act requires is financial assurance for every well in this state. Okay? What the rules require is every privately owned or state-owned wells. Okay?

So there is an obligation in the Oil and Gas Act that we kind of, sort of push to the side because the federal government has their own bonding program. So that's what the testimony was about, why

federal wells have always been included, because there is actually an obligation under the Oil and Gas Act to bond all wells.

COMMISSIONER BALCH: So in a sense, all wells are bonded because the federal ones are bonded through the federal government.

COMMISSIONER MARTIN: That's absolutely right. And what we're talking about is taking them out of the well count for the purposes of obtaining a bonding level for a particular operator. Including those federal wells that are already bonded seems unfair to me.

COMMISSIONER BALCH: That's giving them double jeopardy. They basically have to bond twice.

MR. BRANCARD: Right. But as I think Mr. Larson's closing statement admitted, the blanket bonds don't cover the actual costs of that number of wells.

COMMISSIONER MARTIN: That's kind of a different question, I mean to me.

COMMISSIONER BALCH: That's -- I mean, that's not our place to tell the federal government what to do, right, when it comes to bonding their wells?

CHAIRWOMAN RILEY: Well, even the blanket bonds -- our blanket bond wouldn't cover -- 250,000 over

100 wells, if we're stuck with all of them, will not get you very far.

COMMISSIONER BALCH: My real concern is the prevention of waste. We had at least one piece of testimony from the public, Mr. McMinn, who said if this passes in this form, he'll shut in three wells.

COMMISSIONER MARTIN: I agree.

COMMISSIONER BALCH: Those are three wells that are making oil for the State of New Mexico.

CHAIRWOMAN RILEY: Is he going to shut those in, or is he going to shut in and then plug them?

COMMISSIONER BALCH: He was going to plug them, plug three wells.

CHAIRWOMAN RILEY: Put a bond on -- and so I come back and argue the other side of that, which is if you can't afford to fix them so that they do produce and then you can't afford to put a bond on them, then maybe they should be plugged.

COMMISSIONER MARTIN: But he's talking about plugging producing wells.

MR. BRANCARD: No.

CHAIRWOMAN RILEY: No, I don't think so.

COMMISSIONER BALCH: Doesn't matter if they're producing or not.

COMMISSIONER MARTIN: Or prospective

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producing.

COMMISSIONER BALCH: He's got them temporarily abandoned for a reason, and that's because he hopes to put them in production later on. If he takes them out of that temporarily abandoned status now and puts them into plugged status, they will never produce another drop of oil.

COMMISSIONER MARTIN: Correct. And for the waste issue, you leave reserves in the ground.

COMMISSIONER BALCH: You leave reserves in the ground, which is waste. Then not only were -- nominally using correlative rights to produce the oil.

And the real issue for me for the federal versus state in the well count is exactly what Mr. Martin said. It's double jeopardy. They're paying bonding twice for the same well. Whether the federal bonding is inadequate or not, whether the state bonding ends up being inadequate or not, it just strikes me as unfair.

CHAIRWOMAN RILEY: I think this is going to reduce the amount of bonding that the State has available, perhaps even less than what we had before. It kind of flies in the face of what the legislature was looking to us for.

COMMISSIONER BALCH: Their idea is to

increase the amount of bond money available.

CHAIRWOMAN RILEY: Uh-huh.

MR. BRANCARD: I don't think it's going to reduce anybody's bond.

CHAIRWOMAN RILEY: I think just overall.

COMMISSIONER BALCH: It won't decrease anybody's bond. It will just keep it the same as it is. It won't increase as much as -- it may not increase as much, though, but it's not going to decrease it.

COMMISSIONER MARTIN: I don't think it'll decrease it. You still get that $250,000 tier.

CHAIRWOMAN RILEY: But there are fewer operators that fall into those categories.

COMMISSIONER BALCH: But no operator is going to be below the existing 50,000 blanket bond.

CHAIRWOMAN RILEY: True.

COMMISSIONER BALCH: So it's not going to decrease the amount of bond money.

CHAIRWOMAN RILEY: But you won't have as many -- yeah. I mean, you're not going to have as many operators that will post the 250, which is the max that they allow for it, so we won't have as many at that.

COMMISSIONER BALCH: It would have been nice to see an OCD economic analysis of what they expected to bring in from additional bond money.

CHAIRWOMAN RILEY: I can tell you it was only looked at from the standpoint of how we historically looked at these well counts. They don't even consider that.

COMMISSIONER BALCH: 56 percent of all operators produce less than ten wells, right?

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: So those aren't going to change. The 44 percent are already going to be carrying the burden. The 23.6 percent --

MR. BRANCARD: But if you make that one to ten just state or private, then it will go above 56, right?

COMMISSIONER BALCH: Actually, we already have some of the numbers. 23.6 percent were between 11 and 50. So that's 80 percent that are between -- that are already less than 50 wells. They're not going to see a large impact -- a large change from what they were already doing. So we're talking about maybe changing that order from -- the 20 percent are paying more than the 15 percent are paying more --

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: -- rather than a huge number of people paying more.

CHAIRWOMAN RILEY: Yeah. It would be nice to see those numbers, but I don't know them off the top of my head.

COMMISSIONER BALCH: Well, we're missing the 51 to 100 and more than 100 on the table. We could always pull back the witness and ask if they have those numbers.

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER MARTIN: I'm still opposed to it philosophically regardless of how the numbers --

COMMISSIONER BALCH: I don't think it's going to change as much as you may think. Only 45 percent are going to have any change, and only 20 percent are going to have more than the 25 --

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: -- the way it's proposed. We haven't talked about the numbers in the distribution either.

COMMISSIONER MARTIN: I think before we do this, we should get some more data to see what the impact to OCD is going to be by doing this.

CHAIRWOMAN RILEY: Okay. Well, we could call back our witness and bring in more data.

COMMISSIONER BALCH: Call back Ms. Marks?

CHAIRWOMAN RILEY: How do we want to see

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this? Do you want to see it run --
COMMISSIONER MARTIN: Maybe we should let her do the research first. I doubt she has the numbers at her fingertips.
COMMISSIONER BALCH: She had two numbers at her fingertips.
COMMISSIONER MARTIN: Oh, yeah?
COMMISSIONER BALCH: She may have the others.
CHAIRWOMAN RILEY: As far as the percentages?
COMMISSIONER BALCH: Yeah. It's just a percentage for total number of operators that have less than 10, 11 to 50, 51 to 100 and more than 100, and then we can tell --
CHAIRWOMAN RILEY: But you need to know -- she's not going to have that until she runs those same numbers and excludes federal, because those will change, theoretically.
COMMISSIONER BALCH: That will change.
CHAIRWOMAN RILEY: So she would have to look at that, at an exclusion of federal.
MS. MARKS: It was a significant change. It was a very significant change, during my lunch break.
COMMISSIONER BALCH: We can put her back on

And more than 100?
A. Sorry. There is a lot of talk.
In the greater-than-100, there were 72 operators, which is 11.7 percent.
Q. 11.7 percent?
A. And so during my lunch break, when the whole federal well issue came up, I started to examine a number of operators in those different -- in these other ranges, and I saw that it would lower -- significantly lower the number of operators in those higher ranges and bring them down into the other ranges because we have historically and always included federal wells in our well count.
And then I started to think about the increase in horizontal drilling and those wells penetrating and to state lease land and private lease land. And I brought up -- and I don't have it with me. It's 40 CFR 3103, I believe, the federal bonding rule, and it all addressed the surface bonding for the federal government and surface waters, everything surface.
So when we talked about the laterals and the horizontal laterals and anything affecting the lands Mr. Martin is responsible for, if we don't have a bond in place to address those wells, we would not have any monies available excluding those --

the stand and verify what we want to ask her.
MR. BRANCARD: So you would like to recall Ms. Marks as a witness --
CHAIRWOMAN RILEY: Yes.
MR. BRANCARD: -- for the single purpose of discussing this?
CHAIRWOMAN RILEY: Yes.
(4:20 p.m.)
ALLISON MARKS,
after having been previously sworn under oath, was recalled, questioned and testified as follows:
CROSS-EXAMINATION
BY COMMISSIONER BALCH:
Q. So we would like the other two percentages. You gave us 56.7 for less than ten wells, right, of the total number of operators?
A. That's correct, 56.7 percent for one to ten operators.
Q. And 11 to 50 was 23.6?
A. 23.6 for the 11-to-50 range.
Q. And 11 to 50 was 23.6?
A. Correct.
Q. What's the number for the 51 to 100?
A. 48 operators, which is 7.8 percent.
Q. 7.8 percent.

Q. So I think having -- having any part of a state-leased lender -- any part of state land on your lease could trigger you having a state bond, or it should?
A. Well, that would be a really interesting -- that would -- that would be a very large shift. And right now I can't pull that data because --
Q. I think what I'm going to ask of you is a little simpler.
COMMISSIONER BALCH: And after I ask it, tell me what you want.
COMMISSIONER MARTIN: Sure.
THE WITNESS: And just to clarify, when we switched over from two different systems, we had just looked at certain parts of it. Basically, it was a federal -- it was a mineral interest. It was surface ownership, and not all the interest ownership was properly kind of --
CHAIRWOMAN RILEY: Can you hold on just a minute?
Mr. Marker, could you please be quiet? We've got a court reporter trying to listen and capture this. So --
MR. MARKER: I'm sorry.
CHAIRWOMAN RILEY: That's all right.

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THE WITNESS: -- all converted. So some of it would just affect federal surface mineral owners.

Q. (BY COMMISSIONER BALCH) I think I'm going to ask you something much more simple.

A. Okay.

Q. Given the table that's proposed by OCD, A, B, C D, for ranges and the percent of operators that you have, assuming everybody gets a blanket bond and nobody does single-well bonds, how much money is that in bond money total?

The next question is: How much do they get right now with the $50,000 blanket bond? How much money do they have in bonds at the 50,000 present level? So I want to know what the baseline is. The baseline is current day before we change the rule.

A. Can I ask a clarifying question?

Q. Sure.

A. Not all those operators do have blanket bonds?

Q. Just assume everybody has a blanket bond, to keep it simple. That'll give us kind of a benchmark. So that's a starting point.

The next question is: With these present levels here, what would the bond level be if everybody had a blanket bond?

A. That was the first question anyway, right?

Q. Yes.

And the third one is: For only state wells or wells that have part of a state lease or whatever, excluding federal only wells, what would those numbers be also?

A. That's one that's a lot more difficult to do, because we had an issue with older wells, and sometimes the data has come in based off of the mineral interest. Sometimes it would be based off of the surface ownership.

Q. How close can you get?

A. I couldn't -- I couldn't be certain, to be honest. We are actively working with our district offices to change all -- to accurately reflect mineral ownership and surface ownership of each well. So if you would like to know based off of surface ownership or mineral interest ownership --

Q. One or the other, right?

A. Well, like I said, I believe the federal government only requires bonding on surface ownership; therefore, leaving the liability to the State of New Mexico. I'd have to consult again. I believe, like I said, it's 40 CFR 3103, federal bonding requirements.

Q. So federal bonding is only for surface?

A. Surface. From the surface and then surface

waters and --

Q. So they don't really plug a well?

COMMISSIONER MARTIN: They plug the lateral anyway.

COMMISSIONER BALCH: They just cap it.

COMMISSIONER MARTIN: They plug the vertical portion.

THE WITNESS: Right.

COMMISSIONER MARTIN: Right.

THE WITNESS: But then, again, if the lateral -- and say there was, on a lateral, and there was any sort of restoration type of activity or anything that we wanted to go into the blanket bond and it was on state land -- lease land, we could use that blanket bond to --

Q. (BY COMMISSIONER BALCH) Is there anything you can do to give us a feel for what the impact of removing federal wells from the count will be?

A. I will certainly try.

Q. Okay.

So the fourth thing would be to take IPANM's numbers and do the same exercise. We wanted to compare the level of bond money available to the OCD in those four scenarios. Does that capture what we want to see?

A. Okay.

COMMISSIONER MARTIN: Yeah.

You're good?

CHAIRWOMAN RILEY: All right. Thank you.

COMMISSIONER BALCH: Just to see what the real difference is, if it's pennies or depending on if it's billions of dollars.

COMMISSIONER MARTIN: But the real question -- there is a third point. What's the difference on the state and private well excluding the federal wells. If we increase bonding on that portion, then I think we let -- you know what I'm saying?

COMMISSIONER BALCH: I don't know what they have required. I don't think any of those scenarios increase it from the third -- just bonding levels -- increased.

MR. BRANCARD: Maybe.

CHAIRWOMAN RILEY: I'm sitting here thinking if we had another portion of our rules like 5.9, which is then --

(All parties speaking at one time.)

COMMISSIONER MARTIN: We do. We do.

MR. BRANCARD: So do you want to reserve this section for tomorrow and then --

COMMISSIONER BALCH: We'll have a lot more

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information to talk about levels after that.
THE WITNESS: Can I ask one clarifying question?
MR. BRANCARD: Yes.
THE WITNESS: On the federal -- the federal well excluded, my understanding is if a well is drilled on state trust land and it penetrates any federal mineral, it would require a federal bond. Correct?
COMMISSIONER MARTIN: I think that's true.
COMMISSIONER BALCH: Well, I think one way to look at it probably would be if the well has any state land in it -- state or private land in it, then -- I don't know.
MR. BRANCARD: Well -- no. Our -- our rules require that you need to get our bonding for a well drilled on privately owned or state-owned lands.
THE WITNESS: Right. But then with our new --
MR. BRANCARD: So the only thing we can exclude from that is something drilled on federal land.
COMMISSIONER BALCH: Okay. It probably simplifies your math.
CHAIRWOMAN RILEY: On federal surface? Is that what you're saying?
COMMISSIONER BALCH: Federal surface, yes.

Exclude federal surface. That's where the bond is.
MR. BROOKS: Madam Chair, I apologize to the Commission for leaving, but I was under the erroneous impression that the testimony and evidence had been closed.
COMMISSIONER BALCH: It was closed.
MR. BROOKS: Well, until Mr. Herrmann came upstairs and told me my witness was back on the stand --
MR. BRANCARD: But the Commission reserved the right to recall witnesses.
MR. BROOKS: But you don't need anything further from me?
COMMISSIONER BALCH: We just gave Ms. Marks some homework.
MR. BROOKS: I'm sure she can handle it.
(Open-session deliberations continue, 4:29 p.m.)
COMMISSIONER BALCH: I would like to bring up the concept of putting in a variance clause or a number in there for the case where you can conclusively demonstrate to the Division office that your plugging costs are going to be lower, that you could get a lower individual well bond.
COMMISSIONER MARTIN: I'm okay with that.
COMMISSIONER BALCH: That would be the

variance, so it's up to the discretion of the office. They can weigh any number of factors, including the viability of the operator, to whether or not they would grant that variance.
COMMISSIONER MARTIN: I'm good with that.
COMMISSIONER BALCH: So that would require variance language as part of or associated with 8.9C.(1) and D.(1).
CHAIRWOMAN RILEY: You have to keep in mind --
COMMISSIONER MARTIN: Yeah.
CHAIRWOMAN RILEY: -- that even though we're hearing more from the small operators today, that these also apply to the bigger wells and also apply to injection wells.
COMMISSIONER BALCH: There is absolutely no question for the wells that were closed in the last four years that the 25,000, plus $2 per foot fits extremely well, and that's a very good number. But I think you do want to allow the possibility, if someone can demonstrate that their 500-foot shallow wells only cost them $6,000 to close very reliably, they can get a variance.
COMMISSIONER MARTIN: Right. Right.
COMMISSIONER BALCH: It doesn't mean

they're going to get it. It means they can ask for it.
MR. BRANCARD: How about this as language: "As an alternative, an operator may propose an estimated cost of plugging a well based on actual costs of similar wells in similar location"?
COMMISSIONER BALCH: Uh-huh.
COMMISSIONER MARTIN: Sure.
COMMISSIONER BALCH: That would be good.
COMMISSIONER MARTIN: There could be other factors, too, if a well operator has his own rig, for instance.
COMMISSIONER BALCH: Exactly.
MR. BRANCARD: Well, but the problem is --
COMMISSIONER BALCH: They're not closing it in their case.
MR. BRANCARD: They're not -- remember, the financial assurance is designed to cover the cost if the State has to step in.
COMMISSIONER BALCH: As compared to what the State's cost --
COMMISSIONER MARTIN: But the State would not have to step in if it could compel the operator to plug his own well.
MR. BRANCARD: Right. But the financial assurance cost is not for --

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COMMISSIONER MARTIN: The cost would be lower.

MR. BRANCARD: -- their benefit. It's for the State's benefit.

COMMISSIONER BALCH: I think the way Mr. Brancard wrote it is fine. That's probably going to be sufficient.

COMMISSIONER MARTIN: I'll think about it. Okay. I see what you're trying to do. I understand your point.

CHAIRWOMAN RILEY: The problem is that at the point we need the bond, it's going to be --

COMMISSIONER MARTIN: That's true. Yeah.

COMMISSIONER BALCH: It has to be a cost the State would incur.

COMMISSIONER MARTIN: That's true.

COMMISSIONER BALCH: I like putting the variance in because most of the rules we've done in the last seven years include that sort of language, and it allows exceptions for exceptional cases.

COMMISSIONER MARTIN: I agree.

COMMISSIONER BALCH: A variance for unusual circumstances, I should say. Exceptions are different.

CHAIRWOMAN RILEY: Yes, they are.

So there weren't any changes to D as far

as --

COMMISSIONER BALCH: We talked about moving E above C.

CHAIRWOMAN RILEY: Making it C?

COMMISSIONER BALCH: Making it C and moving everything else down.

CHAIRWOMAN RILEY: Uh-huh.

MR. BRANCARD: Well, what -- okay. But would it be preferable to move E -- or at least after the first clause at E, starting with "the depth of a well," into C.(1) and D.(1)?

COMMISSIONER BALCH: Well, I think you could just change the language in C.(1) to "a one-well financial assurance amount, 25,000, plus $2 per foot of the projected length of a proposed well or the measured depth of the existing well." If you put that same language in C.(1) and D.(1), then you don't need E at all.

MR. BRANCARD: Well, would you have to say proposed -- you'd have to cover all the conditions, which is "the measured depth for deviated and directional and true vertical depth for vertical and horizontal." That's kind of a mouthful.

COMMISSIONER BALCH: In that case, I would just put it above C or put the same clause into -- you'd

have to rewrite C.(1) and D.(1), which already have a different thrust. Becomes cumbersome, maybe.

CHAIRWOMAN RILEY: I think --

COMMISSIONER BALCH: I'm trying to figure out a way to move E above C.

I do have a question on 19.15.12. And there were some suggested changes to the language there, to 33-and-three-tenths. I don't know why they don't just say one-third.

CHAIRWOMAN RILEY: This is an I.T. issue, that it's hard for them to calculate that.

COMMISSIONER BALCH: Well, I would say we change it to say "one-third rounded to the nearest lower whole number," or round it down. If we take five wells, as the example, right, and divide that by three, you end up with 1.77. So you would round that. That would still end up being one well that you could plug. So I think "one-third of the well rounded down" would take care of it pretty clear.

CHAIRWOMAN RILEY: Allison isn't here. When she comes back, we might want to ask her because she worked this out with the capability of I.T.

COMMISSIONER MARTIN: Keeping I.T. happy is probably wise.

COMMISSIONER BALCH: Does she have language

in there for rounding down?

MR. BRANCARD: I don't know.

CHAIRWOMAN RILEY: No.

COMMISSIONER BALCH: I think you need to round to the nearest whole number. I think they technically call it truncating.

MR. BRANCARD: So five would be one as opposed to two?

COMMISSIONER BALCH: Five would be one, yeah.

CHAIRWOMAN RILEY: I'm good with that.

COMMISSIONER MARTIN: I'm okay.

COMMISSIONER BALCH: Any fractional well, as far as I know.

MR. BRANCARD: I think you're correct, but figuring out whether you're rounding down or up is important. Right? Because if you have eight wells, that's 2.66. You can round that up to 3 or round it down to 2. Where do we want to go with that?

COMMISSIONER BALCH: Actually, I almost don't mind just rounding up. We do have to pick one.

CHAIRWOMAN RILEY: Using rounding rules, down if it's .5, up --

COMMISSIONER BALCH: Rounding to the -- I'd say rounding to the nearest whole number would take care

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of that. So 2.6 would become 3, and 1.4 would become 1. I'm comfortable with that.

COMMISSIONER MARTIN: (Indicating.)

COMMISSIONER BALCH: As long as we don't have fractional wells being temporarily abandoned.

COMMISSIONER MARTIN: Temporarily partially abandoned.

COMMISSIONER BALCH: So a little change in language, that would be just fine.

CHAIRWOMAN RILEY: Okay. So does that mean we're good with all of .12. Do you guys have any issues?

COMMISSIONER BALCH: Just the language we have to fix when we get a fresh version.

Do you want to incorporate the OCD language, which is "33-and-three-tenths percent for more than five wells"?

It might be worth -- at some later time when we can query Ms. Marks, but I would really change the language to say something more like "one-third of the wells rounded." It can go into "temporarily abandonment."

MR. BRANCARD: I would say B, "For more than five wells, one-third of the wells rounded to the nearest whole number."

COMMISSIONER BALCH: At this point, you don't even really need A because A would apply the same way.

MR. BRANCARD: Because then A, five wells would get to two.

COMMISSIONER BALCH: Yeah, I suppose. All right. Yeah. I would change the language from the 33-and-three-tenths, if we possibly can. That's not a third anyway.

CHAIRWOMAN RILEY: Technically, it isn't.

COMMISSIONER BALCH: It's off by .03333333.

CHAIRWOMAN RILEY: Which is, I believe, why I.T. had a problem with it.

COMMISSIONER MARTIN: I believe that's right.

CHAIRWOMAN RILEY: So can we please see the cleaned-up language on this, and then we'll make a final decision on 12?

COMMISSIONER MARTIN: Yeah.

CHAIRWOMAN RILEY: But conceptually, we're good?

COMMISSIONER BALCH: And I'm fine with 13, which is basically saying we're not going to approve it until you have the assurance.

CHAIRWOMAN RILEY: Uh-huh.

Are you good with --

COMMISSIONER MARTIN: Yeah.

MR. BRANCARD: Well, then the other issue which I requested a response, we didn't get, which is we need effective dates.

COMMISSIONER BALCH: You know, really, I didn't think the October dates were going to work because they were too close to the end of the rulemaking. But I'm wondering if you should not give a longer grace period for operators that are going to have to come up with another 40-, $50,000 to comply.

MR. BRANCARD: So I think the idea in 8.14 is that it becomes effective pretty close to immediately upon effective date of the rule for anybody applying for a new well --

COMMISSIONER BALCH: Uh-huh.

MR. BRANCARD: -- or deepen or plug back a well.

COMMISSIONER BALCH: Which is fine.

MR. BRANCARD: Right?

And anybody during that period now kicks into having to get temporary abandonment status.

COMMISSIONER BALCH: Originally, we gave them like six months.

MR. BRANCARD: Those are the two categories

that it's effective almost -- almost immediately under what was proposed, but we could make it the effective date. And then they gave more months basically for everybody else, so all existing wells that transition over.

CHAIRWOMAN RILEY: So if you're changing your status, you have to do it right away.

MR. BRANCARD: If you're changing your status, the rule's effective when it's effective, or we could put another date on there.

COMMISSIONER BALCH: Well, a little grace period might not hurt, particularly for smaller operators that might have to cough up an extra large chunk of their capital. I would hate to have a situation where they're driven to walk away from their field because they can't come up with the money fast enough. So a reasonable amount of time I think would good.

MR. BRANCARD: I mean, based on the testimony, you know, 43-plus percent of operators, if they have a blanket bond, will have to increase that blanket bond.

COMMISSIONER BALCH: Uh-huh. Yup.

MR. BRANCARD: Okay?

And then everybody who has a single-well

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bond will either have to increase that single-well bond or get a blanket bond.

COMMISSIONER BALCH: Right.

And I hadn't realized how much a bond would cost. I was really glad that Mr. Marker had given that analysis. That's a third of the money, plus 2 or 3 percent per year in fees. So that would be pretty substantial, a cash bond. It's not a big deal if you're Chevron, which is I guess why they're not in the room.

MR. BRANCARD: So do you want to discuss that further, then, the transition dates?

COMMISSIONER BALCH: I have no problem making it effective immediately for new or change of status. But for existing bondholders or a different category, I think they should be given a reasonable time period to comply. I'm not sure what reasonable is. Three to six months seems like something that would be all right. The original rule -- rule was written in March or May?

MR. BRANCARD: It was submitted in March, and the hearing was supposed to be in --

CHAIRWOMAN RILEY: May 24th, I think.

MR. BRANCARD: -- May. So they were sort of assuming that July was probably when it was going to become effective.

COMMISSIONER BALCH: So they were giving six months from the time of the hearing -- six months from the time of the hearing today would be in January, end of December.

MR. BRANCARD: So if this became effective -- we could just make -- we could just leave the first date blank.

COMMISSIONER BALCH: Uh-huh.

MR. BRANCARD: Right? So when we submit the rule, we will know what the effective date is, and we can fill in the effective date. And the second date you can say is three months from now, so you can fill in that date --

COMMISSIONER BALCH: Or six months.

MR. BRANCARD: -- or six months or whatever.

COMMISSIONER BALCH: Okay. Is there a time period that gives you a feeling of justice being done?

COMMISSIONER MARTIN: I'm good with whatever you guys want to. Whatever grace period is acceptable, I'm agreeable. I don't have a better one.

CHAIRWOMAN RILEY: I think three months is --

MR. BRANCARD: The only thing is that if -- by my calculation, if it gets published in the "New

Mexico Register" on September 24th, three months from then is Christmas.

COMMISSIONER BALCH: December 24th.

MR. BRANCARD: Yeah.

COMMISSIONER BALCH: There goes the Christmas bonus.

We could do four months.

CHAIRWOMAN RILEY: That puts it into next year.

COMMISSIONER BALCH: Doesn't matter except bigger bond picture, I guess.

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER BALCH: Really, the bigger bond pool just reduces the exposure of the reclamation fund, right?

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: Doesn't give you any money.

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: It reduces possible expenditures from that other --

COMMISSIONER MARTIN: Correct.

CHAIRWOMAN RILEY: It can change our P&A program if we would have a better -- if we were juxtaposed better, we can get some of these abandoned

wells off the books, and we'd have the funding to do it.

MR. BRANCARD: So four months?

COMMISSIONER BALCH: I'd say four months.

With that, I think we're waiting for Ms. Marks.

CHAIRWOMAN RILEY: Okay. So shall we adjourn until tomorrow and start this back up tomorrow?

COMMISSIONER MARTIN: That's what I would suggest, give her some time to look it over.

CHAIRWOMAN RILEY: Yeah. Okay. So let's adjourn. We're off the record. We'll start back up tomorrow morning at 9:00.

COMMISSIONER MARTIN: Sounds good.

COMMISSIONER BALCH: Sounds good.

CHAIRWOMAN RILEY: Thank you, everybody.

(Recess, 4:48 p.m.)

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STATE OF NEW MEXICO
COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, Certified Court Reporter, New Mexico Certified Court Reporter No. 20, and Registered Professional Reporter, do hereby certify that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings that were reduced to printed form by me to the best of my ability.

I FURTHER CERTIFY that the Reporter's Record of the proceedings truly and accurately reflects the exhibits, if any, offered by the respective parties.

I FURTHER CERTIFY that I am neither employed by nor related to any of the parties or attorneys in this case and that I have no interest in the final disposition of this case.

DATED THIS 28th day of August 2018.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2018
Paul Baca Professional Court Reporters

EXHIBIT 27

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

IN THE MATTER OF THE:

PROPOSED AMENDMENTS TO THE COMMISSION'S RULES ON FINANCIAL ASSURANCE AND PLUGGING AND ABANDONMENT OF WELLS, 19.15.2, 19.15.8, AND 19.15.25 NMAC. CASE NO. 16078

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSIONER HEARING

July 20, 2018

Volume 2 of 2

Santa Fe, New Mexico

BEFORE: HEATHER RILEY, CHAIRWOMAN
ED MARTIN, COMMISSIONER
DR. ROBERT S. BALCH, COMMISSIONER
BILL BRANCARD, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Friday, July 20, 2018, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

REPORTED BY: Mary C. Hankins, CCR, RPR
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(10:25 a.m.)

CHAIRWOMAN RILEY: Let's now move on to the deliberations of the FA rule.

MR. BRANCARD: Madam Chair, before we get started, Commissioner Balch had asked me at the end of the discussions yesterday about what was the exact language that was in the statutory change so that the Commission could have a sense of just exactly what they're being asked to do and how it fits in with what the statute says.

CHAIRWOMAN RILEY: Okay. Would you please?

MR. BRANCARD: I didn't have that language in front of me, and I have it now.

CHAIRWOMAN RILEY: Okay. Thank you.

MR. BRANCARD: Okay? The prior language said, at the beginning of the sentence, before we get into talking about temporarily abandoned status -- for now I'll just focus on the blanket -- the generic blanket bond. The prior language said, when it talks about "the division shall establish categories of financial assurance after noticing such categories blanket financial assurance in an amount not to exceed $50,000." Okay? That's what the statute used to say. So whereas 50,000 was capped at 50,000, it could have been less, but by rule, this Commission has set that at

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50,000, period. Okay?

The new statute says: "Such category shall include a blanket plugging financial assurance which shall be set by rule in an amount not to exceed $250,000." So the "not to exceed" goes from 50- to 250,000, but basically directs the Commission to establish this rule to implement that.

COMMISSIONER MARTIN: Right.

MR. BRANCARD: I mean, the other part of the Act that has not changed but is sort of the basis for the discussion about the one well, what we call the single-well bond -- the statute calls it a one-well bond -- in listing the categories of financial assurance it says: "Includes a one-well plugging financial assurance in amounts determined sufficient to reasonably pay the cost of plugging the wells covered by financial assurance." Okay?

It then goes on to talk about: "In establishing categories of financial assurance, the agency shall consider the depth of the well involved, the length of time since the well was produced, the cost of plugging similar wells and such other factors as the agency deems relevant."

So those are the two things here, is the increase from 50- to 250- for the blanket and then

implementing the provision in the Act requiring that the one-well bond be in amounts sufficient to reasonably pay the cost of plugging the well. So that's your statutory guidance in this situation.

CHAIRWOMAN RILEY: Thank you.

I think at this point it would be appropriate to bring back up the witness -- the OCD witness, Allison Marks. She was tasked with providing some additional documentation, and it looks like she's come with that.

ALLISON MARKS,

after having been previously sworn under oath, was recalled, questioned and testified as follows:

THE WITNESS: I did also just -- I didn't make a ton of copies, but I had referred to a global bonding compliance report. This is what that report looks like. There are a lot of pages here, but all the operators who are out of compliance with our current bonding is here. You can just look at that. It's not really an exhibit but so you can see there.

And then I thought it might be helpful -- I have lots of copies of these, too. Mr. Marker was here yesterday. This is what his sites look like (indicating).

MR. BRANCARD: I don't think the Commission

asked for that. Okay?

THE WITNESS: I thought it might be helpful to see what the sites look like.

MR. BRANCARD: No. The Commission asked for, I believe, four things yesterday.

THE WITNESS: We'll start with -- we'll start with --

MR. BRANCARD: So the first request I think was what is --

Let me get this straight, Commissioner Balch, and you can step in.

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. Under the current rule, with a $50,000 blanket bond, if every operator had to get that blanket bond, what would be the dollar amount?

Is that correct?

A. That was a simple calculation. With 613 operators times $50,000, it's $30,650,000.

Q. 30 million --

A. $650,000. 613 operators times $50,000, which is $30,650,000.

I think -- I think -- I also did try -- it's not 100 percent accurate, but with the actual blanket bonds we do have on file right now, there's like

493 bonds, it doesn't add up. It's not completely right because it's not an even number, but we have about $24,837,501 in blanket bonds right now. It should be an even number. It's not. But this is what comes up when we queried it from our system.

And then in single-well bonds, we currently have 1,917 bonds, which is $20,842,382.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. What is the total for two then would be what? What is the existing amount of bonds?

A. Depending on the count [sic], it would be $5,000, plus $1 per foot or $10,000, plus $1 per foot.

Q. Okay. Were you able to come up with the actual number in bonds right now, today?

A. Yes. Those are the numbers that I was just -- plus, if we added in the amount of TA, temporary abandoned blanket bonds, that would add an additional 16,900- --

Q. Well, I think we're just worried about the wells that are in Category C right now.

CHAIRWOMAN RILEY: Could you repeat those numbers?

THE WITNESS: Sure. Category C, the active -- well, that would be a little bit of a

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different query, which I didn't run, because some people would have single-well bonds for active -- for active wells, and if you have an active well with just a single-well bond, you wouldn't then place an additional single-well bond when the bond becomes inactive after two years. The single-well bond covers -- and that would stay the same under the proposed rule. So you wouldn't need two single-well bonds for an inactive bond.

So the number of single-well bonds, there could be an overlap because you could have an active well that becomes inactive. So our single-well bond total would include active wells under C and single-well bonds under D.

Q. (BY COMMISSIONER BALCH) Okay. So we really can't use that number effectively right now.

A. Right.

Q. So the best number we can probably use is a fixed [sic] $30 million for everybody having a $50,000 blanket bond.

A. Right.

Q. Okay.

A. So then I know you had asked for a well count -- or to take the well count, which is the spreadsheet before you not labeled "Excluding Federal

Wells," and I put the column "Bonding Under OCD Proposal" and "Bonding Under IPANM Proposal." Put in all the proposed levels and then used an AutoSum. And at the bottom, you will see, under OCD's proposal, the total will be $51,900,000. And under IAPNM's proposal, the total would be $33,825,000. So assuming the $30,650,000, there would be just about a 10 percent increase. However, I also did, when playing with these numbers, saw that the disproportionate increase would be borne by the larger operators whose bonds we actually don't redeem. So the larger operators would put -- they would put more money into the rec fund, and then they would share a disproportionate amount of bonding whose bonds we don't actually redeem. So that did stick out.

I did a lot of research. And, actually, if you're interested, I had a great conversation with Wyoming this morning, and they have a $100,000 statewide blanket bond that's mandatory there. And they're looking at a tiered approach in Wyoming right now with keeping that minimum -- minimum $100,000 and increasing it to over $100,000.

And then we discussed what they do with laterals in Wyoming, whether they penetrate on state land with the increasing lateral depths. They have three-mile-long laterals near Casper and four-miles in

North Dakota. So they're looking at requiring the bonding for just the laterals going into an estate land, and they're extremely worried about making sure they have requisite bonding to cover all those -- to cover all those laterals.

You had asked about the ability to differentiate between the minerals and the surface. And so when we went into the -- transferred to ONGARD on our system, we actually didn't capture all that data, so we'd have to go through 58,000 or so wells. We don't have all that data. We haven't captured all that data in our --

Q. That gives us -- so the second document --

A. The second document does have "Excluding Federal Wells." So the well count goes down significantly. And I did use the -- so there is the OCD proposal and the IPANM proposal there. And I did use the AutoSum feature again. And with OCD's proposal, the sum would be $38,950,000, and with IPANM's proposal, it would bring it down to $24,400,000. So we'd have less in bonding under IAPNM's proposal.

Q. So 56.7 percent of operators have less than ten wells, correct?

A. Yeah. I think that was right.

Q. And what's the total number of operators?

670- --

A. 613.

Q. 613.

A. So what I also -- what I also did -- what I also did, bearing -- keeping in mind some of the discussion yesterday and if there was an idea to exclude federal wells, I did come up with some language, if that -- if that is still a concern to the Commission, of how federal wells -- the double-bonding issue could be addressed. If the Commission would like to hear that suggestion, I'm happy to --

COMMISSIONER MARTIN: I would.

THE WITNESS: Okay. If I may approach with some proposed language?

So in the state of New Mexico right now we have a $25,000 statewide bond. And I believe what we could -- what we could do to address the double-bonding issue -- and -- and for historical purposes, I had some additional conversations, and we actually have -- to Commissioner Balch's discussion yesterday, we actually have plugged a number of federal wells out of the reclamation fund. I know there was a lot of discussion during my tenure -- short tenure as the OCD deputy. We've only had the BLM grant. But as I discussed yesterday, the BLM has never redeemed any of their

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bonds, and when we plug any wells out of the reclamation fund, historically, we just plug those -- we just plug those wells, and we are not able to redeem those bonds. And similarly, I know the State Land Office -- I believe they redeemed one surface -- surface bond ever for surface reclamation. So those bonds do come out of the -- out of the OCD bonds.

So in order to address the double-bonding concern, I thought what we could do is -- I'll read the language. In C.(2) -- 8.9C.(2), we could say something like: "In determining the blanket plugging financial assurance, if an operator has federal wells that move the operator into higher tier, the operator may request the operator's blanket plugging financial assurance be reduced by the federal statewide bond" -- which currently is $25,000 -- "provided, however, that at no" -- that should be "no," not "not" -- "at no time can the amount subtracted from the required financial assurance make the blanket plugging financial assurance required less than the amount of financial assurance required for the operator's total combined state and private well count."

So by example, if, in C.(2), an operator has 60 wells and 48 of them are state and private wells and 12 of them are federal wells, they would be moved

into the $125,000 category. If you subtract the $25,000 that they have, theoretically, to benefit the State of New Mexico, they would only post $100,000 with the State of New Mexico.

Contemplating the fact that maybe the federal government were to increase their bond sometime in the future, it could be maybe $75,000. Then you would take that $125,000, but we wouldn't add -- subtracting $75,000 would make that -- make that bond too low. It would be down to $50,000. So they would still be required to post that $75,000 by the combined total of their state and private wells.

COMMISSIONER BALCH: Ms. Marks --

THE WITNESS: Yes.

COMMISSIONER BALCH: Can I question her?

CHAIRWOMAN RILEY: Yes.

Q. (BY COMMISSIONER BALCH) I have a little calculation here. If you -- if you combined IAPNM's first category and their second category into 1 to 99 wells and made that $50,000, that would give approximately $42-and-a-half million in all blanket bonds, while also providing relief to some of the smaller users. And we had a public commenter yesterday, a stripper-well operator of 77 wells, for example. That's kind of a midpoint number between the 30 million

right now, if everybody had a $50,000 blanket bond, and the $32 million if we went under the OCD proposal. So that would be an increase of 12-and-a-half million in the overall bonding amount, and a lot of that coverage would come from people in that 100-to-200 range, which may be a better measure of the small to middle sized operators than the one to ten wells might be.

A. So if you --

Q. Basically, if you take away that one to ten wells -- 56.7 percent of the operators have less than ten wells. IPANM's proposal is that they pay 25,000.

A. Uh-huh.

Q. I think we can't do that, from Mr. Brancard's reading of the statute, because at a minimum, we'd have to have 25k, plus $2 per foot to cover the cost based on curve-fitting the data you gave us yesterday in Exhibit 6. So 25k is not enough to meet the requirement of a minimal amount to plug a single well --

A. Right.

Q. -- on average.

So if you increase that bottom category for IPANM to 50,000, their Category A, and leave everything else the same, you end up with 12-and-a-half million more in bonds than you have now.

A. Assuming everyone posts a bond -- a blanket

bond --

Q. Only exercise we can do right now?

A. Right. Yes. That would be correct, although then only 12.1 percent of the operators would see an increase in their current bonding.

Q. I think that's not true.

A. Well --

Q. It would be 23-something percent.

A. Well, if you have the 1 to 99 -- 1 to 99 -- because from what I did --

Q. 1 to 99 is 79. -- 80.3 percent, if you have everything between --

MR. BRANCARD: That's 1 to 50.

COMMISSIONER BALCH: Oh, you're right, 1 to 50.

THE WITNESS: Yes, because I had 11 to 99 operators that was 32.1 percent. So total, 1 to 99 would be like 87.9 percent of our operators.

Q. (BY COMMISSIONER BALCH) So perhaps you can see the quandary I'm having right now. The quandary is we want to increase the bonding, but we also don't want to impact other parts of our responsibility under the Oil and Gas Act. The first part of that responsibility is to prevent waste, which is the leaving of oil in the ground that could otherwise be produced. The second

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part is correlative rights. That's the right of producers to produce the mineral that they have leased or gained accessed to. Following that, we have a number of other requirements, but those are the first two things that we're supposed to consider. After that, we consider public health, safety, water, the environment.

So we have to balance the things that we do so that we don't negatively impact the ability of producers to make oil from these existing resources. And this becomes highly sensitive.

I'm also almost done.

This becomes highly sensitive in the case of stripper-well producers. And stripper- or marginal-well production in New Mexico -- not only New Mexico, across the United States, is the backbone of our production. A huge percentage of the oil that is produced comes from these wells, and we don't want to endanger the ability for small operators to enter into those kind of operations.

A. I mean, I don't know if that's a comment or a question. I completely agree.

Q. It's a comment and a question. The question is: How do we address the need for additional bonding without putting undue burden on those people that are producing a critical component in the well supply?

A. I agree that small operators and stripper-well operators are critical to the production of oil and the economy. I don't know that I would prioritize the production and the elimination of waste over the protection of public health, safety and the environment. I believe that the protection of public health, safety and the environment is one of our most concerns. When I do have sites like this (indicating) and if I have completely inadequate bonding and our regulatory concerns -- if a ton of -- as the public comment came in yesterday, a lot of the costs are put into operations as proposed to regulatory compliance, I don't know that we can jeopardize the health of New Mexicans to -- to extract --

Q. An argument was made by Mr. Marker that I think has some validity, and that is that if he can't afford the additional bonding, he will have to quit operations. Now, he seemed like a reasonable person from a business point of view and probably would close down his operations cleanly. Maybe he wouldn't, right? But a lot of people may -- there are other operators that would not. And you may actually find an increase in the number of sites that you have to deal with if you chase these operators out, along with an incremental decrease in production. So we have to balance those three

categories with things, and that's the challenge that we are facing here.

So larger operators -- you're absolutely right. The people that are paying -- I'm not going to say the people that are paying the higher fees would unanimously be the people that are not going to walk away from an operation.

We had an example of a -- well, I'm sorry. It was not given to us. But there is a case in Wyoming where an operator picked up 1,000 wells and then walked away from them. That would be somebody with a blanket bond in New Mexico. Under the proposed rules, in anybody's example, that would be $250,000. So at least you would have that incremental money from that operator.

So the number of wells I think that defines the size of an operator and the risk that that operator will walk from it is something that would really be better addressed by some detailed analytics on the size of operator versus their -- their likelihood to go into a plug-and-abandonment state or an orphan-well state. And those numbers were not presented to us. So what we have to go on is the legal requirement that we have from the legislature to increase the bond to no more than $50,000.

A. I do believe that I did give some numbers yesterday --

Q. Okay.

A. -- on the likelihood of the operators -- the smaller operators who are out of compliance and the likelihood to walk away. And during the -- and I'm happy to, as serving as attorney for the OCD, in my position as the deputy overseeing the compliance and those efforts, get into significant detail, based in New Mexico and other states, as to who constitutes a significant number of noncompliant operators and who --

Q. I would welcome those numbers.

A. Okay.

MR. BRANCARD: Well, I have the numbers in front of me that Ms. Marks presented yesterday.

COMMISSIONER BALCH: Okay. Great.

MR. BRANCARD: I mean, looking at the ranges that OCD proposed, the one to ten, 11 to 50, 51 to --

COMMISSIONER BALCH: We know the size of the operators, but it's looking at the out-of-compliance part.

MR. BRANCARD: For the out-of-compliance, 56 percent of the operators are in the one-to-ten range. Fifty percent of the out-of-compliance range --

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twenty-three percent of the operators are in the 11-to-50 range. Thirty-five percent of the out-of-compliance are in the 11-to-50 range. Okay? And the 50 to 100, it's 8 percent. And operators, 2.5 percent out of compliance. Greater than 100, 11.7 percent and 12.5 percent are out of compliance. So --

Q. (BY COMMISSIONER BALCH) So it's actually the low end and the high end that has risk.

A. It was -- well, in the high-end range, it was -- I did include two operators who had -- because they appeared in our global bonding compliance report and we wanted -- had actually -- they continued to appear in the report, which should actually exclude two of them, which would actually significantly lower that percentage rate because it is such a small amount in that overall data set, the number in the one-to-ten range where 50 percent are noncompliant. You can see, if you graph it out, it is much more so in the lower-end operators, which is consistent with -- I just had conversations with North Dakota and Wyoming this morning, and that's consistent with what you will see in other states -- they have significant production there -- that the noncompliant operators are the smaller -- small-to-midsize operators.

CROSS-EXAMINATION

BY CHAIRWOMAN RILEY:

Q. Yeah. So based on those numbers, it's 85 percent that are less than 100 wells?

A. That's correct.

Q. That are not compliant with the FA rule.

MR. BRANCARD: Or 87. -- it's 85, 50 or less.

COMMISSIONER BALCH: Well, unless you're --

CHAIRWOMAN RILEY: Oh, okay.

COMMISSIONER BALCH: Unless you're more than 100 wells, in which case you're 12-and-a-half percent.

MR. BRANCARD: And the Commission also has before it OCD Exhibit 7, which is a list of all the operators out of compliance with the new -- I assume it's with the inactive well compliance.

THE WITNESS: Right. And then -- and then from there, we should exclude -- again, Canyon should be excluded there.

MR. BRANCARD: I guess I would just throw out for comparison purposes, one thing that the Commission has not been asked to consider is the option that the legislature gave it, which was to require -- simply move the bond for everybody from 50- to 250-,

right? And that would create a number -- instead of 51.9 million, it would create a number of 153 million. So that's -- that's an option that the division is not even offering the Commission, and so the division is offering another option here that is one-third of that.

THE WITNESS: And that was actually something we had contemplated, and that would be consistent with other states.

Like I said this morning, I had a good conversation with Wyoming, and I had gone to the IOGCC Exhibit [sic]. I had conversations with all 50 states on bonding, and New Mexico's was the lowest of every state. So this -- this was to -- to bring our -- to bring our bonding up. I know Texas, with their Sunshine Committee, was looking at increasing their bonding as well. I don't know where they're at right now. But our -- our bonding was -- was grossly inadequate. And so most states do adopt that blanket bonding. So like I said --

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Wait. So when you say grossly inadequate, are you really saying that we're lower compared to everybody else, or are you saying --

A. We are lower and --

Q. -- or are you saying that we don't have enough money to deal with the problem? And to what degree do we not have enough money to deal with the problem? That would be the definition of grossly inadequate, in my mind.

A. Well, and are statutory mandated, that Mr. Brancard read this morning as well.

COMMISSIONER BALCH: Okay.

CHAIRWOMAN RILEY: I'd like to make a point about the people that were here yesterday and some of their claims. And if they -- if they don't have enough money to post bonding, are they going to have enough money to plug their wells? And so at any time they could walk away and leave that for the State. And I don't know whether the revenue that's generated from those stripper wells is enough to offset the cost to plug those at the end of the day.

COMMISSIONER BALCH: So Mr. McMinn testified that he could plug one of his wells for about 10,000.

CHAIRWOMAN RILEY: He can, but we can't.

COMMISSIONER BALCH: Well, I know that.

CHAIRWOMAN RILEY: And that's not -- you can't -- I don't think you can use those numbers because that's him doing it by himself.

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COMMISSIONER BALCH: Sure.

CHAIRWOMAN RILEY: Whereas, we have to go through state -- you know, we're regulated on how it is that we get these bids and how we do it, and we have those numbers to back up what it's costing to plug wells.

COMMISSIONER BALCH: Well, there are some very shallow wells in the Exhibit 6 data that only cost $2,200 to close.

CHAIRWOMAN RILEY: Well, those are wells that were set to surface or just some -- what's their depth?

COMMISSIONER BALCH: 45 feet.

CHAIRWOMAN RILEY: Yeah. They didn't --

COMMISSIONER BALCH: There's not much you can do but throw two bags of cement in there.

CHAIRWOMAN RILEY: Yeah. So those probably shouldn't even be considered in the analysis because they're --

COMMISSIONER BALCH: I mean, really it costs the State, very accurately, $25,000, plus $2 per foot to close a well? That -- that fit is as if you were -- statistical algorithm rather than just Ms. Marks coming up with a -- mathematical mind in there somewhere.

But to me there's a real challenge here. I mean, we don't want to discourage these operations, but realistically, to meet the goals of the OCD here, we should be putting the $50,000 bond on Chevron and the $250,000 bond on IPPC, right, if you really want to distribute the risk in a reasonable fashion?

The problem is what impact is that -- what secondary impact is that? And we had some testimony from the public commenters that it could be hard. And a question that I didn't ask that was given in information by Mr. Marker is the cost of these bonds, and 40 percent of the cash value, plus 2.-something percent per year.

CHAIRWOMAN RILEY: So I think we ought to get -- do you have any analytical data on that?

THE WITNESS: Yeah. I've had, actually, a lot of conversations with surety companies about that and how much it costs to bond, which actually -- what companies have to -- how much it costs to get a bond with them. And it does depend on the company. If it's Concho, they -- the bond may cost 1 -- 1 percent of the actual bond. And it depends on how well capitalized the company is and how -- what their risk value is. So it may cost Mr. Marker that, and they may have to put up some collateral. And they do a risk-based assessment. I think it's -- if it is cost -- if there is a

significant risk to -- for a surety company, there is another mechanism they can -- they can explore. They don't always have to --

COMMISSIONER BALCH: Get a credit bond or something.

THE WITNESS: The can get a letter of credit through the bank, which may cost them 3 percent per year or 5 percent per year, and they don't have to put up an all-cash bond. So they're not locked into going through a surety company and putting up 40 percent collateral.

COMMISSIONER BALCH: We still run into the same problem where the people you're most needing to increase the bonding on are the ones that are least likely to get a good deal on a bond.

CHAIRWOMAN RILEY: So, therefore, they're the highest risk.

COMMISSIONER BALCH: Well, it's because they're the highest risk.

CHAIRWOMAN RILEY: So we have the circular argument.

THE WITNESS: But they're the highest risk to the State of New Mexico, too.

COMMISSIONER BALCH: I know. I know. I just -- I want to be really careful that what we do does

not end up with 500 more wells being closed next year than would have been closed if we didn't change it. Okay? That's my main concern.

CHAIRWOMAN RILEY: Well, another point I want to make is that weekly -- and this was testified to yesterday. But weekly, we have increased the activity on trying to get operators into compliance, and that's holding their feet to the fire on what is within our regulations to do. And every week, it's some of the same operators, and we are trying to figure out how do we get them to respond, how do we get them to appropriately have their financial assurance and be in compliance with the 5.9, which is the inactive well rule. And I'm sorry, but they're representative of a good number of those, so my sympathy isn't really very high.

THE WITNESS: And I will say, Commissioner Balch, we -- we do everything within our powers not to refer those cases over to Legal, to -- to get them to clean up their messes, to get them back into compliance because we don't want to assume that risk. We don't want to clean up these sites. When they kicking -- kicking fresh soil over dirty soil, we ask them to clean up those sites. We don't have the manpower. We don't have the resources. We don't have anything within our

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power to take on all the, you know, $56 million in liability that would be there if we addressed it all. So we do everything possible to work with these small -- the smallest operators and the small-to-midsize operators that we can.

There's one more point I'd like to address at some point on the variance idea. I had walked out to try and reach out to our I.T. I don't know if this is an acceptable time to do so.

CHAIRWOMAN RILEY: On variance?

THE WITNESS: Right.

CHAIRWOMAN RILEY: Yeah. Could you please bring up variance because I have some issues I want to discuss with variance?

THE WITNESS: Okay. In closing, I don't -- I love my attorney, but there was not a consultation on a variance. The OCD vehemently opposes the idea of a variance.

COMMISSIONER BALCH: But that's what this is, is a variance.

COMMISSIONER MARTIN: That's what you submitted.

THE WITNESS: But the idea of the single-well variance, though, with the $8,000, this -- this idea of -- this idea based on the federal wells, we

are okay with. But variances based off of submitting cost estimates, we don't have that manpower to review 30, 80, however many.

CROSS-EXAMINATION

BY COMMISSIONER MARTIN:

Q. I have a quick question: How does the division view this undue burden on smaller operators? How does the division think that's going to solve their compliance problem?

A. I'm sorry. I couldn't really hear.

Q. You have a compliance problem with the smaller operators. How is increasing their bond going to solve that for you?

A. Since the disproportionate number of operators who -- let me -- let me -- I don't think that increasing -- we're increasing the bonds on every operator throughout the state, and we have determined that the amount of bonding we currently have is insufficient.

COMMISSIONER BALCH: By how much? How insufficient is it?

Q. (BY COMMISSIONER MARTIN) Let me rephrase it. How does putting a disproportionate burden on small operators solve your compliance problem with those same operators?

COMMISSIONER BALCH: Well, actually, it's not disproportionate.

THE WITNESS: I don't think it's disproportionate.

COMMISSIONER BALCH: They're actually only gaining, from the 50,000, their operator base case blanket, $3.6 million for the category of operators that cover an 85 percent of noncompliance.

Q. (BY COMMISSIONER MARTIN) Getting back to my original question --

COMMISSIONER BALCH: So I'm wondering how much are you short? Is it more than 3 million? Less than 3 million?

THE WITNESS: If we plugged every single well on -- I mean, we'd have to look at how many wells -- right now we have --

CHAIRWOMAN RILEY: We have 1,738 wells that are inactive.

THE WITNESS: So we have $17,500,000 right now of wells that we have to plug, and we have about $2 million in bonding. And we have a whole bunch of more --

COMMISSIONER BALCH: So $15 million short.

THE WITNESS: Right now. And we have a whole bunch of cases sitting in our Legal Bureau. And

this is a -- this is because we just had the blessing recently to take compliance efforts seriously. And this is, again, just the downhole plugging. I mean, when -- when we have the State Land Office asking us to clean up these sites and we'd like to actually use the reclamation fund to clean up sites, we're not going to have any money in the reclamation fund to actually address issues that may be of serious health and safety to the people of New Mexico.

MR. BRANCARD: Okay. But remember, this discussion is about the blanket bond for active wells. Okay?

COMMISSIONER BALCH: Uh-huh.

MR. BRANCARD: I mean, if you want to look at true-cost bonding, right, which is my experience on the mining side, every mine was bonded for the true cost of reclaiming that mine. You would take, what, 58,000 wells and you'd multiply it by 33,000. I got 1.9 billion.

THE WITNESS: It would actually be a lot more because you have to factor in site restoration and reclamation.

COMMISSIONER MARTIN: But you're assuming you're going to have to plug all those wells simultaneously. That's just not going to happen.

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COMMISSIONER BALCH: No. I mean, it's an unlikely occurrence.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. So under the OCD proposal, the bottom 85 percent where you have -- I'm sorry -- the bottom 80 percent of producers have 85 percent of the problems, and the top -- believe it or not, the top 11.7 producers are the other percent of the problem. So you take the incremental amount of money, $100,000, from the top producers, more than 100 wells under the OCD proposal, the additional 25,000 for the 11-to-50 well category under the OCD proposal, that comes up to your $17 million. So I would say that the OCD proposal is addressing the additional need for bonding, but I don't think it really covers the smallest producers.

A. So we should probably go -- follow -- maybe make it $100,000 to address what you're concerned -- I think you're right on. I think what we were trying to do would be considerate --

Q. No. I'm saying that your highest producers, under your proposal, will generate 17 million more in bonds.

CHAIRWOMAN RILEY: More than current?

COMMISSIONER BALCH: More than present.

And present if everybody has a 50k bond. So it's not a perfect number, but 17 million more, which is about the number you set for the wells you would like to close but you can't because you don't have the money.

MR. BRANCARD: Okay. So I'd like to just address procedurally where we are with the Commission here. It's a good discussion here, but the question is when do you want to close the record and go into formal deliberation here to discuss, whether there is any more --

COMMISSIONER MARTIN: I don't think there is anything new that's going to come out of this discussion.

COMMISSIONER BALCH: No. I think I have everything I need.

MR. BRANCARD: Okay. So are you ready to close deliberation?

MR. LARSON: Madam Chair, before you close, may I make a brief statement about the BLM bonding requirements?

CHAIRWOMAN RILEY: Is that appropriate?

MR. BRANCARD: Sure. Since we've allowed the division, I think it's okay.

MR. LARSON: Thank you.

I believe Ms. Marks cited yesterday to

43 CFR 3104.5, small B, as in boy, and that -- I don't know if she cited to B. I know she cited to a regulation. Subsection B authorizes an increase in the bond amount to the total cost of plugging the well at the BLM's discretion. And there is a 2014 guidance. It's Instruction Manual Number 2013-151, which makes it the responsibility of the state office to do bond reviews. Those can be done in various stages, at the APD, the sale of a well. And then there is a ranking system for increasing a bond. And one of the factors looked at is the actual total cost of plugging the well. And based on that formula and the circumstances presented, the state office has the ability to significantly increase the cost of the BLM bond.

CHAIRWOMAN RILEY: Do you have any knowledge of whether they have they've actually done that?

MR. LARSON: I know that there are bond reviews done, and I know from some small operators that their bonds are increased. Yes. I can't tell you how often and what circumstances. Again, it's done on a ranking point system, so it would depend on specific operators.

THE WITNESS: I think with the proposed language, though, it would still capture -- if there was

an increase in the bond, if it was increased to a million dollars or anything else, it would still be captured in the language that I just proposed because the BLM bond amount would still be subtracted from any tier that the operator would be in.

CROSS-EXAMINATION

BY MR. LARSON:

Q. If there was a million-dollar bond, what category would it be in?

A. Well, what I proposed, if they're in Category C, for example, because of -- and they're in that category because of the -- say they normally would be in Category B because of their state and private wells combined, but then their federal wells puts them in Category C, and then they have a million-dollar federal bond, you would subtract out the million dollars, but they cannot at any time be at any category lower than what is required under their state and private wells together. So they'd still be in Category B, so they'd be only required to post at $75,000.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER MARTIN:

Q. What's your idea on how to implement such a policy as this? How would you go about doing this?

A. If the operator requests that the -- because of

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their total well count, includes federal wells, submits a request to --

Q. To the division?

A. -- to the division with -- with -- we'll assume it's a $25,000 bond, but they provide proof of it being higher, which would be applicable if they were in the DOC type of category. Then we would lower the bond amount. And we're great -- we're great at coding over here at EMNRD, as Commissioner Balch told us yesterday. We would have no problem implementing that.

CHAIRWOMAN RILEY: The other thing I think they would need to provide would be proof of mineral ownership of that well because we don't have a way to track that. So that puts the burden on the operator, and they have their own records to know that.

Q. (BY COMMISSIONER MARTIN) Could the division conceivably refuse to grant that exception?

A. I think that's for you folks to determine. But if the concern is double bonding, I think that addresses the idea of double bonding.

Q. My concern is including the federal wells at all. If you allow them to deduct the amount of federal wells from their well count, that would be preferable to me.

In this instance, absent a million-dollar

bond, you're allowing them to only deduct an admittedly insufficient federal bond amount, which still leaves them liable, I think, for some of the federal plugging. Well, at least that figures in with the mix. You see what I'm saying?

COMMISSIONER BALCH: It cuts their cost by potentially 25,000, which on the smaller end would probably maybe be fairly useful. I'm very comfortable with the compromise that the division presented here.

COMMISSIONER MARTIN: It's better than it was.

CHAIRWOMAN RILEY: Do you have anything else you wanted to say, Mr. Larson?

MR. LARSON: I do not.

CHAIRWOMAN RILEY: Okay. Thank you.

So you're released, Ms. Marks. Thank you.

And we are back in deliberation.

Does anybody need a break?

COMMISSIONER MARTIN: Yeah. Let's --

CHAIRWOMAN RILEY: Mr. Brooks?

MR. BRANCARD: Can we admit these as exhibits? Would you like to move --

MR. BROOKS: Yes. I don't know what exhibit numbers you have there.

MR. BRANCARD: I think the last one we had

is the definition of "true vertical depth" proposal as 12. So we have 13, 14 and 15, then, and 15 being the proposed language change on federal wells.

CHAIRWOMAN RILEY: And how are you doing 13 and 14?

MR. BRANCARD: 13 would be the first document under the current proposal.

MR. BROOKS: This is without the notation "Excluding Federal Wells."

MR. BRANCARD: Right. And 14 would be the one that says "Excluding Federal Wells."

MR. BROOKS: Okay. We'll tender Exhibits 13, 14 and 15, with that understanding.

CHAIRWOMAN RILEY: Mr. Larson?

MR. LARSON: No objection.

CHAIRWOMAN RILEY: Those exhibits are admitted to the record.

(NMOCD Exhibit Numbers 13, 14 and 15 are offered and admitted into evidence.)

(Recess, 11:15 a.m. to 11:24 a.m.)

(Open-session deliberations resume, 11:24 a.m.)

COMMISSIONER MARTIN: Now that we're on the record, everybody shut up.

CHAIRWOMAN RILEY: I know (laughter). It's

like --

COMMISSIONER BALCH: So the reality is the OCD is short about $15 million to plug the wells that are on the list right now.

COMMISSIONER MARTIN: I'm having trouble equating the compliance problem and the bonding.

COMMISSIONER BALCH: Well, I did some numbers on compliance from the bonds, and under OCD's proposal, if you assume that everybody's paying the blanket 50k bond right now, which they're not, then the one-to-ten category, which is more than half the operators, is going to pay no more additional bond.

The 11 to 50, which is about 20 percent of the operators that pay 3.6 million, incrementally more because they're in that $75,000 category.

COMMISSIONER MARTIN: As a group.

COMMISSIONER BALCH: So that number of operators tends to -- incremental amount for the bonding.

51 to 100, the same, 3.5 million more.

And the greater-than-100 category is paying about 14.3 more, which is the lion's share.

The problem is 85 percent of the risk is in less than 50 wells and 12-and-a-half percent of the greater-than-100. So you take those two categories and

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you add up to about 18 million, which is enough to meet OCD's requirements, but it may be disproportionately hitting the higher other well producers with the biggest risk. They are the second highest risk category, but they are still 12-and-a-half percent of the risk compared to 85 percent of the risk on the bottom scale.

So in that sense, the OCD proposal does come up with enough additional bonding money, probably even within the highest risk categories, except for the shift to a relatively lower-risk group at the high end. Probably effectively they're getting 4- or $5 million more for the wells that need to be closed.

COMMISSIONER MARTIN: Most of the problem with those multiple companies, wells drift down -- as it becomes less economical, drift down to the lower brackets.

COMMISSIONER BALCH: Right. So I'm not sure if this is really giving them the money that they need in the risk categories that they have. And to get the money that they need from the risk categories that they have, I think we'll probably add the number of wells that's needed to close, which then increase the -- there are an increasing number of people that walk away from orphaned wells, wells that need to be plugged, which would then actually increase that 17 million

more --

COMMISSIONER MARTIN: Absolutely.

COMMISSIONER BALCH: -- while cutting off some production as well. So it's really an ugly situation. It's one of those things where you raise the taxes enough in the community that the people start moving out, so you raise the taxes some more so more people move out.

CHAIRWOMAN RILEY: So what's the solution?

COMMISSIONER MARTIN: That's the problem. I don't have an answer.

I'm still kind of philosophical about the problem with the federal wells. I'd like to see a compromise fair and reasonable to that, but it has to be -- I'm not sure what that is.

COMMISSIONER BALCH: That would reduce actually -- first of all, it's unfair to double bond them -- require them to double bond. So it should reduce it. At least reduce their liability, as to this language, by the amount of their federal bond.

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: I think that makes sense. But all that really does, though, is shift more people into the other categories where they're not paying any more bonding, so that reduces your

3-and-a-half million probably to a couple million dollars. So the problem doesn't go away.

COMMISSIONER MARTIN: And the only target is to get it company by company. You deem a company a high-risk company, which I could name a few, I'm sure as you could, right off the bat.

COMMISSIONER BALCH: There are certainly those companies that are repeat problems in a number of areas, so those are known.

COMMISSIONER MARTIN: But I don't know how you manage that situation.

COMMISSIONER BALCH: They'll have a bigger bond for operating, or they just walk away.

COMMISSIONER MARTIN: Right.

CHAIRWOMAN RILEY: Uh-huh. But it's kind of back to the point if they don't have the money to do the bond, they're not going to have the money to plug appropriately either.

COMMISSIONER MARTIN: But you don't put them out of business. If you do, then you're cutting off the nose to spite the face. You cut out production. And who is to determine --

COMMISSIONER BALCH: And then those wells go on to the orphaned-need-to-be-plugged wells, which compounds the problem.

I was kind of -- last night I was thinking about this. I'm wondering if there is some way to apply a sliding scale, not make the jump so big. Right? Go 50- to 75- to 125- to 250-, over just the 1-to-100-well range.

CHAIRWOMAN RILEY: Does that help?

COMMISSIONER BALCH: Probably not.

CHAIRWOMAN RILEY: I mean, that just creates more administrative burden for the --

COMMISSIONER BALCH: I don't think that the number of categories changes the administrative burden.

COMMISSIONER MARTIN: You have a team behind you.

CHAIRWOMAN RILEY: It does on the -- you know, your number of wells is going to change, and so then you're going to be chasing bonds all the time, chasing additional bonding.

COMMISSIONER BALCH: I mean, what -- again, a lot of times what we're presented with in rulemaking -- we're given data, but we're not given a full analysis of the data, and we're kind of left to do that with what's given to us. So I don't have a histogram that shows -- well, maybe we do have a histogram of number of operators per -- I think there is one around here. No. Those are fixed costs. A

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histogram of number of operators by bins of 50 or something that might have been useful to show us the real distribution of operators.

So what we're left with is 53. -- 56.7 operators are in the one-to-ten category. 23.5 percent are in the 11-to-50. 7.8 percent are in the 51-to-100, and 11.7 are in the more-than-100. Those are the only four things that we have that we can compare to -- and for whatever reason -- and it's probably just the way the statistics are distributed. The 51-to-100 well category is the lowest risk, for whatever reason. I mean, it's a small sample of statistics that do things like that. So a more continuous distribution of number of operators by number of wells would have been useful.

MR. BRANCARD: Well, my suggestion is that if -- that you need to look at these, sort of, issues one by one, okay? And each set of issues will have a ripple effect on how much of a change this proposal is to the current reality here.

And so the first proposal you might want to look at is what Commissioner Martin has proposed, which is looking at excluding the federal wells, which we have a dollar amount that -- what the impact of that is. Then if you make that change -- it's a pretty significant change -- do you want to make any more

changes after that?

COMMISSIONER BALCH: My concern with federal wells is really the double jeopardy on bonding --

COMMISSIONER MARTIN: Mine, too.

COMMISSIONER BALCH: -- which I think this addresses pretty reasonably. How that's going to impact the overall numbers is to be determined.

MR. BRANCARD: Well, we have an estimate based on if you reduce -- if you eliminated the federal wells from the calculus, what the bonding would be. This proposal lessens that a bit by focusing on the double-bonding aspect.

COMMISSIONER BALCH: I'll hate myself in the morning.

MR. BRANCARD: So in 8.9C, there are basically, as I can see it, three things on the table. One is the tiers and the alternative proposal from IPANM, which you don't have to go for one or the other. You can go for anything in between or do a hybrid.

The second is to exclude federal wells from the calculation, which would have an impact both on the IPANM -- significantly on the IPANM and on the state proposal.

And the third issue, which I'm assuming is

still on the table, is the question of whether to allow an operator to come in and propose a different number with a single-well financial assurance, which OCD expressed its opposition to this morning.

COMMISSIONER BALCH: There's no mathematical basis for doing that. I took the proposed numbers from the small operators that did come in, and I plotted them on Exhibit -- Exhibits 9 or 10? -- Exhibit 10. And I don't know if you want to submit this for the record, or I can just describe it.

MR. BRANCARD: Describe.

COMMISSIONER BALCH: Okay. So Exhibit 10 has a plot of cost to complete by depth of well, and there is a red line on that plot of numbers, which is the $25,000, plus $2-per-foot equation that's proposed by OCD. That line fits the distribution of the data extremely well. If you plot the $5,000, plus $4-per-foot number proposed by I think Mr. Marker, that number falls on the very outside bottom of that distribution of data and would probably be inadequate. I can show you what that number looks like. This is the 5,000 number -- 5,000, plus the 4, and that's the 25,000, plus 2.

Also, the statutory requirement that was given to us by Mr. Brancard earlier today says that by

no means can we be under the cost to complete a well, which is, on average, 3,200. So you cannot have a category of 25,000 blanket bond. It would not be adequate to close an average well.

So I think that -- I think we can't entertain using that other number, the 5,000, plus $4 per foot.

MR. BRANCARD: And I think the 5,000, plus 4 was only for inactive wells. For active wells, it was 5,000, plus 2.

COMMISSIONER BALCH: Which would be even lower. So the $5,000, plus $4-per-foot number only meets the closing requirements of very deep wells, essentially.

MR. BRANCARD: And I have a bit of concern with Mr. Marker's proposal because, again, he did not submit that modification in advance of the hearing, as we normally require.

COMMISSIONER BALCH: Fortunately, I was able to vet it myself.

Is that satisfactory to you?

CHAIRWOMAN RILEY: Yes.

COMMISSIONER BALCH: 25-, plus 2 is really the number for a single well, given the four-year data set that we have.

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CHAIRWOMAN RILEY: Well, I think in the future, that may have to go up based on the wells that are going to start coming in from the big guys.

So how about the federal well issue?

COMMISSIONER MARTIN: This one?

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER MARTIN: I don't have a problem with that. It's nondiscretionary on the division's part.

COMMISSIONER BALCH: There's maybe another approach we could take than what's presented by OCD. And then IPANM has a different version, which is a tiered approach, terminating at 250,000 maximum bond. You could apply smaller bond levels as appropriate to the risk level associated with each of these, and then hold the 250,000 number as something that could be applied to high-risk operators irregardless of size. And we would have to come up with definitions for that.

MR. BRANCARD: So eliminate the 250- as an automatic to anybody?

COMMISSIONER BALCH: Yup.

CHAIRWOMAN RILEY: How would we manage that?

COMMISSIONER BALCH: So here are the numbers that I just ran. If you have one to ten at

$75 -- 75 --

MR. BRANCARD: No party has proposed that, okay?

COMMISSIONER BALCH: I know. But we have considerable latitude, don't we?

MR. BRANCARD: Well, a certain amount of latitude within the proposals that are out there.

COMMISSIONER BALCH: No greater than 250-?

MR. BRANCARD: Yes. You cannot go beyond 250-. But, again, you know, people participated in the hearing assuming what the proposals are.

COMMISSIONER BALCH: Well, if you keep it that way, put the one to ten at 75,000 blanket bond, that generates 8.7 million; 11 to 50 at $100,000 blanket bond, that's 7.2 million. Those numbers for the bond are 16 million, which is a majority of the shortfall, also the majority of the problem. Eight-five percent of noncompliant operators are in those two categories. All right?

CHAIRWOMAN RILEY: So you've essentially increased Tier 1 and Tier 2 by $25,000.

COMMISSIONER MARTIN: Was this included in the OCD proposals?

COMMISSIONER BALCH: Well, with that included, we don't know that the overall --

COMMISSIONER MARTIN: I know. But your proposal is to change those amounts --

COMMISSIONER BALCH: I'm not sure if it's a proposal. I'm just showing you some numbers that make sense for the problem. I'm not sure if it's the best solution overall.

I think the 1-to-100 range, where the lowest risk is, 2-and-a-half percent of operators there are noncompliant. So that generates an additional 4.8 million. And the greater-than-100, where 12-and-a-half percent of the problem is, generates 14 million. So those are redistributing the additional bonding essentially to the groups that have the biggest problems.

CHAIRWOMAN RILEY: Well, you didn't change these numbers, though, right?

COMMISSIONER BALCH: No, I did.

CHAIRWOMAN RILEY: Actually, you increased. That's an increase (indicating).

COMMISSIONER BALCH: Yes. This one could you could actually leave it 125-, but I kept it, kind of scaling up in a geometric progression.

CHAIRWOMAN RILEY: And then that's the same? That's the 250-?

COMMISSIONER BALCH: Uh-huh, 250-.

So this is something that would meet the -- that would match the solution to the problem. The problem there is what are the additional impacts of that type of solution?

CHAIRWOMAN RILEY: Yeah.

COMMISSIONER BALCH: If you want the majority of your bonding to come from the 85 percent risk group, this is the way to do it.

MR. BRANCARD: So what's the proposal again?

COMMISSIONER BALCH: It's not a proposal yet. It's a discussion item.

CHAIRWOMAN RILEY: Tier 1 and Tier 2 increased by 25,000. Kept the numbers the same. Tier 3 on here, he's increased 25,000. Tier 4 is the same.

COMMISSIONER BALCH: I'm not proposing. I'm pointing out that this is what you would have to do to meet the problem based on mathematics. The majority of the problem is in the 1-to-50-wells category of operators. Eight-five percent of noncompliant wells are in this category. So you want to get 85 percent of your $17 million from that group. And this is about 15.9. It's pretty close to that number. That's reality.

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER BALCH: The problem is what

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does reality do?

CHAIRWOMAN RILEY: And what are the impacts?

COMMISSIONER BALCH: What does reality do? And I am completely unhappy with this because I'm afraid of what it will do to small operators. But that's -- that's how you distribute the additional risk appropriately.

COMMISSIONER MARTIN: Well, appropriately in a state government sense. To do anything more exact would take a lot more administration.

COMMISSIONER BALCH: Yeah. Which is why I also threw out the idea of perhaps you could go with something like this but reduce the rates and allow based on some criteria of higher-risk bond level for higher-risk operators. Then you could apply it directly to the problem perceived by the OCD.

COMMISSIONER MARTIN: Could you handle that?

CHAIRWOMAN RILEY: It's fraught with problems.

COMMISSIONER MARTIN: Could you handle that as a division-director-hat person?

CHAIRWOMAN RILEY: I don't think so. I don't see how we would -- we'd have to add all kinds of

employees to just manage that. And then you get into the whole issue of undue process and, you know --

COMMISSIONER BALCH: Well, I think you could do it the way that Mr. Larson described the BLM's process, where it's maybe a review of the -- of the bonding. So you don't have to do it for everybody. Just do it when you have a high-risk case.

CHAIRWOMAN RILEY: My guess is -- and I know that Mr. Larson doesn't have those numbers. But the federal government isn't any better off than we are in terms of pursuing this stuff, and my guess is they haven't done many bond reviews. But --

COMMISSIONER MARTIN: That's not to say we couldn't do that. I mean, I kind of like the idea.

COMMISSIONER BALCH: I mean, do -- put in there as a way to deal with particular operators or to mitigate the risk from a particularly bad operator.

COMMISSIONER MARTIN: Right, as exemplified -- as evidenced by some criteria spills over a period of time or remediation plan over a period of time.

COMMISSIONER BALCH: You want to make -- you want them to be nonarbitrary as possible because division directors change, energy secretaries change, directors change, OCD changes.

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: And you want it to be as clear as possible, which would trigger that possibility than somebody just -- blanket everybody at 250-.

CHAIRWOMAN RILEY: I think determining that criteria is your -- what the risk is.

COMMISSIONER BALCH: We don't have testimony for it, really.

CHAIRWOMAN RILEY: Yeah.

So what do you guys think with the small operator? I mean, I know that they're going to come in and say, "Oh, yeah, we can't do this, we can't do this." But is that really the reality?

COMMISSIONER BALCH: These guys are -- the good ones, they're scrappy. They'll figure out a way. But I'm more afraid of the people that are right on the edge just saying, "I'm done," and they walk away.

CHAIRWOMAN RILEY: So why wouldn't they sell to the operator that is capable of providing that?

COMMISSIONER BALCH: Well, now that operator has less capital because they're putting more money into bonding.

COMMISSIONER MARTIN: I think that is a good point, too. And this group that we're talking

about is not all bad operators. There is a sizable portion that are bad operators, but there are --

COMMISSIONER BALCH: Well, how big is the list of bad operators? We have Exhibit 7, right? How many people are on that list?

CHAIRWOMAN RILEY: It's down to, because we've been working through them, about 139.

MR. BRANCARD: I mean, that's the operators who have inactive well problems in excess of the requirements of Rule 5.9. So Rule 5.9 allows you to have inactive well problems up to a certain amount. These are the ones that have exceeded those ratios. It's not going to include environmental problems.

(All Commissioners speaking at one time.)

COMMISSIONER BALCH: Okay. A list of wells waiting to be plugged, how many operators on that list?

CHAIRWOMAN RILEY: Like 10 or 11.

COMMISSIONER BALCH: So it's a small fraction of the 613 operators?

CHAIRWOMAN RILEY: Uh-huh. All the ones that we've been able to get through all of the due process, you know, that we've talked about. Our legal group is only capable of doing so much, and it takes a long time to get them through. I'm getting your plugging order, and then if they file bankruptcy, you

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have go to through the whole district process with the bankruptcy court, whatever. I mean, it's -- yeah. It's a small group that we've taken care of. And there wasn't a push, I don't believe, in previous administrations to do that. It was kind of just left.

And I'll just -- this is just philosophical on my part, but with going to the IOGCC meeting earlier this year, that was the number one topic from all of the states, was this inactive or idle well problem across the United States, and every state is trying to figure out a way to resolve this. Because looking down the road, every state could potentially have all of these orphaned wells that they're having to deal with. And so being proactive somewhere on the front end of this is critical.

MR. BRANCARD: I mean, the Chair is right, because there is a whole due process issue here. The division can't just say, "You're out of compliance. We're going to plug your well." We have to go through a whole process to get a hearing, and that hearing deals with one of the issues that I think was brought up during this rulemaking, which is oh, you don't want to plug wells that are still, you know, good wells. Well, that's what the hearing process is for, you know. I mean, so you have a hearing examiner looking at that

well. And my recollection in the past -- maybe not recently, but in the past, hearing examiners have denied plugging orders because they thought the wells were still good wells.

CHAIRWOMAN RILEY: Or they come with information that somebody is looking to buy it or whatever. I mean, there is still that opportunity to allow business to take place.

COMMISSIONER MARTIN: There is a possible waste issue that enters into it at some point to me. I think that's basically why the examiners don't issue plugging orders, because they don't want to leave those resources in the ground if they are there.

MR. BRANCARD: Yeah. So that you have to balance against the fact that a well is not being taken care of and potentially becomes a threat to fresh water, to the environment, et cetera.

CHAIRWOMAN RILEY: Which goes into the inactive well rule and why we require the approved temporary abandonment status. And with that is -- we haven't even gotten to -- this other tier not at dispute today, thankfully. But, you know, in other words, to have those on ATA status, they have to provide that additional bonding. But wells just sitting out there shut in, I think are a huge risk.

COMMISSIONER MARTIN: It's good indicator of a problem.

CHAIRWOMAN RILEY: Uh-huh. And right now this snapshot in time, this exhibit, is 1,738 wells that fall on the inactive well list. So those are just the wells -- I have to think about this. This list includes the wells that are beyond the threshold.

COMMISSIONER BALCH: And two of those -- two operators make up 1,500 wells on that list. Nah. It's got to be more than that. Got to be more than 1,700. There are thousands of wells on this list. But you're on a different list.

CHAIRWOMAN RILEY: I'm looking at 7.

COMMISSIONER BALCH: Number of inactive wells?

CHAIRWOMAN RILEY: Yeah. You've got to look at the second column. Some of these -- Blue Sky, we're in court with them. Cano -- Cano is --

COMMISSIONER MARTIN: Cano just filed.

CHAIRWOMAN RILEY: I think Cano is the poster child for what can go wrong.

COMMISSIONER MARTIN: I agree. I mean, there are plenty of posters for that poster child, but Cano is a good one.

CHAIRWOMAN RILEY: Uh-huh. Cano's at the

top of the list.

COMMISSIONER BALCH: Cano.

CHAIRWOMAN RILEY: DeLong is on here. That was one of the gentlemen sitting up front.

COMMISSIONER BALCH: He's only got one well. So if it's inactive --

CHAIRWOMAN RILEY: Yeah. I don't understand. Maybe he has more than one company.

MR. BRANCARD: That could be.

COMMISSIONER BALCH: True.

CHAIRWOMAN RILEY: He testified he had 16 wells.

COMMISSIONER BALCH: He had the very small state wells, and the rest were federal.

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: Maybe that's why it's not on the list. It's federal.

CHAIRWOMAN RILEY: This should pull all that in for purposes of 5.9 when we look at federal wells as well.

COMMISSIONER MARTIN: That's true.

CHAIRWOMAN RILEY: Another thing we didn't even bring up is that they're constantly closing this company down and moving assets to another company and then starting over again or your principals are just

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changing names to start -- restart clocks.

COMMISSIONER MARTIN: I guess you could say whatever we do in this rule, that's still going to happen.

CHAIRWOMAN RILEY: Uh-huh. Just goes to the idea that risk is going to be difficult to manage because of those kinds of --

COMMISSIONER BALCH: The problem is 85 percent of your risk is in operators with less than 50 wells.

CHAIRWOMAN RILEY: Well, I mean, if we were to go with the idea of having to assess a risk number to a company --

COMMISSIONER BALCH: They'll just change -- yeah.

MR. BRANCARD: Okay. The legislature has authorized you to -- they have increased the cap by 500 percent after 40 years and authorized you the ability to implement. How do you want to implement?

CHAIRWOMAN RILEY: "Land the plane," Mr. Brancard is saying (laughter). "Land the plane." We just don't want to fly it into a cliff.

MR. LARSON: "De plane! De plane!"

(Laughter.)

CHAIRWOMAN RILEY: I liked the numbers that

Bob came up.

COMMISSIONER BALCH: You can propose them.

COMMISSIONER MARTIN: Read those again one more time.

CHAIRWOMAN RILEY: But they haven't been vetted.

COMMISSIONER BALCH: Well, I mean, they've been calculated with the numbers we've been provided by the OCD.

So one to ten wells, $75,000 on a blanket bond generates 8.7 million more in bond money compared to a blanket current 50k bond.

COMMISSIONER MARTIN: I mean just your new amounts, not what it brings in, just --

COMMISSIONER BALCH: 11 to 50, 100-; 51 to 100, 150-. And greater than 150, 250,000. We can probably even spread those ranges out. But the problem is we don't have -- I don't have statistics on the binning of those groups.

CHAIRWOMAN RILEY: Why not leave C at 125- because they're 2.5 risk?

COMMISSIONER BALCH: But that's a statistical anomaly. It's because we are looking at just operators basically with less than or more than 100 wells. I'm not sure that's the appropriate dividing

point. What do you call a small, medium and large operator by a well? We don't have that distribution in front of us. I mean, more appropriately, that $250,000 number should apply to a larger set of operators, maybe more than 100 wells. I don't know. But we don't have a way to come up with that number.

But if you want to apply the additional burden on the people with the additional -- with the heightened risk, that's how you do it, and I'm not too happy about it, because then that problem is in the order of $19 million shortfall right now, the reason why I presume that the Secretary went to the legislature and increased the number.

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER BALCH: Keep in mind I have to go to IPANM next week where I'll get lynched.

COMMISSIONER MARTIN: I was going to go, but I may not.

COMMISSIONER BALCH: The other testimony from Ms. Marks is basically this still puts us below everybody else.

CHAIRWOMAN RILEY: Uh-huh.

MR. BRANCARD: Well, I have two comments -- well, one concern and one comment.

My concern is that by increasing the lowest

category, 50- to 75-, you now have 56, 57 percent of the operators who didn't think this rulemaking was going to increase the blanket bond for them, and you just increased the blanket bond for them. So I'm a little worried about the notice issue.

CHAIRWOMAN RILEY: Notice.

MR. BRANCARD: Okay?

On the other hand, in terms of increasing the contribution of people in that category of one to ten, what hasn't been discussed here is the obvious ripple effect of increasing the single-well bond on people in this category.

COMMISSIONER BALCH: I wonder what the average single-well bond is now.

MR. BRANCARD: I think we had numbers of people talking about, you know, 7-, $8,000, which if you look at $5,000, plus $1 a foot, a 3,000-foot well is going to cost you $8,000. And a lot of the wells that have been cleaned up are actually 3,000-foot wells, so 8-, $9,000. So those folks are now going to be paying 33,000 or $31,000.

COMMISSIONER BALCH: Or a blanket bond of 50-.

MR. BRANCARD: Or they'll move them to the blanket bond. Exactly. So a lot of people who had

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single-well bonds in that one-to-ten category will move to the blanket bond. Okay? So it's not that those folks are not getting an increase, which is what you seem to be worried about, Commissioner.

COMMISSIONER BALCH: Uh-huh.

MR. BRANCARD: They are getting an increase because their single-well bonds will go up, or they will then just below go to blanket bonds, because the blanket bond is less than four single-well bonds. Previously, the blanket bond was greater than four single-well bonds.

COMMISSIONER BALCH: All right. So you take that 57.6 percent of the operators that have less than ten wells. You assume they have two single-well bonds at $12,000 or three at — whatever number adds up to 25-. Then you are increasing their bond total by 25,000. That would generate the $8.8 million also. But we don't have complete numbers on single bonds.

MR. BRANCARD: No, we don't. We don't know the range in the one-to-ten bonds and how many have single-well bonds.

COMMISSIONER BALCH: And I think those numbers would follow for the second category being 75,000 -- Category B, 75,000, for 11 to 50.

MR. BRANCARD: So logically, the people in

that category --

COMMISSIONER BALCH: Probably they're more likely to already have a blanket bond.

MR. BRANCARD: Exactly.

COMMISSIONER BALCH: So they would be adding about 3- or $4 million to the pool.

MR. BRANCARD: Going from 50- to 75-.

COMMISSIONER BALCH: Going from 50- to 75-. And they are 35 percent of the risk, and the one to ten is 50 percent of the risk.

CHAIRWOMAN RILEY: Well, that does worry me, about the notice issue. That's a pretty significant change from what was proposed.

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: I only present these numbers to show you what is part of the problem as it was presented to us.

CHAIRWOMAN RILEY: Yeah, but I like them. That was the problem.

COMMISSIONER BALCH: Some bigger analytics before they came to us. We have more numbers to work with. Seemed like there was a significant number of wells that are single-well bonded right now. Ms. Marks gave some numbers.

MR. BRANCARD: 1,900. I caught that

number. That number will go down.

COMMISSIONER BALCH: Yup.

COMMISSIONER MARTIN: Well, the division proposal was to add this language, not change any of these numbers. Maybe we go with that. Maybe we tweak this like we like it, and go with that. Leave it like it was, allow them to come in --

MR. BRANCARD: That will have a significant impact on the total amount coming in. It will go well below the 51.

COMMISSIONER MARTIN: I know, but it was the division's proposal.

MR. BRANCARD: Well, you-all asked for language, so yes, they gave it to you.

COMMISSIONER BALCH: Well, yeah. So if you take -- take the federal wells out of consideration, but you assume that their other bonding takes care of those wells, then that mitigates that problem. And without federal wells, the OCD proposal generates about 9 million more than the blanket's 50k number.

COMMISSIONER MARTIN: Okay.

COMMISSIONER BALCH: I don't think every operator would try for that exception. Many of them would still -- because we're only dealing with basically less than 100 or more than 100, a lot of operators will

already be stuck in that category. It would be more likely to people on the small scale, which is where all of your risk is and where you should have additional bonding, unfortunately.

COMMISSIONER MARTIN: I don't much like lumping them all together, but I see what you're saying.

CHAIRWOMAN RILEY: We are making some broad generalizations, but --

COMMISSIONER MARTIN: Very broad.

COMMISSIONER BALCH: More analytics.

I actually don't think, without increasing the rates on the one to ten and 11 to 50, that you're going to have that group meeting their proportional share of the risk.

COMMISSIONER MARTIN: Probably not.

COMMISSIONER BALCH: Not with 1,900 wells at a single out of 50-some-thousand wells total. That's just the way it is.

COMMISSIONER MARTIN: So in some sense, you're not penalizing the good operators in the small group by penalizing the bad operators, which I think is fair.

COMMISSIONER BALCH: But the goal is to generate more money for the actual risk, which in this case, I don't think it really does. I think it adds a

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few million dollars effectively.
However, if those 1,900 wells are all underbonded by $20,000, then that's $38 million. So that is a chunk of change considering the well closing cost could 32,400, on average, which disproportionately bits the smaller operators because the larger ones are going to hit the blanket bond pretty fast if they're going to single bonding, right?
MR. BRANCARD: Yeah.
COMMISSIONER BALCH: Actually, the one-to-ten category is the one with the most single bonding. It would have to be.
COMMISSIONER MARTIN: That would be my guess.
MR. BRANCARD: That would be logical. And some operators may have single-well bonds, historically, that they've maintained even though they can lump them all. We see very odd things in financial assurance.
CHAIRWOMAN RILEY: Uh-huh.
MR. BRANCARD: But I think by and large, from a logical point, people with single-well bonds --
CHAIRWOMAN RILEY: Okay. Should we --
COMMISSIONER BALCH: Okay. Well, I think if we go with the OCD table, with the change in language for federal bonding, that I can probably at least go to

sleep tonight.
COMMISSIONER MARTIN: With the proviso that this be mandatorily approved by the OCD. If they apply for it, they get it.
COMMISSIONER BALCH: Not a variance.
COMMISSIONER MARTIN: It's nondiscretionary. It kind of alleviates my concern with the federal --
COMMISSIONER BALCH: They will probably have to generate a form they can use to show how much they're paying in federal bonds, how many wells they have, does the math. I can go along with that.
COMMISSIONER MARTIN: Okay.
MR. BRANCARD: Okay. So how about if we flip it around then to read: "If an operator can demonstrate to the division that it has federal wells which move the operator into higher tier, the division shall reduce the operator's blanket plugging financial assurance by the amount of the federal statewide bond"?
COMMISSIONER MARTIN: I'm okay with that.
COMMISSIONER BALCH: Yeah.
CHAIRWOMAN RILEY: And then leave the "however" statement.
MR. BRANCARD: Right.
COMMISSIONER MARTIN: Yeah. I think that

needs to be in there.
COMMISSIONER BALCH: Right.
CHAIRWOMAN RILEY: Okay. So that's going to get added.
MR. BRANCARD: I would make that like a new Section C.(3).
COMMISSIONER BALCH: C.(3).
COMMISSIONER MARTIN: Sounds reasonable. Yeah. Makes sense.
COMMISSIONER BALCH: Right below the blanket bond.
MR. BRANCARD: The tiers.
COMMISSIONER BALCH: Well, the C will probably become D. We can actually move E above C. Sounds like we're ready for a clean copy.
CHAIRWOMAN RILEY: Yeah, clean copy.
COMMISSIONER MARTIN: Page 4?
CHAIRWOMAN RILEY: Uh-huh.
COMMISSIONER BALCH: Nobody said anything about the other category, so --
CHAIRWOMAN RILEY: Yeah. I think that one is okay.
COMMISSIONER MARTIN: Okay.
COMMISSIONER BALCH: Talking about moving this E above C somehow.

MR. BRANCARD: Right. The B.(2) categories are from the current rule.
COMMISSIONER BALCH: Yeah. So there was no discussion -- no proposed changes.
Okay. I think we had some slight language changes elsewhere that you may have tracked.
CHAIRWOMAN RILEY: I think everything else we talked about yesterday.
MR. BRANCARD: And then on the effective date, we were going to go with the first date being the effective date of the rule and the second date being four months later.
COMMISSIONER MARTIN: Right. That's what we talked about.
COMMISSIONER BALCH: Okay. Are you ready for a new pile of noncompliant operators after the rule is filed? If they don't have a bond, they can't operate, right, can't produce?
COMMISSIONER MARTIN: That's the theory.
CHAIRWOMAN RILEY: Well, we have to take them through due process.
COMMISSIONER MARTIN: See, that's kind of a problem I'm having, with forcing compliance from just a rule by itself. There are compliance problems not just in this, but -- based on lack of personnel, lack of

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rules, regulations covering that kind of stuff. Unfortunately, those problems aren't going to go away.

CHAIRWOMAN RILEY: Bill, how much time do you need to put together a clean copy?

MR. BRANCARD: I can do it over the lunch hour.

CHAIRWOMAN RILEY: It's 12:15 now.

MR. BRANCARD: So we accepted the proposed change to true vertical depth, Exhibit 12.

COMMISSIONER BALCH: Yes.

MR. BRANCARD: And then we had other language for 25.12.

COMMISSIONER BALCH: On 25.12, I think I saw you writing something down on that.

MR. BRANCARD: I know. I have to find it. Do you want to come back after lunch then, and I will get you a new draft?

CHAIRWOMAN RILEY: Let's adjourn until 1:30 --

COMMISSIONER BALCH: Yeah.

CHAIRWOMAN RILEY: -- for everybody's plans.

COMMISSIONER MARTIN: Yeah.

CHAIRWOMAN RILEY: Okay. Adjourn until 1:30. We are off the record.

(Recess 12:17 p.m. to 1:34 p.m.; open-session deliberations resume.)

MR. BRANCARD: Okay. I have prepared a revised draft of the rule proposal. It incorporates the changes the Commission has suggested. It's highlighted in yellow. It looks a little different than what you had before just because it's already in the format for filing. So, therefore, we have all of Section 7, not just the relevant parts of Section 7 of 19.15.2 right at the beginning.

And you might want to take a look at some of these because I did try to reword some of these to try to make them flow better or work better.

COMMISSIONER BALCH: There is one grammatical thing here.

MR. BRANCARD: Okay. So 8.9C.(3), I reworded that, I think, to try to get the concept down, "an operator."

COMMISSIONER BALCH: There's only one blanket bond amount for the federal, right?

MR. BRANCARD: For a statewide blanket bond. I think that was the -- there is a nationwide blanket bond, but there is only one statewide blanket bond.

COMMISSIONER BALCH: I noticed the missing

word "it" is there.

MR. BRANCARD: Right.

COMMISSIONER BALCH: But I'm wondering if, after the "amount of federal statewide blanket bond," we want to say "held by that operator," which would make sure they actually paid their federal bond.

COMMISSIONER MARTIN: What's the change?

MR. BRANCARD: So on 8.9C.(3) in the federal language, in the middle it says, "The division shall reduce the amount of the operator's blanket plugging financial assurance by the amount of the federal statewide blanket bond." Commissioner Balch is suggesting adding to the end of that "held by the operator."

COMMISSIONER BALCH: "Held by that operator" or "the operator." Yeah.

COMMISSIONER MARTIN: Okay. I like the way you incorporated E into C.(1) and D.(1).

MR. BRANCARD: And then 25.12, I reworded that to try to make it flow.

COMMISSIONER MARTIN: Looks better to me.

COMMISSIONER BALCH: Yeah, which I think really covers everything.

CHAIRWOMAN RILEY: That's good. Well, that was easy. What took us so long?

COMMISSIONER MARTIN: This wasn't one of the changes, but back on the second page, lest you run afoul of the infamous Records Division, do we want to -- the bottom-hole pressure, or was that the way it was originally, page 2?

MR. BRANCARD: Oh, yeah. I want to make sure that that -- okay.

COMMISSIONER MARTIN: God forbid.

MR. BRANCARD: I know. They will reject it and force us to --

COMMISSIONER BALCH: Oh, yeah. Good catch, Ed. I kept not seeing it because it wasn't in bold.

CHAIRWOMAN RILEY: That's the problem.

COMMISSIONER BALCH: Nicely done.

MR. BRANCARD: But we will run these by the Records Center again before we file these outside of normal practice and --

CHAIRWOMAN RILEY: Time for a motion?

COMMISSIONER BALCH: Well, I guess the motion would be to adopt the order as amended in the last few minutes by the Commission.

COMMISSIONER MARTIN: Second.

COMMISSIONER BALCH: Vote on this?

MR. BRANCARD: So you're adopting the proposed rule changes, with the order to come later.

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COMMISSIONER BALCH: Order to come later. Motion to adopt the proposed rule changes as moved.

COMMISSIONER MARTIN: Second.

CHAIRWOMAN RILEY: Okay. Can I have a raise of hands those that are in favor?

(Ayes are unanimous.)

CHAIRWOMAN RILEY: Opposed?

There is no opposition, so this passes.

COMMISSIONER BALCH: Hold on. So if it comes back before we sign, we can still make changes? It's happened before.

MR. BRANCARD: Right.

(Case Number 16078 concludes, 1:40 p.m.)

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, Certified Court Reporter, New Mexico Certified Court Reporter No. 20, and Registered Professional Reporter, do hereby certify that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings that were reduced to printed form by me to the best of my ability.

I FURTHER CERTIFY that the Reporter's Record of the proceedings truly and accurately reflects the exhibits, if any, offered by the respective parties.

I FURTHER CERTIFY that I am neither employed by nor related to any of the parties or attorneys in this case and that I have no interest in the final disposition of this case.

DATED THIS 28th day of August 2018.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2018
Paul Baca Professional Court Reporters

EXHIBIT 28

STATE TRUST LAND OIL AND GAS LEASE BONDING

State	Surface Estate (Acres)	Mineral Estate (Acres)	O&G Royalty	O&G Lease Terms & Bonds
New Mexico	9 million	13 million	12.5 -25%	5-year primary term 5,700 active leases $10,000 single, $20,000 blanket, $25,000 mega[1]
Wyoming	3.5 million	3.9 million	~16.67%	5-year primary term 4,500 leases ~ 1/3 leases active production $10,000 performance bond; $100,000 blanket bond[2]
Colorado	2.8 million	4.0 million	~ 20%	5-year primary term 990 leases ~ 12% leases active production 1-3 leases $25,000; 4+ leases $100,000[3]
Utah	3.3 million	4.5 million	12.5% -16.67%	10-year primary term; 900-1000 leases $5,000 single well bond; $15,000 statewide blanket bond[4]

[1] NMSA 1978, §19-10-26; NMAC 19.2.100.23
[2] SBLC Rules & Regulations, Chapter 18, Section 12 & 13
[3] Colorado State Land Board, https://slb.colorado.gov/lease/oil-gas
[4] Utah Regulations, R-850-21-200

EXHIBIT 29

GENERATE O & G BOND LISTING (GDBL - PUBLIC)

Report Parameters:

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
17	778	BP AMERICA PRODUCTION COMPANY	778	BP AMERICA PRODUCTION COMPANY	SEABOARD SURETY COMPANY	B	8/27/1979	
315	117139	BP AMERICA PRODUCTION COMPANY	778	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY & SURETY	B	1/13/1994	
1588	218098	BP AMERICA PRODUCTION COMPANY	778	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
432	785	AMTEX ENERGY INC	785	AMTEX ENERGY INC	PIONEER SAVINGS BANK	B	6/3/1996	
666	295943	ANADARKO E&P ONSHORE LLC	817	ANADARKO PETROLEUM CORP	LIBERY MUTUAL INSURANCE CO.	B	1/26/2004	
943	15422	APACHE CORP	873	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
227	43910	ATLANTIC RICHFIELD CO	986	ARCO OIL & GAS CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
791	1092	ARMSTRONG ENERGY CORP	1092	ARMSTRONG ENERGY CORP	JP MORGAN CHASE	M	2/20/2007	
133	1163	ASHER OIL CO	1163	ASHER OIL CO	WESTERN BANK	B	8/16/1988	
227	43910	ATLANTIC RICHFIELD CO	1271	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	1280	ATLANTIC RICHFIELD COMPANY	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
445	1329	AUTRY C STEPHENS	1329	AUTRY C STEPHENS	NORWEST BANK OF NEW MEXICO	B	10/19/1996	
340	1903	BEACH EXPLORATION INC	1903	BEACH EXPLORATION INC	UNDERWRITERBS INDEMNITY CO.		6/14/1994	
206	2096	BENSON-MONTIN-GREER DRILLING CORP	2096	BENSON-MONTIN-GREER DRILLING CORP	CITIZENS BANK	B	9/28/1992	
127	2702	BP EXPLORATION INC	2702	BP EXPLORATION INC	TRAVELERS CASUALTY & SURETY CO	B	4/19/1988	
137	2840	BRIGHT & CO	2840	BRIGHT & CO	NEW MEXICO FEDERAL SAVINGS & L	B	12/16/1988	
1621	260297	BTA OIL PRODUCERS, LLC	3002	BTA OIL PRODUCERS	US SPECIALTY INSURANCE CO.	M	11/1/2018	
1621	260297	BTA OIL PRODUCERS, LLC	3019	BTA OIL PRODUCERS	US SPECIALTY INSURANCE CO.	M	11/1/2018	
204	3044	BURGUNDY OIL & GAS OF N M INC	3044	BURGUNDY OIL & GAS OF N M INC	UNDERWRITERBS INDEMNITY CO.		9/9/1992	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
598	3053	BURK ROYALTY CO., LTD.	3053	BURK ROYALTY CO., LTD.	CONTINENTAL CASUALTY	S	7/30/2001	VA 2432 0
1951	3080	BURNETT OIL CO INC	3080	BURNETT OIL CO INC	U.S. SPECIALTY INSURANCE COMPA	M	12/18/2023	
999	3474	C W TRAINER	3474	C W TRAINER	SECURITY BANK	B	9/13/2013	
731	4115	CHAPARRAL ENERGY LLC	4115	CHAPARRAL ENERGY LLC	US SPECIALTY INSURANCE	M	4/27/2005	
110	4323	CHEVRON U S A INC	4323	CHEVRON U S A INC	UNITED PACIFIC INS. CO.	B	6/26/1987	
258	4378	CHI OPERATING INC	4378	CHI OPERATING INC	RLI INSURANCE COMPANY	B	5/5/1993	
16	4468	CIBOLA ENERGY CORP	4468	CIBOLA ENERGY CORP	TRAVELERS CASULTY & SURETY COM	B	8/20/1979	
657	4537	CITATION OIL & GAS CORP	4537	CITATION OIL & GAS CORP	TRAVELERS CASUALTY & SURETY	B	10/30/2003	
1571	4838	COLEMAN OIL & GAS INC	4838	COLEMAN OIL & GAS INC	CITIZENS BANK	M	11/7/2017	
913	197035	XTO ENERGY INC	5380	XTO ENERGY, INC	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
1910	5691	Dakota Resources, Inc	5691	Dakota Resources, Inc	EVERGREEN NATIONAL INDEMNITY C	M	3/13/2023	
1922	5691	Dakota Resources, Inc	5691	Dakota Resources, Inc	EVERGREEN NATIONAL INDEMNITY C	S	6/12/2023	V0 1355 1
171	5843	DAVCRO INC	5843	DAVCRO INC	SUNWEST BANK-HOBBS	B	4/4/1991	
1591	5898	DAVID H ARRINGTON OIL & GAS INC	5898	DAVID H ARRINGTON OIL & GAS INC	SECURITY BANK	M	1/31/2018	
294	6137	DEVON ENERGY PRODUCTION COMPANY, LP	6137	DEVON ENERGY PRODUCTION COMPANY, LP	AETNA CASUALTY & SURETY CO.	B	9/30/1993	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	6137	DEVON ENERGY PRODUCTION COMPANY, LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
672	6224	DINERO OPERATING CO	6224	DINERO OPERATING CO	FIRST AMERICAN BANK	M	3/18/2004	
1813	6464	DOYLE HARTMAN	6464	DOYLE HARTMAN	CASH BOND	B	3/16/2022	
1813	6464	DOYLE HARTMAN	6473	DOYLE HARTMAN	CASH BOND	B	3/16/2022	
237	6515	DUGAN PRODUCTION CORP	6515	DUGAN PRODUCTION CORP	FIRST NATL. BANK OF FARMINGTON	B	2/22/1993	
507	113927	DWIGHT A TIPTON	6550	DWIGHT A TIPTON	UNDERWRITERMS INDEMNITY		12/14/1998	
102	6676	E T C OIL CO	6676	E T C OIL CO	TRAVELERS INDEMNITY CO.	B	12/11/1986	
543	6742	ECHO PRODUCTION INC	6742	ECHO PRODUCTION INC	RLI INSURANCE CO.	M	4/5/2000	
599	7109	EL RAN INC	7109	EL RAN INC	RLI INSURANCE	B	7/30/2001	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	272	7269 NGX COMPANY		7269 NGX COMPANY	GULF INSURANCE CO.	B	7/27/1993	
	447	7272 ENERGY DEVELOPMENT CORP		7272 ENERGY DEVELOPMENT CORP	SAFECO INSURANCE CO OF AMERICA	B	11/26/1996	
	2043	64432 EOG RESOURCES, INC.		7377 EOG RESOURCES INC	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
	513	7673 EXXON MOBIL CORPORATION		7673 EXXON MOBIL CORPORATION	FEDERAL INSURANCE CO	B	4/1/1999	
	850	65888 FEATHERSTONE DEVELOPMENT CORPORATION		7819 FEATHERSTONE DEVELOPMENT CORP	OHIO CASUALTY INSURANCE COMPAN	B	12/18/2008	
	164	8079 FORTSON OIL CO		8079 FORTSON OIL CO	SUNWEST BANK-ALBUQUERQUE	B	11/28/1990	
	691	213179 H L BROWN OPERATING, LLC		9676 H L BROWN JR	US SPECIALTY INSURANCE	M	7/6/2004	
	903	9974 HANSON OPERATING CO INC		9974 HANSON OPERATING CO INC	U.S. SPECIALTY INSURANCE COMPA	M	2/25/2010	
	1899	10155 HARVARD PETROLEUM COMPANY, LLC		10155 HARVARD PETROLEUM COMPANY, LLC	EVERGREEN NATIONAL INDEMNITY C	M	1/4/2023	
	521	10268 HEADINGTON OIL CO LLC		10268 HEADINGTON OIL CO LLC	CONTINENTAL CASUALTY	B	8/4/1999	
	1770	10825 HUNT OIL CO		10825 HUNT OIL CO	ENDURANCE ASSURANCE CORPORATIO	M	10/30/2020	
	611	11095 J & J SERVICE INC		11095 J & J SERVICE INC	LEA COUNTY BANK	M	4/12/2015	
	152	11506 JACK J GRYNBERG		11506 JACK J GRYNBERG	FIRST INTERSTATE BANK-SANTA FE	B	1/29/1990	
	1869	12254 JPH OIL PRODUCERS DBA JIMMY P HODGE		12254 JPH OIL PRODUCERS DBA JIMMY P HODGE	FIRST AMERICAN BANK	M	8/19/2022	
	821	12361 KAISER-FRANCIS OIL CO		12361 KAISER-FRANCIS OIL CO	TRAVELERS CAUALTY AND SURETY C	M	12/21/2007	
	324	12558 KERR-MCGEE OIL & GAS ONSHORE LP		12558 KERR-MCGEE OIL & GAS ONSHORE LP	SAFECO INSURANCE CO. OF AMERIC	B	3/7/1994	
	348	12627 KEVIN O BUTLER & ASSOC INC		12627 KEVIN O BUTLER & ASSOC INC	UNITED STATES FIRE INSURANCE	B	11/10/1994	
	606	12627 KEVIN O BUTLER & ASSOC INC		12627 KEVIN O BUTLER & ASSOC INC	RLI INSURANCE CO.	B	1/3/2002	
	905	12807 KOCH EXPLORATION COMPANY, LLC		12807 KOCH EXPLORATION COMPANY, LLC	FEDERAL INSURANCE COMPANY	M	3/17/2010	
	218	13046 LANEXCO INC		13046 LANEXCO INC	UNDERWRITERS INDEMNITY CO.		12/9/1992	L0 4634 0

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1960	13089	LARIO OIL & GAS CO	13089	LARIO OIL & GAS CO	U.S. SPECIALTY INSURANCE COMPA	M	1/31/2024	
519	13300	BURLESON PETROLEUM, INC	13300	BURLESON PETROLEUM, INC	LEXON INSURANCE COMPANY	B	6/28/1999	
391	13645	LYNX PETROLEUM CONSULTANTS INC	13645	LYNX PETROLEUM CONSULTANTS INC	RLI INSURANCE COMPANY	B	8/31/1995	
857	154078	MACK ENERGY CORP. AND CHASE OIL CORP.	13837	MACK ENERGY CORP	U.S. SPECIALTY INSURANCE COMPA	M	3/9/2009	
590	13998	MARALEX RESOURCES INC	13998	MARALEX RESOURCES INC	FIDELITY & DEPOSIT	B	6/20/2001	
1509	86997	MARATHON OIL COMPANY LLC	14021	MARATHON OIL CO	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
1509	86997	MARATHON OIL COMPANY LLC	14035	MARATHON OIL CO	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
350	14070	MARKS AND GARNER PRODUCTION LTD CO	14070	MARKS AND GARNER PRODUCTION LTD CO	RLI INSURANCE COMPANY	B	12/14/1994	
1935	14096	MARK L SHIDLER INC	14096	MARK L SHIDLER INC	EVERGREEN NATIONAL INDEMNITY C	B	8/21/2023	
1936	14187	MARSHALL & WINSTON INC	14187	MARSHALL & WINSTON INC	EVERGREEN NATINAL INDEMNITY CO	B	11/8/2023	
446	14462	ME-TEX OIL & GAS INC	14462	ME-TEX OIL & GAS INC	UNDERWRITERM S INDEMNITY		11/12/1996	
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	14538	BURLINGTON RESOURCES OIL & GAS COMPANY LP	SAFECO INSURANCE CO.	B	8/3/1990	
858	149505	MERIT ENERGY COMPANY, LLC	14591	MERIT ENERGY COMPANY, LLC	FIDELITY AND DEPOSIT COMPANY O	M	3/2/2009	
252	14634	MERRION OIL & GAS CORP	14634	MERRION OIL & GAS CORP	FIRST NATL. BANK IN FARMINGTON	B	4/27/1993	
686	14744	MEWBOURNE OIL CO	14744	MEWBOURNE OIL CO	LIBERTY MUTUAL INSURANCE	B	6/4/2004	
972	90723	MEWBOURNE OIL COMPANY	14744	MEWBOURNE OIL CO	LIBERTY MUTUAL INSURANCE COMPA	M	9/20/2012	
1096	14771	MGM OIL & GAS CO	14771	MGM OIL & GAS CO	WELLS FARGO BANK, N.A.	M	12/18/2015	
38	15000	MISSION EXPLORATION	15000	MISSION EXPLORATION	HARTFORD ACCIDENT & INDEMNITY	B	4/14/1981	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	15025	DEVON ENERGY OPERATING COMPANY LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
958	15262	MOREXCO INC	15262	MOREXCO INC	WESTERN BANK	S	1/12/2016	V0 7076 1

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1989	314987	MURCHISON OIL & GAS,LLC	15363	Murchison Oil and Gas, LLC	EVERGREEN NATIONAL INDEMNITY C	M	9/3/2024	
943	15422	APACHE CORP	15422	APACHE CORP	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
51	15439	MWJ PRODUCING CO	15439	MWJ PRODUCING CO	TRAVELERS INDEMNITY CO.	B	2/19/1982	
964	15742	NEARBURG PRODUCING CO	15742	NEARBURG PRODUCING CO	U.S. SPECIALTY INSURANCE COMPA	M	6/13/2012	
2114	342431	NEW MEXICO INSTITUTE OF MINING AND TECHNOLOGY	15847	NEW MEXICO INSTITUTE OF MINING & TECHNOLOGY	FRANKENMUTH INSURANCE COMPANY	M	10/1/2025	
47	16482	OLSEN ENERGY INC	16482	OLSEN ENERGY INC	AMERICAN EMPLOYERS INS. CO.	B	6/24/1991	
876	16513	OMIMEX PETROLEUM INC	16513	OMIMEX PETROLEUM INC	U.S. SPECIALTY INSURANCE COMPA	M	6/18/2009	
1709	96694	OXY USA INC	16696	OXY USA INC	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
261	16903	PIONEER NATURAL RESOURCES USA INC	16903	PIONEER NATURAL RESOURCES USA INC	NATIONAL UNION FIRE INSURANCE	B	6/4/1993	
1673	108688	PAUL SLAYTON	17032	PAUL SLAYTON	BANK OF THE SOUTHWEST	B	6/1/2019	
888	17213	PENROC OIL CORP	17213	PENROC OIL CORP	US SPECIALTY INSURANCE COMPANY	M	11/4/2009	
238	17820	PLAINS RADIO PET CO	17811	PLAINS RADIO PETROLEUM CO	VALLEY BANK OF COMMERCE	B	2/22/1993	
238	17820	PLAINS RADIO PET CO	17820	PLAINS RADIO PET CO	VALLEY BANK OF COMMERCE	B	2/22/1993	
848	100363	PREMIER PRODUCTION COMPANY	17985	PREMIER OIL & GAS INC	WESTERN BANK	B	4/27/2015	
564	18099	PRIME OPERATING CO	18099	PRIME OPERATING CO	FIDELITY & DEPOSIT CO. OF MARY	B	9/1/2000	
607	18100	PRIMERO OPERATING INC	18100	PRIMERO OPERATING INC	VALLEY BANK OF COMMERCE	B	2/15/2002	
1952	18917	READ & STEVENS INC	18917	READ & STEVENS INC	U.S. SPECIALTY INSURANCE COMPA	M	1/22/2024	
323	19111	RHOMBUS OPERATING CO LTD	19111	RHOMBUS OPERATING CO LTD	UNDERWRITERS INDEMNITY CO.	B	3/7/1994	
1600	19174	RICE OPERATING COMPANY	19174	RICE OPERATING COMPANY	THE OHIO CASUALTY INS. CO.	M	6/10/2018	
778	19958	STEPHENS & JOHNSON OP CO	19958	STEPHENS & JOHNSON OP CO	U.S. SPECIALITY INSURANCE CO	B	8/23/2006	
1604	20165	SAMSON RESOURCES CO	20165	SAMSON RESOURCES CO	ARGONAUT INSURANCE COMPANY	B	8/6/2018	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
542	20451	SDX RESOURCES INC	20451	SDX RESOURCES INC	LEXON INSURANCE COMPANY	M	4/5/2000	
297	20497	SEELY OIL CO	20497	SEELY OIL CO	FIRST NATL. BANK OF ARTESIA	B	9/30/1993	
852	20497	SEELY OIL CO	20497	SEELY OIL CO	RLI INSURANCE COMPANY	M	1/9/2009	
358	20572	SG INTERESTS I LTD	20572	SG INTERESTS I LTD	RLI INSURANCE	B	2/17/1995	
104	107685	SHELL WESTERN E & P INC	20676	SHELL WESTERN E & P INC	ST. PAUL FIRE & MARINE INS. CO	B	12/29/1986	
707	20713	SHINNERY OIL COMPANY, INC	20713	SHINNERY OIL COMPANY, INC	LEXON INSURANCE COMPANY	M	10/29/2004	
256	20847	SIETE OIL & GAS CORP	20847	SIETE OIL & GAS CORP	SUNWEST BANK OF ROSWELL	B	5/5/1993	
266	21013	SNOW OIL & GAS INC	21013	SNOW OIL & GAS INC	WAIVER	B	7/7/1993	
287	109937	SOUTHWEST ROYALTIES INC	21355	SOUTHWEST ROYALTIES INC	RLI INSURANCE COMPANY	B	8/24/1993	
640	21566	STEARNS	21566	STEARNS	RLI INSURANCE	B	5/27/2003	
520	21602	TRILOGY OPERATING INC	21602	TRILOGY OPERATING INC	TRINITY UNIVERSAL INSURANCE CO	B	7/19/1999	
870	21712	STRATA PRODUCTION CO	21712	STRATA PRODUCTION CO	RLI INSURANCE COMPANY	M	4/27/2009	
625	22044	MCELVAIN ENERGY, INC	22044	MCELVAIN ENERGY, INC	FIDELITY & DEPOSIT	B	12/26/2002	
15	22256	TENNECO OIL CO	22256	TENNECO OIL CO	AETNA CASUALTY & SURETY CO.	B	8/6/1979	
1392	22767	EASTLAND OIL CO	22767	EASTLAND OIL CO	ENDURANCE ASSURANCE CORP.	B	8/4/2016	
390	24010	V-F PETROLEUM INC	24010	V-F PETROLEUM INC	UNDERWRITERS INDEMNITY	B	8/30/1995	
277	24164	VINTAGE DRILLING LLC	24164	VINTAGE DRILLING LLC	WESTERN BANK	B	7/27/1993	
1010	24173	VINTAGE PETROLEUM,LLC	24173	VINTAGE PETROLEUM,LLC	ARCH INSURANCE COMPANY	M	7/3/2014	
386	24188	VISION ENERGY INC	24188	VISION ENERGY INC	IRREVOCABLE LETTER OF CREDIT	B	12/1/2015	
752	24480	WAGNER & BROWN	24480	WAGNER & BROWN	TRAVELERS CASUALTY	B	11/4/2005	
1805	339667	WALSH & WATTS INC.	24558	WALSH & WATTS INC	U.S. SPECIALTY INSURANCE COMPA	M	1/12/2022	
748	25078	WHITING OIL AND GAS CORPORATION	25078	WHITING OIL AND GAS CORPORATION	RLI INSURANCE	M	10/4/2005	
1925	25454	WTG EXPLORATION INC	25454	WTG EXPLORATION INC	EVERGREEN NATIONAL INDEMNITY C	M	7/12/2023	
303	25482	XERIC OIL & GAS CORP	25482	XERIC OIL & GAS CORP	UNITED NEW MEXICO BANK	B	11/29/1993	
751	25542	YATES ENERGY CORP	25542	YATES ENERGY CORP	US SPECIALTY	B	10/28/2005	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
536	25706	CLAYTON WILLIAMS ENERGY INC	25706	CLAYTON WILLIAMS ENERGY INC	RLI INSURANCE COMPANY	M	1/6/2000	
758	26307	JALAPENO CORPORATION	26307	JALAPENO CORPORATION	US SPECIALTY INSURANCE	B	1/27/2006	
418	130308	SABRE OPERATING INC	26460	SABRE OP INC	RLI INSURANCE COMPANY	B	2/21/1996	
227	43910	ATLANTIC RICHFIELD CO	30271	ARCO OIL & GAS CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	30280	ATLANTIC RICHFIELD COMPANY	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
1788	31560	EVKO DEVELOPMEN T CO	31560	EVKO DEVELOPMEN T CO	CASH BOND	B	9/10/2021	
1509	86997	MARATHON OIL COMPANY LLC	32954	MARATHON OIL CO - OIL	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
1509	86997	MARATHON OIL COMPANY LLC	32966	MARATHON OIL CO - PURCH	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
749	33021	MCBRIDE OIL AND GAS CORP	33021	MCBRIDE OIL AND GAS CORP	US SPECIALTY INSURANCE	B	10/17/2005	
1709	96694	OXY USA INC	33726	OXY USA INC - OIL	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
840	34945	KINDER MORGAN CO2 CO. LP	34945	KINDER MORGAN CO2 CO. LP	SAFECO INSURANCE COMPANY OF AM	M	6/27/2008	
1891	35048	SPEEREX LTD - PARTNERSHIP	35048	SPEEREX LTD - PARTNERSHIP	SOUTH ATLANTIC BANK	B	5/25/2022	
394	36851	YARBROUGH OIL LP	36851	YARBROUGH OIL LP	RLI INSURANCE COMPANY	B	9/26/1995	
1961	36851	YARBROUGH OIL LP	36851	YARBROUGH OIL LP	EVERGREEN NATIONAL INDEMNITY C	B	1/31/2024	
441	37079	GRAND BANKS ENERGY CO	37079	GRAND BANKS ENERGY CO	RLI INSURANCE COMPANY	B	8/1/1996	
322	37197	WEST LARGO CORP	37197	WEST LARGO CORP	UNITED NEW MEXICO BANK	S	3/3/1994	E0 1451 5
1392	22767	EASTLAND OIL CO	37465	EASTLAND OIL COMPANY	ENDURANCE ASSURANCE CORP.	B	8/4/2016	
702	37627	WESTERN GAS RESOURCES	37627	WESTERN GAS RESOURCES	LIBERTY MUTUAL	M	9/29/2004	
660	41452	HESS CORPORATION	41452	HESS CORPORATION	SAFECO INSURANCE COMPANY OF AM	B	11/24/2003	
17	778	BP AMERICA PRODUCTION COMPANY	41874	BP AMERICA PRODUCTION CO.	SEABOARD SURETY COMPANY	B	8/27/1979	
315	117139	BP AMERICA PRODUCTION COMPANY	41874	BP AMERICA PRODUCTION CO.	TRAVELERS CASUALTY & SURETY	B	1/13/1994	
1587	218098	BP AMERICA PRODUCTION COMPANY	41874	BP AMERICA PRODUCTION CO.	TRAVELERS CASUALTY AND SURETY	M	11/11/2017	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1588	218098	BP AMERICA PRODUCTION COMPANY	41874	BP AMERICA PRODUCTION CO.	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
17	778	BP AMERICA PRODUCTION COMPANY	41909	BP AMERICA PRODUCTION COMPANY	SEABOARD SURETY COMPANY	B	8/27/1979	
315	117139	BP AMERICA PRODUCTION COMPANY	41909	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY & SURETY	B	1/13/1994	
1588	218098	BP AMERICA PRODUCTION COMPANY	41909	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
17	778	BP AMERICA PRODUCTION COMPANY	41947	BP AMERICA PRODUCTION CO.	SEABOARD SURETY COMPANY	B	8/27/1979	
315	117139	BP AMERICA PRODUCTION COMPANY	41947	BP AMERICA PRODUCTION CO.	TRAVELERS CASUALTY & SURETY	B	1/13/1994	
1588	218098	BP AMERICA PRODUCTION COMPANY	41947	BP AMERICA PRODUCTION CO.	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
943	15422	APACHE CORP	42614	APACHE CORP	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
943	15422	APACHE CORP	42629	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
943	15422	APACHE CORP	42632	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
227	43910	ATLANTIC RICHFIELD CO	43042	ARCO OIL & GAS CO PERMIAN DIST WEST	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
133	1163	ASHER OIL CO	43602	ASHER OIL CO	WESTERN BANK	B	8/16/1988	
227	43910	ATLANTIC RICHFIELD CO	43864	ATLANTIC RICH CO & COLO OIL CO INC	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	43873	ATLANTIC RICH CO & TEX PROD INC	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	43897	ATLANTIC RICHFIELD & MONSANTO OILCO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	43908	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	43910	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	43924	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	43933	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	43941	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
227	43910	ATLANTIC RICHFIELD CO	43955	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	227	43910 ATLANTIC RICHFIELD CO	43962	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
	227	43910 ATLANTIC RICHFIELD CO	43979	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
	227	43910 ATLANTIC RICHFIELD CO	43986	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
	227	43910 ATLANTIC RICHFIELD CO	43990	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
	227	43910 ATLANTIC RICHFIELD CO	44009	ATLANTIC RICHFIELD CO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
	227	43910 ATLANTIC RICHFIELD CO	44012	ATLANTIC RICHFIELD CO AND DOYLE HARTMAN	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
	227	43910 ATLANTIC RICHFIELD CO	44023	ATLANTIC RICHFIELD CO & EL PASO	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
	227	43910 ATLANTIC RICHFIELD CO	44034	ATLANTIC RICHFIELD CO & EL PASO GAS	TRAVELERS CASUALTY & SURETY	B	12/9/1992	
	2003	45465 PERRY R BASS TRUSTEE	45465	PERRY R BASS TRUSTEE	ARCH INSURANCE COMPANY	M	10/15/2024	
	340	1903 BEACH EXPLORATION INC	45711	BEACH EXPLORATION INC	UNDERWRITERS INDEMNITY CO.	B	6/14/1994	
	206	2096 BENSON-MONTIN-GREER DRILLING CORP	46511	BENSON-MONTIN-GREER DRILLING CORP	CITIZENS BANK	B	9/28/1992	
	206	2096 BENSON-MONTIN-GREER DRILLING CORP	46520	BENSON-MONTIN-GREER DRILLING CORP	CITIZENS BANK	B	9/28/1992	
	206	2096 BENSON-MONTIN-GREER DRILLING CORP	46538	BENSON-MONTIN-GREER DRILLING CORP	CITIZENS BANK	B	9/28/1992	
	1642	46950 BHP BILLITON PETROLEUM (AMERICAS) INC.	46950	BHP BILLITON PETROLEUM (AMERICAS) INC.	LIBERTY MUTUAL INSURANCE COMPA	M	5/24/2019	
	127	2702 BP EXPLORATION INC	48657	BP EXPLORATION INC.	TRAVELERS CASUALTY & SURETY CO	B	4/19/1988	
	648	49239 BROUGHTON PETROLEUM INC	49239	BROUGHTON PETROLEUM INC	NATIONAL AMERICAN INSURANCE	S	7/24/2003	V0 226 0
	2042	49239 BROUGHTON PETROLEUM INC	49239	BROUGHTON PETROLEUM INC	CROSSFIRST BANK	B	1/21/2025	
	1854	49408 JAMES L. BROWN	49408	JAMES L. BROWN	WAIVER	S	7/12/2022	B1 419 67
	691	213179 H L BROWN OPERATING, LLC	49520	H L BROWN JR	US SPECIALTY INSURANCE	M	7/6/2004	
	857	154078 MACK ENERGY CORP. AND CHASE OIL CORP.	50084	CHASE OIL CORP.	U.S. SPECIALTY INSURANCE COMPA	M	3/9/2009	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
204	3044	BURGUNDY OIL & GAS OF N M INC	50348	BURGUNDY OIL & GAS OF N MEX INC	UNDERWRITERBS INDEMNITY CO.		9/9/1992	
1757	51549	CAL-MON OIL COMPANY	51549	CAL-MON OIL COMPANY	COMMUNITY NATIONAL BANK	B	3/31/2021	
857	154078	MACK ENERGY CORP. AND CHASE OIL CORP.	53773	CHASE OIL CORPORATION	U.S. SPECIALTY INSURANCE COMPA	M	3/9/2009	
514	54207	CHEVRON USA INC	54186	CHEVRON USA INC	SAFECO INSURANCE CO OF AMERICA	M	4/1/1999	
110	4323	CHEVRON U S A INC	54190	CHEVRON USA INC	UNITED PACIFIC INS. CO.	B	6/26/1987	
514	54207	CHEVRON USA INC	54190	CHEVRON USA INC	SAFECO INSURANCE CO OF AMERICA	M	4/1/1999	
514	54207	CHEVRON USA INC	54207	CHEVRON USA INC	SAFECO INSURANCE CO OF AMERICA	M	4/1/1999	
514	54207	CHEVRON USA INC	54216	CHEVRON USA INC	SAFECO INSURANCE CO OF AMERICA	M	4/1/1999	
514	54207	CHEVRON USA INC	54284	CHEVRON USA INC	SAFECO INSURANCE CO OF AMERICA	M	4/1/1999	
514	54207	CHEVRON USA INC	54296	CHEVRON USA INC	SAFECO INSURANCE CO OF AMERICA	M	4/1/1999	
514	54207	CHEVRON USA INC	54302	CHEVRON USA INC	SAFECO INSURANCE CO OF AMERICA	M	4/1/1999	
514	54207	CHEVRON USA INC	54326	CHEVRON USA INC	SAFECO INSURANCE CO OF AMERICA	M	4/1/1999	
258	4378	CHI OPERATING INC	54404	CHI ENERGY INC	RLI INSURANCE COMPANY	B	5/5/1993	
840	34945	KINDER MORGAN CO2 CO. LP	57775	CORTEZ PIPELINE CO	SAFECO INSURANCE COMPANY OF AM	M	6/27/2008	
1829	339860	CRESCENT PORTER HALE FOUNDATION	58731	CRESCENT PORTER HALE FOUNDATION	CASH BOND	B	3/22/2022	
913	197035	XTO ENERGY INC	59005	XTO ENERGY, INC.	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
1910	5691	Dakota Resources, Inc	59440	DAKOTA RESOURCES INC	EVERGREEN NATIONAL INDEMNITY C	M	3/13/2023	
673	60289	DAWSON GEOPHYSICAL	60289	DAWSON GEOPHYSICAL	US SPECIALTY INSURANCE CO.	M	3/18/2004	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	61077	DEVON ENERGY PRODUCTION CO., LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	61082	DEVON ENERGY PRODUCTION CO., LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
237	6515	DUGAN PRODUCTION CORP	62230	DUGAN PRODUCTION CORP	FIRST NATL. BANK OF FARMINGTON	B	2/22/1993	
2128	62526	DURANGO PRODUCTION CORP	62526	DURANGO PRODUCTION CORP	CASH BOND	S	1/29/2026	SG 42 0
418	130308	SABRE OPERATING INC	62526	DURANGO PRODUCTION CORP	RLI INSURANCE COMPANY	B	2/21/1996	
1392	22767	EASTLAND OIL CO	62923	EASTLAND OIL COMPANY	ENDURANCE ASSURANCE CORP.	B	8/4/2016	
104	107685	SHELL WESTERN E & P INC	63086	SHELL WESTERN E & P	ST. PAUL FIRE & MARINE INS. CO	B	12/29/1986	
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	63601	BURLINGTON RESOURCES OIL AND GAS CO. L.P.	SAFECO INSURANCE CO.	B	8/3/1990	
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	63615	BURLINGTON RESOURCES & XTO ENERGY	SAFECO INSURANCE CO.	B	8/3/1990	
1793	64269	EOG RESOURCES AND KING RESOURCES	64269	EOG RESOURCES AND KING RESOURCES	LIBERTY MUTUAL INSURANCE COMPA	S	10/5/2021	LG 1869 1
2043	64432	EOG RESOURCES, INC.	64283	EOG RESOURCES,INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
2043	64432	EOG RESOURCES, INC.	64432	EOG RESOURCES, INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
226	172981	EEX OPERATING, L.P.	64476	EEX CORPORATION	ST. PAUL FIRE AND MARINE	B	12/9/1992	
1796	65531	FAIR OIL LTD	65531	FAIR OIL LTD	CASH BOND/ SOUTHSIDE BANK	M	11/17/2021	
1754	151416	FASKEN OIL & RANCH LTD	65792	FASKEN LAND AND MINERALS, LTD.	U.S. SPECIALTY INSURANCE COMPA	M	2/26/2021	
850	65888	FEATHERSTONE DEVELOPMENT CORPORATION	65888	FEATHERSTONE DEVELOPMENT CORPORATION	OHIO CASUALTY INSURANCE COMPAN	B	12/18/2008	
164	8079	FORTSON OIL CO	67463	FORTSON OIL COMPANY	SUNWEST BANK-ALBUQUERQUE	B	11/28/1990	
164	8079	FORTSON OIL CO	67474	FORTSON OIL COMPANY	SUNWEST BANK-ALBUQUERQUE	B	11/28/1990	
164	8079	FORTSON OIL CO	67489	FORTSON OIL COMPANY	SUNWEST BANK-ALBUQUERQUE	B	11/28/1990	
1823	71826	WALTER GRANBERRY JR	71826	WALTER GRANBERRY JR	CASH BOND	B	4/8/2022	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
943	15422	APACHE CORP	73368	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
898	241333	CHEVRON MIDCONTINENT, L.P.	73564	CHEVRON MIDCONTINENT LP	SAFECO INSURANCE COMPANY OF AM	M	2/10/2010	
1913	73935	PEABODY NATURAL RESOURCES COMPANY	73935	PEABODY NATURAL RESOURCES COMPANY	INDEMNITY NATIONAL INSURANCE C	M	3/27/2023	
1813	6464	DOYLE HARTMAN	74572	DOYLE HARTMAN	CASH BOND	B	3/16/2022	
1004	261044	MRC PERMIAN COMPANY	74640	MRC DELAWARE RESOURCES, LLC	ARCH INSURANCE COMPANY	M	1/7/2014	
521	10268	HEADINGTON OIL CO LLC	75035	HEADINGTON MINERALS INC	CONTINENTAL CASUALTY	B	8/4/1999	
1770	10825	HUNT OIL CO	77722	HUNT OIL COMPANY	ENDURANCE ASSURANCE CORPORATIO	M	10/30/2020	
202	78436	J CLEO & JAMES CLEO THOMPSON JR, L.P.	78436	J CLEO & JAMES CLEO THOMPSON JR, L.P.	GULF INSURANCE CO./ TRAVELERS I	B	8/28/1992	
304	83137	ROBERT E LANDRETH	83137	ROBERT E LANDRETH	UNITED NEW MEXICO BANK/ ROSWELL	S	11/29/1993	VB 410 0
458	83137	ROBERT E LANDRETH	83137	ROBERT E LANDRETH	NORWEST BANK OF NM	B	4/7/1997	
1960	13089	LARIO OIL & GAS CO	83338	LARIO OIL & GAS CO	U.S. SPECIALTY INSURANCE COMPA	M	1/31/2024	
1945	83338	LARIO OIL & GAS CO	83338	LARIO OIL & GAS CO	WAIVER	S	11/22/2023	VC 1194 0
1946	83338	LARIO OIL & GAS CO	83338	LARIO OIL & GAS CO	WAIVER	S	11/22/2023	VC 1195 0
1960	13089	LARIO OIL & GAS CO	83346	LARIO OIL & GAS CO	U.S. SPECIALTY INSURANCE COMPA	M	1/31/2024	
1864	84093	LEEDE OPERATING COMPANY, LIMITED LIABILITY CO	84093	LEEDE OPERATING COMPANY, LIMITED LIABILITY CO	CASH BOND	B	8/10/2022	
1661	86143	MACK ENERGY CORPORATION	86143	MACK ENERGY CORPORATION	U.S. SPECIALTY INSURANCE COMPA	M	8/15/2019	
857	154078	MACK ENERGY CORP. AND CHASE OIL CORP.	86143	MACK ENERGY CORPORATION	U.S. SPECIALTY INSURANCE COMPA	M	3/9/2009	
1509	86997	MARATHON OIL COMPANY LLC	86988	MARATHON OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
1509	86997	MARATHON OIL COMPANY LLC	86997	MARATHON OIL COMPANY LLC	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
1509	86997	MARATHON OIL COMPANY LLC	87006	MARATHON OIL CO	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1509	86997	MARATHON OIL COMPANY LLC	87022	MARATHON OIL CO & TEX PROD INC	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
625	22044	MCELVAIN ENERGY, INC	89247	MCELVAIN ENERGY, INC.	FIDELITY & DEPOSIT	B	12/26/2002	
686	14744	MEWBOURNE OIL CO	90712	MEWBOURNE OIL COMPANY	LIBERTY MUTUAL INSURANCE	B	6/4/2004	
972	90723	MEWBOURNE OIL COMPANY	90712	MEWBOURNE OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	9/20/2012	
686	14744	MEWBOURNE OIL CO	90723	MEWBOURNE OIL COMPANY	LIBERTY MUTUAL INSURANCE	B	6/4/2004	
972	90723	MEWBOURNE OIL COMPANY	90723	MEWBOURNE OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	9/20/2012	
972	90723	MEWBOURNE OIL COMPANY	90734	MEWBOURNE OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	9/20/2012	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	91575	DEVON ENERGY PRODUCTION CO.	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
2002	91745	MOBIL PRODUCING TEXAS & NM INC	91739	MOBIL PRODUCING TEXAS & NM INC	LIBERTY MUTUAL INSURANCE COMPA	M	10/15/2024	
2002	91745	MOBIL PRODUCING TEXAS & NM INC	91745	MOBIL PRODUCING TEXAS & NM INC	LIBERTY MUTUAL INSURANCE COMPA	M	10/15/2024	
723	91994	W A MONCRIEF JR	91994	W A MONCRIEF JR	US SPECIALTY INSURANCE	M	2/11/2005	
943	15422	APACHE CORP	93661	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
964	15742	NEARBURG PRODUCING CO	94230	NEARBURG PRODUCING CO	U.S. SPECIALTY INSURANCE COMPA	M	6/13/2012	
964	15742	NEARBURG PRODUCING CO	94242	NEARBURG PRODUCING COMPANY	U.S. SPECIALTY INSURANCE COMPA	M	6/13/2012	
1885	94891	NM OIL CORP	94891	NM OIL CORP	WAIVER	S	9/8/2022	B1 420 183
1709	96694	OXY USA INC	96694	OXY USA INC	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	96704	OXY USA WTP LIMITED PARTNERSHIP	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
124	97134	PALOMA OPERATING CO	97134	PALOMA OPERATING CO	UNITED NEW MEXICO BANK-LEA COU	B	4/15/1988	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	98117	DEVON ENERGY PRODUCTION CO. LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
226	172981	EEX OPERATING, L.P.	98959	EEX CORPORATION	ST. PAUL FIRE AND MARINE	B	12/9/1992	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
627	217817	CONOCOPHILLIPS COMPANY	99210	CONOCOPHILLIPS COMPANY	SAFECO INSURANCE CO OF AMERICA	M	1/28/2003	
20	256999	POGO PRODUCING COMPANY LLC	99834	POGO PRODUCING CO	RLI INSURANCE COMPANY	B	10/15/2008	
848	100363	PREMIER PRODUCTION COMPANY	100363	PREMIER PRODUCTION COMPANY	WESTERN BANK	B	4/27/2015	
1952	18917	READ & STEVENS INC	101924	READ & STEVENS INC	U.S. SPECIALTY INSURANCE COMPA	M	1/22/2024	
71	101924	READ & STEVENS INC	101924	READ & STEVENS INC	COMMERCIAL UNION INSURANCE CO.	B	9/7/1983	
984	101924	READ & STEVENS INC	101924	READ & STEVENS INC	WEST TEXAS NATIONAL BANK	M	3/18/2013	
2037	104738	RUTTER AND WILBANKS CORPORATION	104738	RUTTER AND WILBANKS CORPORATION	CASH BOND	M	1/9/2025	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	106015	DEVON ENERGY PRODUCTION CO.	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	106048	DEVON ENERGY PRODUCTION CO., LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	106114	DEVON ENERGY PRODUCTION CO., L.P.	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	106132	DEVON ENERGY PRODUCTION CO., LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	106176	DEVON ENERGY PRODUCTION CO., LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1140	106718	DOUG J. SCHUTZ	106718	DOUG J. SCHUTZ	WAIVER	S	2/24/2016	VB 2649 0
297	20497	SEELY OIL CO	107021	SEELY OIL COMPANY	FIRST NATL. BANK OF ARTESIA	B	9/30/1993	
852	20497	SEELY OIL CO	107021	SEELY OIL COMPANY	RLI INSURANCE COMPANY	M	1/9/2009	
892	107096	STEVE SELL	107096	STEVE SELL	WAIVER	S	12/14/2009	VA 1188 4
49	107609	SHELL OIL CO	107609	SHELL OIL CO	INSURANCE CO. OF NORTH AMERICA	B	12/18/1981	
49	107609	SHELL OIL CO	107623	SHELL OIL COMPANY	INSURANCE CO. OF NORTH AMERICA	B	12/18/1981	
1710	107647	OXY Y-1 COMPANY	107647	OXY Y-1 COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
104	107685	SHELL WESTERN E & P INC	107685	SHELL WESTERN E & P INC	ST. PAUL FIRE & MARINE INS. CO	B	12/29/1986	
104	107685	SHELL WESTERN E & P INC	107692	SHELL WESTERN E & P INC	ST. PAUL FIRE & MARINE INS. CO	B	12/29/1986	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1673	108688	PAUL SLAYTON	108688	PAUL SLAYTON	BANK OF THE SOUTHWEST	B	6/1/2019	
123	109413	SOFIA EXPLORATION COMPANY	109413	SOFIA EXPLORATION COMPANY	WAIVER - FOREST ATCHLEY	S	10/20/1986	LH 3449 1
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	109818	BURLINGTON RESOURCES OIL & GAS CO., L.P.	SAFECO INSURANCE CO.	B	8/3/1990	
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	109843	BURLINGTON RESOURCES OIL & GAS CO., L.P.	SAFECO INSURANCE CO.	B	8/3/1990	
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	109854	BURLINGTON RESOURCES OIL & GAS CO., L.P.	SAFECO INSURANCE CO.	B	8/3/1990	
287	109937	SOUTHWEST ROYALTIES INC	109937	SOUTHWEST ROYALTIES INC	RLI INSURANCE COMPANY	B	8/24/1993	
287	109937	SOUTHWEST ROYALTIES INC	109944	SOUTHWEST ROYALTIES INCORPORATED	RLI INSURANCE COMPANY	B	8/24/1993	
1891	35048	SPEEREX LTD - PARTNERSHIP	110219	SPEEREX LIMITED PARTNERSHIP	SOUTH ATLANTIC BANK	B	5/25/2022	
445	1329	AUTRY C STEPHENS	110670	AUTRY C STEPHENS	NORWEST BANK OF NEW MEXICO	B	10/19/1996	
324	12558	KERR-MCGEE OIL & GAS ONSHORE LP	111592	KERR-MCGEE O/G ONSHORE, LP	SAFECO INSURANCE CO. OF AMERIC	B	3/7/1994	
170	112688	TENISON OIL COMPANY	112688	TENISON OIL COMPANY	UNDERWRITERS S INDEMNITY CO.		4/4/1991	L0 4333 0
1993	113315	TEXLAND PETROLEUM-HOBBS, LLC	113315	TEXLAND PETROLEUM-HOBBS, LLC	EVERGREEN NATIONAL INDEMNITY C	M	9/17/2024	
507	113927	DWIGHT A TIPTON	113927	DWIGHT A TIPTON	UNDERWRITERM S INDEMNITY		12/14/1998	
999	3474	C W TRAINER	114463	C W TRAINER	SECURITY BANK	B	9/13/2013	
999	3474	C W TRAINER	114474	C W TRAINER	SECURITY BANK	B	9/13/2013	
999	3474	C W TRAINER	114489	C W TRAINER	SECURITY BANK	B	9/13/2013	
999	3474	C W TRAINER	114491	C W TRAINER	SECURITY BANK	B	9/13/2013	
1832	114794	TRIGG FAMILY TRUST	114794	TRIGG FAMILY TRUST	CASH BOND	B	5/11/2022	
355	115804	UNION OIL CO OF CALIF	115804	UNION OIL CO OF CALIF	TRAVELERS CASUALTY & SURETY CO	B	1/10/1995	
649	116196	QEP ENERGY COMPANY	116196	QEP ENERGY COMPANY	LIBERTY MUTUAL	B	7/24/2003	
1739	116962	VALLEY INC	116962	VALLEY INC	UNITED STATES AND GUARANTY COM	M	8/1/2020	
17	778	BP AMERICA PRODUCTION COMPANY	117139	BP AMERICA PRODUCTION COMPANY	SEABOARD SURETY COMPANY	B	8/27/1979	
315	117139	BP AMERICA PRODUCTION COMPANY	117139	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY & SURETY	B	1/13/1994	
1588	218098	BP AMERICA PRODUCTION COMPANY	117139	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
362	119305	RAY WESTALL OPERATING, INC.	119305	RAY WESTALL OPERATING, INC.	GULF INSURANCE CO.	B	3/9/1995	
2079	119305	RAY WESTALL OPERATING, INC.	119305	RAY WESTALL OPERATING, INC.	EVERGREEN NATIONAL INDEMNITY C	M	5/29/2025	
1095	119957	PHILIP L WHITE	119957	PHILIP L WHITE	BOK FINANCIAL	S	12/16/2015	VB 2126 0
1745	120782	WPX ENERGY PRODUCTION, LLC	120782	WPX ENERGY PRODUCTION, LLC	LIBERTY MUTUAL INSURANCE COMPA	B	1/27/2021	
60	121728	WOODS PETROLEUM CORP	121728	WOODS PETROLEUM CORP	ST. PAUL FIRE & MARINE INS. CO	B	7/27/1982	
850	65888	FEATHERSTONE DEVELOPMENT CORPORATION	123330	FEATHERSTONE DEVELOPMENT CORPORATION	OHIO CASUALTY INSURANCE COMPAN	B	12/18/2008	
988	123375	JAMES HAMILTON CONSTRUCTION CO.	123375	JAMES HAMILTON CONSTRUCTION CO.	ALLEGHENY CASUALTY CO.	M	6/1/2013	
1509	86997	MARATHON OIL COMPANY LLC	123419	MARATHON OIL COMPANY LLC & SDX RESOURCES, INC	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
1953	123558	MOUNTAIN STATES CONSTRUCTORS, INC.	123558	MOUNTAIN STATES CONSTRUCTORS, INC.	WESTERN SURETY COMPANY	M	1/11/2024	
2043	64432	EOG RESOURCES, INC.	123807	EOG RESOURCES INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
103	123849	GREAT WESTERN DRILLING LTD	123849	GREAT WESTERN DRILLING LTD	TRAVELERS INDEMNITY CO.	B	1/6/1987	
967	124768	MNA ENTERPRISES LTD CO	124768	MNA ENTERPRISES LTD CO	LEXON INSURANCE COMP.	M	7/26/2012	
114	125839	CENTURY PRODUCTION, INC.	125839	CENTURY PRODUCTION, INC.	FIDELITY & DEPOSIT CO. OF MARY	B	1/4/1983	
631	126430	GOLIAD PARTNERS, L.P.	126430	GOLIAD PARTNERS, L.P.	TRAVELERS CASUALTY & SURETY	B	2/3/2003	
307	126493	SHELL OIL & GAS INVESTMENT L.P., ET AL.	126493	SHELL OIL & GAS INVESTMENT L.P., ET AL.	UNITED PACIFIC INSURANCE CO.	B	11/29/1993	
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	129146	BURLINGTON RESOURCES & OMIMEX PETROLEUM INC.	SAFECO INSURANCE CO.	B	8/3/1990	
521	10268	HEADINGTON OIL CO LLC	129202	HEADINGTON INVESTMENTS, INC.	CONTINENTAL CASUALTY	B	8/4/1999	
521	10268	HEADINGTON OIL CO LLC	129226	HEADINGTON ROYALTY, INC.	CONTINENTAL CASUALTY	B	8/4/1999	
418	130308	SABRE OPERATING INC	130308	SABRE OPERATING INC	RLI INSURANCE COMPANY	B	2/21/1996	
1366	131559	PURVIS OPERATING CO	131559	PURVIS OPERATING CO	FIRST NATIONAL BANK OF MIDLAND	M	6/2/2009	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
354	131994	FOUR STAR OIL & GAS CO	131994	FOUR STAR OIL & GAS CO	INSURANCE CO. OF NORTH AMERICA	B	1/3/1995	
2043	64432	EOG RESOURCES, INC.	134259	EOG RESOURCES, INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1366	131559	PURVIS OPERATING CO	134857	PURVIS OPERATING CO	FIRST NATIONAL BANK OF MIDLAND	M	6/2/2009	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	136025	DEVON ENERGY OPERATING CORP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
999	3474	C W TRAINER	138277	C W TRAINER	SECURITY BANK	B	9/13/2013	
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	138746	BURLINGTON RESOURCES AND MARATHON OIL CO.	SAFECO INSURANCE CO.	B	8/3/1990	
625	22044	MCELVAIN ENERGY, INC	140204	T. H. MCELVAIN OIL & GAS LLLP	FIDELITY & DEPOSIT	B	12/26/2002	
1509	86997	MARATHON OIL COMPANY LLC	140468	MARATHON OIL CO&BURLINGTON RESOURCES OG CO LP	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	SAFECO INSURANCE CO.	B	8/3/1990	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	140544	DEVON ENERGY OPERATING CORP.	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
484	172635	FULFER OIL & CATTLE CO., LLC	141402	FULFER OIL & CATTLE LLC	UNDERWRITERS S INDEMNITY		1/18/1998	B1 1300 3
494	172635	FULFER OIL & CATTLE CO., LLC	141402	FULFER OIL & CATTLE LLC	UNDERWRITERS S INDEMNITY		5/18/1998	E0 1057 0
512	252708	PATTERSON PETROLEUM LLC	141928	PATTERSON PETROLEUM LLC	RLI INSURANCE COMPANY	M	8/6/2007	
238	17820	PLAINS RADIO PET CO	142887	PLAINS RADIO PETROLEUM CO	VALLEY BANK OF COMMERCE	B	2/22/1993	
720	143199	ENERVEST OPERATING L.L.C.	143199	ENERVEST OPERATING L.L.C.	RLI INSURANCE	B	2/10/2005	
819	143199	ENERVEST OPERATING L.L.C.	143199	ENERVEST OPERATING L.L.C.	RLI INSURANCE COMPANY	M	11/8/2007	
1509	86997	MARATHON OIL COMPANY LLC	144121	MARATHON OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
373	145590	SHELL LAND & ENERGY CO.	145590	SHELL LAND & ENERGY CO.	ST. PAUL FIRE & MARINE	B	4/7/1995	
1754	151416	FASKEN OIL & RANCH LTD	145768	FASKEN ACQUISITIONS 95-I, LTD.	U.S. SPECIALTY INSURANCE COMPA	M	2/26/2021	
1053	146906	ANSCHUTZ EXPLORATION CORPORATION	146906	ANSCHUTZ EXPLORATION CORPORATION	TRAVELERS CASUALTY & SURETY CO	M	11/13/2014	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1632	147141	ELAND ENERGY, INC.	147141	ELAND ENERGY, INC.	N/A	B	2/25/2019	
1583	147404	COBRA OIL & GAS CORPORATION	147404	COBRA OIL & GAS CORPORATION	U.S. SPECIALTY INSURANCE COMPA	M	2/15/2018	
1820	147691	CHILDRESS ROYALTY COMPANY	147691	CHILDRESS ROYALTY COMPANY	CASH BOND	B	3/29/2022	
991	148111	SOUTHWESTERN ENERGY PRODUCTION COMPANY	148111	SOUTHWESTERN ENERGY PRODUCTION COMPANY	TRAVELERS CASUALTY & SURETY CO	M	7/18/2013	
567	148376	NADEL AND GUSSMAN AND NADEL & GUSSMAN PERM	148376	NADEL AND GUSSMAN AND NADEL & GUSSMAN PERM	FIDELITY & DEPOSIT	M	11/6/2000	
596	148394	VERNON E. FAULCONER, INC.	148394	VERNON E. FAULCONER, INC.	RLI INSURANCE	B	7/24/2001	
810	148981	MIDLAND OPERATING INC.	148981	MIDLAND OPERATING INC.	LEXON INSURANCE COMPANY	B	7/11/2008	
1866	149315	MAGNUM HUNTER PRODUCTION, INC.	149315	MAGNUM HUNTER PRODUCTION, INC.	RLI INSURANCE COMPANY	M	7/21/2022	
1981	149408	FNF CONSTRUCTION INC	149408	FNF CONSTRUCTION INC	LIBERTY MUTUAL INSURANCE COMPA	M	7/10/2024	
2141	342739	FNF CONSTRUCTION, INC.	149408	FNF CONSTRUCTION INC	TRAVELERS CASUALTY AND SURETY	M	12/22/2025	
977	149424	ICA ENERGY, INC.	149424	ICA ENERGY, INC.	WELLS FARGO BANK N.A.	M	1/22/2013	
573	149441	RELIANCE ENERGY, INC.	149441	RELIANCE ENERGY, INC.	WEST TEXAS NATIONAL BANK	M	7/17/2007	
858	149505	MERIT ENERGY COMPANY, LLC	149505	MERIT ENERGY COMPANY, LLC	FIDELITY AND DEPOSIT COMPANY O	M	3/2/2009	
594	149538	ASHER ENTERPRISES LTD. CO.	149538	ASHER ENTERPRISES LTD. CO.	WESTERN BANK	B	6/3/2016	
934	150182	ROBERT L BAYLESS PRODUCER LLC	150182	ROBERT L BAYLESS PRODUCER LLC	CITIZEN BANK	B	1/21/2011	
414	150661	TITAN RESOURCES I INC	150628	PURE RESOURCES, LP	RLI INSURANCE COMPANY	M	1/23/1995	
414	150661	TITAN RESOURCES I INC	150661	TITAN RESOURCES I INC	RLI INSURANCE COMPANY	M	1/23/1995	
1096	14771	MGM OIL & GAS CO	151067	MGM OIL & GAS COMPANY	WELLS FARGO BANK, N.A.	M	12/18/2015	
531	151067	MGM OIL & GAS COMPANY	151067	MGM OIL & GAS COMPANY	NORWEST BANK	B	12/2/1999	
795	151228	MAR OIL & GAS CORP.	151228	MAR OIL & GAS CORP.	U.S. SPECIALTY INSURANCE COMPA	M	4/23/2007	
541	151323	PRIDE ENERGY COMPANY	151323	PRIDE ENERGY COMPANY	MID CONTINENT CASUALTY	M	2/3/2004	
644	151416	FASKEN OIL & RANCH LTD	151416	FASKEN OIL & RANCH LTD	BANK OF AMERICA	B	6/6/2003	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1754	151416	FASKEN OIL & RANCH LTD	151416	FASKEN OIL & RANCH LTD	U.S. SPECIALTY INSURANCE COMPA	M	2/26/2021	
1604	20165	SAMSON RESOURCES CO	152363	SAMSON RESOURCES CO	ARGONAUT INSURANCE COMPANY	B	8/6/2018	
650	152374	ROCA OPERATING, INC.	152374	ROCA OPERATING, INC.	RLI INSURANCE	B	7/24/2003	
1709	96694	OXY USA INC	153582	OXY USA INC.	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
319	153962	HUNT PETROLEUM, INC.	153962	HUNT PETROLEUM, INC.	UNITED PACIFIC INSURANCE CO.	B	2/2/1994	
857	154078	MACK ENERGY CORP. AND CHASE OIL CORP.	154078	MACK ENERGY CORP. AND CHASE OIL CORP.	U.S. SPECIALTY INSURANCE COMPA	M	3/9/2009	
725	154303	PRIMAL ENERGY CORPORATION	154303	PRIMAL ENERGY CORPORATION	US SPECIALTY INSURANCE	M	3/28/2005	
1565	155669	CONTINENTAL RESOURCES, INC.	155669	CONTINENTAL RESOURCES, INC.	N/A	B	9/27/2017	
1757	51549	CAL-MON OIL COMPANY	156297	CAL-MON OIL CO	COMMUNITY NATIONAL BANK	B	3/31/2021	
323	19111	RHOMBUS OPERATING CO LTD	157434	RHOMBUS OPERATING CO., LTD	UNDERWRITERS INDEMNITY CO.	B	3/7/1994	
659	157984	OCCIDENTAL PERMIAN LTD	157984	OCCIDENTAL PERMIAN LTD	SAFECO INSURANCE	M	10/20/2003	
1600	19174	RICE OPERATING COMPANY	158124	RICE OPERATING COMPANY	THE OHIO CASUALTY INS. CO.	M	6/10/2018	
449	159123	RAND PAULSON ENERGY COMPANY	159123	RAND PAULSON ENERGY COMPANY	NORWEST BANK / NEW MEXICO	M	12/30/1996	
452	159770	SYNERGY OIL & GAS INC	159770	SYNERGY OIL & GAS INC	UNDERWRITERS INDEMNITY	B	2/11/1997	
1262	159826	WESTERN AG-MINERALS COMPANY	159826	WESTERN AG-MINERALS COMPANY	SAFECO INSURANCE COMPANY OF AM	M	5/30/2007	
629	160073	WD PARTNERS, L.P.	160073	WD PARTNERS, L.P.	TRAVELERS CASUALTY	B	2/3/2003	
999	3474	C W TRAINER	160302	C W TRAINER	SECURITY BANK	B	9/13/2013	
877	160825	BC OPERATING, INC.	160825	BC OPERATING, INC.	LEXON INSURANCE COMPANY	M	7/16/2009	
2131	161522	CHALFANT PROPERTIES, INC.	161522	CHALFANT PROPERTIES, INC.	WAIVER	S	11/18/2025	SG 34 0
2132	161522	CHALFANT PROPERTIES, INC.	161522	CHALFANT PROPERTIES, INC.	WAIVER	S	11/18/2026	SG 37 0
2133	161522	CHALFANT PROPERTIES, INC.	161522	CHALFANT PROPERTIES, INC.	WAIVER	S	2/17/2026	SG 47 0
2134	161522	CHALFANT PROPERTIES, INC.	161522	CHALFANT PROPERTIES, INC.	WAIVER	S	2/17/2026	SG 48 0

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
2135	161522	CHALFANT PROPERTIES, INC.	161522	CHALFANT PROPERTIES, INC.	WAIVER	S	2/17/2026	SG 49 0
913	197035	XTO ENERGY INC	161624	XTO ENERGY, INC.	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
418	130308	SABRE OPERATING INC	161690	TEXAS ENERGY SUPPLY, INC.	RLI INSURANCE COMPANY	B	2/21/1996	
975	161968	MESQUITE SWD, INC	161968	MESQUITE SWD, INC	RLI INSURANCE COMPANY	M	12/4/2012	
577	162499	NOVY OIL & GAS, INC	162499	NOVY OIL & GAS, INC	FIDELITY & DEPOSIT CO. OF MARY	B	1/9/2001	
560	162683	CIMAREX ENERGY CO. OF COLORADO	162683	CIMAREX ENERGY CO. OF COLORADO	RLI INSURANCE CO.	M	7/25/2000	
462	162928	ENERGEN RESOURCES CORPORATION	162928	ENERGEN RESOURCES CORPORATION	TRAVELERS CASUALTY & SURETY	M	5/5/1997	
1974	164490	S & J OPERATING COMPANY	164490	S & J OPERATING COMPANY	U. S. SPECIALTY INSURANCE COMP	B	5/29/2024	
481	164557	RIDGEWAY ARIZONA OIL CORP.	164557	RIDGEWAY ARIZONA OIL CORP.	NORWEST BANK, N.M.	B	1/13/1998	
1639	327870	PACIFIC ENERGY DEVELOPMEN T CORP	164557	RIDGEWAY ARIZONA OIL CORP.	ARGONAUT INSURANCE CO.	M	4/4/2019	
1724	164726	HUNT CIMARRON LIMITED PARTNERSHIP	164726	HUNT CIMARRON LIMITED PARTNERSHIP	LEXON INSURANCE COMPANY	B	6/9/2020	
2068	342253	HUNT CIMARRON LIMITED PARTNERSHIP	164726	HUNT CIMARRON LIMITED PARTNERSHIP	ATLANTIC SPECILTY INSURANCE CO	B	4/28/2025	
51	15439	MWJ PRODUCING CO	165255	EDMAR COMPANY LLC (THE)	TRAVELERS INDEMNITY CO.	B	2/19/1982	
51	15439	MWJ PRODUCING CO	165290	ARKLAND PRODUCING CO INC	TRAVELERS INDEMNITY CO.	B	2/19/1982	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	166111	DEVON ENERGY PRODUCTION CO. LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
913	197035	XTO ENERGY INC	167067	XTO ENERGY, INC.	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
791	1092	ARMSTRONG ENERGY CORP	167733	Armstrong Energy Corporation	JP MORGAN CHASE	M	2/20/2007	
1568	168278	SHACKELFORD OIL CO.	168278	SHACKELFORD OIL CO.	RLI INSURANCE COMPANY	M	9/12/2017	
685	168687	SIANA OPERATING LLC	168687	SIANA OPERATING LLC	RLI INSURANCE	S	6/4/2004	LG 7641 1
522	169386	ECLIPSE OIL & GAS, INC.	169386	ECLIPSE OIL & GAS, INC.	RLI INSURANCE CO	B	9/3/1999	
1754	151416	FASKEN OIL & RANCH LTD	169448	FASKEN LAND & MINERALS, LTD.	U.S. SPECIALTY INSURANCE COMPA	M	2/26/2021	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1771	172329	SUMMIT OVERSEAS EXPLORATION, INC.	172329	SUMMIT OVERSEAS EXPLORATION, INC.	CASH BOND	S	6/25/2021	B1 1410 3
484	172635	FULFER OIL & CATTLE CO., LLC	172621	FULFER ELECTRIC, LLC	UNDERWRITERS INDEMNITY	S	1/18/1998	B1 1300 3
494	172635	FULFER OIL & CATTLE CO., LLC	172621	FULFER ELECTRIC, LLC	UNDERWRITERS INDEMNITY	S	5/18/1998	E0 1057 0
484	172635	FULFER OIL & CATTLE CO., LLC	172635	FULFER OIL & CATTLE CO., LLC	UNDERWRITERS INDEMNITY	S	1/18/1998	B1 1300 3
494	172635	FULFER OIL & CATTLE CO., LLC	172635	FULFER OIL & CATTLE CO., LLC	UNDERWRITERS INDEMNITY	S	5/18/1998	E0 1057 0
226	172981	EEX OPERATING, L.P.	172981	EEX OPERATING, L.P.	ST. PAUL FIRE AND MARINE	B	12/9/1992	
684	234550	NOBLE ENERGY INC	173252	PATINA SAN JUAN INCORPORATED	FIDELITY & DEPOSIT	M	3/31/2004	
518	173413	E G L RESOURCES INC	173413	E G L RESOURCES INC	UNDERWRITERS INDEMNITY	B	5/28/1999	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	174447	DEVON ENERGY PRODUCTION CO.,L.P.	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
510	175099	VIERSEN OIL & GAS CO.	175099	VIERSEN OIL & GAS CO.	RLI INSURANCE COMPANY	B	2/1/1999	VC 11 0
787	245872	JUDAH OIL LLC	175260	JUDAH OIL	WESTERN BANK	M	11/29/2006	
1892	177888	WAGNER OIL CO.	177888	WAGNER OIL CO.	ARCH INSURANCE COMPANY	M	11/2/2022	
641	199866	CAMERON OIL	181109	CAMERON OIL & GAS INC	FIRST NATIONAL BANK	M	6/2/2003	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	181622	DEVON ENERGY PRODUCTION CO., LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
884	182937	DOMESTIC ENERGY CORPORATION	182937	DOMESTIC ENERGY CORPORATION	PEOPLES BANK	S	9/18/2009	LH 5272 0
1754	151416	FASKEN OIL & RANCH LTD	183274	FASKEN OIL & RANCH LTD	U.S. SPECIALTY INSURANCE COMPA	M	2/26/2021	
1730	184290	THE ALLAR COMPANY	184290	THE ALLAR COMPANY	PHILADELPHIA INDEMNITY INSURAN	B	6/23/2020	
1853	184290	THE ALLAR COMPANY	184290	THE ALLAR COMPANY	CASH BOND	B	6/7/2022	
528	184357	AGHORN OPERATING INC	184357	AGHORN OPERATING INC	LEXON INSURANCE COMAPANY	B	10/27/1999	
588	185217	FRED F POOL, III	185217	FRED F POOL, III	FIRST FEDERAL BANK	S	6/18/2001	K0 2114 9
545	185239	ENERDYNE, LLC	185239	ENERDYNE, LLC	MAIN BANK	B	5/9/2006	
550	188712	BLUEGRASS ENRGY ENHANCEMENT FUND LLC	188712	BLUEGRASS ENRGY ENHANCEMENT FUND LLC	BANK OF ALBUQUERQUE	S	7/3/2000	X0 647 390

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
898	241333	CHEVRON MIDCONTINENT, L.P.	189100	CHEVRON MIDCONTINENT, LP	SAFECO INSURANCE COMPANY OF AM	M	2/10/2010	
2000	189489	COMSTOCK OIL AND GAS, LP	189489	COMSTOCK OIL AND GAS, LP	SIRIUSPOINT AMERICA INSURANCE	S	10/7/2024	E0 291 58
583	223170	CHESAPEAKE EXPLORATION L.L.C.	189535	CHESAPEAKE EXPLORATION L.L.C.	RLI INSURANCE CO.	M	3/22/2001	
1993	113315	TEXLAND PETROLEUM-HOBBS, LLC	189906	TEXLAND PETROLEUM HOBBS,LLC	EVERGREEN NATIONAL INDEMNITY C	M	9/17/2024	
800	189951	ENCORE OPERATING LP	189951	ENCORE OPERATING LP	SAFECO INSURANCE COMPANY OF AM	M	6/22/2007	
1591	5898	DAVID H ARRINGTON OIL & GAS INC	190439	DAVID H. ARRINGTON OIL & GAS INC.	SECURITY BANK	M	1/31/2018	
901	190595	ENDEAVOR ENERGY RESOURCES, LP	190595	ENDEAVOR ENERGY RESOURCES, LP	RLI INSURANCE COMPANY	M	3/5/2010	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	192278	DEVON ENERGY PRODUCTION CO., LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	192463	OXY USA WTP LIMITED PARTNERSHIP	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
2044	342056	EOG RESOURCES MARKETING, LLC	192516	EOG RESOURCES MARKETING INC	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
518	173413	E G L RESOURCES INC	192841	E G L RESOURCES INC	UNDERWRITERBS INDEMNITY		5/28/1999	
574	192951	GVC VENTURES	192951	GVC VENTURES	BANK OF AMERICA	S	1/9/2001	V0 3750 2
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	193029	OXY USA WTP LIMITED PARTNERSHIP	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
1870	193242	MCAFEE OIL & GAS, LLC	193242	MCAFEE OIL & GAS, LLC	CASH BOND	B	8/12/2022	
2043	64432	EOG RESOURCES, INC.	193526	EOG RESOURCES, INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	194188	OXY USA WTP LIMITED PARNERSHIP (OIL)	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
601	194393	WILBANKS FAMILY PARTNERSHIP, LTD.	194393	WILBANKS FAMILY PARTNERSHIP, LTD.	WAIVER AND CONSENT	S	9/5/2001	B0 2657 0
602	194393	WILBANKS FAMILY PARTNERSHIP, LTD.	194393	WILBANKS FAMILY PARTNERSHIP, LTD.	CONSENT AND WAIVER	S	9/6/2001	A0 2614 4
583	223170	CHESAPEAKE EXPLORATION L.L.C.	194720	CHESAPEAKE EXPL L.L.C. & EOG RESOURCES, INC.	RLI INSURANCE CO.	M	3/22/2001	
587	195797	GREKA AM, INC	195797	GREKA AM, INC	FIDELITY & DEPOSIT COMPANY	B	5/21/2001	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
668	196015	SLAYTON RESOURCES INC	196015	SLAYTON RESOURCES INC	BANK OF THE SOUTHWEST	M	2/3/2004	
595	196069	MOMENTUM OPERATING CO INC	196069	MOMENTUM OPERATING CO INC	FIRST NATIONAL BANK / ALBANY	M	6/13/2024	
2103	342482	MOMENTUM OPERATING CO., INC.	196069	MOMENTUM OPERATING CO INC	CLEAR FORK BANK, N.A.	M	7/8/2025	
913	197035	XTO ENERGY INC	197035	XTO ENERGY INC	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
2123	197035	XTO ENERGY INC	197035	XTO ENERGY INC	FEDERAL INSURANCE COMPANY	M	6/4/2025	
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	197070	OXY USA WTP LIMITED PARTNERSHIP	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
1678	197505	FAIRWAY MINERALS CORPORATION	197505	FAIRWAY MINERALS CORPORATION	COMMUNITY NATIONAL BANK	B	7/11/2019	
17	778	BP AMERICA PRODUCTION COMPANY	197983	BP AMERICA PRODUCTION CO	SEABOARD SURETY COMPANY	B	8/27/1979	
315	117139	BP AMERICA PRODUCTION COMPANY	197983	BP AMERICA PRODUCTION CO	TRAVELERS CASUALTY & SURETY	B	1/13/1994	
1588	218098	BP AMERICA PRODUCTION COMPANY	197983	BP AMERICA PRODUCTION CO	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
598	3053	BURK ROYALTY CO., LTD.	198524	BURK ROYALTY CO., LTD	CONTINENTAL CASUALTY	S	7/30/2001	VA 2432 0
604	198688	CAMBRIAN MANAGEMENT LTD	198688	CAMBRIAN MANAGEMENT LTD	RLI INSURANCE	M	10/9/2001	
641	199866	CAMERON OIL	199866	CAMERON OIL	FIRST NATIONAL BANK	M	6/2/2003	
878	208706	HUNTINGTON ENERGY, LLC	208706	HUNTINGTON ENERGY, LLC	BANK OF ALBUQUERQUE	M	6/16/2015	
713	209564	WILDCAT ENERGY LLC	209564	WILDCAT ENERGY LLC	SOUTHWEST BANK	B	12/29/2004	
159	140519	BURLINGTON RESOURCES OIL AND GAS CO.LP	209842	BURLINGTON RESOURCES/C. E. LONG	SAFECO INSURANCE CO.	B	8/3/1990	
904	210091	DKD,LLC	210091	DKD,LLC	FIRST AMERICAN BANK	M	3/12/2010	
2080	210494	HOG PARTNERSHIP LP	210494	HOG PARTNERSHIP LP	JMORGAN CHASE BANK,N.A.	B	6/3/2025	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	210735	DEVON ENERGY PRODUCTION COMPANY,LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1588	218098	BP AMERICA PRODUCTION COMPANY	211070	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
1915	211455	PROVIDENCE MINERALS, LLC	211455	PROVIDENCE MINERALS, LLC	EVERGREEN NATIONAL INDEMNITY C	B	4/27/2023	
931	212092	SPINDLETOP OIL & GAS CO.	212092	SPINDLETOP OIL & GAS CO.	PROSPERITY BANK	B	1/27/2011	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
734	212253	IMPERIAL OIL PROPERTIES, INC.	212253	IMPERIAL OIL PROPERTIES, INC.	WELLS FARGO BANK	S	6/2/2005	LH 5580 0
972	90723	MEWBOURNE OIL COMPANY	212299	MEWBOURNE OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	9/20/2012	
514	54207	CHEVRON USA INC	212764	CHEVRON USA INC	SAFECO INSURANCE CO OF AMERICA	M	4/1/1999	
2139	212940	VENTURE ENERGY, INC.	212940	VENTURE ENERGY, INC.	WAVIER	S	2/17/2026	SG 50 0
2140	212940	VENTURE ENERGY, INC.	212940	VENTURE ENERGY, INC.	WAVIER	S	2/17/2026	SG 51 0
1588	218098	BP AMERICA PRODUCTION COMPANY	213155	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
691	213179	H L BROWN OPERATING, LLC	213179	H L BROWN OPERATING, LLC	US SPECIALTY INSURANCE	M	7/6/2004	
2130	213190	CROWNQUEST OPERATING, LLC	213190	CROWNQUEST OPERATING, LLC	EVERGREEN NATIONAL INDEMITY CO	M	1/28/2026	
704	213663	JETTA OPERATING COMPANY, INC.	213663	JETTA OPERATING COMPANY, INC.	US SPECIALTY	M	10/1/2004	
792	215099	Coterra Energy Operating Co.	215099	Coterra Energy Operating Co.	FIDELITY & DEPOSIT COMPANY	M	3/22/2007	
2121	252846	COTERRA ENERGY OPERATING CO.	215099	Coterra Energy Operating Co.	UNITED STATES FIRE INSURANCE C	M	12/2/2025	
2136	252846	COTERRA ENERGY OPERATING CO.	215099	Coterra Energy Operating Co.	UNITED STATES FIRE INSURANCE C	M	1/27/2026	
583	223170	CHESAPEAKE EXPLORATION L.L.C.	215234	CHESAPEAKE EXPLORATION L.L.C.	RLI INSURANCE CO.	M	3/22/2001	
655	215732	CHISOS, LTD	215732	CHISOS, LTD	RLI INSURANCE	B	10/27/2003	
643	215758	PECOS PRODUCTION COMPANY	215758	PECOS PRODUCTION COMPANY	COMERICA BANK	M	6/6/2003	
1600	19174	RICE OPERATING COMPANY	215939	RICE OPERATING COMPANY	THE OHIO CASUALTY INS. CO.	M	6/10/2018	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	216835	DEVON ENERGY PRODUCTION CO LP/RAY WESTALL	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
621	216913	LAGUNA PETROLEUM CORP.	216913	LAGUNA PETROLEUM CORP.	LIBERTY MUTUAL	B	10/29/2002	
670	217598	ASPEN OPERATING COMPANY LLC	217598	ASPEN OPERATING COMPANY LLC	BANK OF TEXAS	B	3/10/2004	
622	217680	RUNNING HORSE PRODUCTION CO.	217680	RUNNING HORSE PRODUCTION CO.	WELLS FARGO BANK	M	12/12/2002	
627	217817	CONOCOPHILL IPS COMPANY	217817	CONOCOPHILL IPS COMPANY	SAFECO INSURANCE CO OF AMERICA	M	1/28/2003	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
956	303283	COG PRODUCTION, LLC	217955	COG PRODUCTION, LLC	U.S. SPECIALTY INSURANCE COMPA	M	11/29/2011	
1587	218098	BP AMERICA PRODUCTION COMPANY	218098	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2017	
1588	218098	BP AMERICA PRODUCTION COMPANY	218098	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
964	15742	NEARBURG PRODUCING CO	218860	NEARBURG PRODUCING COMPANY	U.S. SPECIALTY INSURANCE COMPA	M	6/13/2012	
901	190595	ENDEAVOR ENERGY RESOURCES, LP	218885	LCX ENERGY, LLC	RLI INSURANCE COMPANY	M	3/5/2010	
964	15742	NEARBURG PRODUCING CO	218963	NEARBURG PRODUCING COMPANY	U.S. SPECIALTY INSURANCE COMPA	M	6/13/2012	
1604	20165	SAMSON RESOURCES CO	219895	SAMSON RESOURCES CO	ARGONAUT INSURANCE COMPANY	B	8/6/2018	
1604	20165	SAMSON RESOURCES CO	220260	SAMSON RESOURCES COMPANY	ARGONAUT INSURANCE COMPANY	B	8/6/2018	
2043	64432	EOG RESOURCES, INC.	220345	EOG RESOURCES, INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	220364	OXY USA WTP LIMITED PARTNERSHIP	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
785	220758	PXP GULF COAST LLC	220758	PXP GULF COAST LLC	LIBERTY MUTUAL INSURANCE CO.	B	10/30/2006	
1754	151416	FASKEN OIL & RANCH LTD	221040	FASKEN ACQUISITIONS 02, LTD	U.S. SPECIALTY INSURANCE COMPA	M	2/26/2021	
1803	221708	ROY G. BARTON JR.	221708	ROY G. BARTON JR.	WAIVER	S	1/19/2022	VC 937 0
1587	218098	BP AMERICA PRODUCTION COMPANY	221891	BP AMERICA PRODUCTION CO / MARATHON OIL CO.	TRAVELERS CASUALTY AND SURETY	M	11/11/2017	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	221978	DEVON ENERGY PRODUCTION COMPANY, LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1921	222417	FRED BOWMAN INC	222417	FRED BOWMAN INC	ARCH INSURANCE COMPANY	S	5/16/2023	B0 2456 11
957	222759	BUCKEYE DISPOSAL, L.L.C.	222759	BUCKEYE DISPOSAL, L.L.C.	LEXON INSURANCE COMPANY	M	12/5/2011	
1754	151416	FASKEN OIL & RANCH LTD	222938	FASKEN OIL AND RANCH, LTD.	U.S. SPECIALTY INSURANCE COMPA	M	2/26/2021	
583	223170	CHESAPEAKE EXPLORATION L.L.C.	223170	CHESAPEAKE EXPLORATION L.L.C.	RLI INSURANCE CO.	M	3/22/2001	
1588	218098	BP AMERICA PRODUCTION COMPANY	223554	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	897 227984	EDGE PETROLEUM EXPLORATION CO.	224400	EDGE PETROLEUM OPERATING COMPANY, INC.	RLI INSURANCE COMPANY	M	2/9/2010	
	857 154078	MACK ENERGY CORP. AND CHASE OIL CORP.	224482	MACK ENERGY CORPORATION	U.S. SPECIALTY INSURANCE COMPA	M	3/9/2009	
	951 224696	STRATA VIEW OPERATING, LLC	224696	STRATA VIEW OPERATING, LLC	BANK OF CLOVIS	M	10/25/2011	
	705 225243	HORSESHOE OPERATING INC.	225243	HORSESHOE OPERATING INC.	WEST TEXAS NATIONAL BANK	M	10/6/2004	
	674 225514	NORTHSTAR OPERATING COMPANY	225514	NORTHSTAR OPERATING COMPANY	LEXON INSURANCE CO.	M	3/22/2004	
	913 197035	XTO ENERGY INC	225648	XTO ENERGY, INC.	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
	665 225774	RESOURCE DEVELOPMENT TECHNOLOGY LLC	225774	RESOURCE DEVELOPMENT TECHNOLOGY LLC	FIDELITY & DEPOSIT COMPANY	B	1/26/2004	
	1719 338915	MULLOY OPERATING, INC.	225942	MULLOY OPERATING, INC.	COMMUNITY NATIONAL BANK	B	6/4/2020	
	258 4378	CHI OPERATING INC	226159	CHI ENERGY, INC.	RLI INSURANCE COMPANY	B	5/5/1993	
	1588 218098	BP AMERICA PRODUCTION COMPANY	226424	BP AMERICA PRODUCTION CO	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
	1509 86997	MARATHON OIL COMPANY LLC	226538	MARATHON OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
	812 226829	BLUE DOLPHIN PRODUCTION, LLC	226829	BLUE DOLPHIN PRODUCTION, LLC	COPPERMARK BANK	B	8/19/2011	
	1670 226950	INTREPID POTASH	226950	INTREPID POTASH	WESTERN COMMERCE BANK	M	2/27/2004	
	1815 240445	INTREPID POTASH	226950	INTREPID POTASH	INTREPID POTASH-NM, LLC	M	3/9/2022	
	682 227551	BRAZOS LIMITED PARTNERSHIP	227551	BRAZOS LIMITED PARTNERSHIP	FIRST NATIONAL BANK	M	5/3/2004	
	731 4115	CHAPARRAL ENERGY LLC	227725	CHAPARRAL ENERGY, LLC	US SPECIALTY INSURANCE	M	4/27/2005	
	897 227984	EDGE PETROLEUM EXPLORATION CO.	227984	EDGE PETROLEUM EXPLORATION CO.	RLI INSURANCE COMPANY	M	2/9/2010	
	717 228051	AMERICO ENERGY RESOURCES LLC	228051	AMERICO ENERGY RESOURCES LLC	LEXON INSURANCE CO.	S	1/6/2005	B0 9774 3
	543 6742	ECHO PRODUCTION INC	228769	ECHO PRODUCTION, INC.	RLI INSURANCE CO.	M	4/5/2000	
	1611 231269	COG OPERATING LLC	229137	COG OPERATING LLC	ARCH INSURANCE CO.	M	4/30/2018	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
702	37627	WESTERN GAS RESOURCES	229938	LANCE OIL & GAS COMPANY, INC.	LIBERTY MUTUAL	M	9/29/2004	
774	230387	PARALLEL PETROLEUM LLC	230387	PARALLEL PETROLEUM LLC	CITIBANK	M	7/25/2006	
728	230601	JM COX RESOURCES LP	230601	JM COX RESOURCES LP	US SPECIALTY INSURANCE	M	4/6/2005	
1611	231269	COG OPERATING LLC	230930	COG OPERATING LLC	ARCH INSURANCE CO.	M	4/30/2018	
1794	230987	SOUTHWAY CONSTRUCTION COMPANY, INC.	230987	SOUTHWAY CONSTRUCTION COMPANY, INC.	LEXON INSURANCE COMPANY	M	11/16/2021	
1611	231269	COG OPERATING LLC	231269	COG OPERATING LLC	ARCH INSURANCE CO.	M	4/30/2018	
970	231429	MANZANO LLC	231429	MANZANO LLC	VALLEY BANK OF COMMERCE	M	7/30/2012	
1959	237722	ETP CRUDE LLC	231432	CENTURION PIPELINE LP	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
1596	231606	EMERALD ENERGY LLC	231606	EMERALD ENERGY LLC	N/A	B	4/11/2018	
1959	237722	ETP CRUDE LLC	232088	CENTURION PIPELINE LTD PRTN.	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
858	149505	MERIT ENERGY COMPANY, LLC	232249	MERIT ENERGY PARTNERS III, LP	FIDELITY AND DEPOSIT COMPANY O	M	3/2/2009	
726	232611	SUNDOWN ENERGY LP	232611	SUNDOWN ENERGY LP	US SPECIALTY INSURANCE	M	3/28/2005	
726	232611	SUNDOWN ENERGY LP	232818	SUNDOWN ENERGY LP	US SPECIALTY INSURANCE	M	3/28/2005	
819	143199	ENERVEST OPERATING L.L.C.	232882	ENERVEST ENERGY INSTITUTIONAL FUND IX LP ETAL	RLI INSURANCE COMPANY	M	11/8/2007	
1952	18917	READ & STEVENS INC	234165	READ & STEVENS	U.S. SPECIALTY INSURANCE COMPA	M	1/22/2024	
583	223170	CHESAPEAKE EXPLORATION L.L.C.	234363	CHESAPEAKE EXPLORATION L.L.C.	RLI INSURANCE CO.	M	3/22/2001	
901	190595	ENDEAVOR ENERGY RESOURCES, LP	234445	LCX ENERGY,LLC	RLI INSURANCE COMPANY	M	3/5/2010	
684	234550	NOBLE ENERGY INC	234550	NOBLE ENERGY INC	FIDELITY & DEPOSIT	M	3/31/2004	
901	190595	ENDEAVOR ENERGY RESOURCES, LP	234667	LCX ENERGY, LLC	RLI INSURANCE COMPANY	M	3/5/2010	
258	4378	CHI OPERATING INC	234761	CHI ENERGY INC.	RLI INSURANCE COMPANY	B	5/5/1993	
833	236183	TANDEM ENERGY CORPORATION	236183	TANDEM ENERGY CORPORATION	BANK OF TEXAS	M	4/17/2022	
745	286614	CROSS BORDER RESOURCES, INC.	236435	PURE ENERGY OPERATING, INC.	STATE LAND OFFICE	B	8/24/2005	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	236710	OXY USA WTP LIMITED PARTNERSHIP	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
957	222759	BUCKEYE DISPOSAL, L.L.C.	237120	BUCKEYE DISPOSAL LLC	LEXON INSURANCE COMPANY	M	12/5/2011	
1091	240974	LEGACY RESERVES OPERATING, LP	237265	LEGACY RESERVES, LP	ARGONAUT INSURANCE COMPANY	M	10/14/2015	
1959	237722	ETP CRUDE LLC	237722	ETP CRUDE LLC	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	237815	OXY USA WTP LIMITED PARTNERSHIP	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
1662	238004	JOBE MATERIALS, L.P.	238004	JOBE MATERIALS, L.P.	COMPASS BANK	M	7/22/2009	
943	15422	APACHE CORP	238427	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
1535	239442	LEACO NEW MEXICO EXPL. AND PROD., LLC	239442	LEACO NEW MEXICO EXPL. AND PROD., LLC	ARGONAUT INSURNACE COMPANY	M	5/24/2017	
1267	239509	RUSSELL SAND & GRAVEL	239509	RUSSELL SAND & GRAVEL	RUSSELL SAND AND GRAVEL INC AN	M	2/7/2007	
1689	239509	RUSSELL SAND & GRAVEL	239509	RUSSELL SAND & GRAVEL	CENTURY BANK	M	2/7/2007	
1815	240445	INTREPID POTASH	240445	INTREPID POTASH	INTREPID POTASH-NM, LLC	M	3/9/2022	
982	240974	LEGACY RESERVES OPERATING, LP	240974	LEGACY RESERVES OPERATING, LP	WELLS FARGO BANK, N.A.	B	2/25/2013	
1091	240974	LEGACY RESERVES OPERATING, LP	240974	LEGACY RESERVES OPERATING, LP	ARGONAUT INSURANCE COMPANY	M	10/14/2015	
898	241333	CHEVRON MIDCONTINENT, L.P.	241333	CHEVRON MIDCONTINENT, L.P.	SAFECO INSURANCE COMPANY OF AM	M	2/10/2010	
2079	119305	RAY WESTALL OPERATING, INC.	241582	RAY WESTALL OPERATING, INC.	EVERGREEN NATIONAL INDEMNITY C	M	5/29/2025	
1549	241851	PETROGULF CORPORATION	241851	PETROGULF CORPORATION	N/A	B	8/15/2017	
943	15422	APACHE CORP	242071	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
775	242247	BMT O&G NM, LLC	242247	BMT O&G NM, LLC	TRAVELERS CASUALTY & SURETY	B	7/28/2006	
1515	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	N/A	B	4/4/2017	
2027	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	12/11/2024	VC 1311 0
2028	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	12/11/2024	VC 1312 0

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
2029	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	12/11/2024	VC 1313 0
2036	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	12/24/2024	VC 1326 0
2108	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	9/17/2025	SG 11 0
2030	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	12/11/2024	VC 1314 0
2031	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	12/11/2024	VC 1315 0
2032	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	12/11/2024	VC 1316 0
2033	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	1/6/2025	VC 1323 0
2034	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	12/24/2024	VC 1324 0
2035	242767	FEDERAL ABSTRACT COMPANY	242767	FEDERAL ABSTRACT COMPANY	WAIVER	S	1/6/2025	VC 1325 0
776	243014	CTV O&G NM,LLC	243014	CTV O&G NM,LLC	TRAVELERS CASUALTY & SURETY	B	7/28/2006	
874	243452	CORKRAN ENERGY LP	243452	CORKRAN ENERGY LP	JP MORGAN CHASE BANK, N.A.	B	4/23/2009	
779	243544	MAINLINE ROCK & BALLAST INC	243544	MAINLINE ROCK & BALLAST INC	TRAVELERS CASUALTY AND SURETY	M	8/23/2006	
1733	243874	QUANTUM RESOURCES MANAGEMENT, LLC	243874	QUANTUM RESOURCES MANAGEMENT, LLC	ARGONAUT INSURANCE COMPANY	M	6/8/2020	
1604	20165	SAMSON RESOURCES CO	243960	SAMSON RESOURCES COMPANY	ARGONAUT INSURANCE COMPANY	B	8/6/2018	
877	160825	BC OPERATING, INC.	245105	BC OPERATING, INC.	LEXON INSURANCE COMPANY	M	7/16/2009	
1952	18917	READ & STEVENS INC	245329	READ & STEVENS, INC.	U.S. SPECIALTY INSURANCE COMPA	M	1/22/2024	
787	245872	JUDAH OIL LLC	245872	JUDAH OIL LLC	WESTERN BANK	M	11/29/2006	
258	4378	CHI OPERATING INC	246048	CHI OPERATING INC.	RLI INSURANCE COMPANY	B	5/5/1993	
789	246114	TE-RAY RESOURCES, INC.	246114	TE-RAY RESOURCES, INC.	BANK OF ALBUQUERQUE N.A.	B	1/30/2007	
1744	327480	WPX ENERGY PERMIAN, LLC.	246289	WPX Energy Permian, LLC	LIBERTY MUTUAL INSURANCE COMPA	M	1/27/2021	
1716	246368	BASIC ENERGY SERVICES, LP	246368	BASIC ENERGY SERVICES, LP	U. S. SPECIALTY INSURANCE COMP	M	3/17/2020	
1725	246368	BASIC ENERGY SERVICES, LP	246368	BASIC ENERGY SERVICES, LP	US SPECIALTY INSURANCE COMPANY	M	3/17/2020	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
898	241333	CHEVRON MIDCONTINENT, L.P.	247589	CHEVRON MIDCONTINENT, L.P.	SAFECO INSURANCE COMPANY OF AM	M	2/10/2010	
1684	249198	MOSAIC POTASH CARLSBAD INC.	249198	MOSAIC POTASH CARLSBAD INC.	LIBERTY MUTUAL SURETY	M	4/25/2016	
731	4115	CHAPARRAL ENERGY LLC	249841	CHAPARRAL ENERGY LLC	US SPECIALTY INSURANCE	M	4/27/2005	
1910	5691	Dakota Resources, Inc	250158	DAKOTA RESOURCES, INC	EVERGREEN NATIONAL INDEMNITY C	M	3/13/2023	
806	250384	KERNS PETROLEUM, INC.	250384	KERNS PETROLEUM, INC.	IBC LAREDO MAIN BANK	M	8/8/2007	
258	4378	CHI OPERATING INC	250460	CHI OPERATING INC.	RLI INSURANCE COMPANY	B	5/5/1993	
893	250539	JOHN E. MCCOOL	250539	JOHN E. MCCOOL	FIRST NIAGARA	M	2/28/2015	
962	251311	ENCANA OIL & GAS (USA) INC	251311	ENCANA OIL & GAS (USA) INC	TRAVELERS CASUALTY	M	4/13/2012	
1959	237722	ETP CRUDE LLC	251629	CENTURION PIPELINE LP	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
1763	339241	OGX RESOURCES, LLC	252435	OGX RESOURCES LLC	WEST TEXAS NATIONAL BANK	M	4/16/2021	
583	223170	CHESAPEAKE EXPLORATION L.L.C.	252468	CHESAPEAKE EXPLORATION, L.L.C.	RLI INSURANCE CO.	M	3/22/2001	
809	252496	SHERIDAN PRODUCTION COMPANY, LLC	252496	SHERIDAN PRODUCTION COMPANY, LLC	RLI INSURANCE COMPANY	M	8/28/2007	
512	252708	PATTERSON PETROLEUM LLC	252708	PATTERSON PETROLEUM LLC	RLI INSURANCE COMPANY	M	8/6/2007	
1639	327870	PACIFIC ENERGY DEVELOPMENT CORP	252779	RIDGEWAY ARIZONA OIL CORP	ARGONAUT INSURANCE CO.	M	4/4/2019	
792	215099	Coterra Energy Operating Co.	252846	COTERRA ENERGY OPERATING CO.	FIDELITY & DEPOSIT COMPANY	M	3/22/2007	
2121	252846	COTERRA ENERGY OPERATING CO.	252846	COTERRA ENERGY OPERATING CO.	UNITED STATES FIRE INSURANCE C	M	12/2/2025	
2136	252846	COTERRA ENERGY OPERATING CO.	252846	COTERRA ENERGY OPERATING CO.	UNITED STATES FIRE INSURANCE C	M	1/27/2026	
822	255756	MMCP LEASING, LTD	255756	MMCP LEASING, LTD	RLI INSURANCE COMPANY	M	12/26/2007	
475	255864	J R OIL, LTD. CO.	255864	J R OIL, LTD. CO.	WELLS FARGO BANK	B	11/17/1997	
475	255864	J R OIL, LTD. CO.	256073	J R OIL, LTD. CO.	WELLS FARGO BANK	B	11/17/1997	
1994	256073	J R OIL, LTD. CO.	256073	J R OIL, LTD. CO.	COMMUNITY NATIONAL BANK	B	9/17/2024	
512	252708	PATTERSON PETROLEUM LLC	256512	CML EXPLORATION, LLC	RLI INSURANCE COMPANY	M	8/6/2007	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
913	197035	XTO ENERGY INC	256965	XTO ENERGY, INC	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
20	256999	POGO PRODUCING COMPANY LLC	256999	POGO PRODUCING COMPANY LLC	RLI INSURANCE COMPANY	B	10/15/2008	
594	149538	ASHER ENTERPRISES LTD. CO.	257260	ASHER ENTERPRISES LTD., CO.	WESTERN BANK	B	6/3/2016	
237	6515	DUGAN PRODUCTION CORP	257292	DUGAN PRODUCTION CORP.	FIRST NATL. BANK OF FARMINGTON	B	2/22/1993	
823	257794	KODIAK PETROLEUM (MONTANA), INC.	257794	KODIAK PETROLEUM (MONTANA), INC.	U.S. SPECIALTY INSURANCE COMPA	M	1/28/2008	
1621	260297	BTA OIL PRODUCERS, LLC	258369	BTA OIL PRODUCERS	US SPECIALTY INSURANCE CO.	M	11/1/2018	
836	258719	O'CONNELL HOLDINGS, LLC	258719	O'CONNELL HOLDINGS, LLC	U.S. SPECIALTY INSURANCE COMPA	B	5/6/2008	
1916	258983	BRIDWELL OIL COMPANY	258983	BRIDWELL OIL COMPANY	EVERGREEN NATIONAL INDEMNITY C	B	4/27/2023	
1621	260297	BTA OIL PRODUCERS, LLC	260297	BTA OIL PRODUCERS, LLC	US SPECIALTY INSURANCE CO.	M	11/1/2018	
849	260737	BOPCO, L.P.	260737	BOPCO, L.P.	TRAVELERS CASUALTY & SURETY CO	M	11/7/2008	
1588	218098	BP AMERICA PRODUCTION COMPANY	260744	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
1004	261044	MRC PERMIAN COMPANY	261044	MRC PERMIAN COMPANY	ARCH INSURANCE COMPANY	M	1/7/2014	
942	261166	RANGER 40 PETROLEUM, LLC	261166	RANGER 40 PETROLEUM, LLC	BANK OF OKLAHOMA	B	12/14/2014	
1936	14187	MARSHALL & WINSTON INC	261767	MARSHALL & WINSTON, INC.	EVERGREEN NATINAL INDEMNITY CO	B	11/8/2023	
819	143199	ENERVEST OPERATING L.L.C.	262152	ENERVEST ENERGY INST. FUND XI-A & XI-WI, LP	RLI INSURANCE COMPANY	M	11/8/2007	
1585	262196	FAITH TRADING, LLC	262196	FAITH TRADING, LLC	WELLS FARGO BANK	S	2/22/2018	V0 2113 0
999	3474	C W TRAINER	262333	C W TRAINER	SECURITY BANK	B	9/13/2013	
970	231429	MANZANO LLC	263559	MANZANO ENERGY PARTNERS, LLC	VALLEY BANK OF COMMERCE	M	7/30/2012	
851	263940	SOVEREIGN EAGLE, LLC	263940	SOVEREIGN EAGLE, LLC	RLI INSURANCE COMPANY	B	1/8/2009	
583	223170	CHESAPEAKE EXPLORATION L.L.C.	264006	CHESAPEAKE EXPLORATION, LLC	RLI INSURANCE CO.	M	3/22/2001	
1709	96694	OXY USA INC	264073	OXY USA INC.	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1866	149315	MAGNUM HUNTER PRODUCTION, INC.	264560	MAGNUM HUNTER PRODUCTION INC.	RLI INSURANCE COMPANY	M	7/21/2022	
204	3044	BURGUNDY OIL & GAS OF N M INC	264620	BURGUNDY OIL & GAS OF NM, INC.	UNDERWRITERS INDEMNITY CO.	B	9/9/1992	
2141	342739	FNF CONSTRUCTION, INC.	264831	FNF CONSTRUCTION, INC	TRAVELERS CASUALTY AND SURETY	M	12/22/2025	
912	265347	TIMBERLINE PUMP & LEASE SERVICE	265347	TIMBERLINE PUMP & LEASE SERVICE	WELLS FARGO BANK, N.A.	S	4/3/2009	VB 1683 0
1371	265378	G and C Operating, LLC	265378	G and C Operating, LLC	WESTERN BANK	M	6/7/2016	
2113	342587	G AND C OPERATING LLC	265378	G and C Operating, LLC	WESTERN BANK ARTESIA	M	8/27/2025	
849	260737	BOPCO, L.P.	265762	BOPCO, L.P.	TRAVELERS CASUALTY & SURETY CO	M	11/7/2008	
875	266091	VPR OPERATING, LLC	266091	VPR OPERATING, LLC	CASH BOND	M	6/17/2009	
1266	266458	SKANSKA USA CIVIL WEST ROCKY MTN. DIST. INC.	266458	SKANSKA USA CIVIL WEST ROCKY MTN. DIST. INC.	AMERICAN HOME ASSURANCE	M	6/24/2009	
1532	266458	SKANSKA USA CIVIL WEST ROCKY MTN. DIST. INC.	266458	SKANSKA USA CIVIL WEST ROCKY MTN. DIST. INC.	FIDELITY AND DEPOSIT COMPANY O	M	5/15/2017	
512	252708	PATTERSON PETROLEUM LLC	266749	CML EXPLORATION	RLI INSURANCE COMPANY	M	8/6/2007	
2130	213190	CROWNQUEST OPERATING, LLC	267153	CROWNQUEST OPERATING, LLC	EVERGREEN NATIONAL INDEMITY CO	M	1/28/2026	
894	267422	PEDERNALES PRODUCTION, LP	267422	PEDERNALES PRODUCTION, LP	COMMUNITY BANK	M	1/6/2010	
2145	268036	RUBICON ENERGY, L.P.	268036	RUBICON ENERGY, L.P.	GREAT MIDWEST INSURANCE COMPAN	B	3/24/2026	
1863	268114	DELFERN TRUST	268114	DELFERN TRUST	VALLEY BANK OF COMMERCE	B	8/13/2022	
1592	269267	801 LLC	269267	801 LLC	US SPECIALTY INSURANCE COMPANY	M	3/22/2018	
1580	269324	LINN OPERATING, LLC.	269324	LINN OPERATING, LLC.	UNITED STATES FIRE INSURANCE C	M	4/19/2017	
916	269864	CANYON E & P COMPANY	269864	CANYON E & P COMPANY	U.S. SPECIALTY INSURANCE COMPA	M	9/9/2010	
819	143199	ENERVEST OPERATING L.L.C.	269986	ENERVEST OPERATING LLC	RLI INSURANCE COMPANY	M	11/8/2007	
1533	270329	ENDURANCE RESOURCES LLC	270329	ENDURANCE RESOURCES LLC	WELLS FARGO BANK, N.A.	M	5/30/2017	
1579	271620	LINN ENERGY HOLDINGS, LLC	270400	LINN ENERGY HOLDINGS, LLC	UNITED STATES FIRE INSURANCE C	M	5/12/2017	
1959	237722	ETP CRUDE LLC	270593	CENTURION PIPELINE L.P.	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
877	160825	BC OPERATING, INC.	270621	BLACK CROWN ENERGY PARTNERS, LP	LEXON INSURANCE COMPANY	M	7/16/2009	
943	15422	APACHE CORP	270684	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
916	269864	CANYON E & P COMPANY	271487	CANYON E & P COMPANY	U.S. SPECIALTY INSURANCE COMPA	M	9/9/2010	
1579	271620	LINN ENERGY HOLDINGS, LLC	271620	LINN ENERGY HOLDINGS, LLC	UNITED STATES FIRE INSURANCE C	M	5/12/2017	
907	272005	T D & F, LLLP	272005	T D & F, LLLP	WELLS FARGO	S	4/1/2010	L0 541 2
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	272586	OXY USA WTP LIMITED PARTNERSHIP	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
914	272664	G & G OIL AND GAS, LLC	272664	G & G OIL AND GAS, LLC	FIRST AMERICAN BANK	B	7/13/2016	
1932	272853	KENNETH R WADE OR MARIE WADE	272853	KENNETH R WADE OR MARIE WADE	WESTERN BANK	S	10/16/2023	E0 9222 4
2043	64432	EOG RESOURCES, INC.	273395	EOG RESOURCES, INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1744	327480	WPX ENERGY PERMIAN, LLC.	273753	WPX ENERGY PERMIAN, LLC	LIBERTY MUTUAL INSURANCE COMPA	M	1/27/2021	
1268	274182	OTERO/ GREENTREE SOLID WASTE AUTHORITY	274182	OTERO/ GREENTREE SOLID WASTE AUTHORITY	OTERO/ LINCOLN SOLID WASTE AUTH	B	8/2/2010	
938	275015	TIMBERLINE OIL & GAS, LLC	275015	TIMBERLINE OIL & GAS, LLC	WELLS FARGO BANK	S	4/4/2011	VB 1683 0
972	90723	MEWBOURNE OIL COMPANY	275813	MEWBOURNE OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	9/20/2012	
918	277558	LIME ROCK RESOURCES II-A, L.P.	277558	LIME ROCK RESOURCES II-A, L.P.	U.S. SPECIALTY INSURANCE COMPA	M	10/7/2010	
1852	278710	FORTUNE NATURAL RESOURCES CORP.	278710	FORTUNE NATURAL RESOURCES CORP.	U.S. SPECIALTY INSURANCE COMPA	M	6/28/2022	
1763	339241	OGX RESOURCES, LLC	278985	OGX RESOURCES, LLC	WEST TEXAS NATIONAL BANK	M	4/16/2021	
1733	243874	QUANTUM RESOURCES MANAGEMENT, LLC	279617	QUANTUM RESOURCES MANAGEMENT, LLC	ARGONAUT INSURANCE COMPANY	M	6/8/2020	
972	90723	MEWBOURNE OIL COMPANY	279688	MEWBOURNE OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	9/20/2012	
1543	280276	ENDURING RESOURCES,LLC	280276	ENDURING RESOURCES,LLC	RLI INSURANCE COMPANY	M	6/30/2017	
591	280525	CAMPECHE PETRO LP	280525	CAMPECHE PETRO LP	RLI INSURANCE CO.	M	6/28/2001	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1830	280525	CAMPECHE PETRO LP	280525	CAMPECHE PETRO LP	ARCH INSURANCE COMPANY	M	4/25/2022	
2066	280531	ZPZ DELAWARE I LLC	280531	ZPZ DELAWARE I LLC	LIBERTY MUTUAL INSURANCE COMPA	M	4/21/2025	
875	266091	VPR OPERATING, LLC	280979	VICTORY PARK RESOURCES (NM), LLC	CASH BOND	M	6/17/2009	
985	281085	RMR OPERATING, LLC	281085	RMR OPERATING, LLC	WELLS FARGO BANK, N.A.	M	4/29/2013	
833	236183	TANDEM ENERGY CORPORATION	281189	TANDEM ENERGY CORPORATION	BANK OF TEXAS	M	4/17/2022	
943	15422	APACHE CORP	281788	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
1709	96694	OXY USA INC	281850	OXY USA, INC.	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
944	338563	GRIZZLY OPERATING LLC	281994	GRIZZLY OPERATING, LLC	U.S. SPECIALTY INSURANCE COMP.	M	7/7/2011	
943	15422	APACHE CORP	282084	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
946	282096	THE SALIENT ZARVONA ENERGY FUND, L.P.	282096	THE SALIENT ZARVONA ENERGY FUND, L.P.	JP MORGAN CHASE BANK, N.A.	M	7/14/2011	
1357	282096	THE SALIENT ZARVONA ENERGY FUND, L.P.	282096	THE SALIENT ZARVONA ENERGY FUND, L.P.	ALLEGIANCE BANK	M	7/6/2016	
1685	283125	OLDCASTLE SW GROUP, INC.DBA FOUR CORNERS MATE	283125	OLDCASTLE SW GROUP, INC.DBA FOUR CORNERS MATE	FIDELITYAND DEPODSITCOM ARYLANDS	M	4/6/2011	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	283397	DEVON ENERGY PRODUCTION CORP.	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
2066	280531	ZPZ DELAWARE I LLC	284838	ZPZ DELAWARE I, LLC	LIBERTY MUTUAL INSURANCE COMPA	M	4/21/2025	
916	269864	CANYON E & P COMPANY	285493	CANYON E & P COMPANY	U.S. SPECIALTY INSURANCE COMPA	M	9/9/2010	
1600	19174	RICE OPERATING COMPANY	285509	RICE OPERATING COMPANY	THE OHIO CASUALTY INS. CO.	M	6/10/2018	
1733	243874	QUANTUM RESOURCES MANAGEMENT, LLC	286153	QUANTUM RESOURCES MANAGEMENT, LLC., ETAL	ARGONAUT INSURANCE COMPANY	M	6/8/2020	
898	241333	CHEVRON MIDCONTINENT, L.P.	286165	CHEVRON MIDCONTINENT, L.P.	SAFECO INSURANCE COMPANY OF AM	M	2/10/2010	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
877	160825	BC OPERATING, INC.	286391	CROWN OIL PARTNERS V, L.P.	LEXON INSURANCE COMPANY	M	7/16/2009	
641	199866	CAMERON OIL	286417	CAMERON OIL & GAS, INC.	FIRST NATIONAL BANK	M	6/2/2003	
952	286583	PROSPECTOR, LLC	286583	PROSPECTOR, LLC	U.S. SPECIALTY INSURANCE COMPA	B	10/25/2011	
745	286614	CROSS BORDER RESOURCES, INC.	286614	CROSS BORDER RESOURCES, INC.	STATE LAND OFFICE	B	8/24/2005	
943	15422	APACHE CORP	286812	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
583	223170	CHESAPEAKE EXPLORATION L.L.C.	287038	CHESAPEAKE EXPLORATION, L.L.C.	RLI INSURANCE CO.	M	3/22/2001	
955	287160	MAVERICK OPERATING, LLC	287160	MAVERICK OPERATING, LLC	FROST BANK	M	7/8/2014	
956	303283	COG PRODUCTION, LLC	287343	COG PRODUCTION LLC	U.S. SPECIALTY INSURANCE COMPA	M	11/29/2011	
849	260737	BOPCO, L.P.	287510	BOPCO, LP	TRAVELERS CASUALTY & SURETY CO	M	11/7/2008	
1709	96694	OXY USA INC	287524	OXY USA INC	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
904	210091	DKD,LLC	287590	DKD, LLC	FIRST AMERICAN BANK	M	3/12/2010	
1733	243874	QUANTUM RESOURCES MANAGEMENT, LLC	287837	BREITBURN OPERATING, LP	ARGONAUT INSURANCE COMPANY	M	6/8/2020	
1951	3080	BURNETT OIL CO INC	288188	BURNETT OIL CO	U.S. SPECIALTY INSURANCE COMPA	M	12/18/2023	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	288627	DEVON ENERGY PRODUCTION COMPANY, LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	289336	DEVON ENERGY PRODUCTION COMPANY, L.P.	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1978	289408	LOGOS OPERATING, LLC	289408	LOGOS OPERATING, LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/17/2024	
1006	297843	VANGUARD PERMIAN LLC	289511	VANGUARD PERMIAN, LLC	HANOVER INSURANCE COMPANY	M	4/30/2014	
1611	231269	COG OPERATING LLC	290631	COG OPERATING LLC	ARCH INSURANCE CO.	M	4/30/2018	
641	199866	CAMERON OIL	291393	CAMERON OIL & GAS CO., INC.	FIRST NATIONAL BANK	M	6/2/2003	
969	291444	DIAMOND S ENERGY COMPANY	291444	DIAMOND S ENERGY COMPANY	TRAVELERS CASUALTY & SURETY CO	M	8/9/2012	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1980	291669	HYPERION OIL & GAS LLC	291669	HYPERION OIL & GAS LLC	ARCH INSURANCE COMPANY	S	7/1/2024	B0 9613 6
1936	14187	MARSHALL & WINSTON INC	292804	MARSHALL & WINSTON, INC.	EVERGREEN NATINAL INDEMNITY CO	B	11/8/2023	
930	293363	BLACK STONE MINERALS COMPANY, L.P.	293363	BLACK STONE MINERALS COMPANY, L.P.	U.S SPECIALTY INSURANCE COMPAN	B	12/15/2010	
930	293363	BLACK STONE MINERALS COMPANY, L.P.	293704	BLACK STONE ENERGY COM. L.L.C.	U.S SPECIALTY INSURANCE COMPAN	B	12/15/2010	
1896	293704	BLACK STONE ENERGY COM. L.L.C.	293704	BLACK STONE ENERGY COM. L.L.C.	JPMORGAN CHASE BANK, N.A.	M	12/22/2022	
813	293704	BLACK STONE ENERGY COM. L.L.C.	293704	BLACK STONE ENERGY COM. L.L.C.	U.S. SPECIALTY INSURANCE COMPA	S	9/28/2007	L0 3880 5
1827	293809	SYDHAN, LP	293809	SYDHAN, LP	ARCH INSURANCE COMPANY	M	5/3/2022	
1862	293991	RICHARD LYONS MOORE 2006 TRUST	293991	RICHARD LYONS MOORE 2006 TRUST	CASH BOND	B	8/3/2022	
2023	341840	MAGNUM PRODUCING, LP	294093	MAGNUM PRODUCING, LP	ENDURANCE ASSURANCE CORPORATIO	B	12/17/2024	
1074	294619	M&M ENERGY, LLC	294619	M&M ENERGY, LLC	WELLS FARGO BANK N.A.	S	4/21/2015	VB 1847 1
970	231429	MANZANO LLC	294839	MANZANO ENERGY PARTNERS II, LLC	VALLEY BANK OF COMMERCE	M	7/30/2012	
1716	246368	BASIC ENERGY SERVICES, LP	295227	BASIC ENERGY SERVICES, LP	U. S. SPECIALTY INSURANCE COMP	M	3/17/2020	
1725	246368	BASIC ENERGY SERVICES, LP	295227	BASIC ENERGY SERVICES, LP	US SPECIALTY INSURANCE COMPANY	M	3/17/2020	
1710	107647	OXY Y-1 COMPANY	295248	OXY Y-1 COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
957	222759	BUCKEYE DISPOSAL, L.L.C.	295880	BUCKEYE DISPOSAL, LLC	LEXON INSURANCE COMPANY	M	12/5/2011	
1717	295925	C&J WELL SERVICES, INC.	295925	C&J WELL SERVICES, INC.	U.S. SPECIALTY INSURANCE COMPA	M	3/17/2020	
666	295943	ANADARKO E&P ONSHORE LLC	295943	ANADARKO E&P ONSHORE LLC	LIBERY MUTUAL INSURANCE CO.	B	1/26/2004	
964	15742	NEARBURG PRODUCING CO	296154	NEARBURG PRODUCING COMPANY	U.S. SPECIALTY INSURANCE COMPA	M	6/13/2012	
1709	96694	OXY USA INC	296166	OXY USA INC	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
1003	296278	PROBITY SWD, LLC	296278	PROBITY SWD, LLC	COMMUNITY NATIONAL BANK	M	11/6/2013	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1657	296411	CONSTRUCTORS, INC.	296411	CONSTRUCTORS, INC.	DUNAGAN ASSOCIATES, INC.	M	5/9/2011	
956	303283	COG PRODUCTION, LLC	296438	COG ACREAGE LP	U.S. SPECIALTY INSURANCE COMPA	M	11/29/2011	
1266	266458	SKANSKA USA CIVIL WEST ROCKY MTN. DIST. INC.	296794	SKANSKA	AMERICAN HOME ASSURANCE	M	6/24/2009	
774	230387	PARALLEL PETROLEUM LLC	296964	PLL E&P, LLC	CITIBANK	M	7/25/2006	
1663	297442	DEMING EXCAVATING, INC.	297442	DEMING EXCAVATING, INC.	WESTERN SURETY COMPANY	M	5/1/2013	
1006	297843	VANGUARD PERMIAN LLC	297843	VANGUARD PERMIAN LLC	HANOVER INSURANCE COMPANY	M	4/30/2014	
2079	119305	RAY WESTALL OPERATING, INC.	297999	RAY WESTALL OPERATING, INC.	EVERGREEN NATIONAL INDEMNITY C	M	5/29/2025	
2057	298299	CROSS TIMBERS ENERGY, LLC	298299	CROSS TIMBERS ENERGY, LLC	UNITED STATES FIRE INSURANCE C	M	2/24/2025	
1744	327480	WPX ENERGY PERMIAN, LLC.	298649	WPX ENERGY PERMIAN, LLC	LIBERTY MUTUAL INSURANCE COMPA	M	1/27/2021	
849	260737	BOPCO, L.P.	298976	BOPCO, LP	TRAVELERS CASUALTY & SURETY CO	M	11/7/2008	
1682	300221	THE MERCHANT LIVESTOCK COMPANY, INC.	300221	THE MERCHANT LIVESTOCK COMPANY, INC.	LEXON INSURANCE COMPANY	M	6/15/2017	
1078	300825	BLUE SKY NM, INC.	300825	BLUE SKY NM, INC.	NEW MEXICO BANK & TRUST	B	5/20/2015	
1364	300854	CRAIN HOT OIL SERVICE, INC.	300854	CRAIN HOT OIL SERVICE, INC.	FIRST AMERICAN BANK	M	7/25/2016	
1600	19174	RICE OPERATING COMPANY	302145	RICE OPERATING COMPANY	THE OHIO CASUALTY INS. CO.	M	6/10/2018	
956	303283	COG PRODUCTION, LLC	303283	COG PRODUCTION, LLC	U.S. SPECIALTY INSURANCE COMPA	M	11/29/2011	
1364	300854	CRAIN HOT OIL SERVICE, INC.	303735	CRAIN HOT OIL SERVICE, LLC	FIRST AMERICAN BANK	M	7/25/2016	
1051	303900	MEMORIAL PRODUCTION OPERATING, LLC	303900	MEMORIAL PRODUCTION OPERATING, LLC	ARGONAUT INSURANCE COMPANY	M	11/4/2014	
2074	342299	SPECIAL ENERGY CORPORATION	305614	SPECIAL ENERGY CORPORATION	FRANKENMUTH INSURANCE COMPANY	M	4/28/2025	
2057	298299	CROSS TIMBERS ENERGY, LLC	305793	CROSS TIMBERS ENERGY, LLC	UNITED STATES FIRE INSURANCE C	M	2/24/2025	
2043	64432	EOG RESOURCES, INC.	305878	EOG RESOURCES, INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1005	306381	TAPS I ENERGY LLC	306381	TAPS I ENERGY LLC	LEXON INSURANCE COMPANY	S	3/7/2014	VB 1503 3

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
877	160825	BC OPERATING, INC.	306668	CROWN OIL PARTNERS V, L.P.	LEXON INSURANCE COMPANY	M	7/16/2009	
536	25706	CLAYTON WILLIAMS ENERGY INC	307029	CLAYTON WILLIAMS ENERGY, INC.	RLI INSURANCE COMPANY	M	1/6/2000	
1978	289408	LOGOS OPERATING, LLC	308053	LOGOS OPERATING, LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/17/2024	
1258	308080	A-1 QUALITY REDI-MIX, INC.	308080	A-1 QUALITY REDI-MIX, INC.	LEXON INSURANCE COMPANY	M	3/14/2016	
1082	308177	LOMA HOMBRE ENERGY, LLC	308177	LOMA HOMBRE ENERGY, LLC	WAIVER	S	7/10/2014	VB 2196 0
1110	308177	LOMA HOMBRE ENERGY, LLC	308177	LOMA HOMBRE ENERGY, LLC	WAIVER	S	4/30/2015	V0 9113 0
1111	308177	LOMA HOMBRE ENERGY, LLC	308177	LOMA HOMBRE ENERGY, LLC	WAIVER	S	4/30/2015	V0 9348 0
1962	308177	LOMA HOMBRE ENERGY, LLC	308177	LOMA HOMBRE ENERGY, LLC	WAIVER	S	1/8/2024	VC 1169 0
1970	308177	LOMA HOMBRE ENERGY, LLC	308177	LOMA HOMBRE ENERGY, LLC	WAIVER	S	5/1/2024	VC 1255 0
1971	308177	LOMA HOMBRE ENERGY, LLC	308177	LOMA HOMBRE ENERGY, LLC	WAIVER	S	5/1/2024	VC 1256 0
1972	308177	LOMA HOMBRE ENERGY, LLC	308177	LOMA HOMBRE ENERGY, LLC	WAIVER	S	5/1/2024	VC 1257 0
1973	308177	LOMA HOMBRE ENERGY, LLC	308177	LOMA HOMBRE ENERGY, LLC	WAIVER	S	5/1/2024	VC 1258 0
1011	308339	OWL SWD OPERATING, LLC	308339	OWL SWD OPERATING, LLC	FROST BANK	M	7/25/2014	
1966	310548	CART HILL ENERGY, LLC	310548	CART HILL ENERGY, LLC	INDEMNITY NATIONAL INSURANCE C	M	5/8/2024	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	310728	DEVON ENERGY PRODUCTION COMPANY, L.P.	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1072	310761	OASIS WATER SOLUTIONS LLC	310761	OASIS WATER SOLUTIONS LLC	LEA COUNTY STATE BANK	M	3/13/2015	
1037	311845	ONSHORE ROYALTIES, LLC	311845	ONSHORE ROYALTIES, LLC	PIONEER BANK	M	10/2/2014	
1042	370131	ANSCHUTZ OIL COMPANY, LLC	312642	ANSCHUTZ OIL COMPANY, LLC	TRAVELERS CASUALTY & SURETY CO	M	10/15/2014	
1263	314480	VOLCANIC STONE CO.	314480	VOLCANIC STONE CO.	VOLCANIC STONE CO	M	10/6/2015	
1708	96704	OXY USA WTP LIMITED PARTNERSHIP	314567	OXY USA WTP LIMITED PARTNERSHIP	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
1509	86997	MARATHON OIL COMPANY LLC	314705	MARATHON OIL COMPANY	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
849	260737	BOPCO, L.P.	314720	BOPCO L.P.	TRAVELERS CASUALTY & SURETY CO	M	11/7/2008	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1762	317983	GUS H20 L.L.C. & RAZ OIL & GAS, L.L.C.	314757	GUS H2O LLC	ARCH INSURANCE COMPANY	M	5/11/2021	
791	1092	ARMSTRONG ENERGY CORP	314913	ARMSTRONG ENERGY CORPORATION	JP MORGAN CHASE	M	2/20/2007	
1989	314987	MURCHISON OIL & GAS,LLC	314987	MURCHISON OIL & GAS,LLC	EVERGREEN NATIONAL INDEMNITY C	M	9/3/2024	
2057	298299	CROSS TIMBERS ENERGY, LLC	315244	CROSS TIMBERS ENERGY LLC	UNITED STATES FIRE INSURANCE C	M	2/24/2025	
1709	96694	OXY USA INC	315329	OXY USA INC.	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
1004	261044	MRC PERMIAN COMPANY	315528	MRC DELAWARE RESOURCE, LLC	ARCH INSURANCE COMPANY	M	1/7/2014	
1745	120782	WPX ENERGY PRODUCTION, LLC	316485	WPX ENERGY PRODUCTION, LLC	LIBERTY MUTUAL INSURANCE COMPA	B	1/27/2021	
877	160825	BC OPERATING, INC.	316952	BC OPERATING, INC.	LEXON INSURANCE COMPANY	M	7/16/2009	
1083	317049	PRIZE EXPLORATION, LLC	317049	PRIZE EXPLORATION, LLC	WESTCHESTER FIRE INSURANCE COM	M	7/23/2015	
1079	317612	PADUCA PARTNERS LLC	317612	PADUCA PARTNERS LLC	ENDURANCE ASSURANCE CORPORATIO	B	6/12/2015	
1762	317983	GUS H20 L.L.C. & RAZ OIL & GAS, L.L.C.	317983	GUS H20 L.L.C. & RAZ OIL & GAS, L.L.C.	ARCH INSURANCE COMPANY	M	5/11/2021	
1089	318109	CAT SPRING PROPERTIES LLC	318109	CAT SPRING PROPERTIES LLC	CITIZENS STATE BANK	S	8/30/2015	L0 446 3
1259	318697	AGGREGATE TECHNOLOGIES, LLC	318697	AGGREGATE TECHNOLOGIES, LLC	THE OHIO CASUALTY INSURANCE CO	M	7/9/2015	
1744	327480	WPX ENERGY PERMIAN, LLC.	319214	WPX ENERGY PERMIAN, LLC	LIBERTY MUTUAL INSURANCE COMPA	M	1/27/2021	
1664	319310	DEMING SAND & GRAVEL, LLC	319310	DEMING SAND & GRAVEL, LLC	UNITED FIRE & CASUALTY COMPANY	M	8/24/2016	
1676	319333	KEY LIVESTOCK, LLC	319333	KEY LIVESTOCK, LLC	NATIONWIDE MUTUAL INSURANCE CO	M	7/19/2017	
1086	371101	CLEARWATER SWD, LLC	319851	CLEARWATER SWD, LLC	LEXON INSURANCE COMPANY	M	9/14/2015	
1652	319990	ESPANOLA TRANSIT MIX, LLC	319990	ESPANOLA TRANSIT MIX, LLC	INTERNATIONAL FIDELITY INSURAN	M	3/11/2015	
1086	371101	CLEARWATER SWD, LLC	320253	CLEARWATER SWD, LLC	LEXON INSURANCE COMPANY	M	9/14/2015	
1709	96694	OXY USA INC	320929	OXY USA INC	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	321578	DEVON ENERGY PRODUCTION CO, L.P.	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
943	15422	APACHE CORP	321605	APACHE CORPORATION	LIBERTY MUTUAL INSURANCE COMPA	M	6/14/2011	
2043	64432	EOG RESOURCES, INC.	321638	EOG RESOURCES, INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1668	321646	FISHER SAND & GRAVEL-NEW MEXICO, INC.	321646	FISHER SAND & GRAVEL-NEW MEXICO, INC.	LIBERTY MUTUAL INSURANCE COMPA	M	8/23/2007	
2043	64432	EOG RESOURCES, INC.	321701	EOG RESOURCES	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	321750	DEVON ENERGY PRODUCTION CO., LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1978	289408	LOGOS OPERATING, LLC	321818	LOGOS OPERATING, LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/17/2024	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	321882	DEVON ENERGY PRODUCTION CO. LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	322201	DEVON ENERGY PRODUCTION CO. LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1097	322227	JOHN S. CATRON & FLETCHER R. CATRON	322227	JOHN S. CATRON & FLETCHER R. CATRON	LEXON INSURANCE COMPANY	S	12/18/2015	A0 1375 36
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	322429	DEVON ENERGY PRODUCT. CO.,LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1162	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9533 0
1163	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9536 0
1164	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	VB 2385 0
1165	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9516 1
1166	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9652 1
1167	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9635 1
1180	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	VB 2322 1
1181	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9581 1
1182	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9656 1
1183	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	VB 2390 1
1174	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	VB 2401 1
1175	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9637 1
1176	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9605 1

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1177	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9542 1
1178	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	VB 2391 1
1179	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9541 1
1168	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9640 1
1169	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9636 1
1170	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	VB 2214 1
1171	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9568 1
1172	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9535 1
1173	322954	TERRA NOVA ENERGY, LP	322954	TERRA NOVA ENERGY, LP	WAIVER	S	3/3/2016	V0 9534 1
1675	322966	JIM ROSS CAVINESS	322966	JIM ROSS CAVINESS	LEXON INSURANCE COMPANY	M	8/11/2017	
1717	295925	C&J WELL SERVICES, INC.	323096	C&J WELL SERVICES, INC.	U.S. SPECIALTY INSURANCE COMPA	M	3/17/2020	
1086	371101	CLEARWATER SWD, LLC	323408	CLEARWATER SWD, LLC	LEXON INSURANCE COMPANY	M	9/14/2015	
1683	323591	MICHELE'S READY MIX, ROCK & RECYCLE, INC.	323591	MICHELE'S READY MIX, ROCK & RECYCLE, INC.	LEXON INSURANCE COMPANY	M	3/24/2016	
1621	260297	BTA OIL PRODUCERS, LLC	323829	BTA OIL PRODUCERS, LLC	US SPECIALTY INSURANCE CO.	M	11/1/2018	
1744	327480	WPX ENERGY PERMIAN, LLC.	324019	WPX ENERGY PERMIAN, LLC	LIBERTY MUTUAL INSURANCE COMPA	M	1/27/2021	
1762	317983	GUS H20 L.L.C. & RAZ OIL & GAS, L.L.C.	324154	RAZ OIL AND GAS L.L.C.	ARCH INSURANCE COMPANY	M	5/11/2021	
913	197035	XTO ENERGY INC	324373	XTO ENERGY INC.	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
2123	197035	XTO ENERGY INC	324373	XTO ENERGY INC.	FEDERAL INSURANCE COMPANY	M	6/4/2025	
1247	324463	SILVER HILL E&P II, LLC.	324463	SILVER HILL E&P II, LLC.	WAIVER	S	2/24/2016	VB 2225 2
1709	96694	OXY USA INC	324642	OXY USA, INC.	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
1485	324740	KASTLEFORD LAND COMPANY, LLC.	324740	KASTLEFORD LAND COMPANY, LLC.	N/A	S	1/26/2017	VB 2885 0
1517	324740	KASTLEFORD LAND COMPANY, LLC.	324740	KASTLEFORD LAND COMPANY, LLC.	N/A	B	4/11/2017	
1401	324973	HEADINGTON ENERGY PARTNERS LLC	324973	HEADINGTON ENERGY PARTNERS LLC	RLI INSURANCE COMPANY	M	9/27/2016	
1916	258983	BRIDWELL OIL COMPANY	325194	BRIDWELL OIL COMPANY	EVERGREEN NATIONAL INDEMNITY C	B	4/27/2023	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	325460	DEVON ENERGY PRODUCTION COMPANY, LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
1588	218098	BP AMERICA PRODUCTION COMPANY	325517	BP AMERICA PRODUCTION COMPANY	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
1502	325655	REMINGTON MONUMENT, L.L.C.	325655	REMINGTON MONUMENT, L.L.C.	BANK OF ALBUQUERQUE	M	1/25/2017	
1900	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	WAIVER	S	11/8/2022	VC 962 1
1901	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	WAIVER	S	11/8/2022	VC 963 1
1902	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	WAIVER	S	11/8/2022	VC 964 1
1903	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	WAIVER	S	11/8/2022	VC 965 1
1904	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	325718	ROY G. BARTON SR. & OPAL BARTON REV TRUST	WAIVER	S	11/8/2022	VC 966 1
1553	325754	TAP ROCK RESOURCES, LLC.	325754	TAP ROCK RESOURCES, LLC.	BANK OF ALBUQUERQUE	M	9/19/2017	
1455	325830	ASCENT ENERGY, LLC.	325830	ASCENT ENERGY, LLC.	WELLS FARGO, N.A.	M	11/28/2016	
1752	325830	ASCENT ENERGY, LLC.	325830	ASCENT ENERGY, LLC.	ENDURANCE ASSURANCE CORPORATIO	M	2/25/2021	
1461	371762	ABO EMPIRE, LLC	325875	ABO EMPIRE, LLC.	U.S. SPECIALTY INSURANCE COMPA	M	11/16/2016	
964	15742	NEARBURG PRODUCING CO	325984	EAU ROUGE LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/13/2012	
964	15742	NEARBURG PRODUCING CO	325996	ST. DEVOTE LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/13/2012	
1458	371755	PERCUSSION PETROLEUM OPERATING, LLC	325996	ST. DEVOTE LLC	U.S. SPECIALTY INS CO.	M	12/21/2016	
1856	326061	SCR ENERGY CAPITAL, LLC.	326061	SCR ENERGY CAPITAL, LLC.	CASH BOND	B	6/14/2022	
1460	326121	LLJ VENTURES, LLC	326121	LLJ VENTURES, LLC	LEXON INSURANCE CO.	B	6/28/2016	
1599	326258	POGO OIL & GAS OPERATING, INC.	326258	POGO OIL & GAS OPERATING, INC.	US SPECIALTY INSURANCE COMPANY	M	4/23/2018	
1509	86997	MARATHON OIL COMPANY LLC	326310	MARATHON OIL PERMIAN LLC	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	
1540	326341	RCS - NM ENERGY, LLC	326341	RCS - NM ENERGY, LLC	ATLANTIC SPECIALTY INSURANCE C	M	6/5/2017	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1538	326448	DGP ENERGY LLC	326448	DGP ENERGY LLC	N/A	B	6/7/2017	
1562	372583	DGP ENERGY, LLC	326448	DGP ENERGY LLC	FIDELITY & DEPPOSIT CO OF MD	M	10/13/2017	
1715	371838	DJR OPERATING, LLC	326472	DJR ASSETS, LLC	U.S. SPECIALTY INSURANCE COMPA	M	4/14/2020	
1781	372137	CHISHOLM ENERGY OPERATING, LLC	326483	CHISHOLM ENERGY OPERATING, LLC.	U.S. SPECIALTY INSURANCE COMPA	M	6/26/2020	
1550	326495	TROVE ENERGY & WATER, LLC	326495	TROVE ENERGY & WATER, LLC	LEXON INSURANCE COMPANY	M	7/5/2017	
1527	372224	AMEREDEV OPERATING, LLC	326500	AMEREDEV NEW MEXICO, LLC.	ASPEN AMERICAN INSURANCE CO.	M	4/26/2017	
1584	326531	CHRISTEVE OIL COMPANY, INC.	326531	CHRISTEVE OIL COMPANY, INC.	WELLS FARGO BANK, N.A.	B	2/2/2018	
1528	326543	HAYES LAND, LP.	326543	HAYES LAND, LP.	WELLS FARGO BANK	B	5/16/2017	
944	338563	GRIZZLY OPERATING LLC	326554	GRIZZLY OPERATING, LLC	U.S. SPECIALTY INSURANCE COMP.	M	7/7/2011	
1694	338563	GRIZZLY OPERATING LLC	326554	GRIZZLY OPERATING, LLC	SIRIUS AMERICA INSURANCE COMPA	M	9/6/2019	
2098	326582	LONGFELLOW LH, LLC.	326582	LONGFELLOW LH, LLC.	EVERGREEN NATIONAL INDEMNITY C	M	6/5/2025	
1599	326258	POGO OIL & GAS OPERATING, INC.	326598	POGO RESOURCES, LLC.	US SPECIALTY INSURANCE COMPANY	M	4/23/2018	
1527	372224	AMEREDEV OPERATING, LLC	326626	AMEREDEV OPERATING, LLC.	ASPEN AMERICAN INSURANCE CO.	M	4/26/2017	
2097	326665	LONGFELLOW ENERGY, LP	326665	LONGFELLOW ENERGY, LP	EVERGREEN NATIONAL INDEMNITY C	M	6/5/2025	
1998	326734	CAZA PETROLEUM, LLC.	326734	CAZA PETROLEUM, LLC.	EVERGREEN NATIONAL INDEMNITY C	M	10/7/2024	
1543	280276	ENDURING RESOURCES,LLC	326756	ENDURING RESOURCES IV, LLC.	RLI INSURANCE COMPANY	M	6/30/2017	
1890	326760	ESTACADO LAND SERVICES, LLC.	326760	ESTACADO LAND SERVICES, LLC.	WAIVER	S	11/15/2022	VC 1078 0
1895	326760	ESTACADO LAND SERVICES, LLC.	326760	ESTACADO LAND SERVICES, LLC.	WAIVER	S	12/20/2022	VC 1082 0
1060	326806	WYATT PERMIAN, LLC.	326806	WYATT PERMIAN, LLC.	BANK OF AMERICA	M	2/26/2015	
1611	231269	COG OPERATING LLC	326822	SRO3, LLC.	ARCH INSURANCE CO.	M	4/30/2018	
1589	326839	TEXAS STANDARD OIL LLC.	326839	TEXAS STANDARD OIL LLC.	LEXON INSURANCE COMPANY	M	3/9/2018	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
596	148394	VERNON E. FAULCONER, INC.	326888	FAULCONER 1996 LIMITED PARTNERSHIP, LLP	RLI INSURANCE	B	7/24/2001	
596	148394	VERNON E. FAULCONER, INC.	326908	FAULCONER RESOURCES 1999 LIMITED PART, LLP	RLI INSURANCE	B	7/24/2001	
1552	326924	HILCORP SAN JUAN, LP	326924	HILCORP SAN JUAN, LP	WESTERN SURETY COMPANY	M	9/20/2017	
2100	326941	CALM FORT WORTH VENTURES, LLC.	326941	CALM FORT WORTH VENTURES, LLC.	CASH BOND/ WIRE TRANSFER	B	8/11/2025	
1756	327055	YATES INDUSTRIES LLC	327055	YATES INDUSTRIES LLC	LEXON INSURANCE COMPANY	M	3/17/2021	
970	231429	MANZANO LLC	327086	MANZANO ENERGY PARTNERS III, LLC.	VALLEY BANK OF COMMERCE	M	7/30/2012	
2050	327090	STRATEGIC ENERGY INCOME FUND IV, LP	327090	STRATEGIC ENERGY INCOME FUND IV, LP	U.S. SPECIALTY INSURANCE COMPA	M	2/3/2025	
1560	327122	IACX ROSWELL, LLC.	327122	IACX ROSWELL, LLC.	ARGONAUT INSURANCE COMPANY	M	9/14/2017	
596	148394	VERNON E. FAULCONER, INC.	327151	FAULCONER RESOURCES JOINT-VENTURE-1993, LLP	RLI INSURANCE	B	7/24/2001	
2092	327231	FLAG DEVELOPMENT, LLC.	327231	FLAG DEVELOPMENT, LLC.	SIRIUSPOINT AMERICA INSURANCE	M	3/5/2025	
1599	326258	POGO OIL & GAS OPERATING, INC.	327298	POGO OIL & GAS OPER, INC. & APACHE CORP.	US SPECIALTY INSURANCE COMPANY	M	4/23/2018	
1577	327328	SHELMAR E & P NM, LP	327328	SHELMAR E & P NM, LP	LEXON INSURANCE COMPANY	M	1/3/2018	
913	197035	XTO ENERGY INC	327330	XTO HOLDINGS, LLC	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
2095	327330	XTO HOLDINGS, LLC	327330	XTO HOLDINGS, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
2091	327342	STETSON EXPLORATION, LLC.	327342	STETSON EXPLORATION, LLC.	SIRIUSPOINT AMERICA INSURANCE	M	3/22/2025	
1744	327480	WPX ENERGY PERMIAN, LLC.	327480	WPX ENERGY PERMIAN, LLC.	LIBERTY MUTUAL INSURANCE COMPA	M	1/27/2021	
913	197035	XTO ENERGY INC	327529	XTO PERMIAN OPERATING, LLC	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
2094	327529	XTO PERMIAN OPERATING, LLC	327529	XTO PERMIAN OPERATING, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
1599	326258	POGO OIL & GAS OPERATING, INC.	327581	POGO OIL & GAS OPER INC. & APACHE CORP	US SPECIALTY INSURANCE COMPANY	M	4/23/2018	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1593	327594	RILEY EXPLORATION -PERMIAN, LLC.	327594	RILEY EXPLORATION -PERMIAN, LLC.	US SPECIALTY INSURANCE COMPANY	M	5/11/2018	
1603	327648	K. P. KAUFFMAN COMPANY, INC.	327648	K. P. KAUFFMAN COMPANY, INC.	FIDELITY AND DEPOSIT COMPANY O	M	6/26/2018	
1610	327650	MUSTANG RESOURCES, LLC.	327650	MUSTANG RESOURCES, LLC.	BOK FINANCIAL	B	10/4/2018	
1601	327683	VENDERA MANAGEMENT III, LLC.	327683	VENDERA MANAGEMENT III, LLC.	BANK OF OKLAHOMA	M	7/19/2018	
1614	327738	COERT HOLDINGS 1, LLC.	327738	COERT HOLDINGS 1, LLC.	GUARANTEE CO OF NA USA	M	8/29/2018	
1620	327746	FLAT CREEK RESOURCES, LLC.	327746	FLAT CREEK RESOURCES, LLC.	N/A	B	11/12/2018	
2009	327757	DUDLEY LAND COMPANY	327757	DUDLEY LAND COMPANY	WAIVER	S	11/19/2024	VC 1304 0
2109	327757	DUDLEY LAND COMPANY	327757	DUDLEY LAND COMPANY	WAIVER	S	9/24/2025	SG 5 0
2110	327757	DUDLEY LAND COMPANY	327757	DUDLEY LAND COMPANY	WAIVER	S	9/24/2025	SG 4 0
2111	327757	DUDLEY LAND COMPANY	327757	DUDLEY LAND COMPANY	WAIVER	S	9/24/2025	SG 3 0
1626	327774	SALT FORK LIMITED	327774	SALT FORK LIMITED	PIONEER BANK	B	12/28/2018	
596	148394	VERNON E. FAULCONER, INC.	327821	FAULCONER 2004 LIMITED PARTNERSHIP, LLP	RLI INSURANCE	B	7/24/2001	
1639	327870	PACIFIC ENERGY DEVELOPMEN T CORP	327870	PACIFIC ENERGY DEVELOPMEN T CORP	ARGONAUT INSURANCE CO.	M	4/4/2019	
1607	327884	SUMMIT PERMIAN TRANSMISSIO N, LLC	327884	SUMMIT PERMIAN TRANSMISSIO N, LLC	LIBERTY MUTUAL INSURANCE CO.	M	8/29/2018	
913	197035	XTO ENERGY INC	327896	XTO DELAWARE BASIN, LLC.	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
2096	327896	XTO DELAWARE BASIN, LLC.	327896	XTO DELAWARE BASIN, LLC.	FEDERAL INSURANCE COMPANY	M	6/26/2025	
1623	327913	BEXP I, LP	327913	BEXP I, LP	US SPECIALTY INS CO	B	10/30/2018	
1699	327930	THRUST ENERGY, INC.	327930	THRUST ENERGY, INC.	WAIVER	B	12/10/2019	
1601	327683	VENDERA MANAGEMENT III, LLC.	327959	VENDERA RESOURCES III, L.P.	BANK OF OKLAHOMA	M	7/19/2018	
1616	328029	PERCHERON PROFESSIONA L SERVICES, LLC.	328029	PERCHERON PROFESSIONA L SERVICES, LLC.	N/A	B	10/30/2018	
670	217598	ASPEN OPERATING COMPANY LLC	328076	ASPEN OPERATING COMPANY, LLC.	BANK OF TEXAS	B	3/10/2004	
1704	328094	COTERRA ENERGY OPERATING M LLC	328094	COTERRA ENERGY OPERATING M LLC	FIDELITY AND DEPOSIT COMPANY O	M	10/17/2019	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
2063	328094	COTERRA ENERGY OPERATING M LLC	328094	COTERRA ENERGY OPERATING M LLC	UNITED STATES FIRE INSURANCE C	M	4/16/2025	
1625	328195	TASCOSA ENERGY PARTNERS, LLC.	328195	TASCOSA ENERGY PARTNERS, LLC.	WAIVER	B	12/18/2018	
1729	328195	TASCOSA ENERGY PARTNERS, LLC.	328195	TASCOSA ENERGY PARTNERS, LLC.	WEST TEXAS NATIONAL BANK	M	7/13/2020	
2051	328204	ONYX RESOURCES, L.P.	328204	ONYX RESOURCES, L.P.	CLEAR FORK BANK, NA	M	1/15/2025	
1666	328259	Permian Oilfield Partners, LLC	328259	Permian Oilfield Partners, LLC	RLI INSURANCE COMPANY	M	8/1/2019	
1720	328565	BAM Permian Operating, LLC	328565	BAM Permian Operating, LLC	AMERICAN MOMENTUM BANK	M	5/29/2020	
1640	328599	Ring Energy, Inc	328599	Ring Energy, Inc	TRAVELERS CASUALTY & SURETY CO	M	4/5/2019	
1987	328654	R&R Royalty, Ltd.	328654	R&R Royalty, Ltd.	ENDURANCE ASSURANCE CORPORATIO	B	7/24/2024	
1655	328733	Flint Oak Energy, LLC	328733	Flint Oak Energy, LLC	U.S. SPECIALTY INSURANCE CO.	M	6/7/2019	
1742	338408	SPUR ENERGY PARTNERS, LLC	328947	Spur Energy Partners LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/8/2020	
1995	338424	HIGH RIVER RESOURCES OPERATING, LLC	328985	High River Resources Operating, LLC	PENNSYLVANI A INSURANCE COMPANY	M	9/17/2024	
1659	338511	SABINAL ENERGY OPERATING, LLC	328992	Sabinal Energy Operating, LLC	UNITED STATES FIRE INSURANCE C	M	8/1/2019	
2001	341771	LM TOUCHDOWN, LLC	329097	LM Touchdown LLC	U. S. SPECIALTY INSURANCE COMP	M	10/7/2024	
1701	329319	LH Operating, LLC	329319	LH Operating, LLC	U.S. SPECIALTY INSURANCE COMPA	M	10/8/2019	
1638	371416	FORTY ACRES ENERGY, LLC	329326	FAE II Operating LLC	U.S. SPECIALTY INSURANCE CO.	M	3/28/2019	
1731	329487	BXP Operating, LLC	329487	BXP Operating, LLC	ENDURANCE ASSURANCE CORPORATIO	M	7/1/2020	
1560	327122	IACX ROSWELL, LLC.	329556	IACX Roswell, LLC	ARGONAUT INSURANCE COMPANY	M	9/14/2017	
1692	329657	Cotton Draw Midstream, L.L.C	329657	Cotton Draw Midstream, L.L.C	TRAVELERS CASUALTY & SURETY CO	M	11/6/2019	
1769	329727	Sozo Natural Resources LLC	329727	Sozo Natural Resources LLC	ARGONAUT INSURANCE COMPANY	B	6/3/2021	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	1729	328195 TASCOSA ENERGY PARTNERS, LLC.	329748	Tascosa Energy Partners, L.L.C	WEST TEXAS NATIONAL BANK	M	7/13/2020	
	1560	327122 IACX ROSWELL, LLC.	329877	IACX Production LLC	ARGONAUT INSURANCE COMPANY	M	9/14/2017	
	1954	330129 WaterBridge Stateline LLC	330129	WaterBridge Stateline LLC	ARCH INSURANCE COMPANY	M	1/24/2024	
	2056	338948 MORNINGSTAR OPERATING, LLC	330132	MorningStar Operating LLC	UNITED STATES FIRE INSURANCE C	M	3/4/2025	
	1800	339603 REDWOOD OPERATING, LLC	330211	Redwood Operating LLC	U.S. SPECIALTY INSURANCE COMPA	M	12/6/2021	
	1766	330220 RAYBAW Operating, LLC	330220	RAYBAW Operating, LLC	HILLCREST BANK	M	4/6/2021	
	1734	330238 Solis Partners, L.L.C.	330238	Solis Partners, L.L.C.	WEST TEXAS NATIONAL BANK	M	9/8/2020	
	1911	330396 Avant Operating, LLC	330396	Avant Operating, LLC	UMB BANK, N.A.	M	3/27/2023	
	1747	339102 EXTEX OPERATING COMPANY	330423	Extex Operating Company	TRAVELERS CASUALTY & SURETY CO	M	1/15/2021	
	2085	342394 CONTANGO RESOURCES, LLC	330447	Contango Resources, LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/11/2025	
	1927	339497 MR NM OPERATING, LLC	330506	MR NM Operating LLC	UNITED STATES FIRE INSURANCE C	M	8/21/2023	
	1767	330522 Acacia Operating Company, LLC	330522	Acacia Operating Company, LLC	COMMUNITY NATIONAL BANK	M	4/29/2021	
	1768	330608 Roughhouse Operating, LLC	330608	Roughhouse Operating, LLC	WESTERN BANK	M	5/19/2021	
	1824	339847 ROUGHHOUSE OPERATING, LLC	330608	Roughhouse Operating, LLC	CASH BOND	M	4/6/2022	
	1931	330662 K&M RESOURCES LLC	330662	K&M RESOURCES LLC	WESTERN BANK	S	10/16/2023	L0 4493 4
	2090	340011 K&M RESOURCES LLC	330662	K&M RESOURCES LLC	WESTERN BANK ARTESIA	S	7/25/2025	E1 68 4
	1860	741801 EMPIRE NEW MEXICO, LLC	330679	Empire New Mexico LLC	GREAT MIDWEST INSURANCE COMPAN	M	7/12/2022	
	1799	330859 Alpha Energy Partners LLC	330859	Alpha Energy Partners LLC	CASH BOND	B	12/7/2021	
	1780	339305 OPAL OPERATING COMPANY LLC	330887	Opal Operating Company LLC	BANK OF ALBUQUERQUE	M	7/9/2021	
	1790	339406 SILVERBACK OPERATING II, LLC	330968	Silverback Operating II, LLC	ENDURANCE ASSURANCE CORP.	M	10/7/2021	
	1944	339406 SILVERBACK OPERATING II, LLC	330968	Silverback Operating II, LLC	ENDURANCE ASSURANCE CORPORATIO	M	11/28/2023	
	1798	330984 Amalgamated Sludge NM, LLC	330984	Amalgamated Sludge NM, LLC	WASHINGTON FEDERAL BANK, N.A.	M	11/2/2021	
	1795	339548 SELECT AGUA LIBRE MIDSTREAM, LLC	331031	SELECT AGUA LIBRE MIDSTREAM, LLC	RLI INSURANCE COMPANY	M	9/25/2021	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	1814	331165 Earthstone Operating, LLC	331165	Earthstone Operating, LLC	U. S. SPECIALTY INSURANCE COMP	M	2/15/2022	
	1819	331180 Big Star Investments, LLC	331180	Big Star Investments, LLC	ARCH INSURANCE COMPANY	B	3/7/2022	
	1988	756700 Maverick Permian LLC	331199	Maverick Permian LLC	PENNSYLVANIA INSURANCE COMPANY	M	9/3/2024	
	1928	331290 Seattle's Best Consulting LLC	331290	Seattle's Best Consulting LLC	ARCH INSURANCE COMPANY	S	8/28/2023	B1 1410 3
	1949	331451 Black Top Operating, LLC	331451	Black Top Operating, LLC	EVERGREEN NATIONAL INDEMNITY C	M	12/18/2023	
	1883	340227 FINALY RESOURCES LLC	331515	Finaly Resources LLC	CASH BOND	B	10/25/2022	
	1906	331595 Coterra Energy Operating E LLC	331595	Coterra Energy Operating E LLC	UNITED STATES FIRE INSURANCE C	M	11/14/2022	
	1908	331595 Coterra Energy Operating E LLC	331595	Coterra Energy Operating E LLC	UNITED STATES FIRE INSURANCE C	M	11/14/2022	
	2055	341159 COFER & CO. LLC	331911	COFER & CO LLC	PIONEER BANK	B	3/11/2025	
	1939	332148 TEAM OPERATING, L.L.C.	332148	TEAM OPERATING, L.L.C.	STELLAR BANK	M	11/28/2023	
	1937	332195 Civitas Permian Operating, LLC	332195	Civitas Permian Operating, LLC	UNITED STATES FIRE INSURANCE C	M	11/20/2023	
	2142	332228 Waylander LLC	332228	Waylander LLC	FRANKENMUTH INSURANCE COMPANY	M	2/25/2026	
	2061	342023 PALOMA PERMIAN ASSETCO, LLC	332449	Paloma Permian AssetCo, LLC	INDEMNITY NATIONAL INSURANCE C	M	4/10/2025	
	1964	341574 LANDMARK ENERGY PARTNERS, LLC	332519	Landmark Energy Partners, LLC	ARCH INSURANCE COMPANY	M	4/25/2024	
	2137	342649 PBEX OPERATIONS, LLC	332544	PBEX Operations, LLC	EVERGREEN NATIONAL INDEMNITY C	M	2/5/2026	
	2076	342329 AD ASTRA RESOURCES, LLC	332741	Ad Astra Resources LLC	INTRUST BANK, N.A.	M	5/20/2025	
	2081	342358 AVANT OPERATING II, LLC	332947	Avant Operating II, LLC	PENNSYLVANIA INSURANCE COMPANY	M	7/1/2025	
	2038	342009 JONAH ENERGY LLC	333010	Jonah Energy LLC	UNITED STATES FIRE INSURANCE C	M	1/1/2025	
	2101	342376 TEXIAN OPERATING COMPANY, LLC	333122	Texian Operating Company, LLC	U.S. SPECIALTY INSURANCE COMPA	B	8/13/2025	
	2099	333188 Animas Resources, LLC	333188	Animas Resources, LLC	FRANKENMUTH INSURANCE COMPANY	M	7/30/2025	
	2084	333313 EW Operating (NM), LLC	333313	EW Operating (NM), LLC	RIL INSURANCE COMPANY	B	6/25/2025	
	2072	342138 SARVIS PERMIAN LAND FUND I SC, LLC	333342	Sarvis Permian Land Fund I SC, LLC	CASH BOND	M	4/29/2025	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
2138	342498	SEP LEGACY LLC	333683	SEP Legacy LLC	ARCH INSURANCE COMPANY	M	10/21/2025	
2106	342530	BCE-MACH III LLC	333695	BCE-Mach III LLC	UNITED STATES FIRE INSURANCE C	M	9/16/2025	
2122	342722	FED OPERATING LLC	333904	FED Operating LLC	EVERGREEN NATIONAL INDEMNITY C	M	12/18/2025	
1628	338251	MARKWEST ENERGY WEST TEXAS GAS CO. LLC	338251	MARKWEST ENERGY WEST TEXAS GAS CO. LLC	LIBERTY MUTUAL INSURANCE CO.	M	12/5/2018	
1697	338264	PLATFORM ENERGY III, LLC.	338264	PLATFORM ENERGY III, LLC.	WAIVER	B	11/25/2019	
1630	338273	MMCP EQUIPMENT, LTD	338273	MMCP EQUIPMENT, LTD	LEXON INSURANCE CO.	S	11/8/2018	LG 3345 1
1742	338408	SPUR ENERGY PARTNERS, LLC	338408	SPUR ENERGY PARTNERS, LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/8/2020	
1995	338424	HIGH RIVER RESOURCES OPERATING, LLC	338424	HIGH RIVER RESOURCES OPERATING, LLC	PENNSYLVANIA INSURANCE COMPANY	M	9/17/2024	
1645	338479	SEP PERMIAN LLC	338479	SEP PERMIAN LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/5/2019	
1741	338479	SEP PERMIAN LLC	338479	SEP PERMIAN LLC	ARCH INSURANCE COMPANY	M	11/17/2020	
1667	338490	E. L. LATHAM CO., LLC	338490	E. L. LATHAM CO., LLC	TRINITY BANK N.A.	S	8/19/2019	L0 4674 1
1659	338511	SABINAL ENERGY OPERATING, LLC	338511	SABINAL ENERGY OPERATING, LLC	UNITED STATES FIRE INSURANCE C	M	8/1/2019	
1674	338520	AMERIPERMIAN HOLDINGS, LLC.	338520	AMERIPERMIAN HOLDINGS, LLC.	WAIVER	B	8/20/2019	
1679	338557	RED SUN ENERGY LLC	338557	RED SUN ENERGY LLC	LIBERTY MUTUAL	M	9/10/2019	
944	338563	GRIZZLY OPERATING LLC	338563	GRIZZLY OPERATING LLC	U.S. SPECIALTY INSURANCE COMP.	M	7/7/2011	
1694	338563	GRIZZLY OPERATING LLC	338563	GRIZZLY OPERATING LLC	SIRIUS AMERICA INSURANCE COMPA	M	9/6/2019	
1690	338574	WARWICK-ARTEMIS, LLC	338574	WARWICK-ARTEMIS, LLC	UNITED STATES FIRE INS. CO.	B	9/17/2019	
877	160825	BC OPERATING, INC.	338647	CROWN OIL PARTNERS VI, LLC	LEXON INSURANCE COMPANY	M	7/16/2009	
1692	329657	Cotton Draw Midstream, L.L.C	338660	COTTON DRAW MIDSTREAM, L.L.C.	TRAVELERS CASUALTY & SURETY CO	M	11/6/2019	
1693	338678	NORTH FORK LAND MANAGEMENT, LP	338678	NORTH FORK LAND MANAGEMENT, LP	LEXON INSURANCE COMPANY	M	11/11/2019	
1731	329487	BXP Operating, LLC	338685	BXP OPERATING, LLC	ENDURANCE ASSURANCE CORPORATIO	M	7/1/2020	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	1761	338692 MILO D. SMITH & SHEILA M. SMITH	338692	MILO D. SMITH & SHEILA M. SMITH	WAIVER	S	3/16/2021	E0 5184 55
	1743	338719 FAE II, LLC	338719	FAE II, LLC	U.S. SPECIALTY INSURANCE COMPA	B	5/8/2020	
	1638	371416 FORTY ACRES ENERGY, LLC	338719	FAE II, LLC	U.S. SPECIALTY INSURANCE CO.	M	3/28/2019	
	1731	329487 BXP Operating, LLC	338780	BXP PARTNERS V LP	ENDURANCE ASSURANCE CORPORATIO	M	7/1/2020	
	1722	338829 KCK RESOURCES, INC.	338829	KCK RESOURCES, INC.	WAIVER	B	3/27/2020	
	1589	326839 TEXAS STANDARD OIL LLC.	338858	TEXAS STANDARD OPERATING NM LLC	LEXON INSURANCE COMPANY	M	3/9/2018	
	1560	327122 IACX ROSWELL, LLC.	338867	IACX PRODUCTION LLC	ARGONAUT INSURANCE COMPANY	M	9/14/2017	
	1711	338881 ZONGE INTERNATIONAL, INC.	338881	ZONGE INTERNATIONAL, INC.	ENDURANCE ASSURANCE CORPORATIO	M	2/7/2020	
	1858	741932 Colgate Production, LLC	338894	COLGATE PRODUCTION, LLC	U S SPECIALTY INSURANCE COMPAN	M	7/28/2022	
	1719	338915 MULLOY OPERATING, INC.	338915	MULLOY OPERATING, INC.	COMMUNITY NATIONAL BANK	B	6/4/2020	
	2056	338948 MORNINGSTAR OPERATING, LLC	338948	MORNINGSTAR OPERATING, LLC	UNITED STATES FIRE INSURANCE C	M	3/4/2025	
	1750	339000 YUCCA RANCH DEVELOPMENT, LLC	339000	YUCCA RANCH DEVELOPMENT, LLC	WAIVER	B	3/8/2021	
	2086	339018 BLACKBUCK NEW MEXICO LLC	339018	BLACKBUCK NEW MEXICO LLC	PENNSYLVANIA INSURANCE COMPANY	M	7/9/2025	
	1738	339043 HENRIETTA SCHULTZ INHERITANCE PARTNERSHIP, LP	339043	HENRIETTA SCHULTZ INHERITANCE PARTNERSHIP, LP	CASH BOND	B	10/19/2020	
	1527	372224 AMEREDEV OPERATING, LLC	339054	AMEREDEV TEXAS, LLC	ASPEN AMERICAN INSURANCE CO.	M	4/26/2017	
	1747	339102 EXTEX OPERATING COMPANY	339102	EXTEX OPERATING COMPANY	TRAVELERS CASUALTY & SURETY CO	M	1/15/2021	
	1948	339126 PROMONTORY EXPLORATION LP	339126	PROMONTORY EXPLORATION LP	EVERGREEN NATIONAL INDEMNITY C	M	12/18/2023	
	1785	339137 NORTHERN OIL AND GAS INC.	339137	NORTHERN OIL AND GAS INC.	RLI INSURANCE COMPANY	B	8/23/2021	
	1773	339171 STATELINE OPERATING, LLC	339171	STATELINE OPERATING, LLC	WAIVER	S	6/4/2021	VC 479 1
	1774	339171 STATELINE OPERATING, LLC	339171	STATELINE OPERATING, LLC	WAIVER	S	6/4/2021	VC 480 1
	1775	339171 STATELINE OPERATING, LLC	339171	STATELINE OPERATING, LLC	WAIVER	S	6/4/2021	VC 490 1

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1776	339171	STATELINE OPERATING, LLC	339171	STATELINE OPERATING, LLC	WAIVER	S	6/4/2021	VC 491 1
1879	339180	FIVESTAR PETROLEUM CORPORATION	339180	FIVESTAR PETROLEUM CORPORATION	EXCHANGE BANK & TRUST COMPANY	B	9/20/2022	
1786	339199	FIRST PECOS, LLC	339199	FIRST PECOS, LLC	TEJAS BANK	M	7/21/2021	
1763	339241	OGX RESOURCES, LLC	339241	OGX RESOURCES, LLC	WEST TEXAS NATIONAL BANK	M	4/16/2021	
1779	339290	VALION47 LLC	339290	VALION47 LLC	WELLS FARGO BANK, N.A.	B	7/7/2021	
1780	339305	OPAL OPERATING COMPANY LLC	339305	OPAL OPERATING COMPANY LLC	BANK OF ALBUQUERQUE	M	7/9/2021	
1784	339338	ACACIA RESOURCES, LLC	339338	ACACIA RESOURCES, LLC	COMMUNITY NATIONAL BANK	M	7/22/2021	
1790	339406	SILVERBACK OPERATING II, LLC	339406	SILVERBACK OPERATING II, LLC	ENDURANCE ASSURANCE CORP.	M	10/7/2021	
1944	339406	SILVERBACK OPERATING II, LLC	339406	SILVERBACK OPERATING II, LLC	ENDURANCE ASSURANCE CORPORATIO	M	11/28/2023	
1789	339445	CRP XII, LLC	339445	CRP XII, LLC	OKLAHOMA FIDELITY BANK	B	9/24/2021	
1790	339406	SILVERBACK OPERATING II, LLC	339473	SILVERBACK NEW MEXICO, LLC	ENDURANCE ASSURANCE CORP.	M	10/7/2021	
1943	339473	SILVERBACK NEW MEXICO, LLC	339473	SILVERBACK NEW MEXICO, LLC	ENDURANCE ASSURANCE CORPORATIO	M	11/28/2023	
1720	328565	BAM Permian Operating, LLC	339488	BAM PERMIAN OPERATING, LLC	AMERICAN MOMENTUM BANK	M	5/29/2020	
1927	339497	MR NM OPERATING, LLC	339497	MR NM OPERATING, LLC	UNITED STATES FIRE INSURANCE C	M	8/21/2023	
1798	330984	Amalgamated Sludge NM, LLC	339515	AMALGAMATED SLUDGE NM, LLC	WASHINGTON FEDERAL BANK, N.A.	M	11/2/2021	
596	148394	VERNON E. FAULCONER, INC.	339536	FAULCONER ENERGY, LLC	RLI INSURANCE	B	7/24/2001	
1795	339548	SELECT AGUA LIBRE MIDSTREAM, LLC	339548	SELECT AGUA LIBRE MIDSTREAM, LLC	RLI INSURANCE COMPANY	M	9/25/2021	
2117	339569	SIMCOE LLC	339569	SIMCOE LLC	SIRISPOINT AMERICA INSURANCE C	M	9/25/2025	
1790	339406	SILVERBACK OPERATING II, LLC	339572	SILVERBACK MIDSTREAM II, LLC	ENDURANCE ASSURANCE CORP.	M	10/7/2021	
1941	339572	SILVERBACK MIDSTREAM II, LLC	339572	SILVERBACK MIDSTREAM II, LLC	ENDURANCE ASSURANCE CORPORATIO	M	11/28/2023	
1799	330859	Alpha Energy Partners LLC	339595	ALPHA ENERGY PARTNERS, LLC	CASH BOND	B	12/7/2021	
1800	339603	REDWOOD OPERATING, LLC	339603	REDWOOD OPERATING, LLC	U.S. SPECIALTY INSURANCE COMPA	M	12/6/2021	
1787	339614	PECOS OIL & GAS, LLC	339614	PECOS OIL & GAS, LLC	U.S.SPECIALTY INSURANCE COMPAN	M	9/23/2020	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	1805	339667 WALSH & WATTS INC.	339667	WALSH & WATTS INC.	U.S. SPECIALTY INSURANCE COMPA	M	1/12/2022	
	1918	339713 THIRD ROW RESOURCES LLC	339713	THIRD ROW RESOURCES LLC	EVERGREEN NATIONAL INDEMNITY C	M	4/27/2023	
	1988	756700 Maverick Permian LLC	339742	MAVERICK PERMIAN LLC	PENNSYLVANIA INSURANCE COMPANY	M	9/3/2024	
	1814	331165 Earthstone Operating, LLC	339761	EARTHSTONE OPERATING, LLC	U. S. SPECIALTY INSURANCE COMP	M	2/15/2022	
	1819	331180 Big Star Investments, LLC	339809	BIG STAR INVESTMENTS, LLC DBA BIG STAR EXPL.	ARCH INSURANCE COMPANY	B	3/7/2022	
	1768	330608 Roughhouse Operating, LLC	339847	ROUGHHOUSE OPERATING, LLC	WESTERN BANK	M	5/19/2021	
	1824	339847 ROUGHHOUSE OPERATING, LLC	339847	ROUGHHOUSE OPERATING, LLC	CASH BOND	M	4/6/2022	
	1826	339856 EARTHSTONE PERMIAN, LLC	339856	EARTHSTONE PERMIAN, LLC	U. S. SPECIALTY INSURANCE COMP	M	4/18/2022	
	1829	339860 CRESCENT PORTER HALE FOUNDATION	339860	CRESCENT PORTER HALE FOUNDATION	CASH BOND	B	3/22/2022	
	1825	339878 ALADDIN PETROLEUM CORPORATION	339878	ALADDIN PETROLEUM CORPORATION	CASH BOND	S	2/12/2022	B1 889 15
	1833	339938 CD RAY EXPLORATION, LLC	339938	CD RAY EXPLORATION, LLC	U.S. SPECIALTY INSURANCE COMPA	B	5/9/2022	
	1831	339946 DENTON HOLDINGS NEVADA, INC.	339946	DENTON HOLDINGS NEVADA, INC.	ARCH INSURANCE COMPANY	S	5/13/2022	E0 7481 6
	1849	339963 BEXP II ALPHA, LLC	339963	BEXP II ALPHA, LLC	U.S. SPECIALTY INSURANCE COMPA	B	6/23/2022	
	1848	339974 BEXP II OMEGA, LLC	339974	BEXP II OMEGA, LLC	U.S. SPECIALTY INSURANCE COMPA	B	6/23/2022	
	1942	339989 SILVERBACK O-1, LLC	339989	SILVERBACK O-1, LLC	ENDURANCE ASSURANCE CORPORATIO	M	11/28/2023	
	1931	330662 K&M RESOURCES LLC	340011	K&M RESOURCES LLC	WESTERN BANK	S	10/16/2023	L0 4493 4
	2090	340011 K&M RESOURCES LLC	340011	K&M RESOURCES LLC	WESTERN BANK ARTESIA	S	7/25/2025	E1 68 4
	1949	331451 Black Top Operating, LLC	340046	BLACK TOP OPERATING, LLC	EVERGREEN NATIONAL INDEMNITY C	M	12/18/2023	
	1855	340074 GREYHOUND RESOURCES, LLC	340074	GREYHOUND RESOURCES, LLC	ARCH INSURANCE COMPANY	M	6/17/2022	
	1867	340089 CLIME DYNE LLC	340089	CLIME DYNE LLC	WAIVER	S	7/19/2022	VC 1001 0
	1868	340089 CLIME DYNE LLC	340089	CLIME DYNE LLC	WAIVER	S	7/19/2022	VC 1002 0
	1880	340089 CLIME DYNE LLC	340089	CLIME DYNE LLC	WAIVER	S	9/20/2022	VC 1028 0

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1881	340089	CLIME DYNE LLC	340089	CLIME DYNE LLC	WAIVER	S	9/20/2022	VC 1049 0
1857	340109	HANSON MCBRIDE PETROLEUM COMPANY, LLC	340109	HANSON MCBRIDE PETROLEUM COMPANY, LLC	U. S. SPECIALTY INSURANCE COM	M	7/18/2022	
1861	340134	MICHAEL HARRISON MOORE 2006 TRUST	340134	MICHAEL HARRISON MOORE 2006 TRUST	CASH BOND	B	8/2/2022	
1871	340156	ZEUS PETROLEUM, INC.	340156	ZEUS PETROLEUM, INC.	CASH BOND	S	8/25/2022	E0 8587 1
1889	340160	NANCY B. MANSFIELD-STAUDT FAMILY TRUST	340160	NANCY B. MANSFIELD-STAUDT FAMILY TRUST	WAIVER	S	9/7/2022	B0 6869 58
1874	340185	EDGETT BRINE, LLC	340185	EDGETT BRINE, LLC	CASH BOND	B	9/7/2022	
1872	340215	JOHN CHRISTOPHER DUBLIN	340215	JOHN CHRISTOPHER DUBLIN	PHILADELPHIS INDEMNITY INSURAN	B	9/20/2022	
1883	340227	FINALY RESOURCES LLC	340227	FINALY RESOURCES LLC	CASH BOND	B	10/25/2022	
1875	340236	COLL BROTHERS	340236	COLL BROTHERS	VALLEY BANK OF COMMERCE	S	9/13/2022	B0 2884 14
1876	340248	ELLIOTT-HALL COMPANY	340248	ELLIOTT-HALL COMPANY	CENTURY BANK	B	7/26/2022	
1877	340250	ELLIOTT INDUSTRIES LIMITED PARTNERSHIP	340250	ELLIOTT INDUSTRIES LIMITED PARTNERSHIP	CENTURY BANK	B	7/26/2022	
1592	269267	801 LLC	340318	801, LLC	US SPECIALTY INSURANCE COMPANY	M	3/22/2018	
1969	340331	THE JARAMILLO PARTNERSHIP LLC	340331	THE JARAMILLO PARTNERSHIP LLC	WELLS FARGO BANK	S	5/8/2024	E0 2869 5
1897	340403	LIBERTY OILFIELD SERVICES LLC	340403	LIBERTY OILFIELD SERVICES LLC	U.S. SPECIALTY INSURANCE COMPA	M	11/14/2022	
1978	289408	LOGOS OPERATING, LLC	340429	LOGOS OPERATING, LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/17/2024	
1715	371838	DJR OPERATING, LLC	340458	DJR OPERATING, LLC	U.S. SPECIALTY INSURANCE COMPA	M	4/14/2020	
1906	331595	Coterra Energy Operating E LLC	340494	COTERRA ENERGY OPERATING E LLC	UNITED STATES FIRE INSURANCE C	M	11/14/2022	
1908	331595	Coterra Energy Operating E LLC	340494	COTERRA ENERGY OPERATING E LLC	UNITED STATES FIRE INSURANCE C	M	11/14/2022	
2062	340494	COTERRA ENERGY OPERATING E LLC	340494	COTERRA ENERGY OPERATING E LLC	UNITED STATES FIRE INSURANCE C	B	4/16/2025	
1917	340508	BRAD D. BASSORE D/B/A BASIN PETROLEUM COMPANY	340508	BRAD D. BASSORE D/B/A BASIN PETROLEUM COMPANY	NEW MEXICO EDUCATORS	S	4/27/2023	LG 1873 1

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1907	340510	RIDGE RUNNER HOLDINGS, LLC	340510	RIDGE RUNNER HOLDINGS, LLC	FIRST AMERICAN BANK	M	11/28/2022	
1910	5691	Dakota Resources, Inc	340555	DAKOTA RESOURCES, INC.	EVERGREEN NATIONAL INDEMNITY C	M	3/13/2023	
1613	371710	ADVANCED WIRELESS COMMUNICATIONS, L.L.C.	340586	ADVANCED WIRELESS COMMUNICATIONS	THE OHIO CASUALTY INSURANCE CO	B	9/27/2018	
1919	340735	HCDD LLC	340735	HCDD LLC	WAIVER	S	4/17/2023	VC 1118 0
1920	340796	NEW HEIGHT ENERGY LLC	340796	NEW HEIGHT ENERGY LLC	CASHIERS CHECK	S	5/1/2023	V0 8391 2
1928	331290	Seattle's Best Consulting LLC	340802	SEATTLE'S BEST CONSULTING LLC	ARCH INSURANCE COMPANY	S	8/28/2023	B1 1410 3
1923	340844	THREE FORKS RESOURCES, LLC	340844	THREE FORKS RESOURCES, LLC	CASH BOND	B	6/12/2023	L0 4253 4
1968	340865	SUBSURFACE SOLAR, LLC	340865	SUBSURFACE SOLAR, LLC	WAIVER	S	4/17/2024	VC 1027 1
2077	340925	EDITH A. THOMAS TRUST	340925	EDITH A. THOMAS TRUST	CASH BOND	B	5/7/2025	
2049	340966	BUCKHORN PRODUCTION, LLC	340966	BUCKHORN PRODUCTION, LLC	ARCH INSURANCE COMPANY	M	10/2/2023	
1997	341007	ENPLAT III, LLC	341007	ENPLAT III, LLC	WAIVER	S	5/29/2024	VC 635 1
655	215732	CHISOS, LTD	341021	CHISOS, LTD.	RLI INSURANCE	B	10/27/2003	
2120	341021	CHISOS, LTD.	341021	CHISOS, LTD.	EVERGREEN NATIONAL INDEMNITY C	B	10/28/2025	
2048	341049	FE PERMIAN OWNER I, LLC	341049	FE PERMIAN OWNER I, LLC	U.S. SPECIALTY INSURANCE COMPA	B	2/12/2025	
1963	372165	Permian Resources Operating, LLC	341052	PERMIAN RESOURCES OPERATING, LLC	U. S. SPECIALTY INSURANCE COMP	M	3/19/2024	
1933	341113	FSPG, LLC	341113	FSPG, LLC	ARCH INSURANCE COMPANY	M	10/16/2023	
2112	341130	TAP ROCK RESOURCES III, LLC	341130	TAP ROCK RESOURCES III, LLC	ARCH INSURANCE COMPANY	M	10/1/2025	
1985	341142	TRANSCONTINENT OIL COMPANY	341142	TRANSCONTINENT OIL COMPANY	WAIVER	S	6/17/2024	VC 1189 0
1986	341142	TRANSCONTINENT OIL COMPANY	341142	TRANSCONTINENT OIL COMPANY	WAIVER	S	6/17/2024	VC 1190 0
2055	341159	COFER & CO. LLC	341159	COFER & CO. LLC	PIONEER BANK	B	3/11/2025	
1788	31560	EVKO DEVELOPMENT CO	341175	EVKO DEVELOPMENT CO.	CASH BOND	B	9/10/2021	
1938	341193	RIDGE RUNNER ASSETCO II, LLC	341193	RIDGE RUNNER ASSETCO II, LLC	INDEMNITY NATIONAL INSURANCE C	M	11/20/2023	
2124	341193	RIDGE RUNNER ASSETCO II, LLC	341193	RIDGE RUNNER ASSETCO II, LLC	RIDGE RUNNER ASSETCO II, LLC	M	1/13/2026	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1950	341206	REDSOX RESOURCES, LLC	341206	REDSOX RESOURCES, LLC	GREAT MIDWEST INSURANCE COMPAN	M	12/18/2023	
1976	341369	STRATTON LAND LLC	341369	STRATTON LAND LLC	U.S. SPECIALTY INSURANCE COMPA	B	6/3/2024	
1967	341383	ELLIPSIS OIL & GAS INC.	341383	ELLIPSIS OIL & GAS INC.	UNITED STATES FIRE INSURANCE C	B	5/8/2024	
898	241333	CHEVRON MIDCONTINENT, L.P.	341433	CHEVRON MIDCONTINENT, LP	SAFECO INSURANCE COMPANY OF AM	M	2/10/2010	
1963	372165	Permian Resources Operating, LLC	341441	PERMIAN RESOURCES OPERATING, LLC	U. S. SPECIALTY INSURANCE COMP	M	3/19/2024	
1982	341557	YALCH OPERATING, LP	341557	YALCH OPERATING, LP	WAIVER	S	3/4/2024	VC 688 1
1983	341557	YALCH OPERATING, LP	341557	YALCH OPERATING, LP	WAIVER	S	3/4/2024	VC 713 1
1984	341557	YALCH OPERATING, LP	341557	YALCH OPERATING, LP	WAIVER	S	3/4/2024	VC 714 1
1964	341574	LANDMARK ENERGY PARTNERS, LLC	341574	LANDMARK ENERGY PARTNERS, LLC	ARCH INSURANCE COMPANY	M	4/25/2024	
1966	310548	CART HILL ENERGY, LLC	341589	CART HILL ENERGY, LLC	INDEMNITY NATIONAL INSURANCE C	M	5/8/2024	
1977	341647	CIVITAS DE BASIN RESOURCES II, LLC	341647	CIVITAS DE BASIN RESOURCES II, LLC	UNITED STATES FIRE INSURANCE C	M	6/17/2024	
1996	341678	R&R ROYALTY, LTD.	341678	R&R ROYALTY, LTD.	WAIVER	S	6/25/2024	VC 1262 0
2078	341685	ALPHA ENERGY PARTNERS II, LLC	341685	ALPHA ENERGY PARTNERS II, LLC	FROST BANK	S	6/3/2025	VC 1263 0
2115	341692	CERRITO ENERGY, LLC	341692	CERRITO ENERGY, LLC	CASH BOND/ WIRE TRANSFER	S	10/1/2025	VB 2940 0
1992	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	7/29/2024	VC 1265 0
2010	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	11/25/2024	VC 1288 0
2020	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	10/24/2024	VC 1301 0
2021	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	10/24/2024	VC 1302 0
2022	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	10/24/2024	VC 1299 0
2059	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	3/31/2025	VC 1343 0
2060	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	3/31/2025	VC 1342 0

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
2011	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	11/25/2024	VC 1289 0
2012	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	11/25/2024	VC 1299 0
2013	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	11/25/2024	VC 1301 0
2014	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	11/25/2024	VC 1302 0
2018	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	10/24/2024	VC 1288 0
2019	341702	MCCRIGHT & ASSOCIATES, LLC	341702	MCCRIGHT & ASSOCIATES, LLC	WAIVER	S	10/24/2024	VC 1289 0
1999	341719	BUCKEYE WATER, LLC	341719	BUCKEYE WATER, LLC	VALLEY BANK OF COMMMERCE	M	10/7/2024	
1990	341737	NHPP II FORTUNA PERMIAN, LP	341737	NHPP II FORTUNA PERMIAN, LP	U.S. SPECIALTY INSURANCE COMPA	B	9/3/2024	
2015	341753	OPTIMA LAND SERVICES, LLC	341753	OPTIMA LAND SERVICES, LLC	WAIVER	S	9/19/2024	VC 1285 0
2016	341753	OPTIMA LAND SERVICES, LLC	341753	OPTIMA LAND SERVICES, LLC	WAIVER	S	9/19/2024	VC 1293 0
2017	341753	OPTIMA LAND SERVICES, LLC	341753	OPTIMA LAND SERVICES, LLC	WAIVER	S	9/19/2024	VC 1295 0
1991	341765	MRC HAT MESA, LLC	341765	MRC HAT MESA, LLC	ARCH INSURANCE COMPANY	M	9/16/2024	
2001	341771	LM TOUCHDOWN, LLC	341771	LM TOUCHDOWN, LLC	U. S. SPECIALTY INSURANCE COMP	M	10/7/2024	
2045	341780	COASTAL DESERT LP	341780	COASTAL DESERT LP	EVERGREEN NATIONAL INDEMNITY C	B	1/27/2025	
2004	341814	REMORA OPERATING	341814	REMORA OPERATING	CASH BOND/ ORIGIN BANK	M	12/3/2024	
2023	341840	MAGNUM PRODUCING, LP	341840	MAGNUM PRODUCING, LP	ENDURANCE ASSURANCE CORPORATIO	B	12/17/2024	
2054	341867	ROCKWOOD ENERGY LP	341867	ROCKWOOD ENERGY LP	COMMUNITY NATIONAL BANK	M	3/14/2025	
2008	341876	BEXP II OMEGA MISC., LLC	341876	BEXP II OMEGA MISC., LLC	U. S. SPECIALTY INSURANCE COMP	B	12/3/2024	
2006	341881	BEXP II GW ALPHA, LLC	341881	BEXP II GW ALPHA, LLC	U. S. SPECIALTY INSURANCE COMP	B	12/3/2024	
2007	341894	BEXP II GW WI OMEGA, LLC	341894	BEXP II GW WI OMEGA, LLC	U. S. SPECIALTY INSURANCE COMP	B	12/3/2024	
2005	341901	BAFIII GWDC, LLC	341901	BAFIII GWDC, LLC	U. S. SPECIALTY INSURANCE COMP	B	12/3/2024	
2024	341936	FLETCHER R. CATRON	341936	FLETCHER R. CATRON	LEXON INSURANCE COMPANY	S	12/17/2024	A0 1375 55

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	2026	341950 HILCORP ENERGY COMPANY	341950	HILCORP ENERGY COMPANY	AXIS INSURANCE COMPANY	M	12/31/2024	
	2039	341969 XTO PERMIAN CT TXNM, LLC	341969	XTO PERMIAN CT TXNM, LLC	FEDERAL INSURANCE COMPANY	M	1/17/2025	
	2083	341995 SURPRISE VALLEY RESOURCES, LLC	341995	SURPRISE VALLEY RESOURCES, LLC	CASH BOND/ WIRE TRANSFER	S	6/2/2025	VC 1333 0
	2038	342009 JONAH ENERGY LLC	342009	JONAH ENERGY LLC	UNITED STATES FIRE INSURANCE C	M	1/1/2025	
	2061	342023 PALOMA PERMIAN ASSETCO, LLC	342023	PALOMA PERMIAN ASSETCO, LLC	INDEMNITY NATIONAL INSURANCE C	M	4/10/2025	
	2040	342034 XTO CT TXOK NEWMEX, LLC	342034	XTO CT TXOK NEWMEX, LLC	FEDERAL INSURANCE COMPANY	M	1/16/2025	
	2065	342047 STEVENS ENHANCED RECOVERY PARTNERS, LLC	342047	STEVENS ENHANCED RECOVERY PARTNERS, LLC	FROST BANK	B	3/28/2025	
	2044	342056 EOG RESOURCES MARKETING, LLC	342056	EOG RESOURCES MARKETING, LLC	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
	2047	342060 HILCORP ENERGY I, L.P.	342060	HILCORP ENERGY I, L.P.	AXIS INSURANCE COMPANY	M	12/31/2024	
	2046	342085 TECK AMERICAN INCORPORATED	342085	TECK AMERICAN INCORPORATED	LIBERTY MUTUAL INSURANCE COMPA	M	2/11/2025	
	2052	342092 DESERT RAM SOUTH RANCH, INC.	342092	DESERT RAM SOUTH RANCH, INC.	INDEMNITY NATIONAL INSURANCE C	M	2/4/2025	
	2053	342105 RELIANCE ENERGY-CATCHING FREEDOM,LLC	342105	RELIANCE ENERGY-CATCHING FREEDOM,LLC	EVERGREEN NATIONAL INDEMNITY C	M	1/27/2025	
	2058	342120 JONAH ENERGY PERMIAN LLC	342120	JONAH ENERGY PERMIAN LLC	UNITED STATES FIRE INSURANCE C	M	2/19/2025	
	2072	342138 SARVIS PERMIAN LAND FUND I SC, LLC	342138	SARVIS PERMIAN LAND FUND I SC, LLC	CASH BOND	M	4/29/2025	
	2064	342163 COTERRA ENERGY OPERATING F LLC	342163	COTERRA ENERGY OPERATING F LLC	UNITED STATES FIRE INSURANCE C	M	4/16/2025	
	2068	342253 HUNT CIMARRON LIMITED PARTNERSHIP	342253	HUNT CIMARRON LIMITED PARTNERSHIP	ATLANTIC SPECILTY INSURANCE CO	B	4/28/2025	
	2071	342265 SAGUARO PETROLEUM, LLC	342265	SAGUARO PETROLEUM, LLC	COMMUNITY NATIONAL BANK	M	4/10/2025	
	2069	342271 BEXP III SHAKE, LLC	342271	BEXP III SHAKE, LLC	U.S SPECIALTY INSURANCE COMPAN	B	5/12/2025	
	2070	342280 BEXP III BAKE, LLC	342280	BEXP III BAKE, LLC	U.S.SPECIALTY INSURANCE COMPAN	B	5/12/2025	
	2074	342299 SPECIAL ENERGY CORPORATION	342299	SPECIAL ENERGY CORPORATION	FRANKENMUTH INSURANCE COMPANY	M	4/28/2025	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	2076	342329 AD ASTRA RESOURCES, LLC	342329	AD ASTRA RESOURCES, LLC	INTRUST BANK, N.A.	M	5/20/2025	
	2082	342340 NORTHSTAR RESOURCES LLC DBA NSP RESOURCES LLC	342340	NORTHSTAR RESOURCES LLC DBA NSP RESOURCES LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/1/2025	
	2081	342358 AVANT OPERATING II, LLC	342358	AVANT OPERATING II, LLC	PENNSYLVANIA INSURANCE COMPANY	M	7/1/2025	
	2101	342376 TEXIAN OPERATING COMPANY, LLC	342376	TEXIAN OPERATING COMPANY, LLC	U.S. SPECIALTY INSURANCE COMPA	B	8/13/2025	
	2085	342394 CONTANGO RESOURCES, LLC	342394	CONTANGO RESOURCES, LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/11/2025	
	2089	342400 PRONGHORN PETROLEUM, LLC	342400	PRONGHORN PETROLEUM, LLC	VALLEY BANK OF COMMERCE	M	7/24/2025	
	2087	342418 MRC TORO, LLC	342418	MRC TORO, LLC	ARCH INSURANCE COMPANY	M	7/14/2025	
	2088	342425 UNITEX OIL & GAS, L.L.C.	342425	UNITEX OIL & GAS, L.L.C.	EVERGREEN NATIONAL INDEMNITY C	B	6/26/2025	
	2114	342431 NEW MEXICO INSTITUTE OF MINING AND TECHNOLOGY	342431	NEW MEXICO INSTITUTE OF MINING AND TECHNOLOGY	FRANKENMUTH INSURANCE COMPANY	M	10/1/2025	
	2093	342443 APEX NATURAL GAS, LLC	342443	APEX NATURAL GAS, LLC	ARCH INSURANCE COMPANY	S	5/23/2025	LG 864 0
	2125	342454 VENTURE ENERGY, LLC	342454	VENTURE ENERGY, LLC	WAIVER	S	12/16/2025	SG 39 0
	2126	342454 VENTURE ENERGY, LLC	342454	VENTURE ENERGY, LLC	WAIVER	S	12/16/2025	SG 41 0
	2127	342454 VENTURE ENERGY, LLC	342454	VENTURE ENERGY, LLC	WAIVER	S	12/16/2025	SG 40 0
	2102	342477 DESERT ENERGY CORP DBA DESERT MOUNTAIN ENERGY	342477	DESERT ENERGY CORP DBA DESERT MOUNTAIN ENERGY	CASH BOND/ WIRE TRANSFER	M	8/7/2025	
	2103	342482 MOMENTUM OPERATING CO., INC.	342482	MOMENTUM OPERATING CO., INC.	CLEAR FORK BANK, N.A.	M	7/8/2025	
	2138	342498 SEP LEGACY LLC	342498	SEP LEGACY LLC	ARCH INSURANCE COMPANY	M	10/21/2025	
	2105	342504 FINLEY RESOURCES INC.	342504	FINLEY RESOURCES INC.	UNITED STATES FIRE INSURANCE C	B	7/28/2025	
	2104	342513 SAEXPLORATION SEISMIC SERVICES (US), LLC	342513	SAEXPLORATION SEISMIC SERVICES (US), LLC	U.S. SPECIALTY INSURANCE COMPA	M	9/9/2025	
	2107	342528 WESTMORELAND SAN JUAN MINING LLC	342528	WESTMORELAND SAN JUAN MINING LLC	AXIS INSURANCE COMPANY	M	7/7/2025	
	2106	342530 BCE-MACH III LLC	342530	BCE-MACH III LLC	UNITED STATES FIRE INSURANCE C	M	9/16/2025	
	2113	342587 G AND C OPERATING LLC	342587	G AND C OPERATING LLC	WESTERN BANK ARTESIA	M	8/27/2025	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
2116	342621	XTOH CTRT PERMIAN, LLC	342621	XTOH CTRT PERMIAN, LLC	FEDERAL INSURANCE COMPANY	M	12/19/2025	
2118	342635	EW OPERATING (NM), LLC	342635	EW OPERATING (NM), LLC	SIRIUSPOINT AMERICA INSURANCE	B	8/25/2025	
2137	342649	PBEX OPERATIONS, LLC	342649	PBEX OPERATIONS, LLC	EVERGREEN NATIONAL INDEMNITY C	M	2/5/2026	
2119	342652	GEHRIG, INC.	342652	GEHRIG, INC.	MUENSTER STATE BANK	M	11/20/2025	
2143	342706	HILCORP PERMIAN, LLC	342706	HILCORP PERMIAN, LLC	TRAVELERS CASUALTY AND SURETY	M	3/9/2026	
2122	342722	FED OPERATING LLC	342722	FED OPERATING LLC	EVERGREEN NATIONAL INDEMNITY C	M	12/18/2025	
2141	342739	FNF CONSTRUCTIO N, INC.	342739	FNF CONSTRUCTIO N, INC.	TRAVELERS CASUALTY AND SURETY	M	12/22/2025	
2129	342745	TWIN WELLS RANCH LLC	342745	TWIN WELLS RANCH LLC	GREAT MIDWEST INSURANCE COMPAN	M	1/10/2026	
2144	342773	LEACO OPERATING LLC	342773	LEACO OPERATING LLC	PIONEER BANK	B	3/26/2026	
1772	349315	RUTH ANN JEFFERS-CALVERT	349315	RUTH ANN JEFFERS-CALVERT	CASH BOND	B	6/25/2021	
1783	349327	CARLO J. FARINA CO., LTD.	349327	CARLO J. FARINA CO., LTD.	LIBERTY MUTUAL INSURANCE COMPA	B	7/20/2021	
374	349336	MEDALLION PRODUCTION COMPANY	349336	MEDALLION PRODUCTION COMPANY	FIRST INTERSTATE BANK OF NEW M	B	4/10/1995	
168	349348	HALLWOOD PETROLEUM INC	349348	HALLWOOD PETROLEUM INC	RELIANCE INSURANCE CO.	B	3/14/1991	
1589	326839	TEXAS STANDARD OIL LLC.	370019	Texas Standard Midstream LLC	LEXON INSURANCE COMPANY	M	3/9/2018	
1071	370080	BREITBURN OPERATING LP	370080	BREITBURN OPERATING LP	ARGONAUT INSURANCE COMPANY	M	2/8/2015	
1042	370131	ANSCHUTZ OIL COMPANY, LLC	370131	ANSCHUTZ OIL COMPANY, LLC	TRAVELERS CASUALTY & SURETY CO	M	10/15/2014	
1073	370177	HESS CO2 RESOURCES LLC	370177	HESS CO2 RESOURCES LLC	LIBERTY MUTUAL INSURANCE COMPA	B	3/30/2015	
1762	317983	GUS H20 L.L.C. & RAZ OIL & GAS, L.L.C.	370507	RAZ OIL AND GAS L.L.C.	ARCH INSURANCE COMPANY	M	5/11/2021	
1083	317049	PRIZE EXPLORATION, LLC	370729	PRIZE EXPLORATION, LLC	WESTCHESTER FIRE INSURANCE COM	M	7/23/2015	
1084	370740	FOUNDATION ENERGY MANAGEMENT , LLC	370740	FOUNDATION ENERGY MANAGEMENT , LLC	U.S. SPECIALTY INSURANCE CO.	M	8/7/2015	
1442	370767	BLACKBEARD OPERATING, LLC	370767	BLACKBEARD OPERATING, LLC	WESTCHESTER FIRE INSURANCE COM	M	11/23/2016	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	1548 370945	PIMA ENERGY LLC	370945	PIMA ENERGY LLC	GREAT AMERICAN INSURANCE COMPA	M	5/25/2017	
	1248 371029	JR CONE OPERATING, LLC	371029	JR CONE OPERATING, LLC	LEXON INSURANCE COMPANY	S	3/15/2016	E0 2523 0
	1086 371101	CLEARWATER SWD, LLC	371101	CLEARWATER SWD, LLC	LEXON INSURANCE COMPANY	M	9/14/2015	
	1358 371115	ROCKCLIFF OPERATING NEW MEXICO LLC	371115	ROCKCLIFF OPERATING NEW MEXICO LLC	U.S. SPECIALITY INSURANCE COMP	M	6/27/2016	
	1551 371416	FORTY ACRES ENERGY, LLC	371416	FORTY ACRES ENERGY, LLC	N/A	B	8/23/2017	
	1638 371416	FORTY ACRES ENERGY, LLC	371416	FORTY ACRES ENERGY, LLC	U.S. SPECIALTY INSURANCE CO.	M	3/28/2019	
	1507 371449	COLGATE OPERATING, LLC	371449	COLGATE OPERATING, LLC	U.S. SPECIALTY INSURANCE CO.	M	3/14/2017	
	1413 371484	ROVER OPERATING, LLC	371484	ROVER OPERATING, LLC	RLI INSURANCE COMPANY, IL	M	9/29/2016	
	1629 371553	BLUE RUBY OPERATING, LLC	371553	BLUE RUBY OPERATING, LLC	RLI INSURANCE CO.	B	2/4/2019	
	1516 371643	SOLARIS WATER MIDSTREAM, LLC	371643	SOLARIS WATER MIDSTREAM, LLC	ARGONAUT INSURANCE CO.	M	2/15/2017	
	1457 371682	STEWARD ENERGY II, LLC	371682	STEWARD ENERGY II, LLC	U.S. SPECIALTY INS CO.	M	12/13/2016	
	1520 371698	HPPC, INC.	371698	HPPC, INC.	PIONEER BANK	B	4/20/2017	
	1613 371710	ADVANCED WIRELESS COMMUNICATIONS, L.L.C.	371710	ADVANCED WIRELESS COMMUNICATIONS, L.L.C.	THE OHIO CASUALTY INSURANCE CO	B	9/27/2018	
	1458 371755	PERCUSSION PETROLEUM OPERATING, LLC	371755	PERCUSSION PETROLEUM OPERATING, LLC	U.S. SPECIALTY INS CO.	M	12/21/2016	
	1461 371762	ABO EMPIRE, LLC	371762	ABO EMPIRE, LLC	U.S. SPECIALTY INSURANCE COMPA	M	11/16/2016	
	1715 371838	DJR OPERATING, LLC	371838	DJR OPERATING, LLC	U.S. SPECIALTY INSURANCE COMPA	M	4/14/2020	
	1599 326258	POGO OIL & GAS OPERATING, INC.	372000	POGO OIL & GAS OPERATING, INC	US SPECIALTY INSURANCE COMPANY	M	4/23/2018	
	1519 372082	NBL PERMIAN LLC	372082	NBL PERMIAN LLC	LIBERTY MUTUAL INSURANCE COMPA	B	4/17/2017	
	1509 86997	MARATHON OIL COMPANY LLC	372098	MARATHON OIL PERMIAN LLC	LIBERTY MUTUAL INSURANCE COMPA	M	3/13/2017	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
	1781	372137 CHISHOLM ENERGY OPERATING, LLC	372137	CHISHOLM ENERGY OPERATING, LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/26/2020	
	1963	372165 Permian Resources Operating, LLC	372165	Permian Resources Operating, LLC	U. S. SPECIALTY INSURANCE COMP	M	3/19/2024	
	2026	341950 HILCORP ENERGY COMPANY	372171	HILCORP ENERGY COMPANY	AXIS INSURANCE COMPANY	M	12/31/2024	
	2097	326665 LONGFELLOW ENERGY, LP	372210	LONGFELLOW ENERGY, LP	EVERGREEN NATIONAL INDEMNITY C	M	6/5/2025	
	1527	372224 AMEREDEV OPERATING, LLC	372224	AMEREDEV OPERATING, LLC	ASPEN AMERICAN INSURANCE CO.	M	4/26/2017	
	1543	280276 ENDURING RESOURCES,LLC	372286	ENDURING RESOURCES, LLC	RLI INSURANCE COMPANY	M	6/30/2017	
	1559	372290 RILEY PERMIAN OPERATING COMPANY, LLC	372290	RILEY PERMIAN OPERATING COMPANY, LLC	U.S. SPECIALTY INSURANCE COMPA	M	8/21/2017	
	1556	372417 ADVANCE ENERGY PARTNERS HAT MESA, LLC	372417	ADVANCE ENERGY PARTNERS HAT MESA, LLC	U.S. SPECIALTY INS COMPANY	M	9/18/2017	
	1563	372536 PERMEX PETROLEUM COMPANY, LLC	372536	PERMEX PETROLEUM COMPANY, LLC	PIONEER BANK	B	8/22/2017	
	1573	372548 CONTINENTAL RESOURCES, INC.	372548	CONTINENTAL RESOURCES, INC.	RLI INSURANCE COMPANY	M	11/2/2017	
	1562	372583 DGP ENERGY, LLC	372583	DGP ENERGY, LLC	FIDELITY & DEPPOSIT CO OF MD	M	10/13/2017	
	1756	327055 YATES INDUSTRIES LLC	372658	YATES INDUSTRIES LLC	LEXON INSURANCE COMPANY	M	3/17/2021	
	2044	342056 EOG RESOURCES MARKETING, LLC	372812	EOG RESOURCES MARKETING, LLC	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
	1582	372834 EPIC ENERGY, L.L.C.	372834	EPIC ENERGY, L.L.C.	RLI INSURANCE CO.	M	2/6/2018	
	1631	372911 OSTRICH OIL AND GAS, LLC	372911	OSTRICH OIL AND GAS, LLC	N/A	B	3/1/2019	
	1859	372920 NOVO OIL & GAS NORTHERN DELAWARE, LLC	372920	NOVO OIL & GAS NORTHERN DELAWARE, LLC	U.S. SPECIALTY INSURANCE COMPA	S	7/29/2022	VC 995 0
	1717	295925 C&J WELL SERVICES, INC.	372946	C&J WELL SERVICES, INC.	U.S. SPECIALTY INSURANCE COMPA	M	3/17/2020	
	1617	373013 Ridge Runner Resources Operating, LLC	373013	Ridge Runner Resources Operating, LLC	N/A	B	10/31/2018	
	1654	373013 Ridge Runner Resources Operating, LLC	373013	Ridge Runner Resources Operating, LLC	BBVA COMPASS	M	6/25/2019	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
913	197035	XTO ENERGY INC	373075	XTO PERMIAN OPERATING LLC.	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
1618	373121	POCO Resources LLC	373121	POCO Resources LLC	LEXON INSURANCE COMPANY	M	10/11/2018	
1610	327650	MUSTANG RESOURCES, LLC.	373495	Mustang Resources LLC	BOK FINANCIAL	B	10/4/2018	
1791	714391	Salt Creek Midstream, LLC	373554	Salt Creek Midstream, LLC	U.S. SPECIALTY INSURANCE CO.	M	10/12/2020	
2086	339018	BLACKBUCK NEW MEXICO LLC	373619	Blackbuck New Mexico LLC	PENNSYLVANIA INSURANCE COMPANY	M	7/9/2025	
1704	328094	COTERRA ENERGY OPERATING M LLC	373908	Coterra Energy Operating M LLC	FIDELITY AND DEPOSIT COMPANY O	M	10/17/2019	
1671	373910	Coterra Energy Operating F LLC	373910	Coterra Energy Operating F LLC	FIDELITY AND DEPOSIT CO. OF MA	M	8/27/2019	
1808	700026	CHEVRON U.S.A. INC.	700026	CHEVRON U.S.A. INC.	LIBERTY MUTUAL INSURANCE COMPA	M	10/29/2021	
1587	218098	BP AMERICA PRODUCTION COMPANY	700584	BP America Production Company	TRAVELERS CASUALTY AND SURETY	M	11/11/2017	
1753	702834	Southline Transmission, L.L.C.	702834	Southline Transmission, L.L.C.	ENDURANCE ASSURANCE CORPORATIO	M	10/19/2020	
1071	370080	BREITBURN OPERATING LP	703817	Breitburn Operating LP	ARGONAUT INSURANCE COMPANY	M	2/8/2015	
1808	700026	CHEVRON U.S.A. INC.	703822	Chevron U.S.A. Inc.	LIBERTY MUTUAL INSURANCE COMPA	M	10/29/2021	
1959	237722	ETP CRUDE LLC	704616	Centurion Pipeline Limited Partnership	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
1754	151416	FASKEN OIL & RANCH LTD	704739	Fasken Oil and Ranch Ltd.	U.S. SPECIALTY INSURANCE COMPA	M	2/26/2021	
1587	218098	BP AMERICA PRODUCTION COMPANY	705197	BP America Production Company	TRAVELERS CASUALTY AND SURETY	M	11/11/2017	
1588	218098	BP AMERICA PRODUCTION COMPANY	705197	BP America Production Company	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
258	4378	CHI OPERATING INC	705375	Chi Operating, Inc.	RLI INSURANCE COMPANY	B	5/5/1993	
1650	705774	Vulcan Materials Co. Calmat Division	705774	Vulcan Materials Co. Calmat Division	U.S. SPECIALTY INSURANCE COMPA	M	4/7/2017	
1715	371838	DJR OPERATING, LLC	706217	DJR Operating, LLC	U.S. SPECIALTY INSURANCE COMPA	M	4/14/2020	
432	785	AMTEX ENERGY INC	707597	Amtex Energy, Inc.	PIONEER SAVINGS BANK	B	6/3/1996	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1686	707842	Pearce Trust	707842	Pearce Trust	GREAT AMERICAN INSURANCE COMPA	M	6/28/2017	
1740	708124	Centennial Resource Production, LLC	708124	Centennial Resource Production, LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/8/2020	
2123	197035	XTO ENERGY INC	708646	XTO Energy Inc.	FEDERAL INSURANCE COMPANY	M	6/4/2025	
1580	269324	LINN OPERATING, LLC.	708783	LINN Operating, LLC	UNITED STATES FIRE INSURANCE C	M	4/19/2017	
1715	371838	DJR OPERATING, LLC	708854	DJR Assets, LLC	U.S. SPECIALTY INSURANCE COMPA	M	4/14/2020	
1862	293991	RICHARD LYONS MOORE 2006 TRUST	708971	Richard Lyons Moore 2006 Trust	CASH BOND	B	8/3/2022	
2043	64432	EOG RESOURCES, INC.	709423	EOG RESOURCES, INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1560	327122	IACX ROSWELL, LLC.	709460	IACX Roswell LLC	ARGONAUT INSURANCE COMPANY	M	9/14/2017	
1740	708124	Centennial Resource Production, LLC	709798	Centennial Resource Production LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/8/2020	
1527	372224	AMEREDEV OPERATING, LLC	710465	Ameredev Operating, LLC	ASPEN AMERICAN INSURANCE CO.	M	4/26/2017	
1744	327480	WPX ENERGY PERMIAN, LLC.	710594	WPX ENERGY PERMIAN, LLC	LIBERTY MUTUAL INSURANCE COMPA	M	1/27/2021	
1709	96694	OXY USA INC	711074	Oxy USA Inc	LIBERTY MUTUAL INSURANCE COMPA	M	3/2/2020	
1562	372583	DGP ENERGY, LLC	711227	DGP Energy, LLC	FIDELITY & DEPPOSIT CO OF MD	M	10/13/2017	
1587	218098	BP AMERICA PRODUCTION COMPANY	711377	BP America Production Company	TRAVELERS CASUALTY AND SURETY	M	11/11/2017	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	711579	Devon Energy Production Company, LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
898	241333	CHEVRON MIDCONTINENT, L.P.	711664	Chevron Midcontinent, L.P.	SAFECO INSURANCE COMPANY OF AM	M	2/10/2010	
1959	237722	ETP CRUDE LLC	711721	Centurion Pipeline L.P.	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
913	197035	XTO ENERGY INC	712459	XTO Holdings, LLC	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
2095	327330	XTO HOLDINGS, LLC	712459	XTO Holdings, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
1672	712560	PolyNatura Corporation	712560	PolyNatura Corporation	POLYNATURA CORPORATION	M	5/24/2010	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
913	197035	XTO ENERGY INC	712926	XTO Holding LLC	PETROLEUM CASUALTY COMPANY	M	8/2/2010	
1866	149315	MAGNUM HUNTER PRODUCTION, INC.	713069	Magnum Hunter Production Inc	RLI INSURANCE COMPANY	M	7/21/2022	
1740	708124	Centennial Resource Production, LLC	713132	Centennial Resource Production LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/8/2020	
1781	372137	CHISHOLM ENERGY OPERATING, LLC	713522	Chisholm Energy Operating, LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/26/2020	
2043	64432	EOG RESOURCES, INC.	713624	EOG Resources, Inc.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1556	372417	ADVANCE ENERGY PARTNERS HAT MESA, LLC	713875	ADVANCE ENERGY PARTNERS HAT MESA, LLC	U.S. SPECIALTY INS COMPANY	M	9/18/2017	
1791	714391	Salt Creek Midstream, LLC	714391	Salt Creek Midstream, LLC	U.S. SPECIALTY INSURANCE CO.	M	10/12/2020	
1588	218098	BP AMERICA PRODUCTION COMPANY	714957	BP America Production Company	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	
726	232611	SUNDOWN ENERGY LP	714991	Sundown Energy, LP	US SPECIALTY INSURANCE	M	3/28/2005	
1562	372583	DGP ENERGY, LLC	715052	DGP ENERGY, LLC	FIDELITY & DEPPOSIT CO OF MD	M	10/13/2017	
1806	715479	Lincoln County	715479	Lincoln County	GREAT MIDWEST INSURANCE COMPAN	M	2/18/2022	
2123	197035	XTO ENERGY INC	715692	XTO Energy Inc	FEDERAL INSURANCE COMPANY	M	6/4/2025	
1638	371416	FORTY ACRES ENERGY, LLC	715753	Forty Acres Energy LLC	U.S. SPECIALTY INSURANCE CO.	M	3/28/2019	
1461	371762	ABO EMPIRE, LLC	715948	Abo Empire, LLC.	U.S. SPECIALTY INSURANCE COMPA	M	11/16/2016	
1599	326258	POGO OIL & GAS OPERATING, INC.	716014	Pogo Resources, LLC	US SPECIALTY INSURANCE COMPANY	M	4/23/2018	
2043	64432	EOG RESOURCES, INC.	716484	EOG Resources, Inc.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1677	716710	Kennecott Exploration Company	716710	Kennecott Exploration Company	LIBERTY MUTUAL INSURANCE COMPA	M	3/28/2017	
2057	298299	CROSS TIMBERS ENERGY, LLC	717477	Cross Timbers Energy LLC	UNITED STATES FIRE INSURANCE C	M	2/24/2025	
1588	218098	BP AMERICA PRODUCTION COMPANY	717967	BP America Production Company	TRAVELERS CASUALTY AND SURETY	M	11/11/2016	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1639	327870	PACIFIC ENERGY DEVELOPMENT CORP	720273	Ridgeway Arizona Oil Corp.	ARGONAUT INSURANCE CO.	M	4/4/2019	
1627	720408	MarkWest Tornado GP, LLC	720408	MarkWest Tornado GP, LLC	LIBERTY MUTUAL INS. CO.	M	12/5/2018	
1639	327870	PACIFIC ENERGY DEVELOPMENT CORP	720455	PACIFIC ENERGY DEVELOPMENT CORP	ARGONAUT INSURANCE CO.	M	4/4/2019	
1752	325830	ASCENT ENERGY, LLC.	720563	ASCENT ENERGY, LLC	ENDURANCE ASSURANCE CORPORATIO	M	2/25/2021	
1975	721053	LOGOS Resources II, LLC	721053	LOGOS Resources II, LLC	U. S. SPECIALTY INSURANCE COMP	M	5/29/2024	
1651	721732	NGL South Ranch, Inc.	721732	NGL South Ranch, Inc.	NGL SOUTH RANCH, INC.	M	7/31/2019	
2096	327896	XTO DELAWARE BASIN, LLC.	722075	XTO Delaware Basin, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
1715	371838	DJR OPERATING, LLC	722355	DJR Operating, LLC	U.S. SPECIALTY INSURANCE COMPA	M	4/14/2020	
857	154078	MACK ENERGY CORP. AND CHASE OIL CORP.	722450	Mack Energy Corporation	U.S. SPECIALTY INSURANCE COMPA	M	3/9/2009	
1715	371838	DJR OPERATING, LLC	722760	DJR Operating, LLC	U.S. SPECIALTY INSURANCE COMPA	M	4/14/2020	
1801	722817	TRINITY MATERIALS, LLC	722817	TRINITY MATERIALS, LLC	TRINITY MATERIALS, LLC	M	12/29/2021	
1644	722933	SCM Crude, LLC	722933	SCM Crude, LLC	ENDURANCE ASSURANCE CORPORATIO	M	5/13/2019	
2098	326582	LONGFELLOW LH, LLC.	723120	Longfellow LH, LLC	EVERGREEN NATIONAL INDEMNITY C	M	6/5/2025	
2107	342528	WESTMORELAND SAN JUAN MINING LLC	723303	Westmoreland San Juan Mining LLC	AXIS INSURANCE COMPANY	M	7/7/2025	
1666	328259	Permian Oilfield Partners, LLC	723587	Permian Oilfield Partners, LLC	RLI INSURANCE COMPANY	M	8/1/2019	
1740	708124	Centennial Resource Production, LLC	723958	Centennial Resource Production, LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/8/2020	
1658	724039	CB2 LLC	724039	CB2 LLC	MERCHANTS BONDING COMPANY	M	7/25/2019	
2096	327896	XTO DELAWARE BASIN, LLC.	724216	XTO Delaware Basin, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
237	6515	DUGAN PRODUCTION CORP	724296	Dugan Production Corp.	FIRST NATL. BANK OF FARMINGTON	B	2/22/1993	
944	338563	GRIZZLY OPERATING LLC	724585	GRIZZLY OPERATING, LLC	U.S. SPECIALTY INSURANCE COMP.	M	7/7/2011	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1694	338563	GRIZZLY OPERATING LLC	724585	GRIZZLY OPERATING, LLC	SIRIUS AMERICA INSURANCE COMPA	M	9/6/2019	
1516	371643	SOLARIS WATER MIDSTREAM, LLC	724611	SOLARIS MIDSTREAM DB-NM, LLC	ARGONAUT INSURANCE CO.	M	2/15/2017	
2129	342745	TWIN WELLS RANCH LLC	724663	TWIN WELLS RANCH, LLC	GREAT MIDWEST INSURANCE COMPAN	M	1/10/2026	
2001	341771	LM TOUCHDOWN, LLC	724674	LM Touchdown, LLC	U. S. SPECIALTY INSURANCE COMP	M	10/7/2024	
2123	197035	XTO ENERGY INC	725470	XTO ENERGY INC.	FEDERAL INSURANCE COMPANY	M	6/4/2025	
1671	373910	Coterra Energy Operating F LLC	725654	Franklin Mountain Energy, LLC	FIDELITY AND DEPOSIT CO. OF MA	M	8/27/2019	
1752	325830	ASCENT ENERGY, LLC.	726057	Ascent Energy, LLC	ENDURANCE ASSURANCE CORPORATIO	M	2/25/2021	
1720	328565	BAM Permian Operating, LLC	726063	BAM Permian Operating, LLC	AMERICAN MOMENTUM BANK	M	5/29/2020	
1527	372224	AMEREDEV OPERATING, LLC	726768	WASHINGTON CROSSING FIELD SERVICES LLC	ASPEN AMERICAN INSURANCE CO.	M	4/26/2017	
1752	325830	ASCENT ENERGY, LLC.	727066	ASCENT ENERGY, LLC	ENDURANCE ASSURANCE CORPORATIO	M	2/25/2021	
809	252496	SHERIDAN PRODUCTION COMPANY, LLC	727082	Sheridan Production Company, LLC	RLI INSURANCE COMPANY	M	8/28/2007	
1959	237722	ETP CRUDE LLC	727137	CENTURION PIPELINE LP	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
2107	342528	WESTMORELAND SAN JUAN MINING LLC	727224	WESTMORELAND SAN JUAN MINING LLC	AXIS INSURANCE COMPANY	M	7/7/2025	
2043	64432	EOG RESOURCES, INC.	727311	EOG Resources, Inc.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
2129	342745	TWIN WELLS RANCH LLC	727346	Twin Wells Ranch, LLC	GREAT MIDWEST INSURANCE COMPAN	M	1/10/2026	
1583	147404	COBRA OIL & GAS CORPORATION	727391	COBRA OIL & GAS CORPORATION	U.S. SPECIALTY INSURANCE COMPA	M	2/15/2018	
1692	329657	Cotton Draw Midstream, L.L.C	727629	Cotton Draw Midstream, L.L.C.	TRAVELERS CASUALTY & SURETY CO	M	11/6/2019	
1706	727676	Mo's Crushing, LLC	727676	Mo's Crushing, LLC	MO'S CRUSING LLC	M	2/18/2020	
641	199866	CAMERON OIL	727704	Cameron Oil and Gas Inc.	FIRST NATIONAL BANK	M	6/2/2003	
1742	338408	SPUR ENERGY PARTNERS, LLC	727742	Spur Energy Partners LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/8/2020	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
2097	326665	LONGFELLOW ENERGY, LP	728015	Longfellow Energy, LP	EVERGREEN NATIONAL INDEMNITY C	M	6/5/2025	
2095	327330	XTO HOLDINGS, LLC	728205	XTO HOLDINGS, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
2001	341771	LM TOUCHDOWN, LLC	728573	LM Touchdown, LLC	U. S. SPECIALTY INSURANCE COMP	M	10/7/2024	
1715	371838	DJR OPERATING, LLC	728921	DJR OPERATING, LLC	U.S. SPECIALTY INSURANCE COMPA	M	4/14/2020	
2117	339569	SIMCOE LLC	729082	Simcoe LLC	SIRISPOINT AMERICA INSURANCE C	M	9/25/2025	
1560	327122	IACX ROSWELL, LLC.	729286	IACX Production LLC	ARGONAUT INSURANCE COMPANY	M	9/14/2017	
1959	237722	ETP CRUDE LLC	729572	CENTURION PIPELINE L.P.	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
1638	371416	FORTY ACRES ENERGY, LLC	730136	FAE ll, LLC	U.S. SPECIALTY INSURANCE CO.	M	3/28/2019	
1527	372224	AMEREDEV OPERATING, LLC	730275	Ameredev Operating, LLC	ASPEN AMERICAN INSURANCE CO.	M	4/26/2017	
2114	342431	NEW MEXICO INSTITUTE OF MINING AND TECHNOLOGY	730323	New Mexico Institute of Mining and Technology	FRANKENMUTH INSURANCE COMPANY	M	10/1/2025	
1787	339614	PECOS OIL & GAS, LLC	731243	Pecos Oil & Gas, LLC	U.S.SPECIALTY INSURANCE COMPAN	M	9/23/2020	
1507	371449	COLGATE OPERATING, LLC	731304	Colgate Operating, LLC	U.S. SPECIALTY INSURANCE CO.	M	3/14/2017	
1734	330238	Solis Partners, L.L.C.	731359	Solis Partners, LLC	WEST TEXAS NATIONAL BANK	M	9/8/2020	
604	198688	CAMBRIAN MANAGEMENT LTD	731361	Cambrian Management, Ltd.	RLI INSURANCE	M	10/9/2001	
604	198688	CAMBRIAN MANAGEMENT LTD	731375	Cambrian Management, Ltd.	RLI INSURANCE	M	10/9/2001	
1729	328195	TASCOSA ENERGY PARTNERS, LLC.	731567	Tascosa Energy Partners, LLC	WEST TEXAS NATIONAL BANK	M	7/13/2020	
1959	237722	ETP CRUDE LLC	731648	Centurion Pipeline Limited Partnership	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
1671	373910	Coterra Energy Operating F LLC	731695	Franklin Mountain Energy, LLC	FIDELITY AND DEPOSIT CO. OF MA	M	8/27/2019	
1954	330129	WaterBridge Stateline LLC	731763	WaterBridge Stateline LLC	ARCH INSURANCE COMPANY	M	1/24/2024	
1740	708124	Centennial Resource Production, LLC	731789	CENTENNIAL RESOURCE PRODUCTION LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/8/2020	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1752	325830	ASCENT ENERGY, LLC.	732050	Ascent Energy, LLC	ENDURANCE ASSURANCE CORPORATIO	M	2/25/2021	
1729	328195	TASCOSA ENERGY PARTNERS, LLC.	732478	TASCOSA ENERGY PARTNERS, LLC	WEST TEXAS NATIONAL BANK	M	7/13/2020	
1911	330396	Avant Operating, LLC	732766	Avant Operating, LLC	UMB BANK, N.A.	M	3/27/2023	
2086	339018	BLACKBUCK NEW MEXICO LLC	732782	Blackbuck New Mexico LLC	PENNSYLVANIA INSURANCE COMPANY	M	7/9/2025	
1767	330522	Acacia Operating Company, LLC	732887	ACACIA OPERATING LLC	COMMUNITY NATIONAL BANK	M	4/29/2021	
1671	373910	Coterra Energy Operating F LLC	733286	FRANKLIN MOUNTAIN ENERGY, LLC	FIDELITY AND DEPOSIT CO. OF MA	M	8/27/2019	
1752	325830	ASCENT ENERGY, LLC.	733320	Ascent Energy, LLC	ENDURANCE ASSURANCE CORPORATIO	M	2/25/2021	
1731	329487	BXP Operating, LLC	733793	BXP PARTNERS V, L.P.	ENDURANCE ASSURANCE CORPORATIO	M	7/1/2020	
2044	342056	EOG RESOURCES MARKETING, LLC	733809	EOG Resources Marketing, LLC	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
901	190595	ENDEAVOR ENERGY RESOURCES, LP	733878	Endeavor Energy Resources, LP	RLI INSURANCE COMPANY	M	3/5/2010	
2097	326665	LONGFELLOW ENERGY, LP	733957	Longfellow Energy, LP	EVERGREEN NATIONAL INDEMNITY C	M	6/5/2025	
1911	330396	Avant Operating, LLC	734680	Avant Operating, LLC	UMB BANK, N.A.	M	3/27/2023	
1638	371416	FORTY ACRES ENERGY, LLC	734955	FAE II Operating, LLC	U.S. SPECIALTY INSURANCE CO.	M	3/28/2019	
1787	339614	PECOS OIL & GAS, LLC	735269	PECOS OIL & GAS, LLC	U.S.SPECIALTY INSURANCE COMPAN	M	9/23/2020	
1808	700026	CHEVRON U.S.A. INC.	735586	Chevron U.S.A. Inc.	LIBERTY MUTUAL INSURANCE COMPA	M	10/29/2021	
1731	329487	BXP Operating, LLC	735622	BXP Operating, LLC	ENDURANCE ASSURANCE CORPORATIO	M	7/1/2020	
2117	339569	SIMCOE LLC	735871	SIMCOE LLC	SIRISPOINT AMERICA INSURANCE C	M	9/25/2025	
1766	330220	RAYBAW Operating, LLC	736794	Raybaw Operating, LLC	HILLCREST BANK	M	4/6/2021	
1800	339603	REDWOOD OPERATING, LLC	738226	Redwood Operating LLC	U.S. SPECIALTY INSURANCE COMPA	M	12/6/2021	
2094	327529	XTO PERMIAN OPERATING, LLC	738751	XTO PERMIAN OPERATING, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
1978	289408	LOGOS OPERATING, LLC	739221	LOGOS Operating, LLC	U.S. SPECIALTY INSURANCE COMPA	M	6/17/2024	
2043	64432	EOG RESOURCES, INC.	739326	EOG RESOURCES, INC.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1952	18917	READ & STEVENS INC	739727	Read & Stevens, Inc.	U.S. SPECIALTY INSURANCE COMPA	M	1/22/2024	
1927	339497	MR NM OPERATING, LLC	739750	MR NM Operating, LLC	UNITED STATES FIRE INSURANCE C	M	8/21/2023	
2056	338948	MORNINGSTAR OPERATING, LLC	739944	MorningStar Operating LLC	UNITED STATES FIRE INSURANCE C	M	3/4/2025	
972	90723	MEWBOURNE OIL COMPANY	740149	Mewbourne Oil Company	LIBERTY MUTUAL INSURANCE COMPA	M	9/20/2012	
1798	330984	Amalgamated Sludge NM, LLC	740341	Amalgamated Sludge NM, LLC	WASHINGTON FEDERAL BANK, N.A.	M	11/2/2021	
2085	342394	CONTANGO RESOURCES, LLC	740379	Contango Resources, LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/11/2025	
1556	372417	ADVANCE ENERGY PARTNERS HAT MESA, LLC	740839	Advance Energy Partners Hat Mesa, LLC	U.S. SPECIALTY INS COMPANY	M	9/18/2017	
1814	331165	Earthstone Operating, LLC	740979	Earthstone Operating, LLC	U. S. SPECIALTY INSURANCE COMP	M	2/15/2022	
1659	338511	SABINAL ENERGY OPERATING, LLC	741047	SABINAL ENERGY OPERATING, LLC	UNITED STATES FIRE INSURANCE C	M	8/1/2019	
1768	330608	Roughhouse Operating, LLC	741587	Roughhouse Operating, LLC	WESTERN BANK	M	5/19/2021	
1824	339847	ROUGHHOUSE OPERATING, LLC	741587	Roughhouse Operating, LLC	CASH BOND	M	4/6/2022	
1988	756700	Maverick Permian LLC	741652	Maverick Permian LLC	PENNSYLVANIA INSURANCE COMPANY	M	9/3/2024	
1860	741801	EMPIRE NEW MEXICO, LLC	741801	EMPIRE NEW MEXICO, LLC	GREAT MIDWEST INSURANCE COMPAN	M	7/12/2022	
1858	741932	Colgate Production, LLC	741932	Colgate Production, LLC	U S SPECIALTY INSURANCE COMPAN	M	7/28/2022	
1851	742239	Northwind Midstream Partners LLC	742239	Northwind Midstream Partners LLC	GREAT MIDWEST INSURANCE COMPAN	M	6/6/2022	
1954	330129	WaterBridge Stateline LLC	742315	WaterBridge Stateline, LLC	ARCH INSURANCE COMPANY	M	1/24/2024	
1814	331165	Earthstone Operating, LLC	742505	Earthstone Operating LLC	U. S. SPECIALTY INSURANCE COMP	M	2/15/2022	
1944	339406	SILVERBACK OPERATING II, LLC	742520	Silverback Operating II, LLC	ENDURANCE ASSURANCE CORPORATIO	M	11/28/2023	
1941	339572	SILVERBACK MIDSTREAM II, LLC	742538	Silverback Midstream II, LLC	ENDURANCE ASSURANCE CORPORATIO	M	11/28/2023	
1943	339473	SILVERBACK NEW MEXICO, LLC	742546	Silverback New Mexico, LLC	ENDURANCE ASSURANCE CORPORATIO	M	11/28/2023	

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OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1942	339989	SILVERBACK O-1, LLC	742557	Silverback O-1, LLC	ENDURANCE ASSURANCE CORPORATIO	M	11/28/2023	
1826	339856	EARTHSTONE PERMIAN, LLC	743278	Earthstone Permian LLC	U. S. SPECIALTY INSURANCE COMP	M	4/18/2022	
1884	745620	Matt Stockton Livestock, LLC	745620	Matt Stockton Livestock, LLC	INDEMNITY NATIONAL INSURANCE C	M	11/16/2022	
1963	372165	Permian Resources Operating, LLC	746640	Permian Resources Operating, LLC	U. S. SPECIALTY INSURANCE COMP	M	3/19/2024	
2095	327330	XTO HOLDINGS, LLC	746809	XTO Holdings, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
1966	310548	CART HILL ENERGY, LLC	747377	CART HILL ENERGY LLC	INDEMNITY NATIONAL INSURANCE C	M	5/8/2024	
1897	340403	LIBERTY OILFIELD SERVICES LLC	747440	Liberty Oilfield Services, LLC	U.S. SPECIALTY INSURANCE COMPA	M	11/14/2022	
1731	329487	BXP Operating, LLC	747622	BXP OPERATING LLC	ENDURANCE ASSURANCE CORPORATIO	M	7/1/2020	
2129	342745	TWIN WELLS RANCH LLC	747819	Twin Wells Ranch, LLC	GREAT MIDWEST INSURANCE COMPAN	M	1/10/2026	
1949	331451	Black Top Operating, LLC	747837	BLACK TOP OPERATING, LLC	EVERGREEN NATIONAL INDEMNITY C	M	12/18/2023	
1906	331595	Coterra Energy Operating E LLC	748086	Franklin Mountain Energy 3, LLC	UNITED STATES FIRE INSURANCE C	M	11/14/2022	
1908	331595	Coterra Energy Operating E LLC	748086	Franklin Mountain Energy 3, LLC	UNITED STATES FIRE INSURANCE C	M	11/14/2022	
1150	6137	DEVON ENERGY PRODUCTION COMPANY, LP	748197	Devon Energy Production Company, LP	TRAVELERS CASUALTY & SURETY CO	M	2/9/2016	
2117	339569	SIMCOE LLC	748298	SIMCOE LLC	SIRISPOINT AMERICA INSURANCE C	M	9/25/2025	
1929	748627	Uinta Basin Sand LLC	748627	Uinta Basin Sand LLC	MERCHANTS NATIONAL BONDING, IN	M	8/24/2023	
2049	340966	BUCKHORN PRODUCTION, LLC	748683	Buckhorn Production, LLC	ARCH INSURANCE COMPANY	M	10/2/2023	
1959	237722	ETP CRUDE LLC	748928	Centurion Pipeline	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
2049	340966	BUCKHORN PRODUCTION, LLC	749398	BUCKHORN PRODUCTION, LLC	ARCH INSURANCE COMPANY	M	10/2/2023	
1826	339856	EARTHSTONE PERMIAN, LLC	749541	Earthstone Permian LLC	U. S. SPECIALTY INSURANCE COMP	M	4/18/2022	
1814	331165	Earthstone Operating, LLC	750043	Earthstone Operating LLC	U. S. SPECIALTY INSURANCE COMP	M	2/15/2022	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
1963	372165	Permian Resources Operating, LLC	750224	Permian Resources Operating, LLC	U. S. SPECIALTY INSURANCE COMP	M	3/19/2024	
594	149538	ASHER ENTERPRISES LTD. CO.	750963	Asher Enterprises LTD. Co.	WESTERN BANK	B	6/3/2016	
2043	64432	EOG RESOURCES, INC.	751908	EOG Resources, Inc.	TRAVELERS CASUALTY AND SURETY	M	1/13/2025	
1940	752507	Scout Energy Group V, LP	752507	Scout Energy Group V, LP	U.S SPECIALTY INSURANCE COMPAN	M	11/28/2023	
2085	342394	CONTANGO RESOURCES, LLC	754173	Contango Resources, LLC	U.S. SPECIALTY INSURANCE COMPA	M	7/11/2025	
1959	237722	ETP CRUDE LLC	755376	CENTURION PIPELINE LP	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
1991	341765	MRC HAT MESA, LLC	755466	MRC HAT MESA, LLC	ARCH INSURANCE COMPANY	M	9/16/2024	
1937	332195	Civitas Permian Operating, LLC	755932	Civitas Permian Operating, LLC	UNITED STATES FIRE INSURANCE C	M	11/20/2023	
1959	237722	ETP CRUDE LLC	755967	Centurion Pipeline, LP	FIDELITY AND DEPOSIT COMPANY O	M	1/29/2024	
2001	341771	LM TOUCHDOWN, LLC	755976	LM Touchdown, LLC	U. S. SPECIALTY INSURANCE COMP	M	10/7/2024	
1963	372165	Permian Resources Operating, LLC	756072	Permian Resources Operating, LLC	U. S. SPECIALTY INSURANCE COMP	M	3/19/2024	
1937	332195	Civitas Permian Operating, LLC	756194	Civitas Permian Operating LLC	UNITED STATES FIRE INSURANCE C	M	11/20/2023	
1988	756700	Maverick Permian LLC	756700	Maverick Permian LLC	PENNSYLVANIA INSURANCE COMPANY	M	9/3/2024	
2026	341950	HILCORP ENERGY COMPANY	757301	Hilcorp Energy Company	AXIS INSURANCE COMPANY	M	12/31/2024	
2052	342092	DESERT RAM SOUTH RANCH, INC.	763235	Desert Ram South Ranch, Inc	INDEMNITY NATIONAL INSURANCE C	M	2/4/2025	
2096	327896	XTO DELAWARE BASIN, LLC.	763556	XTO Delaware Basin, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
2121	252846	COTERRA ENERGY OPERATING CO.	763611	COTERRA ENERGY OPERATING CO.	UNITED STATES FIRE INSURANCE C	M	12/2/2025	
2136	252846	COTERRA ENERGY OPERATING CO.	763611	COTERRA ENERGY OPERATING CO.	UNITED STATES FIRE INSURANCE C	M	1/27/2026	
2047	342060	HILCORP ENERGY I, L.P.	763831	Hilcorp Energy I, L.P.	AXIS INSURANCE COMPANY	M	12/31/2024	
2121	252846	COTERRA ENERGY OPERATING CO.	763866	Coterra Energy Operating Co.	UNITED STATES FIRE INSURANCE C	M	12/2/2025	

EXHIBIT 29

OG BOND	PRINC_OGRID_CDE	PRINCIPAL NAME	COVERED OGRIDS	COVERED NAME	SURETY NAME	BOND COVG	EFF DTE	REMARKS
2136	252846	COTERRA ENERGY OPERATING CO.	763866	Coterra Energy Operating Co.	UNITED STATES FIRE INSURANCE C	M	1/27/2026	
2095	327330	XTO HOLDINGS, LLC	763937	XTO Holdings, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
2052	342092	DESERT RAM SOUTH RANCH, INC.	764349	DESERT RAM SOUTH RANCH, INC.	INDEMNITY NATIONAL INSURANCE C	M	2/4/2025	
2094	327529	XTO PERMIAN OPERATING, LLC	764690	XTO Permian Operating, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
2095	327330	XTO HOLDINGS, LLC	765687	XTO Holdings, LLC	FEDERAL INSURANCE COMPANY	M	6/26/2025	
2117	339569	SIMCOE LLC	767240	SIMCOE LLC	SIRISPOINT AMERICA INSURANCE C	M	9/25/2025	
2137	342649	PBEX OPERATIONS, LLC	768102	PBEX Operations, LLC	EVERGREEN NATIONAL INDEMNITY C	M	2/5/2026	
2117	339569	SIMCOE LLC	768439	Simcoe LLC	SIRISPOINT AMERICA INSURANCE C	M	9/25/2025	
2138	342498	SEP LEGACY LLC	769450	SEP Legacy LLC	ARCH INSURANCE COMPANY	M	10/21/2025	
2143	342706	HILCORP PERMIAN, LLC	770965	Hilcorp Permian, LLC	TRAVELERS CASUALTY AND SURETY	M	3/9/2026	

EXHIBIT 30

STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

REBUTTAL TESTIMONY OF MIKE CANTRELL

Intervenor Independent Petroleum Association of New Mexico submits the following rebuttal fact testimony of Mike Cantrell:

Q: Please introduce yourself to the Commission.

A: My name is Mike Cantrell. I am the Legislative Committee Co-Chairman of the National Stripper Well Association ("NSWA"), the President and Board Member of the Oklahoma Energy Producers Alliance, and the owner of Cantrell Energy and Cantrell Investments in Ada, Oklahoma. I also own and run Pivotal Strategic Solutions, an oil and gas consulting group. I am a third generation oilman and have owned and run exploration and production companies since 1975. I am offering this testimony based on my five decades of experience, especially in relation to marginal or stripper wells, and active membership as a Boardmember with the NSWA.

Q: You understand that this is sworn testimony to be submitted in writing to the Oil Conservation Commission in connection with a rulemaking proceeding concerning financial assurances?

A: I do.

Q: What is your educational and employment experience?

A: I received a Bachelor of Arts in Psychology from East Central University in Ada, Oklahoma in 1972, but began working in the oil field on the production side with my father after graduating, until I started my own company, Oklahoma Basic Economic Corporation in 1975. I sold that company in 2000, started Cantrell Investments, LLC, and also consulted with Continental Resources and became their Vice President of Government and Regulatory Affairs, before returning to my own business. Since 1984, I have served in the following organizations: Oklahoma Energy Producers Alliance, Texas Alliance of Energy Producers, National Stripper Well Association, North Dakota Petroleum Council, Oklahoma Independent Petroleum Association, Domestic Energy Producers Alliance, Save Domestic Oil, Inc., Texas Independent Petroleum Producers and Royalty Owners Association, Oklahoma Independent Petroleum Association, Oklahoma Energy Resources Board, National Association of Royalty Owners: Industry Advisory Board, Oklahoma Independent Petroleum Association, Liaison Committee of Cooperating Oil & Gas Associations, and the Wildcatter Club of Oklahoma.

Q: What is the National Stripper Well Association?

A: The NSWA represents thousands of small, independent oil and gas producers across the United States. Our members operate the majority of the nation's stripper wells—low-production but long-lived assets that are essential to maintaining domestic energy production, rural economic stability, and critical tax revenue streams. A stripper well is defined as producing less than 15 barrels of oil or 90 MCF of gas per day and represent a significant source of long-tail energy production in New Mexico. With over 38,000 stripper oil wells and an estimated 25,000 gas wells nationwide, these assets contribute over $412 million annually in severance and school taxes. Stripper wells are

part of a responsible extraction industry that maximizes recovery from existing wells to prevent waste.[1] Even after primary production of oil and natural gas, 60% to 70% of the original hydrocarbons remain in place in the reservoir. With advancing technologies such as enhanced oil recovery (EOR), CO2 injection, and improved artificial lift systems, these remaining molecules can be economically harvested by stripper wells. This creates not only long-term economic opportunity but also sustained tax revenue for generations to come. However, once a well is prematurely plugged, that remaining resource is permanently lost.[2]

Q: Have you reviewed the WELC Applicant's proposed rule changes?

A: Yes, and I understand that the Commission is considering adding a bonding requirement proposed by the Applicants of $150,000 single wells bond for "marginal wells" and a single well bonding requirement for every well in an operator's inventory if "marginal wells" make up 15% of the well count. As defined by the WELC Applicants, "marginal wells" are active wells, and would otherwise be subject to the blanket bonding cap of $250,000.

Q: Do you have any concerns about this proposed rule change?

A: Yes. First, the context and scope of a rule change like this is more far reaching than the current concern or activity of the day. All the great horizontal wells that New Mexico has will deplete and will deplete quickly (on average in three years). When they

[1] U.S. Department of Energy NETL, "Stripper Well Consortium Advances Production Technology," Spring 2010. https://netl.doe.gov/sites/default/files/2018- 02/EPNews2010Spring.pdf

[2] Society of Petroleum Engineers, JPT: "Hundreds of Thousands of Stripper Wells: Massive Liability or Golden Opportunity?" https://jpt.spe.org/hundreds-of-thousands-of-stripper- wells-massive-liability-or-golden-opportunity

do, those wells will become stripper wells at some point. So New Mexico needs there to be a stripper well industry in place to continue the life of these wells from that time to their economic end. The proposed rules endanger not only New Mexico's economy today, but the economy from oil and gas in New Mexico's future by ignoring alternate possibilities and advances. Second, WELC's proposal mimics Colorado's efforts to eliminate small producers through unsustainable financial assurance levels, enacted in 2022 after the Colorado Legislature passed SB19-181. Since then, Colorado has seen a surge in orphan wells, with 576 added in FY2023 alone, doubling the backlog of abandoned wells.[3] We have also seen average plugging costs soar to greater than $93,000 per well, and $15 million expended in annual taxpayer-funded plugging efforts. In other words, regulations proposed to eliminate orphan wells created both more wells and made them costlier to plug.

Q: Have you reviewed any testimony by the witnesses in this proceeding?

A: Yes, and WELC's witnesses appear to view stripper wells and marginal wells as simply a "net liability." But stripper wells are not a liability—they are low-risk, high-option value assets that contribute, on average, $14 million a year in tax revenue to the State of New Mexico, create 3,160 jobs, and generate $30 million in royalties. These numbers come from a study by Energy and Industrial Advisory Partners, attached as Exhibit A to my testimony, predicting the economic impact of premature plugging and abandonment

[3] Colorado Public Radio, "Colorado Oil and Gas Companies Orphaned a Record Number of Wells," Sept. 2024. https://www.cpr.org/2024/09/17/colorado-oil-and-gas-companies- orphaned-a-record-number-of-wells/

of stripper wells.[4] Not considered in the WELC testimony I reviewed is the wider reaching effect of independent producers, outside of production numbers and well counts. The stripper well industry supports jobs across a variety of sectors, outside of oil and gas to include real estate, retail, healthcare, finance and insurance, manufacturing, professional, scientific and technical services, and construction, and all in the small towns, communities, and rural areas where independent producers are located. As the Commission can see from the study results, New Mexico is the fourth-most affected state and the cumulative effect on revenue, employment, and royalty income cannot be ignored. Rounding out the top five with stripper well inventory and operation are Colorado, Oklahoma, Texas, and California.

Q: What effect have you seen in Colorado following that state's adoption of escalated financial assurance requirements?

A: Following adoption of the new FA levels in 2022, orphan well numbers have skyrocketed in Colorado. Colorado now has an estimated 27,000 orphaned wells, with increased average plugging costs of $93,000 per well. On top of those expenses, with smaller and stripper well operators eliminated, Colorado has also cut an average of $10 million in state revenue and $27 million in royalties from its economy, compounded by a projected job losses averaging 2,700 per year. *See* Ex. A._In contrast, Texas and Oklahoma have taken a more balanced policy approach to plugging orphan wells and

[4] *See also* New Mexico Tax Research Institute, *Potential State and Local Revenue Impacts of Proposed Ozone Precursor Rule on the Oil and Gas Industry* (August 2021), attached as Exhibit B, and John Dunham & Associates, *Memorandum Re: Estimated Costs of Proposed Ozone Precursor Rule on Oil and Natural Gas Development in New Mexico* (Juen 13, 2021), attached as Exhibit C.

maintain an extensively funded and managed plugging budget which has kept average plugging costs much lower. For easy comparison, I have prepared thistable:

Metric	Colorado	New Mexico (Projected)	Oklahoma	Texas
Avg. Plugging Cost Per Well	$93,000	$150,000	$34,000[5]	$25,000 - $40,000
Estimated Orphaned Wells	27,000	30,000	16,000 (idle)	150,000 (idle/orphaned)
Annual Plugging Budget	$15 million	$0 (currently)	Funded & managed	Extensive state-managed fund
Annual Tax Revenue Loss (Stripper)	Already lost	$412.7 million	Preserved via balanced policy	Preserved via balanced policy

Q: What kind of effect in New Mexico do you predict to result from the WELC bonding rule?

A: First, the increase in financial assurance requirements will create tens of thousands of orphan wells out of the productive 60,000 oil and gas stripper wells in the state, caused by unmanageable bonding burdens imposed by WELC's proposal. Second, the state will forfeit a significant portion of the $412 million in tax revenue, without any alternative in place to supplement or offset those losses. Finally, without an alternate funding source or plugging budget, those newly orphaned wells will fall to the state to plug and abandon. I have reviewed testimony from the Oil Conservation Division witnesses and the Legislative Finance Committee's Policy Spotlight report which recounts the difficulties, delays, and expense that OCD faces in plugging the existing inventory of orphaned wells on state and private lands. Applicants may think they are "solving" the "problem" of orphan wells by increasing financial assurance requirements, but I worry that

[5] Oklahoma Corporation Commission Plugging Cost Reports

New Mexico is wholly unprepared, in terms of finances, resources, and staffing, to handle the unintended consequences of WELC's proposal. Ironically, the effects of WELC's proposed changes will increase orphan well counts, like we saw in Colorado, and the burden falls not on the Applicants, but on the Division and the industry to navigate the aftermath.

Q: Are there any portions of specific testimony by the WELC Applicants' witnesses that you would like to respond to?

A: Yes, WELC's expert witness Thomas M. Alexander states that the proposed rules are "not directed at prudent stripper well operators but those who are problematic based on OCD staff experience." *See Direct Testimony of Thomas M. Alexander*, WELC Ex. 3, 43:3-5. Unhelpfully, Mr. Alexander does not expand to identify the substance of the"staff experiences." Nevertheless, I fail to see how blanket increases in financial assurance which apply to all operators of active wells, regardless of compliance or environmental history, targets "problematic" operators. The changes proposed by WELC to NMAC 19.15.8.9(C)(1) & (2) and NMAC 19.15.8.9(D)(1)-(4), *see WELC Ex. 1-C* at 22-23, make no provision, carve-out, or safe-harbor for prudent stripper well operators. I do not understand how a one-size-fits-all $150,000 single well bond can be described as targeted or selective. The bonding increase will burden responsible, prudent stripper well operators with millions of dollars of newly required financial assurance, with no discretion for Division staff experience or consideration of operational history.

In the same way, Mr. Alexander also claims that the WELC Applicants' rule changes target operators "at the edge of solvency." *Alexander*, Ex. 3, 44:17. But as I explained above, there is no criteria or discretion embedded in the proposed rule change

that targets only imprudent, insolvent operators are at the greatest risk of walking away from their wells. Instead, it would appear that WELC's desire is to simply drive small operators out of business by making it impossible to remain in New Mexico under unmanageable bonding burdens, much like Colorado's strategy to "eliminate small producers." And this desire aligns with WELC's stated mission of ending oil and gas production.

Mr. Alexander also asserts that an operator who "cannot 'pay' for adequate financial assurance" has "no business remaining business," and equates an inability to meet unanticipated capital demands in the millions with imprudent operations. Alexander, WELC Ex. 3, 12:23-13:2. I think this statement ignores the fact that it is industry operators that plug the vast majority of wells—to the tune of over 90% annually—and if stripper well operators are overseeing late-life assets, it stands to reason that stripper well operators contribute a substantial amount to that percentage. In fact, of the 50,000 plugged wells reported by OCD in New Mexico, over 3,600 were plugged and released in the past five years. These responsible operators come in all sizes and business models, from Armstrong to XTO, and number over 200 entities and individuals.

Q: Is there any other witness testimony you would like to respond to?

A: Yes, WELC's expert witness Mr. Dwayne Purvis believes that if stripper well operators disappear from New Mexico, they will not be missed. He makes no attempt to hide or buffer his opinion, asserting that "the companies at risk… [are those] who will be missed the least." *See Direct Testimony of Mr. Dwayne Purvis*, WELC Ex. 30, 44:19-20. But in my review of his statistical analysis, he has limited himself strictly to well count and production levels, with no appreciation of the larger, indirect economic effects made by

stripper well operators. I will refrain from repeating myself on the economic impact of stripper wells to New Mexico, other than to point out to the Commission that this position is short-sighted on a number of fronts.

Q: On behalf of the National Stripper Well Association, what recommendations would you make in response to the WELC Applicants' proposed rule changes and supporting testimony?

A: The Commission needs to understand that stripper wells are not a liability—they are low-risk, high-option value assets with a vast inventory of future possibilities. A one-size-fits-all $150,000 bond would devastate small producers, shrink tax revenue, and shift cleanup costs to the public. New Mexico can lead with a smarter, more balanced regulatory path that is effective now and in the future. A more balanced approach must consider and include the following at a minimum:

- Reflect actual plugging costs incurred by industry (~$34,000 in Oklahoma)
- Encourage continued production from marginal wells
- Preserve the economic benefits of stripper wells for local communities
- Avoid replicating Colorado's costly and counterproductive model

The business model of the stripper well producer is to take assets and restore them to profitability through technology or production efficiencies. Although today's relatively low prices limit that ability, future prices will enable operators to return these wells to production. But if regulations force operators to prematurely plug stripper wells, those opportunities are gone forever, robbing royalty owners, producers, and the state coffers of future revenue.

In short, the NSWA urges the Commission to reject the proposed blanket bonding requirement by the WELC Applicants and instead support policies that sustain New Mexico's energy economy, environmental responsibility, and rural livelihoods.

MIKE CANTRELL

I hereby affirm under penalty of perjury of the laws of the State of New Mexico that the above statements are true and correct to the best of my knowledge, information, and belief.

DATE: 9/18/25

MIKE CANTRELL



PERCENTAGE DEPLETION

ECONOMIC IMPACT OF ITS ELIMINATION

STUDY COMPLETED: 2021

NSWA
National Stripper Well Association

www.nswa.us

INTRODUCTION

Despite the current difficulties facing the global economy, especially due to the adverse impacts of the COVID pandemic on the oil and natural gas industry specifically, the stripper well industry will likely continue to be a major source of energy production, employment, gross domestic product, and government revenues for the United States.

A critical element of that continued success is the percentage depletion allowance.

This allowance is a tax provision that allows oil and natural gas producers, limited to independent operators, to recover some of the investments associated with exploring for and producing oil and natural gas. Landowners also accrue benefits as royalty owners.

Eliminating the percentage depletion allowance would cause an economic ripple effect across the economy because the percentage depletion allowance primarily benefits the nation's smallest oil and natural gas producers and mineral owners; most of whom are farmers, ranchers, and other landowners. Elimination of the percentage depletion allowance would have an outsized impact on these small, economically vulnerable recipients of the allowance.

Energy and Industrial Advisory Partners (EIAP) was commissioned by the National Stripper Well Association (NSWA) to develop a report forecasting activity levels, spending, oil and natural gas production, supported employment, GDP, royalty payments, and government revenue changes if the percentage depletion allowance were to be eliminated.

The information that follows in this report describes who NSWA is, how stripper wells work, as well as a detailed discussion of percentage depletion and the results of the study, both nationally and across the 18 states most directly impacted.

View the 2021 EIAP study at https://bit.ly/3vYYCkc.

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WHO IS NSWA

The National Stripper Well Association (NSWA), founded in 1934, is the only national association representing the interests of the nation's smallest oil and gas operators – and their employees – before Congress and federal agencies. Learn more about NSWA at www.nswa.us.

OUR MISSION

Ensure the critical needs and concerns of producers, owners, and operators of stripper oil and gas wells are addressed regarding federal legislation and regulation.

Due to the high economic sensitivity of our members' operations – greatly exacerbated by the national COVID pandemic in 2020 – primary issues of concern include maintaining the percentage depletion allowance and related tax measures. In addition, and of keen interest, is current or proposed federal regulation of all aspects of small oil and gas operations (i.e., methane emissions).

OUR MEMBERS

With members in 30 states, from California to West Virginia, we are a viable and powerful voice for the American stripper well producer.

- Members of NSWA are the small independent business men and women who own stripper wells producing 15 barrels of oil (equal to 90 Mcf of natural gas) or less per day.
- Our members are the "family farmers" of the United States energy sector.
- The typical NSWA member company employs 11 or fewer full-time employees.



WHO WE ARE NOT:

NSWA does not represent any of the "major" oil companies (i.e., Chevron, Exxon, Shell) or offshore companies.

STRIPPER WELLS

"Stripper Wells" which make up a significant portion of America's oil and natural gas production (i.e., almost 80% of all U.S. wells are strippers) are, for tax purposes, defined as any oil or natural gas well whose maximum daily average oil production does not exceed 15 barrels of oil, or any natural gas well whose maximum daily average gas production does not exceed 90 thousand cubic feet of gas (Mcf), per day, during any 12-month consecutive time period. The term stripper well is often used interchangeably with the term "Marginal Well," although they are not the same.

MARGINAL WELL:

A marginal well's definition depends on oil prices and the cost of production. Specifically, a well is considered a marginal well when the market price of a barrel of oil exceeds the cost of extracting it.

STRIPPER WELL:

A stripper well, by contrast, is defined by its output. Stripper wells tend to be marginal wells, but a marginal well might not be a stripper well.

Despite the current difficulties facing the global economy – especially due to the adverse impacts of the recent COVID pandemic on oil and natural gas producers – stripper wells will continue to be a major source of energy production, employment, gross domestic product, and government revenues for the United States.

PRODUCTION



- The United States has an estimated 760,000 stripper wells in production – about 400,000 oil and 360,000 natural gas wells. That means, of the roughly one million active oil and natural gas wells in the United States, 76% are low production wells, typically operated by small businesses.
- Combined, these stripper wells make up over 7.8% of the total of all oil and natural gas produced domestically (7.4% oil and 8.2% natural gas).

BENEFICIAL ECONOMIC IMPACT



Over the next fifteen years, stripper wells are projected to contribute $332 billion to the overall United States economy in the form of nearly 4.4 billion barrels of oil and 37 trillion cubic feet of natural gas.

If the percentage depletion allowance were to be eliminated, between 2022-2035:

- Approximately 84,000 American jobs would be lost per year.
- Royalty owners would see reduced payments averaging $640 million per year.
- States would see an average of $200 million in reduced revenues each year.

PERCENTAGE DEPLETION

WHAT IS IT AND HOW DOES IT WORK?

Since 1954, U.S. companies that mine a range of materials, including minerals (i.e., oil and gas deposits, sand, and other nonrenewable resources from the earth) have been able to use percentage depletion. It is a tax provision that allows oil and natural gas producers to recoup some of the costs involved in exploring for and producing oil and natural gas.

- Percentage depletion supports the development of U.S. oil and natural gas, along with other mineral resources, that would otherwise be uneconomical to produce.
- For years, certain members of Congress and various groups have called for the elimination of percentage depletion, mistakenly believing it is a subsidy for "Big Oil" companies.

Those who qualify for the percentage depletion allowance must meet the following criteria:

- No more than 15% of gross oil and gas income may qualify for the provision.

The benefit is applied to the producer's first 1,000 barrels of oil [or natural gas equivalent] per day of production.

- Cannot exceed 100% of net income on a property-by-property basis.
- Amount deducted cannot exceed 65% of taxpayer's income from all sources before the deduction.

WHY IS PERCENTAGE DEPLETION IMPORTANT?

Only the smallest, family-owned oil and gas companies can use percentage depletion. Its importance, and benefit, is particularly valuable as the economy slowly recovers from the COVID pandemic when small businesses are under such economic stress.

Percentage depletion allows these operators to retain a portion of their earnings and, in turn, provides the opportunity for them to be used to reinvest cash flows – in some cases in excess of 100% – back into energy development activities. These reinvestments are directly funded from the producer's individual income and investment partners – not a bank.

Royalty owners also rely on this tax provision. The estimated 12.6 million private owners of oil and gas mineral rights in the U.S. are an integral element to the oil and gas industry, particularly to small producers that operate stripper wells. As the "landlords" of the industry, royalty owners play a critical first-step role in the development of their vital assets through an oil and gas lease that assigns the right to drill and produce to an oil and gas operator. In return, they become stakeholders in a drilling venture which provides the basis for economic benefit both for operators and royalty owners, who often receive their main source of income from royalty payments.



Percentage depletion is key to enabling independent producers (businesses with an average of 11 employees) to keep revenues that are vital to the future of their businesses.

WHY WOULD ELIMINATING THE ALLOWANCE HARM THE ECONOMY?

Stripper wells, which rely on percentage depletion, make up a significant portion of America's oil and natural gas production. These wells, which generally produce less than 15 barrels of oil a day, account for nearly 7.4% of U.S. oil production. They also produce less than 90 thousand cubic feet a day, yet account for 8.2% of U.S. natural gas production.

- Eliminating the percentage depletion allowance changes the economic profitability of production and investment for independent oil and gas producers. Independent producers typically invest 100% of their revenue into exploration and production (E&P).
- Without percentage depletion, the money available for reinvestment quickly disappears — which means no E&P and no industry growth.
- NSWA believes it is essential to protect an industry that makes such a significant contribution to the nation's economic security.

WITHOUT PERCENTAGE DEPLETION, STRIPPER PRODUCERS WILL DECREASE PRODUCTION, CLOSE WELLS SOONER, AVOID NEW PRODUCTION, OR GO OUT OF BUSINESS COMPLETELY.

THE ECONOMIC BENEFITS OF STRIPPER WELL PRODUCTION AND RELATED IMPACTS

Eliminating the percentage depletion allowance would cause a far-reaching, negative economic ripple effect across the economy because the percentage depletion allowance primarily benefits the nation's smallest oil and natural gas producers and mineral owners; most of whom are farmers, ranchers, and other landowners.



FARMERS



RANCHERS



OTHER LANDOWNERS

This study, commissioned for the NSWA by Energy and Industrial Advisory Partners, highlights the importance of the Percentage Depletion Allowance. If percentage depletion were eliminated, through the year 2035 we would see an average of:

84,000 fewer jobs per year

$200 MILLION less in state revenues per year

$640 MILLION reduced royalty payments per year

$8.7 BILLION less contributed to the GDP per year

$7.1 BILLION reduced spendings from the oil and natural gas industry per year

Over the next fifteen years, more than 11,000 wells would not be drilled and 4.4 billion barrels of oil and 37 Tcf of gas would not be produced if the depletion allowance is eliminated.

View the 2021 EIAP study at https://bit.ly/3vYYCkc.

LOST JOBS, LOST REVENUE, LOST ECONOMIC SECURITY:

If percentage depletion were eliminated, through the year 2035 we would see an average of:

- Producing stripper wells decrease by 14% per year
- Daily oil and natural gas production decrease by 12% per year
- New wells drilled decline by 9% per year
- Nearly 34,000 direct industry jobs lost, and almost 50,000 indirect industry jobs lost, per year

ECONOMIC IMPACT: NATION

NATIONAL ECONOMIC IMPACT OF ELIMINATING PERCENTAGE DEPLETION

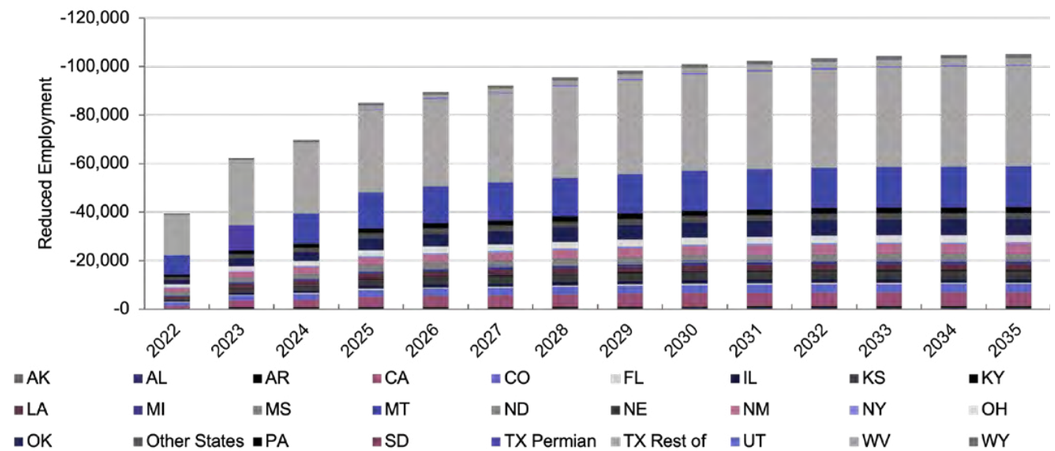
Elimination of the percentage depletion allowance would have a significant impact on hard-working men and women who work in the oil and gas industry.

Employment reductions would result from several factors, including reduced spending on operations and future activities.

Additionally, reduced royalty payments and state taxes would also impact the broader economy – by reducing or eliminating jobs in related "supply chain" manufacturing (i.e., equipment supply and manufacturing) and retail sectors (i.e., food services that supply and support workers). The loss or reduction to over 12 million royalty check recipients, who often rely on royalty checks to survive, would further impact the economy in unforeseen ways.

Projected average employment reductions are estimated at just under 84,000 each year between 2022-2035. By 2035, projected reductions in employment are estimated to reach just over 105,000 jobs each year. (Figure 5)

Figure 5: Projected Employment Reductions
Source: Energy and Industrial Advisory Partners



INDUSTRIES IMPACTED

The stripper well industry supports employment in a variety of industry sectors in addition to oil and natural gas. In fact, some of the largest projected employment reductions, if the percentage depletion allowance was eliminated, are expected in sectors such as:

REAL ESTATE
5,690 jobs per year on average

RETAIL
5,670 jobs per year on average

HEALTHCARE
5,560 jobs per year on average

FINANCE AND INSURANCE
3,520 jobs per year on average

These losses are in addition to sectors that are directly impacted, including:

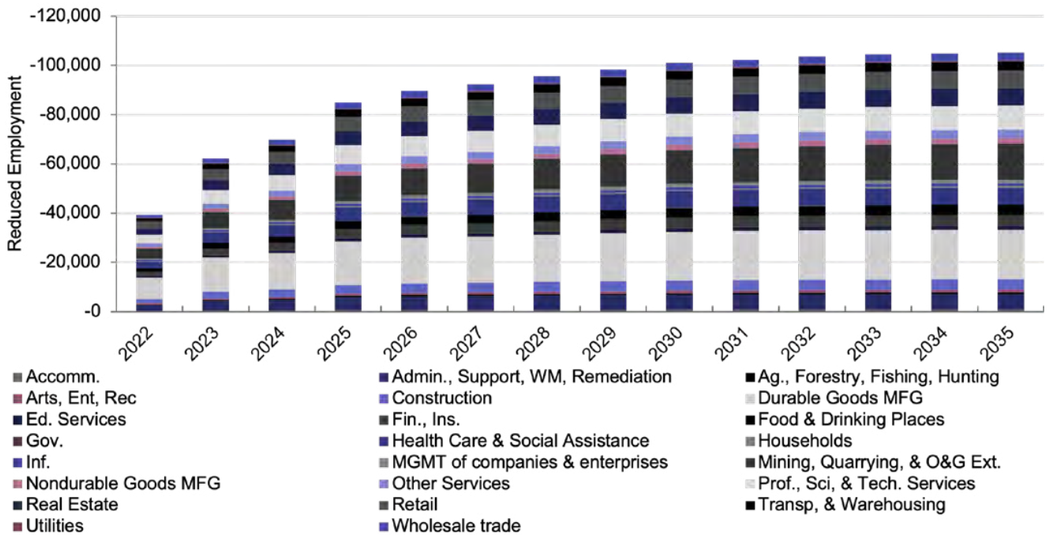
DURABLE GOODS MANUFACTURING
16,700 jobs per year on average

PROFESSIONAL SCIENTIFIC & TECHNICAL SERVICES
7,640 jobs per year on average

OIL AND GAS
10,900 jobs per year on average

CONSTRUCTION
3,450 jobs per year on average

Figure 7: Projected Oil and Gas Supported Job Losses by Industry Sector
Source: Energy and Industrial Advisory Partners



RURAL COMMUNITIES

Eliminating the percentage depletion allowance would primarily affect the nation's smallest and most vulnerable oil and natural gas producers and their employees.

Many of these producers are based, and operate, in small towns and communities in rural areas. They would see an outsized impact, beginning with companies that sell parts and equipment to the producers.

In a time where the spread of the COVID virus has already dealt a serious and painful blow to these communities, the ramifications for a host of average citizens – far from the corporate offices of "Big Oil" – could truly be devastating.

From Round Rock, Texas to Ada, Oklahoma to Bradford, Pennsylvania to Millersburg, Ohio to Mt. Vernon, Illinois – these include pumpers, clerical workers, those who repair equipment (such as machine shops and welders), and people who operate equipment. All of these people are working to earn a living and trying to make a better life for their families.

Elsewhere – from Franktown, Colorado to Bakersfield, California to Phoenix, Arizona to Bolivar, New York – important benefits are shared by farmers, ranchers, and retirees who receive royalty payments from these wells.

COST THE UNITED STATES' ECONOMY

The average economic impact of eliminating the percentage depletion allowance would cost the United States' economy from 2022-2035:

- 84,000 fewer jobs (per year)
- $8.7 billion in annual contributions to the gross domestic product (GDP)
- $7.1 billion in reduced oil and natural gas industry spendings (per year)

ECONOMIC IMPACT: ROYALTY OWNERS

WHO WE ARE

Royalty owners lease their mineral rights for drilling and, in return, receive a share of the revenue from what wells on their land produce. Many state governments and Native American tribes own mineral royalties, as does the federal government.

The National Association of Royalty Owners (NARO) represents the concerns of 12.6 million royalty owners across the country who live and vote in all 50 states. NARO defines private royalty owners as "teachers, farmers, ranchers, homemakers, accountants, firemen, plumbers, retirees, dentists, small business owners, factory workers, engineers, pet groomers, widows, roofers, lawyers, policeman, florists, carpenters, and bricklayers."

Royalty owners spend their money in their communities, give to local charities, and save for the future. Their financial benefits come solely from the mineral interests they own, and when those resources have been exhausted, the royalty income ends.

While collectively the minerals owned are of vast value, the minerals owned by a single individual are often relatively small in amount.



The average private royalty owner is over 60 years old, widowed, and receives less than $500 in monthly royalties — with many earning considerably less — as a supplement to their social security retirement income.

REVENUE AND INCOME IMPACTS

Nationwide, royalty owners pay millions of dollars in property tax, ad valorem tax, severance tax, state income tax, local tax, non-resident income tax, and federal income tax on the revenue from producing minerals.

These sources of income for the state and federal government will decline or be eliminated if royalty owners lose their ability to apply the percentage depletion allowance and if thousands of older wells are prematurely plugged because their production becomes uneconomical.

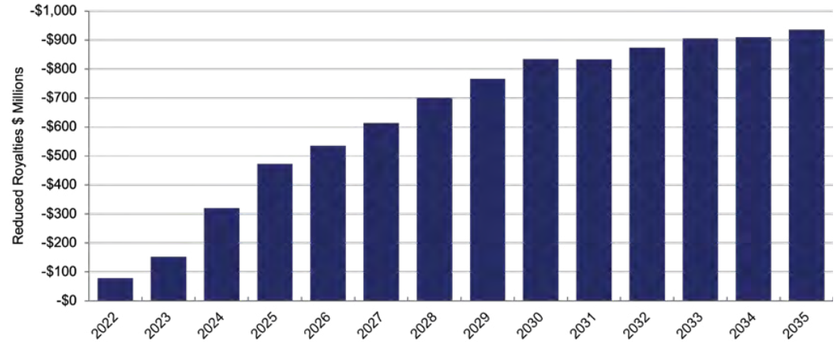
Eliminating the percentage depletion allowance would affect royalty owners in two ways:

- First, it lowers the incentive to lease their mineral rights or provide investment capital for new wells seen as riskier ventures.
- Second, the number of producing wells will decrease, thus diminishing the amount of production revenue, and lowering earnings for royalty owners.
- Third, it means owners of other types of real estate get to continue to depreciate aging assets, but mineral owners (a form of real estate ownership) would not be allowed any depreciation/depletion for a depleting asset.

Bottom line: the percentage depletion tax provision protects the most vulnerable, most likely retired, royalty owners from losing a steady – and perhaps only – source of income which, in turn, benefits federal, state, and local tax revenue.

As the nation continues to recover from the devastating impacts of the COVID pandemic on the economy in general, and our most economically-disadvantaged populations in particular, now is not the time to eliminate percentage depletion.

Figure 9: Projected Percentage Depletion Elimination Case Oil and Natural Gas Royalty Reductions
Source: Energy and Industrial Advisory Partners



ROYALTY OWNERS IN THE UNITED STATES: 12.6 MILLION PEOPLE

The map below displays the estimated number of royalty owners in 2021. The total number of mineral owners is much greater, as vast areas are unproductive or have not yet been explored and developed.
Source: National Association of Royalty Owners

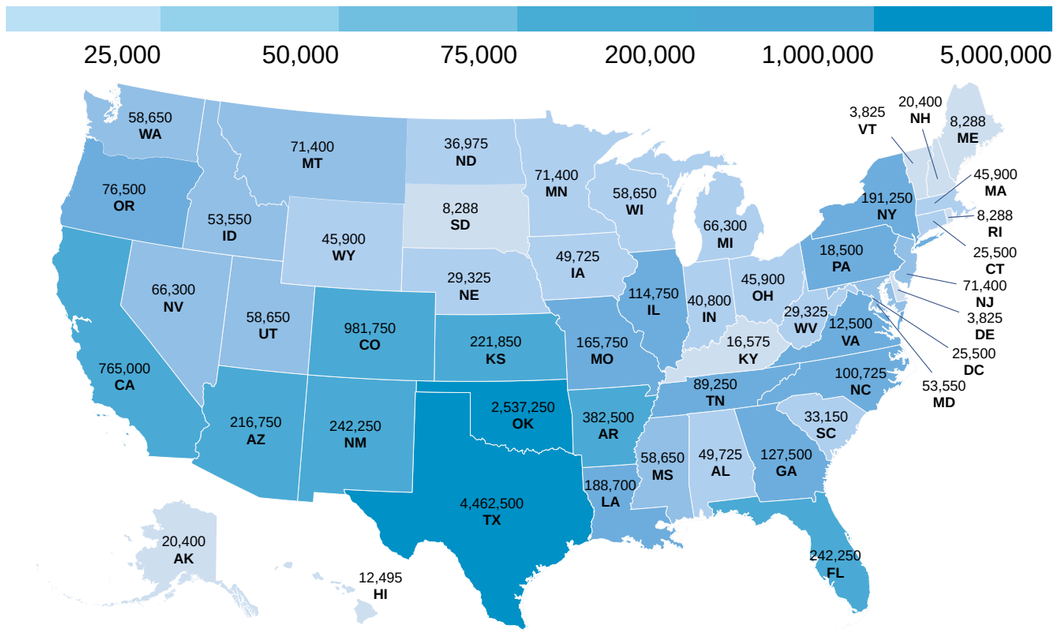


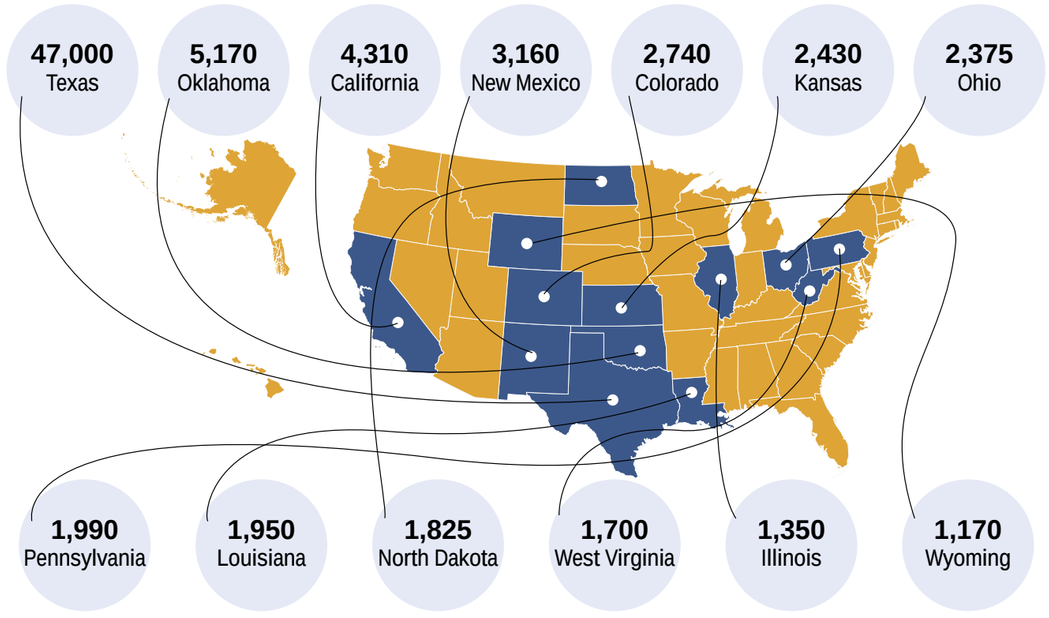
EXHIBIT 30
EXHIBIT A

ECONOMIC IMPACT: STATES

STATES ECONOMIC IMPACT OF ELIMINATING PERCENTAGE DEPLETION

The overall economic costs for the U.S. are large, but they are not equally distributed across all states. Of the 38 oil-and-gas-producing states in the nation, the top-producing states would be hardest-hit by elimination of percentage depletion.

There are 13 states projected to see average reduced employment of over 1,000 jobs per year from 2021-2035:



AVERAGE DIRECT & INDIRECT JOBS LOST PER YEAR (2021-2035)

1	Texas	47,000	7	Ohio	2,375	13	Wyoming	1,170
2	Oklahoma	5,170	8	Pennsylvania	1,990	14	Michigan	905
3	California	4,310	9	Louisiana	1,950	15	New York	580
4	New Mexico	3,160	10	North Dakota	1,825	16	Arkansas	515
5	Colorado	2,740	11	West Virginia	1,700	17	Alabama	405
6	Kansas	2,430	12	Illinois	1,350	18	Utah	400

Over the decade projected (2021-2035), if percentage depletion is eliminated...

ALABAMA

JOBS LOST



404 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

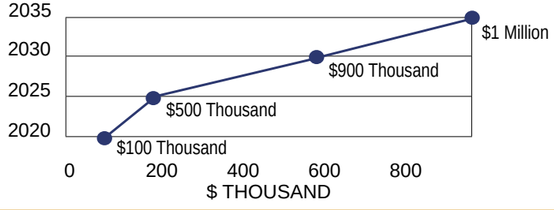
2022	2025	2030	2035
155	402	494	516

*includes direct & indirect employment totals

STATE REVENUE LOST



$600 THOUSAND
AVERAGE LOSS EACH YEAR



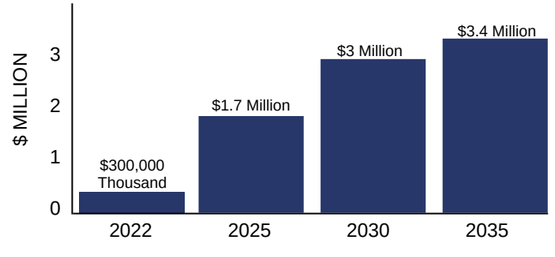
ROYALTY OWNERS



49,725
ROYALTY OWNERS IN ALABAMA

$2.2 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



#17
largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

PRODUCTION

2,630
barrels of oil equivalent reduction per day over 15-year forecast period

STRIPPER WELLS

1,020
producing stripper wells lost each year for the 15-year forecast period

IPANM EXHIBIT #37
IPANM001436

ARKANSAS

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

514 AVERAGE JOBS LOST EACH YEAR over fifteen years

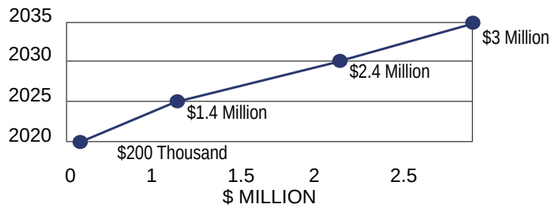
ACTUAL JOBS LOST

2022	2025	2030	2035
189	497	630	694

*includes direct & indirect employment totals

STATE REVENUE LOST

$1.8 MILLION
AVERAGE LOSS EACH YEAR



#16
largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

PRODUCTION

2,445
barrels of oil equivalent reduction per day over 15-year forecast period

STRIPPER WELLS

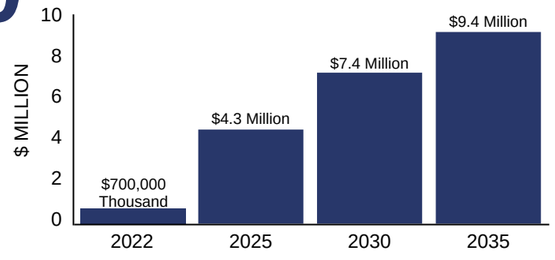
3,820
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

382,500
ROYALTY OWNERS IN ARKANSAS

$5.4 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



CALIFORNIA

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

4,311 AVERAGE JOBS LOST EACH YEAR over fifteen years

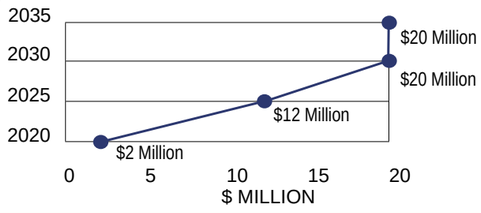
ACTUAL JOBS LOST

2022	2025	2030	2035
1,124	4,137	5,521	5,590

*includes direct & indirect employment totals

STATE REVENUE LOST

$14 MILLION
AVERAGE LOSS EACH YEAR



#3
largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

PRODUCTION

25,320
barrels of oil equivalent reduction per day over 15-year forecast period

STRIPPER WELLS

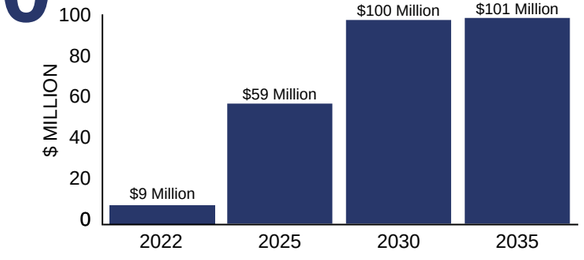
4,745
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

765,000
ROYALTY OWNERS IN CALIFORNIA

$70 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



COLORADO

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

2,739 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
1,367	2,775	3,297	3,517

*includes direct & indirect employment totals

#5

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

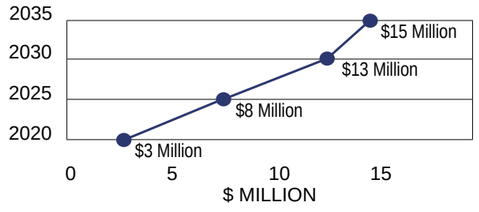
PRODUCTION

22,800

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST

$10 MILLION
AVERAGE LOSS EACH YEAR



STRIPPER WELLS

3,200

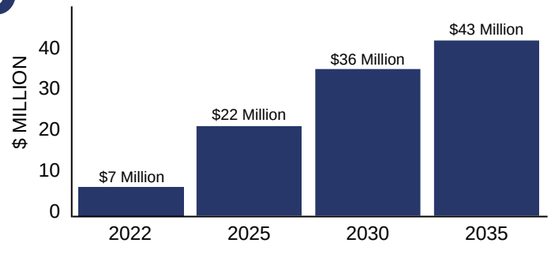
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

981,750
ROYALTY OWNERS IN COLORADO

$27 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



ILLINOIS

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

1,351 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
497	1,335	1,668	1,722

*includes direct & indirect employment totals

#12

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

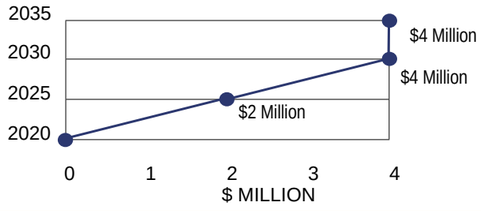
PRODUCTION

3,640

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST

$3 MILLION
AVERAGE LOSS EACH YEAR



STRIPPER WELLS

5,320

producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

114,750
ROYALTY OWNERS IN ILLINOIS

$7 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST

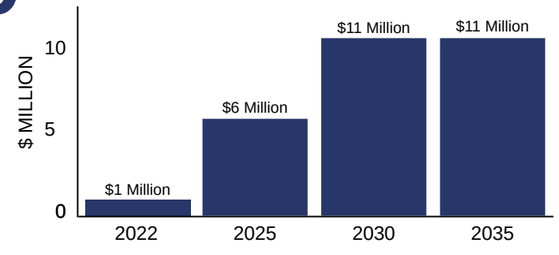


EXHIBIT 30
EXHIBIT A

KANSAS

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

2,432 AVERAGE JOBS LOST EACH YEAR over fifteen years

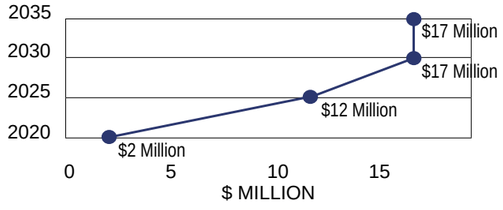
ACTUAL JOBS LOST

2022	2025	2030	2035
641	2,465	3,086	3,071

*includes direct & indirect employment totals

STATE REVENUE LOST

$13 MILLION
AVERAGE LOSS EACH YEAR

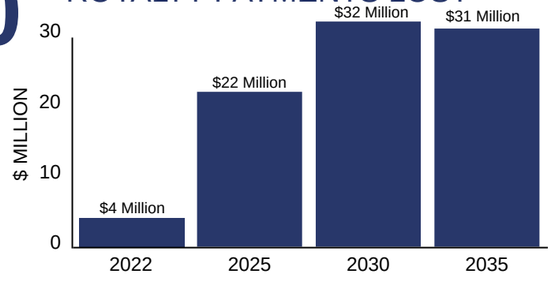


ROYALTY OWNERS

221,850
ROYALTY OWNERS IN KANSAS

$23 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



#6
largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

PRODUCTION

15,470
barrels of oil equivalent reduction per day over 15-year forecast period

STRIPPER WELLS

12,085
producing stripper wells lost each year for the 15-year forecast period

LOUISIANA

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

1,951 AVERAGE JOBS LOST EACH YEAR over fifteen years

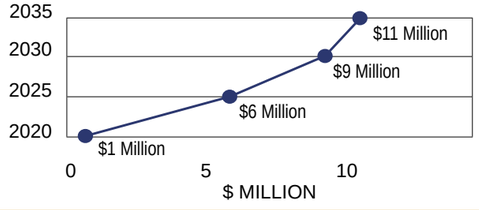
ACTUAL JOBS LOST

2022	2025	2030	2035
950	2,024	2,333	2,429

*includes direct & indirect employment totals

STATE REVENUE LOST

$7 MILLION
AVERAGE LOSS EACH YEAR

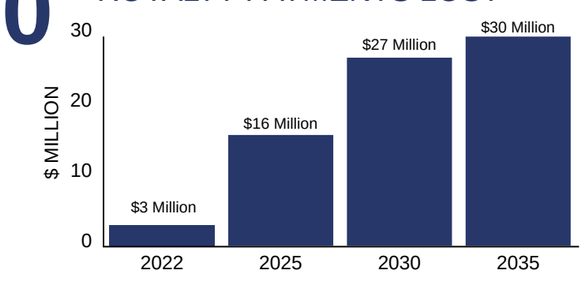


ROYALTY OWNERS

188,700
ROYALTY OWNERS IN LOUISIANA

$19 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



#9
largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

PRODUCTION

7,140
barrels of oil equivalent reduction per day over 15-year forecast period

STRIPPER WELLS

2,785
producing stripper wells lost each year for the 15-year forecast period

IPANM EXHIBIT #37
IPANM001439

MICHIGAN

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

905 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
315	903	1,119	1,150

*includes direct & indirect employment totals

#14

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

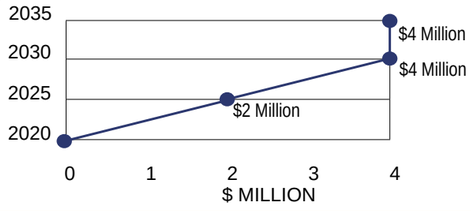
PRODUCTION

5,535

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST

$3 MILLION
AVERAGE LOSS EACH YEAR



STRIPPER WELLS

2,235

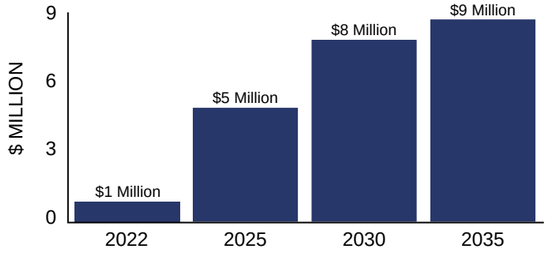
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

66,300
ROYALTY OWNERS IN MICHIGAN

$6 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



NEW MEXICO

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

3,160 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
1,703	3,179	3,787	4,126

*includes direct & indirect employment totals

#4

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

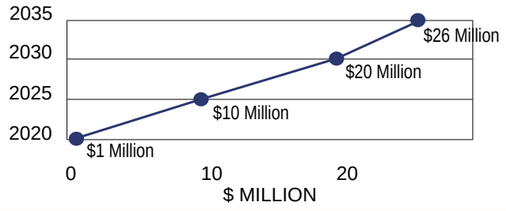
PRODUCTION

25,725

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST

$14 MILLION
AVERAGE LOSS EACH YEAR



STRIPPER WELLS

2,660

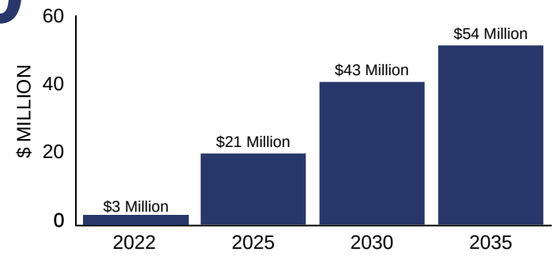
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

242,250
ROYALTY OWNERS IN NEW MEXICO

$30 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



NEW YORK

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

580 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
303	618	684	697

*includes direct & indirect employment totals

#15

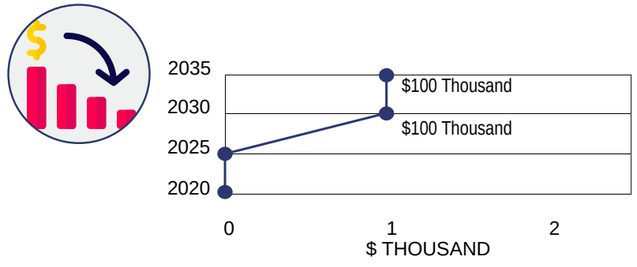
largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

PRODUCTION

390

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST



STRIPPER WELLS

635

producing stripper wells lost each year for the 15-year forecast period

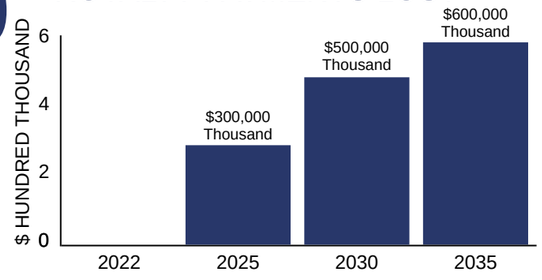
ROYALTY OWNERS

191,250

ROYALTY OWNERS IN NEW YORK

$400 THOUSAND LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



NORTH DAKOTA

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

1,824 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
1,117	1,988	2,114	2,146

*includes direct & indirect employment totals

#10

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

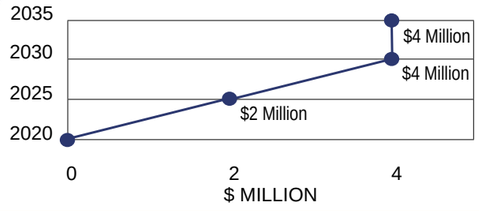
PRODUCTION

3,160

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST

$3 MILLION
AVERAGE LOSS EACH YEAR



STRIPPER WELLS

485

producing stripper wells lost each year for the 15-year forecast period

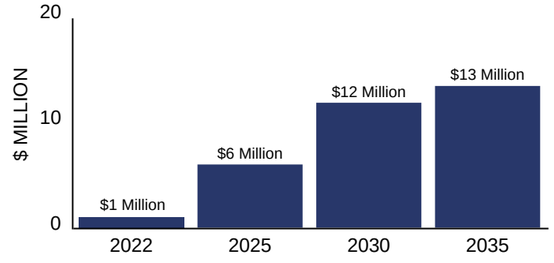
ROYALTY OWNERS

36,975

ROYALTY OWNERS IN NORTH DAKOTA

$8 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



OHIO

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

2,377 AVERAGE JOBS LOST EACH YEAR over fifteen years

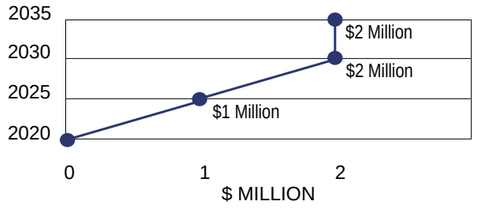
ACTUAL JOBS LOST

2022	2025	2030	2035
1,160	2,478	2,835	2,915

*includes direct & indirect employment totals

STATE REVENUE LOST

$1 MILLION
AVERAGE LOSS EACH YEAR



#7
largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

PRODUCTION

4,765
barrels of oil equivalent reduction per day over 15-year forecast period

STRIPPER WELLS

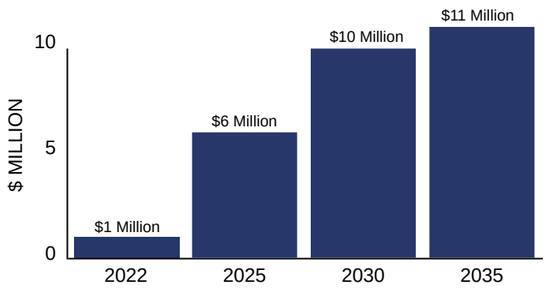
4,430
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

45,900
ROYALTY OWNERS IN OHIO

$7 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



OKLAHOMA

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

5,170 AVERAGE JOBS LOST EACH YEAR over fifteen years

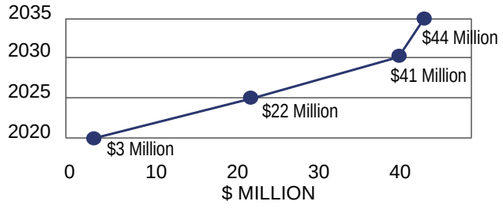
ACTUAL JOBS LOST

2022	2025	2030	2035
2,018	4,870	6,478	6,769

*includes direct & indirect employment totals

STATE REVENUE LOST

$29 MILLION
AVERAGE LOSS EACH YEAR



#2
largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

PRODUCTION

37,305
barrels of oil equivalent reduction per day over 15-year forecast period

STRIPPER WELLS

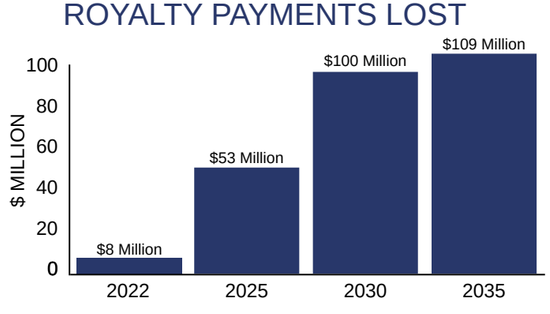
10,405
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

2,537,250
ROYALTY OWNERS IN OKLAHOMA

$71 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



Over the decade projected (2021-2035), if percentage depletion is eliminated...

PENNSYLVANIA

JOBS LOST

1,993 AVERAGE JOBS LOST EACH YEAR
over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
1,003	2,013	2,391	2,476

*includes direct & indirect employment totals

#8

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

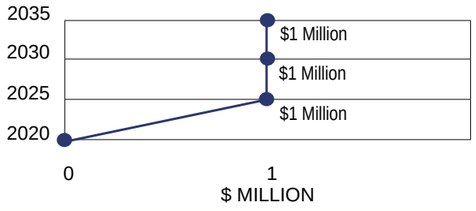
PRODUCTION

7,430

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST

$1 MILLION
AVERAGE LOSS EACH YEAR



STRIPPER WELLS

8,789

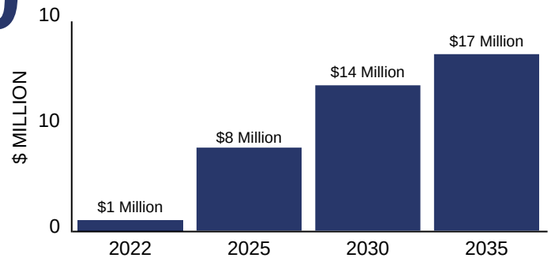
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

178,500
ROYALTY OWNERS IN PENNSYLVANIA

$10 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



Over the decade projected (2021-2035), if percentage depletion is eliminated...

TEXAS

JOBS LOST

47,060 AVERAGE JOBS LOST EACH YEAR
over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
24,260	48,894	56,145	58,228

*includes direct & indirect employment totals

#1

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

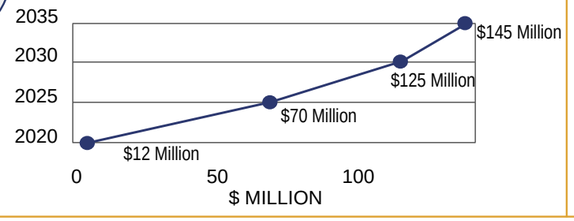
PRODUCTION

109,215

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST

$90 MILLION
AVERAGE LOSS EACH YEAR



STRIPPER WELLS

26,195

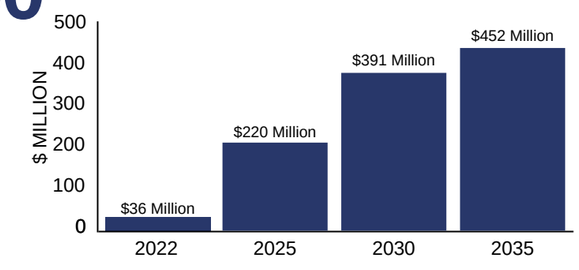
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

4,462,500
ROYALTY OWNERS IN TEXAS

$281 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



UTAH

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

398 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
87	361	557	510

*includes direct & indirect employment totals

#18

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

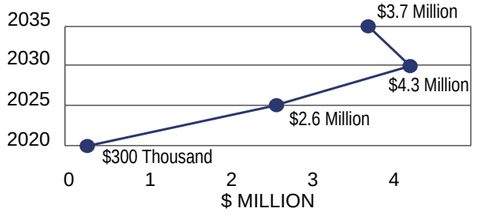
PRODUCTION

5,820

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST

$2.8 MILLION
AVERAGE LOSS EACH YEAR



STRIPPER WELLS

1,610

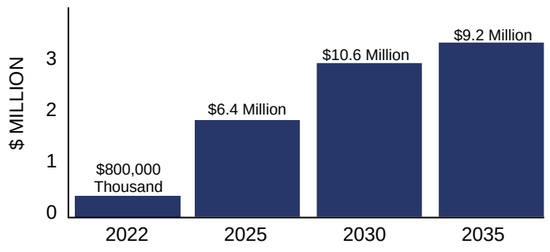
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

58,650
ROYALTY OWNERS IN UTAH

$7.1 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



WEST VIRGINIA

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST

1,697 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

2022	2025	2030	2035
361	1,294	2,144	2,803

*includes direct & indirect employment totals

#11

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

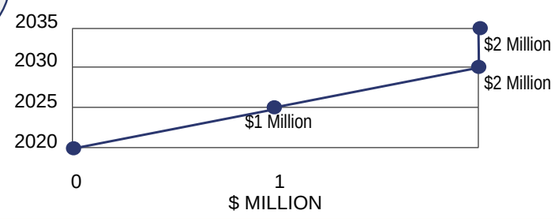
PRODUCTION

2,970

barrels of oil equivalent reduction per day over 15-year forecast period

STATE REVENUE LOST

$1 MILLION
AVERAGE LOSS EACH YEAR



STRIPPER WELLS

4,220

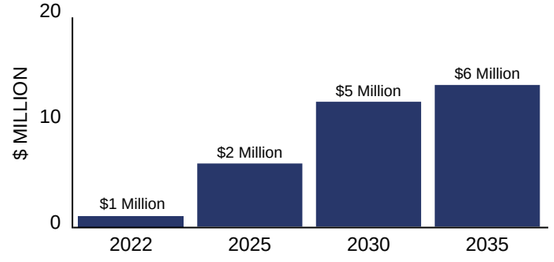
producing stripper wells lost each year for the 15-year forecast period

ROYALTY OWNERS

29,325
ROYALTY OWNERS IN WEST VIRGINIA

$4 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



WYOMING

Over the decade projected (2021-2035), if percentage depletion is eliminated...

JOBS LOST



1,169 AVERAGE JOBS LOST EACH YEAR over fifteen years

ACTUAL JOBS LOST

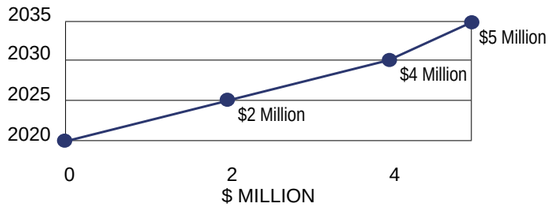
2022	2025	2030	2035
419	1,115	1,491	1,442

*includes direct & indirect employment totals

STATE REVENUE LOST



$3 MILLION
AVERAGE LOSS EACH YEAR



#13

largest state impacted from the elimination of the percentage depletion allowance due to the state's large base of stripper wells

PRODUCTION

5,070

barrels of oil equivalent reduction per day over 15-year forecast period

STRIPPER WELLS

1,750

producing stripper wells lost each year for the 15-year forecast period

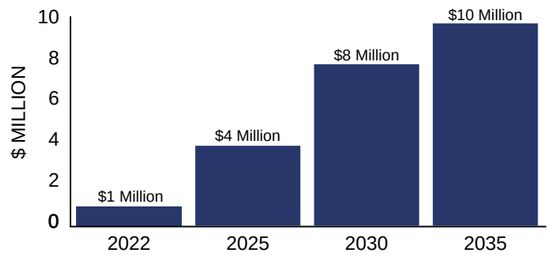
ROYALTY OWNERS



45,900
ROYALTY OWNERS IN WYOMING

$6 MILLION LOST
ON AVERAGE EACH YEAR IN ROYALTY PAYMENTS

ROYALTY PAYMENTS LOST



THANK YOU TO OUR PARTNER ASSOCIATIONS

PLATINUM

ILLINOIS OIL & GAS ASSOCIATION

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

THE PETROLEUM ALLIANCE OF OKLAHOMA

TEXAS Alliance of Energy Producers

GOLD

National Association of Royalty Owners

PAPP Pennsylvania Independent Petroleum Producers Inc.

PETROLEUM ASSOCIATION of WYOMING

SILVER

CIPA California Independent Petroleum Association

Indiana Oil & Gas Association

IPANM INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO

OEPA Oklahoma Energy Producers Alliance

PPRA PANHANDLE PRODUCERS & ROYALTY OWNERS ASSOCIATION

BRONZE

AIPRO ARKANSAS INDEPENDENT PRODUCERS & ROYALTY OWNERS

DEPA DOMESTIC ENERGY PRODUCERS ALLIANCE

GWV GAS & OIL ASSOCIATION OF WEST VIRGINIA

KIOGA Voice of the Kansas Independent Petroleum Industry

ITPRO

as of 5.25.21

THANK YOU TO OUR INDIVIDUAL SUPPORTERS OF THIS STUDY

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Charter Energy

Dewey Bartlett
Keener Oil & Gas Company

Madelon L. Bradshaw

Pete Brown
Brown & Borelli, Inc. &
Cimarron Production Company

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Burns Energy, LLC

Paul Burton
Paul Burton, LLC

Lee Caldwell

Mike Cantrell
Postwood Energy, LLC

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Jerry Hess Operating Company

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Donald Hupp
Gunn Oil Company

Jerry James
Artex Oil

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Steven Johnson
ONEOK

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RJ Energy, LLC

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Burk Royalty Company, Ltd.

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Kincaid Oil Producers, Inc.

King Kirchner
Kirchner Investments, LLC

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Lario Oil & Gas Company

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Wallace Holdings, LLC

Bill Warnock

Frank Weber
Great Southwest Oil & Gas Corporation

Eric Weiss
Muslow Oil and Gas

J. Nelson Wood
Wood Energy, Inc.

David Yost
Yost Energy, Inc.

Transcontinental Company

as of 5.25.21

IPANM EXHIBIT #37
IPANM001446

DEWEY BARTLETT, JR.

Bartlett shares how his family got into the oil business and how the percentage depletion allowance helps his small business.

About Keener Oil and Gas Company.
We are a family-owned company. My grandfather, DA Bartlett, started the company in the very early 1900s in Titusville, Pennsylvania which is where oil was first found by drilling in the U.S. My grandfather was a clerk in a general store, and, as the story goes, he ended up taking the store over when the owner went out of business. He would advance credit to some of the operators and, for collateral, he would take their lease. Apparently, somebody didn't pay the bill so he ended up in the oil business all of a sudden. He then came to Tulsa, Oklahoma in 1910, and was able to buy a few leases on the outskirts of the Cushing Field, and we've been here ever since.

We've had our ups and downs but, generally, our approach has been successful. Like most small companies, we've had to be pretty versatile and look for alternative ways to not only make money but to stay in business.

When did you get involved in oil & gas?
About the time that my father and uncle both died, that's when I got involved with running the company. I worked out in the oil fields with Halliburton for several years and learned the operational side, which was a very, very good experience for me.

How many employees does Keener Oil and Gas have?
Now we have a total of five employees, including me. We contract out a lot of things. All of our field operations are contracted out and we probably have 10 to 15 pumpers that are contracted out at any one time. We contract out our engineering and geological activities, for example.

WHAT TO KNOW

Location: 10 counties in Oklahoma

Number of Wells: 15 operating

Employees: 5 individuals + contractors

Where does Keener operate?
We are in a couple of different areas. Seminole County in the southeast of Oklahoma City is one area that a lot of our production is located. Another area is in Creek County, south of a small town called Bristow, which is southwest of Tulsa. We're also concentrated in an area west of Stillwater, Oklahoma around a community called Orlando. We have operated leases in about 10 different counties. It's a very rural, very small town where the oil and gas industry has been a significant player for decades. When the oil and gas industry is doing well, the towns are very prosperous. When things slow down, you can really tell. It has a negative effect on those towns. It's very similar to how the industry goes, so goes Oklahoma, Texas, New Mexico, Kansas, etc.



How would eliminating the percentage depletion allowance impact Keener Oil and Gas Company?
The big oil companies have a variety of sources of revenue other than selling crude oil or natural gas. Besides refining crude and processing natural gas, many own plants that produce plastics, chemicals, and fertilizer - all using crude oil or natural gas as feed stock. An advantage of owning those businesses is they usually become more profitable when their cost of feed stock is low, thereby subsidizing their lost revenue from selling crude and natural gas in a declining price market. Lower prices can be very beneficial to the major oil companies.

That's terrific for them. But it's not good for us because, we, the independent oil companies, mostly have only one or two major sources of revenue, and that's selling oil and/or natural gas. Our future really depends upon a reasonable, stable, good price of both of those commodities. The percentage depletion allowance is a tax benefit that helps the small companies only, it's really identified and restricted only to small companies, and it does help to a small degree.

When things get a little tight for us financially, it at least gives us a little bit of relief, and it's not a big amount, but it is enough to help keep a person or a few people employed, to have a little bit of extra money left on the side to do some geological research or have some engineering done. It gives us an ability to do a few things that, when prices do recover, then we could take advantage of the research or the work and possibly drill a few more wells or do some workovers. Since we have a finite source of product it is much different than a manufacturing company. Oil is a very finite resource, generally speaking, it does deplete. Percentage depletion makes the economic situation between say, a manufacturing company and an oil company, a little fairer. The percentage depletion allowance recognizes the fact that we do have a depleting asset that will eventually go away.

How would reduced activity impact the communities where you operate?
Most of the additional income from percentage depletion is used for keeping employees. The percentage depletion allowance may be enough to keep somebody employed. If that depletion allowance goes away, so goes that employee. If that employee is laid off, or the spending doesn't happen, it impacts the community where he or she lives and works. In small towns in Oklahoma that are in or around oil and gas production, their economic activity is directly related to oil and gas. Everything from privately-owned companies to public utilities, and the electric co-ops, for example. Some of the co-ops in Western Oklahoma have major clients that are oil and gas companies. When a well is shut-in that electric motor doesn't run, and the $300 or $500 a month of electricity that it had been using stops immediately. That has a real immediate impact upon that particular co-op that's supplying electricity to a multi-county area of Oklahoma, and they employ a lot of people. If the percentage depletion allowance was taken away, it would affect everybody in these communities.

> When things get a little tight for us financially, percentage depletion at least gives us a little bit of relief, and it's not a big amount, but it is enough to help keep a person or a few people employed.

SETH HUNTER

Hunter shares how he is the fourth generation to manage their family business, which has survived due to the percentage depletion allowance.

WHAT TO KNOW

Location: 3 counties in California

Number of Wells: 400 operating

Employees: 60 individuals + 10 contractors

About Vaquero Energy

Vaquero Energy is a fourth-generation business that began with my great-grandfather here in California. Obviously, over the course of time, we've evolved in terms of size and have grown through drilling and acquisitions over the course of time. We currently operate in three counties in California and have approximately 1,800 barrels a day of production.

How many people does Vaquero Energy employ?

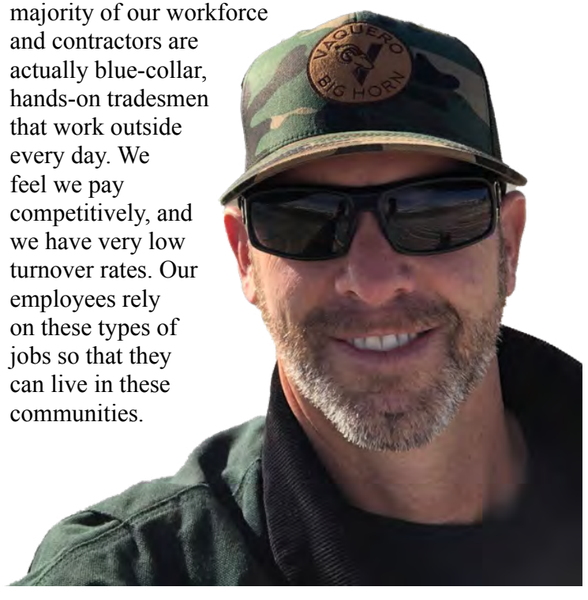
We employ about 60 employees and about 10 full-time contractors.

Where does Vaquero operate?

We are based in Bakersfield, California, and have offices on the central coast in Santa Maria, California. There's a community here that half of our operations are based out of, next to the town of Garey, a very small town, with about 80 people who live in it. We feel that we're very important to the areas we operate in, for example, there's a small store called the Garey Store, a sole proprietorship, and a lot of her business comes from not only my company but also our contractors and neighboring oil and gas companies that eat lunch and buy snacks. There are no majors here in Santa Barbara County or in Kern County in the fields we operate in. Stripper well operators support the oil field supply houses, restaurants, hospitality industry, and other businesses in these areas.

What kind of employees does Vaquero hire?

The majority of our employees are on the operations side, who operate oil wells, associated facilities, and equipment. We also employ welders and various tradesmen who make an oil field function on a day-to-day basis. We also have engineers, geologists, and accountants but the majority of our workforce and contractors are actually blue-collar, hands-on tradesmen that work outside every day. We feel we pay competitively, and we have very low turnover rates. Our employees rely on these types of jobs so that they can live in these communities.



Without companies like ours, they might be forced to work in another industry for lower pay. We're definitely in the upper tier in terms of compensation relative to other industries in the areas that we operate. We offer benefits packages, health care, vision, dental, as well as retirement that a lot of other industries just can't offer.

How have market conditions impacted you in the last year?

Greatly. Everybody else in every other industry has been very affected but we're directly affected because of the reduction in demand for crude oil by refineries. That trickled down to our level and the economics of producing a barrel of oil. As a stripper well operator, two-thirds of our wells produce about a barrel of oil per day, and for every barrel of oil, they make nine of water (average well is 90% water and 10% oil). It's costly to produce that small amount of oil and keep a stable workforce when the price is impacted by the economy in general. We have struggled over the last year but we haven't laid anybody off in hopes that the industry will recover in 2021.

How would the elimination of percentage depletion impact your company?

It would trickle down and leave us with less ability to access capital or operating cash. The percentage depletion directly affects the bottom line, and if that bottom line sees a change for the worst, that affects everything, not only our production but the number of employees or contractors that we can employ. We redeploy 100% of that cash from percentage depletion back into our business and the local community. We are a family-owned, privately held company that utilizes percentage depletion to keep our people working during the challenging economic times that have plagued the industry since 2015. It's a commitment to reinvesting into our business to make it last so that I can teach my children the art that is the energy creation business. Beyond that, it affects the community because we support the communities that we operate in, whether that's through our employees spending money or donating time and money for programs in our communities.

How important is the stripper well industry to Kern County and Bakersfield?

It's extremely critical. Kern County, where Bakersfield is located, is the largest in terms of oil production per county in the U.S. That's a fact that gets lost, most people don't think of California as a large energy producer outside of renewables, but it is. The county and the community rely very heavily on the industry because there really isn't anything else other than agriculture in Kern County, which can only support so much employment. If oil and gas were to dry up, then obviously people will have to move on to other places, whether it's in or outside of the state, but there would definitely be an exodus. It's very critical to the community and the county that oil and gas stays a part of the economy.

> We redeploy 100% of that cash from percentage depletion back into our business and the local community.

PRODUCER PROFILE - OHIO

JERRY JAMES

James explains how a past employer convinced him to join the oil industry and how the percentage depletion allowance helps to grow his small business.

WHAT TO KNOW

Location: Ohio & New Mexico

Number of Wells: 250 operating

Employees: 15 individuals + field crews

About Artex Oil Company.
Artex actually goes back to the 1950s. Mr. Rupe, who is 103 years old, started Artex Oil Company back in the 1950s. Thirty years ago, my business partner Gene Huck and I were engineering consultants and we did a lot of work for Mr. Rupe. He convinced us that we could be good at this and to go into business with him full-time. Right now, we're concentrated mainly in Ohio doing conventional and unconventional work. We previously had operations out West, but as prices over the last decade have trended down, we've sold most of our western operations, but still have a bit in New Mexico.

How many employees does Artex currently have?
We have 15 full-time employees, most of them are engineers and accountants. We do have some field people, too, that are foremen.

What kind of vendors does the company use?
Our list of vendors is 75 companies. It's everything. Oil and gas service companies of course, but everything - the local copier shop, the local computer support company, the local office supply company, cleaning services for the office.

How important is the oil and natural gas industry to Eastern Ohio?
In Eastern Ohio, the oil and gas industry is one of the stalwart industries in the area. What most people don't realize is that the modern oil and gas industry really starts in Ohio. Not taking away anything from our brethren in Pennsylvania. The first well was drilled in Pennsylvania, but within a month, they were drilling wells in Ohio and by the late 1800s, Ohio was the leading producer of oil and gas in the world. That's how Ohio became such a large industrial manufacturing state. We have a lot of manufacturers because we had the energy to run the businesses and we had molecules to make things. Most people forget that there are over 6,000 products made from oil and gas. A lot of those products are made here in Ohio. There are over a thousand businesses in Ohio that make products from plastics. When you have both energy and a market, it's a great place to manufacture things. The oil and gas industry has always been important, and the shale industry has really increased that importance.

We did a study with one of the groups I volunteer with and found that if Ohio, West Virginia, and Pennsylvania were our own country, we would be the third-largest natural gas producer in the world, behind only Russia and the rest of the United States. If you look at the energy that comes out of the Appalachian Basin, the energy equivalence is comparable to the Permian Basin. Natural gas is not only cleaner but if you look at the increase in natural gas production, and the savings to Americans, conservatively, over the last 10 years, it saved consumers $1.2 trillion.

How would the elimination of percentage depletion impact Artex Oil and Gas?
We're a good example of percentage depletion because the majority of the money that we've used to drill is our own company money. We're not a publicly held company. We can't go out and issue stock. Bankers just won't, for a small company, lend you money to drill oil and gas wells. They just won't. We have to drill out of cash flow. Because wells deplete, we have to continually replace our production every year. Hence, we need to redeploy as much capital as we can which is why you have percentage depletion in mineral industries. It's because your asset depletes and you've got to continually replace it.

If you had to pay higher taxes, you just wouldn't be able to drill as many wells, and therefore production would decrease. Then the whole American economy will suffer from higher prices. The lack of spending will hurt our communities. We're locals, we're much more engaged with companies that are in the community. The fracturing company we use is a small fracturing company located in Ohio. It's employee-owned. Whereas a lot of big companies may be reluctant to use a local company, we've used them for years. Millions of dollars aren't flowing somewhere else, it's flowing right back to the employees in the company right here. We're very open-minded about using the small companies that are embedded in our communities.

What other regulatory changes are you concerned about?
We're extremely concerned about methane emissions. When you look at stripper wells, they're not very large sources of methane at all. Eliminating methane emissions from them wouldn't make any difference to the climate whatsoever but it would destroy our economics. The new wells that we're drilling, we can afford to put on the methane emission reduction equipment, but our wells that have been out there 20 or 30 years we can't and don't need to.



Another thing people don't realize is that a lot of these wells are supplying income for a farmer and gas at their house. In the East, for a lot of people, their primary source of energy is from the well itself. They don't have utilities and the well is their source of heat. You'd not only destroy the economics and we'd have to plug the well, but you would eliminate heat for a lot of people.

What else do you think is important for readers of this report to understand?
What most people don't realize is prior to COVID, every recession for the last 50 years was preceded by a spike in energy prices. All energy prices are set on the margin and when you start having public policies that discourage energy production, you're going to send prices up. These recessions can have really negative impacts on the average person. That's what happens when you start banning stripper well production on the margins because it's 10% or 15% of U.S. production.

Let's say you've got a husband and wife, they're struggling, raising a couple of kids, and all of a sudden, you double the price of energy. It may be an extra $5,000 a year. Where's the average couple who's struggling going to get $5,000 more a year to pay these bills? All the prices set on the margin, most experts say when you look at the economic equations for every 1% that you adjust supply, the price will move about 10%. You may not be able to travel when you want to travel and you may not be able to work when you want to work because there won't be enough energy to have the lights on at the place you work.

> Bankers just won't, for a small company, lend you money to drill oil and gas wells. They just won't. We have to drill out of cash flow...which is why you have percentage depletion.

PRODUCER PROFILE - WEST VIRGINIA

SAM MCKOWN

McKown shares how his company supports his community and how the percentage depletion allowance is helping keep his business afloat.

WHAT TO KNOW

Location: 12 counties in West Virginia

Number of Wells: 400 operating

Employees: 20 individuals

About C.I. McKown and Son, Inc.
My parents and I started the company. Nine months later, my dad got sick, and I took it over far too young at the age of 22. Early on we bought wells from larger companies that were exiting West Virginia, such as Pennzoil and Ashland. Then later we started drilling our own wells. We currently have less than 400 wells in central West Virginia, in 12 counties, right in the middle of the state, which are all stripper wells.

How many people does C.I. McKown and Son employ?
We employ just over 20 people directly but also buy equipment and services from other companies. We buy oil and gas-specific items from primarily three suppliers. One is a medium-size regional company. The other two are small, locally owned suppliers that have been around forever. One of them is actually a producer like ourselves who started his own supply house. We buy a lot of auto parts from locally owned suppliers, as well as the larger national chains. We buy a lot of fuel; we buy a lot of electricity. One of our suppliers is in a small town near our office, it used to be a booming oil and gas town, of course, it's not now. He owns an oilfield supply store. He runs it himself and he has one employee. Of his business, I would guess three-quarters of it is from small independents. That's his livelihood, if there were no independent producers, his entire income stream would be gone, and there really aren't that many of us that he caters to, probably 20.

How important is your company and the stripper well industry to West Virginia?
Well, I'm biased, but I think it's very important. While my company is small, small producers on aggregate are very significant. We pay pretty fair. For West Virginia, it's well above the median income and we try to do the right thing. We provide health insurance and a retirement plan so they're good jobs for Central West Virginia. Another thing we've done is, and I've loved to say this for years, I like to be stable. A lot of people in our business tend to ramp up employees, especially when there's a lot of drilling going on. Ramp up employees in the summer and then lay them off in the winter, and that's just something we've never done. When we hire someone, it is full-time, and if they work out, it's for as long as we're in business, and we make that clear. It creates stability for the employees. I just never thought it was good for an employee to always think they may get laid off come November. That's just been my thing.

What would be the impact on C.I. McKown and Son of eliminating percentage depletion?
Percentage depletion is very important for us. Things are still bad in the industry, but they've improved a little bit. Percentage depletion is one shining spot in our industry right now. Even though right now most entities are posting operating losses, especially given what gas prices were last year, so depletion doesn't come into play. But one of the reasons we hang around is because hopefully it will be used in the future. I would be lying to you if I told you I was taking full advantage of it right now, just because the industry is so bad. I have always viewed it as just a little bit of relief for the fact that we're in a, by it's very name, depletable industry. By its nature, the value of my business is worth less every year, and that's different than most industries. I've always thought depletion was a little bit of an offset of that to encourage people to stay in business in a depletable industry.

Other than the ability to utilize percentage depletion how else does the stripper well industry differ from larger producers?
The percentage depletion cutoff is 1,000 barrels, that takes out all of the majors and big independents. They have to use cost depletion. We are just a completely different animal than the bigger companies, I won't even use Exxon and BP as examples, but large independents, or the unconventional gas that we have in the Appalachian basin right now. Our capital is raised completely differently. We sell our own labor. The economics are different. In the early days I bought wells from companies that would not qualify for percentage depletion, the economics of those just didn't work for them anymore. That's why they got rid of them. Without us those wells would hopefully end up plugged and not end up being as I would call it, wards of the state. We have continued to produce wells that otherwise would not have been. One of the reasons we're able to do that is percentage depletion.



How important is the natural gas industry to West Virginia?
We supply local utilities, even more so now because the local utility just bought a big gathering system. A lot of our royalty owners, the checks go out, and they're West Virginia addresses. There is also free gas for most of these surface owners. I would say we supply around 200 homes with free gas. Where we supply the utilities, it keeps their cost of gas down, because they don't have to store it. A lot of the utilities have to buy storage, and we're just a direct supply. Their cost of gas is much lower than it would be otherwise, which they can pass on to consumers.

> We have continued to produce wells that otherwise would not have been. One of the reasons we're able to do that is percentage depletion.

Are there any other regulatory concerns facing the industry in West Virginia?
Probably one of my biggest concerns about the new administration is where they may go with methane emissions on existing low-volume-producing wells. A vapor recovery unit is a small cost on a well flowing a few hundred barrels a day of condensate, and 5 million cubic feet a day in gas, versus a well that's only flowing five thousand cubic feet of gas a day. The economics just don't work at the smaller levels. Having said that, I love the environment. Nobody wants dirty air and dirty water. The emissions from the unconventional wells producing large volumes could really be significant. But the emissions off of an oil tank that we have on a well, that makes half a barrel a day, pale in comparison to that. I live in Charleston, West Virginia, and I remember as a kid, the air quality used to be so bad it would be nauseating. We've done so much to clean that all up.

PRODUCER PROFILE - MONTANA

PATRICK MONTALBAN

Montalban talks about his generational business and how the percentage depletion allowance keeps smaller oil producers in business.

WHAT TO KNOW

Location: Montana & North Dakota

Number of Wells: 410+ operating

Employees: 11 individuals + 2 contract pumpers

About Montalban Oil & Gas Operations
Montalban Oil & Gas Operations (MOGO) has been in business since the late '50s. My father started the company and I took it over from him. My son is the third generation to continue building the company. We currently operate over 410 stripper oil and natural gas wells. However, throughout our career in the industry, we have been involved with every sector of the oil and gas business.

How important are MOGO and the industry to employment in the areas where you operate?
We work hard as operators to treat our employees very well with a good benefits package. Many of our employees have worked for us for over 20 years. Oil and gas companies traditionally pay a much higher wage. It is like a few other local industries; such as the rural electric or railroad companies. We've been in the business for a long time and we understand that to have a good operation, you need to have loyal employees.



How important is the industry to the region, especially in rural areas?
You will find that stripper properties that are operated in rural communities are critical to the area because they provide high-paying jobs. Most of the people in the oil and gas business have an average income of between $50 and $80 thousand per year. Some of the jobs associated with the industry are rig operators, water haulers, truck drivers, roustabout crews, etc. These service entities would not exist if not for the local stripper well operators.

The stripper well industry is extremely important to rural communities, as it provides high paying jobs. The money stays in the rural communities and adds to the local tax base, providing support for schools, hospitals, and other small businesses, restaurants, bars, grocery stores, etc. It takes a company the same amount of time, effort, and cost to produce a three-barrel-a-day well as it takes to produce a 300-barrel-a-day well. The bottom line is that stripper wells still create jobs.

What role does the stripper well industry play in producing older fields that may have been developed by larger companies?
The way it works, in our business, is that a lot of these fields were discovered back in the 1930s and 1940s. The Cut Bank field was discovered in the 1920s. It was developed by independents until the 1940s and 1950s. Then, major oil companies moved in. We had Exxon, Phillips, Conoco, Unocal, just about every major oil corporation here at one time, until they sold out. The latest acquisition that we made, almost a year and a half ago, was a property originally developed by Unocal in the 1940s to 1970s. They sold it to a larger independent in the early 2000s. This company had it for 18 years, and then we, as a small independent stripper producer, bought it. These stripper properties are always going to return to the local small independents.

How damaging would it be for the industry if percentage depletion were eliminated?
The depletion allowance is extremely important to the oil and gas industry because for stripper businesses these wells are not making 20 to 100 barrels a day. These wells are only making 1/2 a barrel to two barrels a day. When you take away 15% of your income by eliminating the expenses that we are allowed to take on these wells, it is very drastic because of the very low volumes and very low income at low prices for the commodity. It is also very critical to our mineral owners who also take advantage of the depletion allowance.

> If we did not receive the depletion allowance, you would see several wells shut down. If we plug these wells, that income is no longer generated, jobs are lost that created taxes paid by employees, and no money flows back into the local communities.

Many of the incentives that larger companies receive are not available to stripper well producers. For example, the foreign tax credit is an incentive for the major oil companies to develop natural resources around the world. This is not an incentive that benefits the stripper operator. Intangible drilling costs can be a benefit to stripper operators when the price of oil allows for development with internally generated cash flow. Thus, one of the only tax incentives that benefits small stripper producers is the depletion allowance. The important thing about the depletion allowance is that it enables us to produce half, one, or two-barrel-a-day wells for a longer period-of-time and delays the need to plug and abandon the wells. It allows us to keep our costs down when the price of the commodity is down. If we did not receive the depletion allowance, you would see several wells shut down. If we plug these wells, that income is no longer generated, jobs are lost that created taxes paid by employees, and no money flows back into the local communities.

How important is the depletion allowance when oil prices are low?
Most people do not realize that when the price of oil goes down, our service costs do not go down. One of the largest costs of producing a stripper oil well is electricity. If our price goes from $50 a barrel to $20 a barrel, we still have the same cost for electricity and the same cost for chemicals. That is why the depletion allowance is so important to us. We do not see the cost of hauling water, service rigs, backhoes, and other services for these wells decrease. In these rural communities, there are only one or two different service companies from whom you can get a competitive bid. The depletion allowance allows us to operate stripper wells economically at low crude prices.

Can you speak to the pricing differentials companies in areas like Montana receive?
Yes, I think that it is a very critical part of the oil and gas business. When you watch Bloomberg, CNBC, or Fox and see the price of oil, it is based on WTI (West Texas Intermediary). We are currently receiving a $9.50 differential from that posting. Essentially, our price at the wellhead is $9.50 less than the posting price people see in the news. In Billings, Montana, where there is local refining, they can pick all the barrels that they want from Alberta and ship them via pipeline. That is what we compete within our area, the Alberta barrel. The important part is to look at the net value of what we receive for our barrels. We are producing in a very rural area and far away from the Cushing area of Oklahoma where prices are set.

NICK POWELL

Powell explains how he got started in the oil business and how the percentage depletion allowance supports micro businesses and small communities.

WHAT TO KNOW

Location: Eastern Kansas

Number of Wells: 800 operating

Employees: 32+ individuals

How was Colt Energy founded?
The Colt family started this business back in the 1920s. It's an almost 100-year-old company that has always operated in Eastern Kansas. Our headquarters for operations is Iola, Kansas in Allen County and we produce across Eastern Kansas.

How did you get involved in the oil industry?
I got started in the business working for a trucking company back in the 1970s. The trucking company was consuming about a quarter of a million gallons a day of diesel fuel, and I was doing the purchasing of the fuel. They decided to get into the oil and gas E&P business like many other utilities and transportation companies were doing as a result of the oil embargo. We were being allocated 80% of last year's sales by suppliers of diesel. They started a company called Overland Energy as a subsidiary and got into investing with other E&P companies and I managed that.

In 1981, the trucking industry was deregulated. When they got out of the energy business, I decided to stay in the oil business in Kansas and then I made an acquisition of the Mack P Colt Energy company in 1986. That was really my move into the industry and we then changed the name to Colt Energy. We grew from about 125 barrels a day up to 800 barrels a day by 1998. In 1998, the price of oil then dropped drastically again from the mid-30s back down to 12. We currently do about 400 barrels a day of crude oil production and just under 2,000 cubic feet a day in gas production.

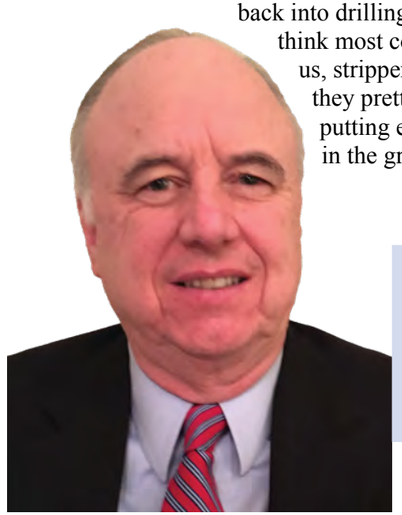
How many people does Colt Energy employ?
We've got 32 full-time employees currently and a few part-time people on top of that. Of those, about six of them are based in Kansas City and most of the rest are based in Allen County, but we also have some down in the south. So, for the most part, they are in smaller towns.

Most of our employees are field employees who are not college-educated. We have our pumpers to manage our leases. We have crews to do our own small scale well workovers like repairing downhole problems. Then we have a team that repairs and installs tank batteries and production lines. We do all those things in-house, and outsource all of our drilling and completion work.

How many new wells did Colt Energy drill in the last year?
We drilled four this year so far, including some in December and some in January that were more exploratory. If pricing stays where it currently is for another few months, we'll probably be looking at starting a drilling program in the spring or summer. We operate in an old field and we're just drilling to see what's left behind. Our wells are generally less than 1,200 feet in depth. Typically, 500 to 1,300 feet in depth for oil, and for gas a little deeper. Our average well makes a barrel a day or less.

That's what separates us from larger companies, and it's why we're the type of people who can take advantage of percentage depletion because it only covers the first thousand barrels a day. The majors have single wells that produce a thousand barrels a day. We're on the lower end of wells in Kansas that produce on average 5 barrels or less per day with an average production of a barrel a day or less per well.

What would be the impact on Colt Energy of eliminating percentage depletion?
When you look at percentage depletion for these stripper wells, most of these old wells have already used up all their cost depletion and so the only way to be able to reduce the tax burden is through percentage depletion. These are also low-margin wells because it costs a lot more in terms of man-hours to manage so many wells to get so little oil, so we've got higher operating costs per barrel, high lifting costs, whereas the majors might be $10 a barrel, we've got thinner margins, no cost depletion, and so that percentage depletion of 15% of gross income on a well that may only have 30% operating margin when oil and gas prices are good, it's a big impact on your taxable income and then dollars that can be put back into drilling and hiring. I think most companies like us, stripper oil producers, they pretty much end up putting everything back in the ground that they are earning in order to maintain their production. So, if you eliminate percentage depletion then you just take that off our cash flow and we drill less, see slower to no growth rates, and fewer, if any, people hired.



> I think most companies like us, stripper oil producers, they pretty much end up putting everything back in the ground that they are earning in order to maintain their production.

How would eliminating percentage depletion impact Kansas and the communities where you operate?
Kansas, in particular, is almost exclusively a stripper well state. We have a lot of old wells where if you eliminated percentage depletion, you'd take a big chunk of wells and they'll just knock-off into the uneconomic category. We're people-intensive, when we're putting dollars into new wells, the ratio of that money going to people instead of steel and drilling rigs is much more people-intensive. A bigger share of our investment goes back into jobs instead of steel that is imported from overseas, it drives right back into local hiring.

That hiring helps small communities that are struggling. In states like Kansas, we've become a pretty good employer in the areas we operate in. We have good jobs in the industry. We pay an average of over $20 an hour. Our field employees average 45 hours a week based on nine-hour days, and we provide health insurance, 401(k) matching, and vacations. Many of the people we hire were making less than $15 an hour or making $15 an hour with no benefits. If you lose those jobs, that's a loss for the communities as well. In a town of 6,000 including the surrounding community, these jobs are important. In these communities, there are not very many employers who offer jobs that pay $55,000-60,000 a year or better plus full benefits.

DICK SCHREMMER

Schremmer shares when he started his first oil and gas business and how the percentage depletion allowance has allowed him to succeed.

WHAT TO KNOW

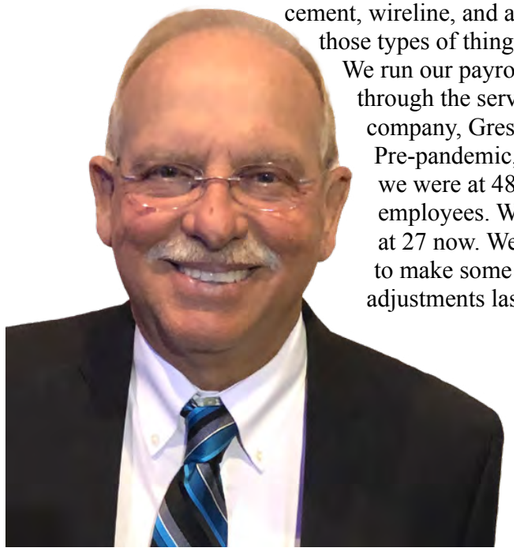
Location: 25 counties in Kansas

Number of Rigs: 13 well service rigs

Employees: 27 individuals

About Bear Petroleum.
I started Bear Petroleum in 1985. I had previously been with Gulf Oil where I was a production supervisor for 12 years. I went out on my own in 1985 and put some money together to drill a few wells, and then I've just grown the company from there. We operate in 24 counties in Kansas, and one county in Oklahoma. We're scattered from the Colorado line belt to Eastern Kansas, all the way north to Nebraska.

How many people does Bear Petroleum employ?
Bear Petroleum doesn't have any employees. I also own a service company named Gressel Oil Field Service. We use that company for most of our services and supplies such as acid, cement, wireline, and all those types of things. We run our payroll through the service company, Gressel. Pre-pandemic, we were at 48 employees. We're at 27 now. We had to make some major adjustments last spring when the low prices hit because we didn't know how long it was going to last. We shut down two wells servicing crews and a tank truck, plus a couple of other things. We're pretty self-sustaining. We do electrical service work, we have acid, cement, a wireline company as well as field supply stores. We also have downhole pump shops, and a packer, plug, and tool rental business. We've got 13 well service rigs, though we're down to just two crews. We're trying to get more started up, as we've been working four or five contract crews lately. We use a few different tank trucks and pulling units from outside the company.



You mentioned Bear Petroleum operates in 25 counties, what are those counties like?
They are all rural counties except for Sedgwick County, which would be the county that Wichita, Kansas is in. Other than that, most of them are really rural. When you get up to areas around Western Kansas, Morton County, and up North in Decatur County by the Nebraska line, it gets pretty rural.

How do the jobs you offer compare to others available in the communities where you operate?
Oh, there's no doubt they're good jobs. Our minimum wage, we start people out as $13 per hour on the well-servicing rig. If they're around very long at all, they're making $18 or $20. Other jobs like wireline, propane, acid, are all Department of Transportation certified and pay even more. I have to have more experienced and qualified drivers for those jobs, with Hazmat licensing. We've got good-paying jobs for the industry, and we have full health insurance and 401ks we fund, as well as safety programs. In these communities, the people that work for us are doing very well.

What would be the impact on these communities if oil and gas jobs were to go away?
Well, it would be huge because these people wouldn't have the money to go to restaurants and they wouldn't have health insurance to go to the doctor. It'd make a big difference. There's just lots of money being spent that comes from the industry. In Kansas, for many years, oil and gas has been the second biggest moneymaker for the state. It creates a lot of jobs and creates a lot of tax dollars for roads, schools, etc. It would be a huge impact to lose those jobs.

What has been the impact on Bear Petroleum of recent low oil prices?

Our biggest cost in producing stripper wells in Kansas is our electrical rates. We've got wells that lift a lot of water to get a barrel of oil and, due to those high lifting costs, we just couldn't afford to produce those back through June. We didn't have any choice but to shut them down.

Then once you're shut down, there's always an expense to starting back up. You have to have your cash flow up to where you can afford to turn these wells back on. As we've come into the end of the year, we still have wells down that we shut down last March. We're trying to get them back on now, but want to make sure we've got the money to pay our bills at the end of the month.

What is your biggest regulatory concern right now?
Methane emissions regulations are one of our biggest concerns. The initial study on methane emissions looked at wells around the Dallas–Fort Worth airport, and those wells were leaking pretty badly. They just took those numbers and ran them across the board for the rest of the United States.

In Kansas, for many years, oil and gas has been the second biggest moneymaker for the state. It creates a lot of jobs and creates a lot of tax dollars for roads, schools, etc. It would be a huge impact to lose those jobs.

I'm part of the Kansas Independent Oil and Gas Association and we funded a study to see what kind of methane we were leaking. They came up with hardly anything. As a matter of fact, they sent their meters in for repair because they didn't think they were working because they weren't coming up with any methane gas. That tells us that the stripper wells are not the big problem with methane gas.

When they come out with a one-size-fits-all regulation, "it has to be the same for each installation," then the small producers will be forced out of business and all our jobs will be lost. Our economics just don't work. We're independent and we own the wells. We're putting our own money in it, it's not investor money, it's not Wall Street money, it's not stock money. It's money that we've gone out and raised ourselves and we put it back into our business.

Is there anything else you think readers should know about the industry?

In the Midwest, and Kansas again, we're actually the oil reserve for the country. When we need it, when the price goes up, that's when we can afford to produce it. When the nation has too much oil and the price goes down, we don't produce as much oil because we can't afford to do it with our lifting costs. You give us $60, $70, we'll go out there and start producing the oil and drilling wells and getting things done. Without that, when you go to a gas pump, the price of gasoline will be higher, people may not be able to afford to heat and cool their house.

DARLENE WALLACE

Wallace shares about her experience in the oil industry and the impact of the potential elimination of the percentage depletion allowance.

WHAT TO KNOW

Location: Seminole County, Oklahoma

Number of Wells: 20 operating

Employees: 2 individuals

Tell us about Columbus Oil Company.
Columbus Oil Company was established by my husband in 1971 in Seminole County, Oklahoma, and is still based in the city of Seminole. He started it in '71, we married in '79, he died in 2004, and I've been running it ever since. Seminole is still pretty active in the oil and gas business. Back in the '20s, it was the largest oil field at the time. Now, almost everything is stripper wells. It's a very small operation and has always been somewhat of a mom and pop organization.

How many employees do you have?
Right now, it's just me and my field manager. We source everything else out. My field manager has been with me now for 27 years.

How many wells do you operate?
We operate 20 wells in Seminole and Pottawatomie County, which are side by side. We can drive to all of our wells in one day, even though it's a rural area.

What kind of services does Columbus Oil contract for to support your operations?
For paperwork and administration. I contract things out to our accountants, and my five pumpers are contracted. The people that do work on the wells themselves, pumping units, roustabouts, hot oil treatments, trucks that haul water, are all contracted. We also buy supplies here in town. We have electricians, welders, chemical companies. Whatever goes on in the oil business, we use.

How important is the stripper well business for the communities where Columbus Oil is located?
Oil is a good business for rural areas. You have the opportunity not to live in a crowded urban area and you get that small-town atmosphere. Everybody knows everybody. That includes in the business. We know all the service companies and they know us. We do business with everybody and we support each other.

Tell us about your wells.
All of our wells are vertical stripper wells. Most of the oil companies in this area are small stripper well producers employing eight or nine people, many even smaller. The husband takes care of the field, the wife takes care of the books, and they have one person that helps them do everything else. For everything in this town, including the schools, the oil business is probably 80% of the tax revenue. It trickles down to the grocery stores, the restaurants, and the churches.



How does oil support other organizations in your community?
We're a member of the Chamber of Commerce for the town. All those things that our community has the oil and gas industry helps keep alive. When times are good, we give money to all these organizations. We also have a junior college where we give out two scholarships every year. Most of the producers in this area are like that. We're just a small community of people helping each other make a living.

How important is percentage depletion to companies like Columbus Oil?
I am truly one of the smaller producers. I've got some wells that I haven't switched back on since April 2020, when we had to shut down all of the wells for two months until prices got back up. Percentage depletion has allowed me to keep my wells in really top-notch running condition. If a well goes down, I have the money in my reserve to fix it or to do an acid job or change a pump. Percentage depletion helps small producers keep wells viable. If you don't take care of your wells, they can't produce. If I can't change my pumps every year or so, they wear out just like everything else and wells start declining. When you change a pump out, you've got to buy the pumps, you've got to have the crew, you've got tank trucks out there to flush it out. All these things cost money, and percentage depletion helps us do them. Without percentage depletion we would see a decline in the industry, and the areas we live in can't afford that.

How could Seminole be affected if percentage depletion was eliminated?
Seminole is pretty small, about 6,800 people, but we are the largest city in the county. It would be devastating if the oil and gas business really gets any worse for this town.

Oil companies do things like buying the equipment for the football, basketball, track, and cheerleading teams.

How do you help people who are affected?
I was born and raised in the DFW area and then lived in New York City for two years when I left home after high school. In big cities like New York or Dallas, you do not see how these things affect people because there's so much industry in large towns. We have a huge low-income housing development because getting those people to move to rural areas helps them get housing, health care, and jobs. You see people who can't get a job in the city come down here without an education, without a lot of skills, and they can get a pretty decent job when the oil field is going well. We know our neighbors from the churches and community centers, and if you know your neighbor hasn't worked for six months you see if you can't help him get a job. That's how small rural towns do things. We work with what we've got and to make it good for everybody.

> Percentage depletion helps small producers keep wells viable. If you don't take care of your wells, they can't produce. Without percentage depletion we would see a decline in the industry, and the areas we live in can't afford that.

J. NELSON WOOD

Wood explains how the oil price downturn hit his company and how the percentage depletion allowance impacts his community.

WHAT TO KNOW

Location: Illinois Basin

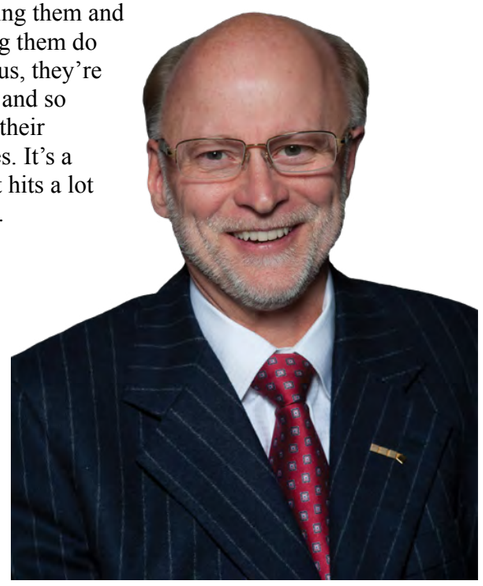
Number of Wells: 160 operating

Employees: 13 individuals

About Wood Energy
Our company had its beginning in 1952 in Illinois. It was formed by my mother and father. My mother got into the oil business in 1938, my dad in 1948. They eventually formed a partnership and created our company in 1952. They are both deceased, and I've taken over. We started as, and remain, a small independent company drilling and operating oil wells in the Illinois Basin. We operate around 160 wells, the average production two barrels a day.

How many people does Wood Energy employ?
We presently are at 13 full time employees due to the downturn and the pandemic. Historically, we have had around 25 employees. My three supervisory personnel have high school educations, but they command six-figure wages because of their abilities and their leadership. Southern Illinois, particularly, is an economically depressed area and there are not a lot of jobs with those types of salaries. All of our jobs, our laborers, rig hands, and roustabouts all make more than minimum wage. I have several long-term employees that have been with me in excess of 10 years.

What types of goods and services does Wood Energy purchase?
Wood Energy purchases casing, tubing, rods, and other products to operate and drill wells from supply stores, hardware stores, and plumbing supply stores. We outsource a lot of our well repairs, infrastructure repairs, pipe repairs, that sort of thing to third parties. There are several companies that have existed here since the 1950s or 1960s, they're still in business and our spending hits them directly because if I'm not buying supplies from them, hiring them and not having them do work for us, they're impacted and so are all of their employees. It's a chain that hits a lot of people.



How has the oil price downturn impacted you?
In April, we did not sell a barrel of oil. That's the first time our company has not sold any oil in a month since 1952. We were hanging on trying to survive, but it's been very difficult. Due to the layoffs we are all taking on more responsibility and duties to keep the doors open. As is the case with any business of commodities, we are governed by that commodity price. Because of the slight recovery in oil prices, we're starting to see a little activity, not near as much as there needs to be, but I do see things improving a bit slowly because we can't turn things right back on, particularly the wells that were shut in as the pandemic raged. For many of those, you can't just flip the switch and turn them back on. We're having to go back in and do repairs. We're in the process of that, and I think many other companies are. We're certainly not back up to optimum levels. As far as drilling, I have projected that I'm going to try to drill two new wells this year, that's what I hope to do, which is down from my normal average of five to six wells a year, so it's about half or less than half of what I normally would have done.

How would eliminating the percentage depletion allowance impact the industry in Southern Illinois and the communities where it operates?
Eliminating the depletion allowance would be devastating because the wells we have are stripper wells, therefore we have to go back out and replace barrels that deplete every year. Every company in Illinois has a minimum of around 5% a year of loss in production due to natural declines in the reservoirs. If you're not replacing those barrels, either by drilling or acquiring new production you are withering away. If you have a 20-year life cycle, then you're completely without anything. If you're not going back and drilling and finding new production, you go away and your employees go away. The depletion allowance allows us to take that money to drill and acquire more wells to keep our company viable. When that resource has been depleted, we can't go back and tap it anymore. We're not like a factory that can keep producing widgets. We have to have incentives to go back out. They're not subsidies, we're not handed a check by the government for this. This is just a deduction, just like any normal business does under normal business activity.

Eliminating the depletion allowance would impact everyone that touches our company and most importantly our employees' lives. In Illinois, we have over 4,000 direct employees in the oil and gas industry. That exceeds coal or any other natural resource in Illinois and those jobs would be at risk.

> "Eliminating the depletion allowance would impact everyone that touches our company and most importantly our employees' lives. In Illinois, we have over 4,000 direct employees in the oil and gas industry.

How does the stripper well industry differ from the rest of the oil and natural gas sector?
We are typically lumped in with major integrated companies, with all of the oil and gas industry, but are a separate and distinct part of the industry. We are small business people who risk capital and explore to find new oil in the U.S. not overseas. Independents find almost all the new oil and gas in the continental United States and develop it. If we're gone, then we have to go to unstable sources overseas such as Saudi Arabia and other OPEC countries. It helps shape our foreign policy; it does many things. The stripper well industry is the small independents, but collectively we amount to a lot. Most areas where stripper well companies operate are also in economically depressed areas. We are in areas that need jobs and need the stable jobs that we provide.

JOHN YATES, JR.

Yates shares how his family company evolved and how the percentage depletion allowance is for the small producer.

WHAT TO KNOW

Location: Eddy & Lea Counties, New Mexico

Number of Wells: 5 operating

Employees: 20 individuals

About Abo Empire.
The company started when my sister and I merged our old family companies. A lot is owed to our ancestors including grandparents, whom we never met, and our parents, who laid the groundwork for the businesses that we participate in. It's all because of their foresight and risk-taking acumen. We had some remnant of leaseholds, leftover properties that were mostly marginal, some undrilled federal acreage in New Mexico, and we had working interests in other people's operated properties.

My sister and I decided that our family would continue on in the industry in a smaller way. We called our new company Abo Empire. Most of our production now is from stripper wells and as a small producer, we are challenged here in New Mexico with all the regulatory issues. Most of our wells don't make enough production, especially at low oil prices, or low gas prices, to be very economic, even in good times, and they are especially uneconomic in bad times. Our bread and butter is just trying to make these marginal wells pay.

Where do you operate?
We operate in Eddy County and Lea County here in New Mexico. Those are the two prominent counties in New Mexico, then in the Delaware Basin.

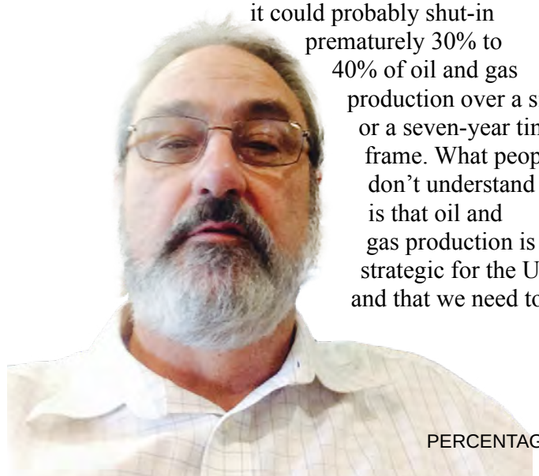
How many employees does Abo Empire have?
We have about 20 employees. Whenever there are low oil prices, people don't appreciate the fact that we're continuing to produce, and we still have to pay our employees. Our costs don't come down with the price of oil. Our employees mostly have been fine during COVID, and we didn't have to lay anybody off. Lots of people around us did, and a lot of businesses went under. A lot of the employees here have been with us for a long time. Some of these people have worked for us as many as 40 years, and others 30, and some 20. Most of our employees are long-time employees.

What types of services do you buy to support your operations?
Most people that are in the field, that are pumping wells and working on wells. Mainly because our production that we operate is mostly really marginal so we use outside contractors to pump the wells. We hire pulling and workover units. Occasionally, we ourselves drill, but mainly our partners do and they hire drilling rigs and fracturing crews. It's sometimes the kind of thing where a guy lives up by a well and checks on it every day. It can be like a mom-and-pop type thing.

How do these jobs compare to others available in the communities where you operate?
For sure, these are good jobs. I would say most of our bookkeeping folks have just learned the job by doing, for example, but don't have advanced education. But there are some people that have degrees or have parts of degrees. A lot of what our people do is just by experience. I think that for every job that's in the office, the 15 to 20 employees that we have, there's probably a multiplying factor of two and a half to four times, of other jobs that are created in the community that would be lost if these jobs went away. The state of New Mexico receives a third of the state budget from our industry as well so, anything that impacts the industry will impact that also.

How would the elimination of the percentage depletion allowance impact companies like Abo Empire in New Mexico?
I think it would really hurt the small independent operators if percentage depletion were eliminated. To me, percentage depletion is for the small producers. It may not be good for the majors of the world who make different decisions because they have upstream and downstream operations. It's helpful to build capital so that we can reinvest. It would get a lot harder to operate marginal wells as the economics just wouldn't make sense.

If we lost percentage depletion in New Mexico, it could probably shut-in prematurely 30% to 40% of oil and gas production over a six or a seven-year time frame. What people don't understand is that oil and gas production is strategic for the U.S., and that we need to support plenty of reliable cost-effective energy. Cost-effective strategies where we don't pay high prices for electricity and saddle people with costs that they just can't afford.



> If we lost percentage depletion in New Mexico, it could probably shut-in prematurely 30% to 40% of oil and gas production over a six or seven-year time frame.

Is there anything else you think readers should understand about the oil and gas industry?
Many of the countries where oil is produced have terrible environmental records. In the U.S., the industry is far better at doing things right. We're much better stewards of the land here in the U.S. We're also innovators that have brought a lot of new things to the fore in the last 60 years including fracking which started basically after World War II.

My dad was at the forefront of trying it over here, he was probably the first operator in the Permian to frack a well and it worked. Of course, he had to learn about it. He was an avid reader, he found out about it and he took a big risk, but it worked. We are always trying to uncover new technologies that are coming to the fore to make production more efficient, and also potentially even be more benign to the environment. These technologies may really take off, but it takes a lot of money upfront and we don't know what the results could be. The domestic industry is good at promoting novel technologies and startups. Finally, when state and federal governments provide encouragement by making terms reasonable to justify taking risks, by having risk profiles commensurate with the potential of suitable rewards, that is the key to encouraging entrepreneurship and stewardship.

GLOSSARY OF TERMS

COST DEPLETION

One of two accounting methods used to allocate the costs of extracting natural resources, such as oil and natural gas, and to record those costs as operating expenses to reduce pretax income.

EXPLORATION & PRODUCTION (E&P)

The early stage of energy production, which includes searching for and extracting oil and gas.

GROSS DOMESTIC PRODUCT (GDP)

The total value of goods produced and services provided in a country, state, or another area during one year.

GROSS INCOME

For a business, also known as gross profit or gross margin, includes the gross revenue of the firm less the cost of goods sold, but it does not include all of the other costs involved in running the business.

IDLE WELL

A well that is not producing or injecting and has received state approval to remain idle.

INTANGIBLE DRILLING COSTS (IDC)

Costs related to drilling and necessary for the preparation of wells for production, but have no salvageable value. These include costs for wages, fuel, supplies, repairs, survey work, and ground clearing. They compose roughly 60 to 80 percent of total drilling costs, and are 100 percent deductible in the year incurred.

INVESTMENT CAPITAL

The money used to acquire plants, equipment, and other items needed to build products or offer services. Investment capital is also referred to as financial capital. In the context of the oil and natural gas industry, it typically refers to outside investment capital.

MAJOR OIL & GAS COMPANIES

Typically the largest of all oil and gas companies that are vertically integrated and directly involved in exploration, production, refining, transportation, and marketing.

MARGINAL WELL

A marginal well definition is about economic viability, whether the extraction of oil and gas is profitable. To define a particular well as a marginal well depends on oil prices, and the cost of production, unlike a stripper well that has a definite output attached. Stripper wells tend to be marginal wells, but a marginal well might not be a stripper well.

NET INCOME

Calculated as sales minus cost of goods sold, selling, general and administrative expenses, operating expenses, depreciation, interest, taxes, and other expenses.

PERCENTAGE DEPLETION

A tax provision that allows oil and natural gas producers to recoup some of the costs involved in exploring for and producing oil and natural gas. Percentage depletion is calculated by applying a 15% reduction to the taxable gross income of a productive well's property. The reduction is determined on a property-by-property basis and is limited to the taxpayer's first 1,000 barrels of oil (or 6,000 Mcf of natural gas) of production per day. It is also capped at the net income of a well and limited to 65 percent of the taxpayer's net income.

PLUGGED AND ABANDONED

Wells that have had plugging operations during the calendar year. It does not include wells that have been plugged back up-hole to kick the well, etc. This category does not necessarily exclude those with site restoration remaining to be completed.

ROYALTY OWNERS

Ownership of a portion of a resource or the revenue it produces. A company or person that owns a royalty interest does not bear any operational costs needed to produce the resource, yet they still own a portion of the resource or revenue it produces.

STRIPPER WELL

For tax purposes, a stripper well is defined as any oil or natural gas well whose maximum daily average oil production does not exceed 15 barrels of oil, or any natural gas well whose maximum daily average gas production does not exceed 90 Mcf, per day, during any 12-month consecutive time period.

TEMPORARY ABANDONMENT

Cessation of work on a well pending determination of whether it should be completed as a producer or permanently abandoned. A temporary abandoned well can include wells that were formerly producing but are temporarily abandoned, waiting on a decision to restart or plug.

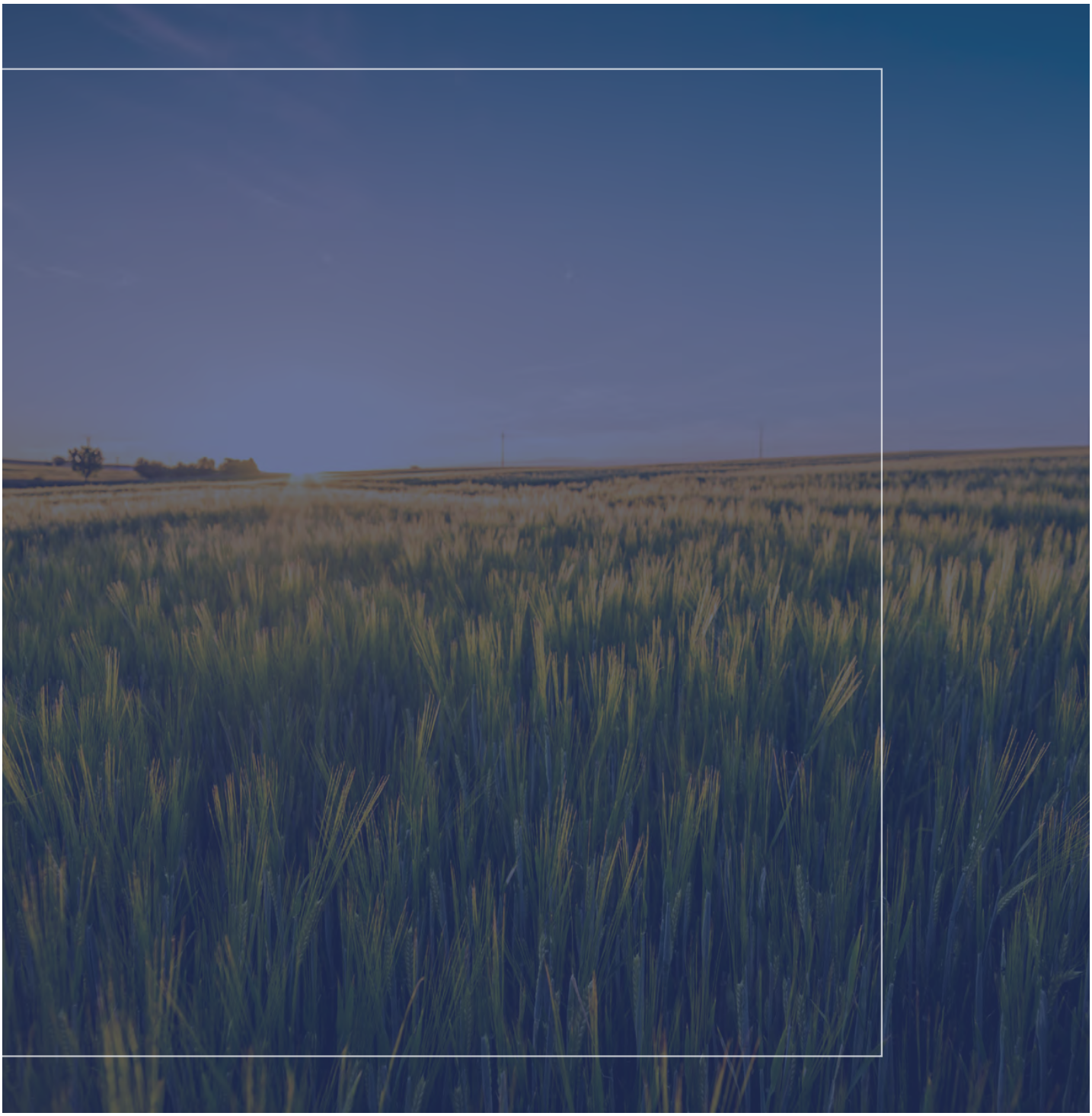
SOURCES

Energy & Industrial Advisory Partners [2021, February]. The Economic Impacts of Eliminating the Percentage Depletion Allowance

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National Association of Royalty Owners, U.S. Senate Committee on Energy and Natural Resources Hearing (February 4, 2010)

EXHIBIT 30
EXHIBIT A



2313 N. Broadway, Ada, Oklahoma 74820

(405) 228-4112

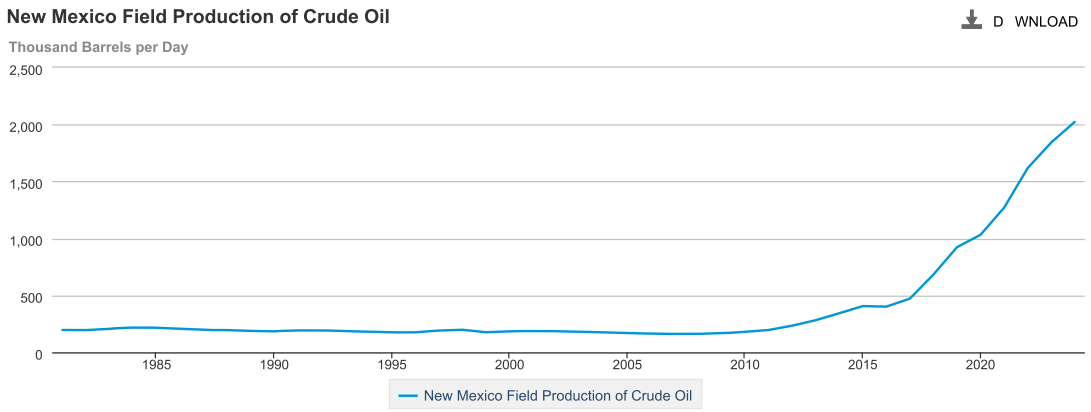
admin@nswa.us

www.nswa.us

National Stripper Well Association

Petroleum & Other Liquids

View History: ○ Monthly ○ Annual | Download Data (XLS File)



eia Data source: U.S. Energy Information Administration

This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

New Mexico Field Production of Crude Oil (Thousand Barrels per Day)

Decade	Year-0	Year-1	Year-2	Year-3	Year-4	Year-5	Year-6	Year-7	Year-8	Year-9
1980's		196	195	206	217	215	207	198	195	188
1990's	184	193	191	187	180	177	176	191	198	176
2000's	184	186	185	182	176	167	163	162	164	168
2010's	180	196	234	282	343	406	401	472	683	923
2020's	1,032	1,270	1,617	1,842	2,023					

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 8/29/2025
Next Release Date: 8/31/2026

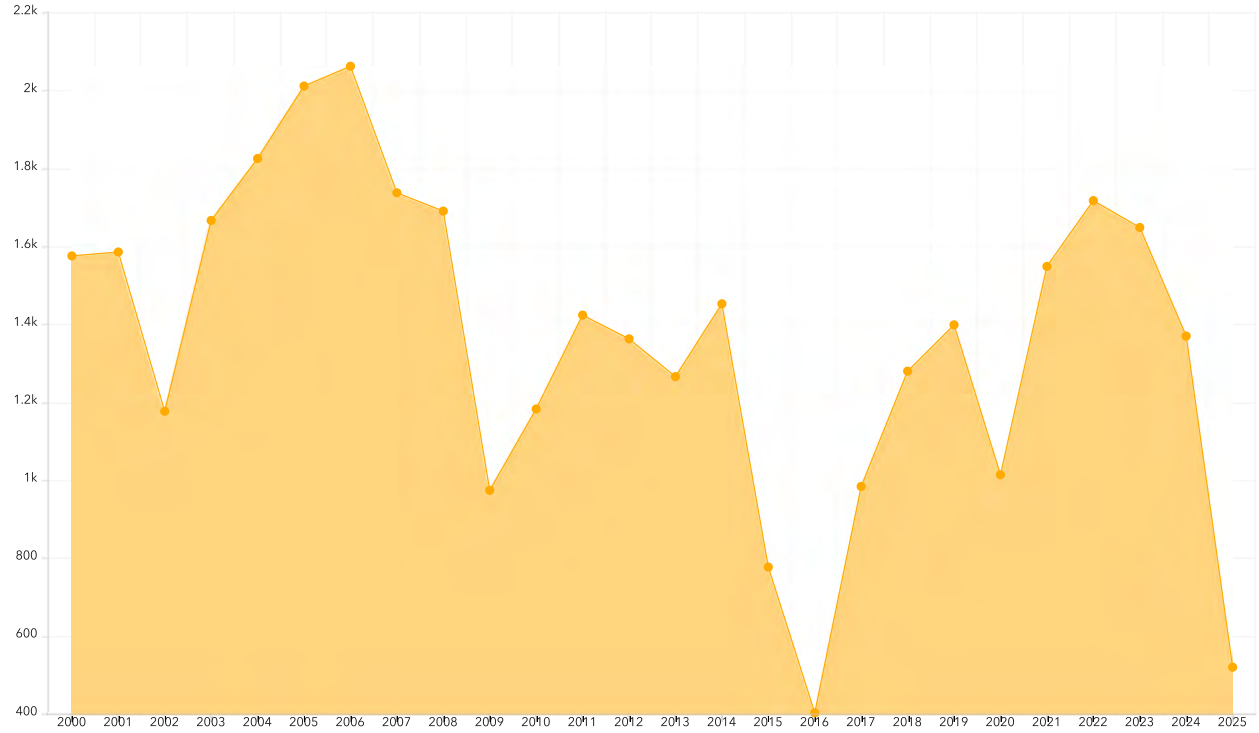
Referring Pages:

OCD Geospatial Hub

The Oil Conservation Division (OCD) is developing a geospatial hub enabling access to interactive maps, tools, and geospatial data related to the oil and gas industry in New Mexico. This website is a work in progress and is provided as a public service for informational purposes only. Information provided within is not intended to be used as an authoritative public record for any geographic location and may not be suitable for legal, engineering, or surveying purposes.

OCD Oil and Gas Overview	Filter by Well Type	Filter by Well Status	Filter by Lease Type	Select by County
	No category selected	No category selected	No category selected	No category selected

Wells Spudded by Year



Oil Production

EXHIBIT 30

STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

REBUTTAL TESTIMONY OF T. CALDER EZZELL, JR.

Intervenor Independent Petroleum Association of New Mexico submits the following rebuttal testimony of T. Calder Ezzell, Jr.:

My name is T. Calder Ezzell, Jr. I have previously discussed my qualifications and background in my Direct Testimony submitted to the Commission on August 8, 2025. There is one other item in my background that is pertinent to this Rebuttal Testimony in addition to the qualifications I have already discussed. In particular, my wife served ten consecutive terms in the New Mexico House of Representatives and, in 2024, opted not to run for reelection to her House seat and successfully ran for an open New Mexico Senate seat. In short, she has served in the New Mexico Legislature for 21 consecutive years, through 2025. The names and duties of various committees in the House of Representatives can change over time. However, for almost all my wife's tenure in the House of Representatives and her one year in the Senate, she has served on committees responsible for considering proposed oil, gas and other energy legislation.

Although the amount of time can vary somewhat depending on whether we have someone looking after our agriculture properties and other demands for my time in Chaves County, for the past 21 years I spent most of the time in each Session of the Legislature with my wife in Santa Fe. Given my background, I generally assist her and

others on the various committees considering oil and gas legislation in analyzing bills and working up amendments. Additionally, during each of the Sessions my wife has served, I have actively participated in an ad hoc group organized by the New Mexico Oil and Gas Association that analyzes bills that effect the oil and gas industry and discusses the strategy respect to such legislation. In short, I have in depth personal knowledge regarding all the legislation pertaining to the oil and gas act and other statutes pertaining to oil and gas exploration and production activities in New Mexico for the past 21 years.

In my Direct Testimony, I mentioned that I have definitive views about the powers of this Commission to enact the current rulemaking but did not offer opinions. In my experience with judicial bodies, judges typically do not accept testimony from witnesses on such purely legal matters. However, from reviewing the testimony submitted by Applicants, there are non-lawyers commenting on this Commission's power to enact the proposed rulemaking. If the Commission is going to consider that testimony, I am submitting this Rebuttal Testimony to offer my opinions as well.

1. The Commission's Powers Generally.

As an initial matter, I observe that this Commission is a creature of statute. It has considerable authority granted to it by the Legislature (as approved by the Governor) in the form of the Oil and Gas Act. However, as a creature of statute and part of the executive branch, its powers are only those granted by statute, circumscribed by statute, and not implied. As the New Mexico Supreme Court stated: "The Oil Conservation Commission is a creature of statute, expressly defined, limited and empowered by the laws creating it."[1]

[1] *Continental Oil Co. v. Oil Conservation Comm'n,* 1962-NMSC-062, ¶ 11,373 P.2d 809 (citation omitted).

For instance, in 2005 this Commission adopted a rule allowing the Division the ability to assess civil penalties. At the time, the Oil and Gas Act authorized the Attorney General to file suit to pursue civil penalties for violations of the Act.[2] The Commission argued that its broad powers over matters covered by the Oil and Gas Act and the silence in the Act as to who assessed the penalties permitted the Commission to authorize the Division the power to impose civil penalties for violations of the Oil and Gas Act.[3] The Supreme Court clearly ruled that the Commission did not have that authority.[4] As the Supreme Court stated: "we defer, as we must, to the Legislature for the grant of that authority, and so too must the Commission."[5] Subsequently, the legislature amended the Oil and Gas Act to permit this Commission to adopt regulations concerning civil penalties and imposed civil penalties consistent with the provisions of the Oil and Gas Act and this Commission enacted rules concerning the imposition of civil penalties for violations of the Oil and Gas Act and regulations promulgated thereunder.

2. The Commission's Powers Concerning Financial Assurances.

Concerning financial assurances, the Oil and Gas Act provides:

> Each person, firm, corporation or association who operates any oil, gas or service well within the state shall, as a condition precedent to drilling or producing the well, furnish financial assurance in the form of an irrevocable letter of credit or a cash or surety bond or a well-specific plugging insurance policy pursuant to the provisions of this section to the oil conservation division of the energy, minerals and natural resources department running to the benefit of the state and conditioned that the well be plugged and abandoned in compliance with the rules of the oil conservation division. The

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[2] *Marbob Energy Corp. v. N.M. Oil Conservation Comm'n*, 2009-NMSC-013, ¶ 8, 206 P.3d 135 (citing the versions of §§ 70-2-28 and -31 in force at the time).
[3] Id.
[4] Id. at ¶ 11.
[5] Id. at ¶ 23.

> oil conservation **division shall establish categories of financial assurance after notice and hearing. Such categories shall include a blanket plugging financial assurance, which shall be set by rule in an amount not to exceed two hundred fifty thousand dollars ($250,000), a blanket plugging financial assurance for temporarily abandoned status wells, which shall be set by rule at amounts not to exceed fifty thousand dollars ($50,000), and one-well plugging financial assurance in amounts determined sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance. In establishing categories of financial assurance, the oil conservation division shall consider the depth of the well involved, the length of time since the well was produced, the cost of plugging similar wells, and such other factors as the oil conservation division deems relevant. The oil conservation division shall require a one-well financial assurance on any well that has been held in a temporarily abandoned status for more than two years or**, at the election of the operator, **may allow an operator to increase its blanket plugging financial assurance to cover wells held in temporarily abandoned status.** All financial assurance shall remain in force until released by the oil conservation division. The oil conservation division shall release financial assurance when it is satisfied that the conditions of the financial assurance have been fully performed.[6]

The Applicants urge this Commission to adopt rulemakings concerning individual well bonding of so called "marginal wells." The proposal is contrary to Section 14 of the Oil and Gas Act in numerous ways.

a. Single Well Bonding Considerations Mandated by Section 14.

Applicants propose a $150,000 single well bond for thousands of wells that they define as "marginal wells." The Commission lacks the authority to promulgate such a rule. First, considering single well bonding, the statute mandates that one well financial assurance be set "in amounts determined sufficient to reasonably pay the cost of plugging." Additionally, the Oil and Gas Act requires that the OCD "shall consider the

[6] §70-2-14 NMSA (emphasis added).

depth of the well involved, the length of the time the well has produced, the cost of plugging similar wells, and other such factors as the Oil Conservation deems relevant."

First, in setting any single well bond, the Division "shall consider the depth of the well involved." In briefly reviewing OCD Exhibits 21-23 which seem to be some sort of proxy for potential marginal wells, those include wells that I recognize as being drilled to the drilled in the Delaware Basin in the 1970's or 1980's, to produce natural gas from one or more Pennsylvanian sand formations.[7] The Morrow formation is the deepest of the five Pennsylvanian sand formations and was the most frequent target of producers in those days. While depths vary depending on general location, Morrow wells often exceed a depth of 12,000 feet. Those gas wells have been producing for decades and those still active tend to produce at low volumes. Conversely, those lists also include wells that are east of Roswell and drilled in the same basic time frame to the San Andres formation that are as shallow as 900 feet deep. Some of those wells mostly now produce at very low volumes. In my experience it is not uncommon to see both south Eddy County Morrow wells and Chaves County San Andres wells producing less than 1,000 BOE/year and therefore would be potential candidates for "marginal well" designation under the proposed rulemaking. Especially given New Mexico plugging requirements which require plugging various intervals between the producing formation and the surface,[8] there is simply no way that a "marginal" Chaves County San Andres well and a "marginal"

[7] In my testimony about depths, I use as exemplars some formations commonly found in the Permian Basin (southeastern New Mexico) which is the basin with which I have extensive experience as an attorney, investor and operator. There are also depth disparities in the San Juan Basin between the Basin Fruitland Coal, Pictured Cliffs, Mesaverde, and Dakota formations (to name some common target formations in that part of New Mexico).
[8] Rule 19.15.25.10(A) NMAC.

southern Eddy County Morrow well are going to have the same plugging cost—the deeper Morrow well will be more expensive. More importantly, the rulemaking makes no pretense of making depth considerations that the Legislature mandates be considered when setting the amount of a single well bond.

Second, the Division is mandated to consider "the cost of plugging similar wells." Those considerations are relevant as certain Division witnesses point out in describing a few expensive plugging jobs, the tubulars in a much older well generally may be expected to have more potential for deterioration than a younger well. Additionally, over the years, New Mexico has imposed additional casing requirements on wells which means that the casing integrity of older wells drilled prior the adoption of some of those requirements may be subject to more deterioration and pose greater risk than newer wells. Other factors that are relevant to "similar" wells is the prevalence of corrosive hydrogen sulfide (H2S) gas in the production stream of the well. H2S is most common in sour oil production, and its prevalence is ubiquitous a single pool (a formation that consistently is productive of oil underlying a discrete area as delineated by the Division). The only similarity that I can discern that Applicants are proposing is universal to all the wells—the amount a well produces in a 12 month period and the number of production days, neither of which have a thing to do with the cost of plugging.

Third, the proposal for a one size fits all marginal well bonding does not comply with the statue's requirement that the amount be "determined sufficient to reasonably pay the cost of plugging." The Division's testimony and Applicants' witnesses all acknowledge in some form or fashion that wells being plugged by the Division pursuant to the Reclamation Fund are generally those determined to be the most in need of plugging

activities and the result is anecdotal evidence of various very costly projects. The Division's witnesses testify to some of the most expensive and difficult examples.

Fourth, the proposal is based on a supposed average of OCD's costs to plug, abandon, and reclaim individual wells. Under the Oil and Gas Act, only "plugging" costs can be considered.

Finally, these individual bonding considerations mandated by the Legislature clearly contemplate individual well considerations and are not meaningful unless the operator has substantive opportunity to provide information about "similar[ity]" and "reasonableness" ("depth" is known) before a bond amount is set. The proposed rulemaking denies individual operators that process by setting a single amount for every "marginal well."

b. Legislative Grant of Single Well Bonding Authority.

The provisions in Section 70-2-14 also indicate that the legislature has considered the issues of wells that should be bonded individually in addition to the blanket bond authorized. In particular, the legislature has permitted one well bonding only for wells that have been temporarily abandoned for two or more years. This rulemaking proposes individual well bonds on "marginal wells" which are not and have never been on temporary abandonment (TA) status, let alone on that status for two years. It also proposes financial assurances at three times the highest amount authorized for wells on TA status for two years. The Oil and Gas Act provisions reflect legislative appreciation of the fact that wholly unproductive wellbores retain value and might be returned to some productive use. The legislature has made the judgment that the industry participants or operators may hold these wells in temporary abandonment status with no additional financial assurances

costs for a period of up to two years. After that, the legislature has made the judgment that the risk to the State is such that an individual bond should be posted so long as it "reasonably" reflects the costs of plugging considering issues of depth and age of the well. It makes absolutely no sense that the legislature circumscribed this Commission's and Division's authority to individually bond wells that are temporarily abandoned for two years and $50,000 maximum but allows this Commission to adopt rules and the Division to impose financial assurances requirements on individual well bonding on wells that have not even reached TA status at a level three times that of what is authorized for TA wells. Indeed, the entire provision concerning financial assurances for any current temporarily abandoned wells for less than two years and any future TA wells effectively is prospectively repealed if this rulemaking is adopted since each such well is "marginal" under the proposed definitions and will be bonded at 300% the maximum amount authorized by statute. In what I hope is needless to say, regulatory bodies have no authority to enact rules that effectively repeal or moot statutes granting that body limited authority.

3. Lack of Power to Regulate Transfers.

The proposed rulemaking includes provisions regulating or restricting acquisitions of New Mexico oil and gas properties. Those include:

1. An addition to Rule 19.15.8.9(A) which would allow the Division to decline to approve a change of operator simply because they did not have required financial assurances while proceeding with an "acquisition."
2. Adding a new Rule 19.15.9(B) containing disclosure and certification requirements for an operator.

3. Changes to Rule 19.15.9.9(B) and (C) requiring similar certifications.

When the seller and buyer of oil and gas properties in New Mexico are both located out of state, the very first activity concerning the transaction may be the recordation of the real property transfers evidencing the sale/acquisition and/or submissions of paperwork to the Oil Conservation Division or some other regulatory agency such as the SLO or BLM. The Commission and Division have no statutory authority to regulate such out of state activity such as negotiating the terms of an acquisition. The Commission likewise lacks the power to require financial assurances from a person or entity that is merely contemplating entry into New Mexico by acquiring existing oil and gas production.

4. The Legislature Has Declined to Grant Such Authority.

Importantly, there is substantial evidence that the Energy, Minerals, and Natural Resources Department agrees with me given recent legislative activity. In particular, the Department and the Executive strongly urge the passage of House Bill 133 in the 2024 Regular Session of the Legislature. A copy of that proposed legislation as introduced is IPANM Exhibit 41. In HB 133, the Department sought changes to the Oil and Gas Act to permit this Commission to adopt and the Division to increase financial assurances by increasing the blanket bond and grant the Division authority to regulate transfers of wells. HB 133 never passed the Legislature. With the Legislature having declined to expand financial assurances to address perceived present and future orphan well problems and to give the Commission the ability to regulate transfers as requested by EMNRD, the Commission has its answer that it has no authority to do so.

5. The Rulemaking is Contrary to the Commission's Paramount Duties.

On a more fundamental level, Applicants are proposing regulations that they effectively acknowledge will create "waste" by leaving otherwise economically recoverable oil, gas and other valuable hydrocarbons in the ground. The fundamental obligations of this Commission and the Division are to prevent waste and protect correlative rights:

> The commission has jurisdiction over matters related to the conservation of oil and gas in New Mexico, but the basis of its powers is founded on the duty to prevent waste and to protect correlative rights. * * * Actually, the prevention of waste is the paramount power, inasmuch as this term is an integral part of the definition of correlative rights.[9]

The Oil and Gas Act defines "waste" as, first, underground waste:

> "waste," in addition to its ordinary meaning, shall include:
>
> A. "underground waste" as those words are generally understood in the oil and gas business, and in any event to embrace the inefficient, excessive or improper, use or dissipation of the reservoir energy, including gas energy and water drive, of any pool, and the locating, spacing, drilling, equipping, operating or producing, of any well or wells in a manner to reduce or tend to reduce the total quantity of crude petroleum oil or natural gas ultimately recovered from any pool, and the use of inefficient underground storage of natural gas;[10]

To be clear, at its most fundamental level, waste as "generally understood in the oil and gas industry" is leaving economically produceable oil or gas in the ground. Put another way, rules that "reduce or tend to reduce the total quantity of crude petroleum oil or natural gas ultimately recovered" promote waste, not prevent waste. Applicants' witnesses are candid and unapologetic about encouraging this Commission to adopt rules that will leave

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[9] *Continental Oil Co.*, 1962-NMSC-062, ¶ 11 (statutory citation omitted).
[10] §70-2-3 NMSA.

producible oil and natural gas in the ground. The concept of waste is not obviated because a witness characterizes it as insignificant. In defining waste, the Legislature did not give this Commission the ability to promote waste at the later stages of the life of an oil or gas well. Rules encouraging leaving recoverable reserves in the ground are contrary to this Commission's most fundamental duty as charged by the Legislature.

6. The Reclamation Fund and Making Policies Concerning it are the Legislature's Responsibility.

The Reclamation Fund is a creature of the Legislature.[11] The Division is charged with responsibly and properly spending that money on reclamation activities and regulation thereof as directed by the Legislature.[12] This Commission is not charged with protecting the Reclamation Fund by passing rules that supposedly are designed to "insure" against the Division using the Reclamation Fund for plugging, abandoning, and reclaiming some New Mexico wells. Indeed, in the two statutes concerning the Reclamation Fund that I cite in this paragraph, this Commission is not mentioned.

Funding for and protecting the Reclamation Fund are the duties of the Legislature, duties it has not delegated to the Commission. For instance, over industry objections, during a budget crisis occurring in the administration of Governor Martinez, the Legislature "raided" or spent all the money in the Reclamation Fund to balance the State's budget. While some of us may disagree with such decisions, those are decisions for the Legislature. There has been and likely will be continuing debate in the Legislature as to how to address the orphan well issues. IPANM, for whom I am testifying, most recently

[11] §70-2-37 NMSA.
[12] §70-2-38 NMSA.

supported more robust funding for the Reclamation Fund by putting all the Oil and Gas Conservation Tax revenues into that Fund. I agree with that position as only industry participants receiving revenue from production pay that tax and the tax imposed on those revenues will provide the necessary funding. Applicants may disagree but certainly are advocating a different set of policies that they claim will solve or mitigate the issues. It is my opinion that the Legislature, not this Commission, is where the issues should be resolved and the policy of the State of New Mexico is set.

T. Calder Ezzell, Jr.

I hereby affirm under the penalty of perjury of the laws of the State of New Mexico that the above statements are true and correct to the best of my knowledge, information, and belief.

DATE: 9/18/2025

T. Calder Ezzell, Jr.

EXHIBIT 30

Summary of Testimony



T. CALDER EZZELL, JR.

Summary of Qualifications of Calder Ezzell

Washington & Lee (BA 1974, JD 1977)

Licensed NM Attorney concentrating on representing upstream industry for almost 50 years

- Title Opinions
- Contract Advice
- Other transactional & regulatory advice
- OCD Practice

Active oil and gas investor for over 40 years

Operated some wells in the 1980s

Actively handled all land & legal matters from one NM oil and gas operator for ~20 years

The Commission's Lack of Authority to Adopt This Proposal for Single Well Bonding

The Commission's Powers Generally

"The Oil Conservation Commission is a creature of statute, expressly defined, limited and empowered by the laws creating it."

- *Continental Oil Co. v. Oil Conservation Comm'n*, 1962-NMSC-062, ¶ 11

Commission Authority to Adopt The Rulemaking Concerning $150,000 bonds

For single well bonding Section 70-2-14 provides: "In establishing categories of financial assurance, the oil conservation division **shall** consider

-the depth of the well involved,

-the length of time since the well was produced,

-the cost of plugging similar wells,

-and such other factors as the oil conservation division deems relevant."

What Applicants Considered in Setting Single Well Bond Amounts for "Marginal Wells"

Proposed Amendments to 19.15.2.7(M)(2) & 19.1.8.9(D) have two considerations:

- Volume of BOE produced in trailing 12 months
- # of Production Days in trailing 12 months

Applicants' testimony says the following considered:

- Average of cost to OCD of plugging orphan wells
- Vertex 2021 Study
- Fed Cost to Plug and Remediate
- IOGC Data on Plugging costs
  - Peltz Direct at 39-41 & Applicants Ex. 39

Applicants Failed to Consider the Mandatory Statutory Considerations for Single Well Bonds

1. Depth

- Common Permian formations vary from San Andres which is less than 1,000' in some places to Morrow which is below 13,000' in some places.

2. Length of time well produced

- Mechanical failures more common in older wells. Newer wells subject to stricter requirements for casing integrity.

3. Cost of plugging similar wells

- All Applicants' referenced studies are "all wells" plugged
- The OCD data most heavily relied upon is likely "biased towards the most expensive wells". Peltz Direct at 41, ln. 16

Applicants may ignore statutory mandates. The Commission cannot.

Single Well Bonding Conflicts with the Commission's Duties to Prevent Waste & Protect Corelative Rights.

"THE BASIS OF [THE OCC'S] POWERS IS FOUNDED ON THE DUTY TO PREVENT WASTE AND TO PROTECT CORRELATIVE RIGHTS…ACTUALLY, THE PREVENTION OF WASTE IS THE PARAMOUNT POWER, INASMUCH AS THIS TERM IS AN INTEGRAL PART OF THE DEFINITION OF CORRELATIVE RIGHTS."

CONTINETAL OIL, 1962-NMSC-062, ¶ 11

Waste includes “underground waste” which occurs when “operating or producing, of any well or wells in a manner to reduce or tend to reduce the total quantity of crude petroleum oil or natural gas ultimately recovered from any pool…”

SECTION 70-2-3(A)

Single well bonding of $150k will render wells uneconomic more quickly

Many small operators post cash bonds.

Even assuming that money can be raised by owners in the well, immediate heavy "thumb" on the economic scale.

As Applicants seem to acknowledge, wells will be plugged earlier in their life leaving otherwise recoverable oil and gas in the ground.

Surety market probably available to most big operators and perhaps some smaller.

Single well bonds for so-called marginal wells will be expensive.

Assuming operator can pass on cost, still skewing costs to make well uneconomic faster leading to waste.

Large scale single well bonding does NOT work with standard industry contracts.

STARTING POINT: OPERATOR OWNS AS LITTLE AS NONE OF THE WELL, AS MUCH AS ALL, AND OFTEN A %.

Joint Operating Agreements (JOAs)

If >1 WI Owners in a well, relationship governed by AAPL Form 610 Joint Operating Agreement.

The JOA attaches accounting procedures (COPAS) defining rights & obligations of the parties regarding billing for and paying certain expenses.

- Certain expenses, expressly described, can be billed ratably among the owners each month
- Operator is also entitled to ratably bill owners for a **fixed overhead or administrative charge** which covers all other expenses

JOA and COPAS forms can be amended by Parties, but unusual to see changes to expense & overhead provisions

Forms of JOAs & COPAS

AAPL drafts JOA form; 1956, 1977, 1981, 1989 & two 2016 versions (IPANM Exs. 14-19)

- Old forms continue to be used for new wells after new forms created.
- 1977 form most prevalent
- Most common JOA form for potentially “marginal” wells are 1977 and 1989 versions

COPAS drafts COPAS forms; 1962, 1974, 1984, 1995, 2005, and 2022 versions(IPANM Exs. 20-25)

- Older forms (esp. 1974) continued to be used after new forms issued.

JOAs & Bonding

Form JOAs typically allow Operator to bill in advance for certain large cost outlays including P&A work.

Bond is not P&A work. Under Oil & Gas Act, bond not released until Division approves, P&A and reclamation.

Opinion: Absent unique language or a new agreement, the standard JOA provides no basis for an Operator to bill Non-op working interest owners for single-well bond.

COPAS & Bonding

1974 COPAS most used in my experience

1962, 1974, and 1984 COPAS (near identical): only 1 or 2 provisions for types of direct charge that might be grounds for an argument that bonding costs billed to Non-Ops.

- But fixed overhead charge includes "matters before or involving governmental agencies"—therefore any increases in bonding are for the operator to bear because non-ops overhead charges fixed

1995 COPAS : "self-insurance" for direct charge might allow operator posting a cash bond to pass on bonding costs, but overhead still stronger argument against.

2005 and 2022 COPAS: new "other" expenses that directly benefit the joint property and are "necessary and proper" to operations may allow operator to pass bond on as direct charge.

EXHIBIT 30

Why talk about these contracts in this rulemaking?

Few Operators own 100% of the working, cost-bearing interest in a well.

Cost of single-well bonding "marginal" wells will manifest in JOA disputes and, unless 2005/2022 COPAS in place, Operator cannot pass bonding cost on to Non-ops.

The lower an Operator's WI in a well, the more quickly single-well bonds will motivate operators to P&A and/or.

If P&A –waste created because owners are abandoning recoverable hydrocarbons to avoid bonding costs

If Resign, state risks acquiring new generation of inexperienced replacement operators. That may not be a policy the Commission wants to encourage even inadvertently.

IPA NM
INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO

PROPOSED DEFINITIONS OF BENEFICIAL USE, BENEFICIAL PURPOSE & MARGINAL WELL

CREATE WASTE

LACK NECESSARY FLEXIBILITY

Proposed Definition "Beneficial Use/Purpose" at 19.15.2(B)(7)

- Requires the well being "used" for "production, injection or monitoring" and "does not include use of the well for speculative purposes"
- The entire business of owning and operating oil and gas wells can be characterized as "speculative."
- No definition of "speculative purposes" to give Operators or Division guidance or certainty

Effect of Definitions in Proposed Rules

Proposed NMAC 19.15.25.9 adds administrative determination of "No Beneficial use" based on production or injection volumes/days over consecutive 12 month period:

- oil or gas well: < 90 days, < 90 BOE
- injection well: < 90 days, < 100 bbls

Operator can rebut presumption with evidence of projection to produce in paying quantities, ability to meet financial obligations, and other "relevant evidence requested by the division"

Proposed Marginal Well Definition 19.15.2.7.M.2

THREE PARTS: Produced less than 180 days, and

Produced less than 1,000 BOE

In any trailing 12-month period

Incorporated at 19.15.8.9.D to require single-well $150,000 FA and, if operator has more than 15% marginal wells, required to bond every well.

5 Industry Issues where Proposed Rules Inadequate

1. Formation of Secondary Recovery Units
2. Gas wells
3. Efficient use of workovers & recompletions
4. Held by production
5. Displacing common law

Formation of Secondary Recovery Units

(Tertiary Recovery Units Usually Formed from Secondary Units)

Waterfloods—significant source of NM's historic production

Forming & approval is extensive and time consuming (not all sequential)

Geologic work to determine feasibility and desirable acreage to include in unit

Engineering work to estimate costs, injection patterns, potential for productivity, future return, etc.

Land work to ID , negotiate with owners & operators to form unit

Locate & source produced water for injection

Obtain Government approvals.

Construction of unit infrastructure.

Project timing for injections to increase productivity.

Facts About Secondary Recovery Units

- IMMENSE up-front capital requirements
- Very expensive before inject first barrel of brine water
- Each injector is purely a cost center—cost of water + cost to operate;
- More injectors > Producers
- Most logical time to form SRU as primary production techniques (i.e., artificial lift) place wells close to the end of economic life
- But once plugged, a well is valueless in SRU
- NM's Statutory Unitization Act clear policy in support of SRUs

Effect of Proposed Rules on SRUs

- Many wells that will be used in SRU likely marginal prior to formation; some wells in SRU below beneficial use definition or inactive
- Adding per well FA requirements to those wells will materially increase up front costs to develop SRU
- Until unit is governmentally approved, unit operator does not exist so there are all sorts of operators involved, not just a capitalized proposed unit operator

Gas Well Issues under Proposed Rules

Oil and gas leases typically allow gas wells to be “shut in” or unproductive for extended periods of time (newer leases sometimes cap the time period, older leases do not)

Rationales:

- Virtually all gas wells are easy to turn on and off with no adverse effect to productivity
- Gas prices vary
- Rarely more than one pipeline option where production can flow from wellhead to transmission pipeline (e.g., only one gathering system)

Complication: once posted, FA bond cannot be released until OCD approved plugging and abandoning. §70-2-14(A), NMAC 19.5.8.12

Gas Prices & Productivity of Well

- Historically gas prices fluctuate seasonally—highest in winter, lowest in summer
- As US moved from coal production to gas, variability diminished but other issues led to a ~5 year period of low & even negative prices in NM Permian Basin
- Rational operators and owners shut in gas wells during periods of low production to save the resource for better days.
- Benefits everyone including State (~9% severance taxes on gas, plus royalty from State minerals)

Effect of Proposed Rules on Rational Gas Well Operation

For gas wells, days produced and volumes over months may not have any relationship to well's ability to produce.

Importance of production days and volumes over 12-month period give operators artificial incentive to produce more during low price environments to avoid FA costs.

If produce to avoid bonding:

- Everyone, including State, gets less revenue over life of well
- Operator is exposed to liability from royalty owners for placing operator's interests above those of royalty owners

Takeaway & Productivity of Gas Wells

All gas wells connected to gathering systems that aggregate production, transport, & treat gas for mainline transportation to distant markets

To produce, gas well's production pressure must be higher than gathering line pressure (can't "buck")

Mainlines and Gathering Systems have limited capacity; to limit volumes:

↓ compression, ↑ line pressures, ↓ productivity of connected well

- Typically happens during low demand periods

Maintenance on any part of the transportation system shuts in everyone.

- Usually longer for legacy systems

Recent Permian Constrained Takeaway

Permian Basin experienced lengthy period (most of ~5 years) ending in late 2023 of limited takeaway capacity

Horizontal oil wells produce casinghead gas with oil

- Oil was the target; gas was nowhere near as significant

Insufficient mainline gas pipeline capacity to take all the gas to distant markets

Gas prices were historically low and even negative (paid people to take your gas)

Gas well operators were severely squeezed and many shut in for extended periods

- Because of high pressures, some of the shut ins were not voluntary

New mainlines opened and prices recovered with better access to interstate markets

Proposed Rules & Takeaway Issues

- Productivity of gas wells over months (and recently years) variable for reasons that are not indicative of the well's productive capacity or ability
- Active Wells in normal circumstances are rendered "marginal" based on factors out of the operator's control and unrelated to the well capacity
- Potential for waste much higher where gas well operators face diminished revenues from low market prices and additional FA costs under Proposed Rules, leading to premature plugging.

Reworking & Recompletion Issues

Mature oil and gas wells on a single lease or group of nearby leases usually are operated by smaller operators & produce from the same formation

- Multiple owners & governed by JOAs

Reworking jobs on similar wells more efficiently done sequentially on multiple wells.

- Ability to get contractors on site based on volume of work

Recompletions to a shallower formation usually done sequentially at same time for same reasons.

- Some wells may be “played out” in current formation while others still produce.

Both reworkings & recompletions require some sort of majority of interest under JOA to approve (typical is simple majority)

Proposed Rulemaking: Reworking/Recompletions

- Similar concerns
- Lack of flexibility in definitions would mean economic waste—higher costs and/or waste of oil and gas in place
- Operators and interest owners will be forced into taking actions in noneconomic ways
- Reworkings and, more so, recompletions are all to some degree “speculative”

Held by Production Issues

Operators have limited capital

There is high demand for drilling rigs and related contractors in Permian

Typical for operators to prioritize drilling decisions by geologic potential and lease expiration deadlines

Most oil and gas leases last so long as production in paying quantities, so maintaining "marginal" well allows operator to plan for development and investment in new projects where rig and contractor availability limited

Proposed Rules place heavy thumb on scale of Prudent Operator decisionmaking

Common Law & Rulemaking

NM and many other states follow the Texas Supreme Court's *Clifton v. Koontz* test for whether well is producing in paying quantities

- Over a "reasonable period of time" of at least 12 months ("reasonable" can be longer, even much longer), well produces more income than operating costs
- Not being held for "purely speculative" purposes

Rulemaking largely displaces common law with fixed production volumes rather than P&L, potentially adding cost to the "L" side of the ledger

- It remains to be seen how courts will treat bonding costs under JOA/COPAS or as operating cost under PPQ analysis

Bad Faith Accusations

Why no alternate proposals?

- Don't think Commission has this power
- Single well bonding bad policy for many reasons
- HB 133 experience of "with industry input"

What Commission should do if it disagrees on power & authority

Remaining Issues

Concerns about 19.15.9.8 & 19.5.9.9

Applicants' Ex. 72 resolves some of my vagueness and arbitrariness concerns

Still provides for certification about "unresolved adjudicated orders and unresolved settlements for any state or federal violations"

Do we know what constitutes "adjudicated" in other states?

What does "unresolved" mean in this context?

- What if an agreement calls for performance for a period of time and operator is in good standing but still performing?

"Any" violations still raises the same concerns about relative seriousness of "violation"

Comments on Temporary Abandonment

Bonding before Acquiring

Proposed Amendment to Rule 19.15.8.9(A) says that operator "shall not proceed with any proposed…acquisition" until FA in place

Multiple problems

- May be attempting to regulate activity occurring wholly outside NM
- Auctions—multiple potential purchasers
- Why would rational acquirer get FA before acquisition especially since FA not refundable
- Rest of rule deals, appropriately, with operator who "has acquired"
- No new operators will seek to come to NM if has to bond just to negotiate acquisition

EXHIBIT 30

Calder Ezzell's Surrebuttal



Mr. Alexander's Definition of "Speculative"

- Mr. Alexander testified to one definition of "speculative".
- dictionary.com includes a second definition: "*bought or done to make a profit in the future*."
- Agree with Mr. McGowen's statements that virtually everything the industry does involves a degree of speculation.

Mr. Alexander's Testimony Regarding Inactive Wells Being Put Back Into Use Within 8 Years

- Mr. Alexander testified that virtually all inactive wells were put back into use within 8 years.
- Capital flows into the Permian for horizontal drilling, principally, the Wolfcamp and Bone Spring formations (recognized by Mr. Peltz).
- In my experience, these wells have extremely high success rates where geology known and return investments quickly.
- EOR projects have historically been the target of capital, but are more uncertain, capital intensive, and returns tend to occur long after expenditure.
- If Mr. Peltz is right that horizontal targets have a limited life, more capital to flow to new secondary and tertiary projects
- The Division and operators should keep flexibility to permit longer TA.

Mr. Morgan's Testimony regarding Financial Assurance and Collateral Requirements

- It is standard industry practice for operators to use a revolving line of credit.
- Banks require all an operator's oil and gas assets as collateral, not just as to a specific project.
  - Result of the bankruptcies during the 1980s busts
- Heard no testimony that surety companies are willing to take second position which can be undesirable.
- Maximum indebtedness clause in NM mortgage is typically double the loan amount.

Contra Applicants, Current Ex. 72 Rulemaking Applies to Inactive & TA Federal Wells – 19.15.8.9.E Deletes Reference to Subpart A

single instrument.

E.~~D.~~ Inactive wells and wells in approved and expired temporarily abandoned status. An operator shall provide financial assurance for wells that are inactive and wells in approved and expired temporarily abandoned status, ~~covered by Subsection A of 19.15.8.9 NMAC that have been in temporarily abandoned status for more than two years~~ or for which the operator is seeking approved temporary abandonment pursuant to 19.15.25.13 NMAC in one of the following categories:

Contra Applicants, Current Ex. 72 Rulemaking Applies to Federal Wells –19.15.8.9.A Contains Federal Bonding Carveout

19.15.8.9 CATEGORIES AND AMOUNTS OF FINANCIAL ASSURANCE FOR WELL PLUGGING:

A. Applicability. An operator who has drilled or acquired, is drilling or proposes to drill or acquire an oil, gas or injection or other service well within this state shall furnish a financial assurance acceptable to the division in accordance with 19.15.8.9 NMAC and in the form of an irrevocable letter of credit, plugging insurance policy or cash or surety bond running to the state of New Mexico conditioned that the well be plugged and abandoned and the location restored and remediated in compliance with commission rules, unless the well is covered by federally required financial assurance. The division shall not approve and the operator shall not proceed with any proposed drilling or acquisition until the operator has furnished the required financial assurance.

Mr. Purvis and Mr. Morgan's Testimony – Single Well Bonds or a Single Instrument

- The testimony of Mr. Purvis and Mr. Morgan reference the proposed requirement that if 15% of an operator's portfolio consists of so-called "marginal wells" that the operator is required to have all its wells bonded with single well bonds or by a single instrument.
  - Blanket bonds cover all wells.
  - Covering all an operator's wells through a single instrument is still a blanket bond.
  - Requiring a bond for each well regardless of the well's characteristics is still just a blanket bond.

Restricted Use of the Permanent Fund

- Answer question posed by Comm'r Bloom—don't want Permanent Fund used to P&A Wells
- The Permanent Fund cannot be used for oilfield cleanup absent constitutional amendment.
- Enabling Act creates Permanent Fund. Monies must be appropriated to the beneficiaries. 36 State. 557 (6/20/1910) §§ 7-10
- Enabling Act part of NM Constitution. N.M. Const. Art. XXI, § 9

Mr. Powell's Theory of Plugging Low Producing Wells to Allow a Different Operator to Develop

- Mr. Powell: preventing waste by force plugging low producing wells to enhance development of other horizons.
- Plugging does not prevent waste if that well still has the capability to be produced economically.
- The Commission does not have the power to coerce development.
- If there are additional barrels of developable oil and gas, they remain. They are not wasted.
- Adding additional costs for operators of low producing wells that have the capability to continue to produce economically will increase waste.

Mr. Powell's Theory of Plugging Low Producing Wells to Allow a Different Operator to Develop

- Mr. Powell: rulemaking protects correlative rights, forcing operators to plug low producing wells allows another operator to step in and develop.
- Non-Op WIOs may utilize mechanisms under the JOA to perform operations if the Operator does not propose that action.
- Oil and gas leases terminate by their own terms if not producing in paying quantities PPQ.
- Top lease: market if the lease is terminated and there is perceived current value in the acreage and production is such that PPQ is not possible.

Morgan is Wrong. OCD cannot release bond if Well is No Longer Deemed Marginal

The Oil and Gas Act states:

> "All financial assurance shall remain in force until released by the oil conservation division. The oil conservation division shall release financial assurance when it is satisfied the conditions of the financial assurance have been fully performed." (last two sentences of 70-2-14(A))

- Bonds provide surety that the well will be plugged, not that the well will increase production above "marginal" status.
- Statute only authorized OCD to release the bond on satisfaction of proper plugging.
- If this is an incorrect interpretation of the statute, I agree with Mr. Emerick that the OCD form surety bond is not cancellable, so a "release" likely does not help the operator.

EXHIBIT 30

STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

DIRECT TESTIMONY OF MARK B. MURPHY

Intervenor Independent Petroleum Association of New Mexico submits the following technical testimony of Mark Murphy:

Q: Please introduce yourself to the Commission.

A: My name is Mark Murphy. I am a resident of Roswell, New Mexico, and the President of Strata Production Company.

Q: Describe Strata's business.

A: Strata is a small, independent, family-owned oil and gas producer with 23 employees. Strata was formed as a New Mexico corporation in 1988 and it has been continuously headquartered in Roswell, Mexico. Strata has made 11 field discoveries or extensions in the Delaware Basin, drilling the first lateral in in the Delaware Basin in 1990 and the first well permitted as a long reach lateral in 2001. These discoveries include the Nash Draw Brushy Canyon Pool and the Forty Niner Ridge ("FNR") Project, together covering almost 15,000 acres in Eddy County, New Mexico. The FNR Project is planned for almost 150 horizontal wells, with 31 drilled and producing as of the date of this testimony. Strata currently operates 72 oil and gas wells in the Permian Basin of New

Mexico, situated in Eddy and Lea Counties on state, federal, and private lands. Stata holds about 40 federal leases covering roughly 20,000 acres. As an operator in New Mexico, we have also plugged and abandoned 38 wells during that time.

Q: Describe your education after high school experience in the oil and gas industry.

A: I have a bachelor's degree in General Studies with an emphasis in geology from the New Mexico Institute of Mining and Technology in Socorro, New Mexico. However, my family has been in the oil and gas business for four generations. I went to work in the oil fields of Southeast New Mexico and West Texas in 1976. At this point, I have over 40 years of oil and gas operational, geological, and management experience. I have also served as a Director and President of the Independent Petroleum Association of New Mexico, Treasurer of the New Mexico Oil and Gas Association, Chairman of Independent Petroleum Association of America's Land and Royalty Committee, a member of the National Petroleum Council, Chairman for the energy industry research consortium Research Partnership to Secure Energy for America, and as an industry advisor to New Mexico Tech's Petroleum Recovery Research Center.

Q: What is your role at Strata?

A: I bought Strata in 1991 with a small staff of 8, as the majority stockholder. I have led the company in that role for the past 34 years, as we grew from 8 to 23. I have overseen every aspect of the company, from leasehold acquisition, exploration and development, through reclamation and remediation of the wells we drilled and operated. For example, Strata drilled the Paisano Federal #002 in Lea County in July 1992, and was the single operator of that well for over 20 years, and plugged the well in June 2024.

Q: Are you familiar with the proposed rule makings submitted by Western Environmental Law Center, et al. (WELC) and by the Oil Conservation Division (OCD)?

A: Yes, I have reviewed the proposed rule changes by WELC and the redlines submitted by OCD as well.

Q: Have you testified in rulemaking or committee hearings previously?

A: Yes. I testified before the U.S. House Subcommittee on Energy and Mineral Resources in March 2021 with respect to the federal ban on oil and gas leasing under the Biden Administration and five proposed bills during that session. I also testified before the House Committee on Natural Resources in April 2001. Both were on behalf of the Independent Petroleum Association of American and the National Stripper Well Association. On behalf of the organizations I am involved in and with Strata, I have also been an active voice in State Legislative committee hearings and meetings over the past 20- to 30 years, prior to becoming a Representative in January of this year.

Q: So you understand that you are submitting this written testimony as your sworn testimony for consideration by the Oil Conservation Commission?

A: Yes.

Q: Were you involved in the 2018 Rulemaking following legislative enactment of Senate Bill 189, which specifically authorized and directed OCC to increase financial assurance requirements for blanket bonds and temporarily abandoned status wells?

A: Yes, through company representatives. Strata supported IPANM's proposed revisions and the position that federally bonded wells should be excluded from the scope of NMAC 19.15.8, which the Commission adopted.

Q: What are your thoughts on WELC's proposed rule changes?

A: Strata has a number of concerns with WELC's proposal and the changes inserted by OCD. If the Commission were to adopt WELC's changes wholesale, I feel it would be the end of most if not all responsible, independent operators in the State of New Mexico. Being involved in the industry as long as I have, I don't make that claim lightly. To start, WELC's approach is not designed for success or compliance.

Q: Why do you think that?

A: On the surface, WELC's financial assurance scheme looks like it creates a much bigger pot of money for OCD to use for plugging, reclamation, and remediation. But over 90% of the wells that get plugged in this state are plugged by operators—not OCD. The wells that OCD does plug take longer and cost more. Raising bond amounts does not solve the problem of orphaned wells and does nothing to protect the state against "bad actors" who are responsible for most of the delinquency cases where abandoned wells are left behind for others to plug, reclaim, and remediate. In reality, WELC's proposal to introduce single-well bonding at $150,000 will hold an enormous amount of capital hostage for operators with little actual benefit to the State, because EMNRD freely admits that it does not have the manpower or interest to pursue forfeited bonds. WELC's proposal approaches the problem backwards: targeting operators at the back-half of a well's life rather than using the funds already collected over that well's entire productive lifespan to assist operators in plugging wells.

Q: What fund are you referring to?

A: The State of New Mexico has about $66 million in its Reclamation Fund to plug and abandon "orphaned" state and fee wells. Monies in the Reclamation Fund come from the Oil & Gas Conservation Tax (which I will call the "Conservation Tax"), which is paid by all industry participants on all products severed and sold, with limited deductions for federal and state royalties and transportation expenses to first point of sale. That tax was created in 1959 to enforce the Oil & Gas Act, and in 1977 the Legislature created the Reclamation Fund created for the specific purpose of plugging and remediating abandoned wells and well sites. However, depending on market prices, only 10-20% of the Conservation Tax goes to the Reclamation Fund. Since 1991, when the Legislature dissolved the Conservation Fund, the remaining 80-90% of the Conservation Tax has been funneled to the General Fund. But this is controlled by statute and can only change if the Legislature elects to act. As industry and I have consistently argued, were the Conservation Tax redirected to its initial purpose rather than diverted to the General Fund, the Reclamation Fund could easily exceed $1 billion in principle in the next decade, likely in the next 7 to 8 years. Since FY2019, the Oil and Gas Conservation Tax has collected $360 million, but only $66 million has been earmarked (yet not used) to plug abandoned wells. These are decisions that have been made by majorities in both houses of the New Mexico Legislature with the approval of the Governor in the form of budgets.

Q: How many taxes are there on oil and gas production?

A: There are five that I am familiar with: the Emergency School Tax, Severance Tax, Conservation Tax, Production Ad Valorem Tax, and Production Equipment Ad Valorem Tax, which create an effective tax rate of roughly 8.15% for oil and 9% for gas with some

variance depending on where the well is located. Like any other business or employer, we pay all the other associated taxes as well, which is why total contribution by the industry to the state's economy is about $15 billion.

Q: What is the Conservation Tax?

A: Created in the 1950s, the Conservation Tax, codified at NMSA 1978, § 7-30-4, applies a tax rate of 0.19% - 0.24% to all production in the state, regardless of surface or mineral ownership. Then, a piece of that $100 or $137 million is distributed to the Reclamation Fund and administered by OCD under Section 70-2-38 to employ personnel to service, inspect, and plug abandoned wells, well sites, and associated production facilities. Before the Legislature terminated the Conservation Fund, the percentage directed to the Reclamation Fund was much lower, but the funds remained within the control of EMNRD to enforce the Oil & Gas Act. When the Legislature repealed the Conservation Fund in 1991, it directed only 5% to plugging wells, and sent the other 95% to the general fund.

Q: Have there been prior legislative efforts to address use of the Reclamation Fund or the Conservation Tax?

A: Yes, legislators on both sides of the aisle have repeatedly proposed bills to redirect more of the Conservation Tax to the Reclamation Fund. I have been active in discussing legislative issues with legislators as a citizen and member of IPANM for decades and there have been consistent concerns expressed by industry and responsible legislators that more or all the Conservation Tax should be directed into the Reclamation Fund. In this recent 2025 session, bills were proposed in the House and the Senate to restructure use of the Conservation Tax and direct more funds into the original purpose of

reclamation. HB 403, sponsored by Representatives Meredith A. Dixon (D), Rod Montoya (R), Elaine Sena Cortez (R), Jonathan A. Henry (R), and I proposed a phased approach to shift 50, 75, and then 100% of the net receipts from the Conservation Tax to the Reclamation Fund. In the Senate, Senators James Townsend (R) and George K. Munoz (D) introduced SB-519, which targeted putting the Reclamation Fund to use. Both were referred to a committee but not taken up on the floor. In the 2024 Session, Senators Greg Nibert (R), Joseph Cervantes (D), George Munoz (D), and Steve McCutcheon (R) introduced the bipartisan SB-249, which designated $5 million monthly to the Reclamation Fund from the O&G Conservation Tax and encouraged OCD to use the fund by reverting unexpended funds over $80 million to the general fund. This effort also stalled, but I am encouraged after the most recent Legislative Finance Committee meeting this summer that our elected representatives are starting to grasp the disconnect.

Q: What other aspects of WELC's proposal concern you?

A: From my perspective, WELC is asking the Commission to take steps that far exceed its authority under the Oil and Gas Act. I am no attorney, but I have lived and worked with the Oil and Gas Act and its regulations for the past 40 years. The Commission's primary purpose has always been to prevent waste and protect correlative rights. Although the Commission's enumerated powers have expanded since 1935, after the 2015 and 2018 amendments, it was clear to me that the Legislature sets the upward limits of financial assurance in Section 70-2-14 and directs the circumstances for single-well bonding. For example, the 2018 amendment increased blanket bond levels from $50,000 to $250,000, but only for state and private wells not otherwise covered by federal financial assurance.

Q: Does the WELC proposal exclude wells that are covered by other financial assurance?

A: Under the changes proposed, those federal wells, and state or private wells on leases which are communitized with federal leases and covered by federal financial assurance, are still excluded. NMAC 19.15.8.9(A), which is Exhibit 1-C to the WELC revised proposal, maintains the language that the categories and amounts of increased financial assurance applies only to those wells that are not "covered by federally required financial assurance." I point this out because the "windfall" anticipated under WELC's proposal will either not materialize or fall far short of expectations. From my review, Colorado experienced the same following its financial assurance rulemaking in 2022. IPANM fought for the federal assurance exception during the 2018 rulemaking and the Commission agreed that operators should not be subject to double-bonding. In case the Commission is not yet aware, the Bureau of Land Management finalized its own rulemaking and increased its lease bonding requirements under 43 CFR § 3104 effective June 22, 2024 from $10,000 to $150,000 per lease, from $25,000 to $500,000 for statewide bonds, and abolished the nationwide bond option. Separately, the Commissioner of Public Lands increased surface bond requirements from $10,000 to $25,000. The State Land Office also adopted the interpretation that not only operators, but also all lessees of record must maintain a bond for each active state lease to avoid lease cancellation. And at the end of the day, bonds do not plug wells, responsible operators do. Do you know the amount recovered in forfeited bonds by the OCD in FY2023? $0. FY2020 and 2021? Also $0. It does not make financial or regulatory sense

to punish current, active small operators based on the actions of a few bad actors in the past.

Q: Have you worked with Legislature on any other projects related to plugging or orphan wells?

A: Yes, just this summer the Legislative Finance Committee drafted a Spotlight Report on orphan wells. I discussed the effort with a LFC staff member shortly before it was released. We mainly discussed the inefficiency and problems with the OCD's plugging program. I would say overall that industry had virtually no input in the research and drafting of that report, but it does highlight the inefficiencies in wells plugged by the OCD versus operators. First, OCD only has 5 plugging contractors based in the Northwest corner of the state, which means the "cost" of plugging includes substantial expenses for travel related expenses. OCD is also requiring an extended cement curing period than has not been historically followed, which drives the total plugging costs higher due to crew and equipment standbys costs. In my opinion and experience plugging wells with Strata, if the $66.7 million in the Reclamation Fund were properly managed, the Fund could be used to plug anywhere from 800-1,000 wells.

Q: What would the effect of WELC's proposal be on Strata's operations?

A: Strata operates 72 wells in the State of New Mexico, a large number of which are 1-2 mile lateral horizontal wells. So Strata today may not be as harmed by the bonding increases for "marginal wells," but it would have been in the not too distant past. As a small company, the increased administrative and reporting burdens would be difficult, especially given the existing delays experienced by Operators with OCD being short-staffed. Strata got its start, like most other independent operators, by smart and efficient

operation of lower-volume producing oil and gas wells, commonly referred to as "stripper wells." WELC's proposed rule changes would shut that side of the industry down because the capital demands on smaller operators would be too great to remain profitable, no matter how small the margins.

Q: Why are stripper wells important to New Mexico?

A: Even after primary production, 60-70% of the original, recoverable hydrocarbons remain in place in the reservoir. In 2021, New Mexico had about 27,000 stripper wells which accounted for 10% of oil production and 20% of gas statewide, using a 2021 analysis from OCD. Using 2023 data, stripper wells in New Mexico generated roughly $890 million in revenue, and even the lowest producing wells contributed $48 million to the state—and this is in a single year. Even at lower levels, wells can continue to produce steadily for another 20 to 30 years with an attentive operator. Not only would prematurely plugging stripper wells forfeit annual revenue and create waste of natural resources, the loss of the stripper well industry in New Mexico is predicted to eliminate well over 3,000 local jobs.

Q: Are you familiar with the term "marginal well"—which WELC's proposal introduces as a new defined term?

A: Yes, I know and use the term marginal well, but not in any sense as WELC has defined it. Where stripper wells are identified by output, a marginal well generally refers to the profit margin between the costs of extracting and producing oil or gas and market price. A marginal well depends on the oil prices and the cost of production, so that when the market price of barrel of oil is close to or greater than the cost of extracting that same

barrel of oil, or gas equivalent, the well is considered marginal. WELC has defined a marginal well without any economic consideration, only an arbitrary production threshold.

Q: What do you anticipate the broader effect of WELC's proposal the State of New Mexico?

A: Surviving as a small business in New Mexico is not easy. Being both a small business owner and an independent oil and gas well operator compounds the difficulty, and piling on financial assurance and administrative reporting requirements would eliminate most small and mid-size operators from the state. We have seen the industry consolidate in ways I could not have predicted 20 years ago, with mergers at the highest levels and the immense capital requirements associated with development of horizontal wells. In New Mexico in 2024, 60% of total oil and gas production was attributable to just 8 companies. Moreover, the effects of WELC's changes are far from limited to killing off existing production, but will also create a chilling effect on exploration—an area small operators, or "wildcatters" are famous for making discoveries and advances. Operators like Strata have limited capital that is best utilized in making the next discovery. Our segment of the industry fulfills a critical function for this reason and because we maintain the domestic energy infrastructure during downtimes. The June 11, 2024 Legislative Finance Committee report on oil and gas revenue in the State of New Mexico cited to Rystad Energy's prediction that oil production in New Mexico will peak in the 2030s. But that prediction relied on continuing exploration and development, where adoption of the WELC and OCD changes will eliminate a large segment of the population in the industry responsible for those advances. Finally, as responsible citizens looking to the future of New Mexico, we cannot blindly ignore that our state is energy dependent and

economically dependent on the extraction industry. The oil and gas industry funds $15 billion in state and local governmental revenue, and makes up 49% of General Fund spending. Paradoxically, initiatives like we see from WELC will result in substantially less production and activity (which aligns with its publicly stated goal to end "oil and gas leasing and drilling on our public lands"), but at the same time result in fewer operators to plug wells, less revenue in the Reclamation Fund, and a drastically weakened economy overall.

Q: Does New Mexico have an orphan well problem and will WELC's proposal solve it?

A: No to both. A lot of different numbers get thrown around when discussing wells and well status in New Mexico. We do not have a regulatory definition for "orphan wells." So, first you need to distinguish between merely inactive wells and abandoned wells, because not all inactive wells are orphan wells. Using OCD's metric of 15 months without production, there are about 3,100 inactive wells in New Mexico, which does not include the 550 wells in approved temporary abandonment. Of those 3100, OCD has consistently reported about 1700 orphan wells in New Mexico, representing around 2% of total wells. But just 349 of those orphan wells are on state and fee land. I know I have already said this, but it bears repeating: WELC's proposal to increase financial assurance to $150,000 per well will not plug a single one of those 349 orphan wells. Increasing bond amounts simply puts more money in a bank or surety's hands, not the State. Instead, if the Legislature acted to redirect the Conservation Tax paid exclusively by owners of oil and gas interests to the Reclamation Fund, at over $100 million a year, those funds would be immediately available to the State, without the administrative burden of compliance,

enforcement, or the bond claim process. In a decade, the state would have $1 billion principal in the Reclamation Fund, and even at $150,000 plugging cost estimates, the fund would be sufficient to plug, remediate and reclaim over 6,660 wells.

Q: What do you say to the contention that failure to increase financial assurances will leave the costs of plugging and abandoning wells to the taxpayers?

A: With one exception on a federal level, that is a false statement if "taxpayer" is supposed to mean an average New Mexico taxpayer—either individual or a business outside the oil and gas industry. The exception I mention is that New Mexico and other states are allocated monies under the federal Inflation Reduction Act for plugging and abandoning wells, such that some very small fraction of those federal funds is conceivably born by New Mexico taxpayers. Based on my decades of experience with government, there will be some motivation to spend the federal monies before state monies. However, those monies are already allocated and there is nothing this rulemaking could do to change that. As to the Reclamation Fund, the average New Mexico taxpayer does not pay a dime. The Conservation Tax was designed to shift certain costs from the average taxpayer to the oil and gas industry participants who receive revenue from oil and gas production. Industry is paying for plugging and abandoning orphan wells and a lot more under the Conservation Tax. If the New Mexico Legislature and Governor determine that there is a need for more money for orphan wells, they only need to apply more of those industry-generated dollars to the Reclamation Fund

MARK B. MURPHY

Under penalty of perjury of the laws of the State of New Mexico, I hereby submit this direct testimony and swear or affirm that the statements above are true and correct to the best of my knowledge and belief.

DATE: 4/11/16

MARK B. MURPHY

EXHIBIT 30

Mark Murphy



STRATA PRODUCTION COMPANY - BACKGROUND

- Independent, family-owned oil and gas producer; 23 employees
- Formed and headquartered in Southeast New Mexico since 1991; started by acquiring & operating stripper wells
- Made 11 field discoveries; over 15,000 acres in Eddy County, NM
- Drilled first well permitted as long-reach lateral in 2001
- Currently operates 72 wells in Permian Basin

Experience in New Mexico

- Fourth-generation in oil & gas industry
- 40 years experience in operations, geological, management, acquisition, E&D
- Boardmember & Officer in IPANM, NMOGA, Industry Advisor to NM Tech Petroleum Recovery Research Center
- Responsible for plugging 38 wells in New Mexico
- Led Strata for past 34 years
- Previously testified before U.S. House Committee & Subcommittee on oil & gas issues

Strata Concerns with Proposed Rules

- Proposed Rules ignore that Industry plugs 95% of wells
- Single-well bonding at $150k per well limits operators with little to no benefit to the State
- OCD ill-suited to plug wells: no manpower to pursue bonds, take longer to plug wells, costs more to plug wells, using NW crews to plug Permian Basin wells
- Legislature sets upper limits of FA and circumstances of single-well bonding
- Bonds do not plug wells, Operators do

Importance of Stripper Wells in NM

- After primary production, 60-70% h-carbons remain in place
- 2021: 27,000 stripper wells, 10% oil & 20% gas production
- 2023: $890 million in revenue generated by stripper wells
- Stripper wells support over 3,000 local jobs across the state

Role of the Independent Operator in NM

- Industry continues to consolidate, 60% production in 2024 by 8 companies
- Smaller, Independents responsible for exploration of new plays, new technologies – Proposed Rules will have chilling effect
- Independent Operators maintain domestic energy infrastructure during down cycles

O&G Conservation Tax & Reclamation Fund

- Currently $66M in Reclamation Fund, none of the funds are "taxpayer" all from industry
- 80-90% of Conservation Tax funneled to General Fund
- Since 2019, $360M collected via Conservation Tax; averages between $100-137M/yr
- Altogether effective tax rate of 8.15% gas and 9% on gas
- If bi-partisan legislative reforms adopted, State would see over $1B in Reclamation Fund in a decade
  - At $150,000 Proposed Rule estimate, could P&A 6,660 wells

Orphan Wells in New Mexico

- Distinguish between inactive wells and abandoned wells
- OCD reports about 1700 orphan wells; 2% of total wells statewide
- Of 1700, only 349 on state or fee wells
- At Proposed Rules $150,000, need $52 million to plug those 349 wells
  - Compare to the $66M currently in the Reclamation Fund, or the $100M+ collected annually by Conservation Tax

EXHIBIT 30

PUBLIC HEARING
STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

Pecos Hall, 1st Floor, Wendell Chino Building
1220 S. Saint Francis Drive
Santa Fe, New Mexico

IN THE MATTER OF:
PROPOSED AMENDMENTS TO 19.15.2, 19.15.5 19.15.8, 19.15.9 and 19.15.25 NMAC

TRANSCRIPT OF PROCEEDINGS

November 4, 2025

HEARD BEFORE:

HEARING OFFICER FELICIA ORTH

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ALBERT CHANG, Chair
GREGORY BLOOM, Member (virtual)
DR. WILLIAM AMPOMAH, Member

COUNSEL TO THE COMMISSION:

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(On the record at 9:00 a.m.)

TRANSCRIPT OF PROCEEDINGS

HEARING OFFICER ORTH: All righty. Good morning. We are on the 12th day of hearing in OCC 24683 on well plugging and financial assurance. My name is Felicia Orth, hearing officer appointed by the Commission.

We have come to another public comment opportunity. I do see three names on the list for this morning. Just a few things about public comment. I will ask you to spell your first and last name. I will ask you, pursuant to Commission rules, to swear or affirm to tell the truth.

And I will ask you to keep your comments to three minutes. If you have more to say to the board, please put those comments in writing and send them to Sheila Apodaca, the Commission administrator.

So do we have Bob McGonigle on the platform? Mr. McGonigle, can you unmute yourself?

MR. MCGONIGLE: Can you hear me now?

HEARING OFFICER ORTH: Yes. Thank you. Would you spell your first and last name for the transcript, please.

MR. MCGONIGLE: My name is Robert McGonigle. It's R-O-B-E-R-T. My last name is M-C, capital

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G-O-N-I-G-L-E.

HEARING OFFICER ORTH: Thank you. Do swear or affirm to tell the truth?

MR. MCGONIGLE: I do swear, so help me God.

HEARING OFFICER ORTH: Thank you. I will start your time.

MR. MCGONIGLE: Good morning. And, again, thank you for letting me speak at this Commission today. My name is Bob McGonigle. I'm a native of Las Cruces, New Mexico.

My mother's family goes back to the mid-1800s here in the Mesilla Valley. Actually, my great-grandfather, born in Mesilla, was able to obtain a physician's license. His name was Anthony Montero. They called him Mateo. He was known as a stagecoach doctor because he was able to obtain a physician's license. He actually worked on Billy the Kid in Mesilla in the late 1800s.

But as for me, I'm a graduate of NMSU. I'm a retired small business owner of an independent insurance agency called McGonigle Insurance, here in Las Cruces. I spent about 40 years in the business. And my father actually started here as an Allstate agent in 1955.

But we're here today to talk about the

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oil industry, which provides three essentials of life: food, water, and shelter. The industry provides direct revenue to my state, which helps fund teachers, first responders, infrastructure, food, water, and home heating.

The oil and gas industry employs over 15 percent of New Mexico's population. This helps the growth of our gross domestic product. Also, these employees spend their paychecks right here in New Mexico.

As a retired small business owner who employed seven to ten people, I want to keep small business in New Mexico strong. My small business would not have survived being overregulated and assessed, such as the oil industry would be required to pay.

Education, travel expenses are a common cost of small business, not to mention insurance costs. The oil and gas well owners already have a big expense, especially commercial general liability insurance. Liability insurance protects small business owners and me. It would pay should the oil rig operation have a mishap. It would pay bodily injury, death, or property damage caused by their operations. Plus, it's not getting any cheaper to

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pay for the cost of insurance.

The oil industry does not want to cause any harm to anyone and already are taking precautions as they do not want any claims. Regulators want to charge an additional assurance fee, which I don't understand when they're already paying insurance fees -- insurance premiums, I should say. As the insurance policy premium and adding more assessments, testing regulations will not be beneficial for New Mexico. And New Mexico depends on oil and gas revenue. And adding additional overhead to this industry would most definitely cause a decline in our GDP.

But I want to thank the Commission for your understanding that oil and gas production needs to remain high here in New Mexico. I want to thank you again for your time.

HEARING OFFICER ORTH: Thank you, Mr. McGonigle.

Next we have Candy Ezzell. Would you unmute yourself, Ms. Ezzell. I think I can hear you.

SENATOR EZZELL: Good morning. My name is, yes, my name is Candy Spence Ezzell, C-A-N-D-Y, E-Z-Z-E-L-L.

HEARING OFFICER ORTH: Thank you. Do you

swear or affirm to tell the truth?

SENATOR EZZELL: Yes, I do.

HEARING OFFICER ORTH: Thank you. Please go ahead.

SENATOR EZZELL: Again, my name is Candy Spence Ezzell. I am a rancher, I am a farmer and I'm a New Mexico State Senator representing District 32 in Chaves and Eddy counties.

This is an attempt to end-run the legislative process. In the 2024 session, House Bill 133 tried to do much of what these proposed rule changes would do. House Bill 133 and the two committee substitutes were rejected by the legislature. You cannot amend legislation by regulation.

This Commission is charged with preventing waste, and the adoption of these amendments will cause waste. The applicants are not trying to protect the taxpayers of New Mexico, as they claim. Instead, this is a scheme to achieve: Leave it in the ground.

In 1959, the New Mexico Legislature had the wisdom to create the oil and gas conservation tax in order to have the industry fund its regulators.

In 1977, the New Mexico Legislature had

the wisdom to create the reclamation fund, which is funded by the conservation tax. Unfortunately, not all of the conservation tax goes to its intended use.

The oil and gas industry pays over $100 million a year in conservation tax. Applicants argue that the industry should clean up its own mess. If we used the conservation tax for its intended purpose, industry would be cleaning up its own mess.

Thank you for the chance to be able to speak to you all today.

HEARING OFFICER ORTH: Thank you, Senator Ezzell.

Next we have Jonny Heins. Mr. Heins.

MR. HEINS: Yes. Jonny Heins, J-O-N-N-Y, H-E-I-N-S.

HEARING OFFICER ORTH: Do you swear or affirm to tell the truth?

MR. HEINS: I do.

HEARING OFFICER ORTH: Thank you very much. Go ahead.

MR. HEINS: Commissioners, thank you for the opportunity to provide comments. My name is Jonny Heinz and I'm the vice president of corporate affairs at Permian Resources Operating, LLC.

Permian Resources is the seventh largest

oil and gas operator in New Mexico based on barrels of oil equivalent produced per day, paying nearly half a billion dollars annually in state taxes and royalties with approximately 1,250 producing wells operated by our company in the state of New Mexico, all of which are in Eddy and Lea counties.

Permian Resources opposes WELC's rulemaking petition. As one of the state's top oil and gas operators and benefactors to the state's economy, for the following reasons, we are extremely concerned about the near-term and long-term impacts these unprecedented changes sought by WELC would create.

First, as noted in NMOGA and IPANM's motion to dismiss, the proper avenue for such reforms is through legislation, not a regulatory rulemaking proceeding. Simply put, substantive changes to the Oil and Gas Act should not be made without legislative input.

Various bills have been proposed at the legislature over the past several years, seeking to increase bonding requirements and restrict well transfers, and each has failed. This rulemaking is a transparent attempt by WELC to circumvent the legislative process, where they and other

environmental organizations have previously failed to find traction for their initiatives.

Second, Permian Resources and other New Mexico operators already pay substantial taxes each year that go into the oil and gas reclamation fund, which was established by the legislature for the explicit purpose of plugging and reclaiming orphaned wells.

The OCD currently has over $60,000 [sic] in the reclamation fund and should deploy these funds for their intended purpose.

Third, the considerable and unnecessary increases to statewide bonding requirements proposed by WELC will have the unintended consequence of creating more orphan wells in the state. $150,000 bonds on individual wells will drive smaller, independent operators out of business, thereby increasing the number of orphaned wells throughout the state, eliminating quality jobs and reducing taxes and royalties that would otherwise be paid to the state.

Last, and perhaps most importantly to our company, the proposed rulemaking changes would grant OCD the extraordinary authority to deny well transfers in the event an applicant is out of

compliance with federal and state oil and gas laws and regulations.

While we are confident that the current OCD staff will not abuse this new authority, the language as currently proposed in WELC's petition could be broadly interpreted by future OCD staff to deny almost any proposed well transfer. Regulatory certainty is critical for all businesses. And creating a new subjective framework for denying well transfers is untenable, especially when applied to the industry that is most critical for the New Mexico state economy.

For these reasons, we urge you to deny WELC's petition. WELC and other environmental organizations are free to pursue their sweeping reforms through legislative processes. Allowing them to implement drastic policy changes through the back door of a rulemaking proceeding is a dangerous precedent and would be catastrophic for the state's economy. Thank you.

SENATOR EZZELL: Thank you, Mr. Heins.

Next we have Melissa Troutman.

MS. TROUTMAN: Yes. Good morning.

HEARING OFFICER ORTH: Hello. Would you spell your first and last name, please.

MS. TROUTMAN: Sure. It's M-E-L-I-S-S-A, T-R-O-U-T-M-A-N.

HEARING OFFICER ORTH: Do swear or affirm to tell the truth?

MS. TROUTMAN: I do.

HEARING OFFICER ORTH: Please go ahead.

MS. TROUTMAN: Good morning, Chair and Commissioners. My name is Melissa Troutman and I represent the Permian Basin Coalition, which is a group of over 20 organizations dedicated to reducing the pollution and other harms from intensified oil and gas operations in the Permian.

Our organizations include staff and members and volunteers who live and work and recreate in the Permian. And I'm here today to strongly support the proposed bonding and cleanup rule changes on behalf of the coalition.

Those of us who have lived in oil country know what the industry means to communities. But we also see the mess that some companies are leaving behind, abandoned wells, leaking equipment, and pollution that's creeping closer and closer to people and their homes and water supplies.

Right now, oil and gas companies are making billions off the land, but when the wells

deteriorate or stop producing, too many are walking away. And they can because even where there are protective laws in place, like the spill rule, penalties and fines are so rarely issued that it costs them nothing to just pollute and walk away. They leave behind aging, leaking infrastructure, and it's New Mexicans living in the front lines, mostly, who are left paying for it and assuming risk.

Members of our coalition have been monitoring well sites in Loco Hills and other parts of the Permian for years, and often, the same older, non- or low-producing wells are leaking. The equipment is so corroded that the tanks and the joints have collapsed, and we've witnessed many recurring spills, some of which are never cleaned up.

For example, a company named Poco Resources has several aging and dilapidated well sites in Loco Hills that were observed leaking in 2023, 2024, and again, just a few weeks ago on October 9th. Oil and waste fluids pooled inside the unlined containment of two tank batteries, also around a spurting leak in a flow line, and around the wellhead of a partially dismantled pump jack that clearly has not operated in years.

I've included photos, photo evidence and

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GPS coordinates of this spill, these spills in my written version of these comments, so that will be added to the record for anyone who wants to take a look.

Over 700 wells have already been flagged for public cleanup in New Mexico, but more than 4,000 are at risk of being abandoned and orphaned soon. And we are concerned that these spill sites of Poco Resources are among them.

Oil and gas lobbyists want us to believe that the reclamation fund can replace corporate responsibility, but the fund holds just 66 million, while state data shows that New Mexico's cleanup liability ranges between 700 million and 1.8 billion.

That means the public could be on the hook for over a billion dollars in cleanup costs, while oil and gas companies walk away with the profits off of natural resources that are owned by everybody.

Moreover, the number of abandoned wells will increase as oil and gas production slows, and we need to be prepared for that inevitability.

Families in Loving and across southeastern New Mexico are surrounded by pipelines in their backyards, frac sites down the road. And

they've been left to live in a toxic cloud, whether they know it or not, while corporations walk away with the profits. And we can't let this continue.

These rule updates are commonsense fixes to the problem of an unfair system. They require bonding of $150,000 per high risk or inactive well. That's still less than the total cleanup cost. They stop bad actors from inheriting wells they can't afford to clean up. And they close the loophole that lets companies call wells "temporarily abandoned" for eight years or more with no action and no cleanup.

HEARING OFFICER ORTH: Ms. Troutman, please wrap up.

MS. TROUTMAN: Sure. If you drill it, you clean it. That's the promise we need these rules to enforce. So we encourage you to vote to adopt these long overdue bonding reforms. Thank you.

HEARING OFFICER ORTH: Thank you very much.

Next we have Liliana Castillo.

MS. CASTILLO: Can you hear me?

HEARING OFFICER ORTH: Yes, I can now. Thank you. Would you please spell your first and last name.

MS. CASTILLO: Liliana, L-I-L-I-A-N-A, Castillo, C-A-S-T-I-L-L-O.

HEARING OFFICER ORTH: Do swear or affirm to tell the truth?

MS. CASTILLO: I do.

HEARING OFFICER ORTH: Thank you. I'll start your time.

MS. CASTILLO: Thank you. Good morning, Commissioners. Thank you so much for your service and the opportunity to give public comment today.

I'm one of the many New Mexicans who believe oil and gas operators, regardless of size, should be held responsible for cleaning up after themselves. Some small operators claim that if bonding is increased, they'll walk away from their wells.

That argument is quite concerning. Does that mean that they never intended to clean up after themselves to begin with, despite that responsibility being part of what they agreed to when they bought a well or drilled a new well? This argument to me is exactly why these reform are urgently needed.

Bonding is about prevention. It's how we make sure wells don't get abandoned in the first place. Because once they do, the cleanup costs skyrocket and the risks to our health and water grows.

In addition, we can keep hearing that the reclamation fund should be, you know, handling this issue. But here's the truth. The reclamation fund is only part of the solution. We need both a robust reclamation fund and right-size bonding. Right-size bonding ensures the state has sufficient funds funded by oil and gas corporations when corporations walk away from their plugging responsibilities. The reclamation fund is a backup if the state doesn't have enough funding for plugging and cleanup. We need both.

A broken plugging system makes it even more important to get bonding right now. A broken system only amplifies the risk when bonds are insufficient. We cannot afford to underfund risk, especially when the cost of inaction falls on our communities.

If we wanted to scale up the reclamation fund, it would require, in my mind, a completely new significant fee on industry, rather than just shuffling around tax revenues. That would result in pulling dollars away from other public needs, like schools and healthcare, just to clean up oil and gas wells that corporations should be responsible for.

Bottom line is, if you drill it, you

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clean it 100 percent of the time at your own expense. That's what we expect as New Mexicans. Regulators should not need to chase companies down to fulfill this responsibility.

Please adopt these reforms and make sure the people who profit from drilling also pay for cleanup. Thank you.

HEARING OFFICER ORTH: Thank you, Ms. Castillo.

Next we have Roland Glenn.

MR. GLENN: Good morning.

HEARING OFFICER ORTH: Good morning. Would you spell your first and last name, please.

MR. GLENN: Yes. My first name is Roland R-O-L-A-N-D, last name Glenn, G-L-E-N-N.

HEARING OFFICER ORTH: Do you swear or affirm to tell the truth?

MR. GLENN: Yes, I do.

HEARING OFFICER ORTH: I'll start your time. Thank you.

MR. GLENN: Good morning, Commissioners. Thank you for your time this morning.

Like I said earlier, my name is Roland Glenn. I hold a master's degree as a geological engineer. I retired out of Colorado and moved down

here to New Mexico for a little peace of mind. I retired back in 2017. I'd like to slow down here away from the oil field here in New Mexico. I enjoy the beautiful scenery.

The oil field does support many different kinds of jobs, especially here in my community, such as the plastic injection molding company, semi-truck drivers, the power industry here in New Mexico. It brings a constant charge to the electrical grid. It also helps, like I said, the plastic molding injection company, which supports roughly 150 jobs here Rio Communities.

And if these regulations continue to go through, the loss of experienced workers and the tragedy for the State of New Mexico, for many different reasons, such as the loss of income for schools and other state jobs, would be detrimental to the State of New Mexico. So I'm asking you to consider the effect on the State of New Mexico that we all call home.

I truly thank you for your time and your consideration.

HEARING OFFICER ORTH: Thank you, Mr. Glenn.

Now we have Kendra. I don't know the last name.

MS. PINTO: Thank you. It's Kendra Pinto.

HEARING OFFICER ORTH: Hello. Would you spell your first and last name, please.

MS. PINTO: K-E-N-D-R-A, P-I-N-T-O.

HEARING OFFICER ORTH: Do you swear or affirm to tell the truth? Hello? I think you've re-muted yourself, Ms. Pinto.

Sheila, can you send her a prompt that she can unmute herself again?

MS. PINTO: There we go. It turned off on me when I was talking.

HEARING OFFICER ORTH: Okay. Do you swear or affirm to tell the truth?

MS. PINTO: I do.

HEARING OFFICER ORTH: I'll start your time.

MS. PINTO: Thank you. My name is Kendra Pinto and I'm the Four Corners indigenous community field advocate and a certified optical gas imaging thermographer with Earthworks. I grew up on the Navajo Nation surrounded by oil and gas development.

This work is personal to me. I've seen the impacts of these operations my whole life on the land, the air and the people who live near them.

Last month, I joined my colleague, Mandy Sackette, on a field trip to the San Juan Basin. We

visited dozens of oil and gas sites to document pollution and see firsthand what's happening in this aging and declining oil infrastructure. What we found is deeply troubling. What I always find, having done thermography work for four years, is deeply troubling.

So many of these wells are old, drilled in the early '90s, and poorly maintained. Communities have to live with that, the smells, the noise and the health risk, while companies often walk away as production in the San Juan Basin continues to decline.

Last week my colleague Mandy mentioned the low producing Hilcorp site that is less than 900 feet from Dzilthnaodithle Community School. I have visited that site several times and we have filed a total of three complaints, yet it still has continuous emissions from three different sources on site.

There's another Hilcorp site near Herfano that is 0.6 miles from the Hanaa Dli Community School that has three points of continuous emissions. We filed a complaint last month.

These sites aren't isolated incidents. They're part of a pattern, low-producing, neglected

wells that keep polluting long after the profits have dried up. We reported multiple emissions to the New Mexico Environmental Department, and what I see in the field clearly makes it clear the system is not working.

You've heard a lot about the potential impacts on small operators, but really, when wells like these are left to decline without proper oversight or bonding, it's my community, my neighbors and my family that pay the price.

Oil wells leak toxic chemicals like benzene and hydrogen sulfide into our air and water and pose a threat to everyone living in close proximity. And most of us who live on tribal lands do live in close proximity.

This rule is not about punishing small operators. It's about fairness and accountability and protecting human lives and communities. Every company that drills in New Mexico should be prepared to take full responsibility for its wells. Our communities deserve to breathe clean air and taxpayers shouldn't be left holding the bill when industry fails to act.

Please adopt this rule to protect our land, our people and our climate. Thank you.

HEARING OFFICER ORTH: Thank you, Ms. Pinto.

Next we have Blythe Maunders.

MS. MAUNDERS: Hello.

HEARING OFFICER ORTH: Hello. Would you spell your first and last name please.

MS. MAUNDERS: Sure. It's B-L-Y-T-H-E, M-A-U-N-D-E-R-S.

HEARING OFFICER ORTH: Do swear or affirm to tell the truth?

MS. MAUNDERS: I do.

HEARING OFFICER ORTH: Thank you. Go ahead.

MS. MAUNDERS: Hello. My name is Blythe Maunders. I'm a concerned citizen. I'm here in support of our public lands and a more responsible use of New Mexicans tax dollars.

The oil industry, which makes millions of dollars in profit each year, should be held accountable for cleaning up the wells they leave once they're done profiting from the land.

I'm speaking in support of the New Mexico Oil Conservation Commission's new bonding and cleanup rules to hold the oil industry accountable for cleaning up their mess.

It's a shame in Mexicans even have to make these comments trying to get the wealthy oil

industry to do the bare minimum, by cleaning up their wells.

If New Mexicans are paying to clean up the mess from the oil industry, are we really profiting from having them here in the first place? These new rules will ensure that corporations, not communities, pay to plug their wells. Thank you.

HEARING OFFICER ORTH: Next we have Kelly Francisco. Would you spell your first and last name, please.

MS. FRANCISCO: Yes. Kelly, K-E-L-L-Y, Francisco, F-R-A-N-C-I-S-C-O.

HEARING OFFICER ORTH: And do you swear or affirm to tell the truth?

MS. FRANCISCO: I do.

HEARING OFFICER ORTH: Thank you. Go ahead.

MS. FRANCISCO: Good morning, Chair and Commission. My name is Kelly Francisco and I'm speaking as a resident of New Mexico and a concerned citizen of the Navajo Nation in strong support of the proposed bonding rule changes.

I believe that no matter the size of an oil or gas operator they should clean up after themselves. That's the law, their responsibility, and it is just common sense.

Right now, there are nearly 700 wells that oil and gas corporations have abandoned and another 4,400 that could be abandoned in the future, which threatens our health and drinking water unless we make them clean up.

New Mexico's are paying the price when corporations walk away from their responsibilities. Nearly 100 million in public funds have been used to clean up abandoned wells in just the last five years. That's money that could have gone to our schools, our roads, and our clean energy future.

The truth is, most wells in New Mexico are owned by wealthy corporations that can afford to do the right thing. If a corporation can't afford to clean up, then maybe they shouldn't be drilling in the first place. Fair rules make a fair playing field. Responsible operators already plug their wells. This rule will make sure the rest do, too. Thank you.

HEARING OFFICER ORTH: Thank you, Ms. Francisco.

Next we have Brian Sweeney.

MR. SWEENEY: Morning.

HEARING OFFICER ORTH: Good morning. Would you spell your first and last name please.

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MR. SWEENEY: B-R-I-A-N, S-W-E-E-N-E-Y.
HEARING OFFICER ORTH: Thank you. Do you swear or affirm to tell the truth?
MR. SWEENEY: Yes.
HEARING OFFICER ORTH: Thank you, go ahead.
MR. SWEENEY: Good morning, Chair and Commissioners. I want to speak in favor of the proposed bonding rule changes because I'm a big fan of fairness.
The law requires oil and gas companies to plug wells when they're done with them, and there's a growing problem of companies not following that law. Bankruptcy has become an irresponsible part of the business plan.
But if you make a mess, you should clean it up a hundred percent of the time. This is not grade school and 95 percent is not an A. 95 percent in this case results in 702 abandoned wells in New Mexico, with over 4,000 about to be abandoned at a cost of $700 million to $1.6 billion of public money. That is not right.
Non-plugged wells present risks to public health, clean water, and the environment, so they should be plugged. The law says that the companies who have profited from these wells should

pay to close them up and clean up the area.
When people rent apartments, they have to put down a security deposit proportional to the costs to repair any damage. For decades, oil and gas companies have put down bonds that don't come close to covering plugging and cleanup costs, causing the very expensive and growing abandoned-well problem. This is the wealthiest industry in the history of the world. They can afford to follow the law.
People in this hearing have complained that the reclamation fund is adequate for that purpose, but at $66 million, it doesn't come close to covering the $700 million to $1.6 billion price tag for plugging. That fund was created, quote, for use by the Oil Conservation Division in carrying out the provisions of the Oil and Gas Act. That is to say, not just plugging wells. So that fund is too small to address the problem. The reason that fund is growing is because New Mexico received federal money for plugging that if we didn't use it, we would lose it.
Don't be distracted by the oil and gas industry's many deflections. They want to talk about anything but how inherently fair it is to require adequate bonding and how unfair it is for the state

to use hundreds of millions of dollars of public money to pay to cleanup industry's messes that companies have profited from. Cleaning up after yourself is a cost of doing business, not a public liability. Thank you.
HEARING OFFICER ORTH: Thank you, Mr. Sweeney.
Do we have anyone else on the platform would like to offer -- let's see, Robert Briani.
Sheila, do you see the RB there?
MS. APODACA: Yes, I'm admitting him right now.
HEARING OFFICER ORTH: If you called the platform using your phone, you can raise your hand by dialing star 5, by the way.
Mr. Briani, can you unmute yourself? Mr. Briani may have stepped away. Mr. Briani, if you can hear me, you have permission to unmute. You're not unmuted. Perhaps you could submit your comments and writing, or perhaps you could join us Thursday morning when we are certain we will have another public comment session.
Sheila, do you want to unmute the 575-993 number? I don't know who this is.
MS. APODACA: I've given them the

permissions to unmute themselves.
HEARING OFFICER ORTH: Okay. Let's see. I think unmute on the phone.
Oh, I think you're unmuted. Can you hear me?
MR. PATTERSON: Yes, I can hear you. Can you hear me?
HEARING OFFICER ORTH: Yes, now I can. Would you tell us your name and spell it for the transcript, please.
MR. PATTERSON: Yes. David Patterson, D-A-V-I-D, P-A-T-T-E-R-S-O-N.
HEARING OFFICER ORTH: Thank you. Do you swear or affirm to tell the truth?
MR. PATTERSON: I do.
HEARING OFFICER ORTH: All right. I'll start your time.
MR. PATTERSON: Thank you for the opportunity to speak to this Commission. It's been fascinating listening to all the comments.
Mine is that I would like to say my grandfather was the most influential person in my life. He had a fifth grade education. He lived through a Great Depression and two World Wars and had some strong views that were developed out of those

life experiences. One was that you don't waste anything and the other one was that if you make a mess, you clean it up. I had to apologize for some of the messes I created as a rebellious teen and I had to clean them up.

Sadly, we do not live in such a simple, naive world. Everyone on this Commission knows that fossil fuels over the past 250 years have brought some of the greatest advancements civilization has ever known. I love the quality of life that fossil fuels have provided.

Everyone on this Commission also knows that we, collectively, have made a mess and we know we must clean up the mess. We also know that the fossil fuel companies have known since at least 1986 from reports by their own scientists that continuing to burn these fuels would heat the atmosphere. Their response has been to spread disinformation instead of just being honest. Sadly, that's why this Commission exists, to make sure these companies clean up their mess.

We know that methane and other toxic gases are leaking from oil and gas wells all over New Mexico, around the country, and around the world. We can't make everyone clean up their mess, but we

can do it in New Mexico.

The job description for the director of the Oil Conservation Division says, in part, it enforces the state's oil and gas statutes, ensures abandoned wells are properly plugged, and that the land is properly restored once production activities are completed.

I think my grandfather with his fifth grade education refined everything into one sentence, "If you make a mess, clean it up." Thanks again for the chance to speak today. Let's clean it up.

HEARING OFFICER ORTH: Thank you very much, Mr. Patterson.

I see Mr. Briani has raised his hand again. Let's see if he's able to unmute himself this time.

Mr. Briani, it might help to press control-shift-M to unmute.

I believe there are some folks in the room.

Again, Mr. Briani, I'm sorry that you're not able to unmute yourself at your end.

But we do have some folks in the room, and I'm going to turn to them. Yes, ma'am, in the white cap. Right over here. You would share your

first and last name.

MS. BROOKINS: Lura Brookins, L-U-R-A, B-R-O-O-K-I-N-S.

HEARING OFFICER ORTH: Thank you. Do you swear or affirm to tell the truth?

MS. BROOKINS: I'm sorry?

HEARING OFFICER ORTH: Do you Swear or affirm to tell the truth?

MS. BROOKINS: I still didn't understand.

HEARING OFFICER ORTH: Do you swear or affirm to tell the truth?

MS. BROOKINS: Oh yes.

HEARING OFFICER ORTH: Thank you. Go ahead. I'll start your time.

MS. BROOKINS: Being a resident for Santa Fe for 30 years as a landscape designer, artist, I've become an ardent protector of our beautiful landscape. I've also come to see that we citizens of our land must speak now to defy corporate misuse of our land or resources and our precious water.

Without adequate remediation we're witnessing cynical disregard of our land and waters. The oil and gas industries have also avoided their obligation to clean up the damages they inflicted on our land.

Increasing number of wells have expired and temporarily abandoned and others are out of compliance. That can mean a possible 1.6 billion cost for this state to plug and remediate orphaned wells in the future. These costs must be borne or shared by the operators of these wells to pay for the cleanup. It has been their profit to capture our oil resources using our scarce water.

We need guaranteed assurances from these oil and gas companies that they will honor and guarantee environmental safeguards to protect our waters and land and to set up funds for all cleanup costs. There needs to be guardrails to hold these companies accountable for damages and remedial costs. It is our land, our air, and our sacred water that must be protected.

I would like to close with a quote from N. Scott Momaday, a member of the Kiowa tribe, a poet and novelist and resident of Santa Fe, who passed last year, from his book Earthkeeper. "We humans must revere the Earth, for it is our well-being. Always the Earth grants us what we need. If we treat the Earth with kindness, it will treat us kindly. If we give our belief to the Earth, it will believe in us. There is no better blessing than to be believed

in. There are those who believe that the Earth is dead. They are deceived. The Earth is alive. It is possessed of spirit. Consider the holy tree. It can be allowed to thirst. It can be cut down. Worst of all, it could be denied our faith and our belief. But if we speak to it, we pray it will thrive."

Thank you.

HEARING OFFICER ORTH: Thank you Ms. Brookins.

Is there anyone else in the room who would like to offer public comment during this session? We're certain we will have another session this Thursday morning at 9:00.

Your first and last name, please.

MS. TSOSIE-HARVEY: Alicia Tsosie-Harvey.

HEARING OFFICER ORTH: And would you spell that.

MS. TSOSIE-HARVEY: A-L-I-C-I-A, T-S-O-S-I-E dash H-A-R-V-E-Y.

HEARING OFFICER ORTH: Thank you. Do you swear or affirm to tell the truth?

MS. TSOSIE-HARVEY: Yes.

HEARING OFFICER ORTH: I'll start your time.

MS. TSOSIE-HARVEY: Good morning, Chair, Commissioners. My name is Alicia Tsosie-Harvey, and

I'm speaking on behalf of Concerned Citizens of New Mexico and the Navajo Nation and as a representative of Dine Care and in strong support to the proposed bonding rule changes.

I believe that no matter the size of an oil or gas operator, they should clean up after themselves. That's the law and their responsibility.

I have firsthand witnessed the lasting impacts of oil and gas corporations on and near the Navajo Nation. Right now, there are nearly 700 wells that oil and gas corporations have abandoned and others that could be abandoned in the future, which threatens our health and drinking water unless we make them clean up.

Please vote to adopt stronger bonding rules. Let's protect our air, water, and land and make sure no one gets to profit while leaving the rest of us with a mess. Thank you.

HEARING OFFICER ORTH: Thank you.

Anyone else in the room? Yes. Come on up. Your first and last name, please.

MS. ANTONIO: My name is Cheyenne Antonio. C-H-E-Y-E-N-N-E, Antonio, A-N-T-O-N-I-O.

HEARING OFFICER ORTH: And do you swear or affirm to tell the truth?

MS. ANTONIO: I swear.

HEARING OFFICER ORTH: Thank you.

MS. ANTONIO: Good morning, Chair, Commissioners. My name is Cheyenne Antonio and I am speaking on the behalf of the Check Board Navajo Nation community and also with Dine Care in support of the proposed bonding rule changes.

I heard the argument that we shouldn't be changing bonding requirements because our well-plugging system is broken, but I think that is exactly backwards. Within the community that I'm from, there are idle wells, sleeping wells. It's crazy that wells can be asleep, idle and abandoned. And we do see leaks in our desert area where I live in the checker board region.

The reclamation fund is there for emergencies. Not for the corporations to rely on as a backup plan when they walk away. If we don't fix the bonding system now, the problem only gets bigger and more expensive. And you can ask impacted communities for those systems and see if it works, because it doesn't.

The rule is about preventing the future risk of more abandoned wells. If we require fair bonding now, we don't need to drain public funds

later. That's not just smart government, it's basic risk management. A broken system doesn't mean we wait to act. It means we act now to keep things from getting worse.

Please adopt the proposed rules and protect my future, the checkerboard area of New Mexico and the Navajo Nation for our future. Thank you.

HEARING OFFICER ORTH: Thank you, Ms. Antonio. Is there anyone else in the room who would like to offer public comment during this session? No? All right.

I saw one more person on the platform, Sheila. I think GH, perhaps? Gene Harbaugh. Mr. Harbaugh, can you unmute yourself? Control-shift-M might work. No? All right.

And Mr. Briani has -- I'm sorry if I'm mispronouncing your name, Briani -- has his hand up, so we'll try one more time.

MR. BRYANT: Good morning, Commissioners.

HEARING OFFICER ORTH: Oh, good morning. Would you state and spell your first and last name, please.

MR. BRYANT: Okay. My name is Robert Bryant, spelled R-O-B-E-R-T, B-R-Y-A-N-T.

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HEARING OFFICER ORTH: Thank you. Do you swear or affirm to tell the truth?

MR. BRYANT: I do.

HEARING OFFICER ORTH: Thank you. I'll start your time.

MR. BRYANT: My name is Robert Bryant. I reside in Corrales, Mexico with my wife, Karen, who is a retired RN, and she is a second-generation New Mexican. And we have four children, six grandchildren and six great grandchildren.

I was from Virginia originally and I served in the U.S. Navy over 30 years, and then I became a New Mexico State Trooper. I retired from there. I was stationed at Kirtland Air Force Base, went into the Navy. When I retired, I had a rental business at one time in Corrales which sold because of irritants with tenants.

And my reason for keeping the oil and gas industry growing in the U.S. is, number one, it's national security. At this point, we are buying oil from countries that are not friendly to us and they can shut off supply at any time.

The cost of fuel has raised prices for everything from groceries to clothing and everyday items. And it's because of shipping with the oil

prices for semis. People are losing jobs as businesses are shutting down due to the high cost of fuel. And people can't afford to put fuel in their vehicles to go to work anymore. It's either food or gas.

And cutting back on or curtailing drilling in New Mexico also cuts out many needed jobs in New Mexico and also revenues from oil and gas for education in New Mexico.

When the wells are shut down, it takes time and money to re-drill. And the communities in the drilling areas are struggling economically and it's stressing our agricultural industry due to the cost of fuel.

Thank you, Commissioners, for listening to me this morning.

HEARING OFFICER ORTH: Thank you, Mr. Bryant.

Anyone else at all on the platform? I don't see any other hands.

We will go back to our technical case then. Mr. Ezzell would you join us up at the front.

MR. CLOUTIER: Madam Hearing Officer, while Mr. Ezzell is taking the stand, IPANM has Exhibits 37, 38 and 39, which were sponsored by Mr. Cantrell,

who we withdrew as a witness. We just ask that those three exhibits be treated as part of his written public comment which was his former testimony.

Second we have IPANM Exhibit 45, which I used in cross-examining Mr. Powell. We will not be using it in our case.

And the declaration of Ms. Johnson, which is 45, simply authenticates certain documents. We received in the request for the department, and we move the admission of Exhibit 45.

HEARING OFFICER ORTH: All right. I'll pause for a moment in the event there are objections to the Cantrell Exhibits 37, 38 and 39, with them becoming public comment. No?

All right. They're admitted.

(Admitted: IPANM Cantrell Exhibits 37, 38 and 39.)

HEARING OFFICER ORTH: And now Exhibit 45, this documented receipt of documents through IPRA. Any objections?

All right. Exhibit 45 is admitted.

(Admitted: IPANM Exhibit 45.)

HEARING OFFICER ORTH: Thank you Mr. Cloutier.

MR. TREMAINE: Madam Hearing Officer as

another housekeeping and threshold matter. I did just circulate this morning to all of the parties proposed OCD Rebuttal Exhibit 34. I'm sure people have not had a chance to review that yet. It directly rebuts the testimony which arose on cross-examination by Mr. Armstrong yesterday.

I think it's imperative for the Commission to see this. I'm happy to take it up at a later time. I just want it on the record that we need to discuss that. I will be moving for its admission. I do think it is appropriate as rebuttal or surrebuttal as the point made by Mr. Armstrong only came up yesterday afternoon.

I do have alternative bases that I believe would achieve its admission, but I prefer not to get into those if not necessary.

HEARING OFFICER ORTH: All right. Let's take that up when we have finished with Mr. Ezzell.

All right. So when we broke last night, Mr. Ezzell had completed his testimony. And we move now to cross-examination, which is limited to 45 minutes. And we'll start with Ms. Fox or Mr. Tisdel.

MS. FOX: Thank you, Madam Hearing Officer. I have a few questions for Mr. Ezzell.

THE WITNESS: Good morning.

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MS. FOX: Good morning.

CALDER EZZELL,

having first been previously duly sworn, testified as follows:

CROSS-EXAMINATION

BY MS. FOX:

Q. Mr. Ezzell, my name is Tannis Fox. I'm a lawyer with Western Environmental Law Center, and I represent applicants in this proceeding.

In your testimony yesterday, Mr. Cloutier referred you to a part of the definition of underground waste in Section 70-2-3A of the Oil and Gas Act, which includes the language I'm showing on the screen, that when operating or producing of any well or wells in a manner to reduce -- which requires when operating or producing of any well or wells in a manner to reduce or tend to reduce the total quantity of crude petroleum oil or natural gas ultimately recovered from any pool.

You relied on this language, correct?

A. Yes, Madam.

Q. And Mr. Cloutier asked you something to the effect of how much waste is allowed under the statute, and you said zero waste, correct?

A. Yes, madam.

Q. In order to comply with the standard of zero waste, does that mean that an operator must produce a well to its very last hydrocarbon, without regard to the economics of that well?

A. No, madam.

Q. And why is that?

A. Because no well ever produces the last molecule of hydrocarbon. You cannot recover 100 percent of the oil or gas in a reservoir.

Q. Then under your --

A. Hopefully we will have the technology to later with the help of New Mexico Tech.

Q. Then under your formulation, that waste means zero waste, does that mean that the operator must produce a well to the very last hydrocarbon that that operator can produce without regard to well economics, that is physically possible, technologically possible to produce?

A. No. There is an economic limit, and we all know that.

Q. And what's that economic limit?

A. When a well is no longer capable of producing in paying quantities. And of course that varies from operator to operator.

Q. In your testimony yesterday, you raised

concerns about applicant's proposed provisions in 19.15.9.8 and 19.15.9.9 regarding operator registration and change of operator, correct? And that citation at the beginning for operator registration --

A. Yes.

Q. -- has an incorrect 1 at the very end. I don't know how that popped up, but there it is.

Anyway, you gave testimony on these provisions yesterday, correct?

A. I don't believe I did give testimony on it. It's in my direct, in my written.

Q. You gave testimony on it when you were discussing slide 38 in your --

A. I don't know what --

Q. Do you want me to pull it up for you? Let's see here.

A. Oh, yes, have, I did give testimony. Because, if I remember correctly, I was concerned with the unresolved adjudications.

Q. And applicants at OCD propose in these provisions that the operator be required to provide certain information to OCD prior to registration or well transfer, correct?

A. Yes.

Q. And part of that information is a certification by the authorized official of the operator that the operator, as you noted, does not have unresolved adjudicated orders or unresolved settlement agreements for any state or federal violations in any domestic jurisdiction, correct?

A. That's what it says, yes, ma'am.

Q. Yesterday, and maybe this is just mistaken testimony, but yesterday you testified that the OCD doesn't have authority to require another state to provide that authority to OCD, correct? That was your testimony?

A. Yes, it was.

Q. But doesn't this provision provide that it's the authorized official from the operator that provides the information to OCD, not another state?

A. So the authorized official is intended to be a representative of the entity that wants to be the operator?

Q. Correct. And the operator registration provision, it says the certification by an authorized official that the new operator is not blah, blah, blah.

A. Right.

Q. S refers to the authorized official of the

operator, correct?
A. Correct.
Q. Yesterday, you testified that applicants in OCD's proposals at 19.15.8.9A NMAC, which I have up on the screen for you, regarding financial assurance, attempts to require operators to, quote, bond just to negotiate acquisition, correct? That was from your slide 40?
A. Repeat your question, please.
Q. You testified regarding this provision that it was requiring operators to, quote, bond just to negotiate acquisition, correct?
A. Yes.
Q. So do you appreciate that this provision was the subject of a motion to dismiss filed by IPANM and NMOGA and to dismiss this particular provision on the ground that it regulates the sale of wells between operators?
A. Yes.
Q. And are you aware that IPANM and NMOGA made this argument in their motion to dismiss, even though Peter Morgan, our expert, explained in both his direct and rebuttal testimony that the intent of the redline language was simply to clarify current OCD practice and simply require financial assurance prior to

acquisition of operating authority? Are you aware of that testimony by Mr. Morgan?
A. I'm embarrassed to say no. And I have not read the motion to dismiss either.
Q. Well, the motion to dismiss was -- the subject or your testimony was also the subject of the motion to dismiss. And perhaps not having read the pleadings, that motion to dismiss, are you aware that in IPANM and NMOGA's reply in support of their motion to dismiss that they suggested, quote, an easy fix to the problem and that was to -- and this is language from the motion to dismiss here in front of you, and that was to modify any time the words "acquire acquisition" came up in the rule, to modify that using the terms operating authority?
I'll let you read all that.
A. I see that, but I don't know that I agree that that's an easy fix. I think even with that amended language, that it would still have a chilling effect on the ability for an operator to sell its assets. And I think I testified that it is quite common to hire a broker that will create a data room for you and basically hold an auction online. But an auction and think requiring financial assurance prior to proceeding with any proposed acquisition is

chilling on the freedom to exchange properties.
Q. But you understand that the intent of this is to clarify current practice and just require financial assurance to be in place before an operation begins, correct?
A. Then take the word "acquisition" out.
Q. Well, the hearing officer -- interesting you say that about wordsmithing this, because this language was offered by your counsel and the hearing officer -- are you aware that the hearing officer in her recommendation asked applicants at OCD to address this language in their presentations?
A. I have not been involved with anything other than my direct testimony.
Q. Okay. Well, I have the hearing officer's language up here and she suggested that applicants and OCD be asked to address the suggested insertions by the moving parties. And are you aware that we did exactly that through Mr. Morgan's testimony and exhibit? And she asked us to do that to attempt to avoid the wordsmithing that I think was just going on right now.
A. That's what we do.
Q. She asked us to address that and that we submitted the proposed language, the language proposed

by IPANM as Exhibit 88 through Mr. Morgan's testimony. Are you aware of all that?
A. No. As I say, I have not been involved in any of the procedural aspects of this, especially not -- I'm a transactional lawyer. I can't spell motion to dismiss.
Q. Well, I guess this wasn't as easy a fix as we were led to believe.
In your surrebuttal testimony, you disagreed with Mr. Alexander's testimony that virtually all inactive wells were reactivated within eight years, correct?
A. Yes.
Q. And you testified yesterday something to the effect of, "I don't know what he based that representation on," correct?
A. That is correct.
Q. So are you familiar with applicant's Exhibit 13, which shows that 99 -- and this was an exhibit developed by the Environmental Defense Fund, which shows that 99.5 percent of reactivations of inactive wells occur within eight years of activity?
A. That's what it says. Yes.
Q. Are you familiar with this exhibit at all?
A. No, Ma'am.

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Q. So you don't have any data to the contrary, correct?
A. Only in my personal experience with helping clients for secondary recovery units.
Q. So you have anecdotal experience, but you don't have any data looking at the whole of reactivations and inactive wells over --
A. No ma'am, I do not.
Q. Correct? And you don't have a basis to dispute the data before you in applicant's Exhibit 13, correct?
A. Not without studying it independently.
Q. Okay. I'm going to bring up your slide 5 from your surrebuttal. Now, yesterday you testified -- now slide 5 from your surrebuttal is up, Mr. Ezzell. And yesterday you testified that federal wells are no longer exempt from the Commission requirements for financial assurance because applicants and OCD had proposed to delete a reference in this section here to 19.15.8.9A, correct?
A. Can you put them up on the same screen.
Q. I can't do two screens, but this is your slide that you testified from yesterday, where you stated that because of the deletion of 19.15.8.9A in this section, that that deleted the exemption for

federal wells from OCD rules for financial assurance.
MR. CLOUTIER: I think Ms. Fox is overstating the testimony. I think he testified that it eliminated for the wells that are subject to Subparagraph E, not all wells.
MS. FOX: For federal wells.
MR. CLOUTIER: For federal wells that would be subject to Subparagraph E.
MS. FOX: So you think his testimony was that inactive and TA federal wells are exempted.
MR. CLOUTIER: Are not exempted --
MS. FOX: Are not exempted.
MR. CLOUTIER: -- because of the strike. That, I think, was the intent of the testimony.
MS. FOX: Fair enough.
BY MS. FOX:
Q. Do you do you agree with your counsel's --
A. That's the way I interpret --
Q. Maybe wait till I finish my question.
A. Sorry.
Q. Yeah. It's hard for the court reporter. I don't mind so much, but the court reporter does.
A. Absolutely.
Q. Okay. So you agree with what your counsel just said in terms of what your testimony is, correct?

A. Yes.
Q. Okay. So can we stop sharing and go back to my slides.
Okay. So the provision that you referred to where the federal well exemption lives is 19.15.8.9A, correct? That's what you said in your slide? This is the provision that exempts federally -- essentially exempts federal wells from the Commission's rules on financial assurance, correct?
A. Yes. The language, unless the well is covered by a federally required FA.
Q. And you see that that language has not been proposed to be deleted by applicants or OCD, correct, the language that exempts federal wells from the state's financial assurance requirements?
A. That is correct. But the proposed amendment deletes the reference to that. And I think that is problematic.
Q. Do you think that reference was deleted just in order to clarify that all wells in inactive and TA status, not just those that have been TA status under two years are subject to that particular financial assurance requirement in Subpart E? Isn't that what that language -- why that language was deleted?

Because the language exempting federal wells is left unchanged.
A. That may be how it was intended. I don't think it was done very artfully.
Q. We can agree to disagree on that.
Yesterday you testified in surrebuttal that Mr. Morgan was incorrect that OCD can release a bond if a well is no longer deemed a marginal well, correct?
A. Yes.
Q. And you cited to the Oil and Gas Act at 70-2-14A for that proposition, correct?
A. Probably.
Q. Let me read it to you. You'll probably recognize it. That provision provides all financial assurance shall remain in force until released by the Oil Conservation Division, blah, blah, blah.
A. Right. But that goes to the issue of whether a bond is cancelable. And I think Mr. Morgan said it was, that they are, and I disagree.
Look at the OCD bond form.
Q. Mr. Morgan testified that the bonds are not cancelable and that that makes good policy sense.
A. Releasable --
Q. Isn't that correct?

A. Releasable and cancelable are the same to me.
Q. Let me just continue here.
A. I keep forgetting --
Q. In support --
A. -- I don't' get to ask the questions.
Q. Okay. But you don't recall his testimony in support of the idea that surety bonds should be non-cancellable? You don't recall that testimony?
A. No.
Q. Okay. But your testimony yesterday was that he was wrong, that you -- that OCD can release a bond if a well is no longer in marginal status. That was your testimony yesterday, correct?
A. Yes.
Q. Okay.
A. And I stand by that.
Q. But looking at the Commission's rules at 19.15.8.12, which I have up here, doesn't it clearly state in those rules that financial assurance can be removed if it's covered by another financial assurance that the Division has approved so that an operator can replace financial assurance if needed?
A. But doesn't the statute say that the financial assurance cannot be released until the well

has been plugged, since that was the condition upon which the financial assurance was entered into and issued?
Q. But that wouldn't preclude the Commission from passing rules that says that a financial assurance needs to be replaced, for whatever reason. The financial assurance requirements could go up. They could go down. An operator might want to use a different company for financial assurance. That provision in the statute doesn't preclude OCD from approving replacement financial assurance, correct, which is what this provision allows?
A. I would agree with that.
Q. And so then isn't it also true that applicants specifically, specifically for marginal wells, don't applicants and OCD propose that an operator, and this is the second language down here --
A. Okay.
Q. -- on that slide, that an operator with a marginal well or wells must annually review the number of marginal wells that that operator has and shall update the one-well plugging financial assurance of May 1st of each year? Isn't that what applicants and OCD propose?
A. Yes. But, again, I don't like the language

because it implies to me that the only thing they can do is add marginal wells to their list and come up with more bonding, rather than saying that -- there's nothing in that language that -- what if an operator plugs one of the marginal wells? Then he should be able to take that off the list, right?
Q. This language says that -- it doesn't say that the number of wells is -- it only applies when wells are increased. It says that the operator shall update the one-well plugging financial assurance after an annual review of the number of wells.
So it's neutral as to whether the number of wells increases or decreases, correct?
A. It has no express language that it covers both, and that's what I'd like to see.
Q. And you're aware, because this is highlighted language, that this is language that was negotiated with Oxy, correct?
A. No. I have no idea what was negotiated with Oxy.
MS. FOX: That's all the questions I had, Ms. Ezzell. Thank you very much for your testimony.
THE WITNESS: Thank you, ma'am. Nice to meet you.
MS. FOX: You, too.

HEARING OFFICER ORTH: Thank you, Ms. Fox.
Mr. Tremaine?
MR. HALL: It's going to be Mr. Hall, Madam Hearing Officer.
HEARING OFFICER ORTH: Thank you.
MR. HALL: Thank you.

CROSS-EXAMINATION

BY MR. HALL:
Q. Good morning, Mr. Ezzell. Good morning. My name's Michael Hall. I don't think we've had occasion to meet. I'm a lawyer with the Oil Conservation Division. How are you this morning?
A. I am well. How are you.
Q. Good. I wanted to respond, first of all, to your gratitude. It's Mr. Tremaine that you should thank for pointing out that you had cited a statute that doesn't exist.
A. No, it exists. I just misquoted it.
Q. Well, I guess we'll have a chance to explore that a little bit. Let me go ahead and ask you about that. Are you saying that the statute you cited is law in New Mexico?
A. Yes.
Q. Okay. Well, let's go ahead and just start there. I'm looking at -- and I'll pull it up. This

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is page 3, the bottom of page 3 of your rebuttal.
A. Yes.
Q. And would you agree it continues on to page 4?
A. Yes, sir.
Q. Okay. And I'm going to highlight some language here. You would agree that that part is operative law in New Mexico?
A. Yes.
Q. So you think the statute states shall be set by rule at amounts not to exceed --
A. No.
Q. -- $50,000?
A. No, I corrected that in my mea culpa errata statement yesterday. It is the blanket bond for those wells cannot be less than $50,000.
Q. I understand. I just took what you had said as quibbling over whether that's a real statute or not. Would agree that parts of it are real and parts of it aren't, correct?
A. The printed version or --
Q. The printed version, yes, sir.
A. Look, I really don't care. I amended it to make it correct.
Q. Okay. And you would agree you're under oath

here today?
A. Correct.
Q. And so you're under obligation to continue with your amendments and not claim that this is the law? Because it's actually the opposite of that provision, isn't it?
A. Until I corrected it, yes.
Q. Okay. Now, in what capacity are you testifying here today?
A. I am here because I am the only witness that is a licensed attorney in New Mexico.
Q. Are you here as a partner of Mr. Cloutier? Are you here as a witness? Are you here --
A. I am here as a witness. And it's not Cloutier, it's Cloutier.
Q. Mr. Cloutier is your partner, correct?
A. Yes.
Q. And so you are profiting from representation of IPANM in this matter?
A. I will admit to that. Although I want to say you haven't seen our firm's compensation plan.
Q. Nor do I want to. I'm simply exploring possible bias here. The gentleman is a gentleman, so are you. But you are profiting as an attorney and a witness in this matter? I just want that to be clear.

Is that right?
A. Yes.
Q. Okay. Now, yesterday you made several references to standard JOAs. A JOA and a COPAS agreement, those are contracts, correct?
A. Yes.
Q. They are easily modified, changed, or left in place?
A. Yes.
Q. Your familiarity is because people need a lawyer to look at those and change them, correct?
A. Exactly.
Q. The form almost never works as it stands, right?
A. I would disagree with that.
Q. Okay.
A. I mean, the AAPL took great pride in each of its forms, so that it could be executed without alteration. They did, however, in each of them have an Article 15, which is blank on the form and allows people to make any additional amendments that they want.
Q. And in your experience, these are arm's-length transactions between sophisticated parties, correct?

A. Normally. Although, with the -- in the wells that I've participated in, there's not a lot of room for negotiation because the lay operator wants to have the language that the operator likes. And so, if there is Oxy and XTO, yeah, there's a lot of arm's-length negotiation. But for a shoe clerk going in to a drilling deal, you pretty much -- it's take it or leave it.
Q. Correct me if I'm wrong. Your testimony, the crux of your testimony about JOAs and COPAS is that it's going to cause a lot of problems, correct?
A. My testimony was that I don't think that under any of those forms, an operator can pass along the cost of the financial assurance.
Q. However, that's something an operator or anyone else who's a party to those contracts could have contemplated, correct?
A. No. Because every non-operator in the world will swear on a Bible that bonding costs should be covered by administrative overhead.
Q. I see. So there's disagreement in the industry about the effect of these agreements?
A. I don't know that there's disagreement because I don't know that operators -- none of my operators have ever attempted to pass along the cost

of bonding.
Q. But my question is really simple. A provision to contemplate bonding and how those risks and costs are borne by the parties to the contract, that's always been possible, hasn't it?
A. Always.
Q. Now, I'm going to jump around just a touch. Did I hear you claim that an operator has to have more than zero percent property interest in a well yesterday? That's what I wrote down, and if that's not what I heard --
A. No. An operator can have no interest.
Q. Okay.
A. If they're contract operators or under the JOAs, I think I gave the example of an operator resigning but being forced to continue to operate the well.
Q. Fair enough. And an operator may or may not own a property interest, a mineral interest, et cetera, correct?
A. Or leasehold. Yes.
Q. So the idea that regulating operators necessarily regulates property interest would be incorrect, wouldn't it?
A. If an operator owned no interest in the real

property, then I would agree with that. But if an operator owned any interest, then I stand by it.
Q. And once again, that's an agreement between the parties as they see fit, correct?
A. Yes.
Q. And so the corollary to that is -- is it your claim that New Mexico does not have the right, OCD does not have the right to regulate operators and who can be an operator?
A. I think it is OCD's job to regulate operators, but I don't think it's their job to choose who gets to be one.
Q. Well, who would do that?
A. Well, I'm a free-market guy. I think you have the right to enter into a business and fail.
Q. Sure. So you think extremely non-compliant -- I don't think of some -- Cano. You think Cano should be an operator and OCD should have no say in that because of your free market beliefs?
A. Well, in hindsight. But we did allow to be an operator and we did accept their bonds, and so they were. It turns out they were lousy.
Q. Do you think, as you sit here today, OCD should have no right to regulate Cano, for instance, as an operator?

A. I think they have the right to regulate and enforce, but not to pick who isn't worthy. It's not like an operator has to apply for a permit to be an operator.
Q. Well, they do, don't they?
A. Well, they do, but not to be able to even enter into a negotiation to buy a property. That's just not the OCD's business.
Q. You do some work in Texas oil and gas; is that right?
A. No.
Q. Are you familiar with the language Ms. Fox put up about acquisition of operatorship? Does that comport with your understanding of what the railroad commission does in Texas?
A. I'm not licensed in Texas, and I've never even participated in oil.
Q. What is problematic about that language?
A. As I've already stated, I think it is chilling on the free exchange of real property interest.
Q. You would agree that that proposed rule does not, in any way, inhibit or regulate the transfer of real property? It only regulates who may be an operator, correct?

A. I didn't say it regulated. I said it chilled the free-market ability to enter into negotiations to potentially buy properties.
Q. You have to read some language in there about owning property for that to be accurate, though, correct?
A. Say that again, please.
Q. Sure. You have to read some language that's not there in the rule for that to be regulating real property.
A. No, I don't think you have to imply any language. I think it says you can't -- you have to promise not to even negotiate the acquisition of a property unless you posted a bond.
Q. Of operatorship, not property, correct? It doesn't say property?
A. But it still has the chilling effect on the free exchange of real property interest.
Q. At any rate, the rule says what it does, right? It doesn't say property; can we at least agree on that?
A. The word "property" is not in it.
Q. Thank you. Now, in some of your testimony, is it your position that OCD has not considered depth in these proposed rules, depth of wells?

A. Yes. There is nothing in it that -- in the proposed rules that refers back to the statute which says the OCD shall consider these things.

It's just the proposed rules say here's the amount of the blanket, here's the amount of the single well. The only remaining discretion that the rules give to the OCD is on the blanket bonds not to be less than 50,000 and on a single-well bond for an active well that has to be in an amount equal to the cost of plugging.

Q. It says consider the depth, correct?

A. Yes.

Q. It doesn't say you have to -- you have to make financial assurance attached to depth. This says that should be a factor considered. Can we agree on that?

A. Yeah. That is what the statute requires.

Q. And you surrebutted Mr. Powell's testimony -- was part of that testimony that you heard that it was considered and it wasn't found to be correlated to -- depth wasn't correlated to plugging costs in the manner that age did, for instance?

A. Would you restate that.

Q. Sure. Did you hear Mr. Powell say that depth was considered, but it did not really correlate

to the cost of plugging?

A. I heard -- I heard that. I disagree with it.

Q. Sure. So, at any rate, we agree that it was considered?

A. I don't know that it was considered in the manner required by the statute. You cannot say a 900 foot San Andres well is going to need $150,000 bond. That's just reality of the business.

Q. But my question was, would you agree it was considered, Mr. Powell's testimony makes clear it was considered? You don't agree with how he considered it, but it was considered. Can we at least agree on that?

A. I will agree that he claims it was considered.

Q. Fair enough.

A. Isn't it fun?

Q. Much like you claim it wasn't, right?

A. Yeah.

Q. Now, speaking of the statute, you would agree that it's OCD's costs that bonding needs to cover, not industry's, correct?

A. That's the way it's written, and I think that's the biggest problem with it in the beginning.

The OCD they've got wonderful experts, but industry can plug any well cheaper than the OCD.

Q. But an orphaned well hasn't been plugged, correct, by industry?

A. That's right. And I would love to see the reclamation fund be adequately funded and then have the OCD have the ability to say --

Q. Fair enough. Would you agree to just answer my questions? Only at 45 minutes. I know you'll have your opportunities to say what you think should happen with the reclamation fund.

A. You can't blame me for trying to kill your time.

Q. Well, I kind of do blame you for that.

Now, your testimony also stated that reclamation was part of the 163,000 average costs for OCD's well plugging. Do you still maintain that.

A. I don't know that I said that.

Q. Okay. Well, we can pull it up.

A. Because I don't -- I don't agree with that number in the first place.

Q. All right. Okay. Can you see the top of the page there? Could you read that paragraph for me, please?

A. Starting with fourth.

Q. Yes sir.

A. "Fourth, the proposal is based on a supposed average of OCD's cost to plug, abandon, and reclaim individual oils. Under the Oil and Gas Act, only 'plugging' costs can be considered."

Q. Do you still maintain you didn't say that?

A. No. I put it in my direct testimony.

Q. Would you like to change that testimony?

A. No.

Q. You do think that part of the 163,000 was to reclaim wells?

A. I don't know anything about the 163,000 other than what's been said here. I also know that if you look at the annual reports from the department to the legislature and the governor, and this was in Morgan's testimony, I guess, from 2019 to 2024, the OCD extended 15.5 million to plug 93 wells --

Q. So --

A. -- at an average cost --

Q. -- let me ask you a different way. What is the basis for your statement that the proposal is based on a supposed average of OCD's cost to plug, abandon, and reclaim individual wells?

A. Well, the word "supposed" is -- was there because --

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Q. What's your basis for that statement, sir, in your testimony?
A. The basis for it is that the Oil and Gas Act does not talk about reclamation costs in the financial assurance.
Q. What evidence makes you think that the proposal is based upon that?
A. Because that's the figure that the applicants have been using, that it is 163,000 and that it's etched in stone and it doesn't matter on the depth of the well or the age of the well or anything else.
Q. Would you agree that that 163,000, the testimony is solely that that is plugging cost and not a reclamation cost?
A. Yes.
Q. You'd dispute that?
A. No. You asked me if I agreed. Now you're killing your time.
Q. Okay. Now we're going to get to the part where your statute -- that had parts that don't exist, and some of your testimony relies on that as opposed to just single words.
Do you maintain that under the proposed definitions, marginal wells will be bonded at

300 percent, the maximum amount authorized by statute?
A. No. That's the minimum amount as -- we're going back to what I've already corrected.
Q. Well, 300 percent is incorrect, too, isn't it?
A. Oh, I don't think so.
Q. Okay. That's 300 percent of the minimum amount?
A. This is just --
Q. We can take that whole sentence.
A. Three times 50 is 150.
Q. Do you agree that when you make the maximum TA 50,000 instead of the minimum 50,000, the entire crux of this entire paragraph changes?
A. It doesn't matter other than -- I mean, the statute is what the statute is.
Q. I very much agree with that.
A. The fact that we got the wrong word on the page does not change the statute. It does not make the statute not exist.
Q. The statute does exist, just not as you stated it in your rebuttal testimony, correct?
A. It exists as I stated in my correction to typographical errors.
Q. Just so the record is clear, your testimony

is based upon that faulty understanding of the statute, correct?
A. No.
Q. It's not?
A. My testimony is based on the statute.
Q. Okay. The statute I cited in your rebuttal testimony, correct?
A. The statute as in the book.
Q. Okay. Now, down here on page 9, line 18 --
A. Of what? Oh, okay.
Q. Of your rebuttal testimony. Would you agree that you don't know why the legislature did or did not take actions?
A. Because they could agree on -- the parties couldn't agree on what -- the proponents of House Bill 133 could not agree. And anytime the industry tried to comment, it was basically flatly ignored. The fact that --
Q. Well --
A. -- there were two -- I'm talking.
The fact that there were two committee substitutes, one in energy, one in --
Q. Well, hold on. You're talking, but you're not answering my question. My question should be yes or no. Do you agree that you don't know why the

legislature did or did not act a certain way, that you're not the arbiter of that?
A. No. But I was there and witnessing it, and they didn't act --
Q. Would you agree that --
A. -- because it was a bad bill?
Q. Would you agree --
MR. CLOUTIER: Mr. Hall keeps interrupting the witness. He's entitled to answer, even if Mr. Hall wants a yes or no.
HEARING OFFICER ORTH: All right. So, Mr. Ezzell, if you would please bring more focus to the question that's being asked. And, Mr. Hall, please don't step on the end of his sentences.
BY MR. HALL:
Q. At any rate, it could have been that the legislature, like the LFC, thought that the statutes weren't necessary because the rules already allowed what's happening here today, for instance, correct?
A. I cannot speak to that. I do not know.
Q. Fair enough. That's what I wanted us to agree on.
Okay. I'm going to go to a couple of comments in your surrebuttal. If I can find it. Excuse me.

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Mr. Ezzell, now, on your surrebuttal, it's slide 10, and I'll pull it up here in a sec. But would you agree that based on 180 days of production, this proposed rule is not requiring low producers to simply plug? It's requiring low producers to produce or take appropriate actions.

A. I don't understand why the 180 days comes into your question, so...

Q. Well, would you agree that the definition of -- proposed definition of marginal will includes both days of production and volumes?

A. Yes.

Q. Okay. And I believe your testimony was that these rules are going to require people to plug wells?

A. I think it will, that is the effect. Yes.

Q. And so --

A. It won't require them to. It will force them to.

Q. What's the difference between forcing and requiring?

A. Requiring is a regulatory action or a legal action. Forcing is a businessman making a decision that he's got to plug.

Q. Well, at any rate, an operator producing less than 180 days could go above 180 and that well

wouldn't be marginal, correct?

A. That is correct.

Q. There was some discussion about a release of financial assurance. Would you agree the Oil and Gas Act does allow and, in fact, requires OCD to release bonds at the appropriate time, and not only in the event that they're plugged?

A. That's the only time the statute says that the OCD can release a bond, is after the plugging has been performed according to the rules then in effect.

HEARING OFFICER ORTH: Mr. Hall, you still have 15 minutes. But I'm wondering if this would be a good time for a break.

MR. HALL: Whatever pleases the Commission is fine with me.

HEARING OFFICER ORTH: All righty. Let's come back at 11:00. And, again, you have 15 minutes left.

(Recess held from 10:50 to 11:00 a.m.)

HEARING OFFICER ORTH: All right. When we broke, Mr. Hall had 15 minutes left of his 45.

Go ahead, Mr. Hall.

MR. HALL: Thank you, Madam Hearing Officer.

BY MR. HALL:

Q. Ezzell, I think we were starting to talk

about financial assurance a little bit. Is it your contention that OCD cannot release a bond unless a well is plugged?

A. I believe that's what the statute says.

Q. Okay. Which statute?

A. The Oil and Gas Act.

Q. Just wondering if you had one in mind, because I think what you're talking about is 70-2-14 relating to financial assurance?

If I could, I'm going to highlight this last sentence there and ask if you could please read that.

A. The Oil Conservation Division shall release financial assurance when it is satisfied that the conditions of the financial assurance have been fully performed.

Q. So that doesn't mention plugging, does it?

A. Not directly, No.

Q. Okay. So is there another statute that you're getting -- that you're referring to?

A. Well, on a plugging bond, that is the condition of the financial assurance, is that the well be plugged.

Q. Right. But that wasn't my question, was it? I didn't limit that to the plugging bonds. I said

bonds. And so if you'd like to correct your understanding, that's fine?

A. My understanding of what.

Q. Do you still stand by your statement that a bond can only be released in the event a well is plugged? That was my question, and you said yes, that that's what the statute requires. So I'm asking --

A. And of a condition of the bond was the plugging of the well --

Q. Okay. Did you understand my question? Just please pay attention to my question. It does not have the words "plugging bond." Okay?

A. That is correct.

Q. All right. My question is, do you maintain that OCD can only release a bond of any kind in the event that a well is plugged?

A. They can only release a plugging bond after the well has been plugged. What other bonds are you talking about?

Q. Do you maintain -- can OCD release a bond when a well is transferred amongst operators?

A. The bond is generally transferred in the well. I guess -- I think the OCD probably has the authority to enter into a new bond if the selling party was under a blanket bond and the buying party

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was going to be a one-well bond. That would require a new bond.

Q. Did you understand my question?

A. I think I answered your question.

Q. Does OCD release bonds when operatorship of a well is transferred?

A. They have the authority to, especially if the bond is not transferred.

Q. And so that's an example of a bond being released even when a well is not being plugged, correct?

A. It's not so much being released, as it is being replaced.

Q. Do you agree this highlighted sentence here does not say anything about plugging?

A. I agree.

Q. Okay. So would you agree that in the event a marginal well rule is passed, that if the conditions of that bond are satisfied, regardless of plugging, it can be released? Reading that line right there, that would be compliant with that statutory authority?

A. If it is a plugging bond.

Q. Would you agree with that -- okay?

Now, Ms. Fox asked you a little bit about waste. I think your testimony focused on

underground waste. Would you agree with that?

A. No.

Q. I'm sorry, I didn't understand?

A. No.

Q. No, that's not what you focused on?

A. Economic waste, the drilling of unnecessary wells, specifically underground waste in -- caused by premature plugging. But no, there is more than one definition of waste.

Q. My question was, you would agree your testimony focused on underground waste, correct?

A. I talked about economic waste as well.

Q. Well, let's just pull it up. 70-2.3, correct, that's the waste statute you're referring to and citing there?

A. That's the definition of underground waste, yes.

Q. And so you have to point to me in your testimony, and I'm happy to shift it around, where you talked about all these other kinds of waste.

A. I talked about the economic waste and the drilling of unnecessary wells yesterday in my live testimony, not in my written.

Q. Do you agree the statute also defines surfaced waste?

A. Oh, yeah.

Q. Do you agree that excess production beyond the reasonable market demand may be waste?

A. Yes.

Q. Are you aware that unauthorized venting or flaring of natural gas is prohibited as waste?

A. Yes.

Q. Are you aware that 60 percent of orphaned wells observed by OCD are venting natural gas?

A. I cannot answer that.

Q. Do you have any reason to dispute that?

A. I assume I could confirm it with independent research, but...

Q. Do you have any reason to dispute that, sir?

A. I have no reason to dispute it or agree with it.

Q. So that would be 60 percent of orphaned wells are wasteful, committing waste under the statute, correct, if --

A. Correct.

Q. -- that percentage is correct?

A. Yes.

Q. And so you would agree that waste is a little more complicated than just produce all you can, wouldn't you?

A. Oh, absolutely.

MR. HALL: I'll pass the witness.

Thank you, Mr. Ezzell.

HEARING OFFICER ORTH: Thank you, Mr. Hall, Mr. Biernoff or Mr. Moore.

MR. BIERNOFF: Good morning, Madam Hearing Officer. Ari Biernoff here for the commissioner of public lands and the State Land Office.

CROSS-EXAMINATION

BY MR. BIERNOFF:

Q. Good morning, Mr. Ezzell?

A. How are you.

Q. I'm well. How are you today?

A. Good. Thanks.

Q. Okay. I wanted to just follow up on some of Mr. Hall's questions?

You're not testifying in this proceeding on behalf of the Hinkle Law Firm, are you, Mr. Ezzell?

A. No. I'm testifying on behalf of IPANM.

Q. Okay. You're not speaking as a representative of Hinkle, you're giving your own personal opinion; is that right?

A. Yes.

Q. Okay. You're not here on behalf of any particular client of you or your firm, are you?

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A. I am here on behalf of IPANM, of which I am a member.
Q. Okay. Not any particular oil and gas operator or producer?
A. No.
Q. Okay. Just wanted to clear that up?
You've talked in your oral testimony and also written in your pre-filed testimony about joint operating agreements. And you've provided a lot of detail on specific forms that the American Association of Professional Landmen have developed, right?
A. Yes.
Q. Generally speaking, who are the parties to a joint operating agreement?
A. The operators and the non-operators.
Q. The OCD is not a party to joint operating agreements, right?
A. No.
Q. The OCD does not approve or disapprove joint operating agreements, right?
A. No, it does not.
Q. Okay. And the OCD as a non-party is not bound by the terms of joint operating agreements, right?
A. Absolutely. Correct.

Q. Okay. In your written testimony, your direct testimony, you make an observation that I want to review and discuss with you. This is from page 46 of your written direct testimony?
You state that: On an overall basis, this. And I think you're referring to beneficial use is a brand-new legal concept as applied to oil and gas wells and operations. Beneficial use is a concept that is used and well developed in water law in New Mexico and other western states. It has never been a concept in oil and gas law in New Mexico statutes, regulations, common law, or contracts. And that's the end of the quote.
Do you stand by that testimony, Mr. Ezzell?
A. I think the term "beneficial use" is in the administrative code for maybe the definition of an inactive well. I can't remember. But I think the term "beneficial use" or "beneficial purpose" appears somewhere.
Q. Okay. And, in fact, the term beneficial use is in statute, isn't it?
A. I could not point you to the statute other than the water law.
Q. The term beneficial use is in the Oil and

Gas Act, section 70-2-3, isn't it?
A. Probably.
Q. Do you want to look at it together?
A. I don't have it in front of me, but I believe you.
Q. Okay. And it's also, I think you noted, in NMAC provisions, in Title 19, Chapter 15, regulatory provisions that apply to the OCD, right?
A. Yes.
Q. Okay. Thank you. Mr. Ezzell, in your written direct testimony, you state the following. This is from page 50 of your testimony: We all know the handful of operators out there who are giving industry a bad name in this regard. There must be other regulatory means of cracking down on these abuses. End of the quote?
Mr. Ezzell, how many operators are out there, approximately, giving industry a bad name in New Mexico?
A. I couldn't put a number on it.
Q. Okay. You used the phrase "a handful." How many is that, more or less?
A. I can't give it a number.
Q. Mr. Ezzell, if there were 50 or 100 bad operators flagrantly out of compliance with OCD rules

and perhaps other obligations, would you consider that to be just a handful?
A. If there were a hundred, probably -- no, I wouldn't consider that a handful.
I use that term just to say that most of industry is responsible, and that there should be a better way than to punish good operators with this rule. There should be a better way to get the enforcement done on the bad operators.
Q. Okay. Well, so before we move on from this point, I know you said that you don't think 100 would be a handful. Do you think 50 is a handful? Would you consider that to be a handful?
A. Yeah, probably. I think there was testimony there's over 600 operators in the state. I don't know. I don't know that for a fact. I thought there was testimony to that somewhere.
Q. Okay. It doesn't trouble you if there's in the neighborhood of 8 or 10 percent or more operators in New Mexico who are out of compliance with OCD rules?
A. Well, it troubles me. But that's why we have the OCD and they have the enforcement powers they do to get 'em.
Q. Okay. Good, good. Well, that's good to

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hear. The passage that I read from your direct ends with the following statement: There must be other regulatory means of cracking down on these abuses? What are those other regulatory means? Have you given any thought to that?

A. Well, all the tools that the OCD has in the toolbox. The notice of violations. You know, you can get the attorney general to go after them. You've got a lot -- OCD has lots of tools to regulate the industry.

Q. Is claiming bonds, financial assurance held by non-compliant operators, one of those tools?

A. It should be. I don't know how often it's done. I think there's been testimony that it's problematic to get them collected.

Q. Okay. Well, do you happen to know how many clients of the Hinkle law firm, your law firm, have had their bonds pulled by the State Land Office for their pervasive environmental non-compliance? Do you know what that number is?

A. I have no idea.

Q. Okay. Mr. Ezzell, do you support additional legislative appropriations to give OCD the ability to develop additional alternative means of cracking down on the abuses that you describe committed by a

minority of oil and gas operators on page 50 of your direct testimony?

MR. CLOUTIER: Objection. Vague.

HEARING OFFICER ORTH: What was vague about it? I'm sorry.

MR. CLOUTIER: He's asking about legislation solutions generally. There's no specific legislation that Mr. Ezzell is being asked whether he supports or -- assuming this is even remotely relevant. But I think he's entitled to know what the proposal is that he's supposed to support or not support.

HEARING OFFICER ORTH: Mr. Biernoff, I thought you described it, which was to get OCD more resources. But if you want to be a little more specific, perhaps Mr. Ezzell can answer it.

Q. Well, so I'm not a legislator. I know that we have at least one legislator who was on the call, on the hearing this morning, who happens to be married to Mr. Ezzell. And so I'm not in that position. I don't introduce legislation. I did think the question was clear and I'll restate it?

BY MR. BIERNOFF:

Q. Mr. Ezzell, you reference other regulatory means of cracking down on abuses by bad operators. And I'm asking you, do you support additional

resources through the legislature for OCD to identify and implement alternative regulatory means of cracking down on the abuses that you've referenced?

A. I think in your original question you said appropriations, and I don't necessarily agree with just appropriating money. I would support legislation, and hope I get a chance to in January, I would support legislation that uses the conservation fund and funds the reclamation fund and not a dime is diverted to the general fund, which is what the legislature did years ago to balance the budget.

I think the conservation fund needs to be used for its intended purpose, and that's funding the OCD and funding the reclamation fund.

Q. Mr. Ezzell, are you in favor of, do you support additional FTE, that is additional staff for the Oil Conservation Division, to develop and implement other regulatory means of cracking down on operators' abusive conduct?

MR. CLOUTIER: Objection. Relevance.

MR. BIERNOFF: Madam Hearing Officer.

HEARING OFFICER ORTH: Go ahead, Mr. Biernoff.

MR. BIERNOFF: Yeah, I think it's very appropriate, since Mr. Ezzell has mentioned that

there are alternatives to dealing with the bad operator problem, to explore what those might be, and that's what I'm doing here.

HEARING OFFICER ORTH: That's what I thought. Please go ahead.

A. It's not my job or my place to tell the OCD how to do their business. I assume that the director knows the capabilities of his staff. And if they are not enforcing compliance because they don't have enough staff, they need to hire more people. And that's what --

Q. -- what I'm asking you --

A. -- the budget is.

Q. Mr. Ezzell, I'm asking you if you would support such an effort, since you have identified alternatives to this proposed rule. You're saying you don't support the rule. I think we've all heard you loud and clear on that score. And you're saying -- you recognize that there's a bad operator problem, and you're saying there's alternatives. So I'm asking you, would you support additional staff resources for OCD to implement your proposed alternatives?

A. If I were a litigator, I'd say asked and answered. But I think I just answered that.

Yes, if the OCD cannot do the compliance

it wants to because of lack of staff, they need to get more staff.

Q. And you would support such an effort; is that right?

A. I just said that, yes.

Q. Okay. Good. Now it's been asked and answered?

Mr. Ezzell, let's keep moving through your direct testimony. I'm not going to read all of it because there's a lot of text. But on page 56, you are discussing the ability of OCD to consider regulatory violations by operators in other jurisdictions. And now I'll start reading it.

As written, these provisions seem to suggest that the Division in the first instance is empowered to decide whether the applicant or proposed new operator is out of compliance with some other state's or federal law. The suggested provisions do not require that, for instance, state or federal regulatory agency charged with enforcing those laws have found the applicant or new operator to be out of compliance, just that they are out of compliance.

I do not know of any expertise within the Division, and would be surprised if it existed, to interpret another state's laws and regulations or most

federal oil and gas laws and regulations. I also question what resources would have to be devoted to that issue.

Okay. I have a few questions for you about that testimony. And The first is, is it your position here in this proceeding that the oil conservation Division should ignore compliance violations that a particular operator, a New Mexico operator, may have encountered in another state or with the United States government?

A. I think that is certainly a factor that the OCD could consider. But the way the proposed rule is written, it does not address the severity of the violation, whether the violation has been corrected. That's the problem I had with the unresolved adjudications issue that we talked about yesterday.

Yeah, I absolutely think that it is within OCD's interest to investigate. But I don't think it's in the OCD's purview to be able to just thumbs up or thumbs down someone that wants to do business in New Mexico.

Q. Well, let's explore that a little bit further. You said that it's a factor that's reasonably considered by OCD, the compliance or non-compliance of companies in other states or with

respect to the federal government. And then you also said, but it's not something that OCD should give a thumbs up or thumbs down?

Help me understand that gap between it being a factor, non-compliance in other jurisdictions being a factor, but not being something that OCD can take any action on.

A. Well, to the extent that the OCD is determining a bond amount on the blanket, on the plugging bond for the TA wells, then I would think the OCD would certainly want to investigate the operator's history elsewhere.

I do not want to see a situation created when all of our environmentalist friends will start running around the country trying to find violations so they can turn them into the OCD to get OCD to try to come down on somebody.

Q. Mr. Ezzell, is it your view that anyone who wants to operate oil and gas wells in the State of New Mexico should be allowed to do so regardless of their compliance track record?

A. If they are adequately bonded, yes. As I told Mr. Hall, I'm a free-market guy and I don't think -- you know, bad operators will be bad operators and they will fail. But I don't think that the

government should be able to say, "You cannot do business, this business, in our state."

Q. Okay. So just to be clear, an operator like Cano Petro that leaves behind scores or more of inactive wells, if it comes back from bankruptcy or finds new venture funding, can resume operating in New Mexico from your point of view, that's not a problem?

A. If they are adequately bonded and the OCD has the ability to enforce their compliance rules, then yes --

Q. Well, so --

A. -- they should be.

Q. Okay. And I'm sorry for interrupting you. I didn't realize you were still answering?

Mr. Ezzell, what does adequate bonding look like for a company like Cano Petro? Your testimony from a minute ago is that a company that's left behind a very large number of inactive wells unplugged should still be allowed to operate as long as there's adequate financial assurance. So, what is adequate?

A. 250,000 statewide bond, or just the bonds that are in the statute.

Q. Okay. A $250,000 statewide bond. Cano

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Petro operated scores of wells, and let's say that it wants to do so again. And you're aware of what average plugging costs are, according to your own testimony and other IPANM witnesses' testimony, right?

A. I have learned that there is no agreement on average plugging costs. But I know that the 250,000 bond would not cover all of the Cano wells.

But if they came back -- well, they're not going to come back into the state because you guys would be able to do your enforcement against them. And so I don't really think that that's a good example to use.

Q. Well, do you have another example in mind of an operator who has left behind a large number, and let's say for purposes of discussion, we're talking about a few dozen or more inactive wells unplugged and their sites unremediated? Do you have an alternative example that you'd like to discuss?

A. Well, in that situation, again, we've already discussed the fact that the conservation tax has been collected from even the bad operators, because you can't dodge the tax that is withheld basically at the wellhead.

And so, if that money were used as it was intended, there would be adequate funding to cover

the type of wells you're talking about when an operator disappears.

Q. Okay. So I just want to make sure that I understand you, Mr. Ezzell. Whether we're talking about Cano Petro or another non-operator, if you think of an example, let me know. I will do the same? Whether we're talking about Cano or somebody else, a company, as you see it, can leave behind a multi-million dollar compliance problem, reconstitute or emerge from bankruptcy or find new investment, return to active operations in New Mexico, operate scores of wells or more, and that's okay as long as there's a $250,000 bond in place because money is collected through the tax that you described? The conservation tax that you referenced will pick up the difference? Is that right?

A. I think that is the best scheme. I think it is unfortunate that situations like Cano even occurred in the first place, because they just -- all of their wells didn't just become out of compliance overnight.

And that's why I have testified that I would support the OCD in vigorously enforcing the rules. And I think the rules that we have in place now are adequate.

Q. Well, okay, thank you. That was actually a

question I had for you and you've answered it. So thank you for reading my mind?

We can look at page 58 of your direct testimony and you state the following: If this Commission determines it has the authority to adopt such a policy, and in parentheses, and I do not think it does, and agrees that some risk-based approach is needed, arbitrary numbers like 15 percent marginal wells do not assess any risk. That can only be done by looking at individual operators. That's the end of the quoted passage.

My question for you, Mr. Ezzell, is do you support OCD undertaking an analysis of the risk profile of individual operators? You say here that can only be done by looking at individual operators. Do you support that kind of an operator-by-operator individualized analysis?

A. On existing operators or prospectives?

Q. Let's start with existing operators. Do you support an analysis of individual operator's risk, compliance history, whatever else you have in mind when you say that a risk-based approach is possible?

A. So I'm sorry. I thought you were through.

Q. Go ahead and answer?

A. If the OCD is doing its job and has the

manpower to do its job, then that is already occurring. That's what they do. That's an assessment of the risk. They look -- you know, the field inspectors do what they do. They go and inspect.

And if it is a minor violation, generally fixed with a phone call. If it's more serious, then hopefully the OCD is able to pursue it. And that operator will not turn into a Cano.

Q. But, again, to be clear, your view is that $250,000 is the most that any operator, regardless of compliance behavior, that's the most that they should be required to bond with OCD, right?

A. That's what the statute says.

Q. But I'm asking you about what your view is of what's adequate. Because we've been talking about what's adequate. Is $250,000 adequate for any operator?

A. I think -- yes.

Q. Okay. And would you, Mr. Ezzell, would you support -- you mentioned manpower as a consideration. If OCD needed additional staff resources to undertake this very granular risk assessment, would you support OCD receiving those additional resources from the legislature?

A. As I've already stated, I would support them

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that they reset receipt of those additional funds from the use of the conservation tax. Everybody has said that time and time again that the oil and gas industry needs to clean up its own mess. The oil and gas industry by paying the conservation tax for the life of a productive well is repaying a fund to clean up its mess.

Q. And what if there's not enough -- okay, Mr. Ezzell. What if there's not enough money in the fund to pick up and cover the cost of outstanding plugging, remediation and reclamation activities?

We heard in public comment this morning from one commenter who said that there's a significant shortfall Between what's in the fund and what's needed to actually do the work. If there is such a shortfall Let's assume the commenter is right for the time being, what then? Where do those additional resources come from?

MR. CLOUTIER: Madam Hearing Officer, I ask that the witness be allowed to complete his answer before Mr. Biernoff interrupt and pose a new question.

HEARING OFFICER ORTH: All right. Thank you.

Go ahead, Mr. Ezzell.

A. The only gas industry pays over $100 million a year in conservation tax. If it all was funneled to pay for the operations of the OCD and to fund the reclamation fund, that's over a billion dollars in ten years. The --

Q. Okay. Mr. Ezzell, you're not --

A. There's plenty --

Q. -- answering my last question?

A. There's plenty of money.

Q. Mr. Ezzell, you've made this point several times, and it's not responsive to my question, so I am going to need to interrupt you. And I'm going to remind you of what my actual question was and ask you to answer it?

My question was, assume for the moment -- I'm not asking you to agree that it's true, but assume for the discussion that what the commenter this morning said is true, and that there is indeed a shortfall between what is available in the fund and the total cost of addressing inactive wells, remediation that needs to be done, et cetera, cleanup. How does the shortfall get filled? Where does that money come from?

A. I think I've answered that.

HEARING OFFICER ORTH: I haven't heard an

answer, Mr. Ezzell.

A. I want it to come from the collection of the conservation tax and the appropriate use -- I don't want to dime of the conservation tax going to the general fund, which is what's happening to it now. That's why there is a shortfall.

If the shortfall continues -- the conservation tax is collected every month. And the reason the result of having a shortfall will not be that wells won't get plugged and sites remediated. It will just mean they won't get that done as fast. It will cause a delay.

Q. I want to make sure I understand your answer. Are you testifying, Mr. Ezzell, that money that should be going to well-plugging and spill remediation and related activities is instead from the conservation tax that's collected, is instead going to the general fund, and you believe that to be a problem? Is that your testimony?

A. That is my testimony.

Q. Okay. Mr. Ezzell, on page 58 of your direct testimony, you're discussing the 15 percent threshold. That's the context. And here's the statement that you make: In my testimony already, I have described situations why an operator might want to have inactive

wells or marginal wells in their portfolio because of future development plans?

Do you have any idea, do you have either a precise number or an approximate number of how many of the oil and gas companies that are out of compliance with OCD rules who have made this argument? Do you have any idea of the number or, let's say, the percentage of oil and gas companies who say in response to a compliance demand, "We have future development plans for these wells"?

A. I have no idea how many or what percentage.

Q. Okay. Do you have, you reference here -- I don't know if you have a specific company in mind, because you go on to say, I'll quote: You may be looking at an operator with a very strong balance sheet and has a significant portion of highly productive wells in its portfolio, but has marginal wells for reasons of, for instance, forming a unit. That operator does not seem to pose any danger of default to the State of New Mexico. End of the quote.

Do you have a specific operator or operators in mind, that is, when you refer to companies that have a lot of inactive or marginal wells, but that don't seem to pose a risk to the state? Who are you thinking of there?

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A. I was not thinking of anyone in particular. I was describing a situation where an operator was well-funded, had lots of capital, and good wells and bad wells. And they might want to hang on to the bad wells when secondary recovery and tertiary recovery come back in to vogue.

Q. There's not secondary and tertiary recovery happening now?

A. There is, but I think most of the activity is in the shale place.

Q. How does the Oil Conservation Division make a determination if an operator has a number of inactive wells or marginal wells? How does the Oil Conservation Division discern between an operator that has a great balance sheet and real bonafide assets versus an operator that is just blowing smoke at everybody and trying to avoid plugging or other cleanup obligations? Do you have any thoughts on that?

A. Well, I think the OCD should have the ability to use a little bit of discretion in its enforcement. And again, depending on the severity of the violation. But the OCD already knows who the good guys are and who the bad guys are.

Q. Mr. Ezzell, you referenced balance sheets

and I agree that that's a significant -- can be a significant piece of information. Do you think a company's and operator's balance sheets should be made public so that OCD or other parties who have a vested interest in whether that company operates here in New Mexico have an understanding of the company's financial strength?

A. Well, in the public companies, it already is published in annual reports, things like that. As far as a small independent, I do not think that the public should be able to see their balance sheets or financial information.

Q. What about the OCD?

A. Same answer. No.

Q. So if the balance sheet is a secret that only the operator and its investors, if there is any debt to know about, how can oil conservation Division or any other interested party determine whether an operator with a lot of inactive or marginal wells has a strong balance sheet or doesn't?

A. Well, that's where the discretion in enforcement would come in, because if they have all these inactive wells, the OCD has the tools to cite them for violations. And you will almost immediately know their financial capability if they comply with

the enforcement actions or pay their fines on time, whatever is done. The OCD will know that.

MR. BIERNOFF: Okay. Mr. Ezzell, I appreciate your time and your testimony today.

Madam Hearing Officer, I don't have any more questions for Mr. Ezzell this morning.

HEARING OFFICER ORTH: Thank you very much, Mr. Biernoff.

Let's see. I don't believe we have Ms. Nanasi with us.

Mr. Maxwell is at the polls today.

Mr. Rankin, do you have questions?

MR. RANKIN: Nothing for me. Thank you, Madam Hearing Officer.

HEARING OFFICER ORTH: All right. EOG is monitoring.

Mr. Suazo, do you have questions?

MR. SUAZO: Just a couple of questions, Madam Hearing Officer.

CROSS-EXAMINATION

BY MR. SUAZO:

Q. Mr. Ezzell, good morning?

A. Good morning.

Q. Mr. Biernoff with the land office asked you, and don't let me misstate your testimony, but I think

generally speaking, you stated that generally, you're not opposed to bonds in excess of $250,000 for certain operators that are problematic under the blanket bond structure, correct?

A. Yes.

MR. HALL: Objection. Leading.

HEARING OFFICER ORTH: Yeah. Please avoid that, Mr. Suazo.

MR. SUAZO: I'll move on.

BY MR. SUAZO:

Q. But it is your testimony in this proceeding that the Commission and the Division do not have the statutory authority to increase bonds beyond 250,000 correct?

MR. HALL: Objections. Leading.

HEARING OFFICER ORTH: Would you turn those into questions.

BY MR. SUAZO:

Q. I'm confirming his testimony, what he said? And he can say yes or no.

HEARING OFFICER ORTH: That's true.

A. I do not think that the Division or the Commission has the authority to increase bonds outside of the limitations of the Oil and Gas Act.

Q. And to do that, your testimony is an act of

the legislature would be required, correct?
A. Yes.
MR. SUAZO: No further questions.
HEARING OFFICER ORTH: All right. Thank you.
Mr. Cloutier, do you have redirect?
MR. CLOUTIER: Just a couple, Madam Hearing Officer. If we could pull up the Alexander exhibit. Was it 13? Ms. Tripp, if she could have authority share. All right. We'll go with this question first. OK. There we go.
REDIRECT EXAMINATION
BY MR. CLOUTIER:
Q. There's a sentence below the phrase: Years before return to activity. Can you read that sentence?
A. The one beginning with histogram.
Q. Yes, sir?
A. Histogram of length of time inactive prior to return to activity, across a sample of wells that reactivated following 12 plus months of no production.
Q. Do you know what that sample of wells was that Mr. Alexander used?
A. I have no idea.
Q. Did you hear Mr. Alexander testify that he

knew what the sample of wells was?
A. I did not hear that testimony.
Q. Thank you. Now if we could just go to the statute that Mr. Hall was asking you about?
You see the highlighted language at the top talks about the instruments of financial assurance being conditioned that the well be plugged in abandoned?
A. That is correct.
Q. Do you understand section 70-2-14 to require any other sort of bonding besides the financial assurance for plugging and abandoning a well?
A. No. It is just plugging bonds.
MR. CLOUTIER: All right. That's all my questions, Madam Hearing Officer.
HEARING OFFICER ORTH: All right. Thank you, Mr. Cloutier.
Commissioner Ampomah, do you have questions of Mr. Ezzell.
COMMISSIONER AMPOMAH: Yes, I do have a few.
EXAMINATION
BY COMMISSIONER AMPOMAH:
Q. Mr. Ezzell, thanks so much for your testimony today. So I'm Dr. Ampomah from New Mexico Tech. So I do have a few questions for you. So if we

can bring up your slides, your direct slides. And I'll start from slide Number 5. Yeah, right there?
So in here, you're talking about -- let's put aside whether the Commission do not have authority.
A. Right.
Q. I mean, the lawyers will take care of that. Yeah. So in here, you describe the factors that need to be considered when the Commission or the OCD is more or less making a rule for a bond or financial assurance. Can you tell the Commission how you will quantify the cost associated with the age of the well?
A. The age of the well will directly affect the cost to plug, and it also will directly affect the ease with which plugging can occur. Because older wells are more likely to suffer from corrosion and all sorts of other types of damage. Until you get into one -- and I'm not an engineer, so I don't know why I'm telling this to you, because you know way better than I do, but you don't know whether rods are parted, you don't know whether there are holes in the casing. But with older wells, that's more likely than with newer ones.
Q. Yeah. So let's go to slide number 7 and then I'll ask you, can you provide to the Commission

the range of age of wells, you know, the range of age of wells that you will classify as a high risk?
A. Are you asking the age.
Q. Yes. Age range. Because you said newer and then older. Now, when you say newer and older, what is the range for the older which you were saying that those could be a high risk that we should pay more attention to?
A. I've not really given that much thought. But I would say if the well was drilled before 1970, then it's probably going to have a much greater chance of being a high risk.
Q. So you can see how difficult the Commission's job is, right? Because when all these three factors are provided and if we have to more or less quantify them and use that to come up with a single number or, let's say, risk-based, you can imagine how difficult that is?
So 1970, then you're saying that a well that has probably been in operation for about 55 years?
A. Yes.
Q. One witness from my IPANM I believe said 40 years?
A. Like I said, it's not something that I had

given much thought to. But I'm happy that I was that close to what IPANM said.

Q. So let's go to slide Number 28. Yeah, so slide Number 28, my question to you is, so you're saying that everyone -- you know: If produce to avoid bonding?

Now, your first point, you're saying everyone, including state, gets less revenue over life of the world?

Have you done independent analysis to support this claim, or is just based on a hypothetical situation?

A. I have not done any independent analysis. That is just my opinion based on my experience.

Q. Based on your experience. Okay. So there has been a lot of discussions, even with regards to the marginal wells, if the Commission can consider some exceptions to the marginal wells?

In your testimony, you describe how, let's say, if a well is producing and the commodity price is so low, you made an argument whether the well is going to produce or not.

Now, can you quantify the impact of economics, let's say, can you give some suggestions with regards to how that description of the commodity

prices can be incorporated as an exception into the marginal definition?

A. In general, I think that other royalty owners, state, federal, fee, understand that they will benefit more if production is decreased in times of poor price and brought back on later.

I mean, that's been manifested by -- we had a statute that is no longer -- I don't know if it's statute or not, but we had a policy in New Mexico on state trust lands that it was decided that they would rather, in low price environments, they would rather have the revenue later, even though it would cause hardship up front.

A stripper well royalty rate is the federal effort to continue to produce. We have similar activity in New Mexico where you can apply to the land commissioner to reduce your rate if your wells are approaching uneconomic status.

So I think it is in everybody's interest to get all the production you can out of every wellbore, especially in times when -- yeah, I kind of lost my train of thought.

Q. I think I'm good. I think your point is well made. So you believe that the Commission can include something in terms of economics to give OCD

the flexibility to make that determination when that instance happens?

A. I would not disagree with that. Yeah.

COMMISSIONER AMPOMAH: Thank you for your time. No for the questions.

HEARING OFFICER ORTH: Thank you.

Commissioner Bloom, do you have questions?

COMMISSIONER BLOOM: I do, Madam Hearing Officer. Thank you.

EXAMINATION

BY COMMISSIONER BLOOM:

Q. Good morning. It's still just morning here for a little bit longer, Mr. Ezzell. Thank you for your time on the stand today?

I love history and appreciated hearing from you on the development of JPAs over the decades. I heard something similar at the annual conference of the National Association of Petroleum Accountants in Dallas this year, and this filled in some of the other pieces. So I appreciated that.

I also just wanted to thank you and your family for your service to the state. I know that having a state legislator in the family is a sacrifice of time and money.

I've come in front of your wife before, and as you know, she is thorough and tough?

A. Welcome to my world.

Q. Mr. Ezzell, did you read the, much discussed here, LFC report that was part of the applicant's pre-hearing statement?

A. No, I did not.

Q. Okay. I'll read you something from it. It says, quote: The Federal Environmental Protection Agency estimates annual methane emissions from the nation's inactive and unplugged oil and gas wells are comparable to adding an additional two million gas-powered cars to the road. End quote?

Is that methane a wasted resource?

A. Yes.

Q. We heard from the OCD, and you and Mr. Hall discussed this as well, but the OCD has said that 60 percent of inactive wells in New Mexico leak methane. Is that fugitive methane a waste?

A. Yes.

Q. Does the OCC regulate waste?

A. Yes.

Q. Does proper plugging stop methane leakage in waste?

A. Proper plugging would stop leaks, yes.

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Q. And would it stop the waste that is associated with fugitive methane emissions?
A. Yes.
Q. Mr. Ezzell, the LFC study goes on to say the following, quote: A 2011 study by the Groundwater Protection Council, an organization whose members are state groundwater regulators, found inactive and unplugged wells responsible for 22 percent of oil and gas-related groundwater contamination incidents in Ohio and 14 percent in Texas over a 16-year study period. Improperly plugged or unplugged wells have also been implicated in surface contamination incidents, including recently near the Texas/New Mexico border, where the wells have served as conduits for large leaks of produced water and hydrocarbons. Unplugged or improperly plugged wells can also leak gases, including hydrogen sulfide, which is toxic and highly corrosive, and methane, which is both a potent greenhouse gas and explosive. End quote?
Mr. Ezzell, it's my understanding that the OCC is also charged with protecting the environment, water and public health. Do you agree with that?
A. Yes.
Q. I just wanted to get through some of these

questions about does the OCC have the ability to and the authority to regulate here. And of course I believe given issues of methane waste and threats to the environment, public health and water, that we do?
Mr. Ezzell, I believe that your rebuttal spends time looking at the relationship between the OCC and the legislature. Correct?
A. Yes.
Q. When I looked at the first document filed in this case, I see June of 2024. That's when the applicants made their application. Does that sound right to you?
A. Yes.
Q. So that was last year, about 16 months ago. And during that time, from mid January to mid March of this year, 2025, the state had a 60-day legislative session, correct?
A. Yes.
Q. So our legislators had six months to introduce a bill on this topic, if they'd chosen, correct?
A. Yes.
Q. So the legislature could have, for example, stopped cold this effort here by, say, passing legislation that would have prohibited the OCC from

setting any new bonding levels; is that right?
A. That is correct, they could have.
Q. The legislature did not legislate in this area in 2025, did it?
A. No.
Q. The three commissioners here were designated by the governor and/or her administration; in my case, the commissioner of public lands. Would you agree that these two duly elected officials, the governor and the commissioner of public lands can pass their administrations to pursue rulemaking?
A. Yes, they can.
Q. And that our duties include rulemaking on the OCC?
A. The Oil and Gas Act gives the OCD and the OCC limited authority to do rulemakings, I agree.
Q. Do you also agree or have knowledge that the public has the right to petition the OCC to do rulemaking?
A. I don't know where that authority comes from, but I agree with the public.
Q. Yes. That's the basis, of course, of the applicants coming from the public and doing this?
And would you agree that they have the right to do this, regardless of what the legislature

is doing?
A. Yeah, they have the right to do anything. They're not restricted by the legislature at all.
Q. Yes. Thank you. You mentioned the land office and the permanent fund in your surrebuttal. And yeah, I agree with you, sir, that land grant permanent fund moneys can't be spent directly on well plugging and reclamation?
But my initial comments were meant to be more along the lines that the land office has worked for over 100 years to generate funds for its beneficiaries, and that ultimately money for the beneficiaries in the state. And it would be unfair and unjust for the state to have to spend a large percentage of that sum on cleaning up orphaned and/or unplugged, inactive wells throughout the state. Does that make sense?
A. I agree with that wholeheartedly. That's why I would like to see the conservation fund used for its intended purpose.
Q. Mr. Ezzell, are you aware of the Land Office's land maintenance fund?
A. Generally, yeah. I know there is one. I have no idea how it's funded or how it's spent.
Q. Yeah. So this gets kind of arcane. But the

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land grant permanent fund, as you know, collects the royalties from oil and gas for the state and it's invested by the state investment council. And then the legislature can spend 6 percent of the five-year rolling average?

The land maintenance fund is money that comes in from renewable resources. That includes renewable energy, rights-of-ways, and oil and gas lease sales. We can continue leasing land as leases come back to us. And so that money goes into the maintenance fund, and it's immediately distributed to the beneficiaries.

This year, we're four months into the fiscal year, and we've already earned close to half a billion dollars for this fund. Do you know that the State Land Office has a reclamation fund that takes money from the maintenance fund to clean up messes on state trust land?

A. That is my understanding, yes.

Q. The land office will continue to spend beneficiary money to clean up messes made by its lessees, correct?

A. Yes.

Q. Would you agree with me if I told you that the land grant permanent fund is somewhere between $34

billion and $36 billion today, somewhere in that area?

A. Yes.

Q. Are you aware of the Center for Applied Research's 2021 bonding financial assurances gap study?

A. No, I am not.

Q. I believe applicants may have mentioned that or the VERTEX study that went into it in their prehearing statement?

But that study by the Center for Applied Research said that in 2021, there was a bonding gap of $5 billion on state trust lands. So today we have inflation and the higher inflation we have seen in the oil patch, I think, then higher, higher than -- certainly higher than the other inflation elsewhere.

I believe we are looking at a bonding gap of probably closer to $7 billion. You compare the $7 billion to $35 billion and that would be about 20 percent or one-fifth of everything that the permanent fund has done over the past hundred years; is that right?

A. That's correct.

Q. So this is where my concerns come from with the relationship to the permanent fund and the liabilities that are out there. So I just wanted to

spend a little time on that?

I think just lastly, I believe you're aware that the land office has instituted, right about four years ago, an accountability and enforcement program to get orphan wells and inactive wells P&A'd on state trust land. Are you aware of that?

A. Yes, I am.

Q. I think you may have represented some companies that have been involved with the land office related to some of these issues, correct?

A. Not to plugging, no.

Q. Unrelated to their bonds?

A. I have been involved in a case where a couple of state leases were terminated. And the reason for the termination being that the lessee had not posted a surface damage bond as required by the statute. The statute and the State Land Office regs say that that damage bond is supposed to be posted prior to the lessee doing anything on the lease. And in the case I was in, that portion of the lease had never been drilled, and the lessee had never set foot on it.

Q. Okay. Okay. But --

A. Yeah, I --

Q. Yeah, sorry. Go ahead. I didn't want to

cut you off?

A. Oh, no. I was through.

Q. Yeah. I think as you know, as well, the commissioner asked us to review all 6,000 leases at the time on state trust land, to see if they were bonded. And we found that about on-eighth, some 800 wells, were not bonded. And I think as you know, ultimately we only canceled less than a couple dozen. And we worked with companies and gave some people a little bit extra time to actually get their binding in place?

If you don't know if you've seen any of the news releases or stories in the press. But, you know, we've had to work with and sometimes sue operators and lessees on state trust land to get them to plug what is now 750 wells P&A'd under this program. Are you aware of that?

A. Not the number, I did not know that.

Q. Are you aware that we still have maybe that many wells left to get cleaned up on state trust land?

A. I did not know that, but I do not dispute it.

COMMISSIONER BLOOM: Mr. Ezzell, thank you for your time. I don't have any further questions for you.

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HEARING OFFICER ORTH: All right. Thank you, Commissioner Bloom.

So, Chair Chang, we are past time when we usually take a lunch.

CHAIR CHANG: I do not have any questions anyway.

HEARING OFFICER ORTH: You do not. All right.

CHAIR CHANG: So there you go.

HEARING OFFICER ORTH: So we can excuse Mr. Ezzell, it sounds like. Thank you very much, Mr. Ezzell.

Let's come back at 1:15 from lunch.

(Lunch recess held from 12:11 to 1:15 p.m.)

HEARING OFFICER ORTH: Ms. Tripp, are you calling the next witness?

MS. TRIPP: Madam Hearing Officer, I believe we may need to address the surrebuttal exhibit from OCD, if we need to do that. We planned to do it before lunch but did not get to it.

HEARING OFFICER ORTH: Was that OCD exhibit 34, I believe, surrebuttal for Armstrong.

MS. TRIPP: Yes, Madam Hearing Officer. And so I know that the surrebuttal has been filed in

response to Mr. Armstrong's testimony during cross-examination yesterday.

Mr. Armstrong was able to speak with his staff again to clarify -- I think there was a miscommunication or misunderstanding. So it's our position first that the objection -- the objection was not made during his cross-examination, but we're not opposed to withdrawing or otherwise addressing the record.

MR. CLOUTIER: Yeah, we're not going to rely on that testimony for any purpose in this rulemaking, Madam Hearing Officer. And we stipulate to the admission of the exhibit, if that's what OCD wants to do. And Mr. Tremaine and I visited, but if there's some other suggestion that they have, I'm happy to listen to it.

MR. TREMAINE: I really appreciate the meaning of the minds on this from Ms. Tripp and Mr. Cloutier.

I do have to quibble because I did object to the foundation of his statement, but it was to Commissioner Ampomah. So just for clarity in the record, we're not fighting over that or the result.

I don't think it matters whether the exhibit comes in. What I want for the Commission is

if they have questions about OCD's instructions related to production reporting, that they're able to take notice of OCD's instructions, which are on the website and referenced in that e-mail.

So if it's beneficial to the Commission, we'll admit it. No need to belabor the point with the stipulation.

HEARING OFFICER ORTH: All righty. I mean it does seem like the kind of thing the Commission could take notice of and so it would not usually be objectionable as an exhibit either, just for convenience sake.

Are there objections to OCD 34? No? All right. Let's admit it. It'll just make it more convenient, I think, for the Commission to refer to it.

MR. TREMAINE: Thank you.

(Admitted: OCD Exhibit 34.)

HEARING OFFICER ORTH: Mr. Cloutier, are you going to call your next witness?

MS. TRIPP: Madam Hearing Officer, IPANM calls Representative Mark Murphy to the stand.

HEARING OFFICER ORTH: All right, thank you. Representative, would you please spell your first and last name for the transcript.

THE WITNESS: Yes, Madam Commissioner. My name is Mark, M-A-R-K, Murphy, M-U-R-P-H-Y. I'm president of Strata Production Company and also providing comments on behalf of IPANM.

HEARING OFFICER ORTH: Thank you. Do you swear or affirm to tell the truth?

THE WITNESS: I did.

HEARING OFFICER ORTH: Thank you.

Go ahead, Ms. Tripp.

MARK MURPHY,

having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. TRIPP:

Q. Representative Murphy, if you could just introduce yourself to the Commission, tell us about your education and experience?

A. Sure. I served in a number of capacities, and with respect currently, I'm president of Strata Production Company, which was formed in 1988 by my former father-in-law and business partner, Frank Morgan, who has since passed.

It began with a small volume of -- or a small number of low-volume producing wells, also known as stripper wells. At the time we had eight employees. They had eight employees. I purchased the

majority of the company in 1991, and we're now at 23 employees.

We made 11 field discoveries. That early stripper production basically allowed us to begin an exploration and leasing effort that led to those Delaware, primarily Delaware Formation discoveries, but also Bone Spring, Wolfcamp and deep oil and gas.

We currently are operating some 15 -- well around 20,000 acres, 15,000, which is the main project in Eddy County. Strata drilled the first lateral well, long-reach lateral in 1990. We drilled the first permitted horizontal well in the state in 2001.

We currently operate 72 wells. At the time of this, we're actually up to 75 now. We've got an active drilling program going. And so we're pleased to report that that's happening.

Experience in New Mexico I think is the next slide perhaps. It says I'm fourth generation in the oil and gas industry. I am a fourth generation producer, second generation for New Mexico.

Grandfather, great grandfather were very active in the early east Texas boom and the discoveries in Arkansas, northern Louisiana, and so

forth. During the 1920s my father remembers an early -- well, actually early '30s, very vividly staying on top of the Gardner Denver store in Kilgore, Texas, because his uncle ran that store.

And so I have 40 years of experience in operations, geoscience, management. We've actively acquired and divested properties. I've served as a board member and past officer and I'm a current board member of IPANM and past officer, president of IPANM; past treasurer and board of directors of New Mexico Oil and Gas Association; industry advisor to Mexico Tech Petroleum Recovery Research Center; served as project manager for numerous joint national laboratory university of private company partnerships.

I've also served as an advisor to the United States Department of Energy, secretary of energy under the Clinton administration, that was Hazel O'Leary; informally under the George H.W. Bush administration, with Michael T. Halbouty and later Admiral Watkins. And then lastly, under the Clinton administration, with Hazel O'Leary. I've also served as an advisor to the United States Department of Interior, Secretary of Interior Manuel Lujan, during the Bush administration.

I've led Strata for the past 34 years

and I've testified numerous times in front of both the U.S. House and Senate energy committees, primarily.

I think now maybe to concerns.

Q. Well, I also wanted to -- you mentioned how many wells that Strata is operating. Does Strata also plug wells?

A. We do plug wells. According to numbers that I've looked at, we plugged 38 wells.

Q. And so have you had a chance to review the proposed rules in this proceeding?

A. I have.

Q. Okay. And do you have any concerns with those?

A. I have quite a few concerns with them. The proposed rule really ignores that 95 percent of the wells are plugged by industry. The other 5 percent are paid for and essentially plugged by industry. So we plug 100 percent of the wells. We may pay private contractors 100 percent or 95 percent, but we pay the state the other 5 percent, and then they pay contractors.

So this notion that we're not plugging the wells, we're not cleaning up our messes, is simply incorrect. It's just not factually correct, and it shouldn't continue to be stated in these proceedings,

because it's not right. 3.

And so, you know, when we contribute to the conservation fund, that fund kicks off some 100- to $130 million a year. Between the Senate and the House process during the legislative session, the OCD makes a budget request, and that's typically somewhere in the $20 to $25 million range. That's all they can spend. And the reason is mainly because of procurement issues and process issues.

I break this into a three-legged stool. We've got payment to plug the wells. That's not a problem. You've got hundreds of millions of dollars coming in; over $630 million that's been swept in the last five years into the general fund. So payment is not the problem. Procurement's the problem and process is the problem.

This notion -- somebody said this morning, and I take real issue with it, that this is not grade school and 95 percent isn't a passing grade.

I would say this. We're not asking for 95 percent. We plug 100 percent. And so my question to the WELC people and to this Commission and so forth is, how many times does industry have to pay for this?

We post our individual well bonds, and then we plug our wells. And for those in the

industry, either through misfortune or bad actors or bad intentions or whatever else, leave a portion of wells behind.

And those of us that are good operators, we pay for those, too. Although it's really paid through the oil coming from those wells. Every well, in essence, is paying for some amount of its own plugging. But as an industry, we pay for it all. So I really would like to make that point.

The single-well bonding, $150,000, will not solve this problem because it's not a funding problem. And it also, I think, shifts the analysis from a traditional analysis of, okay, what is the proper bonding amount, whether you do it by individual wells or you do it by tiers of wells or whatever, to an economic analysis?

And it's an arbitrary economic analysis. They basically are proposing, I believe, 750 BOE per year and 180 days as being outside the realm of marginal.

In my experience, I can show you 2,000-foot wells that will not make money at 750. And I can show you 7,000-foot wells right now in my portfolio that do. And so when you shift this analysis over to where the OCD and the OCC is now

supposed to make this risk assessment, it's really arbitrary. It's very, very arbitrary. Because at the end of the day, it's really, as Mr. Ezzell commented before, that the standard in the industry has always been paying quantities and the economics of the operator. And they make that decision.

And if that is taken over by an outside party, I can guarantee you there will be waste. And I also guarantee you there will be takings. Because you'll prematurely force wells to be plugged, which will hurt the state beneficiaries and also hurt the owners of those wells. So these arbitrary limits make no sense to me.

The reality is, OCD is ill-equipped to plug wells. They've demonstrated that. And that's not necessarily through their own fault. It's because of the procurement procedures in some cases and what I call process. The ability -- in some cases they have it -- in my opinion, have not expeditiously used the tools they've had. In other cases, they haven't used the tools at all. They've tried to collect a few bonds. We're told it costs more than it's worth.

But they haven't, to my experience or knowledge, really utilized the court systems to the degree that they have to pursue these bad operators.

Now there's some testimony this morning on who are the bad actors and how many are there and who are they. Well, as a state legislator, I have the benefit of hearing a lot of information from the OCD. And from last week's testimony, during the water and natural resources committee, we were told, and we've been told many times, we know who, OCD knows who are the bad actors.

Ten companies are causing 80 to 90 of the problem. I've heard it time and time again. And so go after those ten. You've got legal avenues. If you need additional powers from the legislature, I can tell you the industry would support those, as long as they're reasonable and constrained so you don't begin getting into taking private property rights.

But I believe that everybody wants to solve this problem. I believe the regulators want to solve this problem, but they're approaching it from a payment standpoint and not from a process of procurement standpoint.

And at the end of the day, bonds don't plug wells, operators do. And that's what we have to remember, is that we shouldn't throw the baby out with the bath water. And that is really critical.

I have a couple other points, and one is

the TA limits. Now, early in my career -- I've been involved in numerous secondary and tertiary -- well, secondary recovery projects primarily, and also have looked at EOR projects, tertiary -- primarily CO2 projects.

These are very, very complicated and long-term projects to put together. And for those of you that don't understand the process, let me give you a quick explanation. Somebody goes in and discovers a field. Well, most likely, they're not going to own that entire field. There's going to be multiple leases. There's going to be fee leases, federal leases, state leases. The field is developed and it goes through its primary production phase.

Not all that happens at the same time. In other words, not all those wells are coming online and producing the same volumes and the same -- in complete sync. So towards the end, towards the point where the field is becoming marginally economic across the board, the negotiations are usually started amongst the operators and the owners of that field to see if there's anything else that can be done.

Now, let's keep in mind -- you know, I heard keep in mind what the New Mexico oil reservoirs generally look like. Very few are water driven.

There's some exceptions, but they're solution gas drive, and they lend themselves very well to pressure projects, such as waterflooding and CO2 flooding. And when the well reaches that end of its primary life, it still has somewhere between -- depending upon the nature of the reservoir, somewhere between probably 60 and 80 percent of the original oil in place is still there.

And if we don't go after that oil, we've wasted it. And this is the problem with the policy, is that the best way to clean up an old oil field is to make it a new oil field. And if you go from primary recovery to secondary recovery, all of that infrastructure is replaced, the production comes back up to state. Many times secondary recovery projects perform as well as the primary production. And you can sometimes get one to two times the amount of oil you got on primary.

So the problem is, and this relates to the TA portion of it, the eight-year hard TA. I have been involved in the formation of secondary recovery units that took in excess of ten years. My father started them, my sister and I and others picked them up, and some of them went on 12 or 15 years. And it is a very laborious and difficult process because you

have to get a lot of people together, you got to form an operating committee, there's always discussions about who is going to operate, what's the formula going to be for unitizations. You know, all of these things. And that those meetings occur many times over years and over multiple management changes.

So the idea of a hard deadline to a TA is I think really going to be policy-wise very, very bad for the state. And let me give you some perspective on this.

I was born in 1959. My father and family came to Artesia, New Mexico, in 1960s. He implemented the first commercial water flood project in New Mexico. I implemented the first horizontal drilling project in New Mexico. The only reason I'm here is because he was here. And he came in and he formed these secondary recovery projects that added hundreds of millions of dollars and billions of dollars to the state.

The Grayburg Jackson field, for example, between Artesia and Loco Hills and Maljamar is one that he was responsible for flooding on behalf of Newmont Mining Corporation, a company we don't even hear about around here.

So that technology basically allowed a second life to that field, to all those fields, decades and decades of life, and hundreds and hundreds of millions of dollars to the state.

Now, many of those fields have since declined. They are probably very good tertiary candidates, CO2 candidates. We have CO2 sources, and yet there's no real policy push to try to get that.

Now, one of the reasons is that we've seen the dominance of capital flow to the shale revolution since about 2015. There was a slide that was put up, and maybe we can address it later, on this eight-year life, and I can tell you that once you read the disclaimers at the bottom, you need to discount that slide. But let me give you another point.

If that slide was taken at a point in time, which it has to be, and then looked back, you would not see any secondary recoveries or tertiary recovery projects in this period. If that point, zero was taken in, I don't know, either 1965, '75, or '85, you would see a huge number in that 10- and 12-, 15-year period.

So, from a first glance, I haven't talked to the analyst about this, but from my first glance, I don't believe this is telling you, the

policymakers, and deciders what they're telling you it's telling you. Right?

And so, this is what's going to happen, in my opinion, from 50 years of prospective in the oil and gas industry. We have gone through now -- we are now going through a major shale boom. These wells are going to decline, and they are going to recover less crude in place than previous reservoirs because they're naturally tight reservoirs. However, that leaves us a huge resource to go after, right?

And there's only the beginnings of a discussion about how to do that, because this is going to be -- it's a technological challenge that the industry has not ever met before.

When secondary recovery was originally initiated, it was pretty well understood. There were basically two types of patterns, line drive and five spot. And there's other alternatives to that, but those were the typical ones utilized in New Mexico.

So, a lot of the question now is going to become, how do we basically utilize horizontal wells for enhanced recovery, and what do we do with this? And if we don't preserve those well bores in that production, we're going to leave -- there's even going to be a bigger waste. So, there's the

challenge, but there's also the opportunity.

Now, we have some 27,000 stripper wells, and we've heard testimony that they don't really mean much, right? That they don't contribute much here, they don't contribute much there, we're maybe talking about 8 million, 10 million. The problem with the analysis is that it only considers taxes, right, production taxes, a fraction of the economic value that these wells contribute to the society.

And the other part, which is typically two to three times that much, is the royalties. And yet it still doesn't -- it also doesn't take into account the 3,000 jobs it supports, the fact that those payments go to local vendors. The economic impact of these wells and the companies that operate them is huge to this state. So, don't be misled by the LFC report that says this is nothing.

And speaking of the LFC report, the LFC report is one that I've studied in some detail. And the reason I have is because it is so inherently flawed. And I will start off by telling you about my experience with the LFC report.

In late May, I was approached by members of the New Mexico Oil and Gas Association and IPANM as a member of the state legislature. As has been

mentioned here, I represent District 59, Roswell, Chaves County. And they had heard a rumor, that LFC had developed a report and that the report calls for massively increased bonding. And they had arranged for a meeting with director Sallee of the LFC. And the director gave them very limited information, only said that it was something that they were looking at, but it mainly had to do with procurement and bonding processes.

They weren't satisfied with that, so they came to me and asked me to arrange a meeting with him. And so I called him. He came over to my office on June 3rd. And I'll read you my notes from that meeting.

No member requested an internal LFC group looking at the -- looking for this. It was an internal LFC group that was concerned about the inflow of federal plugging and abandonment dollars. The federal plugging and abandonment dollars were the dollars that were allocated either through the Investment Recovery Act or the Inflation Reduction Act. I don't care which one, but it's been mentioned here.

He told me that it was some $90 million, which is consistent with my understanding, and that it

was allocated, I believe what he told me, over a three-year period.

But they were getting concerned because they couldn't meet the standards. They can't meet the standards and that the money might get cut off. And so that was the purpose -- the standards of the federal grants, right? That was the purpose of the study, as it was stated to me.

And I said, "Director Sallee," I said, "this seems to me to be a procurement issue. I mean, if you're talking about not being able to meet these standards, it's because you're not plugging wells fast enough or you're not plugging them right."

And he goes, "Well, there's a number of issues."

And so I took it to mean that they weren't plugging them fast enough. And the reason I took that is I also had conversations in D.C. where people were beginning to voice that perhaps the program wasn't as robust as it should be, could it be expanded.

I then said, "Well, this doesn't really add up from what I've heard on the street, because I've heard about all this increased bonding."

And he said, "Well, there is a portion

of the report that deals with that. We're pretty concerned about one-barrel-a-day wells."

And I said, "Why are you concerned about one-barrel-a-day wells? What's the threshold there?"

He goes, "Well, there's just a lot of one-barrel-a-day wells out there, and we're concerned about them."

And I said, "Well, let's talk about that."

And he said, "I'm sorry, I can't talk to you about it anymore until the LFC reviews our study and approves our findings."

And so I got no more information.

Now, I had known a little bit about the money that was available to the state; I believe it was back in either -- I want to say 2022, but it could have been as early as 2021, whenever those acts were passed and it was clear that there was money in there for the state to plug wells.

And when we heard about that, it was, okay, if there's really this big, large volume of wells out there that need to be plugged, why aren't they getting plugged? Well, the OCD can't seem to plug more than about 50 of them a year. There's been some times that they could, but that's generally the

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number.

And so I thought of it as an incredible business opportunity. Because if the OCD is saying that there's all these wells need to be plugged, most of which are federal, I think this body understands that, there's very few state that the state is going to be responsible for, and there's federal dollars to do it -- I know from experience that we have trouble even scheduling P&A operations.

There is, you know, greatly limited -- there's not very many contractors that do this. The ones that do it for the state are almost all in the northwest. We have principally two in the southeast that will do this.

And so me and several of my company people contacted -- and I don't recall who it was. It was dealing with the OCD plugging issue. But there was a gentleman there and he basically explained.

I said, "We understand that there's going to be all this money coming in to plug all these wells. How are you going to deal with that?"

And he said, "Well, we're still evaluating it. But we plan to just give these wells out in groups of small numbers, five, ten, 25 at a time," which is a real problem if you're if you're

trying to build a company off of plugging a lot of wells. Right?

And so one of the things that we looked at was standing up a plugging company, and started designing very high tech, self-contained rigs that would do this quickly, cheaply and effectively.

But when it became clear that the procurement issues were not going to change, that we might or might not -- if we got a contract, it's going to be very small. And that's fine. But at least if you have the chance at a big contract, you have a chance. And just decided that it -- that, combined with the fact of how they were being bid out.

In my business, we have what's called an authority for expenditure, AFE. It's just basically a budget. It basically says we're going to spend X, Y and Z going through these wells, you know, so much for drilling, so much for this. So it's a line item.

For example, the top line item is usually the most expensive and it would probably be a pulling unit or plugging rig, right? And there will be a price for that. And then we'd have another one that would say cement and rental tools and all the various categories of equipment, materials, supervision, all the things that we need.

Well, what the procurement officer explained to us is that they would basically pick and choose. So you might get the rig on one well and the trailer on the other and the lights and the porta potty on the other. But you weren't getting a turnkey operation to turn even that one well into a plugged well, much less 100, when they're stating that there's thousands to be plugged.

So there's a procurement issue here. And I think industry would love to see that solved.

Now, the role of the independent operator. Now, it's been mentioned that 60 percent of the production in 2024 was by eight companies. Okay? I would venture that seven, and possibly all eight of those companies were not New Mexico producers 15 years ago.

XTO re-entered the basin when we sold them our NAS project. Chevron, Exxon, Oxy, all of the major companies left New Mexico in the late 1980s and early 1990s. They returned through acquisition in the shale boom. So when people sit here and say, well, we really don't need independents because we have eight companies are producing 60 percent of the production. Well, guess what? Those eight probably wouldn't have been here without the independent.

I've talked about what our company does. We also have been very involved, and I suspect we can get into this when we talk about some of the individual wells that my company operates, but not only have we been very involved in exploration and new plays, as have other witnesses in front of you.

You heard from my friend, Jeff Harvard. His dad, Lee Harvard, was a well-known exploration geologist and made numerous discoveries. Jeff is now second generation. And while he has operations, as I do, in New Mexico, I don't think either one of us anticipate that we'll have very many more.

You heard from the Hannigans, Michael Hannigan, he's a second generation. His father was very involved, and also his brother Robert and son Rob.

And so you're seeing an exodus of companies like mine, and I think from a policy standpoint, you really need to ask, not only what does the impact have today, but what will impact will it have five years from now, ten years from now.

We've also been, as I've described, really interested in the new technology that has implemented horizontal drawing. And one very underutilized one and one I'm very familiar with

because of my work at New Mexico Tech, is CO2. But some of that work needs to be done in terms of how do we utilize these resources to maximize production and prevent waste, and now a new type of geometry, if you will, with respect to wells.

The other thing that we do, and I think this is critical for people to understand, is during the down times and the exits of the majors, we maintain the infrastructure. Now, the pipes may not be as full as they are during boom times, but they still have crude oil and natural gas running through them, and they're being maintained. The electrical lines, the road systems, but also the company infrastructure.

It's not Chevron that's paying Baker Hughes to log their wells at low prices. It's not Exxon that's paying Halliburton. Those shops and those offices and those yards, as we call them in many cases in the oil field, are there because the independents are still using them. And then when things ramp back up, those yards typically ramp back up. But we preserve them, and that's critically important.

I don't think most people realize that you just can't turn things on and off. Sometimes it's

a little more difficult than that.

Q. Representative Murphy, while we're speaking about independent operators, what is it about the proposed rules and how do they disproportionately impact independents or smaller operators when it comes to financial assurance burdens?

A. Well, I think that the entry into the business, any time that you create obstacles of entry into a business through regulation, it's difficult; it's going to discourage business, right?

And so if you have a relatively new operating company with not a lot of history coming in, it's going to be very difficult for them to get surety bonds.

Now, my company is very well established. We have 40-year relationships. So, you know, it's not necessarily going to be my company that's going to be impacted, but it sure could have been. And in the early days, it would have.

And the main thing is, is that I think it ties up a lot of unnecessary capital that could better be utilized for either redevelopment of the field, a new exploration idea, or something else.

I think that these -- I think what's going to happen is -- from my experience, the security

market is rapidly exiting the financial assurances realm, and all natural resources, but particularly in oil and gas. The bonds are getting much tougher to get. They're getting more expensive. They're getting more restrictive.

And so the small operator, in many cases, is either going to have to pay a much higher rate, or if they can even get a bond, or they're going to have to put up cash. And in my experience, that's generally what has to happen. Or letter of credit, which is the same thing.

Q. Thank you. And I think you hit on it earlier, but if you could expand on the reclamation fund and the conservation tax and how those two things work together.

A. Sure. You know, it's been well described about how the conservation tax is collected and then a forcing us into a reclamation fund. And the reclamation fund, stated here, is actually -- is 60 -- is as stated 66 million.

Last week at Water and Natural Resources, we were told it's 76 million. So in the last few months, it's gone up almost 20 percent. So it's grown $10 million in just a matter of months.

Senator Pat Woods made a really

interesting statement. He sits on Senate finance during last week's committee meeting, and he said, you know, "We only send to the OCD what they can spend." And that's been my experience, too. I don't sit on finance, but that's simply what I've seen as a legislator.

And their request is typically -- as a matter -- and last week, OC requested -- said their request was going to be for another $21 million, the same as the year before, about the same as the year before.

That doesn't tell me that they're going to plug any more wells, and the fund has grown. And so I think there's some real attention that ought to be given there as to why that's occurring. Why send more money to an agency that can't spend what they have? So let's collectively figure out how to fix that.

Over -- about 80 to 90 percent of that fund is swept into the general fund because the legislature can't see it effectively utilized. Since 2019 about just shy of $400 million has been collected. The numbers I have seen is that -- has been collected and swept. Excuse me. The numbers I typically see on any given year average reach between

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100- and $137 million that the industry pays on this tax, and the OCD spends about 20.

So when there's testimony to the fact that these are taxpayer dollars, they're not. The oil and gas industry has paid these in for a specific purpose, and they are not being utilized for that purpose. And I see no reason to raise more money for an agency that can't spend what they've got.

Now, what I would do and what I'm working on currently is making sure that that's protected better than it has been in the past. And just as I -- along with -- just as there was bipartisan legislation introduced last session regarding this issue, there's going to be bipartisan legislation, assuming it makes the governor's call this session, on this issue. And it's going to have protection mechanisms in there that will make it much more difficult for that to happen and for that fund to build as it was intended.

And the last bullet point I think is one that was raised, and that is that we would see -- I think in -- we calculate in ten years it'll be a billion dollars. I think it'll be a billion and seven probably, but that's my personal opinion.

Q. Have you had a chance to look at any of the

orphaned wells statistics or the abandoned wells information that's presented in this rulemaking? Do you have any opinions?

A. I have. And I understand there's about 350 orphaned wells that need to be plugged. I think there's some 1,450, something that totals up to 1,350 perhaps, totals up to 1,700 that are federal wells.

Now, those federal wells are, of course, being plugged with federal dollars, so they don't impact the state dollars. They're given -- that's part of the grant money and other money that routinely comes to the state and has for decades from the federal government, who contracts with the state to plug those federal wells.

So there's a relatively small number. I know it was mentioned today about Cano, and it'll probably be discussed some more. But my recollection of this, and it's totally a recollection, is of those 299 wells or so that Cano operated, only a very small fraction were state and fee wells. The vast majority of those were federal wells. So once again, they're not going to fall on the state taxpayer.

So at 150,000 we need about 52 million to plug those 349. I think I rounded to 350, excuse me. And we currently have 75 in the fund with a

hundred plus coming in every year.

MS. TRIPP: Thank you. And that concludes Mr. Murphy's direct testimony. We do have some points to raise on surrebuttal, Mr. Murphy -- I'm sorry, Representative Murphy.

HEARING OFFICER ORTH: Thank you.

BY MS. TRIPP:

Q. And so Exhibit 82 of the applicant's, Mr. Adam Peltz, he explained in response to your testimony, this is at page 2, lines 5 through 21, that any number of steps can be taken to avoid increased bonding for an operator. And he provided examples like plugging idle wells, or simply producing more than 180 days, or reducing an operator's populations of idle and marginal wells to below the 15 percent threshold.

Do you see any problems with these three recommended approaches and the effect of the proposed rules on operators?

A. I do. And let me comment. I've read Mr. Peltz's testimony, and I noted that he really focused on about the last four or five years that he's been looking at this issue.

Now, I've always been told it takes about 10,000 hours to master anything; that's about

ten years of work. So I'm going to forgive him because he only has about half of that work in.

I've got about four times that amount of that work in. And so I'll tell you, the first one has to do the secondary recovery projects where you're plugging idle wells. I think I went through that example on TA status. And my recommendation there would be that the OCD keep its existing TA status of five years, that you allow at least another TA status. Because I can tell you, it's going to take ten years, and you probably need some discretion beyond that.

So this eight-year hard number is very problematic in my opinion. It's going to take a long time to get not only a lot of these projects developed, but also unitized and up and running.

And so let's just call that effect on secondary and tertiary recovery projects. Reduced populations of idle and marginal wells to below the 15 percent threshold. Well, you can't always produce a well in 180 days. And the reason being is that these wells -- see I started my career as a roustabout. I was hoeing weeds and working the shovel. The next promotion up there is a relief pumper. And after that you go to the pumper.

And so as a relief pumper, one of the

things that you've learned is that every well almost has its own personality. You can have a well right here and if you produce it three hours a day, it'll make the most production. You have a well right next to it and you can shut that well in for five days and produce it for two days. And that's the way it makes the most production.

Now, people will say, "That doesn't make any sense to me. I mean, these wells are in the same field and they're close together and everything else." Well, that's because everybody thinks this is a big pool of oil, and it's not.

There's the thing called heterogeneity in the rock. And that means that different areas of the rock react differently and the fluids in them react differently. Some maybe more fractured, some may be more naturally permeable. So that's the answer to that, is that's another hard deadline that, from a practical standpoint, makes no sense.

I could shut a gas well in for 200 days and make more gas in a month than I would if I produced it every day. So that's just the reality of the world that we live in.

Let's see here. And the last one, reduce populations below the 15 percent threshold.

Well, I think the only way to do that is to either plug or divest. And once again, if you plug prematurely, you're wasting. And divesting of a single, low-volume well is probably not practical. And then once again, I think they tied back to a 15 percent threshold, which is, in my opinion, like the two-barrel a day, as arbitrary as you can get.

Let's say you have a company that has a number of high volume wells and all of a sudden they hit this threshold and they've got to put up this bond for every well. That makes no sense to me. So these are arbitrary, and that's a problem.

And I think the biggest problem that independent operators, and I suspect all operators in the state, have is regulatory certainty. And we've seen none of that in this state in a long, long time. And that's why you're seeing the -- and that's why you're seeing some of the reaction to this proposal.

Q. So Mr. Peltz, at pages 15 to 16, he also referenced House Bill 133 as a multi-stakeholder process in the fall of 2023 and raised in the 2024 legislative session. Were you familiar with that effort?

A. I was very familiar with that effort. I wasn't directly involved in negotiations, but as one

of the gray hairs in the room, I was consulted a lot from IPANM and NMOGA's position about what sort of things might make sense.

And, you know, some of the factors that -- well, some were discussed this morning. But let me just characterize that as, those negotiations were probably some of the most frustrating I've ever seen in either policy, regulatory or business because the OCD and the other parties would consistently move the goal post.

Come in, we'd explain something, and we would say, okay, all right, well, how about this, this might work for these operators, let's try this. We'd put that forward.

Okay, we'll consider it. And then the next week, the next two weeks, wherever the next meeting came up, not only had they rejected our proposal, they'd moved their proposal even further as being more punitive.

And sometimes after a while of that, you get really frustrated and say, what's the point, right? What's the point?

And I'll tell you the other time that it happened, and this is probably what will explain a lot, is during the methane. Industry showed up to the

methane rule, negotiated in good faith, had negotiated a number of exemptions. And let me tell you, let me start with this. We were told that the methane rule was designed to only target the biggest emitters, we got to take care of the big problems first. We're not worried about the little guys. We want to take care of this. We want to do that.

And so we came up with a series, both on an operator-based basis and a production-based basis, that we provide some exceptions, be able to provide a little more time to comply, to do all of these things.

The majority of those were accepted and in the draft until the final draft. The environmental community went to the OCD, convinced them that they shouldn't have the exceptions, and they were deleted.

Now, that is not good faith negotiation. That is not fair rulemaking. That is not the development of good policy. And when I talk about policy, I have some experience there at the national level and some at the state level, too. And you don't take and author a report against an industry without ever consulting them.

When I talked to Mr. Sallee and asked for input in or some questions into this report and was told they couldn't talk about because the findings

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weren't quite finished, what, we know from Mr. Peltz's testimony, he was in the LFC in April working on this report.

So you have no industry input to this report and you've got the environmental community basically writing it. Wild Earth Guardians was allowed in there, from what I've been told. I know for a fact. Mr. Peltz swear to it in his own testimony. In April he made presentations and began working on this report. No industry input.

Now, you cannot take a report like this, in my opinion, and create good policy.

Q. Thank you, Representative Murphy. I just have one more question, and this is in response to Mr. Purvis as Exhibit 74, page 51, lines 5 through page 53, line 6.

And he referred to your testimony regarding the effects of these proposed rules on small operators and the state to be a common trope. And he used Exhibit 79 which reflected that 90 percent or something of production produced by 10 percent of the top operators. Do you have any response to that?

A. Somewhat. I guess what I would say is that you don't get that 97 percent without the small operator starting to play, or, you know, whatever it

may be, whether it's exploration, the new technology.

And I think that's part of the problem, is that many of the young staff that are involved in the development of not only the report I just mentioned, but also in the discussions regarding this policy, have never seen a downtime. They've only known the booms.

If you have primarily been involved in analysis and worked on this since 2015, you've never known what it looked like in 1986 or '87 or the early '90s or any of the downtime. And so it's really easy to sit here and say, "Well, geez, you know, we got to pin these few small" -- "big operators. Let's toss everybody aside." Well, what happens when they leave? You'll have no industry left.

And then finally, he's talked about -- talking about production. And I think at one point peaking and so forth. And I know that it's difficult for people to sometimes come up with empirical data. But I can tell from Mr. Peltz's testimony and other testimonies that they really only need to look at one place to understand how this industry works and to get a really good historical perspective on it.

A good friend of mine, Pulitzer winning prize author, Dan Yergin, has written a series of

books. The first one is called "The Prize," and it talks about the oil and gas industry from the 1850s up until about the early 1990s. That will show you historically how this industry works, being the independence going back all the way to Oil Creek in 1859 in Pennsylvania. It wasn't a big guy that made the discovery, it was a small guy. And every one of the discoveries after that were small independent companies.

The big companies, John D. Rockefeller and Standard Oil and so forth, acquired those companies. And then at some point, they had to divest of it. But it's difficult for someone with so little experience in the industry and such a limited perspective to really be able to understand this. But hopefully my testimony today will be helpful to the Commission to understand some of it.

MS. TRIPP: Thank you Representative Murphy.

That completes his direct testimony and surrebuttal. I'll proffer his direct testimony for admission to the record.

HEARING OFFICER ORTH: Thank you, Ms. Tripp and Representative Murphy.

I'll pause for a moment in the event there are objections.

MS. TRIPP: I apologize, Madam Hearing Officer, also submitting his demonstrative slides.

HEARING OFFICER ORTH: All right. Thank you. Another moment. All right. They're admitted.

MS. FOX: I'm sorry, Madam Hearing Officer.

Were you offering your demonstratives as exhibits? I thought they were demonstratives. That was my understanding. That's what I'm asking.

MR. CLOUTIER: Some have, for the record.

MS. FOX: Yeah, that's not my understanding.

HEARING OFFICER ORTH: All right.

MS. FOX: We did not add ours on that.

HEARING OFFICER ORTH: To Mr. Cloutier's point, I think some haven't and some haven't.

All right. They're admitted. Thank you.

(Admitted: IPANM Murphy Direct Testimony and Demonstrative slides.)

HEARING OFFICER ORTH: Let's see, Ms. Fox, do you have questions of Representative Murphy?

MS. FOX: Yes. Thank you, Madam Hearing Officer.

CROSS-EXAMINATION

BY MS. FOX:

Q. Hello Representative Murphy. My name is

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Tannis Fox. I'm a lawyer with Western Environmental Law Center and I represent applicants in this proceeding.

You had stated in your testimony that you thought there were about 350 wells that OCD is online to plug; is that correct?

A. That's the number, as I understand it, yes.

Q. And I know you're very familiar with the LFC report, and in that report, on page 4, LFC says currently, OCD has -- oh, and also you said most of the wells -- something to the effect of that most of the wells that need to be plugged are federal wells, something along that line, correct?

A. I believe the numbers -- I understand there's 1700 wells that are slated to be plugged. 350 are state and fee, and 1350 then would be federal. So the vast majority of them, about a quarter state, three-quarters federal.

Q. Okay. Well, let me read to you from the LFC report and ask what you think about that. So on page 4, LFC says, currently, OCD has plugging authority for roughly 700 wells on state and private, that is, fee lands. The state likely will need to plug an additional 1400 inactive wells, for which OCD has not yet pursued plugging authority. On top of that, there

are more than 3,000 wells on state or private land producing extremely small quantities of oil and gas, whose expected cleanup costs far exceed their predicted future revenues, increasing their risk of being orphaned.

And so isn't it correct that the LFC report is identifying wells for which OCD has authority or may need authority to be plugged for wells on state and private lands and not federal lands?

A. It is true. But my point is that no matter how many wells that is, there's ample funding to plug those wells. But perhaps that's another discussion. Please continue.

Q. No, and you had estimated that there are 350 wells that OCD needs to plug. But my point is that LFC is estimating there are approximately 5,000 on state and federal land; is that correct?

A. They're estimating that, but I take issue with it. So there is the wells that we know that they have authority to plug, those we know.

Q. Those 700.

A. And the other is pure speculation. Because industry has historically plugged 95 percent of the wells, and we don't need a perspective LFC study to

try to say, "Well, this might happen."

We have 100 years of history, Ms. Fox, in this state of operators plugging wells. And we plug 95 percent of them. So for them to come in and say, "Oh, there may be all these others," the history doesn't support. That is pure speculation.

Q. And just to correct the record on Mr. Peltz's testimony, so, Mr. Peltz -- did you hear his testimony or only read his testimony?

A. I read all of it, heard some of it.

Q. And so, if you heard some of it, you might recall that LFC contacted him in April and he gave a presentation to LFC in May. Is that correct?

A. That is correct.

Q. And that was the extent of his involvement with the LFC report, correct? He didn't, quote, unquote, write the report, help write the report, correct? He never testified that he had any involvement in writing the report, only that he gave a presentation to LFC. Correct?

A. The reason -- that's correct in terms of the written testimony. But the reason that I believe there were multiple meetings is I confronted director Sallee over that issue, and he would not deny it.

So in terms of your written testimony,

I'm reading it, it says he was contacted in April, producing a well, gave a presentation in May, and then has also worked comprehensively with the applicants through this process.

But I was -- it was at least intimated to me that there were multiple meetings, not only with the Environmental Defense Fund, but with other WELC participants.

Q. Well, the only testimony we have before you is Mr. Peltz's, and that is that he was contacted in April and gave a presentation in May; is that correct?

A. That's correct.

Q. And then, did you hear Mr. Peltz's testimony that he specifically asked LFC if industry was being requested to participate in the analysis, and LFC said that industry was? Did you hear that testimony from him?

A. I did not hear that testimony. But he was misled.

MS. FOX: Thank you for your testimony.

THE WITNESS: Thank you.

HEARING OFFICER ORTH: Mr. Tremaine or Mr. Hall.

MR. TREMAINE: Mr. Tremaine. Thank you, and Madam Hearing Officer.

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CROSS-EXAMINATION

BY MR. TREMAINE:

Q. Good afternoon, Representative Murphy. My name is Jesse Tremaine. Good to meet you.

A. Nice to meet you, as well.

Q. I'm the legal director for the Oil Conservation Division, and I do have a number of questions for you today.

A. Sure.

Q. You just testified that industry is plugging 95 percent of wells, and I just want to clarify that. By that, you mean that number refers to the number of wellbores that are actually plugged by the registered operators?

A. I believe that -- the basis of the number, the way I understand it, and I believe I got this from IPANM, was that you take the total number of wells that are plugged in in a year, and you look at how many OCD or some other agency plugged, and how many the operator plugged. And we plugged -- the operator, the industry, plugged 95 percent. So that's how I get to the math.

Q. Thank you for that. That's really helpful. Because I think we're working -- yeah, so you're working backwards from how many you've been able to

review that OCD plugged. So I just wanted to clarify that.

A. Not federal wells, by the way.

Q. Well, we're going to get to that. We'll get there.

The 5 percent number is after a review of how many wells were plugged pursuant to the state's orphan plugging program, whether that's the rec fund or something else, right?

A. Correct.

Q. Okay. Would you agree that there's approximately 63,000 wells in New Mexico right now?

A. That's my understanding.

Q. So you have represented some different numbers. But, you know, if the status quo of 5 percent of wells getting plugged pursuant to a state plugging program persists, we're looking at about 3,150 wells that would be plugged on the program based on the existing portfolio of active and producing wells. Would you agree?

A. I would agree with that.

Q. Okay. Just a few minutes ago, you clarified that you -- and I don't want to misstate your testimony representative, but I want to paraphrase here. I think you said that the production thresholds

for either marginal wells or the presumption of no beneficial use or both were arbitrary. Is that accurate?

A. It is.

Q. Okay. So you're testifying that production thresholds as a definition or the criteria to define different categories of wells is not acceptable or appropriate?

A. I believe it's arbitrary. I don't think it's reflective of the reality. And I can tell you, when I saw that number, I pulled our production. We have four wells that might fall in that number, depending upon what period you average. Both were less than, I think both were, or excuse me, four were all in the 700 BOE range. Those wells would not meet -- well, they produced more than 180 days, so it wasn't an "and," right?

But under that definition, you would say, okay, these are -- we have two federal wells, two state wells, part of a ten-well package, ten-well field. Those four would qualify from a production standpoint as being marginal, yet they are not marginal. They make money every -- well, make money every month, yeah.

Q. I understand.

A. But my point is, is that we have real-world examples of production below those thresholds being economically viable, and I've got real-world examples of a shallow well that would exceed that and not be -- you know, that would be uneconomic, and a deep well that would be less than that, that would be economic. So I believe it's quite arbitrary, yes.

Q. Okay. Quite arbitrary. Thank you for that.

So, Representative, would you agree, however, that using production thresholds are acceptable or not arbitrary when they're used as a sole criteria to define stripper wells for the purposes of tax incentives?

A. I think it's a different matter. Because on one hand, you're creating a policy that's encouraging production and preventing waste, and on the other hand, you're creating a policy that's encouraging waste and preventing profits. So they're not the same at all.

Q. Representative, I didn't ask you about the end-point policy, I asked you about the use of the production threshold as the sole criteria for defending a category of wells.

A. I don't know -- I don't how the tax -- IRS drafts all that. I know what the numbers are, but I

don't know all the...
Q. Well it's TRD, so it's New Mexico, and it's under New Mexico Statutes Annotated 7-29B-2L(1) and (2), which defines, for the purposes of tax incentives, in certain instances for stripper wells, that stripper wells are defined as those wells producing less than ten BOE per day.
A. And I'm sorry, I'm not an attorney, but the citation you're making, is that under the Oil and Gas Act?
Q. No, sir. It's under the tax code.
A. Okay. Well, I --
Q. I can show it to you, but I'm not going to belabor it.
A. Okay. I'm not a tax expert, so that would be a waste of time.
Q. Just trying to get the distinction of that. It's a common use in New Mexico to define categories of wells. Thank you.
Representative, do you agree that legislatively approved funds in the reclamation fund, specific to plugging expenditures, have increased substantially from approximately $3.5 million in Fiscal Year 20 to almost 18 million in Fiscal Year 25?
A. Yeah, I think I've seen numbers similar to

that. I'll say I can't swear to those numbers, but the trend is probably right.
Q. And would you agree with me that OCD's related expenditures for well plugging have kept pace with those approvals?
A. I'm sorry. Repeat that.
Q. Would you agree that OCD's expenditures for well plugging through use of the reclamation fund have kept pace with those approvals in their respective fiscal years?
A. So what you're saying, is OCD proportionately plugging the same number of wells relative to the dollars? Has their plugging program grown along with the resources that were available?
Q. That's one paraphrase, sure, yes.
A. Okay. Then yes, I would agree with that. But they seem to be capped at that level.
Q. Representative, can we agree that OCD should focus its enforcement efforts on those operators that are substantially out of compliance?
A. Yes.
Q. Okay. On page 12, lines 8 through 10 of your direct testimony, you testified that New Mexico does not have an orphaned well problem. I want to make that as a foundational statement. Do you agree?

A. I'm sorry. On page 12?
Q. Page 12, lines 8 through 10.
A. Yes, I agree. That's my testimony.
Q. And do agree that, in part, you support that statement by pointing out that New Mexico does not have a definition of "orphaned well"?
A. Yes.
Q. Okay. And further, Representative, you distinguish inactive wells from orphaned wells?
A. Yes.
Q. Would you agree with me that once a well has been inactive for more than 12 months, it must be plugged within 90 days, according to OCD's current rule?
A. I don't know the answer to that.
Q. Okay. Do you dispute it?
A. I would, in a sense. Because I think there's other -- I mean I think we've had wells that have gone longer than that, either because we had -- it may not have been under temporary abandoned status, but we -- we had a retrievable bridge plug in there and so maybe it did go a period. Maybe we were talking to the OCD inspector about why we were doing what we were doing.
So there could be a lot of exceptions to

that just from a practical experience standpoint. I don't have any way to dispute what the rule says, but I can only describe what happens.
Q. Okay. So you're testifying that there could be reasons why there would either be enforcement discretion or perhaps wells placed in approved temporary abandonment or something else that's going on.
A. Sure.
Q. Okay. Can I show you the existing rule? Looks like I have lost permission to share screen. If I could request that again, I'll come back to this.
Representative, would you agree that OCD may issue what's called a notice of violation, under the existing rule, for any wells that are required to be plugged by the rule, but the operator has failed to plug them?
A. I would agree with that, yes.
Q. So, Representative Murphy, I just want to highlight here that 19.15.25.8B states that the operator shall either properly plug and abandon a well or place the well in approved temporary abandonment in accordance with 19.15.25 NMSA within 90 days after. And here it says, under (2), a determination that a well is no longer usable for beneficial purposes or

(3), a period of one year in which a well has been continuously active.

So, I just wanted to clarify, as a foundation for my question, that under the existing rule, that requirement exists, notwithstanding the clarifications or exceptions that you highlighted. Would you agree?

A. Sure. I would.

Q. Okay. Thank you. So, Representative, if the division issues a notice of violation and brings an enforcement action for inactive wells, do you know generally what happens to the wells that are referenced in that notice of violation?

A. Only generally.

Q. Would you agree that it's possible that they could be plugged by the operator?

A. I would.

Q. They could also be plugged by a third party?

A. Yes.

Q. And they could be plugged by the Division?

A. Correct.

Q. Have you reviewed any of OCD's inactive well NOVs or settlements?

A. No. I think only the ones that may have been in the media. But no, I've not gone into the OCD

records.

Q. Okay. So as you sit here today, are you able to testify as to a percentage or number of the wells that, after the necessary enforcement action, end up getting plugged by the Oil Conservation Division?

A. Do I know that percentage?

Q. That's not my question.

A. No.

Q. And similarly, again, not to belabor the point, but likewise, you wouldn't be able to testify as to the number or percentage of wells after a necessary enforcement action that are plugged by a third party, pursuant to a plugging demand made by another agency, such as the State Land Office or BLM?

A. No, I don't know those percentages. But I guess I would have to say that whatever they are, those funds are being provided by the reclamation fund to plug. Just as the 3,100 wells that you mentioned earlier, some potentially $450 million in a worst case, would also be plugged by the reclamation fund. And it would generate enough money to do that in less than four years.

Q. So, I understand the distinction, Representative Murphy, but I have to ask, is it within

this Commission's power to increase the appropriation from the reclamation fund for use by the Division?

A. It is not. But it is within the power of the Commission to direct the OCD to request a higher budget amount. And if they can demonstrate that that budget amount would be utilized, they would get it.

Q. Thank you. Thank you for that.

Representative, did you hear the testimony of deputy director Brandon Powell?

A. No.

Q. You were traveling, I take it.

A. I believe I was, yeah.

Q. Okay. So have you had an opportunity to see what is listed and admitted into the record as OCD Surrebuttal Exhibit No. 33? Have you seen it?

A. You know, I believe I've seen a version of this somewhere, yes.

Q. Okay. And this is a list of all operators. And this is in the records, so there's no attempt at trickery here, Representative. But Mr. Powell testified that he pulled this list and it represents operators who have submitted no production reports since August of 2024.

So I guess what I'm getting at here is that, according to Mr. Powell's data and testimony, we

have 113 operators and 2,318 wells for which there is no production reported for over a year?

Will you accept that as a premise?

A. Sure.

Q. Okay. And so based on my earlier questions in our discussion about the current rule, 100 percent of these wells are out of compliance. Do you accept that? Okay. And so --

A. Sure.

Q. -- every -- and as a caveat here, I just want to be clear about what the record says and what it doesn't. This includes federal wells and this includes some operators that are already on OCD's master reference spreadsheet. Okay? So it is over-representative of what OCD may take enforcement actions for. Nevertheless, there's still close to 100 operators on here who are 100 percent non-compliant.

Representative, would you dispute Mr. Powell's testimony that approximately 40 percent of inactive wells are what OCD classifies as private wells?

A. No, I wouldn't dispute that. I assume he means they're on private lands.

Q. Yes, private lands or private minerals or both. Okay. Thank you.

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A. Yeah. And by "private lands," that's what I meant.
Q. Private. Then we're good, yeah.
I want to show you -- all right. So there's been a lot of discussion about the reclamation fund, and I just want to clarify here, particularly with your experience as a representative, that when we look at what the reclamation fund may be used for, that the statute indicates, in part, that the Division may use the reclamation fund for the purposes of employing the necessary personnel to survey and abandon wells, well sites and associated production facilities, and preparing plans for administering and performing the plugging of abandoned wells that have not been plugged or that have been improperly plugged, and for the restoration and remediation of abandoned well sites and associated production facilities that have not been properly restored and remediated.
So just, as a foundation. So, Representative, do you agree that the reclamation fund may be used to plug and abandon both wells and associated production facilities?
A. Yes.
Q. And it may be used for surface reclamation and remediation activities, correct?

A. Yes.
Q. Okay. I also want to point you down here to -- I'm going to highlight the section here, and among other things, 70-2-38B states that the Division may order wells plugged and well sites and associated production facilities restored and remediated on federal lands, on which there are no bonds running to the benefit of the state, in the same manner and in accordance with the same procedure as with wells drilled on state and fee land, including using funds from the oil and gas reclamation fund to pay the cost of plugging.
So, Representative, is my understanding of the legislature's language and intent here that OCD may order wells plugged and may plug wells, regardless of their surface or mineral type, if they exist within the geographical boundaries of the state of New Mexico?
A. Once again, I'm no lawyer, but that's the way it appears to read, yes.
Q. And I just want to be clear that we just talked about remediation and reclamation. Is it consistent with your understanding that neither the petitioner nor OCD are proposing to base financial assurance for the single-well financial assurance on

either reclamation or remediation costs?
A. That was not clear to me, actually.
Q. Okay. If I clarify that to you and the record reflected that the average cost proposed to the Commission was based solely on wellbore plugging, would you accept that?
A. Yeah, I would accept that in the sense that if you tell me that they only plugged the wells and didn't do the reclamation, then I have no reason to dispute that. But I would still reject the premise that an arbitrary $150,000 bond is the way to cure this problem. But, proceed.
Q. Okay. Would you also agree that, similarly, reclamation and remediation of associated production facilities is not factored into that average wellbore plugging cost?
A. I've heard testimony to that effect. But I'd also add that the cost of plugging federal wells has historically -- and remediation has historically been reimbursed to the state.
Q. Okay. Yes. Understood. Thank you, Representative.
So I want to, I'm going to backtrack a little bit here, just loop back. So I had asked you about 70-2-38B. In your direct testimony, you also

distinguish the orphan well problem by pointing out that many of the inactive wells are federal. But we've just gone over the statute, so I just want to see if we can reach an agreement that those federal wells are actually potentially orphaned and are a problem under the use of the reclamation fund. Would you agree with that?
A. I would agree that -- well, here is where I think you have to make the distinction.
OCD may very well have the authority to go plug those wells, and it sounds like they do, and they should. What the difference is, when I make the distinction, I'm talking about who pays for it, right? And if it's a state or fee, then a state or fee well is typically paid for with the reclamation fund. But apparently, even if it's a federal well and the federal government didn't pay for it, the reclamation fund would pay for that too.
But historically, and we know recently, the state has received as much as $90 million to plug federal wells. So that's where I am.
Q. Okay. Thank you, Representative.
Representative Murphy, are you aware that OCD does and has, in fact, engaged in plugging of federal wells by either agreement or consultation with

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the Bureau of Land Management?

A. It's my understanding that the vast majority of federal wells are plugged by OCD under contract with the BLM, or some sort of arrangement.

Q. So I want to distinguish here. So there's -- would you agree that there are different sources of funding which OCD can use to plug, quote, unquote, orphaned wells, including the state reclamation fund, the bipartisan infrastructure law grants, and more specific, discrete grants from the Bureau of Land Management? Would you agree with that?

A. Yes, I would.

Q. I believe the ones that you were referring to just now were specific wells that were plugged using OCD contractors, after the BLM had called federal bonds and then awarded that to the OCD for plugging by agreement or contract. I'm not sure which. But by agreement, OCD plugged those wells using that more discrete grant. Is that accurate?

A. I don't know the details. I understand there's federal dollars, including the 90 million, that are going to this issue. That's the only point I will make.

Q. Yeah, and that's the distinction, Representative Murphy, that I'm trying to make.

Because you had testified that the BIL grant money may be used on federal wells. So, have you reviewed the specific terms of the BIL grants?

A. I have not. I was only familiar with it from my conversations with Mr. Sallee.

Q. Okay.

A. And some media reports.

Q. Okay. If I told you that that was inconsistent with the legal analysis and the understanding of the Division, that those BIL grant funds may only be used on non-federal wells, would that change your concern or your testimony?

A. No, it really wouldn't. Because money is fungible, right? I mean, if they gave you $90 million to plug whatever wells, you've got $137 every year to plug the rest of them.

So once again, I mean, coming back to this as being a revenue or payment, as I say, funds problem, it just doesn't wash with me. And the reason being is, I think the proof is in the pudding. You've got a $75 million balance you can't spend, and you've got $100 million a year that also you can't spend.

And I apologize, Mr. Tremaine. I mean the OCD. I don't mean you personally.

Q. No, certainly.

A. The Oil Conservation Division.

Q. Sir, I've been in-house, so to speak, for so long that I dip into the weeds too much.

So, Representative Murphy, in your direct testimony, you had talked about a couple different numbers, the 56 million, the 66.7 million, and you just referred to a more recent number of 70, I believe it was 76, but that same material. So, there's a lot of money in the quote, unquote, reclamation fund, you would agree?

A. Yes.

Q. Okay. But we ran through an analysis here on cross that, you know, the status quo of plugging might be 3,150 wells plugged under an orphaned program. And, you know, using your analysis of 66.7 million could plug either 800 to 1,000 wells. That looks like -- if you're plugging 1,000 wells, you think that there should be a per-well plugging cost averaging $66,700, that would mean that there would have to be $210 million over -- to plug those 3,150 wells. And if we're using those OCD's average cost from FY24 of $163,000 for the well-bore plugging, that would be $513 million, in excess of $513 million. Would you agree with that?

A. Yes, I would agree with it. But I think

here's the point, and I think it's easy to get people confused about these numbers, and sometimes I even get a little bit confused.

So let's just agree, for sake of agreement, that we have 3,000 wells that the OCD is worried about, and $150,000 seems to be the number, that's $450 million. You went back just now between 210 on the low estimate and 00 on a high estimate. So let's just take your number. Let's take 500 million. All right. That's what's been swept out of that fund in the last four years. That's what that fund will generate over the next four or five years.

So I keep coming back to the point, Mr. Tremaine, that this is not a funding problem, and I don't know why it's being described that way. Even at 3,000 wells, which I don't begin to accept for a moment, but let's just do that, $500 million, 137-, $125 million a year coming into the reclamation fund, how long does it take to pay that $500 million?

Q. That's fine. Well, I understand the point you're trying to make, Representative. I have kind of a different -- a little different analysis I want to examine with you.

So even if the reclamation fund were dramatically increased, as I think you're

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suggesting --

A. Actually, I'm not suggesting that. I'm suggesting that the balance be moved into a protected fund, that you all be given whatever you can spend. So no, I mean let's be clear about what I'm suggesting.

I'm suggesting that the OCD be given the resources that it needs and the funding that it needs to plug these wells. And I don't care if there's 350 of them, I don't care if there's 3,000 of them. You've got the money to do it. You spend 20 -- you've got a balance of $75 million, you spend about 25 a year. You've got three years of plugging fund in your balance right now.

This year, industry will generate another 100 and to 125 million, none of which you'll need to plug wells. And next year.

Q. So I think what you're saying, Representative Murphy, is that there are funds being utilized or appropriated by the legislature to other purposes, which would need to be placed into the reclamation fund. That would be step one, right? And then step two, would require --

A. Well, it's a little different than that.

Q. -- an approval or appropriation by the

legislature for OCD to actually spend the funds. Is that accurate?

A. I'm sorry I interrupted you. But let me see if I can answer it. Is that the legislature, by nature, is not going to give any agency more money than they can spend, because there are so many perceived needs for that money. So when you submit a budget for roughly $21 million a year and say, "This is what we need to plug wells," that's what they're going to give you and that's what you've gotten.

Now, you say over a period of some years, you're going to need roughly another $425 million. And that will be there in that fund because historically it's been generating that, and there's no reason to believe that it won't continue to generate that.

And so I'm not sure -- I'm not sure where we're miscommunicating here, but maybe --

Q. No, sir, we're not. I don't believe we're miscommunicating. I think it's different perspectives and I'm trying to get at something else.

So let's talk about -- let's say that hypothetically there are no procurement problems, there are no recruitment problems, we can get every staff that is necessary to administer the increased

fund.

And let's say that tomorrow, the Division went from -- I believe your number was plugging an average of 50 wells per year. Say tomorrow, the Division went to plugging 200 wells per year like that. All right? There's no other problems.

If we're talking about 3,150 wells, that's going to take us what, 12 to 15 years to plug all of those wells, assuming that OCD was able to instantaneously ramp up everything to the point of where everything that you're asking us to do was entirely possible with no restrictions.

A. Mr. Truman, I think he can plug 500 wells a year with a robust plugging industry. And that's what I was trying to get to before. We were hoping to be part of that industry. But that opportunity doesn't exist because of these procurement issues.

So, I mean, we designed our rigs -- what I recall is, we figured one would plug 50 wells a year. About one -- a little less than one per week, or a little more than one per week, given holidays and so forth. And we planned for a minimum of two and up to four rigs. So we'd be able to, just my company, we'd be able to plug 200 wells a year.

Assuming that there are other companies out there that would do the same thing we were doing, which there would be, then you would be up to probably 400 or 500 wells a year, and you'd have your problems solved very rapidly.

Q. Representative, I greatly appreciate the vote of confidence and being able to plug 500 wells a year.

A. Well, that's what happens when you engage industry. And when you ignore it, we end up in a room like this.

Q. Well, Representative, how is that going to work? I mean, where are those OCD staff coming from?

A. Well, you know, we talked about this in committee, and I was assured that you all could get it because of all the federal employees that are going to be laid off. As a matter of fact, that was a direct quote from -- I don't know if it was Ben Shelton or one of the representatives at OCD. I'm not going to mischaracterize it. But I asked that question, "Can you ramp up?" "Oh, yeah, we can ramp up." So there's your answer.

Q. Well, Representative, I would submit that there's a distinction between ramping up, even aggressively ramping up, and multiplying the current

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capacity as you stated it by 10 times over a short period of time.

A. Well, I can only speak to what we plan, right? And so from our company business plan, we would have ramped you up four times. And I have a hard time believing that once somebody sees that opportunity, we wouldn't have a lot of competition.

And so it goes back to process. And that's -- we've talked about procurement, but we haven't talked about process. And I don't -- once again, I'm not a lawyer, I don't know what your constraints are within the legal framework, but I know this. You've sued companies before, you've won a district court. You've taken over their wells, I believe you've plugged them.

And my question is, why hasn't the OCD done that more aggressively? Why haven't they done it sooner? And why aren't they doing it more?

And if that's not adequate, if you need more authority from the legislature, then please come to us and tell us what you need. I don't know if you need some sort of emergency power -- once again, I'm not a lawyer -- you need some sort of emergency powers to expedite things. But that's the process problem.

You don't have a pool of wells big

enough to really be very concerned about. And that's why I say you don't have an orphaned well problem. What you've got is speculation that you might have an orphaned well problem, which runs into a hundred years of industry history, which says that you won't have an orphaned well problem. But if you do have an orphaned well problem, you're going to have $125 million a year to solve it.

Q. Do you agree that we have an inactive law enforcement problem?

A. I can't speak to that really. I mean, I look at your list, it appears that you did. You know, I can't -- we don't have any inactive wells -- well, we may have one that we're waiting to be plugged. NM3, I believe, may be inactive. But it'll be plugged soon. So we don't -- I don't have a lot of direct experience with that. But according to your numbers, it does appear you did.

Q. Representative Murphy, I greatly appreciate the vote of confidence and the blessing to more aggressively pursue an active well-enforcement. I guess I am struggling with apparent presumption that if we more aggressively pursue an active well enforcement, that we won't simply be adding wells, a substantial number of wells to the orphaned well list.

A. Well, you will --

Q. Because that's been the history.

A. You will be, but you'll have the funds to do it, Mr. Tremaine. But here's the other thing, and this is something that I'd hoped to talk to the LFC about.

They talked a lot about the Colorado experience, and this goes directly to what you just asked me. In Colorado -- and this is one thing I want to talk to them about. It's interesting they mentioned the Colorado experience, but they failed to include the impact of that experience. Right? They failed to include the fact that 2,000 wells were added to the inactive well list immediately or the orphan list or whatever it was.

And so under your numbers, the state immediately, immediately picked up $300 million of liability at $150,000 per well. So if you pursue the $150,000 per well, you're absolutely -- and maybe that's your point, is that that is your process, is that you want to force these people out of compliance so you can expedite the process to get it.

All I would say to that, if that's where you're headed, there's a lot easier ways to do it, and the legislature can probably help you with that.

Because we want this process solved as well, and the industry wants this process solved as well. Because quite frankly, as an oil and gas operator, I'm sick and tired of hearing about how we're not cleaning up our own messes when we pay to clean up our own messes. That's insulting to me, and it's not true.

Q. So, Representative Murphy, the reason you say that is because of the existence of the reclamation fund?

A. Correct.

Q. Okay. And so, again, last question here. Representative Murphy, I think the sum total of our discussion today and my understanding of your recommendations, is that you think that the OCD or Commission should wait for the legislature to take action in one of the future sessions; is that fair?

A. I would welcome -- as a legislator, I would welcome a dialogue. OCD's never come to me and said, "Will you help us fix this problem?" And I know the legislature feels very strongly, both sides of the aisle, that this issue needs to be addressed.

There will be a bill. I don't know if it'll make it up on the call or not, but it will be bipartisan, as the past bills have been. I can't predict what that will do, but I will say this. We

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should have some optimism. Because when Meredith Dixon and myself and Rob Montoya and a few others, proposed 403 in committee, it came out unanimous. Matthew McQueen, the chairman, worked closely with me in making that bill a good bill. Vice Chairman Sarinana did the same thing. And for those of us that are familiar with the energy and natural resource committee, that's a pretty rare feat, to have a bill come out unanimously.

Unfortunately, it came out late and we couldn't get it in front of the finance, Representative Lente's committee in time. But there seems to be a lot of bipartisan support for this approach.

And I also feel like it's the proper venue. And I'm, once again, not a lawyer and don't mean to get into whether you have the jurisdiction or you don't. I personally believe you don't, I'm not a lawyer.

But I will say this, is that I think the people, the early leadership of New Mexico, recognized how important oil and gas is to our economy and put some real constraints on what can be done to this industry, and largely retained a lot of that power within the legislature. And I believe that this is

such an important issue and it could have such a huge impact on this day, that that's the body that should be debating this.

And it bothers me that an applicant who has a mission statement of working to end oil and gas leasing and drilling on our public lands, that is on the website, and the environmental defense fund, had so much influence in the report that's driving this hearing and driving this action. And I think that from a policy standpoint, that's a very dangerous thing.

Q. Representative Murphy, the legislature has, despite bipartisan support, not taken any action to address this issue or finalize any action to address this issue in the last several years. Would you agree?

A. I disagree. We've been -- legislative process moves at the pace of legislative process. There was a lot of -- there was a lot of discussions and everything under 403, and there were there was a lot of movement.

If you take that what happened at 403 to my bill, our bill, in this year, I mean, it made it through a hearing. We had a similar bill that advanced on the Senate side. I think there's a lot of

legislative process that's being done and there's a lot of debate. And quite frankly, there's a lot of thought going in to how to solve this problem without jeopardizing a very, very important industry.

MR. TREMAINE: Thank you, Representative Murphy. No further questions.

HEARING OFFICER ORTH: Thank you, Mr. Tremaine. Mr. Biernoff, do you have questions?

MR. MOORE: Good afternoon, Madam Hearing Officer. I'll be representing the commissioner this afternoon, at least for a little while longer. Chris Grazer should be joining later. Our schedules are in flux. I just have a couple of questions for Representative Murphy.

CROSS-EXAMINATION

BY MR. MOORE:

Q. Good afternoon, Representative Murphy. My name is Richard Moore. I represent the commissioner of public lands and the State Land Office.

A. Nice to meet.

Q. Nice to meet you as well, and thank you for your testimony this afternoon.

In testifying about the number of orphaned or inactive wells on federal versus state or private land, you used Cano Petro as an example; is

that correct?

A. Actually, I was referring to previous testimony by the commissioner, I believe, because Cano came up. And so yes, I was referencing that.

Q. But I believe that you testified that Cano Petro only has a handful of wells that are not on federal land; is that correct?

A. My understanding is there were roughly 299 wells, somewhere around 300 wells of Cano, and the vast majority of those were federal. That's been what I've been told.

Q. I'm just going to share my screen here quickly. Are you familiar with the inactive well list? I know that's come up.

A. I am.

Q. So having then searched for inactive wells on Cano Petro, this is the results. Would you characterize -- so you mentioned that you're familiar with the list. You're familiar with what the F and the P stand for under lease-type and surface owner, correct?

A. Yes.

Q. Looking at this inactive list for Cano Petro, would you characterize the number of wells that are indicated as private lease or surface owner as

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merely a handful?
A. No, I wouldn't. I would say that there's -- just glancing at it, I haven't counted it, but to be fair, it would probably be a mix of mostly federal and private. I see very little state on there.
However, I would also note there -- well, we're getting down to quite a few of the federal. But regardless of whether they're federal and they're paid for federal, even if they're private, federal or state, as was established earlier, the recommendation fund is available to plug them. So whatever number of wells there were or are, there's ample funding.
MR. MOORE: Well, thank you for your answers and your testimony today.
That is all the questions that I have and I'll pass the witness.
THE WITNESS: Thank you, Mr. Moore.
HEARING OFFICER ORTH: Thank you, Mr. Moore.
Let's see. I don't believe we have Mr. Nanasi. Mr. Maxwell --
CHAIR CHANG: May I recommend a mid-afternoon break at this point, before we move on?
THE COURT: Oh, yes. Absolutely. Thank you so much for the reminder, Mr. Chair. Let's come back

at 3:00.
(Recess held from 2:48 to 3:00 p.m.)
HEARING OFFICER ORTH: Again, I think we do not have Ms. Nanasi. I believe Mr. Maxwell is at the polls.
Mr. Rankin, do you have questions?
MR. RANKIN: I have no questions for Representative Murphy. Thank you very much.
All right. EOG is monitoring.
Mr. Suazo, do you have questions of Representative Murphy?
MR. SUAZO: No questions.
HEARING OFFICER ORTH: All right.
Ms. Tripp, do you have redirect?
MS. TRIPP: Yes, Madam Hearing Officer, just very briefly.

REDIRECT EXAMINATION

BY MS. TRIPP:
Q. So, Representative Murphy, you went through some math with Mr. Tremaine, and the figures that were used were 63,000 wells at 5 percent, being 3,150 wells potentially that would be orphaned; is that right?
A. That's my recollection, yes.
Q. Okay. About how long would you estimate a well's lifespan?

A. 30 to 50 years.
Q. In the 63,000, that 63,000 is composed of all active wells. Was that your understanding?
A. That's correct.
Q. So do you have any expectation that there will be 3,000 or 3,150 wells orphaned next year?
A. No.
MS. TRIPP: No further questions.
HEARING OFFICER ORTH: All right. Thank you very much, Ms. Tripp.
HEARING OFFICER ORTH: Commissioner Ampomah, do you have questions?
COMMISSIONER AMPOMAH: Yes, I do.

EXAMINATION

BY COMMISSIONER AMPOMAH:
Q. Representative Murphy, thanks so much for your testimony today. I'm Dr. Ampomah from New Mexico Tech, so nice for meeting you.
A. Nice meeting you.
Q. I do have a couple of questions if we can bring up the slides and walk through that the direct.
Let's start from slide number 3. I thank you once again for the testimony. Here, item Number 4 is showing that your company has blocked 38 wells in New Mexico.

Can you share with the Commission the average cost of the plugging?
A. The average cost, typically these wells vary between 5,000 and 8,500 feet. Principally, Delaware wells, but there are probably some exceptions.
Our actual plugging and reclamation costs would be somewhere around 100,000 to 120,000, on average. We've had some higher and some lower. And it might be a little bit more if you include reclamation on some sites. But it'd be somewhere in that range, 100,000, either way.
Q. So we heard the same from Armstrong, as well, averaging 120, but his wells were much deeper. But it sounds like you are combining a little bit of the reclamation to it.
A. Yes.
Q. So it's a little bit difficult to distinguish between how much is actually for the well plugging?
A. That's right, Commissioner. And the other thing I would say is that many of his wells, they're deeper, but they're single horizon or single zone.
In the Delaware Formation, where we operate, there's many times 15 to 17 individual sands, not necessarily all present at the same time. But we

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might have multiple sets of perforations, so there's differences.

Q. Thank you. Let's go to slide Number 4. So slide Number 4, based on your discussion, you said that it will not solve -- let's say you're talking about a single well bonding of 150,000 per well limit. You're saying that it will not solve this problem.

But I'm asking you, will it not make sure that OCD has enough bonding to support the plugging for companies that are bonding their wells?

A. Respectfully, Mr. Commissioner, not in my opinion. And I tell you why, is that the problem, people are not going to be able to come up with 150,000, and so they're going to simply -- and this is the Colorado experience -- they're going to simply walk away. And when many of those wells might have been plugged by them over a course of time.

They just can't -- think they can deal with the plugging of wells periodically, two or three wells a year, or whatever their plans are for over a period of years. But to be hit with $150,000 bond that they have to meet immediately is not going to make economic sense to them. So the ones that can pay it, are the ones that you don't need it from; and the ones that can't pay it, that you need it from, can't

pay it.

And so I don't think -- I think you'll collect very little of that, especially amongst the, quote, unquote, problem operators. Even if you go to a good operator, if you came to me and you said, "All right. Your well is" -- you know, "You either have to put this $150,000 bond up, or plug it," I think I'd be inclined to plug it, because I eliminate all regulatory, you know, dangers. At a low-volume well like that I'd have to see the payout. You know, I'm going to put up $150,000 bond and then I'm going to have to plug it, too.

I mean, it doesn't make economic sense to me. Because when you think about the categories of operators, the real problem ones are not going to be able to come up with the money. Especially when the money is already there through the reclamation fund. So that's the basis of that comment.

Q. But if you're looking at your average well plugging cost, and in the same as what Armstrong Energy, more or less presented to the Commission, it sounds like the actual plugging cost can probably not be less than 120,000?

A. Excuse me, Mr. Commissioner. You asked me what the average was. So we have many, many wells

that are less than 125. So if I have a well -- if I look at a well, and it's going to cost me $50,000 to plug it, and I have to put up 150, I think the decision is pretty clear.

Q. So then on that one, do you know if IPANM or NMOGA has presented to the Commission a quantified risk-based way of assigning the bonds for the Commission's consideration? Do you know?

A. I do not know. But I approach it a little bit differently. And the reason I have is that I've looked at it mainly, how does New Mexico compare to adjoining states? For example, we are competing primarily with Texas and Oklahoma, less so with Colorado. So I look at it from an economic competitive standpoint, is that it's going to impact that. And I hope that answers your question.

Q. Okay. Yeah. So I'm sure you understand the situation the three of us, you know, Commissioner Bloom on the platform, that we are in. Because we need to make all these difficult decisions. And the industry, I mean, you guys have plugged over 95 percent, yeah. And we've heard about risk based, risk based, risk based. You know, the applicant is putting their case direct, direct.

So are IPANM and NMOGA going to go back

and try to help us quantify the risk base, you know, as it is stated in the application for our consideration?

A. You know, I can't speak for them, Commissioner. I would say that history is the best, you know, past is prologue, right? We've got a hundred years of history in this state, 1926 to 2000 almost 26 of producing oil and gas wells. And historically, we've seen somewhere between 2 and 5 percent of those wells being orphaned, over a hundred-year period. And there's no reason, in my mind, for there to be a lot of speculation about what the future may hold.

As you know, in the oil and gas industry, we have what's called a decline curve. And that curve, that forward-looking curve, is based upon past performance. And it's a pretty solid scientific method of judging future performance as well. So that's how I'd answer that question.

Q. And I appreciate that. Let's go to slide Number 5. So when we started the hearing, you know, the TA issues were something that I also was concern with because of the production cycles, primary, secondary and tertiary. And I did not -- based on the experience, I don't feel like put in the eighth year,

you know, where -- I mean, we're probably not going to be able to go through secondary, not even to tertiary without really having premature plugging.

You know, so there have been a lot of discussions here where there is a potential where the applicant, even -- that was Mr. Alexander who provided some exceptions, you know, for the beneficial use. And that is definitely going to handle -- if the applicant brings that back, that is definitely going to help on the premature plugging in terms of the beneficial use.

But I want to talk to you about the TA status. So the TA status, too, I do like what the applicant put forward, because they do have the approved and then the expired TA status.

So let's focus on the approved TA status, for instance. Based on the current rule, if enacted, it sounds like approved TA will still need it to be borne at 150,000. Is that your understanding?

A. That's my understanding.

Q. Now, on that one, don't you believe that, let's say, an approved TA status means that OCD has inspected this well to know that the mechanical integrity of this well is so good? Is there any -- you know, should that approve TA also, more or less,

be in the same category as expired TA in terms of the bonding?

A. No, I don't believe so. I mean, the industry practice with respect to temporary abandon is to set a cast iron bridge plug and usually some volume of cement above it to circulate the well with inert fluids and to pressure test. And if I recall the rule, it's required, I think, every five years unless otherwise notified by the Commission. But it's at least a five-year test. That pretty well ensures the mechanical integrity of that well.

And we've got to remember what we're looking at in terms of wells. These are wells whose bottom hole pressure is essentially zero. I mean, right, you've got a fluid that can only -- if you've got a 3,000-foot well, your bottom hole pressure might be 200 or 300 pounds. So what does that mean? The fluid can only migrate up 300 or 400 feet. It can never get to the surface because there's not enough bottom hole pressure at the bottom to push it all the way up.

Now, some gas can migrate, you know, if not TA'd. But if it's TA'd, everything is sealed down there. And so to me, it's really -- in many ways, when you think about the future potential of that

well, it's much better to leave a well in that sort of status if it has future potential than to plug it.

Now, many of the studies that we did back when I was working primarily on secondary and tertiary recovery projects, and this is also -- I'm going to complicates your policy plate here a little bit -- is that one of the things that we found was that when you take any given reservoir, when you plug out some percentage of those wells, the economic viability of that secondary or tertiary recovery project is no longer there because you have to re-drill those wells.

And the reason you have to re-drill those wells is you have to be able to establish the patterns to get the efficiencies to get the recoveries to get the revenues. And so from a policy standpoint, I am very reluctant to plug wells.

And the reason is, is that I think many policymakers look at them and say, "Well, these things are long-term liabilities." Well, not if they're handled correctly, right? And the way I look at it is they are long-term assets. They are the key strategic petroleum reserve because they allow us access back into the reservoir in order to apply some sort of technology.

And so that's -- I probably took a long way around the barn. And I apologize.

Q. But you believe that the expired TA wells, they have to be bonded because those are wells that probably OCD might be responsible for?

A. I would say that a properly TA'd well and maintained should not be bonded. And in terms of -- whether there's some detail -- I would say, look, an unapproved or a TA'd well that's out of compliance, then I could see where that might require bonding. But I think there's statutory limits as to what that can be.

Q. Well, the applicant, you know, they do have, you know, in the proposed rule -- and you did not go through this rule exactly, so I don't want to really push on that line. But in that they do have the bonding for inactive wells; you know, it includes approved and even expired. But what I'm suggesting is that the approved needs to be dealt with separately.

A. I would agree with that.

Q. Yeah, from the expired. And they are putting 150 bonding on expired because they are non-compliance. And I don't think you disagree with that.

A. I believe -- well, I'm not sure I

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understand. Putting a hundred and -- well, putting a single-well bond on, in my opinion, that ought to be something that's looked at very, very carefully.

Because once again, if you've got a well that is out of compliance in whatever way it's out of compliance, then there ought to be a process that that well is put back into compliance. And if the OCD doesn't have the tools to do that, they should have the tools to do that.

But I don't believe bonding is that solution, especially when there's so much money available from other sources and reclamation fund. Now, when you take -- and the reason being it's largely about capital. And capital is pretty precious not only in the oil and gas industry, but in business in general, for investment purposes.

Q. Okay. Let's go to slide Number 6. So slide Number 6, bullet point two, you said propose rules would have chilling effect. Is that based on the details you've provided to us or specifically -- how is the marginal rule? So let's take the marginal definition for instance and then the beneficial use and combine them.

A. Okay.

Q. So how is that going to provide a chilling

effect, you know, to the industry?

A. Okay. So with respect to margin -- well, there's a number of areas. With respect to marginal wells, it'll be clear that they either need to be plugged or a substantial amount of money needs to be put up very quickly.

And that goes back to my point of -- well, and this is going to answer your question, because it really is about what the impact of that would be.

I believe the chilling effect is going to be that we have another example of regulatory uncertainty going to an extreme. And that you also have an expansion of regulatory authority into areas that the industry typically has not seen before, calling for financial records of private companies, for example. That's chilling.

Private companies are private for a reason. And there are metrics on their ability to perform. But in this case, I'd have to agree that as long as they meet the statutory requirements, that diving in and having an agency that is charged with protecting correlative rights, preventing waste, protecting health and the environment, to some degree, that's not exactly a mission that falls very well in

that agency.

Q. So let's talk about -- let's still talk about marginal wells. There has been a lot of discussions about changing the 1,000 to about 750 BOE. Is that something that you will support?

A. It's not. And it's because I reject the premise. I do. And with all due respect, Commissioner, the thing is, is that we now have agencies that are getting into economics. And they don't know my wells' economics.

And unless you allow the owner to continue to produce that asset, as long, as it's economic to do so, if you disrupt that system, then you're going to lose waste.

And in my opinion, I think -- and once again, I'm not a lawyer, but in thinking about it, if I have to prematurely plug a well because of the arbitrary either production number or other number, and I lose access to my profits and reserves, that's a taking, in my opinion.

And that's not something that the OCC, with all due respect, should be in the middle of. I think, you know, you set reasonable bonding limits, and we can debate about what those are in terms of blanket bonds, that are consistent with other area

states, so that we stay competitive. And then you ensure, through the procurement, through the process of populating, as I think it was described, access to these wells, and then you make sure that there's funding. And we know that there's funding. And so the whole approach to me is, from a public policy standpoint, really poorly thought out.

Q. So, you are not -- so you've described, from an operator standpoint, these marginal worlds, some of them are economic, you know, based on, let's say, from an operator's point of view.

You know, Commissioner Bloom has proposed, or based on the discussion, we've discussed about putting some exceptions with regards to the definition, you know, to make sure that we are really targeting the bad operators that are not really in compliance. So it sounds like you are not in a position to even help us with some of these exceptions.

A. Well, I could be. But under the current framework, I mean, I think I would have to really be convinced that this is the right policy approach, and I just don't see it right now.

I mean, it's -- and when you start thinking about those exceptions, you're not going to

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be able to catch them all, right? Maybe we'll catch some of them.

But, you know, when I looked at it -- I'll just explain my situation. When I looked at it, I said, Okay, I described the four wells, two federal, two state, both of which are around 700 BOE, all of which produce over 180 days. Okay?

But if you eliminated -- let's say they produced 100 days. They produced 100 days, but they made 1,000 BOE or 750 or whatever that threshold is. Then I wouldn't make that, right? Because it would have to be -- no, I would make that because I hadn't produced the 180 days. But it's economic, right? So I've got an economic well that doesn't produce the 180 days. That's marginal.

Q. No, it's not.

A. Or maybe I had that backwards.

Q. Yeah.

A. Excuse me. Yeah, it at least has to produce 180 days, right?

Q. And less than 1,000.

A. Yeah, less than 1,000. Okay. Well, I was just using numbers. But let's say that -- let's say I have a well, which I do, I have four wells that produce 700 BOE, they produce over 180 days. All

right? So they're okay. But what if they produced 100 days? They wouldn't be okay because it's "and." Here, it hurts. Right? Because I can show that well being economic, but it didn't make the 100 days -- or 180 days of production. So it's got to be 750 and 180. I'm 750 and 100. I'm not exempt.

Q. So let's attach on that one. And that is where the Commission is also considering that -- let's say in this instance there could be an issue why the well was not able to produce after the, let's say, 750 or, let's say, 1,000.

So there are some of these issues that could happen that the Commission is looking into to put it as an exception so that you do not really go after a well that because of, let's say, a mechanical issue or some kind of issue, pipeline, whatever, they were not able to meet that criteria.

So we're trying to see if we can come up with some exceptions to make sure that we do not necessarily go after wells that are economical.

A. I'd be interested to hear, you know, how that would go. I think the approach is -- when I began sort of that thought process of what you're talking about, I considered sort of the factors that I could think of that might go into sort of that

economic analysis, and they would probably be better than this, but not much better.

And the reason -- here are the facts. We talked about age. I think everybody sort of agreed with that. We talked about depth. I think -- but we also have to talk about location, northwest or southeast. We have to talk about is it primary oil or gas. I mean, is there hydrogen sulfide available? What is the gathering situation? What is the -- what are the natural processes that are going on with the well that might make a 200 BOE well profitable that produces 30 days. It wouldn't meet that either.

And so what I'm saying is, is that when you approach it in that way, you're never going to get it really right.

The way to do it I think historically has been correct, and that is, you leave the owner and the operator in charge of determining the economic benefit, and then you protect yourself and you protect the state through reasonable bonding and through the use of the funds the industry has dedicated to plugging that. And that is the ultimate protection.

Once again, I probably took the long way around the barn. I apologize, Commissioner.

Q. So you talked about funds holdup. You know,

you talked, still on this slide, you talked about funds hold up that could have been utilized instead of using to pay high premiums on financial assurance surety bonds.

And Mr. Gilstrap yesterday testified to the Commission presenting two scenarios. And one of the one of the scenarios that he presented here was a situation where an operator has to put up 3.75 million to 5.25 million yearly payments on the surety bond. I mean, there's a lot of numbers.

A. That's a lot of money.

Q. Now, you know, you talked about funds is not the problem, right for the orphan, or let's say for the plugging. Now, with this huge amount of money that is going to be held up to just paying premiums, just paying premiums to the surety companies, I'm not sure how that solve the plugging problem. I don't know.

A. I don't know either, and I'm not familiar with those particular circumstances. I guess this has been -- this is my experience, and that is, even if you had -- let's say that you created a brand-new company and you funded it with a whole lot of money, you just put $100 million into a brand-new company and it's going to come into New Mexico and it wants to

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explore and buy wells and do all the things, and it needs bonding. Right? It would probably, even with a lot of money in the bank, would have to put that bonding up in cash.

And the reason is, is that, this would have been my experience, the surety companies are not going to write a bond just based upon your assets. They're going to write a bond based upon how long you've been in business, what your track record is and so forth.

So when I say it has a chilling effect or there's all these input -- all these impacts, it's primarily to those people that are entering the business, right? Those of us that are well established in the business are probably paying some of the premiums you heard, 1, 2, 3, 5 percent maybe. But the entrants, many of the companies coming into this, are either going to have to put up a cash bond or they're going to pay a very, very high percentage.

And my point is only this, is that capital is very, very precious. And given that, in my opinion, the orphan-well situation, the reclamation, the plugging is largely addressed through the reclamation fund, is it good policy to take millions or tens or hundreds of millions of dollars and put it

into a fund that may be released later, may not, but probably will, when that money could be invested in this state, actually finding and producing oil and gas?

And if you think about that, when a company comes into the state, they're not looking just to get their money back, right? So let's say they have to pay the $5 million in premiums. Well, if they invested that $5 million, they would expect probably $15 million back, two or three to one return, or otherwise they won't stay in business.

That money, a good portion of it, comes right to the beneficiaries, comes right to the state. So where do you want the money? Do you want it sitting in a can under grandma's bed? Or do you want it out drilling wells, producing, paying salaries? I mean, that's the policy argument, I believe.

Q. Yeah. But we all agree that the orphan well could be a problem for our state, right? So based on the discussion that we're having, my question to you is what is the alternative situation?

A. Well, I had this conversation with Mr. Tremaine, and he said there's roughly -- I disagree there's that many wells, but let's take his number. And we'll take a compromise number. He said

3,100. I'll use 3,000 because I'm sitting here. 3,000 times $150, 450 million would be generated in three years from the reclamation fund, if they could spend it.

Now, remember, not all those wells are ready to be plugged. They're worried about them. Some they're somewhat worried about, some they're really worried about. But once again, it's speculation.

We've got, I think, 700 wells, I think was the number that was discussed here. That's, I don't know, what, $15 million, 12 and a half million dollars, something like that. So that's why I say that the money is not a problem, because the money is coming in faster than the activity is happening.

Q. So you don't believe that operators should more or less be asked to put a bond that could be utilized -- or let's say a bond that is almost close to how much it costs to plug the well?

A. I don't believe -- and let me speak to I think what we've all been trying to address, either the bad actors or the unfortunate situations where the state is left with a lot of wells, right? I don't think that's -- and historically we haven't seen that that just drops in our lap; it happens over time and

we can deal with it, as we have for 100 years.

And I'll just go back, I think the ones that you want to collect it from, you'll never collect it from. In other words, if you go to the 10 operators that they have talked about being 89 percent of the problem, you're probably not going to collect from them. If you go to the list that was even more expensive than I thought, however many hundreds there are that haven't put up the 150, most of them probably won't either.

So what's going to happen? What's the impact of that? No money collected, huge transfer of wells over to be the plugging fund. When many of those wells might very well have been plugged over time. So I just don't see the policy or economic win, Commissioner.

Q. Yeah, but so assuming those ten companies -- or let's say the companies that are going to earn the most, assuming OCD was able to bond each of these wells, 150, 150, and then they've neglected their responsibility, don't you believe that OCD can go to the surety companies and get the same amount instead of using the state funds to plug these wells?

A. I don't believe so. I don't believe, from my knowledge of the sureties and bonding and the state

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of the industry, that the operators that you target are going to are going to do that.

Look, how realistic is it to think of an operator having, let's just say, 50 wells and he doesn't report production on them for 12 months. Right? But he's going to come up with seven and a half million dollars in bonds? That's just not realistic to me, Commissioner.

COMMISSIONER AMPOMAH: Yeah. Thank you for your time, sir.

THE WITNESS: Thank you, sir. I really enjoyed the discussion. I think we're fleshing it out a little bit.

UNIDENTIFIED FEMALE: Thank you.

Commissioner Bloom, do you have questions.

COMMISSIONER BLOOM: Yeah, thank you Madam Hearing Officer.

EXAMINATION

BY COMMISSIONER BLOOM:

Q. Good afternoon, Representative Murphy.

A. Hi, Commissioner. How are you?

Q. Fine. Thanks. Yourself?

A. I'm good.

Q. All right. Again, thank you for your

testimony. Thank you for your service as a state legislator. I hear the pay is not great.

A. I've heard that too?

Q. Hey, I appreciate you having mentioned Daniel Yergin' work, "The Prize." It's a fantastic history of oil and gas. And you mentioned Oil Creek. I was born in Oil City and grew up with Oil Creek in the backyard. And my family's worked -- my dad's an attorney, started off doing oil and gas law, finished in oil and gas real estate.

My stepfather worked for Gulf, Mobile, Halliburton over the years. When you talked about downturns, I remember the '80s, I remember the l'90s when he was out of a job for, you know, a year or two at a time, and it was tough times.

Representative Murphy, I'd like to get into some of the issues around OCC's authority and jurisdiction, as you said, and some of the issues that you raised around that.

You stated in your written testimony, Page 7, I quote: From my perspective, WELC is asking the Commission to take steps that far exceed its authority under the Oil and Gas Act. I'm no attorney, but I have lived and worked with the Oil and Gas Act and its regulations for the past 40 years. The

Commission's primary purpose has always been to prevent waste and protect correlative rights. End quote. Did I get that right?

A. Yes. I read along the same, yeah.

Q. So, Representative Murphy, you mentioned engaging with the LFC staff on the well report and being dissatisfied with it. I take it you've read the report in its entirety?

A. I have.

Q. Yeah. Okay. I quoted a section to Mr. Ezzell, and I'll read that again. It says, quote, the federal Environmental Protection Agency estimates annual methane emissions from the nation's inactive and unplugged oil and gas wells are comparable to adding an additional 2 million gas-powered cars to the road. End quote.

Is that methane a wasted resource?

A. If that report is accurate, I would -- I would say yes. And I'm sorry, Commissioner Bloom, I'm not familiar with it, but you said that's a national report, not a New Mexico-focused report; is that correct?

Q. Yeah. That's a federal EPA estimate of annual methane emissions from inactive and unplugged oil and gas wells.

A. I'm sorry. Yes, I accept that.

Q. We heard from the OCD that 60 percent of inactive wells in New Mexico leak methane. If that's true, is this also fugitive methane waste, and then does the OCC regulate waste?

A. Yes. Along with others.

Q. Yeah. Does proper plugging stop methane leakage and waste?

A. It does, but it's not the only method.

Q. You're a long-time --

A. But I think it's important --

Q. Yeah, go ahead. Finish.

A. Yeah, Commissioner Bloom, I also think it's -- to put this in perspective -- and I see where you're headed and I share the concern about methane being vented from unplugged wells.

But I would also note this, is I think we always sort of have to quantify what we're talking about. And plugging the well is one option. We can talk about the pros and cons of that. But the easy option would be to TA the well, or the even easier option is to basically just fix the minor leaks, which should be done.

But in order to quantify this -- because I've really had a question about it. And during last

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week's water and natural resources, we were presented with a presentation from the New Mexico Environment Department, and it talked about this very subject. It talks about the New Mexico oil and gas greenhouse emissions inventory for year 2023 for methane and carbon dioxide. And this is a report director Miano, of EPA Division, New Mexico Environment Department, presented in Artesia.

And I find it interesting that we have a number of categories. We have production, gathering and boosting, processing, transportation and storage, and inactive oil and gas wells. Now, all of these colors represent these first four. This red color, inactive oil and gas wells, does not appear on this chart. So I think when we talk about this, we need to quantify the numbers, right? They're so low that the New Mexico Energy Department isn't even graphing them.

So I hope that answered your question.

Q. Yeah, it did. Thank you, Representative Murphy.

So I know you're a long time oil and gas man, and so in terms of those emissions, we'd also be getting some of the volatile organic compounds, the BTEXs, benzene, toluene, ethylbenzene and xylene, correct?

A. Correct.

Q. You know, it's certainly my understanding. I believe it's the Commission's understanding that the Commission is also charged with protecting the environment, water and public health. Do you agree with that?

A. I do agree with that.

Q. I'm not sure where we're going to end up in this rulemaking, but, you know, I am interested in exploring where we have authority, and we wouldn't want to exceed that. And, you know, perhaps from what I'm seeing, this probably ends up in the courts or something, and they can decide.

We've been over some of this. I feel like I'm repeating, you know, questions with the same answers I got from Mr. Ezzell and other, you know, NMOGA witness also. But I guess we're seeing some commonalities in the testimony as well.

A. Representative, if you also talked to us about your legislative work in the last session and for the upcoming session; is that correct?

Q. I mean, at the end of the day, can anyone guarantee what the legislature will do?

A. No. Just like we can't guarantee what the courts would do.

Q. You know sometimes we think our bills are -- you get the promises and it doesn't happen. I mean, I'm sitting here, you know, from the land office perspective. It took us seven years and six attempts to get our royalty rate bill through.

A. Glad you got it done. Well, let me offer this, Commissioner Bloom, that when I present the reclamation bill with the protections in there, I hope that the State Land Office will be there as an expert witness supporting that testimony.

Q. That's actually something to think about.

A. Yeah, maybe the OCD will show up, too.

Q. Finally, I go back to some other questions that I asked Mr. Ezzell about, and that's just related to the land office, you know, feeling the need back at the end of I think it was 2020, to institute an accountability and enforcement program to get orphan wells and inactive wells closed on state trust lands, because the companies weren't doing it.

And, I mean, you've probably seen some of the information we've put out that, you know, so far that program has succeeded in plugging -- you know, really kind of working with and enforcing and sometimes suing operators and lessees on state trust land, to plug 750 wells.

A. Yeah I've heard that testimony, Commissioner Bloom. I'd also -- I've encouraged both the Bureau of Land Management and I would encourage your office to look at issuing leases with unplugged wells as long as the purchaser is willing to take on that responsibility and bond them.

And that would actually eliminate a lot of problems, both on -- at any rate, that's a policy discussion we can have later.

Q. And that's interesting because that might require legislation as our oil and gas lease is set statutorily when we re-lease land to the next lessee, gets that free and clear.

COMMISSIONER BLOOM: All right, I think, Representative Murphy, I'm starting to fade at the end of the day. I'm going to leave it there. Thank you so much for your time and testimony today?

THE WITNESS: I very much appreciate your background there. I hope you're putting on some skis and hitting the Matterhorn or something. It looks good.

COMMISSIONER BLOOM: I'd love to?

HEARING OFFICER ORTH: Thank you, Commissioner.

THE WITNESS: Thank you, Commissioner Bloom.

HEARING OFFICER ORTH: Chair Chang, do you have questions?
CHAIR CHANG: Representative Murphy, thank you very much for joining us here and providing us with your testimony.
I'll just make a brief comment that whatever comes of this current bonding petition, I certainly agree with you that OCD needs to make the best possible use of every dollar in the reclamation fund, and I certainly hope we can work with all the various stakeholders to make that happen in terms of the specifics. I think we've covered it in fairly exhaustive detail, so I think I'll let you go for the afternoon.
THE WITNESS: Thank you very much. I appreciate you.
CHAIR CHANG: Thank you.
THE WITNESS: Thank you, Commission.
HEARING OFFICER ORTH: Thank you, Representative Murphy.
THE WITNESS: I guess that you didn't actually release me, so I spoke a little bit.
HEARING OFFICER ORTH: Is there any reason not to excuse Representative Murphy?
MS. TRIPP: Thank you so much. No.

HEARING OFFICER ORTH: Thank you very much.
Well, it is 3:47. Sheila, do we have -- it looks as though there are a number of names for the 4 o'clock. Do we have some of those folks on the platform already?
MS. APODACA: I haven't seen any, and we had forewarned some of them that we may not be in session this afternoon, so they may not all be in attendance.
HEARING OFFICER ORTH: All right. Thank you. Do you want to take the first 15 minutes?
MR. CLOUTIER: We can introduce Dr. Arscott, and he can start it up. We've discuss that we may need to chop him up a little bit.
MS. APODACA: We do have one in-person commenter, if you'd like to take him down.
HEARING OFFICER ORTH: No. We're going to do 15 minutes of Dr. Arscott, and then we'll go to the public.
MS. APODACA: Very good.
MR. CLOUTIER: IPANM calls Dr. Rob Arscott.
And, Ms. Apodaca, if you could give Mr. Arscott -- would you e-mail him the hearing notice so he can log in to the Teams meeting. Ms. Tripp and I forgot to do that.
Ms. APODACA: He's logged on and he has the

permission.
MR. CLOUTIER: Thank you. All right. Appreciate it, Ms. Apodaca.
So we're going to do our best to speed Dr. Arscott up by having me ask a few questions and then get out of the way and let him run through his presentation with fewer questions from me.
HEARING OFFICER ORTH: Dr. Arscott, would you please spell your first and last name.
THE WITNESS: Robert Arscott, R-O-B-E-R-T, A-R-S-C-O-T-T.
HEARING OFFICER ORTH: Do you swear or affirm to tell the truth?
THE WITNESS: I do.
HEARING OFFICER ORTH: Thank you very much.
Go ahead, Mr. Cloutier.

ROBERT ARSCOTT,
having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. CLOUTIER:
Q. Would you please introduce yourself to the three members of the Commission.
A. May I share my screen? There you go.
Yeah, my name is Rob Arscott. I'm here to offer testimony on behalf of the Independent

Petroleum Association of New Mexico.
Currently, my role is as an economist. I do consulting work at a company called Applied Economics in Austin, Texas. Prior to this role, which I've been in for about two years now, I was an assistant professor of finance at Syracuse University, where I taught courses on corporate finance topics and real estate.
And in a previous life, a long time ago, I worked in syndicated lending at an investment bank, and in private equity as an acquisitions associate at a real estate fund in London, England.
My education, I have a bachelor of business administration from Concordia University in Austin. I have an MBA from Oxford University in the UK. And I have an MSBA in applied economics, and a PhD in finance from the University of Rochester.
Q. And very briefly, what do you do at Applied Economics, Dr. Arscott?
A. Yeah, so Applied Economics and I regularly consult on matters related to oil and gas. I would say the majority of my work over the past little over two years now has been with various oil and gas clients, both upstream operations as well as in midstream.

EXHIBIT 30

Here's a brief little sample of some clients that I've worked with over the past year. Some of them are fairly large producers. Some of them are not so large. Kraken Resources, for example, would be an example, a private equity backed operator that primarily operates out of the Bakken in North Dakota.

Q. Thank you. And you submitted direct and rebuttal testimony in this matter?

A. I did.

Q. Do you have any corrections to that testimony?

A. I do not.

MR. CLOUTIER: All right. We offer Dr. Arscott's direct and rebuttal testimony into evidence. And then Dr. Arscott is the sponsor of IPA and Exhibits 1 through 9 and 29 through 36, which we also tend to read I'm hearing officer.

HEARING OFFICER ORTH: Thank you. I'll pause for a moment in the event there are objections.

BY MR. CLOUTIER:

Q. And from now on, Dr. Ascott, I'm going to let you take it away. And I may interrupt if I think something needs clarification, but why don't you go ahead and talk to the Commission, at least about the

first point you'd like to make.

HEARING OFFICER ORTH: The exhibits are admitted.

MR. CLOUTIER: Thank you. I apologize, Madam Hearing Officer.

(Admitted: Arscott Direct and Rebuttal Testimony, IPANM Exhibits 1 through 9 and 29 through 36.)

A. All right. Well, thank you very much.

So I guess I'll start with this question as to what is the right amount of financial assurance. And so I've been asked to work on this financial assurance aspect of the proposed rule.

And in part of my work in this, I've been doing a lot of research on -- I've been doing research into some of the theoretical, at least in a perfect rule, theoretical amount of financial assurance, how would you determine that.

But it's really based on something known as the judgment-proof problem, which is related to this concept of limited liability, which is very important to our capitalist economy. If it weren't for limited liability, we would likely not have the level of innovation and investment and entrepreneurial activity that we enjoy in this country. It encourages

people to take risks.

And the dark side of this is sometimes we run into moral hazard issues, such as this concept known as the judgment-proof problem. The judgment-proof problem arises when you have, in this case, an operator that becomes insolvent. They declare bankruptcy, and through bankruptcy protection, an operator can shirk its responsibility potentially to properly plug and abandon its wells.

And so the duty to plug and abandon the wells then falls to the state, at the state's expense. And this is obviously not an ideal outcome, especially from a social standpoint. And so we have to come up with ways in which we can encourage bad actors, for example, to behave like good actors.

One of the ways that we do this is with a bond. So what the bond does is the bond requires the operator to put up some monetary incentive to provide for the incentive to plug and complete the well according to his obligation.

If the operator fails to plug the well, he'll forfeit the bond. That money will then go to the state to aid in plugging the wells. And in addition to providing an incentive to plug the wells, this actually delivers money to the state to help with

the plugging effort. So in that sense, it's an efficient way to deal with this judgment-proof problem.

Now, there is this tension between economic growth and public protection. Obviously, the bond can protect the public from the costs of plugging and abandoning wells that are abandoned by private industry. But if we set the bond amount too high, it will stifle economic growth.

Now, there is a theoretically ideal amount of bond protection. And the economic literature is actually clear on this. It's related to the expected P&A cost of a well. But actually, the P&A cost and expectation for a well is actually the maximum bond amount that, in theory, you should require.

The reason why the ideal bond amount may actually not be equal to expected P&A costs is because operators face a lot of other potential deterrence to defaulting on their obligations to plug their wells. Some of those deterrence are non-monetary. For example, the operator faces a reputational risk if they fail to honor their obligation to plug wells. Aside from non-monetary considerations, operators also have monetary considerations related to lost profit,

potentially from continued operations.

You can imagine an operator that, in expectation, might think that they might be able to reap substantial profits from continued operations in the state. But if they fail to plug their wells, they may find that they face permit denials from the regulatory authority, in addition to possibly revocations of their authority to transport oil and gas in the state. That would effectively end that operator's ability to do business in the oil and gas industry in the state and represent a significant monetary cost if he fails to plug his well.

So, in the portfolio of incentives that the operator faces that would lead him to honor his obligation, in some cases, the bond, even a bond in the full amount of the expected plugging and abandonment expense, may not really move the needle much in terms of affecting the operator's decision to honor his obligation.

So, in that case, the bond amount, whatever the cost of that bond is, would be a pure cost and not necessarily have any associated benefit. In that respect, the ideal bond amount might actually be considerably lower than the expected cost of plugging and abandonment.

Because the ideal bond amount is in some ways connected to expected P&A costs, it's important to recognize that there's considerable variation in plugging and abandonment costs in the data. For example, the OCD's plugging costs may not reflect typical costs of plugging wells throughout the state. According to Ben Shelton, the OCD's cost may be anywhere between 10 to 15 percent higher than what private industry's costs are.

Regardless, if we were to set a bond amount at, say, 150,000 per well, if this is somewhere near the average cost for wells in the state, by definition, the median or the average is going to be set higher than about half of the wells in the state.

Now, to the extent that we're talking about wells that, in expectation, have plugging costs that are less than 150,000, for example, a well that maybe costs 50,000 or even, let's say, 100,000, a well that, in expectation, will cost 100,000, we know that, theoretically, the optimal bonding amount should be no more than the expected costs of P&A'ing in the well. So if a well is an expected cost of P&A equal to 100,000, imposing a financial assurance burden in the amount of 150,000 on that well presents an economically unjustified cost.

We're not necessarily talking about forcing operators to fully internalize the costs of their activity at that point. We're now imposing a cost in excess of what is economically justified. Now, this can lead to the premature plugging of wells, which ultimately would lead to waste, reserves that are lost beneath the ground because we plugged the well prematurely.

There are other sources available to address the orphan well problem. We've heard from several people during this hearing. The OCD reclamation fund is one such source. There is a conservation tax of anywhere between .19 percent and .24 percent that is charged on all hydrocarbons severed and sold in the state. Depending on oil prices, either 10 to 20 percent of that revenue is diverted to the reclamation fund.

According to the LFC report that was published earlier this year, the fund had a balance of 60 million as at the end of fiscal year 2024. Although, as we've heard from Representative Murphy, that may be significantly higher. I think he said 76 million.

There are also federal grants that can be used to address the orphan well problem. According

to the LFC report, a little over $55 million of such grants have already been used in New Mexico. And New Mexico remains eligible for a further 111.8 million.

So, the proposed rules will lower the incentives to produce oil and gas in New Mexico. And I say that because there is an increase to the cost of production related to the amount of financial assurance that's levied on the operator. To the extent that that financial assurance is economically unjustified, it's too high. And if it's too high, then it increases fixed costs above what's economically justifiable and, therefore, reduces the incentives for operators to continue to produce oil and gas.

The effects will vary by operator depending on the types of wells that they operate in their own financial condition. This one-size-fits-all $150,000 per single well is, I would argue, overly broad because it ignores the default likelihood and cost of default that is unique to each individual well. In some cases, FA costs will be extreme.

And in these cases, I'm going to mention two specifically. One is an instance of a cash bond. The other is this 15 percent threshold that we've

heard about many, many times. So the cash bond is, as opposed to a surety bond, this is a bond that requires 100 percent collateralization. The operator that is taking out a cash bond has to put up full $150,000 today. They may not plug the well for years to come, after which they can get the money from their bond back only after the well has been verified as plugged correctly. All the while, the operator is out that capital. If I have to deposit $150,000 today, that's $150,000 that I don't get to deploy for other purposes.

To the extent that we're talking about operators of PDP reserves, or proven develop producing reserves, those typically have a discount rate of about 10 percent per year. So an operator that's setting aside $150,000 on a cash bond actually faces a bonding cost on an annual basis equal to 10 percent of that amount. So these cash bonds are actually quite expensive relative to surety bonds that may have fees ranging between 2 percent and 3 percent.

The other case in which FA costs will be extreme, in my estimation, will be in cases where the portfolio of the operator contains more than 15 percent either marginal or inactive wells as the proposed rules define them. I'll give you two

examples after comment.

HEARING OFFICER ORTH: Thank you very much. I thought perhaps before you started your next slide we could do public comment.

So we have reached another public comment session. Is there anyone in the room who would like to -- so, Dr. Arscott, if you would vacate the witness stand.

And, sir, if you would come up. If you would say and spell your first and last name please.

MR. MCQUEEN: My name is Matthew McQueen, M-A-T-T-H-E-W, M-C-Q-U-E-E-N.

HEARING OFFICER ORTH: Do you swear or affirm to tell the truth?

MR. MCQUEEN: I do.

HEARING OFFICER ORTH: Thank you. Go ahead.

MR. MCQUEEN: Thank you, Chair, Members of the Commission. My name is Matthew McQueen. I'm a member of the New Mexico Legislature. And I've been in the legislature for 11 years, and for the past nine years, I've chaired the House energy, environment and natural resources committee.

I'm here today as an individual, as a legislator, to encourage you to adopt a strong and effective bonding rule. I caught a little bit of the

testimony and my colleague, Representative Murphy, and he's on the committee that I chair.

I will tell you, I was also at the water and natural resources committee meeting in Artesia last week. And it was interesting to me -- the recommendation fund was discussed at some length. And it was discussed shortly after we discussed the liability in un-remediated uranium mines that exist in New Mexico.

To me, the bonding is -- I describe it as an insurance policy. I think it is a form of insurance. This is what we will draw on if we ever need to. Hopefully, we don't need to. But the State of New Mexico can't continue to leave itself in the position where it has to clean up after industry when industry goes south.

The reclamation fund is being used. I support Representative Murphy's legislation to stop diverting a portion of that fund so we have more of that fund available and that we can ramp up the expenditures of that fund. But the reclamation fund serves a different purpose. It's different than bonding.

The reclamation fund, in my mind, is what we use to plug and abandon wells that have

already been abandoned or already been orphaned. And the bonding is what we will use in the future, especially if there is a downturn and a lot of these are orphaned at the same time, whether it's a single company or industry-wide.

And I will say, I hear occasionally that the smaller operators can't afford the bonds. And it sends a shiver down my spine because if they can't afford the bonds, how are they going to plug and abandon their wells?

And those my comments. Thank you very much.

HEARING OFFICER ORTH: Sheila, who do we have on the platform?

Ms. APODACA: I don't see anybody on the platform.

HEARING OFFICER ORTH: If you're on the platform and would like to offer public comment at this time, please raise your virtual hand. If you have dialed in, you would raise your hand by pressing star 5. No one?

All right. Our next public comment session will be at 9 o'clock tomorrow morning. We will also have a public comment session Thursday at 9 o'clock in the morning.

EXHIBIT 30

Let's go back to the technical case, Dr. Arscott. Sorry for the interruption. Please go ahead.

A. No. Thank you. Okay. So I'm going to move back one slide. The issue I was discussing is what I think the proposed rules, what effect they'll have on the incentives to produce oil and gas in New Mexico.

And I think in particular this 15 percent threshold may have a barely significant distorted effect on the incentives to produce oil and gas. To illustrate, I'll give you two examples. Both examples will be operators with only ten wells.

This first example we'll call Operator A. Operator A has ten wells, eight of which are highly productive; one with low production, but not marginal, as defined in the proposed rule, and one inactive. Now the 15 percent threshold is, again, if there's 15 percent either marginal or inactive wells in the operator's portfolio. And as it stands, with only one inactive well, this operator is currently at 10 percent.

Under the proposed financial assurance rules, the inactive well will require a single bond in the amount of $150,000. But the other nine would qualify for a blanket bond in the amount of $250,000.

All in, this is a $400,000 financial assurance amount.

Now, the issue is if the low-producing well declines into marginal status, if that happens, the operator will have 20 percent of his wells in either inactive or marginal status. That will trigger the 15 percent threshold rule, which will increase the required bonding amount to $150,000 on all ten of this operator's wells. As a result, the financial assurance amount will increase from $400,000 to over -- well, to $1.5 million.

And I almost said over, because the actual increase in the cost might be more than, say, three times as much. We've almost tripled the amount of bond required. But there is also a secondary effect in terms of the premiums that this operator may have to pay on those bonds, because all else equal, if we increase the amount of debt or the amount of bonding required that's extended from, say, a surety provider, that increases the risk to that provider. And as you increase the risk, a rational provider of that security will charge a higher premium.

And so what you may have is not only an increase in the bond amounts, but you may also have a concomitant increase in the premiums charged on those bonds.

I'll give you a second example. We'll call this Operator B. Operator B also has ten wells, five of which are highly productive, and five are marginal. Five of these ten wells would be classified as either marginal or inactive, therefore triggering the 15 percent threshold rule.

Under existing financial assurance regulations, this operator could have covered its financial assurance obligation with a $50,000 blanket bond. However, under the proposed rules, all ten of this operator's wells would require $150,000 each. Again, resulting in a financial assurance amount of 1.5 million.

There are two aspects of this that I would like to point out. In reference to Operator A, who had nine -- or rather eight highly productive wells, in comparison to Operator B, which has only five highly productive wells, both of these operators are charged the same amount of financial assurance.

To the extent that marginal wells are argued to be more risky from an orphaned-well perspective, which to be clear, I'm not saying one way or the other, although that is the implication, I believe, we have two portfolios that vary in their risk in terms of producing orphaned wells and yet they

have the identical amount of bonding assurance.

I think it's worth asking how we think operators will respond to this 15 percent threshold. As the previous two examples have shown, there is a significant incentive to immediately plug or sell these marginal wells.

In the case of Operator A, who had a low-producing well that was declining into marginal status, incentive to plug that well that is not yet marginal before it gets to marginal status. The increase in financial assurance as a result of the 15 percent threshold presents a very large increase to the fixed cost of operating wells. Therefore, I would expect operators to expend considerable effort in order to plug these wells before they can cause the cost to the operator to skyrocket because of the $150,000 bonding requirement on every single one of the operator's wells.

Ultimately, I think this will lead to premature plugging. Because we have to ask ourselves, how will this operator get rid of these marginal wells? Maybe you could try to sell them. I don't think there would be a market for these wells, because any likely buyer would face the same concerns about the 15 percent threshold. Therefore, it is highly

likely that these marginal wells would all be prematurely plugged.

In of why increasing financial assurance would affect the economic life of a well, I'm going to give you guys a picture. This is IPANM Exhibit 2. And what I'm showing here is money on the vertical axis, and time on the horizontal axis.

The declining curve that starts out very high and declines over time becomes very low and the slope becomes shallower, is my sort of rough approximation of the net inflow produced from a well over time. So as the volume of production declined over time at a constant assumed price, we get this curve that captures our net inflow, meaning the amount of hydrocarbons produced multiplied by price minus any variable costs associated with that production.

In addition to this curve that represents the net inflow from the well, I'm also showing a horizontal line that I'm calling fixed outflow. These represent the fixed costs associated with the well. These are the costs that you have to pay every month regardless of how many barrels you produce. So things like labor and electricity and also financial assurance.

To the extent that the financial

assurance that's proposed in this proposed rulemaking would lead the financial assurance costs in this well, in this example, to exceed the economically justified amount of financial assurance, those costs would increase the fixed outflow line up, holding everything else constant. It must be the case at the point at which the net inflow curve crosses below this fixed outflow line would move to the left.

This is an important point, because when this curve, this net inflow curve, falls below the fixed outflow line, the well starts producing at a loss. So it's about that point that the operator would find an economic incentive to plug the well, not necessarily exactly that point because there's some auction value in the well. Who knows? Maybe commodity prices will increase tomorrow. But generally, this is about the time that an operator would find it from a purely economic perspective advantageous to plug the well.

So having established that the economic life of oil and gas wells will be shortened by the proposed rule, I've asked myself this question: What would have happened had we applied this rule several years ago? Because I think, based on what I believe the incentives are for operators in terms of avoiding

the 15 percent threshold, I think that it would be highly likely that a lot of marginal wells would be plugged prematurely.

And so I looked at June of 2017 in the data supplied by Enverus. I'm looking at vertical wells only. And in this month, June 2017, I applied the definition for marginal well status to every single one of these vertical wells in New Mexico. And I collected all of the wells that would have been categorized as marginal under the proposed rule, and there is about 7,800 of these, exactly 7,844 of these wells.

A great majority of them are listed in row 1. Row 1 through 6, as you decline down the table, increase in terms of the amount of barrels of oil equivalent produced on a per well basis.

So the top row consists of all marginal classified wells in June 2017 that ultimately went on to produce next to nothing. And there are quite a few of these wells. In fact, there's 6,260 of them. Collectively, these 6,260 wells produced only 418,000 barrels of oil equivalent in the seven years after June 2017. So pretty much none of these return to any sort of meaningful production. Now, a number of these have actually been plugged in the years since. In

fact, of those 6,260, 2,561 have already been plugged.

As we move down the table, I'm categorizing wells into buckets according to how productive those wells are. In the second row, this consists of wells that went on to produce between 1,000 and 5,000 barrels of oil equivalent. In total, when you think about aggregating these 892 wells on row 2, they cumulatively, over those seven years, produce almost 2.3 million barrels of oil equivalent.

This gets larger and larger as you move down the table. If we look at the last row, these would be the most prolific of these wells. There's only six of these wells, but these six wells went on to produce over a million barrels of oil equivalent. Again, this all would have transpired after the point at which these wells would have been characterized as marginal.

Given the incentives that I think operators would have with regard to should I plug this well I think that's entering into marginal status, because it has the threat of dramatically increasing the financial assurance burden on the entire portfolio, given the 15 percent threshold, I think there's a strong incentive to plug marginal wells. Had these wells been plugged prematurely, we never

would have realized this production.

Some specific examples of the wells in this data set. Here is one, the San Juan 36 Unit 407. You can see here, it's got a fairly -- it almost looks like the classic arc/decline curve. For decades, this well was very, very consistent. You can see there was a brief cessation of production, though, right at the point where -- I think this was about June 2017, in which it was characterized as marginal because there's about a year where it didn't produce anything.

Now, that obviously was a brief cessation in this overall consistent period of production. And it may be that this well would have returned to production and would not have been prematurely plugged. Although you have to consider the fact that the likelihood that it would have been plugged is much higher than it would be absent the 15 percent threshold.

Other examples include the federal G 1 well. This almost looks like a poster child of a well that should be plugged. If you were to look at this in June of 2017, you can see that the production had been declining for a long period of time. In the few years preceding June 2017, not only was the production extremely low, but it was erratic. It may have been

determined that this is a well that should have been plugged. And yet, with some stimulation, this well has gone on to become a prolific producer.

Another example, this one is almost certainly involved in a CO2 flood, but has undergone a couple different rounds of stimulation. You can see at multiple points in its history it would have been classified as marginal and, again, the likelihood of it being prematurely plugged cannot be ignored.

It's something that I think is visually, at least for me, convincing that -- there are a lot of different stories here behind where a well -- a well's individual story in terms of what brought it to marginal status. I don't think it's a uniform categorization. I think there's a lot of variety in the types of wells that you find categorized as marginal.

And certainly in these cases that I'm showing you, these are wells that should not have been plugged at those times. I'll give you one last example. This is the Scott 2A well. This is operated by San Juan Resources, a small independent operator.

San Juan Resources purchased this well right at the bottom of that first hill. Right at the point where it would have been classified as marginal,

it had effectively ceased producing entirely, San Juan Resources purchased the well, brought it back onto production, and it's been producing at a stable rate ever since.

So again, examples of marginal wells that have plenty of productive potential in the months and even years after which it would have been classified as marginal. The effects of these proposed rules, I think, will disproportionately affect small operators.

Now, in order to make this a little bit more clear, I'm going to give you guys this table here, which is IPANM Exhibit 8.

In this table, I've taken my Enverus data, which, again, is a subset of vertical wells only. But here, I'm looking only at the vertical wells in my sample that are either on state or private fee lands as of November 2024, which is where my data ends.

Now of these 376 operators identified in the data, I've ranked them according to how many wells each operator operates. So the first row is the very smallest of these operators. There are 61 of these operators, each operating a single well. So in comparison to the total number of wells that we've

been talking about here, I know Mr. Purvis has mentioned 63,000 wells, we're talking about a very, very small amount of wells in terms of the grand scheme.

I'm offering this table as a way to illustrate how the proposed rule can be somewhat regressive in terms of actually producing financial assurance burdens that are particularly high on the smallest operators and low for the largest operators.

For these 61 operators that operate a single well, the average bond per well under the existing rules was about $39,000. Under the proposed rules, the average would be $150,000; again, because the rules require a uniform single-well bonding requirement of $150,000 per well. It represents a very significant increase in the actual bonding amount, but again, the costs associated with the bonding proposal here may actually be more than just the multiple increase in the amount of the bond because this may coincide with an increase in the bonding premium charged on those bonds.

As we move down the table, we get to row 2, it's operators that operate between two and ten wells. There are 130 of those operators. You can see their average bond per well increases from almost

28,000 to a little over 100,000.

As you move down the list, you get larger and larger operators in terms of the size of their portfolio. However, I want to remind you that this is only for vertical wells. And the largest operators, take the last row, for example, operators with more than 500 wells, these are some of the largest operators in the state, they almost certainly have large numbers of horizontal wells, for example, that would not be included in this data.

Nevertheless, the table hopefully makes clear that the proposed rules disproportionately affect the smallest of the operators out there.

Continuing on this theme, I'd like to maybe do a little bit of an example, sort of a toy example, thinking about what would be the percentage increase to the fixed operating costs for wells, given various levels of these operating expenses.

Going back to my earlier picture of that straight, flat, fixed outflow line and the declining curve representing net inflows, we know that the decision to plug the well occurs about where the net inflow meets the net outflow.

And so the wells that we should expect to be the most sensitive to increases in the financial

assurance costs should be wells that have fixed costs extremely close to their net inflows. So this table provides a sort of toy example for various bond premia and various lease operating costs to show you what the percentage increase would be over the base case lease operating expense that operators would face for these wells.

I'm going to assume an increase in average bond amount per well of 110,000. I'm choosing that because that is the increase associated with the most sensitive of the operators in my previous table. That is the 61 operators, each operating a single well. I'm really asking what would happen to their lease operating expenses if they were to pay the proposed financial assurance burden at various rates of return.

So starting in row 1, I'm going to assume that the bond required rate of return is 10 percent, which, again, would probably be consistent with a cash bond. Again, if we're thinking about an operator that has a 10 percent cost of capital, which is fairly typical, there are studies done by -- sorry, not studies, but surveys done by the Society of Petroleum Evaluation Engineers, annual surveys that ask, amongst other things, what types of discount

rates do people assign in valuing various categories of reserves. For proven developed and producing reserves, PDPs, the most common discount rate is 10 percent. And so this is very typical, I think, of what most operators would actually face in terms of the cost of capital.

As you move down the table, the bond premium declines until eventually you get to 1 percent. Now, for most operators that satisfy the financial assurance obligation through a surety bond, they're paying premiums on the order of 2 percent to 3 percent. But again, I want to caution that if we're going to increase the amount of financial assurance, it could be that the bond premium is going to increase along with the amount of bond face value that's required of these operators.

Nevertheless, I want to calculate the percentage increase above the base lease operating expense, assuming three different scenarios. In one scenario, which is column 4, I'm going to assume a lease operating expense of only 1,500 per month. This is extremely low. This is an amount that was quoted to me from one of six operators I interviewed. I also was quoted amounts of 2,500 a month and 5,000 a month.

The lease operating expenses typically

for oil wells will be much higher than this. In fact, there may be gas wells that have higher lease operating expenses as well. But these three give us at least a rough approximation of what the effect would be on the percentage increase above fixed costs for the smallest, most sensitive operators.

At a rate of return of 10 percent in column 1, this amount of bonding increase, given a lease operating expense of $5,000 per month, would represent an 18 percent increase above base case fixed operating costs. If we're talking about an operator that has a margin of 15 to 20 percent, this represents almost all of the profit margin on the well.

Now, as we move down the table, we might think about if this operator is paying a premium between 2 and 3 percent, let's say 2 percent, that same $5,000 a month LOE, the increase in financial assurance, would represent only a 4 percent increase.

And so the point of this table is really to illustrate that the sensitivity in terms of how we think that the -- or how I think the proposed financial assurance will affect operators, it's going to be operators that face very high bond premium, perhaps operators that are only posting cash bonds because their cost of capital then becomes their cost

of bonding. Not only is it about the rate of return on the bond, but it's also a function of the well in terms of how costly it is to continue operating that well.

So, the conclusion from all this is that the operators that are going to be the most affected are likely going to be small and potentially financially constrained. Financially constrained operators are highly likely to have no recourse other than a cash bond. They likely do not have the resources required to access the surety bond market. These would be operators that have very little working capital, have very limited access to debt markets, very little collateral with which they can post secure loans and bonds. These are the types of operators that will be facing the highest increase in the financial assurance cost.

And to the extent that these are the most financially sensitive operators in the sample, my concern would be that the proposed rules may push some of these operators into financial distress and possibly bankruptcy. If there is no accommodation for financially constrained operators in the short run, my concern is that responsible operators may be rendered insolvent because of the increased financial assurance

demands. This may ultimately, potentially, reduce the amount of private funds available for plugging.

I'm going to pivot here. Number one, I'm amazed that I -- I think I speed ran through that. I was a little thrown. But I would like to get into my rebuttal points at this point.

To begin with, I would like to address this notion of holdback that has been sponsored by Mr. Purvis. Mr. Purvis has talked about this concept of holdback, which he characterizes as when a well reaches a point in its life cycle where the amount of expected cash flow in the future equals the amount of plugging liability that will eventually have to be paid in connection with that well.

And so there are a couple problems with this. They're all rooted in this concept called the "time value of money," which is central in finance. This time value of money concept could be summed up in one sentence, and that's that: A dollar tomorrow is worth less than a dollar today.

And when you think about it, this has to be true. If, for example, you could deposit a dollar into a savings account with no risk, let's say that the savings account pays you 5 percent in a year. In one year's time, your dollar would grow to become a

dollar and five cents.

Therefore, a dollar today cannot be worth a dollar tomorrow. It's worth a dollar and five cents. And this idea that money has a time value is critical in how we value assets of all types.

Now, holdback ignores the time value of money because it adds cash flows from various periods in time together without making the proper adjustment to account for the time value of money.

In some sense, it's worthwhile to think about why you can't do this. I've already sort of described intuitively from a mathematical standpoint that a dollar today would be worth a dollar and five cents a year from now. But I would really suggest that you think about it in terms of money having time units.

A dollar a year from now is denominated in time units a year from now. And just like it doesn't make sense to add a U.S. dollar to a Canadian dollar, it doesn't make any sense to add a dollar today to a dollar tomorrow. They simply cannot be added together with any economic sense.

The way to think about plugging decisions in terms of the expected value or the expected future cash flows on a well is actually the

net present value, or NPV. I'm going to argue that this is the right way to think about when to time the plugging and abandonment of a well.

And so what I'm showing you here is a plot of the NPV as a function of the time until a well is plugged and abandoned. In this simple example, we're going to assume the plugging cost is normalized at negative 100. And so if you decide to plug the well immediately at time zero, all the way over at the left side of the chart, the NPV is worth negative 100 because you have no cash flows from operating the well. Instead, all you have is the negative 100 in plugging cost.

As you wait to plug and abandon the well, you will operate the well, presumably collecting some positive net inflows from the sale of hydrocarbons, less your fixed cost. And if you do this long enough, the NPV grows and grows and grows until eventually you get to the top of the hill.

If you plug the well before you get to the top of the hill, you're leaving profitable resources out in front of you. You're plugging too early, premature plugging. If you wait too long, you will have entered a state where you start to operate the well at a loss, and this starts to chip away at

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the net present value of the well.

And so when you're thinking about a valuation exercise to determine mathematically when is the right time to plug and abandon the well, it's not by adding cash flows together inter-temporally without any regard for the time value of money, it's by using the proper time value of money technique to calculate the NPV and find the top of the hill. In this case, the optimal time to plug and abandon the well is about 12 years.

I'm going to work through a few examples. We'll start with the simplest one. And this is actually fairly similar to Mr. Purvis' example in his direct testimony in which we have an asset that produces a positive 25 million and ultimately has a plugging expense of negative 25 million. I'm going to simplify this as much as possible.

So I'm going to say you're going to get positive 25 million today and you're going to plug the well in exactly a year for negative 25 million. So this well would be in holdback because negative 25 million plus 25 million is zero.

I'm also going to assume a return on savings equal to 10 percent, which, when we're thinking about PDPs, operators with PDPs, a 10 percent

discount rate again is pretty typical. This well is in holdback, but it doesn't have no value. Mr. Purvis has said that a well in holdback is a liability. I'm going to show you that it's anything but.

Not only is this not a liability, it has considerable value. And it has to be the case because if you take that positive 25 million and you deposit it at your rate of return of 10 percent, in exactly one year, it will grow by 10 percent of 25 million or 2 and a half million dollars.

So at the end of one year, you're going to end up with positive 27.5 million, at which point you pay the 25 million in plugging expense and you're left with a surplus of 2 and a half million dollars. It cannot be the case that this is a liability. This is a valuable asset.

Let's look at a slightly more complicated example, but the same rules apply, the same concepts apply. This, again, is going to add $25 million in positive cash flows, but this time instead of coming at one lump sum at time zero, I'm going to spread this out over time, similar to an oil well where it's declining over time until eventually, in year five, you have to pay the negative $25 million in plugging expense.

This well, again, is in holdback because if you add up the positive 25 million in green cash flows, they equal exactly the negative 25 million in plugging expense. While this well is in holdback, I'm going to show you again that this well actually does have considerable value. And I'm going to show you a couple of these tables, and so I'm going to invest a little bit of time to walk through this table.

This is IPANM supplemental Exhibit 30, and what I'm showing you here is a table that tracks the balance of an investment over time. As you walk down the table on column 1, you're keeping track of which year it is, starting in year one and then eventually ending up in year five at the bottom of the table, our beginning balance, we start at zero dollars. Our growth in savings, because we started with zero dollars, is zero dollars.

But in year one, we get to the third column, or rather the fourth column, where we invest, or withdraw -- in this case we invest the $10 million positive cash flow we received from operating the well.

I'm going to walk back to that picture one more time to show you that 10 million. That's that first green bar over on the left. It's a

positive 10 million in year one, then it declines to 7 million in year two, and 5 million in year three, 3 million in year four.

When we go back to this table, you can see in that column where, in row one, we have positive 10 million. If we walk down that column, we see those positive cash flows, 10 million in year one, 7 million in year two, 5 million in year three, 3 million in year four. Then ultimately, at the end of year five, we pay our negative 25 million dollar plugging expense.

The trick here is to notice what happens along the way, because before we have to pay that negative 25 million, we have a series of positive cash flows that we've been able to invest at some positive rate of return; in this case, 10 percent.

So in the first row, we start with a zero balance, we make our first deposit of 10 million, our ending balance is 10 million. At the beginning of year two, we start with the previous year's ending balance, $10 million, and now we have our first instance of a growth in savings. Because we earned 10 percent on our money, we're going to earn $1 million over that year two.

To this $11 million, we're going to add

the $7 million from operating the well, to ultimately end up at $18 million as our ending balance at the end of year two.

That balance carries forward to the next row down, where the beginning balance starts at 18 million. This time our growth in savings is 10 percent times 18 million, or $1.8 million. To that, we add the $5 million from operating the well in that year. Now we get an ending balance of $24.8 million.

And we keep doing this until eventually we get to year five, and in year five, we have a beginning balance of a little over $30 million. We accrue interest or growth in savings of a little over $3 million on that balance. And then we pay the plugging liability of 25 million. But at the end of the day, after we've paid the plugging liability, we end up with a surplus of a little over $83 million.

So again, we have a case in which we have a well in holdback, which Mr. Purvis, again, defines as a liability; by definition, something that has no value. And yet, it has considerable value, in this case over $8.3 million, five years from now. Now that surplus of $8.3 million, that only arrives in exactly five years, right, because we have to get to a

point where we actually pay all the cash flows, right, we pay the plugging expense, we've collected the cash flows from operating the well for these five years.

How does this surplus in five years time relate to the net present value that I was trying to convince you is the way to think about valuing the well? Well, it turns out that the net present value is the amount of money that we would have to deposit today in order to end up with exactly $8.3 million five years from now.

I can show you that with another table. So if we start in year one and we deposit the net present value of 5.1 million, and then we make no investments at all -- so we're not thinking about the same example where we have positive cash flows, we deposit into the account over time. This example, we're not making any other investments other than the initial investment of the NPV 5.1 million. If we do that at our 10 percent rate of return, we will end up with $8.3 million in surplus, the exact same surplus from the project we just looked at.

And so that's really what the NPV is. It tells us in today's dollars what the expected surplus is associated with the project.

So again, we've got a project that is

not a liability. In fact, it's an asset that any rational buyer in the market would be willing to pay $5.15 million for.

Staying on this topic, again, sort of using these tables that we sort of invested a little bit of time in figuring out how they work, let's ask some other questions that have to do with the time value of money and the expected plugging expense.

One question might be, how much money do we have to set aside today in order to make sure that we cover that $25 million five years from now? Because if we go back to my original picture with the NPV in terms of what is the optimal time to plug the well, if we have an estimate of when we think that is, we could plan for it. We could set aside money for it.

Question is, how much would we have to set aside today? You have the savings rate of 10 percent. Turns out we would only have to set aside $15.5 million. That's the beginning balance investment in year one in this table, which is IPANM supplemental Exhibit 32. If we deposit that amount, and it grows at a 10 percent rate of return, we will end up with exactly 25 million, the exact amount we will need to make sure we can plug that well.

And as this relates to the optimal or ideal, theoretical ideal, financial assurance bonding amount, again, we see that there is another reason why we would expect that the ideal bonding amount should fall short of the expected cost of plugging and abandoning the well. In this case, our expected P&A cost is 25 million, and yet, because we have a positive rate of return on our savings, we only have to set aside $15.5 million today in order to satisfy that obligation.

Now, I have played a little bit of a trick on you, because 10 percent rate of return is an appropriate cost of capital for a risky business. This assumes that the operator can take that money and redeposit it into his own operations, but those operations are risky. So to the extent that I may be exaggerating somewhat the amount of money you have to deposit today in order to satisfy that future obligation, it could be that I'm ignoring some of the risk inherent in this 10 percent rate of return, and that may be true.

So let's do the same exercise, except this time let's completely remove risk from the equation. What if we, instead of deploying that 15 million into our own operations at a rate of return of

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10 percent, let's think about what if we deposit it in treasury bills or a risk-free rate of return. This way our money is going to grow at 4 percent, and I looked this up a couple months ago when I wrote my testimony, and it turns out not much has changed in treasury yield since. The ten-year treasury yield is still about 4 percent. So this is actually a realistic, risk-free rate of return.

If we deposit $20.5 million today risk-free in treasury bills, we will end up with the $25 million we need to plug the well in five years? So again, even absent risk, it is still the case that the optimal amount we need to set aside today to cover future plugging expenses is strictly lower than the expected value of P&A costs. And that's just because of the time value of money.

There is one last example I want to provide because the last example I gave you assumed that we have an operator that actually has $20 million to set aside today to cover that future cost, which as we've heard from numerous people, and as I've tried to suggest as well, that we have a number of operators that are financially constrained. And this means that their financial resources are limited, and we shouldn't expect that they have that type of liquidity

that they can pump that amount of money down right now.

So let's relax this even further, again, keeping the risk-free rate of return, so we've got no risk here whatsoever. Instead of having to deposit anything right now, let's just use the cash flow from operating the well to self-finance the plugging liability at the end of five years. We invest the $10 million from operating the well in year one, that then grows. We invest the $7 million that we get from operating the well in year two, that then grows and we keep doing this.

We could self-fund the liability at a risk-free rate of return and still end up with a surplus of $3.1 million at the end of five years. Again, this is a well that would be characterized as a liability, it is in holdback.

And this is emblematic of why this notion of holdback should not be relied on in any matters concerning the value of oil and gas wells. It shouldn't be used as a measure of determining the optimal time to plugging and abandoned well, because it's divorced from fundamental economic principles regarding the time value of money.

I'd like to say a little bit about what

I think would be practical limitations to avoiding the proposed 15 percent threshold. Mr. Purvis has testified that over 52 percent of operators in New Mexico are already in breach of the 15 percent threshold. This strikes me as a lot of operators, and so to the extent that we think that operators would have no trouble in adapting to this policy, half of operators in the state is a large number. I'm not necessarily confident that all of them would be able to adapt in time.

This is to say nothing of the permitting processes that are involved, the availability of plugging services. All of this likely limits the number of wells that could be plugged in short order. And, of course, if we're going to credit operators with an ability to adapt to the proposed rules, I believe they'll do so by prematurely plugging their marginal wells in order to avoid the steep FA cost increase associated with the 15 percent threshold.

All of this should be administratively burdensome, because, of course, plugging wells necessarily means they have to be inspected, and all of this takes time and resources.

Another aspect of the proposed rule that I think might be difficult to implement in terms of

feasibility, the definition of marginal well, as you've heard, is a two-pronged inquiry.

It's the number of production days, does it produce less than 180 days a year, and does it produce fewer than 1,000 barrels of oil equivalent in a year. This is a graph showing these two dimensions in Mr. Purvis' testimony. And he's got some color-coding here to identify marginal wells in blue, and in purple we have some no-beneficial-use wells, and so on and so forth. Although the wells in black, presumably, are wells that would not be classified as marginal.

Now, I looked at this picture, and one thing jumped out at me, looked a little bit strange, and I highlighted these, what appear to be vertical lines with some red arrows just to draw your eye. This type of bunching, where we see almost really vertical lines throughout the data, as you move from right to left or left to right, these bunching occur almost exactly at intervals of 30 or 31 days, right?

So 30, 31, 60, 61, 62, they are almost certainly the number of calendar days in a month, which this tells me that there's already considerable leeway in how operators are able to report this data. Now, if you are going to adopt a rule that requires

that you need to depend on an accurate measure of the number of production days, this may be quite difficult to monitor.

And this type of bunching tells me that this rule may actually serve to help to weed out honest reporters who will not fudge what they tell the department, the Division, as opposed to bad actors who, by definition, would have less misgivings from misleading the department -- Division, excuse me, along the dimension of the number of production days.

And so my concern is that this may not catch the bad actors we're concerned about, and may actually weed out honest, responsible operators at the same time.

Lastly, this is a chart from -- I know this is credited to the Interstate Oil and Gas Compact Commission, but I believe I pulled this from one of the Department of Interior's annual reports, regardless. The source of the picture is the IOGCC. And what this shows us here is the recent trend in documented orphaned wells.

And I'm going to argue that the recent trend is almost certainly policy-induced as opposed to any real indication of the physical number of orphaned wells in the United States.

So if I can draw your attention all the way to the right side of the plot, in 2024 we have 141,000 and almost 142,000 orphaned wells. If you walk back to the left, the next data point is 131,000 orphan wells, and that's in 2021. So pretty significant increase, right? We're increasing by about 10,000 over a three-year period.

But the real increase occurs between 2019 and 2021. 2019, we have a count of 61,246 orphaned wells, and by the time you get to 2021, only two years later, you're all the way up at 131,000 plus.

Question is, why do we see this steep increase? Again, this is the amount of documented orphaned wells. There is a pretty unfortunate data visualization cardinal sin here which is not making the units of one of your axes consistent.

I want you to look at the leftmost data point, the 49,743. Based on the number of years that elapsed between the 2019 number and the 2024 number, you might expect this leftmost value would be somewhere around 2010, and yet it's 1992. So the x-axis here is not uniform in terms of spacing.

What this graph actually tells us, as opposed to a recent trend, and this is between 1992

and 2019, so almost a 30-year period, the number of documented orphaned wells is relatively flat, fluctuating between 49,000 and 62,000. It's only in the last couple of years, especially between 2019 and 2021, that we've had this large increase in the number of documented wells.

And I'm going to argue the most likely reason for this is it's policy-induced. There are federal grants earmarked toward addressing orphaned wells at this time. If we go back to the passage of the BIL, the Department of the Interior has grants that they're going to award states based on need. And so there is an incentive at the state level to document as many orphaned wells as possible at this time, and that could go a long way toward explaining why we see the recent trend.

And to the extent that people have been citing this trend as an indication of some future continuation of this trend, I would hesitate somewhat. I would argue that, because this is likely policy-induced, there isn't as much reason to expect that this trend is going to continue.

MR. CLOUTIER: Madam Hearing Officer, that concludes Dr. Arscott's direct and rebuttal testimony. We're right at 5 o'clock. I would

anticipate he's got about 15 minutes of surrebuttal. So I don't know what we want to do with our time.

HEARING OFFICER ORTH: I think we want a break now.

MR. CLOUTIER: That's what I thought.

HEARING OFFICER ORTH: Well, we've actually been going two hours.

MR. CLOUTIER: Yes. That's fine. I'm just not in charge, so I don't want to presume that I am.

HEARING OFFICER ORTH: Thank you so much.

All right, we'll resume at 9:00 in the morning and we'll start with public comment and then we'll do your surrebuttal.

THE WITNESS: Okay. Thank you very much.

HEARING OFFICER ORTH: Thank you so much.

(Proceedings adjourned at 5:00 p.m.)

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AFFIRMATION OF COMPLETION OF TRANSCRIPT

I, Kelli Gallegos, DO HEREBY AFFIRM on November 4, 2025, a hearing of the New Mexico Oil Conservation Commission was taken before me via video conference.

I FURTHER AFFIRM that I did report in stenographic shorthand the proceedings as set forth herein, and the foregoing is a true and correct transcript of the proceedings to the best of my ability.

I FURTHER AFFIRM that I am neither employed by nor related to any of the parties in this matter and that I have no interest in the final disposition of this matter.



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