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 JEFF HARVARD

Q: Would you please introduce yourself to the Commission?

A: My name is Jeff Harvard and I am president of Harvard Petroleum Company, LLC which his based in Roswell, New Mexico. I received a Bachelor of Science Degree in Petroleum Engineering from the University of Texas at Austin in 1984.

Q: Would you please give the Commission a summary of your work history?

A: Yes. During my high school and college summers I worked for various oil and gas companies; Steven's Oil Company, Read and Stevens Oil and Gas Company, Harvard Petroleum Corporation, Peninsula Drilling Company and D III Petroleum Company as a roustabout, pulling unit hand, roughneck, pumper and/or field supervisor. When I graduated from UT, I went to work for Harvard Petroleum Corporation, the company my father founded in 1970. I have been working with Harvard Petroleum ever since as a petroleum engineer, manager, vice president and president. Harvard Petroleum Corporation was converted to Harvard Petroleum Company, LLC ("HPC") in 2002. Throughout its existence HPC has been and involved in drilling and operating wells, primarily in southeast New Mexico and West Texas.

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: Tell the Commission about HPC's business today, what it is doing and what its focus is.

A: HPC has participated as a non-operating partner with other companies since it's inception. In 1980 we started drilling and operating oil and gas wells and have been operating wells ever since. While there are certain wells that Harvard Petroleum drilled originally and operate today, our biggest effort involves a 2021 purchase of approximately 220 New Mexico wells from a large, publicly traded operator and are operating those wells for a group of investors put together to purchase those wells.

Q: Describe the well package you purchased in 2021 from this operator.

A: It was approximately 220 wells in southeastern New Mexico. Most of them were oil wells, and all produce some natural gas. On average, the wells were producing on average 4 barrels when we purchased the package. This average included 100 wells that were shut in.

Q: Do you understand the term "stripper well?"

A: Yes, it's a common term in the industry. For oil wells, it typically means wells averaging production of less than 15 barrels of oil per day.

Q: Were all the wells you purchased in 2021 and now operate stripper wells at the time of purchase?

A: The vast majority of the wells were stripper well at the time of purchase.

Q: Are you familiar with the proposed rulemaking from Western Environmental Law Center and others?

A: I am.

Q: Were any of these wells in the 220 well package "marginal" wells as that term is defined in the proposed rulemaking?

A: There were approximately 180 wells in the package that would have qualified as marginal at the time of purchase and others that were near marginal status.

Q: Tell the Commission what the motivation was to purchase 220 primarily stripper wells from a larger operator.

A: HPC operated wells around the package of wells that were being sold. We knew the formations that the wells were producing from and believed that by investing money and effort in those wells we could achieve greater production from the potential of higher production and be able to profit from the acquisition when factoring in both our acquisition costs and the anticipated costs to enhance production.

Q: Why didn't the prior operator do that?

A: These wells were not the focus of their business model and were largely a liability on their balance sheet. They were costing business and personnel expenses that could be allocated to more profitable wells. They were focused on projects that were going to have a much, much greater impact to their bottom line and show significant increases in production for their shareholders. The bigger publicly traded companies are looking to acquire acreage and develop that acreage into highly productive oil and gas properties. These bigger companies rarely devote resources to studying how to increase production from older wells. Accordingly, larger companies often seek to sell older wells that no longer produce at significant volumes and, when they get to this point, these wells are grouped together to sell in a package. As I will describe, we successfully increased production on most of those wells but the amount of work we put in and the level of production increase is not something larger companies are very likely to pursue.

Q: Before we talk about your results, let's discuss bonding. How were these 220 wells bonded by Harvard Petroleum?

A: Under a state-wide blanket bond.

Q: Have you reviewed the proposals for rulemaking that is the subject of this case?

A: I have.

Q: How does Harvard Petroleum procure its bonding for operations?

A: For a small operator, we are fortunate to have a long-standing history with a surety and bond company and, with the investors in this particular project, a strong balance sheet. We have been able to bond for a fee of 2% of the face value of our various bonds on an annual basis.

Q: If the WELC proposal were enacted at the time of this purchase, what would the effect have been on the purchase of these 220 wells?

A: The bottom line is that Harvard Petroleum and the investors would have had to have $27,000,000 in additional bonding to cover the so-called marginal wells (which does not include any other "marginal" wells Harvard operates). I cannot predict what will happen with the commercial bond market if the WELC proposal is enacted. Presently, I understand that the large, publicly traded oil companies and some independents are able to bond through the commercial market where the company pays an annual premium for the bonding. But I question if they will be able to do so if the WELC proposal is enacted.

Q: Was that bonding available to you commercially?

A: Well, fortunately, we did not have to face that issue at the time; however, that is more than 20 times our current bonding. I have never heard of a commercial market available to an oil and gas operator that would support that kind of bonding. Perhaps that is available to the very largest publicly traded multibillion dollar companies, but I doubt nothing like that is available to someone the size of HPC as it would have been an increase.

Q: How would your deal to purchase these 220 wells have differed if each marginal well was required to have a $150,000 bond and other wells were close to needing such a bond?

A: We would not have even bid on it and neither would anyone else. The bonding obligation would have eliminated any potential upside to acquire the properties. The seller may have plugged and abandoned some or all these wells rather than paying the bonding costs. As to any of those wells that were not plugged and abandoned and they tried to sell, any purchase price paid to the seller would include an additional $150,000 to transfer the bond on that well. In the package we purchased, it would have been over $27,000,000 of additional bonding, an amount that the investors and Harvard Petroleum did not have.

Q: Under the well proposal, if passed, would you have to bond those wells at $150,000 today?

A: We have many wells that produce what is defined in the rules proposal as marginal. We did plug and abandon some of the wells that we determined were not feasible to increase production and operate economically and continued to do so. However, of the remaining wells, virtually all of them were worked over and are averaging over 5 barrels per day per well showing we have increased production of most of the wells above the "marginal" status proposed in the rulemaking.

Q: How is that possible?

A: We evaluated each of the wells and determined what workover possibilities there were, whether repairing or replacing tubing, artificial lift and/or other equipment, re-stimulating or cleaning out the wellbores to increase production. As I described earlier, this is the sort of effort a small independent will undertake whereas larger companies are rarely willing to devote resources to low producing wells like these.

Q: What did it cost to workover these wells and achieve these levels of production?

A: We spent approximately $15 million on over 600 workover jobs averaging $25,000 per job. These costs primarily went to third-party contractors and equipment providers for the labor and equipment needed to get the well back producing.

Q: What was the result of your workover efforts?

A: For a handful of wells, those efforts were unsuccessful, and we ultimately plugged and abandoned those wells. However, our workover efforts were successful in over 200 wells and those wells, on average, produce about 5 barrels of oil per day.

Q: If it had been in effect at the time, how would the proposed regulations on financial assurances affect this transaction?

A: I think the most likely scenario is that the transaction simply would not have happened. The seller may have attempted to sell the production in smaller packages before the wells got to the production stage where individual bonding was required. As to any wells that the seller had individually bonded in a typical sales transaction, the seller would be reimbursed the cost of the bond if it was put up in cash or the purchaser would be responsible for securing bonding.

Q: What do you think the most likely result would have been?

A: For the 220 well package, our group would not have even considered it because the financial assurance cost would have priced out any chance of recouping the costs to work over the wells. Assuming it was offered at that size and that none of the wells had been plugged and abandoned, we could not have afforded the acquisition and bond costs for the wells. Accordingly, we would not have restored production. Frankly, I have a hard time believing that there would be anybody who could take on wells with so-called "marginal" production, put up $150,000.00 per well in bonding, and then have the capital to workover, repair and improve the functioning of the wells.

Q: Even if the wells no longer had to be bonded given the production rise?

A: Even that is an issue. I do not see any provision under the Applicants' rule proposals that an operator coming in and restoring production above stripper well levels would even get the bond back. As I read the Applicants' proposals, once the production levels drop down to "marginal well" levels for a twelve month period, the well has to be bonded until it is plugged and abandoned and, sometime after the operator incurs the costs of plugging, abandoning and reclaiming, the government will then release the bond.

Q: What are your views on the rule proposal?

A: If adopted, it will create significant waste in that, otherwise easily recoverable hydrocarbons will be left in the ground. I have no doubt that many wells would be plugged and abandoned that could economically produce for quite some time without the huge bonding amount. In a commodity pricing environment where oil has consistently remained above $50.00 a barrel, the number of low producing wells are going to require the significant up front expenditure of $150,000.00 to continue to producing for the bonding requirements, money that will be tied up for a long period of time, and it will reduce the incentive for operators to invest time and money in doing what HPC and its partners have done with the well package I have been describing and significantly increase production which directly benefits the State through increased severance tax and income tax revenues, benefits to the royalty owners, which include the State of New Mexico and the Federal Government. There are other benefits such as employing local workers to do the needed work and supporting local businesses we hire to perform work. That, of course, results in further tax revenues to the State.

Q: Do you consider your story of these 220 wells some sort of outlier?

A: No. We know many companies that are seeking to do the same sort of thing. Frankly, the fact that there are 220 wells that I am talking about, most of which were restored to higher production numbers, suggests that these are not outliers. We did not have the ability, and the seller did not give us the option to cherry pick properties we wanted. The seller put together a package which we bought. It was a single seller and, undoubtedly, other larger operators like our seller will have similar packages of wells for sale in this current pricing and regulatory environment. However, that part of the economic life of oil and gas wells will likely be significantly curtailed if not shut down by adding additional costs such as $150,000.00 per well bonds.

Q: Based on your experience, if adopted, what do you think the large effects of this rulemaking will be?

A: It will put some smaller operators out of business, probably right away. It will at best discourage and probably kill deals like our 220 mature well deal that I have described. That means that otherwise economically recoverable hydrocarbons will remain in the ground and never benefit the owners of interests or the State. My non-legal understanding is that the Commission and Division are supposed to prevent waste and to protect the correlative rights of the various owners. This rulemaking will create waste and will create premature cessation of the owners' rights to produce because it will render production uneconomic much faster.

JEFF HARVARD

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: 8/5/2025

JEFF HARVARD