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 T. CALDER EZZELL, JR.

Intervenor Independent Petroleum Association of New Mexico submits the following technical testimony of T. Calder Ezzell, Jr.:

I. BACKGROUND.

Q: Please introduce yourself to the Commission.

A: My name is T. Calder Ezzell, Jr. I reside in rural Chaves County, New Mexico.

Q: What is your educational background after high school?

A: I received a B.A. from Washington & Lee University in Lexington, Virginia in 1974 and my J.D. from Washington & Lee in 1977. I am licensed to practice law in New Mexico and each year I take continuing legal education courses to satisfy the annual requirements imposed by the Supreme Court of New Mexico. The vast bulk of the continuing legal education courses I have taken over my career were in oil and gas law.

Q: What do you do for a living?

A: I do a few things. I practice law as a partner at Hinkle Shanor LLP in Roswell, New Mexico. I was hired as an associate at the Hinkle Law Firm in 1977 (it was then called Hinkle, Bondurant, Cox, & Eaton), became a partner in 1981, and have practiced at that firm continuously since 1977. I also invest in oil and gas projects individually and through a couple of entities. Finally, I help my wife run our ranch in Chaves County.

Q: In which areas of law do you practice?

A: Since I started practicing law in 1977, almost 100% of my practice has been devoted to practicing oil and gas law. Almost all that work has been representing participants in the upstream portion of the oil and gas industry. Much of my practice is focused on preparing title opinions for oil and gas industry participants. Those opinions consist of acquisition opinions for purchasers of oil and gas interests, opinions for an oil and gas company seeking financing, and, most commonly, drilling and/or division order title opinions for operators. I also devote a significant portion of my practice to providing legal advice to the oil and gas industry participants on contractual matters, the application of real property law principles to oil and gas interests, and on various legal requirements imposed by the federal government and/or State of New Mexico on participants in the oil and gas industry. Additionally, in the 1980s and early 1990s, I maintained an active Oil Conservation Division or OCD practice in which I represented clients in compulsory pooling and other cases before the OCD and this Commission. Our firm's Santa Fe office took over the OCD practice in the 1990s. I have been listed in Best Lawyers in the field of oil and gas law for 19 consecutive years.

Q: You mentioned that you invest in oil and gas matters. Tell us about your investing activity that is relevant to your testimony.

A: My largest investments and activity in the oil industry outside of my law practice has been in two entities. The first and longest lasting is my ownership of Polo Oil and Gas Company. I am the only shareholder and do all the work except preparation of tax returns.

A: Polo as in the Ralph Laruen brand?

A: Spelled the same way but not the reason for the name. After I moved to Roswell, I was invited to a polo match hosted at the artist Peter Hurd's property in San Patricio, New Mexico. I became an enthusiastic participant in playing polo in San Patricio and the name reflects my passion for the sport at the time I founded the entity.

Q: How long has Polo Oil and Gas been around?

A: More than 40 years and it is still active.

Q: What does Polo do?

A: It invests in oil and gas projects, primarily non-operated working interests. I invested in New Mexico initially with clients and friends in the oil and gas industry. As Polo had some successes and grew, I made the decision that I should concentrate my oil and gas investment in an area where my law firm was not advising clients to avoid any appearance of conflict. I became aware of a reputable, active operator in Oklahoma and have primarily invested in Oklahoma oil and gas opportunities for the past 30 or so years.

Q: Do you have any other experience operating oil and gas properties?

A: I incorporated Polo in 1984 because the operator of some of the wells in which I had a working interest went bankrupt. Polo took over operations of the wells in which I had an interest. I relied on two friends, a geologist and an engineer respectively, to take care of all the field work on a contract basis and bill Polo. Eventually, these two friends formed their own company and Polo turned over operations of these wells to their entity. As I said, the principals of the new entity were a geologist and an engineer, and neither had any prior business experience. Their entity became one of my clients and I handled all legal and contract matters for them over the life of that company. I advised them on the acquisition of leases and other properties and drafted, reviewed and negotiated all their operating agreements and other contracts. I also handled their oil purchase agreements and gas contracts and dealt with various federal and state regulatory issues. My geologist friend continued to generate prospects, and the company drilled and operated dozens of wells until he and his partner retired about ten years or so ago.

Q: Earlier you mentioned taking continuing professional educations courses to satisfy your licensure requirements. Have you ever taught any such courses.

A: Yes, I have taught courses directed to lawyers, others directed to petroleum landmen, and some to oil and gas division order analysts.

Q: Were any of those courses particularly pertinent to this rulemaking?

A: I do not remember each course or lecture with particularity as I have given those over many decades. However, one course stands out when considering your question. The Rocky Mountain Mineral Law Foundation, which is now known as the Foundation for Natural Resources and Energy Law, is the preeminent energy law organization in the Western Hemisphere if not the world. It concentrates on natural resources law and energy law globally with concentration on the Americas. Its membership consists of law professors, industry participants, and practicing attorneys and its signature educational event is its Annual Institute. At the Foundation's 56th Annual Institute in 2010, Tom Beron and I co-wrote and co-presented a paper on decommissioning on-shore and off-shore oil and gas projects with Mr. Beron handling the off-shore issues and me handling the on-shore issues.[1] I also co-authored and presented a paper entitled "Risks of Acquiring Aging

[1] 56 Rocky Mt. Min. L. Inst. 29-1 (2010).

Oilfields" and presented it at the Foundation's 2015 Special Institute of Enhanced Oil Recovery that is relevant to the topics to which I am testifying.

Q: Mr. Ezzell, have your read the rulemaking proposed by the Applicants in this case?

A: Yes.

Q: By education and experience, do you consider yourself qualified to offer technical testimony to the Commission concerning the interaction between the proposed regulations on the one hand and oil and gas contracts, common law, and statutes on the other.

A: I do. My experience gives me significant insight into how various legal matters such as oil and gas statutes, regulations, common law, and contracts intersect and affect the business side of the oil and gas industry and business decisions that oil and gas operators and Non-Ops will make.

Q: Why do you think legal testimony will help the Commission as opposed to briefing?

A: I do not intend to offer what I consider to be purely legal opinions. For instance, while I have strong views on the scope of the Commission's lack of authority under the Oil and Gas Act for aspects of the proposed rulemaking, I do not intend to offer testimony on that issue. Where I think I have expertise that would be helpful to the Commission is how the proposed rules, if lawfully adopted, will interact with both the business of the oil and gas industry and the legal concepts, whether typical contracts or common law, that govern that business. I seek to point out the unworkability and/or undesirability of aspects of the proposed rulemaking when confronted with the legal concepts that govern how the industry commonly conducts its business and creates expectations for industry participants.

Q: How are you going to organize your technical testimony to the Commission?

A: I inserted a few captions to divide my testimony into topics. For instance, this testimony is in the section I denominated as "Background." Also, since my testimony necessarily involves some legal principles, I inserted some footnotes to my answers that either provide citations to the legal concept I am discussing or, where I refer to the evolution or history of a legal concept, citations to sources that confirm my testimony and that I may have used to refresh my memory of some particulars.

II. Joint Operating Agreements & Bonding.

Q: Is it alright if we refer to operating agreements as JOAs in your testimony?

A: Yes. That is the standard industry shorthand term for an operating agreement.

Q: In general, what is a JOA?

A: It is a contract that defines the relationship between the operator of an oil and gas property with all or some of the owners of interests in the property who are responsible for costs of exploration, development, and production but who are not the operators. In the oil and gas industry and oil and gas law, each cost bearing owner is referred to as a working interest owner and those working interest owners who are not the operator are usually referred to as "Non-Ops."

Q: Have you encountered JOAs in your legal career?

A: Yes, constantly throughout my legal career. Normally in preparing any title opinion, I am provided with any JOAs applicable to the lands and depths subject to the title examination. JOAs can create ownership interests generally called contractual working interests and contain various provisions that can alter the size of the interests that various parties own if certain events occur. Outside of title opinions, I regularly advise operators and non-operating working interest owners about their rights and obligations under applicable JOAs and the facts that my client brings to my attention.

Q: Do you have experience with JOAs outside of your legal career?

A: Yes. As I described earlier, I have drafted, negotiated and revised JOAs for clients for many years. In my personal oil and gas investing, I have been a party to dozens of JOAs as a Non-Op so I must read the JOA to understand my rights and responsibilities under that document. This is true both at the outset of the deal and as questions or issues arise over the life of the investment.

Q: Are there any common types of JOAs?

A: Yes. From my review and preparation of title opinions, while there could be commonalities, until the 1950s there was no form of JOA in common usage in the oil and gas industry (if I refer to "industry" in my testimony, I mean the oil and gas industry). Most larger operators seem to have had their own internal form that they commonly used, but those forms were not the same from operator to operator. In 1956, the American Association of Professional Landmen, called AAPL for short, released its Form 610-1956 which was a form operating agreement. That form was created by landmen and attorneys familiar with the industry, representing the interests of operators and non-operators, and was intended to be a standard form of contract to allow for regular and predictable development of oil and gas properties. Over the years, AAPL has issued various revisions of the Form 610 JOA for onshore operations. The APPL issued revisions to the form JOA in 1977, 1981, 1989 and 2016. In 2016, the AAPL also issued a special form of JOA that pertained to onshore horizontal wells. Since all New Mexico operations are onshore, I do not discuss forms of JOA drafted for use in off-shore development.

Q: I would like to call your attention to IPANM Exhibits 14-19 and ask you if those are, sequentially, true and accurate copies of the onshore JOA forms promulgated by AAPL in 1956, 1977, 1981, 1989 and the two 2016 forms respectively.

A: Yes, they are. They are numbered sequentially with the 1956 form beginning as Exhibit[2] 14 and the two 2016 forms as Exhibits 18 and 19.

Q: Are these forms commonly used in New Mexico oil and gas operations?

A: They are. Just so it is clear, in performing title examinations the client may request an opinion from inception which, for fee oil and gas leases, typically goes back to patents from the United States government predating New Mexico's statehood so I often examine historical documents affecting title. Oil and gas operations in New Mexico began in the early 1920's and exploration and production activities that occurred prior to the 1956 AAPL JOA occurred under a variety of operating agreements seem to have been created by each individual operator. Those bespoke JOAs may have provisions in common but must be read individually to understand the rights and obligations of the parties. However, in my experience reviewing title-related documents from the time shortly after the 1956 AAPL form JOA for new exploration and production activities, almost all the development in New Mexico occurred and is still occurring under one of these AAPL form operating agreements.

Q: Is it possible to give percentages to which form of operating agreement has been used in New Mexico?

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[2] If I refer to an Exhibit number in my testimony, I am referring to an IPANM exhibit in this rulemaking unless I state otherwise.

A: No. Sometimes, an operating agreement is recorded in the real property records of the county in which the lands described in Exhibit A are situated. However, more often there is a short recorded memorandum of operating agreement notifying persons searching or obligated to search the county real property records of the existence of an operating arrangement and/or there is a reference in assignments of oil and gas interests that the assigned interest is "subject to" a particular operating agreement with reference to the operator, the first named non-op and the date of the operating agreement. Also, even as the AAPL adopted new forms, some operators continued to prefer and propose JOA's under an older AAPL form with which they are familiar and comfortable. Thus when development first began does not reveal the vintage form JOA used.

Q: So these AAPL form JOAs create standardized terms governing the operations of oil and gas wells?

A: Yes, with a few caveats. First, those AAPL forms allow the parties to add additional provisions to a form. It is a rare JOA that does not have some additional provisions added. Also, the forms have certain "options" that the parties elect between. Finally, operators, based on experience or unique development circumstances, modify some parts of the AAPL forms either by striking some language and/or by interlineating some additional language. However, my testimony will concern provisions in these forms that, in my experience, are not commonly altered in a manner material to my testimony.

Q: How many operating agreements have you reviewed over the course of your career as an attorney and investor participant in the oil and gas industry pertaining to New Mexico production?

A: It is impossible to say as I never attempted to keep count, but in my legal career and personal investments, I would say at least 750.

A. JOA Forms

Q: In looking at Exhibits 14-19, there are references in those to exhibits to the form JOAs. Are those exhibits unique?

A: Some of them are. For instance, Exhibit A to a JOA typically describes the lands and depths which the JOA governs and breaks out the percentage interest of the parties to the JOA in those lands and depths. Therefore, Exhibit A is usually unique to each JOA. In my testimony to the Commission, I am going to focus on what is usually attached to a JOA as Exhibit C which is an accounting procedures document. Since 1962, virtually all those Exhibit C's have been a form drafted by the Council for Petroleum Accountants Societies or COPAS. That document is generally referred to by the initials of its drafting organization or as "COPAS." I will testify to that form exhibit after testifying about AAPL form JOAs.

Q: What is the best way to efficiently explain to the Commission the issues related to JOAs and the COPAS form?

Q: I think the easiest way would be to take one of each forms from a particular vintage and explain those to the Commission and explain potential differences in other versions.

Q: What would be the best versions to start with?

A: I think, in my view, the 1977 JOA form and the 1974 COPAS form. Both were, as I will describe, widely adopted in the industry and used in New Mexico well beyond the introduction of newer versions of those forms. It is probably best to start with the JOAs and move to the COPAS.

Q: Why the 1977 JOA form which is IPANM Exhibit 15?

A: The 1977 JOA form was the first improvement on the original 1956 version by the AAPL and was published just as a drilling boom was under way during the energy crisis in the 1970s. In my experience, that form was widely adopted in New Mexico almost immediately. Its use continued well beyond the 1982 version (which was not particularly well received by the industry and never achieved popular usage, although it was used). The 1977 version also continued beyond the adoption of the 1989 version, although from my perspective, the 1989 version did gain acceptance and largely but not completely displaced the 1977 version over time. Most importantly, I suspect given this usage history, a significant number of marginal wells as the proposed rule would define that term would have been drilled under the 1977 form.

Q: What do you mean when you use the word "continued" in your prior answer?

A: I mean that, at least in New Mexico, after the release of the 1982 form and after release of the 1989 form parties to some JOAs still used the 1977 form for new JOAs. In my experience, the 1977 form was the most used form for new JOAs after revisions were released by AAPL.

Q: Do the parties to an operating agreement change their JOA they are using when a new version comes out?

Q: No, not as to existing production or an area covered by an operating agreement. In fact, I have never seen parties discard one operating agreement and use a newer form for the same acreage and depths covered by the first operating agreement except in cases where the parties wish to eliminate a certain provision such as the preferential right of the maintenance of uniform interest clauses.

Q: Let's proceed with the 1977 operating agreement. What provisions do you think are pertinent to the Commission's consideration in this rulemaking?

A: I think there are four provisions that should be considered: those pertaining to abandonment of a well, those pertaining to payment and billing of expenses, the force majeure provisions, and the resignation of the operator provisions. Let me take abandonment first. The provisions are found in Article VI(E) on Pages 7 and 8 of Exhibit 15. These are pertinent because this would be the provision in the body of the JOA that would likely be scrutinized for applicability if an operator contended that the non-operating working interest owners would have to contribute to a single well bond. Section VI(E)(2) deals with abandonment of wells that have been produced so would apply to wells that the rulemaking seeks to address. That provision only pertains to a proposal by the operator to actually abandon the well and authorizes the operator to allocate the costs of abandonment to the working interest owners after all working interest owners consent to the abandonment. If some owners oppose the proposed abandonment, the parties wishing to abandon must pay the parties who want to keep the well the departing parties' proportionate share of the cost of abandonment less salvage value. The 1977 form JOA also provides for payment to the abandoning parties if the difference between salvage value and abandonment costs are positive. However, while that was an issue for much of my career, I have not encountered a situation in the past 15 or 20 years in New Mexico where this provision is anything other than a liability for the parties wishing to abandon the well, meaning that one does not often encounter plugging where salvage value exceeds estimated plugging costs. Since the bonding is supposed to represent some estimated cost of plugging, abandoning, and reclaiming a well, I point the Commission to this provision because it only allows the operator to charge the costs when the actual abandonment is occurring, not in some situation where a financial assurance is posted for the future abandonment.

Q: What relevance do you see to the resignation provisions for the operator?

A: Those provisions are found at Article V(B)(1). Very basically, if an operator is faced with a marginal well as defined in the proposed rules, it can tender its resignation if some of the working interest owners do not want to abandon the well. However, the operator is obliged to stay until the first day of the month following the expiration of a 90 day period tendering the resignation. Essentially, as I understand the proposed rules, once a well is "marginal" an operator who does not want to continue producing the well and therefore need to post a bond cannot resign before the bond obligation kicks in.

Q: What does all that mean practically in your view?

A: An operator will be incentivized to watch wells closely to see when they are approaching marginal status and proposing to plug the wells at that point in order to avoid the $150,000 bond and leave itself enough time to resign and be out prior to the well hitting marginal status. This, of course, presumes that there is not some reworking opportunity to restore or improve production that the working interest owners would want to pursue. However, eventually every well will reach a point in its life cycle where reworking or recompletion into a shallower formation is not a viable option and plugging is inevitable.

Q: We have covered the abandonment and reservation of operator provisions. What is the pertinence of provisions concerning expenditures?

A: The provisions related to expenditures and liabilities are found in Article VII of the 1977 JOA which are on Pages 8 through 10 in Exhibit 15. Section A of Article VII provides that each party is only liable for its "proportionate share of the costs of developing and operating the Contract Area." The Contract Area is the lands and depths described in the unique Exhibit A to a JOA. The question with relation to a single well bond for a marginal well would be whether that is a "cost of… operating." The provisions of Subsection (C) provides for the operator to pay all "expenses incurred in the development and operation of the Contract Area pursuant to this agreement," allows the operator to charge the parties their respective proportionate shares but only as provided in the accounting procedure that is Exhibit C which, as I have described and will testify further, is almost always a form COPAS accounting procedure. However, perhaps most directly pertinent in this provision is Subsection (F) which pertains to insurance. Typically, as provided in that subsection on Page 10 of Exhibit 15, there is an Exhibit D to the operating agreement which will list the amount of insurance and type of insurance which an operator is required to maintain to insure the joint operations. In my experience, most operators will propose a form of an Exhibit D that the operator has made specific to the state in which it is operating in order to comply with any state laws. Importantly, the insurance premium for listed policies or, in the case of self-insurance, an amount equivalent to a premium, may be charged to the joint account. I have never seen a financial assurance instrument listed in an Exhibit D to a JOA. If I were representing a non-operating working interest owner that an operator proposes to charge, I would contend that the absence of listing financial assurance for bonds in Exhibit D would mean that the operator was not entitled to charge for any "premium" associated with a single well bond, whether that is a cash bond or obtained via premium via some sort of surety or insurance company.

Q: Are there any other provisions in the insurance provisions in the 1977 form JOA that are pertinent to the bonding issues in this rulemaking?

A: Yes. I already observed that the 1977 form JOA allows the operator to self-insure and charge the Non-Ops a premium equivalent for workers' compensation insurance. If I am wrong about the ability to pass on premiums for single well bonds under the insurance provisions, it will not benefit operators who will post cash bonds for marginal wells because surety companies will not bond that operator. Since only one form of insurance permits the operator to charge the non-ops if there is self-insurance, the operator could not charge some form of premium to the non-operators. The operators posting a cash bond are likely operating on thinner margins, they are the operators who probably need the Non-Ops' payment for a cash bond the most.

Q: You also mentioned the *force majeure* provision. What is the applicability of that provision to the Commission's considerations in this rulemaking?

A: *Force majeure* provision is located in Article XI on Page 13. Bottom line is that I do not think that any change in regulation requiring a single well bond on a marginal well would change any of the payment analysis, even the application of the *force majeure* provision. First, it only protects a party when it is prevented from "carry[ing] out its obligations under this agreement" excepting obligations to pay money. There is some possibility that might allow an operator to resign sooner. In the third paragraph, the definitions of what constitutes an event of *force majeure* include "governmental action, governmental delay, restraint or inaction." It does not seem to include a change in regulation. Accordingly, I do not think that my analysis of the other provisions could be altered via exercise of the *force majeure* provisions in the 1977 form.

Q: So, at least under the form provisions of the 1977 AAPL form JOA, an operator could not charge its non-operating working interest owners for costs of an individual single well bond?

A: I think that, at this point in my testimony, that it is premature for me to say so. First, we must analyze the COPAS provisions which I will do below. However, even if those do not permit billing non-ops for a bond cost, it is not possible for me to predict the result of an individual lawsuit under New Mexico law to determine the rights and obligations of the parties to a particular JOA. I can only do so based on my experience and reading the form contract. There are legal doctrines in New Mexico that require individualized inquiry under a particular contract. For instance, New Mexico follows the "contextual approach" to contract interpretation and allows the Court to consider extrinsic evidence in determining whether a contract is unambiguous or ambiguous. If it is ambiguous, extrinsic evidence is further admissible to show the meaning of the contract. Additionally, there are doctrines such as course of performance, course of dealing, and custom and usage in the industry which can affect a court's contract interpretation. In that regard, I will point out that the custom in the industry is that the operator recovers for his cost of bonding pursuant to the overhead charges permitted in the COPAS Agreement which I will describe below. However, my testimony cannot be understood in absolute terms for every JOA.

Q: Does that conclude your testimony concerning the 1977 Form JOA?

A: It does.

Q: Tell us how your analysis under the 1956 JOA would differ from your analysis from the 1977 JOA.

A: Substantively, the abandonment of wells provision in the 1956 JOA which is found in Section 16 on Page 7 of Exhibit 14 is the same as my testimony for the 1977 JOA. The cost and expenses provision is found in Section 8 on Page 3 of the 1956 JOA Form and is likewise substantially the same as the 1977 Form as far as my testimony in this rulemaking goes. Finally, the *force majeure* provision is found in Section 29 on Page 11. This *force majeure* provision does not include any events related to government action and inaction and, therefore, is even more inapplicable to affording an operator the ability to bill its non-ops for a single well bond. There are not any other provisions in the 1956 Form that I think that are pertinent to the Commission's considerations of this rulemaking.

Q: Lets move to the 1982 JOA Form which is Exhibit 16 and I will ask you the same question how would your analysis of the 1982 JOA differ from your analysis of the 1977 JOA?

A: There were changes to the abandonment language which is found in Article VI(E) found on Pages 8 and 9 of Exhibit 16. However, those changes do not pertain to matters to which I testified regarding the 1977 Form. The anonymity requirement and what happens if some parties want to abandon and others do not remain substantially the same. Likewise, the expenditure and liability provisions found in Article VII beginning on Page 9 are substantively the same. The resignation of operator provisions are found in Article V(B)(1) on Page 4 and are substantially identical to the 1977 Form as far as my testimony goes. The provisions of the *force majeure* clause are found in Article XI on Page 13 and are, for purposes of my testimony, substantially identical to the 1977 Form.

Q: Moving to the 1989 JOA form that is Exhibit 17, can you tell the Commission how your analysis changes from the 1977 form?

A: As I mentioned earlier, the 1981 AAPL Form JOA was not widely adopted and AAPL essentially went back to the proverbial "drawing board." While there are several material changes that are the subject of scholarly articles, there are not that many changes that affect my prior testimony. One of the major changes is that many of the JOA provisions were reorganized as compared to the three earlier versions. The abandonment provisions for wells that produced are found at Article VI(E)(2) on page 10. My primary conclusion--that the abandonment provisions of the JOA provide no basis for an operator to seek contribution for a single well financial assurance bond—is unchanged. The only notable change is that the Non-Ops have 60 days to act on the abandonment proposal which somewhat accelerates an operator's timeline for proposing abandonment and/or resigning.

Q: Did the resignation of operator provisions that you testified to change materially?

A: This is a good example of there being a lot of changes in the 1989 Form but those changes are not material to my testimony. The resignation and removal of operator provisions (or most of the removal provisions) are found in Article V(B)(1) on Page 4 of Exhibit 17. The substantially new provisions relating to the non-ops' rights to remove the operator in this section and in Article VII.D.1, but the resignation provisions concerning which I testified in the 1977 Form are the same.

Q: What about the expenditure and billings rates concerning which you testified?

A: Those are subject to the reorganizations that I mentioned. The rate to bill for costs of development and operation is found in Article V.D.2 and is the same, namely that a bond would have to be deemed a cost of "operation of the Contract Area" to be billable and has to be billed "as provided in Exhibit C." Similarly, the insurance provisions I discussed are substantially unaltered but are found in Article V.D.9 on Page 5 of the 1989 form.

Q: The last provision regarding which you have been testifying is the *force majeure* clause, are there any material changes in 1989?

A: No. That provision is found on Page 16 in Article XI and my analysis is unchanged from the 1977 and 1989 versions.

Q: There are two 2016 Forms as you have already mentioned which are Exhibits 18 and 19. What are the differences between those two forms?

A: For purposes of my testimony, not anything material. One of the 2016 Forms was specially drafted to take into consideration some issues pertaining to the development and operation of horizontal wells but remains the same. On an overall basis, I would observe that, at this point, consideration of the 2016 Forms is largely academic. I find it hard to believe that there are many, if any, wells in New Mexico that were drilled pursuant to the 2016 Forms which would qualify as "marginal" as that term is defined in the proposed rulemaking.

B. COPAS Forms

Q: You described the evolution of forms of JOA promulgated by AAPL, could you please provide the Commission with a description of the COPAS evolution?

A: Yes. It predates me, so I have referred to a published legal article that trace discuss the history of the COPAS form which is identified in a footnote to this answer. Very basically, there was a Petroleum Accounting Society (PAS) formed in Los Angeles, California in the late 1920's and, sometime thereafter, nobody is exactly sure when, it enacted a PAS form to deal with accounting issues for operating agreements. There were other petroleum accounting societies formed in larger cities in producing states such as Oklahoma and Texas. Many of those societies started producing their own forms of a PAS exhibit to a JOA which forms tended to have regional usage. Those forms often were similar but there were differences. In 1961, the COPAS, which was a national organization whose membership was all the various petroleum accounting societies, decided to create a uniform COPAS exhibit to replace the various PAS forms from around the country and enacted such a form in 1962. There have been a few revisions to the form and each new revision. In fact, COPAS has a practice of ceasing to publish a some of its superseded COPAS forms.[3]

Q: Does Exhibit 20 contain a true and accurate copy of the original 1962 COPAS form?

A. It does. It is found at pages 3-9 of that Exhibit. COPAS does not make its three oldest forms available for purchase on a standalone basis so IPANM purchased the 1966 COPAS publication entitled "COPAS 1962 Model Form Accounting Procedure Interpretation" at COPAS's online store[4] the entirety of which is Exhibit 20.

Q: You mentioned revisions to the COPAS form. When were those revisions?

A: 1974, 1984, 1995, 2005, and 2022.

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[3] For my testimony in this paragraph, I refreshed my recollection as to certain details by referring to two articles: Baughman, Jonathon et al., "COPAS and the 2005 COPAS Accounting Procedure—Significant Changes for Changing Times" which is available at no charge at https://www.mcginnislaw.com/media/publication/15221_05-03-01_Baughman_Copas_and_the_2005.pdf.

[4] https://copas.org/product-category/publications/model-form-accounting-procedures/.

Q: Are Exhibits 21 through 25 true and accurate copies of the 1974 through 2022 COPAS forms in chronological order?

A: They are. The true and accurate copies of the 1995, 2005, and 2022 revisions are Exhibits 23, 24, and 25 respectively. Each is a blank form purchased from the previously mentioned online COPAS "store." COPAS does not have standalone copies of the 1974 and 1984 forms available for purchase and I was not able to locate those forms elsewhere on the internet. I asked one of the younger lawyers in my law firm to search our document management system for those two older COPAS forms. Exhibit 21 is a true and accurate copy of the 1974 form that was completed and attached to a September 3, 2013 JOA. Exhibit 21 is an unaltered copy of the 1974 form except for that the parties included some typewritten information at the top of the first page identifying the JOA to which this was attached, indicated the choice between two options provided in the form, and filled in certain blanks with dollar figures or percentage amounts. Exhibit 22 is a true and accurate copy of the 1984 form that was completed and attached to an August 20, 2001 JOA which is unaltered except for similar typewritten information as I described for the 1974 form.

Q: You testified earlier that the parties to a JOA on an AAPL Form often include additional terms or alter certain form provisions with strikeouts and/or interlineations. Is the same true with the COPAS form?

A: In my experience, changes to the COPAS are less common than to JOA forms, and where occurring, usually not extensive. There are some blanks to fill in on the COPAS forms, most of which are for a dollar or percentage amount, and some options to elect that alter the form but are an intended part of the form. Exhibits 21 and 22 are typical of COPAS forms in actual use in my experience—neither has any change to the wording of the form.

Q: You mentioned earlier that it would be good to start with the 1974 COPAS Form, would you explain to the Commission why that is?

A: Yes. In my experience, the 1974 COPAS Form was used long after there were subsequent revisions to that form. I note initially for the Commission that Exhibit 21 was attached to a September 3, 2013 JOA between Yates Petroleum Corporation and Chi Operating, Inc. as operators, and Chi Energy, Inc., et al., as non-operators so the 1974 form is still being used on a JOA despite three subsequent revisions to that form being available in 2013. While there certainly are wells that predate 1974 that would qualify as "marginal" under the proposed rulemaking definitions, I believe that the largest number of wells that would be subject to that definition would be wells drilled under JOAs using the 1974 COPAS Form because it was the form available during a period of prolific vertical well drilling in New Mexico history that was over in the mid-1980s when the price of oil collapsed in 1986.[5] In my experience the 1974 form continued to be used beyond the 1984 revisions as a number of companies had computerized their accounting systems while the 1974 version was current and used those systems for many years beyond 1984. The 1974 COPAS form should be considered carefully on the question of whether bonding can be passed on to the non-operators by the operator because it was the form used most prevalently.

[5] https://en.wikipedia.org/wiki/1980s_oil_glut#cite_note-1.

Q: Under the form language of the 1974 COPAS, there is a definitive answer to that question?

A: Yes. While there are two categories of direct charges in Article II on Pages 2 and 3 of Exhibit 21 that might be a basis on which to charge for a bond, namely the services under Paragraph 6 and other expenditures under Paragraph 12, I believe that Article III.1.I answers the question definitively. That paragraph defines "overhead" that the operator charges in a fixed dollar amount or percentage of costs (the form provides for an election between those two options). In the last sentence of that paragraph, the 1974 Form overhead charges covers: "the cost and expense of services from outside sources in connection with matters of taxation, traffic, accounting or <u>matters before or involving government agencies</u> shall be considered as included in the overhead rates… unless such costs and expense are agreed to by the Parties as a direct charge to the Joint Account." (emphasis added). Bonding is, and always has been viewed in the industry as, a cost "involving governmental agencies." The proposed rulemaking seeks to impose bonding requirement via regulation which clearly would involve governmental agencies. Accordingly, the only way that the bonding expense could be considered a direct charge is if the parties agreed to do so. Where the 1974 COPAS form is utilized in a JOA, it is my opinion that bonding charges could not be passed on to non-ops absent an affirmative agreement by the non-ops.

Q: How is that agreement achieved?

A: Normally, to amend a JOA, each of the parties to the JOA must agree to the amendment. JOAs can be partially amended between the operator and some of the non-ops if the operator and some, but not all, of the non-ops agreed to the amendment.

However, absent an express provision providing for some sort of vote that is binding on all parties, there is no majority rule or threshold vote to make a change binding on all parties. A party must agree in order to be bound by the change. As I will describe, COPAS provisions under later forms can be amended if certain voting thresholds are achieved. However, while individual non-ops could agree to a change that is binding on that non-op, a 1974 COPAS form remains binding for the life of the JOA on the operator and any non-op that does not agree to a change

Q: As a practical matter, how would you see that it was possible for an operator under the 1974 COPAS to collect from his non-ops for purposes of a bond?

A: Of course, there would be variances depending on the relationships between the operator and its working interests owners. However, in an arm's length economic transaction, a non-op would only be motivated to contribute if they saw some sort of sustained long-term value in the well. Given that once classified as marginal under these proposed rules a well can never emerge from that marginal status in terms of refunding the bond, it is extremely hard for me to believe that an operator would be able to obtain agreement from many, if any, non-ops.

Q: Describe the thought process for such a decision in concrete terms based on your experience as an operator and non-op?

A: The oil and gas business is risky. Even when you are as certain as you can be about the productivity of a formation, there are a lot of things that can go wrong that can cause an investor in a well to lose some or all its investment. This Commission and the OCD recognize that risk in every compulsory pooling case by imposing a risk penalty on owners who refuse to participate financially in the drilling and completion of wells subject to a particular compulsory pooling order. Tolerances vary by investor, but it is very typical for oil and gas companies and investors to look for a 15 percent annual return on capital committed to an oil and gas project at its inception. This assumes relatively tame inflation of course. The usual term in the industry is "hurdle rate"—a project, if successful, has to project to return 15% annually to justify the capital investment. In the case of existing production where there are fewer risks, an investor may reduce that hurdle rate to 10 percent. Positing a newly marginal well and a 10% working interest owner with an operator who posts cash bonds, the bond cost would be $15,000 and the investor would be looking at an annual return of $1,500 or more for an investment in that owner's ratable cost of a cash bond. Absent realistic prospects of workover, recompletion in an uphole zone, conversion to a SWD that the owners would control, or using the wellbore in a future secondary or tertiary recovery unit, a rational 10% non-op would likely not be favorably inclined to contribute to a cash bond.

Q: How would your testimony differ under the 1962 form?

A: It would not differ. Again, there are a couple of provisions under the direct charges portion of the form that, on a standalone basis, one could argue would support treating in bonding charges as a direct charge that could be billed proportionally to the non-ops. However, like the 1974 form, the definition of administrative overhead seems to, in my opinion, completely moot any such argument. In particular, Section III.2 on page 5 of Exhibit 20 provides that the "cost and expense of… matters before or involving governmental agencies shall be included in the overhead rates provided…" The only exception is found in the same paragraph and allows billing of the full amount if "such costs and expense are agreed upon by the Operator and Non-Operators as a direct charge to the Joint Account." So, like the 1974 Form, the 1962 Form would not permit bonding to be billed proportionally to the non-ops absent an agreement between the parties.

Q: Does your opinion change for JOAs using the 1984 COPAS Form which is Exhibit 22?

A: It does not. There are additional direct charges that are permitted to the Joint Account under the 1984 Form such as those "as a result of governmental or regulatory requirements to satisfy environmental considerations applicable to the joint operations. Such costs may include surveys of an ecological or archaeological nature and pollution control procedures as required by applicable laws and regulations." That provision is found in Section II.1. However, the provisions concerning overhead, with an option to be billed on a fixed basis or percentage basis, are again much more explicit and applicable. In particular, that paragraph provides: "The cost and expense of… matters before or involving governmental agencies shall be considered as included in the overhead rates provided for above… unless such cost and expense are agreed to by the Parties as a direct charge to the Joint Account." Very basically, the language across the first three COPAS Forms defining overhead charges is a charge involving governmental agencies which are covered by overhead rates billed monthly to the non-ops and the charge of a single well bond could not be billed to the non-ops unless they agree to pay.

Q: What are typical overhead rates?

A: Those are fixed in the COPAS Form by agreement of the parties and typically is unique to each JOA or operator although there tends to be a range of what is common at particular times in industry history. Completed COPAS Forms typically provide for much higher overhead rates when a well is drilling versus the producing well rate. However, until recently, those monthly rates generally expressed in hundreds of dollars, not even $1,000.00. For instance, Exhibit 21 at Section III.1.iiA.(1) provides for producing well rate of $540.00 in a 2013 JOA and Exhibit 22 provides for a $550.00 producing well rate in 2001 in Paragraph III.1.iii.A(1). COPAS provisions typically provide for annual adjustments to the rates based on a defined inflationary measure published annually by the United States Department of Labor. Those can be found at Paragraph III.1.ii.A.(3) in Exhibit 21 and Paragraph III.1.iii.A(3) of Exhibit 22.

Q: How would your testimony differ for the 1995 COPAS Form which is IPANM Exhibit 23?

A: There were changes to the COPAS Form in 1995 that I find pertinent to this issue. Direct charges are covered in two sections, Section III beginning on Page 3 of Exhibit 23 are costs incurred on the joint property that the operator is entitled to bill on a percentage basis and also Section IV which are costs incurred off the joint property and that begins on Page 5 of the same Exhibit. Meanwhile, overhead is covered in Section V and is treated the same way—an option to charge either a fixed monthly fee or percentage fee, is simply defined as the operator's costs other than those permitted as recovery as direct charges by Sections III and IV.

Q: Are there categories of direct charges that an operator could use to charge non-ops for financial assurances from marginal wells?

A: In my view, the 1995 COPAS has two provisions that provide closer questions. First, if financial assurance is the same as insurance (and I do not think that it is), the operator could charge the net premiums to the joint account under Article III.9 on Page 5 of Exhibit 23. However, the provision does not seem to define insurance that broadly as it provides that "where the Operator acts as self-insurer, the Operator shall charge the Joint Account manual rates, as regulated by the state in which the joint property is located…" I am not aware of any rate regulation for financial assurance products in the State of New Mexico. However, even if the insurance provision covers financial assurance, for the operators who do not have the financial wherewithal to participate in the financial assurances market, they are going to have to post their own bond of $150,000.00. Charging some facsimile of a "premium" to the Joint Account would not compensate the operator for at least an extended period of time.

Q: What is the other potential option?

A: Financial assurance strikes me as a cost that is incurred off the joint property, it is just a question of whether it is a direct charge. The first category is Article IV.2 which deals with ecological and environmental charges. "Ecological and environmental costs are those that arise from compliance with governmental or regulatory requirements or prudent operations." This section provides for an option as to whether those charges are allocated to the joint account or included in the overhead rates. So, for an operator to even consider using this provision, the COPAS would have had to have an election to bill the direct account. Financial assurance costs is not really a environmental or ecological costs, even if required reclamation is environmental. However, unless an operator defaults on its plugging and abandoning obligation and the Division uses money from the bond to do all P&A work, the individual bond cost is never used for anything environmental or ecological. Accordingly, I do not think that this provision allows billing for a one well bond.

Q: How do you think the question of whether the operator can charge the non-ops under the 1995 COPAS comes out?

A: Like I said, the operator has a somewhat better argument under the 1995 form than under the first three versions of COPAS, but not a lot better. Since financial assurances are not typically the type of insurance listed in Exhibit D to JOA and are not mentioned in the COPAS, I am of the opinion that the operator can charge for a bond absent an agreement by the parties.

Q: How does an agreement work under the 1995 provision?

A: It is governed by Article I.7 on Page 3 of Exhibit 23. That provision contains some blanks but it requires an affirmative vote of a certain number of the working interest as designated by the parties when they fill out the COPAS and those must represent a certain percentage of the interest, again to be defined by the parties.

Q: Is there any typical way that these blanks in Section I.7 are typically filed out?

A: The number of parties typically is some number more than the sum of the operator and any entities or individuals affiliated with the operator. It may just be one additional vote but it is typically some number so that somebody besides any entities or individuals associated with the operator are in favor. There usually is, at least, a majority requirement and often a super majority of some form but there is no standard that I am aware of in the industry for that second blank. This at least creates a possibility that an operator could achieve agreement to bill for a bond directly with a vote that is not unanimous and that decision would be binding on all the non-ops. However, the economic motivations to vote for such a proposal remain the same as I described earlier—there would need to be some significant future upside in the well for the non-ops to consider an affirmative vote for such a proposal.

Q: What are the pertinent changes in the 2005 COPAS which is Exhibit 24?

A: The 2005 COPAS returned to the practice of simply having direct charges defined with specificity and all non-direct charges covered by the overhead provisions in III.

Q: Are there any direct charges in which the operator could bill for a marginal well financial assurances bond?

A: Again, you have the insurance provision, but since financial assurance bonds are rarely listed in Exhibit D to the operating agreement, it is probably not covered. Again, you are limited to premiums and so my testimony about operators having to pass cash bond remains the same. Those provisions are found in Article II.11 on Page 8 of the exhibit. In this exhibit, ecological, environmental and safety is covered in Section II.13. This 2005 provision, however, explicitly concerns labor, services, and equipment which none of which cover a financial assurance bond. However, there is an “Other Expenditures” provision at Section II.15 under which charges which are a “direct benefit to the joint property and is incurred by the operators and is necessary and proper conduct of the joint operations.” Joint operations include matters such as the “protection” and “maintenance” of the joint property. Under the latter provision in the 2005 COPAS from, it is my opinion that the operator has the strong case for charging non-ops for a single well financial assurances bond to preserve the ability to operate a well that is been deemed marginal.

Q: What about the 2022 COPAS which is IPANM Exhibit 25?

A: I think that analysis of that form in this rulemaking is largely academic. This form is just coming into use in New Mexico and would be used for the most recent JOASs. The likelihood of there being a “marginal well” where the 2022 COPAS is at issue seems to me to be very slight at present and the very near future. However, a similar other expenditures provision is found in Section II.14 on Page 10 of that form. Additionally, there is some specificity of what goes into overhead found in Section III on Page 11 and I do not read that list to definitively include bonding. Accordingly, I view the operator’s chances under the 2022 COPAS as similar to the 2005 COPAS.

Q: Mr. Ezzell, would you summarize for the Commission how, contractually, smaller independent operators in New Mexico would be able to bond a marginal well.

A: As I have mentioned, based on my experience, most older wells in New Mexico that are currently marginal or approaching marginal status (using the definition of “marginal” in the proposed rulemaking), are going to be subject to one of the three oldest COPAS forms. Unless the operator is large enough and liquid enough to have a surety company post the bond for a fee that could be absorbed into the operator’s overhead, an operator would have to post a cash bond and would not be able to charge the cost of the bond to the non-ops unless the non-ops saw some significant economic upside to the well—upside that is probably only going to realized by another significant capital infusion from the working interest owners. In short, I do not think it likely that the operator would be able to successfully bill the non-ops for the cost of a cash bond.

Q: How will the issue resolve?

A: With large increases in bonding amounts, surety companies with take various actions to secure their position such as raising rates, becoming increasingly discerning as to the financial strength of their customers, and/or require collateral to secure bonding. Some operators currently relying on the surety market will be forced to use cash bonding because their balance sheets will not be of sufficient quality for a surety company to sell them single well bonds. For cash bonding, I expect that there will be messy disputes between operators and non-operators over who is to pay the bond that will result in operator resignations and unwillingness of Non-ops to step into the role of operator. The result as far as New Mexico is concerned will be that marginal wells and wells approaching marginal status, many of which could otherwise be economically produced, being plugged and abandoned or the bankruptcy or dissolution of the operator.

III. <u>Marginal Well Definitions</u>

Q: Did you have some concerns about the definitions of marginal wells in the proposed regulations?

A: Yes. I do not wish my testimony to be misunderstood to suggest that I think that the Commission has the authority to adopt these bonding requirements absent an amendment to the Oil and Gas Act or that I think the rulemaking is a good idea. However, I have concerns about whether the marginal well definitions have any place in any regulatory scheme adopted by the Commission. In particular, the rulemaking proposes to effectively displace or overturn judicial decisions governing oil and gas matters.

Q: What are your concerns specific to the WELC proposal?

A: I read the WELC Proposal to provide that, once a well qualifies as a marginal well based on a 12-month trailing average, no future activity is possible to take the well out of marginal well status. In a word, once the $150,000 bond is posted for a well, it can never be returned because of better production volumes or more production days. As someone who has operated a company, the requirement of posting at $150,000.00, if the bond could be returned or released, would incentivize the operator to increase production volumes to over the 1,000 barrel of oil equivalent called for in both rules. The WELC proposal lacks that incentive.

Q: What other concerns do you have about the marginal well definitions being proposed?

A: The proposal would require bonding at the level of $150,000 per well the month after the well is not showing 1,000 BOE per year and produced for at least 180 days in the trailing 12 months. In addition to what I would perceive to be the administrative burden on the Division and I know the administrative burden on an oil and gas operator, does not take into account the realities of the industry and the terms of oil and gas leases and expectations on the lessee/operator. I will go into more detail in a minute, but typical oil and gas leases in New Mexico create a fee simple determinable in the mineral estate which fee determines when oil or gas is no longer being produced or capable of being produced.[6] My concern here focuses on the "capable." If a well goes down and the primary term of the oil and gas lease is expired, the operator typically has a few months, 60 or 90 days is pretty common, to "commence" reworking or recompletion activities to restore the well to production in some fashion or to drill another well. That could include repairing the wells it can use to produce from the same formation or recompleting uphole to another formation capable of production. However, those reworking and recompletion activities, even when diligently pursued, can take as much as a year. There may need to

[6] *Maralex Resources, Inc. v. Gilbreath*, 2003-NMSC-023, ¶ 9, 76 P.3d 626; *Terry v. Humphreys*, 1922-NMSC-013, ¶ 21, 209 P. 539.

stage of different crews over time. In the Permian Basin area of the state, there is high demand for various service companies with all the drilling and completion activities and the smaller operators that are IPANM members typically do not have the pull to get to the top of a service company's work list. The bottom line is that it is relatively easy for a well that is holding an oil and gas lease to be down for six months before production is restored and that period of time could be longer. The operator/lessee who commenced those operations timely, would likely be in compliance of all its lease obligations and perpetuate the oil and gas lease, but shortly after undertaking a expensive reworking or recompletion project would be saddled with a $150,000 bond because those completely unproductive months result in an extended period of no production volumes or days. In the realities of the oil and gas business and the legal relationships governing the life of oil and gas leases, it would make much more sense to define marginal wells based on average production and the average production days over a period of a few years rather than a constant trailing 12 months.

Q: You mentioned concerns about gas and oil wells, what is your concerns about gas well?

A: The proposed rules do not take into account the standard or common provisions of oil and gas leases and, in particular, the shut-in royalty clause.

Q: Please explain.

A: Under most oil and gas leases (and a typical example is the Form 342P which is IPANM Exhibit 26[7] and is very prevalent in fee oil and gas leases throughout the State of

[7] Hall-Poorbaugh Press which printed the Form 342P is no longer in business, so Exhibit 26 is a recorded oil and gas lease on that form with the blanks completed but the substantive text unchanged.

New Mexico) there is a shut-in royalty clause as part of the gas royalty provisions. There are other forms of oil and gas leases but I am hard pressed to remember reviewing an oil and gas lease (and I have reviewed thousands of leases over my career) that does not provide for some form of shut-in gas royalty. Those provisions allow the operator to shut-in a gas well that is capable of producing in paying quantities for an extended period if it pays certain defined royalties called shut-in royalties to the lessee.

Q: Why would an operator shut-in a gas well for such an extended period?

A: There are two common reasons. First, building the infrastructure to connect gas wells to the interstate pipelines system can be expensive and time-consuming. The shut in royalty allows an operator to perpetuate an oil and gas lease when it cannot market the gas. Second, historically, the price that a producer can realize from the sale of natural gas can vary greatly. Over my entire career, the usual pattern is that prices for natural gas tend to be the highest in winter months when it is consumed in large areas of the United States for heating and lowest in the summer when it is not needed for heating. Additionally, more recently, in the Permian Basin area of New Mexico, there had been constrained takeaway issues that substantially impacted the price of gas even driving it negative for periods of time where producers had to pay a transporter or consumer to take the gas.

Q: What is constrained takeaway?

A: There simply was not the infrastructure to move all the gas produced out of New Mexico to distant markets. Pipelines all have some form of capacity constraint and can only handle a certain volume of gas and the Permian Basin area of New Mexico suffered a few years of constrained takeaway and low to negative gas prices. Those issues have been alleviated with some new pipelines that flow to the Texas Gulf Coast market.

Q: What do low or negative gas prices have to do with the shut-in royalty clause?

A: The operator of a well that produces high volumes of oil and casinghead gas almost always will absorb negative gas prices as a cost of realizing the revenue generated from the sale of oil. Operators of gas wells do not have that optionality. Very simply, the producer or operator can shut-in a gas well capable of producing during low or negative price periods to effectively save the gas in the ground to be produced at a time of higher prices. Over time, this ability benefits all owners of interests in a well, including the royalty owners and the State of New Mexico in terms of severance tax revenue on gas which is taxed at about 9% of its value.[8]

Q: How does the proposed marginal well definition affect this industry practice?

A: An operator may want to shut-in during an entire extended period of low or negative gas prices, but if faced with a need to produce the well at least to a 1,000 BOE per year or 180 days, the operator could decide to produce during a low price period and receive either low prices on which lower royalty is paid or negative prices on which no royalty is paid in order to avoid the cost of a single well bond under the proposed rulemaking.

Q: Can an operator legally produce gas at low to negative prices just to avoid a bond?

A: Before I answer that question, let me be clear about terminology. In an oil and gas lease, the lessor is the mineral owner that “leases” or grants its minerals to a lessee. Both interests can be divided. An operator of an oil and gas lease may be an owner of

[8] § 70-29-1 *et seq.*, §§ 70-30-1 *et seq.*, §§ 70-31-10 *et seq.*, and §§ 70-32-1 NMSA are the statutory schemes for the four forms of taxation on the value of severed oil and gas.

some or all the lessee's interest but, under the form JOAs we have discussed, obligated to discharge the lessee's duties to the lessor on behalf of all owners of a portion of the lessee's interest. Although there can be some legal differences between a "lessee" and an "operator", those differences do not matter for purposes of my testimony on this issue. I use the term "operator" as synonymous with the term "lessee" in my testimony on this issue as the legal distinctions between those two roles are not relevant to this issue.

Q: Thank you. With that explanation, can you tell the Commission if an operator could produce a well during periods of low pricing when motivated to have enough production days to avoid a marginal well bond under these proposals?

A: In my view, an operator would be at legal peril. Although New Mexico common law tends to favor the lessor, any New Mexico practitioner will tell you that one cannot predict how the Court of Appeals or Supreme Court will rule on a previously undecided question. Obviously, since this regulation is only in the proposal stage there is no case on point. However, there are cases concerning a lessee's (which is the operator and working interest owners) obligations with respect to production and use of the shut-in royalty clause. In those cases, New Mexico courts state that an operator/lessor "must proceed with reasonable diligence, as viewed from the standpoint of a reasonably prudent operator, having in mind his own interest as well as that of the lessor."[9] Under this standard, an operator making a decision to produce a gas well in an unfavorable pricing environment might create liability for itself if produces the well with the motivation to make sure the well produces above the 180 day threshold to avoid a marginal well bond under

[9] *Libby v. DeBaca*, 1947-NMSC-007, ¶ 7, 179 P.2d 263.

the proposed rules. Put another way, the bond cost is not a cost to the lessor so, if avoiding that cost drives the operator's decision to produce, the lessor could sue and might be successful.

Q: Does your operator in your hypothetical have any defense?

A: It would depend on the facts, but probably so. To my mind, the best defense (if true) would be the operator contending that the well's economics were so tight that a $150,000 cost that brought no benefit to the well's productivity would put the well on the wrong side of the economic tipping point. In other words, the only reasonable and prudent options were to either produce the well or plug and abandon. Of course, if there is a dispute over the issue, victory in litigation can be pyrrhic given the cost of defending the lawsuit.

Q: Earlier you mentioned that you are of the opinion that proposed rulemaking would displace or overrule some judicial rules. Have you fully explained that issue?

A: No. As I mentioned earlier, the habendum clause in a typical fee or state oil and gas lease is for a specified term of years and "so long thereafter as oil or gas is produced." Following a well-known Supreme Court of Texas opinion, the New Mexico Supreme Court reads "produced" to mean "producing in paying quantities" and seems to adopt the Texas test for what production in paying quantities means.[10]

Q: Have New Mexico courts explained how to apply that test?

A: No. The *Maralex* case and the federal district court case both involved complete termination of production so, to use the property law terms, the determinable fee granted

[10] *Maralex*, 2003-NMSC-023 at ¶ 9, citing *Clifton v. Koontz*, 325 S.W.2d 684, 689 (Tex. 1959). See also, *King v. Estate of Gilbreath*, 215 F.Supp.2d 1149, 1166 (D.N.M. 2016) (same).

by the oil and gas lease determined within 60 to 90 days of the date of last production. However, the fact that the New Mexico Supreme Court mentioned production in paying quantities and cited to the *Clifton* test causes me to believe it is the test in New Mexico. Based on the *Maralex* citation and the fact the *Clifton* is widely accepted in numerous producing states causes me to advise clients under that test

Q: What is that test in the *Clifton* case?

A: The test is pretty clearly stated in *Clifton*: "in the case of a marginal well, such as we have here, the standard by which paying quantities is determined is whether or not under all the relevant circumstances a reasonably prudent operator would, for purpose of making a profit and not merely for speculation, continue to operate a well in the manner in which the well in question was operated." The Court cautioned that a trial court applying the test "must take into consideration all matters which would influence a reasonable and prudent operator." It then went on to identify the following as "some of the factors" a trial court should consider: "the depletion of the reservoir and the price for which the lessee is able to sell his produc[tion], the relative profitableness of other wells in the area, the operating and marketing costs of the lease, his net profit, the lease provisions, a reasonable period of time under the circumstances, and whether or not the lessee is holding the lease merely for speculative purposes."[11]

Q: What is a "reasonable period of time under the circumstances" as used in the *Clifton* formulation?

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[11] All the quotations in this paragraph are taken from two successive paragraphs found at Page 691 of the *Clifton* opinion.

A: The *Clifton* Court explains: "there can be no arbitrary period for determining whether or not a lease is terminated for the additional reason that there are various causes for slowing up of production, or temporary cessation of production, which the Courts have held to be justifiable." The *Clifton* Court went on to emphasize that "there can be no limit as to the time whether it be days, weeks or months, to be taken into consideration in determining the question of whether paying production from the leas has ceased."[12] However, the ligation and reported decision concerning that particular question is so rampant that there is an entire Law Review article devoted to the topic.[13] For instance the lessor tried to use a 16-month period showing a net loss, but as the Cout observed, it was really only the last three months of that period that took the well from slightly profitable to slightly unprofitable. There are various examples cited by Mr. Martin and the law review article I have cited with some courts applying up to six years.[14] In the same article, the author cites extensively from a Supreme Court of Kansas Decision that sates in dicta that a 13-year accounting period is too long but contains the following language concerning why there should not be a defined period of time: "as generally accepted that profitability on an oil and gas lease should be determined over a relatively long period of time in order to expose the operation to the leveling influences of time. The arbitrary use of a short period of time while a well is down for a workover is obviously untenable. On the other hand, the use of a reasonably long period would entail the use of past glories during flush

[12] These quotations are taken from the same paragraph found on Page 690 of the Opinion.

[13] Martin, Andrew D., "What Is the Appropriate Time for a Paying Quantities Analysis?", 57 Rocky Mountain Min. Law Fnd'n Journal Vol. 2 at 379-430 (2020) (also published at 8 LSU J. Energy L. & Resources 367-418(2020)).

[14] See the discussion at Footnote 105 in the Martin Article cited above.

production to determine the lease's present condition… The better rule precludes the use of a rigid fixed term for determination of profitability and uses a reasonable time depending on the circumstances of each case…"[15] Very simply, the court decisions applying the *Clifton* test have been flexible about the period of time applying the common law principle that the law prefers to avoid forfeiture.[16]

Q: Does the proposed rulemaking institute a production of paying quantities test?

A: Facially, no. Practically, yes. Let me explain. The rule deals with plugging of marginal wells, not a termination of a lease per se. However, if the marginal well is the last producing well holding the lease, the effect of the rule is to make a production paying quantities determination. Additionally, as quoted from the *Clifton* case, the whole focus of the production paying quantities test is on "marginal wells." Effectively, the rule is going to displace the production paying quantities test with an inflexible test that the Courts have long rejected.

Q: What would that mean?

A: Several things. First, the rule flips the burden of proof. In the production in quantities test, it is the lessor's burden to prove that the lessee's leasehold is terminated. Under the proposed rules, once there is a presumption of no beneficial use because of low production, the well must be plugged and the burden to prove otherwise is on the lessee/operator. Second, the rule effectively proposes that the OCD replace the courts where these questions are normally decided. In my view, the Division's qualifications are

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[15] Martin at 399-400 quoting *Texaco v. Fox*, 228 Kan. 589, 593 [other citations omitted].

[16] New Mexico follows this principle in other areas of law. E.g., *State v. Benally*, 2015-NMCA-053, ¶ 7, 348 P.3d 1039 (citation omitted) (affirming a narrow interpretation of New Mexico's Forfeiture Act).

much better directed at technical and scientific issues related to the wells, not applying flexible common law rules that require multi-faceted factfinding and balancing. I do not see that the Division has any expertise in determining the reasonableness questions raised in the production in paying quantities test or the "speculative" motivation that is part of the Clifton test and also found in the proposed rulemaking. I am also unaware of a situation in which the Division's rules adopted by this Commission effectively displace the courts and established jurisprudence, but that is being proposed here. I know that some of IPANM's fact witnesses that are going to testify to circumstances such as failure of a midstream gathering system for gas wells that might effectively, under the definitions, create the presumption of non-beneficial use and it is exactly the sort of situation that the courts are saying should influence what a reasonable period of time is rather than the fixed period of time set forth in the rule. Finally, the fixed periods of time in the Rule would effectively displace the prudentially flexible time periods that the courts have adopted and explained.

Q: You mentioned the term "speculative" in your last answer, what does that mean?

A: That is another troubling aspect of the rulemaking as the term is proposed but is not defined. The oil and gas business involves speculation at all stages: Will the geological target be productive? Will the goods and equipment used in drilling and completing work properly? Even if desirable production rates are achieved, will demand and commodity prices allow for a return on the capital committed? Will spending money on this new equipment or reworking restore production to a higher level? Those are just a few of the gambles or speculations, although at least somewhat educated, an operator and its working interest investors take all the time. In the paying quantities test, that term is not well defined in the jurisprudence, but it part of the entire framework of decisions that seem to give operators some benefit of the doubt when they wish to continue to produce marginal wells. The purely speculative purposes part of the *Clifton* test is generally understood to mean that the operator is trying to maintain the lease by production after the conclusion of the primary term for the sole reason of holding the acreage because it hopes that some other formation may be profitably developed at some point in the future. Put another way, it is impermissible speculation if the operator's sole motivation is avoid the expiration of the lease and the concomitant risks that the operator would not successfully re-lease the acreage or would bear additional costs in re-leasing such as bonus price paid or higher royalty rates. There is no such narrowness of the term "speculative" in the proposed rulemaking and, given the nature of the industry, could be interpreted much more broadly to cover the types of speculation that are inherent in the oil and gas business. Again, it is my opinion that this type of balancing test on judgment of subjective motives is a matter best left to the courts. Going back to my example of low and/or negative gas prices for a period that motivates the operator to shut in a gas well and pay shut-in royalties to perpetuate its lease, there is nothing that I detect in the proposed rulemaking that would prohibit the Division from requiring the well to be plugged because it is "speculative" for the operator to hold the well in hopes of better gas prices. Never mind that gas prices are historically cyclical and, in a constrained takeaway environment, it is easy to determine if additional takeaway capacity is being planned. Under the production in paying quantities test, a court would carefully consider that sort of issue.

Q: Concerning the "marginal well" definitions, are there any other issues or conflicts that you see with existing law?

A: Yes. I think that the definition conflicts with existing State policy as expressed in enacted statutes concerning severance taxation in New Mexico.

Q: How so?

A: The legislature defines "stripper well property" as a production unit where the wells produce on average less than 10 barrels per day of oil or less than 60,000 cubic feet of natural gas per day. If it produces both gas and oil, the gas is converted to a barrel of oil equivalent (in the same manner as suggested in the proposed rulemaking) at that rate of 6 mcf of gas equals one barrel of oil for the less than 10 barrels per day calculation.[17] The conflict arises with the tax policies adopted utilizing this definition.

Q: Before we get into that, you mentioned the term "production unit" in your last answer. How does that term differ from a single oil and gas well?

A: The Department of Taxation and Revenue is given statutory authority to designate the property that constitutes a production unit and it is to be one "from which products of common ownership are severed."[18] Accordingly, a production unit and a stripper well property can have multiple wells so long as ownership is common. However, for purposes of the stripper well property, the average well production must be within the prescribed levels that I described above. The basic point for the Commission in this rulemaking,

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[17]§ 7-29(B)-2(L) NMSA.

[18] §7-1-12.1.1 NMSA.

however, is that the definition proposed for a marginal well would include wells that are stripper wells under the statutory definition.

Q: So what is the conflict?

A: The definition of stripper well property that I have cited is part of the taxing provisions on the value of severed oil and gas products or severance taxes that I have previously mentioned. The Legislature has adopted the Natural Gas and Crude Oil Production Incentive Act which is codified at Sections 7-29(B)-1 through -6 and creates production incentive tax exemption for ten years for production restoration projects approved by the Division. The State effectively reduces, for ten years, the severance taxes that I have previously cited if an operator invests in an approved workover project for a stripper well property. This statutory scheme represents legislative policy that seeks to create financial incentives for such production restoration or workover projects by allowing the producer to recoup some or all the costs through these tax exemptions. However, to the extent that any of the stripper wells in the production unit would also qualify as "marginal wells" under the rulemaking, the rulemaking proposes to saddle the operator with an additional $150,000.00 costs for each such marginal well. It makes no sense for the Legislature to adopt such a tax incentive program and this Commission to add such a tremendous cost to the operator of wells eligible for that program. Even if this Commission disagrees and determines that it has authority to adopt the financial assurances proposals in the rulemaking, this tax incentive program strongly suggests that the Legislature is the one who should be balancing these issues. In my opinion, this tax incentive program represents New Mexico public policy adopted by legislation and signed by the governor in an enacted statute that contradicts the policies advanced before this

Commission in the proposed rulemaking. It does not make sense that the Legislature would want to saddle wells with an upfront cost of $150,000 but make that well eligible for a tax incentive program likely worth a few hundred dollars per month to incentivize workover investment.

IV. <u>Proposed Time Limits for "Beneficial Use" of a Wellbore</u>

Q: Mr. Ezzell do you have concerns about the proposed definitions of beneficial use and the related concepts in the proposed rulemaking?

A: I have a few concerns. Before I discuss some specific concerns, I have two comments. First, all my testimony about the use of the term "speculative" in the preceding few pages of my testimony also is applicable to this part of the proposed rulemaking.

Q: What is your other comment?

A: On an overall basis, this 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. I have never heard of it as a concept in oil and gas law of any other state as it pertains to wells as the rulemaking proposes. While I do not hold myself out as an expert in the law of other states, I note three things. First, oil and gas common law in New Mexico is not as well-developed as it is in some other states and any New Mexico practitioner in the area needs working knowledge of oil and gas common law in other producing states. Second, much of the oil and gas continuing legal education that I have attended is put on by organizations that cover the law of many states and courses necessarily cover common law from other states. Finally, I consulted the widely recognized definitive treatise on oil and gas law in the United States which only makes mention of the concept in oil and gas law as a water law principle and the very narrow area of the regulations concerning the calculation of royalty owed to the federal government for natural gas produced.[19]

Q: What problems do you see with the definition of beneficial use?

A: I understand the definition to apply on a per well basis and require plugging and abandoning. It is a complex answer so I will probably need to answer it over a few questions. However, let's begin with proposition that, under prior New Mexico regulations for plugging and abandoning wells, it was expensive but not necessarily uneconomic to drill through the plugs and reuse an otherwise useable wellbore. With the current regulations that require plugs set at every potentially productive zone, it simply not economic to re-enter so the hole, once plugged, is lost forever.

Q: Describe how that impacts your views on beneficial use?

A: There are a few things going on here. I have already described the workings of typical oil and gas leases such as Exhibit 26. It may be easiest for me to use an example. Assume you have a 160-acre oil and gas lease in northeastern Eddy County and the operator has four wells drilled and completed into the Yeso formation (also sometimes known as the Paddock formation). Those Yeso wells may have up-hole potential into the Grayburg formation or the San Andres formation which are two generally productive

[19] Volume 8 (the "Manual of Terms") the Williams & Meyers Oil and Gas Law treatise is widely acknowledged as the authoritative and most comprehensive dictionary of oil and gas terms and endeavors to include every definition given to those terms in the industry, including those recognized by courts, by statute, or by regulation. It contains a total of two definitions for "beneficial use": (1) as used in water law and the doctrine of prior appropriation which can affect oil and gas activity; and (2) in the federal regulations governing the calculation of gas royalty owed to the federal government under federal oil and gas leases. Martin, Patrick & Kramer, Bruce 8 Williams & Meyers Oil and Gas Law at 93 (2024). Neither definition is used in the proposed rulemaking.

formations that can and do occur in northeastern Eddy County and are shallower than the Yeso formation. If three of those wells are no longer economic to produce but one well is, production from that one well will continue to hold the oil and gas lease. I understand that properly equipped, inactive wells that are periodically checked do not pose any immediate threat to public health and welfare. Under the typical forms of joint operating agreements, this lessee operator is an independent who probably has multiple investors or non-operating working interest owners whose approval is needed for major operations such as recompleting a well into another formation.[20] That must be achieved by a majority vote or some other percentage of votes above 50.1% depending upon the terms of that JOA. The operator itself and/or a majority of the working interest owners may view it as a future priority but not a present priority to deploy capital for recompletion efforts. Additionally, I know that if you can conduct the same operation on multiple wells in sequence in or around the same area, it is cheaper and more efficient to do so sequentially rather than spread those out over time. The beneficial use regulations seem to leave it up to the Division's discretion whether to believe the operator and its working interest owners about their recompletion efforts and put time constraints on those in any event that are going to create waste of resources and/or economic waste enforcing people to act within certain timeframes or must plug and abandon wells.

Q: What about the definition of beneficial use in general?

[20] For instance, under the 1977 JOA which is Exhibit 15, the provisions governing larger expenditures (the amount is chosen by the parties to an individual JOA, there is no form amount) are governed by the provisions of Articles VII.D.1 -.3 and VI.B.1.

A: I am concerned that it is too constrained. In my over 40 years involvement in the oil and gas industry, the industry has seen amazing technological developments that I would have thought impossible when I first started becoming a participant in the late 1970s. Just the concept of horizontal well drilling as opposed to the relatively novel concept of directional drilling that I was familiar with early in my career is astounding. What is even more astounding is that a horizontal well with a 2 or 3 mile lateral can be drilled in vastly less time today than a 5,000 or 6,000 foot conventional vertical well that was drilled in the 1980s.

Q: What relevance does all that have to your views of beneficial use?

A: Well, there are various uses that wellbores can be used for now. I have just testified about recompleting up-hole into other productive formations which either may not have been economic to drill for as the sole target of a well and/or where there could be formations that participants in the original well planned to test once their target, deeper formation was played out. Or those formations may not have been technically feasible to develop when the well was drilled but now are. There are uses such as saltwater disposal.[21] I have seen instances where wellbores are plugged to a relatively shallow depth and turned over to the rancher or farmer for use as water well. Technology seems to be evolving so that circulating water into non-volcanic subsurface rock can create geothermal energy.[22] Carbon capture is a potential use for wellbores and would be much

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[21] A typical oil and gas lease does not allow the lessee to operate a commercial saltwater disposal well, although most would allow the lessee to dispose of its on-lease saltwater production. In my view, New Mexico will adopt the rule that the pore space belongs to the surface owner and can only be used by the lessee to the extent reasonably necessary to develop the mineral estate. Nevertheless, while the owners may vary or completely change, oil and gas wellbores have been converted to SWD operations.

[22] Low temperature geothermal energy development apparently is becoming more prevalent. https://www.koat.com/article/billion-dollar-investment-in-geothermal-coming-to-new-mexico/65069917.

more economic if using extant wellbores permits access to the target formation as opposed to drilling new wells. There is literature and apparently some experiments where wellbores into salt beds are being used to store electricity. All these things may be "speculative" but why waste the potential by prematurely plugging and abandoning wells?

Q: But isn't your proposal open to more abuses of operators keeping far too many non-productive wells unplugged and abandoned?

A: I can see that argument. However, 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. I think that these proposals on beneficial uses and plugging wells so quickly is overkill and the regulatory equivalent of using a cannon where a flyswatter will do the job.

Q: What other concerns do you have with the proposed rulemaking?

A: I am very concerned that the proposed rulemaking, if adopted, would make unitization for purposes of secondary and tertiary recovery cost prohibitive or impossible.

Q: Briefly explain what you mean by secondary and tertiary recovery unitization.

A: I expect that the Commission is familiar with these concepts as the Commission and Division approve these units before they are commenced. Unitization basically refers to the process of combining multiple oil and gas leases to be produced together using facilities common to the unit which could include the development and production of different oil and gas leases. Secondary recovery unitization is unitization for purposes of a water flood and typically used for recovery of oil reserves after artificial lift or pumpjacks

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A billion dollar geothermal project was announced for New Mexico a few months ago. https://www.koat.com/article/billion-dollar-investment-in-geothermal-coming-to-new-mexico/65069917.

are no longer efficacious. The secondary recovery units in my experience usually involve unitizing a number of leases that have been producing from a common formation and that each lease is adjacent to another so that a single tract of land can be traced as the unit's footprint. Water (generally salt or produced water) is injected into the target formation to recover more oil. I will describe some more of the process below. While it can be an existing unit that is switched over to secondary recovery, more often, a secondary recovery unit is the first unitization the leases have experienced at least for that depths or formation which are to be unitized. Tertiary recovery unitization usually occurs within a secondary recovery unit when the use of water flooding has played out and the operator injects super compressed carbon dioxide into the unitized formation to recover additional volumes of oil.

Q: How are you familiar with unitization?

A: Primarily through my legal career. Our firm has historically written a chapter of a unitization treatise put out by the Rocky Mountain Mineral Law Foundation (now the Foundation for Natural Resources Law). My former partner and mentor, Lewis C. Cox, was the primary author of that chapter for a number of years in my career and I assisted him in updating that chapter annually. Authorship went from Mr. Cox to my partner, Gregory Nibert, and again, I assisted from time to time in the update process in consulting how to describe changes or evolution of the law. Additionally, I have assisted a number of clients over the years in unitization issues. Legal concerns are very prevalent when forming a unit and as a primary lawyer advising clients in unitization, I was part of unitization teams and had to understand what other functions within the company were contributing to the process and what those contributions were.

Q: What goes into forming a secondary recovery unit when there is not a prior unit in place for the acreage and formation?

A: Again, this is the usual situation with the formation of a secondary recovery unit. An operator in a particular area in a formation with a significant ownership percentage (which typically is something more that 20% of the leasehold interest but can be less) will take the initiative in determining the feasibility of unitization which involves engineering and geology work to map out the top and bottom of the target formation over an area, land work to identify the operators and owners of the various leasehold interests in that area and then the time consuming process of persuading other operators and owners in the area that they should participate in unitization. The land work also involves identifying oil and gas leases covering the area which unitization is wanted to determine whether those oil and gas leases have unitization provisions that allow the lessee to consent to unitization is wanted to determine whether those oil and gas leases have unitization provisions that allow the lessee to consent to unitization without the lessor's consent or, in the absence of such a clause, determining that the lessor consent is needed. In my experience, once an operator begins to build momentum with at least some of the neighboring or nearby lessee/operators expressing a willingness to join a unit, the process of negotiating a unit agreement and a separate unit operating agreement begins. Some of the operators may not be interested in, or able to meet the capital demands of, the proposed unit. In that situation, one of the better capitalized proponents of unitization will attempt to buyout the owners of reluctant interests and those negotiations are often drawn out and sometimes unpredictable where the proposed transaction evolves into a deal with a broader scope. Where the State of New Mexico or federal government own the minerals underlying a tract to be contributed to the unit, federal and state regulations need to be followed regarding treatment regarding treatment of federal and state royalty.

Q: What else is done?

A: There is a lot. This is a time consuming, detailed process. One of the most significant tasks is the petroleum engineering and geology determinations of the best injections patterns. Certain wells will be turned into injectors in which, in a secondary recovery unit, produced water is injected down certain wellbores and into the producing formation to push or drive oil toward wells that remain productive. There is no set way to design a unit with injectors and producing wells and determinations must be made concerning the localized conditions, especially geology and the elevation of the producing formation in the various wellbores to determine the optimal injection pattern.

Q: What is an injection pattern?

A: In a secondary recovery unit, it is common to have what are called four spot or five spot injection patterns. In a four spot pattern, there are three injectors for every producer attempting to drive oil to that producer. A five spot is the same except there are four injectors for every producer. Very basically, in many waterflood units, 75 to 80% of the wellbores are converted from producing wells (or former producers if they have been shut-in) into injector wells.

Q: What is the timeline for a secondary recovery unit?

A: Planning, paperwork, agreements, technical analysis, and regulatory approvals take at least two years at the fastest and often longer.

Q: What sort of capital commitment are we talking about when forming a secondary recovery unit?

A: There are factors that can vary but we are talking tens of millions of dollars for the equipment to convert wells to injectors, reconfiguring post-production facilities on the unit, new measurement facilities, securing a source of water and all the administrative, legal and consulting costs associated with forming a unit. One of the important issues to realize on this capital commitment is that the upfront capital commitment is huge at the same time as you are taking wells offline to convert them into injectors. Once injection starts, it takes at least months for the first response to be detected in the producing wells. Accordingly, you are taking 75 to 80% of the wells, converting them to injectors, and there is a corresponding decrease in revenue for at least a period of months.

Q: How would the proposed rulemaking effect unitization?

A: Well, take a hypothetical relatively modest 100 well area that is to be unitized and a four spot design like I discussed, about 75% of the wells will be injectors and, therefore, definitionally marginal wells under the proposed rulemaking. That is $11.25 million dollars added to the cost in bonding if the operator is posting cash bonds. Of course, whatever the cost of bonding is going to be, I would expect that the negotiating unit agreement would provide that all the working interest owners share in the bonding costs proportionally unlike the JOAs. However, you are talking about people who are already committing a couple times that sum in capital for returns that are not likely to start up for more than a year after the capital is invested and probably more like two years.

Q: What about bonding for a fee?

A: My experience as an operator is with cash bonds. However, I understand from legal work that I have done for clients that being able to bond for a fee, as opposed to a cash bond, requires some combination of a very strong, audited balance sheet and/or collateral. Also, I think it is far from clear how the surety market is going to respond to posting single well bonds. I would guess that, with the large dollar amount and the fact that the bonded asset is going to be late in its productive life, is going to mean that those bonds are expensive if they are even offered at all. All that said, even at a fee, I anticipate you would be talking about a significant additional expense.

V. <u>Changes Regarding Temporary Abandonment of Wells</u>

Q: Have you reviewed the proposed rulemaking in terms of the temporary abandonment issues?

A: I have, and I have concerns about those.

Q: What is your first concern?

A: I have been able to preview the testimony of Clayton Sporich that the New Mexico Oil and Gas Association is presenting. As a matter of efficiency for the Commission, I hereby adopt and join in the testimony of Mr. Sporich contained in the section of his testimony entitled "Proposed Changes to New Mexico's Temporary Abandonment Program." While I may have rebuttal or live testimony on this issue, Mr. Sporich's current testimony encapsulates my current thoughts and the testimony I would presently give.

VI. <u>Miscellaneous Issues</u>

Q: Do you have any other concerns about the proposed rulemaking?

A: Yes, I have a number of concerns that can be described more concisely than some of the issues to which I have testified above.

Q: What is the first of those concerns?

A: There are identical proposals regarding registration of operators and change of operators that provides that the applicant/new operator is ineligible if it "is out of compliance with federal and state oil and gas laws and regulations in each state where the applicant does business." I have three issues with this. First, as written, it charges the Division with decision making authority for which it has little or no necessary expertise. Second, even if that issue is addressed, it is incredibly vague. Third, it strikes me as disproportionate.

Q: Describe the concern about agency's expertise.

A: 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.

Q: What is your vagueness concern?

A: My vagueness concern is it is unclear what oil and gas laws and regulations the provisions intend to address. If it is just regulations of an operator as an operator, that is one thing. However, there are statutes related to payments of severance taxes, laws relating to calculations of royalty, and any other number of laws and contracts governing the conduct of the oil and gas industry that are rightly considered part of the body of oil and gas law but have nothing to do with an operator's qualifications to operate. For instance, if an operator is successfully sued for miscalculating royalty under a royalty provision in a particular oil and gas lease in another state, is that operator somehow ineligible to become an operator or take over operations from a payor operator just because of that verdict? If so, when do they become eligible again? As written, a finding against that operator on royalty calculation renders it ineligible to operate in New Mexico under the proposed rulemaking. There is an incredible amount of vagueness in this provision that lacks clarity, will cause tremendous enforcement issues if enacted, and do not give New Mexico operators and prospective operators standards to which they can be expected to conform.

Q: You mentioned a third concern about disproportionateness. What is that concern?

A: I touched on it in the last answer with my royalty example, but even when you are dealing with the oil and gas regulations that govern operators on federal leases and in other states, there are, like in New Mexico, regulations that are more serious than others. For instance, assume Pennsylvania has a regulation that requires visible signs at each well site and an operator is cited (or whatever the correct verb would be) by the Pennsylvania regulating agency because one of its wells signs was knocked down and therefore not visible. Is that operator somehow ineligible to become an operator in New Mexico? Under the wording of the proposed regulation, that operator certainly appears to be ineligible. I cannot imagine why New Mexico should care about a single sign in Pennsylvania. While this example may seem trivial, it is because the wording of the rulemaking covers such trivial violations. Overall, this regulation seems to be designed to have people who want to eliminate oil and gas production tattle on New Mexico operators to the OCD based on anything that happened in another state.

Q: What is your next concern?

A: The 15% more or threshold which would require an operator to bond all its wells individually strikes me as arbitrary and not well thought out. 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. 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. It makes no sense for each of its wells to be bonded. The rulemaking suggests that some risk-based approach to increasing financial assurances is needed. If this Commission determines it has the authority to adopt such a policy (and I do not think it does) and agrees that some risk-based approach is needed, arbitrary numbers like 15% marginal wells do not assess any risk. That can only be done by looking at individual operators.

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: 8/7/25

T. Calder Ezzell, Jr.