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

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

IN THE MATTER OF THE:

PROPOSED AMENDMENTS TO THE COMMISSION'S RULES ON FINANCIAL ASSURANCE AND PLUGGING AND ABANDONMENT OF WELLS, 19.15.2, 19.15.8, AND 19.15.25 NMAC.

CASE NO. 16078

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSIONER HEARING

July 19, 2018

Volume 1 of 2

Santa Fe, New Mexico

BEFORE: HEATHER RILEY, CHAIRWOMAN
ED MARTIN, COMMISSIONER
DR. ROBERT S. BALCH, COMMISSIONER
BILL BRANCARD, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Thursday, July 19, 2018, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

REPORTED BY: Mary C. Hankins, CCR, RPR
New Mexico CCR #20
Paul Baca Professional Court Reporters
500 4th Street, Northwest, Suite 105
Albuquerque, New Mexico 87102
(505) 843-9241

APPEARANCES

FOR NEW MEXICO OIL CONSERVATION DIVISION:

DAVID K. BROOKS, ESQ.
Office of General Counsel
New Mexico Energy, Minerals and Naturalization Department
Wendell Chino Building
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
(505) 476-3215
davidk.brooks@state.nm.us

FOR INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO:

GARY W. LARSON, ESQ.
HINKLE SHANOR, LLP
218 Montezuma Avenue
Santa Fe, New Mexico 87501
(505) 982-4554
glarson@hinklelawfirm.com

INDEX

INDEX

EXHIBITS OFFERED AND ADMITTED

(9:05 a.m.)

CHAIRWOMAN RILEY: So the first case we're going to hear today is 16078. It is a rulemaking. It's been continued from the May 24th hearing date, and it's In the Matter of Proposed Amendments to the Commission's Rules on Financial Assurance and Plugging and Abandonment of Wells, 19.15.2, 19.15.8 and 19.15.25 NMAC.

It looks like we have two parties to this. We have the OCD represented by Mr. Brooks.

MR. BROOKS: David Brooks, with the Energy, Minerals and Natural Resources Department, general counsel for the Oil Conservation Division.

CHAIRWOMAN RILEY: Thank you.

And then we have a second party.

MR. LARSON: Good morning, Madam Chair, Commissioners.

Gary Larson for the Independent Petroleum Association of New Mexico. I do not have any witnesses.

CHAIRWOMAN RILEY: Okay. Thank you.

MR. BROOKS: I have two witnesses.

CHAIRWOMAN RILEY: Two witnesses. All right. All right.

Mr. Brooks, do you want to --

MR. BROOKS: I think we should swear in the witnesses first.

(Ms. Marks and Mr. Goetze sworn.)

CHAIRWOMAN RILEY: Thank you.

Mr. Brooks.

MR. BROOKS: These are very simple rule changes, and my witness will explain them. So I think in the interest of time, I will defer -- I will not make any opening statement and begin by calling Ms. Marks.

Do you want to make an opening statement?

MR. LARSON: I do not have an opening statement.

I would like to point out to the Commission on IPANM's proposed modifications of the Division's proposed rules -- and Ms. Marks was kind enough to point this out to me -- in Subparagraph D, we have a category of 149 to 199 wells. That should be 150 to 199 wells.

MR. BROOKS: Very well. I'll call Allison Marks.

ALLISON MARKS,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BROOKS:

Q. Good morning, Ms. Marks.

A. Good morning, Mr. Brooks.

Q. State your name, please, for the record.
A. Allison Marks.
Q. And what position do you hold at the Oil Conservation Division?
A. I am the deputy director.
Q. And how long have you been in that office?
A. A little over two years, I believe.
Q. Very good.
Were you involved in directing the proposed amendments being submitted for adoption at this hearing?
A. I was.
Q. Rather than doing a detailed Q and A, since this is a rulemaking proceeding, I'm going to ask you to go through the rule section by section, explain the changes and state for each one the reasons which the Division came in and offered these amendments for the Commission's consideration.
A. Very well. It will be my pleasure.
So in 19.15.2.7, in (6), we have added a definition of "measured depth," with that definition being "means the total length of the wellbore."
Since Phil Goetze prepared a nice diagram, I believe Exhibit 8 in your packets, to explain the proposed changes to "measured depth" and "true vertical depth," I will let him testify as to both of those

definitions. Both are new definitions that are used in the proposed 19.15.8.9E.

Finally, the only other new definition is under 19.15.2.7.T.(3). The words "or temporarily abandoned status" have been added after "temporary abandonment." And this serves as a means to simply clean up this definition, as the Division uses this term regularly.

And also the phrasing has been incorporated into the proposed amendments to 19.15.8.9.D, and the term "temporarily abandoned status" is also used in statute. So defining it in our rule is helpful and consistent with the new rulemaking statute, I believe, as well.

Q. Ms. Marks, for a considerable time, we have had a situation where a well -- where we had a requirement and I believe we still do under the present rules that will change under this amendment.

Under the present rules, if a well is abandoned temporarily but is not permitted for temporary abandonment by the Division, it is -- it is required -- the operator of that well is required to supply additional financial assurance of that well, correct? Under present rules, if a well is temporarily abandoned, it's not being used, but it is not -- has not been approved by the Division for temporary abandonment, then, in that event, the operator is currently required to supply financial assurance -- to provide the Division with additional financial assurance for the plugging of that well, correct?

A. Correct.

Under -- under 19.15.2, "temporarily abandoned" is synonymous with the term "inactive."

Under the proposed rule, "approved temporarily" -- "approved temporary abandoned" and "approved temporarily abandoned status" is a different term. And under this proposed amendment, it puts the well in approved temporary abandoned status. They still have to place additional financial assurance.

Q. But under the present rule, that is not the case, right?

A. Correct. If you want -- wish to -- a condition to get an approved temporary abandoned permit, it's not a condition precedent to place additional financial assurance.

Q. Okay. So this change in definition, to make the terms synonymous of -- temporary abandonment and approved temporary abandonment are synonymous or will be under the new rule if it's adopted and, therefore -- that goes along with the substantive change that both --

either one will require the filing and maintenance of additional financial assurance?

A. No, that's not correct.

Approved temporary abandonment and -- approved temporary abandonment will still be a term of art under 19.15.25.12. "Temporary abandonment" and "temporarily abandoned status," the Division is proposing just to simply modify those terms, but the word "approved" has a different meaning under 19.15.25.12.

Q. Okay. But "temporary abandonment" includes both a generic temporary abandonment, that is: This well is abandoned with the new intention that it will be restored in the future, but it's not being used currently, and it also includes approved temporary abandonment status. Either way, it's temporarily abandoned, right?

A. "Temporary abandonment" and "temporarily abandoned status" simply means that the well is inactive.

Q. Whether it's proved that they're inactive status -- whether it's approved temporary abandonment or not? Doesn't make any difference about it being temporarily abandoned status?

A. I think we should just address if they're "temporary abandoned" later on in the section on "Approved Temporary Abandonment."

Q. Well, you will agree with me that it makes no difference as a matter of requiring additional bonding under the new rules that it is approved to be temporary abandonment status, right?

A. I'm sorry. Can you restate your question?

Q. You will agree with me, will you not, that under the proposed changes, it will make no difference for the purpose of -- the requirement of additional funding whether a well is in temporary abandonment status generically or whether it is approved for temporary abandonment -- well, no. I put it -- it does make a difference whether it's one or the other. It doesn't make a difference which category it's in.

A. That's not correct. If a well is seeking to be in approved temporary abandonment, which I will discuss later on, to get that permit, you will need to place additional financial assurance. Just for a well to be temporarily abandoned or in temporarily abandoned status or temporary abandonment, which is at the two-year mark, the existing financial assurance requirements remain in place.

Q. I don't understand, but go ahead.

A. Okay. Should I continue?

Q. Yes.

A. Okay. The Division is also proposing modifications to 19.15.8.9 here. And the title to this section, we added the words "categories and amounts of" before the words "financial assurance for well plugging."

And then before I go into specific changes, I'd like to just give a bit of an overview of what prompted some of the proposed changes and what we as the Division have seen over the last several years.

First, during the last legislative session, the legislature passed and the governor signed Senate Bill 189. While the bill cleaned up a few matters not relevant to this rulemaking, the bill also raised the amount of blanket plugging financial assurance to $250,000 from $50,000 and instructed the blanket plugging amount to be set by rule before this Commission. For reference, the blanket plugging amount has not been increased since 1977.

In addition and in contemplating the Division's proposed amendments, there is some statutory language I'd like point out to the Commission. Namely, 70-2-14(a) states in part that "one well plugging financial assurance amounts determined to be" -- "to reasonably pay the cost of plugging the wells covered by the financial assurance. In establishing categories of financial assurance, the Oil Conservation Division shall consider the depth of the well involved, the length of time since the well has produced, the cost of plugging similar wells, and such other factors as the Oil Conservation Division seems relevant."

In drafting a rule before the Commission, the statutory requirements are really taken to heart, and we have tried to develop the most fair and equitable proposal while also considering the Division's actual plugging costs in conjunction with the Division's compliance efforts and potential risk exposure.

With the above in mind and having undertaken over the past several years an analysis of the Division's expenditures due to underbonding of well plugging, we worked to develop new appropriate financial assurance levels. On that note and before diving into the proposed changes, it may be helpful to look at Exhibits 3 through 7 at this time, which I believe are in the packets before the Commission.

So if we could start with Exhibit 6, what I did here is I pulled from fiscal year '14 all the wells that the Division has plugged since fiscal year '14 until a certain time in fiscal year '18. And I can't tell you exactly when I stopped in fiscal year '18. I believe it was sometime in February or March. And you'll see all wells listed by API, depth and the total plugging costs and the price per foot and the fiscal year the well was plugged.

Then this data was plotted in Exhibits 3 and 4 in your packet. Exhibit 4 excluded some of the unusually high outlier well plugging the Division saw. You'll see one for $140,000, $146,023, and some of the really shallow wells of 45 feet, which cost $50.89 per foot. I didn't think it was really fair, in contemplating a rule change, to include those very high outliers.

Then if you turn to Exhibit 5, I wanted to see what our fixed costs, plus price per foot looked like with different fixed costs. And since we have mobilization costs and other expected costs in every plugging job, bearing those minimum costs in minds and in consideration of our statutory duty, I wanted to develop an appropriate cost -- an appropriate single-well bond amount, and that's how we came up with $25,000, plus $2 per foot.

Then if you turn to Exhibit 7 in your packets, this is a list of operators as of June 28th, 2018 who are not compliant with our inactive well rule. There are 136 operators on this list, with a total of

1,738 wells out of compliance.

As a matter of reference, when an operator continues to be out of compliance with the Division's inactive well rule and fails to come into compliance, whether it be by plugging the well, bringing the well back in production or entering into an agreed compliance order with the Division, the Division pursues a compliance case against the operator, and we seek a plugging order. When the operator fails to plug the well, the Division plugs the well, and then if the operator has financial assurance, the Division first seeks to recover under the financial assurance, which the Division is the beneficiary of. And then as the Oil and Gas Act under 70-2-14(e) allows, the Division will bring suit for indemnification for all costs incurred by the Division in plugging the well.

So I'll just point out some of these operators in Exhibit 7 because I think that could be helpful. Some Commissioners may not be familiar with some of these operators. So Canyon E & P on this list, they have 271 inactive wells showing up, and we have a plugging order against this company. And they went through bankruptcy, and we aren't going to recover anything further from this company.

Then the same can be said about DC Energy, LLC. So there is a broad range of small operators to larger operators. DC Energy, they also went through bankruptcy, and the Division recovered $50,000. Again, we're not going to recover any other funds from this operator, and we still have six wells to plug, along with any reclamation.

Giant Operating, LLC is yet another operator -- operator the Division is left with recovering -- covering plugging costs. The operator went through a receivership, and the Division received $37,000 from the receiver. Giant still has five wells to plug.

Then we have a number of operators on this list with 100 percent of their wells inactive and have plugging orders or have a very high number of noncompliance rates with our Legal Bureau. And I can anticipate, based on history with the Division, the Division will have to plug these wells, and the cost will be paid out of the oil reclamation fund.

For instance, Dominion Production Company, LLC, the Division has a pending district court case against the operator for inactive well violations and for violations of financial assurance rules, amongst other violations. Dominion has 126 noncompliant wells and requires additional financial assurance on 62 wells.

Blue Sky NM is another operator we filed suit against in district court. They have 32 wells in need of additional financial assurance and 38 inactive wells.

So just Blue Sky and Dominion alone, we're looking at millions of dollars in plugging costs that will come out of the reclamation fund. So by illustration, there are several noncompliant operators for which we turn to the reclamation fund to fill the gap when financial assurance isn't enough. And we have really stepped up our compliance efforts, and, therefore, we will have a lot of operators whose wells will be added to the plugging list. Since February of this year alone, we have added hundreds of wells onto the plugging list, and at present, we have about 500 or so wells on our plugging list with only a million and a half or $2 million in bonding to cover our anticipated plugging jobs.

So with that said, I'll go back to the rule before you. If you turn to 8.9C. and D., I have attempted to add a lot of clarity for operators, as the existing language is confusing. Our bond administrator was just back from maternity leave, and I filled in for her for several months. And I had the pleasure of interacting with a number of operators during this time, and I saw a lot of the confusion and frustration that they faced, so I think this does a nice job of cleaning up the rule for them.

So Subsection C sets forth the financial assurance requirements just for wells that have been producing within the last two years or which is in new, not in approved temporary abandoned status. Consistent with statute, an operator can either post a single-well bond or a blanket bond for the wells produced within the last two years.

Thus, we propose striking the existing Subsection C and replacing it with the words "the division accepts the following categories of financial assurance for wells that are not required to provide financial assurance under Subsection D of 19.15.8.9 NMAC: (1) a one well financial assurance in the amount of $25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well";

Or "(2) a blanket plugging financial assurance in the following amounts covering all oil, gas or service wells drilled, acquired or operated in this state by the principal on the bond: $50,000 for one to 10 wells; $75,000 for 11 to 50 wells; $125,000 for 51 to 100 wells; $250,000 for more than 100 wells."

I did an analysis of the 613 operators in

OCD's database, and for reference, there are 348 operators in the one-to-ten operator range. That's 56.7 percent of all of our operators. There are 145 operators in the 11-to-50 range, which is 23.6 percent of all of our operators. Forty-eight operators in the 51-to-100 range, which is 7.8 of all of our operators, and 72 operators in the greater-than-100 range, which is 11.7 percent of all of our operators.

Of those operators, I further determined how many operators as of July 16th are currently out of compliance with our existing financial assurance requirements. In the one-to-ten well range, 40 operators are out of compliance with our financial assurance requirement, which is 50 percent of all of our operators who are out of compliance with our financial assurance requirements. Twenty-eight operators in the 51-to-100 well range are out of compliance. That's 35 percent of all of our noncompliant operators. Two operators in the 51-to-100 range are out of compliance with our financial assurance requirements. That's 2.5 of all noncompliance operators. And ten operators in the over-100 range, and that's 12.5 percent of all noncompliance operators.

And I will point out, too, you know, when I ran those numbers -- and this was done after we filed this application -- it was kind of striking to see such a small number of operators, 7.8 percent, in that 51-to-100 range. And from an administrative perspective, initially I had contemplated three tiers in C.(2). And I thought, you know, we want to be fair and equitable. That's always a consideration of the Division in developing tiers. So we did come up with a fourth tier in consideration of the broad range of operators that do operate in this state. So we did add a fourth tier. But from an administrative standpoint, we can't have -- it would just be way too burdensome, and there would be too many operators coming in and out of compliance, and we do have so many compliance problems from a bonding perspective, so too many tiers would be problematic, but we did add that fourth tier in.

I did also review IPANM's proposed breakdown for 8.9C.(2), and for reference, what their proposed range is, the breakdown of operators would be as follows: The one-to-ten range, that would stay the same because it's consistent with what the OCD has proposed. In the 11-to-99 range, there are 193 operators, which is 31.2 percent of all of our operators. In the 100-to-149 range, there are 13 operators, which would be 2.1 percent of all of our operators. In the 150-to-199 range, there are ten operators, which is 1.6 percent of all operators. And in the over-200 well operator range, there are 49 operators, 8 percent of all operators.

So with IPANM's proposed breakdown, 56.6 of operators would see a reduction in their financial assurance with the Division. 31.5 percent of operators would see no change in their blanket bond. And that's -- just under 12 percent of operators would see an increase in their blanket bonding. And despite the number of noncompliant operators in our statutory mandate, 56.6 percent of operators would see a decrease in their financial assurance with that proposal, which caused me a little bit of heartburn with the plugging costs that the Division has seen and the out-of -- out-of-pocket expenses out of the rec fund that I have seen.

So moving on to 8.9D., we strike the existing Subsection D and add clarity to this section. We eliminate the distinction based on most producing -- on the most producing counties, since this is not relevant, and actually can be more expensive to get a plugging range out to areas like the Bravo Dome and eliminate the administrative headache of allowing up to a 500-foot variance in well depth.

This subsection then sets forth the financial assurance requirements for wells that have been inactive for more than two years and keeps the same plugging financial assurance for temporarily abandoned wells that the Commission adopted in rulemaking about three years ago, I believe. The only addition to this section is the proposed rule requires that any well the Division places in approved temporary abandoned status, pursuant to 19.15.25.13 NMAC, must also place the normally required additional financial assurance required after two years.

Then we have added a Subsection E, which clarifies how depth is measured, and Phil can answer any table questions regarding this subsection, since he will be discussing those two terms.

Then in 19.15.8.14 -- it's the "Effective Dates" provision -- the Division proposes the following language: "The 2018 amendments to 19.15.8.9 NMAC apply to applications for permit to drill, deepen or plug back and applications for approved temporary abandonment filed on or after July 24th, 2018, and for all other wells on October 31st, 2018." This will allow operators with existing financial assurance a grace period to come into compliance and work with the banks or surety companies to provide the Division with correct financial assurance.

Then if we move on to 19.15.25.12, in this section the Division proposes to limit the number of wells an operator can place in approved temporary abandonment. After this application was filed, I noticed we just need to clean up the proposed sentence a little. I'd suggest a little language change here. I propose the following: "The operator is limited to the number of wells it can place in approved temporary abandonment status as follows: (A) one well for one to five wells; (B) 33-and-three-tenths percent for more than five wells."

In the language before you, the third percent would be difficult from an administrative perspective because a third is obviously an unknown number, and the introductory prepositional phrase causes a bit of confusion, and the proposed language to adjust it would make it a bit easier and clearer, I think, for operators. So --

MR. BRANCARD: Could you go over that language again?

THE WITNESS: Sure. "The operator is limited to the number of wells it can place in approved temporary abandonment status as follows: (A) one well for one to five wells; (B), 33-and-three-tenths percent for more than five wells." The actual meaning and intent doesn't change. It just adds some clarity.

Then if we move on to 19.15.25.13, here in Subsection B, we've added the words "a permit for approved" before the words "temporary abandonment," since we are, in fact, granting a permit. And this provides clarity to the subsection.

Then in Subsection E, we have clarified that "no permit shall be approved until an operator has complied with Subsection D of 19.15.8.9 NMAC, which requires the financial assurance to be posted before approval of the approved temporary abandonment permit." And this really protects the Division in a lot of ways. From a compliance perspective, I see a lot of cases where we bring plugging cases against an operator who have no additional financial assurance, and the well is in expired temporary abandonment status. And a well can be placed in approved temporary abandonment status for five years, and an operator can encounter financial difficulties during this time. Since the status allows an operator to allow the well -- since this says allows an operator to allow the well to not produce, this gives the Division more protection from the onset so we don't have to chase down additional financial assurance in seven months when the well hits the two-year mark, which statutorily requires additional financial assurance at this time.

Certainly when a well is producing, there is less likelihood of a wellbore deteriorating, and an operator knows if there are any problems with the well -- with a producing well.

When a well is inactive, the risk of something happening to the wellbore increases, and the risk of damage to a producing zone or the migration of hydrocarbons or other leaks increases. During a five-year cycle, there is no way to monitor the wells if anything is happening with the wells, so this provides more protection to the Division.

These are all of our proposed changes.

Q. (BY MR. BROOKS) Well, I need to ask you some questions about them because I don't understand it very well myself. The test of whether a presentation is sufficient is whether the dullest person in the audience understands. So assuming I am in that category, I do need to understand.

One thing this -- this rule has not specifically discussed is it increases the amount of certain financial assurances, right?

A. Correct.

Q. It increases the amount pursuant to legislative authorization --

A. Correct.

Q. -- at the last regular session of the legislature?

This rule would increase the amount of the blanket plugging bond required of an operator who has no wells in temporary abandonment status, correct, from 25,000 to 250,000?

A. I'm sorry?

Q. I'm sorry. Yeah. It increases the amount of the blanket bond required of an operator that has no wells in temporary abandonment status, correct?

A. If an operator has a well in approved temporary abandonment status --

Q. No. That's not what I asked you. I'm sorry.

Suppose an operator has no wells in temporary abandonment status. Under present law, what is the required blanket bond of that operator if the operator chooses to use a blanket bond instead of single-well bonds?

A. $50,000.

Q. And what would it be under this new rule?

A. It would depend on the number of wells that an operator has.

Q. Okay. Let's assume the operator had 15 wells.

What would it be?

A. $75,000.

Q. And that schedule is found in 8.9C.(2) of the proposed new rule, correct?

A. Correct.

Q. And depending -- and if you want to know what the blanket bond is required of an operator regardless of the existence of temporary abandoned wells, supposing he has none, you go to 18 -- you go to 8.9C.(2) of the proposed rule and look at how many wells does the operator have. You've got to figure that's the amount of blanket bond that will be required to provide under this new rule, correct?

A. That's correct. And just to clarify -- I just want to bring clarity to the term "temporary abandoned." It simply means an inactive well.

Q. Correct.

A. So an inactive well, regardless, will be included in this well count. But I don't think -- I don't think we need to make any distinction over whether a well is temporary abandoned or not.

Q. Well, not -- I assume they were not temporarily abandoned. Merely to clarify what purpose, but your point is very -- what is the -- the bonding requirement in that situation, but your point is well taken.

The existing $50,000 bond and the -- under the existing rule and the revised -- the amended $50,000 bond required under 8.9C.(2) would apply based on the number of wells regardless of how many of them may be in inactive temporary abandonment, correct?

A. Correct.

Even if they're in approved temporary abandonment, the blanket bond -- if an operator chooses to place all of their wells under a blanket bond, if they are in approved temporary abandonment, that just requires additional bonding.

Q. Yeah. Well, I'm going to get to that in a minute. I'm trying to go through this step-by-step.

Now, an operator under present law and under the proposed rules has the option of putting a single-well bond on each well that he has --

A. Correct.

Q. -- instead of using a blanket bond, right?

A. Correct.

Q. But it's seldom to the operator's advantage to do that, correct? Most operators have a blanket, don't they?

A. Most operators have a blanket bond.

Q. Okay. Now, when it comes time to -- when an operator has wells that go inactive and they stay inactive for two years, they are deemed to be in temporary abandonment status for two years, correct?

A. Correct.

Q. At that point, whether or not the operator has applied -- well, if the operator had applied for temporary abandonment previously under the existing rule, no bonding would have been required at the time of that application for temporary abandonment, correct?

A. For approved temporary abandonment, we have not previously required financial assurance at the time of application.

Q. Right.

Now, if a well -- this is perhaps where I'm missing -- where I need clarification, maybe where I'm misunderstanding.

If a well is placed in approved temporary abandonment, under the present rule, without regard to these amendments, and then the two years passes and that well has been in temporary abandonment status for two years, it's been approved maybe for two months but the approval is still current, is the operator then required under the present rules to provide additional financial assurance?

A. All operators, whether a well is in approved temporary abandonment status or temporary abandonment status, which is just synonymous with inactive, are required to post additional financial assurance after two years.

Q. Even if a well is in approved temporary abandonment status at that point?

A. Correct.

Q. Okay. That was a misunderstanding. And because I was dealt with this some time ago and there have been several amendments to the rule, that's probably the source of my misunderstanding.

A. That's okay.

Q. So additional bonding is required for wells that have been in temporarily abandonment status for two years under the present rule and under the new rule regardless of whether they are approved for temporary abandonment or not?

A. Yes, with the caveat that any well under the proposed rule to be in approved temporary abandonment status will require additional financial assurance in order to get that approval. But yes. Any well in the state of New Mexico that is on private or state land will require -- does require financial assurance after two years, and if it is to be an approved temporary abandonment status, will require additional financial assurance under the Division's proposal in order to get approval.

Q. Well, but you said two different things there. And I'm trying to get this clear, and I'm still not clear. And I thought I was until you answered the last question.

Let's say well X is inactive. Two years passes. It's still inactive. No application for temporary abandonment has been filed. Then when the clock hits two years, the additional financial assurance requirement kicks in, correct?

A. Correct.

Q. But that's not because the operator doesn't have financial assurance because the operator does have financial assurance. They have to have additional financial assurance because that well is in temporary abandonment status, correct?

A. Correct.

Q. Okay. And that's true under the old rule, and it's true under the new rule?

A. Correct.

Q. Now let's say the well was completed on November the 1st, 2016. Well, no. Let's go back so we're under the old rule. The well was completed on November the 1st, 2015. On November the 1st, 2017, it would have required additional financial assurance?

A. It's over two years, so it would be November 2nd, 2017. Yes.

Q. Okay. November 2nd. I stand corrected.

That is still true under the new rule if the operator has not applied for temporary abandonment status before November 2nd, 2017 for that well, correct?

A. That's correct.

And I will amend my answer to say I did not consider whether this is a leap year or not of any other years, so that's not a consideration. And I don't know if our I.T. people consider leap years or not.

Q. I don't either. We'll assume they don't for purposes of these illustrative questions.

A. And I --

Q. Okay. Now, under the new rule, if, on October the 1st -- let's say instead of 2017 -- 2015 and 2017, it's 2016 and 2018. The well was completed November 1st, 2016. On October 1st, 2018, after this rule has presumably gone into effect, the operator files for temporary abandonment status. At that point, under this rule, the operator would be required to file additional bonding, correct?

A. If the operator applied for approved temporary abandonment status.

Q. That is what I asked.

A. Yes.

Q. Okay. But if he files that additional financial assurance with his application, then November the 2nd comes around. The operator is -- and the well has been, then, in temporary abandonment status for two years, he is not required to file -- I do not understand if he is required to file further additional financial assurance, is that correct --

A. Correct.

Q. -- or he has additional financial assurance in effect?

Now, let's go back and get the thing that I was mixed up about in the first place and get it straightened out.

On November the 1st, 2015, while I was up in Durango, this operator completed a well. On October the 1st, 2017, the second year after I had come back from Durango, this is the third, the operator filed an application for temporary abandonment, but the well was not at that time in temporary abandonment for two years because it only been temporary abandonment for 23 months. Under the old rule, he was not -- he or she was not required to file an application for -- an additional bonding with the application for temporary abandonment, right?

A. That's correct.

Q. But 30 days later, when November 2nd -- 32 days later, when November 2nd rolls around, then the operator was required -- it would have been required by the existing rule to file temporary -- to file additional bonding on that well?

A. Correct.

Q. Okay. That was what I was confused about, because there was one stage in the sequence of amendments in this rule when that was not the case, but I lost track of what was happening with this rule between then and the adoption of the present rule apparently.

So the only thing -- the only thing the present rule changes in regard to the requirement for additional financial assurance, other than the amounts, is that if you file an application for temporary abandonment before you are required to file -- that is the two-year time -- or before you have, in fact, filed a temporary -- a required temporary assurance -- a required additional bonding for temporary assurance -- for additional financial assurance for temporary abandonment -- I'm sorry. I've got to get my wording right. If you request approval of temporary abandonment, at the time you make that request, either you're not yet required to have additional bonding on that well, or, two, you are required, but you haven't done it, in either of those situations, you have to file an additional bonding at the time that you apply for temporary abandonment, correct?

A. At the time you apply for approved temporary abandonment permit, you'd have to submit additional financial assurance. And under 5.9, when an operator does not want the well on the inactive well list, there would be incentive to place it into approved temporary abandonment to reduce its non -- potential for noncompliance with the inactive well violations.

Q. Okay. And that is the reason why we want to make it a condition precedent rather than simply a condition to get that additional bonding in place because that's the best time to get him to -- that's when the operator has the best incentive to file -- to comply?

A. That's correct.

Q. Now, we have a lot of operators who do not comply with that additional financial assurance requirements when their well's been inactive for two years?

A. That's correct.

And that's where I did a breakdown earlier in my testimony. In the one-to-ten operator range, 50 percent of our noncompliant financial assurance operators -- of our noncompliant financial assurance operators, 50 of those operators are in the one-to-ten operator range. And I can go back to my numbers if desired. But yes.

Q. Well, you don't need to go back through the numbers. But if that's the case, the well is inactive, the operator has not complied with the additional financial assurance, and either it is in temporary abandonment status or the operator is not approved for temporary abandoned status or the operator has not applied for that status, then the only way to enforce the requirement is to file an enforcement action, correct?

A. That's correct.

And oftentimes we bring -- we'll bring compliance actions and whether -- we either will bring a financial assurance compliance case or a plugging case, and we still won't get compliance from those operators. We won't get them to post the additional financial assurance. Sometimes we do. Sometimes we don't. We have had a lot of success with the Division's internal efforts to get -- get operators to come into compliance.

But once we have to refer it over to Legal, we'll have orders for operators to post their required financial assurance. But if they don't, we'll be left with operators who need to post the additional financial assurance, but then the wells are also inactive. So we are left with insufficient financial assurance and a plugging order for those wells.

Q. Okay. Now, the amounts for -- well, if an operator has more than one inactive well, it would be kind of a moot point for only one. But if it's more than one inactive well, the operator has a choice, does he not, under the present rule and under the new rule to file a blanket plugging bond for temporarily abandoned wells under 8.9D.(2) or to file an individual bond -- a one-well bond for each temporarily abandoned well, correct?

A. That's correct.

Q. And have the amounts of the required blanket bonds for -- for corresponding to the number of temporarily abandoned wells been changed by the new rule?

A. The amounts for the blanket plugging financial assurance for temporarily abandoned status wells under D.(2) have not changed since my testimony before the Commission about three years ago. I think they are still sufficient.

Q. So the proposed rule would make no change in the present rule for that particular -- those particular amounts?

A. Correct.

Q. And, of course, the schedule in C.(2) for blanket bonds for all wells is a new schedule because we had a plat amount before by statute?

A. That's correct.

Q. Okay. Now, the amounts of a one-well bond have been changed -- or are proposed to change; are they not?

A. That's correct.

Q. And what will be the new amounts for one-well bonds? Well, before you answer that question, let me clarify. The amount for one-well bond, is that the same amount if you choose to use one-well bonds for all your wells as it is for a temporarily abandoned well?

A. For one-well bonds, that's correct. Yes.

Q. And what is that amount?

A. $25,000, plus $2 per foot. And that's based off of our statutory duty to determine the appropriate well plugging costs.

Q. And you have already testified to the fact that we have made a study of well-plugging costs and that those figures are justified pursuant to that study?

A. Yes, based off of our downhole plugging costs, and those are reflected in Exhibit 6.

Q. Again, you'll have to pardon me because I'm a Texan and I speak very slowly, and when someone speaks very fast, I'm not sure if I'm covering everything or not because I lose track. I haven't developed the talent to speak both Texan and American --

A. I'll try to speak Texan.

Q. Well, I'm not sure there's much hope for you (laughter). But New Mexico is not Texas. Somebody around here used to have a sign that said, "I know how you do it in Texas. Now let's talk about how we do it in New Mexico."

Okay. I think I've covered all the questions that I have, and I think I now understand what you're doing. So I will move on to a couple of other things.

You did cover, specifically, the fact of the 500-foot tolerance on the depth bracket. In other words, it used to be if you have -- if a well goes 500 feet below the depth bracket for which -- waiver for additional bonding is required when going into the next depth category, correct?

A. The district office had that ability and we -- it was very difficult from an administrative perspective to manage that.

Q. And you propose to eliminate that?
A. Correct.
Q. Okay. Now, you also -- also, the district office had discretionary authority to waive the additional bonding requirement for inactive wells if a well was inactive because of the lack of a pipeline connection? That's a part of the existing rule, right?
A. Let me see. We've actually never had that request. I don't -- I mean, I don't know if it's the district office or if it's Santa Fe, but --
Q. That's in existing 9.C, I believe, but I don't have my rule book with me.
A. It says "the division," but it's not specific to a district office.
Q. Well, it doesn't matter.
A. But yeah, we propose to eliminate that.
Q. But you propose to repeal that entirely?
A. Correct.
Q. And if it's inactive for any reason, it's inactive under the proposed rule?
A. Correct.
Q. Okay.
MR. BROOKS: I believe I've covered all the things except those I'm supposed to cover with Mr. Goetze, so pass -- I will pass the witness.

Oh, I need to get the exhibits tendered. I would tender Exhibits 1, 2, 3, 4, 5, 6 and 7.

Q. (BY MR. BROOKS) Before I do that, were these exhibits prepared by you or under your direction from OCD records?

A. They were.

MR. BROOKS: I tender Exhibits 1 through 7.

CHAIRWOMAN RILEY: Exhibits 1 through 7 can be accepted into the record.

(NMOCD Exhibit Numbers 1 through 7 are offered and admitted into evidence.)

MR. BROOKS: And I will pass the witness.

MR. LARSON: No objection (laughter).

(Laughter.)

MR. BROOKS: To the exhibits or me passing the witness?

MR. LARSON: No objection to the exhibits.

CHAIRWOMAN RILEY: Thank you, Mr. Larson.

CROSS-EXAMINATION

BY MR. LARSON:

Q. Good morning, Ms. Marks.

A. Good morning, Mr. Larson. I don't think you could be any more difficult than my own attorney (laughter).

Q. You mentioned a number of operators in the one-to-ten well category. I'm afraid I didn't catch that number, 300 something.

A. Sure. 348.

Q. And what was the percentage of the total number of approved operators?

A. 56.7.

Q. Would you agree with me that the reclamation fund is the primary source of funds for the Division to plug wells?

A. For the Division to plug the wells, generally the reclamation fund is the primary source. During fiscal year '18, I believe, the Division does not have sufficient funds to plug wells out of the reclamation fund, so we relied on a federal grant and plugged -- I believe Commissioner Martin would know this. We've only plugged, I believe, four or five wells that were nonfederal wells because of unfortunate gross deficiencies in the reclamation fund. So we plugged significant federal wells under that grant.

Of course, statutorily -- and I have the -- I have the statute in front of me. The funds should come out of -- should be coming out of an operator's financial assurance.

Q. And during fiscal year '18, were any redeemed bonds used to plug wells by the Division?

A. I'd have to look, of the four wells that we did plug, if we -- if there was any financial assurance on file, we would have redeemed those bonds. I don't believe we've plugged any in the northwest. But at $5,000, plus $1 per foot, that's not much financial assurance. We would have maybe redeemed $28,000, at max, assuming every operator would have had financial assurance in place.

Again, with the number of operators who fail to comply with our financial assurance requirements, unfortunately -- and I've been -- we've been plugging a number of Canyon wells. Unfortunately, we've plugged a number of wells where the operator does not have bonding in place. So we plug out of the reclamation fund 100 percent as the plugging costs come out of the reclamation fund, and we don't have any financial assurance to offset any of the plugging costs. So even with the increase -- proposed increase in financial assurance, a lot of the expenses will still come out of the reclamation fund.

Q. Does the Division have an enforcement mechanism to prevent an operator from being out of compliance with financial assurance?

A. Sure. Of course. And we -- we -- our dockets are very full. I believe we have 102 cases on our docket. Poor Florene over there. And we take -- we take compliance very seriously, and we've really stepped up our financial assurance compliance and our inactive well compliance, which it's a double-edged sword.

When we increase our inactive well compliance, our inactive well -- our plugging list continues to grow. We didn't have much of a remedy before and now -- but we have to do our -- take over our statutory duty to protect human health, the environment and safety. And so in doing so, our plugging list continues to grow, and that will inevitably lead to more expenditures out of the reclamation fund to cover those plugging costs. And despite the best efforts of our legal department and our internal OCD efforts to bring operators into compliance, there will always be operators who are out of compliance.

We see oil prices. They go up. They go down. And when oil prices go down, unfortunately, we have a lot of operators who just walk away. The best operators will go through a formal bankruptcy or a formal process to wrap up their businesses, but a lot of times, the Division will be left holding the bag to plug those wells or the operators are noncompliant. We have operators that aren't formal business entities. They're just sole proprietors. They, unfortunately, pass away.

They haven't done the -- with probate estates or don't have the most formal probate processes, and so we don't file a claim in their estate. So in those cases, we don't receive the financial assurance, and we have to plug those wells as well.

So yes, despite phenomenal efforts, I believe by the Division and our Legal Bureau, unfortunately, we can't have 100 percent success rate, and the reclamation fund is used for its intended purpose, to offset those costs.

Q. And who contributes to the reclamation fund?

A. Oil and gas operators in the state.

Q. And what's the formula for those contributions, off the top of your head?

A. If you give me a minute, I can go pull the statutes. If you have the statutes with you, I can --

Q. I don't.

A. Or I'd ask the Commission to take notice of whatever is in the statute under -- it's based off the price of oil. When the price of oil is over $70 a barrel, it's one factor, and under, it's another.

Q. So it's a certain fraction per dollar of oil produced, generally speaking?

A. Yes.

Q. And would I be correct to say the same operators who are required to post blanket and/or single-well bonds are also contributing to the reclamation fund?

A. That's correct.

Q. And exactly what wells does the Division plug with reclamation fund money?

A. Are you asking for a priority of wells or wells on state lease land, private land?

Q. Type of well.

A. Oil and gas wells, generally.

Q. And are they orphaned wells?

A. Yes, and any well that an operator -- that we received a plugging order for.

Q. Okay. When you say a plugging order, that's going to Division hearing, getting an order requiring the operator to plug the well?

A. Correct. And if an operator is noncompliant with said order, then we would go and plug the well.

Q. You mentioned priority. Could you go into some detail on that?

A. Sure. If there's -- if there's a well that would affect human health, safety, the environment, water, those are certainly our top priorities. We take those statutory duties very seriously, and we do everything -- everything within our power to make sure we do protect any -- any water zones and any -- we make those wells the absolute most priority -- highest operator priority.

After that, we would look to see about old wells in certain areas. We try to keep our costs down. We'll go into a certain unit and plug a number of wells within that unit all at once. It wouldn't make sense to go just jump all around to different units. So we look to see if an operator does have bonding, especially with -- I have our numbers from the reclamation fund. But when our reclamation fund was down to, you know, $3 million -- presuming we're paying salaries out of there -- we couldn't -- we tried to maximize the amount of plugging we could do with -- at our lowest cost for an operator who did have bonding in place. We would try to plug wells that had financial assurance in place and use as little of the reclamation fund as possible.

Q. And for these plugging orders that you mentioned, do you redeem those operators' single-well or blanket bonds if they have them?

A. Of course.

Q. And do you know roughly the current balance of the reclamation fund?

A. I have -- let's see. As of June 30th -- I think as of June 30th, 2018, I believe it is $5,774,700.

Q. And that money is earmarked for plugging costs?

A. No. That's the total balance of the reclamation fund. In fiscal year 2019, I believe we have $2,181,000 earmarked in contractual services, which plugging costs would fall under.

Q. What about the remainder of the balance?

A. Actually, this probably does not -- let's see. The balance -- in general -- in general, we don't -- we don't earmark the entire -- that would be my quick math here. We do have some operating costs as well that comes out of there. We only had 100-and-something-thousand dollars this year. We did a -- it was great this year of only having about $145,000 per month come out of the reclamation fund for salaries this year.

We never earmark the entire reclamation fund. We never spend down the entire reclamation fund every year. That would -- that would be ill-advised from a budgetary standpoint. We also -- and, again, that's just for the downhole plugging. Usually we do earmark some monies, and we set aside some monies for reclamation efforts.

So, again, we talked about prioritizing wells based off of public health, safety and the environment. We do have -- we do use money from the reclamation fund for cleanup and environmental matters as well. So we've been very fortunate not to have any matters in need of environmental cleanup, but we do set aside funds in the reclamation funds to address environmental matters that may come up that can be very expensive. And so it's nice to keep money set aside in the reclamation fund to clean up sites. And we have plugged and not released a number of sites. And if the fund balance were to continue to grow in the reclamation fund, we could certainly clean up a number of additional sites and then release those sites and continue to clean up a lot more sites from the reclamation fund, which is an additional purpose which the fund is allowed to use as opposed to just downhole plugging.

Q. And does the legislature allow the Division to carry forward the balance from the previous fiscal year?

A. Yes, it does. It's nonrecurring funds.

Q. And does the Division have access to the Office of Natural Resources trustee for environmental and surface-location issues?

A. I would have to get back to you on that.

Q. You mentioned, in looking at particular operators in one of your exhibits, that several of them declared bankruptcy or had gone into receivership, and you mentioned funds received. Are those based on proofs of the claim, for instance, in the bankruptcy?

A. Yes.

Since I've -- before becoming deputy director, I worked in the Legal Bureau with EMNRD and was in charge of a lot of bankruptcy matters, and in the deputy director position, I have worked in conjunction with the Attorney General's Office on bankruptcy matters. And we've done a great job of being much more proactive in filing claims in bankruptcy matters. So we will certainly file a proof of claim in all bankruptcy matters and have been diligent in converting claims to administrative claims when applicable. So an unsecured claim -- for example, in Vanguard, we filed an unsecured claim. Obviously, there is no need to convert that claim to an administrative claim, but --

Q. Are those claims to cover plugging costs?

A. It depends on the nature of the claim, but yes. If it's an administrative claim, certainly.

Q. And do you have a sense of the Division's success rate in terms of proof of claims that are filed in bankruptcy?

A. Could you clarify success rate?

Q. How many times do you receive funds from a bankruptcy estate?

A. If it's -- it depends on the amount of monies in the bankruptcy estate and how well funded the bankruptcy estate is. A lot of times, unfortunately, some operators aren't well funded in their bankruptcy estates.

In the DC Energy case, unfortunately, when we received $50,000, that certainly wasn't enough to cover our very large claim that we filed in that case, and we were in the administrative claim in that case. Administrative claims, obviously, are paid before even a priority claim. We got paid before -- before Tax and Rev. So I think we've done a great job in getting paid. It's a matter of what per- -- what percent on every dollar we are getting paid. But our success rate -- I think we're batting 100 on our success rate in getting paid, if we get a penny for every dollar, but I don't know if I'd say that's successful.

Q. You and a lot of other unsecured creditors.

Does the Division track the number of its blanket and/or single-well bonds that are redeemed for plugging costs?

A. Historically -- historically, I don't believe we had. We have -- we have now started to track the number of bonds that aren't redeemed. We have developed -- about a year and a half ago, we worked with our I.T. department to develop a new bonding module, which develops bonding compliance reports and also tracks every bond that comes in -- into our system. It's readily available for the public to see, and also any redemptions to any bond are also available. So if you look up any well, you will see -- say it's a $50,000 bond. You'll see the remaining balance on that bond.

Q. And what's the Division's process for retaining plugging contractors?

A. We go through our mandate through the State. The contract goes out to bid, and we receive bids from any -- any and all contractors that are interested. Unfortunately, during the last -- the last offer about a year ago, we -- we had two interested pluggers. We tried to get a second plugger in the southeast even to bid on the contract, and we were unsuccessful in doing so. So it's very difficult to compete with industry. We go through -- you have to do a purchase order, and then you wait for payment, and I think industry pays a lot faster than we do. And to bid on the right -- purchase order and a lot the paper associated with working with the State sometimes can be a lot more difficult than working directly with a company.

Q. Does the Division attempt to have a plugging contract to plug multiple wells and, therefore, get a discount on the per-well plugging costs?

A. We -- when we talked about prioritizing wells, we certainly looked into certain units, and that brings down our costs. And what we also do is we always try -- under the Oil and Gas Act, we are allowed to offset our plugging costs with salvage. And I actually have an invoice right here on a well.

So actually in Exhibit 6 before you, those costs actually reflect the salvage equipment offset. So the true -- true costs of plugging a well are actually more, but the -- the plugger automatically deducts all of its salvage -- salvage costs in the invoice. So those are reflected in Exhibit 6.

But in this last -- last invoice I received on April 23rd -- I just pulled the latest one from one of our budget people, when I talked -- to be honest, there was salvage -- let's see -- about $633 in salvage costs there. And sometimes it can be $2,000. Sometimes you show up to a site and all the tubing and everything has been stripped from the site. So there is no way to know until our plugger actually goes out to a site.

Q. And I'll direct your attention to your proposed tiers under 19.15.8.9.C.(2), tiers for blankets bonds. Do the well counts included in the Division's tiers have fee, state and federal wells?

A. Yes, they do.

Q. And aren't federal wells subject to BLM bonding requirements?

A. They are. An operator is not required to post additional single-well bonds or post single-well bonds with the Division for any federal wells. And if an operator has all federal wells, then they would not be subject to place any blanket bond with the State.

Q. For an operator that has a mix of fee and federal wells, did the Division consider excluding the federal wells from that well count category?

A. No, it did not.

Q. Why is that?

A. Our total well count always has included federal wells. When we do our inactive well rule, all well counts consider the federal wells.

Q. And along those same lines, has the Division considered excluding wells with single-well bonds separate and apart from the blanket bond in the well counts, in the tiers you proposed?

A. I'm sorry. Can you repeat that?

Q. If an operator is submitting a blanket bond and also has, say, two single-well bonds, did the Division consider deducting those two wells with single-well bonds from the total well count?

A. No, it didn't. I think administratively -- I mean, we can go through a number of various scenarios, but administratively, I don't know how difficult it would be.

If you'll just bear with me for a minute, I just want to confirm statutorily what's required on the blanket bond (reading).

I'm just not seeing it -- yeah. Okay. So if you turn to 70-2-14, to your earlier question, (A) to your excluding federal wells, we aren't required. And I think statutorily, the direction is: "Each person, firm, corporation or association that operates any oil, gas or service well within the state shall," and then it talks about financial assurance. So I don't think we are supposed to be excluding any operator's federal wells in our consideration of wells. But that was the intro to 70-2-14.

Q. Do you have a sense of the total number of current orphaned wells that the State intends to plug?

A. Our current plugging list is around 500, and we have, I want to say, about 30 cases pending with our Legal Bureau which -- we had prioritized our referrals over to our Legal Bureau of operators who were noncompliant with 19.15.9C, the inactive well rule, who were still operating in this state because we thought we could get them back into compliance and they would still be solvent and still operating within the state, but they just haven't been responsive to the Division's compliance efforts.

And then after -- because it's problematic -- what's problematic for the OCD has been the fact that operators had inactive wells and then the wells had last produced since 1995, but likely we're not going to get any response from those operators. So in prioritizing those cases, because we can't -- we have one compliance attorney who can't bring 100 cases at once, the next tier of cases are going to be inactive well cases where they are 80 percent inactive, 90 percent, 100 percent inactive.

So I certainly imagine the inactive well plugging list is going to grow significantly from the 500 wells because the operators are perhaps deceased or, again, haven't produced since 2000 or the late '90s or substantially a long time and the wells are 100 percent inactive.

Q. Okay. What in your mind is the distinction between an inactive well and an orphaned well?

A. Inactive well is described in 19.15.2 as a well that's not producing. I don't believe an orphaned well is defined in 19.15.2. I don't have my rule book with me to confirm that, so I don't want to give any testimony of an undefined term.

Q. Sure.

And out of the approximately 500 wells on the Division's plugging list, how many bonds have been redeemed for those wells?

A. I'm sorry?

Q. Of the approximately 500 wells that are currently on the Division's plugging list, how many bonds have been redeemed to cover plugging costs for those wells?

A. We don't redeem a bond until we actually plug a well. And what we do is we plug a well. We see what our actual costs are. We get an invoice, similar to this here. And we'll see that this was a well that was 3,326 feet, and the cost to plug the well was $34,000, $10.22 a foot. And the operator may have a $7,000 bond. If they -- if they had, say, a $50,000 bond, we would send -- our process is we usually send a copy of the hearing order, a copy of the invoice and a copy of the bond to the surety company, and we would make demand for the $34,001 to the surety company. So we would certainly not make demand on any of the bonds on the 500 wells until we knew what the actual cost expended by the Division would be.

MR. LARSON: Madam Chair, I still have more questions, but I would request a break at this time.

CHAIRWOMAN RILEY: That sounds good. Why don't we break for 15 minutes, come back at quarter till, a little less than 15 minutes.

(Recess, 10:31 a.m. to 10:46 a.m.)

CHAIRWOMAN RILEY: I believe we're all here. Let's get started again.

Mr. Larson, do you want do to continue with this witness?

MR. LARSON: Yes. Thank you, Madam Chair.

Q. (BY MR. LARSON) Ms. Marks, what is the increase for the amount of a single-well bond?

A. So if we -- if you refer to my earlier testimony, we have a statutory mandate. Let me pull our language from the statute. "In establishing categories of financial assurance, the Oil Conservation Division shall consider the depth of the well involved, the length of time since the well has produced, the cost of plugging similar wells and such other factors as the Oil Conservation Division seems relevant." So that's obviously a consideration.

There has been inflation, obviously, since 1977. And I don't know the last time that we really did an analysis of all of our expenditures from the reclamation fund. And if we turn to Exhibit 6 and we look at what our expenditures -- and, again, this is just our downhole expenditures and no other -- no other costs associated with plugging, which if we consider those, they would be more. I believe this is very much fair and reasonable and sufficient to cover the downhole plugging costs.

Q. Again what is the Division's average of costs?

A. From FY '14 to present, around 33-, $35,000 per well for the downhole plugging cost.

Q. And what is the average in fiscal year '18?

A. If you would like me to do that calculation, I can do so. I can pull them up from Exhibit 6 and do an average (laughter.)

Q. Do you know off the top of your head?

A. No. It won't take me long to --

Q. Okay. Go for it.

A. We can all do it together. But I have a calculator.

It may be easier if we take a break, and they're on a spreadsheet in my office. These are all mixed by fiscal year here, so it would be easier to break and I just do it quickly as opposed to -- but -- unless we want to just wait, but it will probably take me about two minutes to run up there to do it.

Q. That's okay.

Would it be in the ballpark of 30,000 per well?

A. Certainly no less. On average, it is about 33-, $35,000.

Q. And that's for '14 through '18 or just '18?

A. '14 through '18, it is around $33,000.

And, again -- and I misspoke earlier, because the four wells were for FY '17. In '18, we did plug more state and private wells. But when we worked off of the BLM grant, that was in FY '17, so we were very limited.

But when we have been very limited in our expenditures -- when we've been very limited in our expenditures, again, we've focused on -- you'll see a lot of these depths here. They're pretty shallow wells. And we have SWD wells or wells that are going deeper into the Devonian or deeper wells. The plugging costs are going to be more. So when we've had a lower balance in the reclamation fund, we need to -- we have an LNC [sic] mandate to plug a certain number of wells. We need to meet that. Plus, we also want to plug wells. We're not going to be -- with drilling, we're not going to be plugging a whole bunch of 2,800-deep wells. Wells are drilled much deeper, which means even if we had 30,000 -- you know, 30,000 plugging costs, you can't reasonably expect our costs to be that low going into the future because operators do drill deeper wells than that. But we've been limited in our expenditures from the reclamation fund.

Q. And am I correct to say the Division's also suggesting 100 percent increase in the per-foot cost?

A. I'll defer to your -- I'll defer to your math on that. But, again, I'll state that the per-foot cost and all of our proposed plugging costs are based off of our costs realized and seen by our invoices and what the State has spent from the reclamation fund. And we have a statutory duty to have appropriate financial assurance in place. And, again, those expenditures are just our downhole plugging costs and are not contemplating any other expenditure by the Division.

Q. Is the current rule based on a plus $1 per foot?

A. It is.

Q. And the new rule is $2 per foot?

A. A base amount, plus $2 per foot. And the current amount of either 5,000 or $10,000, plus a dollar per foot has been proven to be grossly insufficient.

Q. At $25,000 base price and $2 per foot, I'm not a math whiz, but it seems to me that you could easily have a single-well bond that exceeds your average plugging cost.

A. Well, I've actually run those numbers. And let me bring up my calculator here. And, again, we don't put a -- we would never make a claim on a bond for more than our actual plugging costs. But let's just go to the exhibit here. So I think there would be certain cases where it may be a couple hundred dollars more, but then there would be cases where it would be very insufficient. So I'm looking at all the 5,000 -- 5,040 [sic]. I'm running those numbers. That would be -- we'd be underbonded there by $3,980.42. And I think if we get to some of the deeper wells, we'll certainly have significant issues. And, again, we're seeing wells drilled deeper and deeper as technology continues to advance.

Q. From IPANM's perspective, the real issue here is how much of the operator's capital is tied up in bonds. So the point I'm trying to make is could you do a single-well bond based on the actual TD of the well, which would be a base amount, plus an amount per foot for those wells that basically overfinance the play?

A. We are proposing a base amount, plus a price per foot.

Q. Okay. But you admit there are some wells where that's going to exceed the Division's average plugging costs?

A. Not significantly. I mean, you're talking a few hundred dollars. But, I mean -- and then there is going to be a much greater -- many greater number of wells where they will be underfunded. So it's a -- it's a case in which a number of operators will continue to be underfunding their plugging costs potentially and, again, just their downhole plugging costs, which the balance would come out of the reclamation fund.

Q. On direct, you addressed the tiers of bonding requirements for blanket bonds, and I believe you testified that too many tiers would create an administrative problem --

A. Correct.

Q. -- is that correct?

And why would that create an administrative problem?

A. So what we do now -- and we've actually tried to do a lot more outreach with operators. We have a list -- and it probably would be -- it would be great if I actually brought this list down and I could just show -- show everybody here. We bring this global bonding compliance list, and this list is pages and pages and pages of noncompliant operators. And what we do as a matter of outreach and to try and work with operators, a lot of times we'll -- first, we'll send a letter to an operator. We'll try to call the operator to get the operator back into compliance. And this is just a matter of an operator not having the required single-well bond in place.

With these different tiers, if an operator acquires the well, gets rid of the well, they'll move within those tiers. So they can easily fall out of compliance with the required bonding, which administratively would be very difficult to -- it would just add to the compliance aspect of getting operators back into compliance.

What we've also done in order to work with operators is we try to give operators the opportunity to enter into agreed compliance orders. You can't enter into an agreed compliance order if you're out of compliance with our financial assurance rules. So we would have operators out of compliance with financial assurance, and then they would -- it would invalidate their agreed compliance orders, which would then make them in violation of our inactive well rule, which would then increase exponentially the number of operators requiring legal action and then force them to get a plugging order against them because they are out of compliance with our financial assurance rules. To combat that on a single-well basis, we're working with operators to post the required financial assurance for the duration of their agreed compliance order.

If we have too many tiers on the blanket bond, it would -- it would kind of limit an operator's ability to transact business from a personal standpoint. I don't like to say, Hey, Operator, you can't buy and sell wells during this agreed compliance order, if they want to acquire wells, sell wells. I don't really want to tell an operator how to transact business in this state. That would be really difficult, and I can envision a ton of problems telling an operator, You can bring your wells into compliance -- we want to work with you to get your wells back into compliance, but now you're out of compliance, and your agreed compliance order is now invalid, and now we're going to have to take action against you. So from an administrative standpoint, that would be, again, very difficult.

And the -- and the percentages are very -- extremely low. So I don't know the utility in having 2 percent or 1 percent operators in certain tiers either.

Q. Doesn't the Division keep current listings of the number of wells that an operator has in the state?

A. Yes.

Q. How often is that updated?

A. Instantaneously. You can bring up how many wells an operator has in the state.

Q. So why would it be difficult to have five tiers? So how you determine, for instance, one to ten, 11 to 50, you could just look at the operator's current well list.

A. Sure. That's true. But then from an administrative standpoint, we would be doing that for all 613 operators on a daily basis, to see if their well count has changed. I mean, we have -- we have a certain full-time employee count, and with our FTE [sic] count, that we couldn't devote an employee to look at all 613 operators every single day to check what their well count is to see if they're in compliance with the bonding rules.

Q. How about at the point in time where a change-of-operator is approved? You or somebody else in the Division is notified there might be an adjustment in somebody's well count.

A. That could -- that could certainly be -- that could certainly be done, but we also have a number of change-of-operators that come in as well. Again, we have very limited resources under our employee count with a -- we are very fortunate to be the number three oil-producing state in the country and with limited employees. Unfortunately, our employee count has not increased with well production increases. If we had increased employees, I think we could devote a full-time employee to this for sure.

Q. So it appears to me that even under the Division's proposed tiers, you have that same issue?

A. Like I said initially, we really wanted three tiers, but we were trying to be considerate of limited financial resources and not affect a tremendous number of people despite the legislative change. So, again, half of all operators will see no change in their blanket bonding. Again, it hasn't been changed in over 40 years.

Q. But the tiers are a new concept, aren't they?

A. I mean, we could just increase it to $250,000 and make it really easy. But I think the tiers are a very -- are an easier way to consider that not every operator could or maybe should be posting a $250,000 bond. I think the legislation allowed flexibility in setting the blanket bond. And so instead of us coming before the Division just asking to raise the blanket of bond from 50,000 to cover all wells in the state, we decided a tiered approach was better than just asking for the increase from 1977 to now, to 250.

MR. LARSON: I'll pass the witness, Madam

Chair.

CHAIRWOMAN RILEY: Do you have any redirect?

MR. BROOKS: Yes.

REDIRECT EXAMINATION

BY MR. BROOKS:

Q. Mr. Larson asked you a question about the primary source of the funds to pay for the plugging of inactive wells. Now, I am looking at Section 70-2-14 of the Oil and Gas Act, New Mexico statutes, and what I find there is that Subsection B of that section says, "If any of the requirements of the Oil and Gas Act or the rules promulgated pursuant to that act have not been complied with, the Oil Conservation Division, after notice and hearing, may order any well plugged and abandoned by the operator or surety or both in accordance with the Division rules. If the order is not complied with in the time period set out in the order, the financial assurance shall be forfeited."

In Subsection C, "If any financial assurance is forfeited pursuant to the division's Oil and Gas Act and the rules promulgated by the act, the director of the Oil Conservation Division shall give notice to the Attorney General who should collect the funds without delay."

Now, I know interpretation of the statutes is somewhat subjective, but does not that suggest -- does not that indicate to you that the primary source to which the Oil Conservation Division should look to provide a source of funding for plugging of wells -- I'm not talking about a source of cash because I understand it's resorted to only after the plugging has been done in practice, and that's another issue. But the primary source that the Oil Conversation Division should look to is the financial assurance.

MR. LARSON: Objection. Calls for a legal conclusion.

MR. BRANCARD: I think the witness can answer. She's a lawyer.

CHAIRWOMAN RILEY: Go ahead.

THE WITNESS: It does. And actually -- in pointing that out, you actually raise another -- you made me think of something else as well. But to answer your question, yes, it does. And Mr. Larson had asked me earlier -- I brought down my rule book just to confirm that there was no definition of orphan, and there isn't. And I will say, when I think of orphan, we go through a whole hearing process, and a well is deemed orphaned after we go through a hearing process and we get a plugging order. And then the operator has its due process before the Division or if appealed de novo before the Division or Commission. But yes.

Q. (BY MR. BROOKS) Okay. I have follow-up on that, and I also have follow-up on my last question. So I'll ask my follow-up on the orphaned well first.

Since there is no definition for orphaned wells, you can't say that anything is or is not an orphaned well unless you first tell us what you mean by orphaned well, right?

A. Right.

And, again, in my -- if I put on my attorney hat, I would say that if an operator -- if an application is filed before the Division and a plugging order is issued, then in that case, there is a whole due process opportunity for the operator. At that point -- there is a plugging order issued at that point. The well would be deemed orphaned.

Q. Okay. Then I have one further. On the primary source, I have one further question.

I read from 70-2-14(B) and (C) and then I go look at 70-14(E), it says, "When the financial assurance proves insufficient to cover the cost of plugging oil and gas wells on federal lands," et cetera, "and funds must be expended from the oil and gas reclamation fund to meet additional expenses," it goes on to say, in that event, you can sue the operator.

Now, my question is: Does not that further reinforce that the legislature contemplated that the loss would fall on the -- would be reimbursed out of the financial assurance, and only then would it be necessary to charge the reclamation fund?

A. I can't speculate as to the intent of the legislature, but that seems like a reasonable conclusion.

Q. Okay.

MR. BROOKS: Pass the witness.

CHAIRWOMAN RILEY: All right. Commissioners?

Ed, would you like to go first?

COMMISSIONER MARTIN: Sure.

CROSS-EXAMINATION

BY COMMISSIONER MARTIN:

Q. Is there a cap on the reclamation fund --

A. No.

Q. -- of how much it can grow?

In your testimony, you mentioned operating cost of the fund. Going forward, what do you consider -- what does the Division consider proper operating costs, and what percentage of that of total expenditures for the year is it? Do you have an idea of that?

A. I can find out what is budgeted in our operating costs budget out of the -- out of our 400 category in the reclamation fund, but there are various expenditures that come out of the operating costs. Usually, we like to have them tied to reclamation-fund activities.

Q. Directly tied?

A. I'll defer to the reclamation fund statutes and allow for legal interpretations, but they are -- the operating -- the budget is set by the legislature. And whatever the legislature and governor deem appropriate to be set aside for the operating costs is what we will use.

Q. Okay. Does the Division have even an informal definition of what is meant by "restoration and remediation on a well location"?

A. Yes. We do have an informal definition. And we do not follow what, for example, the BLM requires for on-site restoration, and I believe our requirements are -- we want the land to be contoured and the site cleaned up. But the site should be cleaned up, debris removed and the site contoured.

Q. And if there is subsurface contamination, that is excavated or otherwise dealt with, would you say, or is it just surface consideration?

A. If there is subsurface contamination, that would be -- are you talking about an abandoned well site?

Q. Uh-huh.

A. That would be an appropriate use of the reclamation fund to use to clean up the site. I believe the State Land Office can also use its restoration fund to clean those sites up as well.

Q. I'm sure it could.

To follow up on Mr. Larson's question --

A. Those sites are very -- can be very expensive.

Q. I understand.

To follow up on Mr. Larson's question, with the assumption that the federal government is not going to implode in the foreseeable future, would the Division object to excluding federal wells, since it remains remote that the State would be liable for plugging those wells?

A. I believe really under 70-2-14 -- again, it's not my position to speculate as to the legislature's intent, but I believe that federal wells are to be included in overall well counts. And we -- there is not a preclusion in using the reclamation fund to plug a federal well. There is bonding. I believe the federal government, the BLM bonding -- I don't know if their bonding is sufficient necessarily at all. We -- we could certainly work with the BLM on plugging certain sites, but I believe it is their primary duty to plug federal sites.

But I wouldn't wanted to get in a position where we exclude federal wells from our well count and then we put an absolute ban on plugging a federal well, especially if that federal well were to be contaminating water within the state of New Mexico and then the BLM doesn't plug that well. I think that's a very dangerous avenue to go down, especially if we are -- if the well is causing harm to public health or the environment.

The reason that we are currently plugging wells on federal land is because the BLM hasn't acted maybe quick enough in plugging their own wells. So I don't know from a policy perspective -- I know our -- our biggest job is to protect public health, safety and the environment, that we'd want to exclude those federal wells and then put a ban on using the reclamation fund to plug the federal well. I think that's a dangerous avenue to go down.

Q. In the cases where the Division reclamation funds are used for federal wells, is the reclamation fund reimbursed by the federal government for those costs?

A. If it's -- so we don't use the reclamation funds if it's under the BLM grant. If it's not under the grant, we would -- we would not be reimbursed by the federal government if it's an expenditure out of the reclamation fund. There could be a nationwide bond that an operator places with the federal government. And so we have had those discussions with the BLM on redeeming those bonds, but, unfortunately, I think from their administrative perspective, it's just too difficult to do in how they do their bonding.

Q. And the last question: In your example where the bond was attached or if it was collected or was redeemed for $34,001, where does that money go? Does it go back in the reclamation fund?

A. It does.

Q. That's all I've got.

CHAIRWOMAN RILEY: Dr. Balch?

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Good morning.

A. Good morning.

Q. I still promise I won't treat you as a hostile witness.

A. Thank you.

Q. I actually have a number of questions, which is not very surprising.

A. Okay.

Q. The first thing is some of the language in 18.9C., and it's the --

A. I'm sorry. 18.9?

Q. 18.9C.(1), 19.15.18 --

A. 8.9?

Q. 8.9, yes. Sorry.

MR. BROOKS: The proposed rule, Mr. Commissioner?

COMMISSIONER BALCH: The proposed amendments to 19.15.8.9.

MR. BROOKS: Thank you.

Q. (BY COMMISSIONER BALCH) Under C.(1), you went through adding definitions for true vertical depth and measured depth, and that's very unclear what depths you're looking at there. I'm wondering if the language ought to read: "Plus $2 per foot of the projected length of the proposed well or the measured depth of an existing well."

A. So I am sympathetic to your concern. I think that is addressed in E, if you go to E, and that is applicable. Instead of restating it in D and C, that is where -- how depth is calculated.

Q. Then in that case, I would move E above --
A. Into both C.(1) and D.(1).
Q. I would move it to C or something like that. I would put it above that.
A. It would then have to go into C.(1) and D.(1) if that move were to take place, because --
Q. Or it could become a new C, and C could become D.
A. That same language for -- in C.(1) that you're referring to is repeated in D.(1).
Q. So I tend to read these rules very linearly, so I don't like it when I find something that makes me have to go back and re-read something that I've already read. So I would really suggest changing the language in C.(1) or moving the language in E above that point in the document.
A. Yeah. I have no objections. I am a linear reader as well, so in drafting, I am sympathetic to your concerns. And I will defer to the Commission. I would just, again, suggest that if it is moved in C.(1), it would have to take place -- the change would take place in D.(1) as well.
Q. Yup, or you can put the language in front of both of them.
A. Yeah. But it's repeated twice, I just want to

point out.

Q. I'd like to look at Exhibit 6. And in response -- I'm thinking about one of Mr. Larson's questions. He was talking about deeper wells under bonding costs. So I just did a quick number, and for wells that are above 10,000 feet -- and there is a pretty small sample of that; there are six wells -- the average cost is 56,000 for plugging those wells, and the bonding cost would have been 45- to 46,000 for deeper wells. In this case, smaller sample statistics are more expensive. And what that made me wonder -- and I'm very appreciative of this table of data, but I think that it would be useful to make -- a picture is worth a thousand words. I think that there are two other things I'd like to see on this here.

I'd like to see another column. There is the bond cost under the new proposed scheme for each of those wells and then the difference in that bond cost from the actual cost.

Also, I think if you could plot the bond cost versus depth -- it would be a simple Excel plot. There are a couple of engineers in the back of the room who could help you with that, if you're not an Excel master. And then put the 25k, plus 2 foot per -- $2-per-foot line on that plot, and that will show you how well the estimate works for different depth branches.

Can we get that exhibit to look at this afternoon?

A. Yes. I think that would not be a problem at all.

COMMISSIONER BALCH: I think Mr. Goetze can do it in two minutes.

MR. BROOKS: Mr. Goetze is very good at that type of thing. Could we ask that --

THE WITNESS: I have no problem getting that to you.

COMMISSIONER BALCH: I think that would be useful for the record.

THE WITNESS: Sure.

MR. BROOKS: Could we ask that the court reporter reproduce for us your request, just get that out of the -- not getting a transcript or anything under certificate. Just get what Dr. Balch said so we would know exactly that we're complying with, what he is requesting.

Q. (BY COMMISSIONER BALCH) Two lines to the table -- two columns to the table. The first column will be what the bond cost would have been with the new scheme, so the 25k, plus $2 per foot. Pretty easily calculated. And then the difference between that number and the actual cost to plug the well would be the next column.

A. Okay.

Q. And then I would like a plot that shows bond cost versus depth, so basically just your shallowest well to your deepest well with the actual cost of the bond closure. And superimposed on that, a line representing the 25k, plus $2 per foot, the proposed change to the regulation.

A. Not a problem. I can get that for you.

MR. BRANCARD: So are you looking at Exhibit 4 then?

COMMISSIONER BALCH: 6.

MR. BRANCARD: No. I'm saying for the -- Exhibit 4 gives you cost per foot per depth, and then you just want to have --

COMMISSIONER BALCH: Yes, a line on top.

MR. BRANCARD: -- a line that would cover the actual bond cost?

COMMISSIONER BALCH: Keep it simpler. You already have an exhibit for it.

THE WITNESS: I understand what you want. I can do it for you. I have become an Excel master.

Q. (BY COMMISSIONER BALCH) Good.

All right. I did the calculation for the 145 wells in Table 6 and the average cost of 32,400 --

A. 32,000?

Q. -- 32,400 and some change.

So if you look at a 5,000-foot well with the new scheme, that would be 35,000. So that's kind of in the middle of that range.

I think that line on Exhibit 4 would help clarify if there is a difference. As I noted for the deeper wells, is there something similar in the midrange or shallow wells that -- is there overpayment or underpayment based on the new scheme?

So when an operator fails, some percentage of those wells will go into -- maybe all of the wells will go into abandonment temporarily. But after that is resolved, their bankruptcy, I presume the properties will get sold off to other producers. What kind of percentage on an average basis of those wells would go into closure? How many of them would just go to another operator that would just -- operation.

A. That's a really -- that's a really difficult question, and let me -- let me have a discussion with you, if you don't mind, about that.

Q. Sure.

A. Unfortunately, we have not -- we've really stepped up the notice -- during the last Commission hearing on financial assurance, we required operators to give us notice of their bankruptcies. So now we actually get notice of bankruptcies, so that has helped, to receive notice. Unfortunately, we have a great number of operators who actually don't go through bankruptcy. They just leave the state. They don't go through any formal wrap-up process. So I will put aside that large chunk of operators whose wells just are abandoned, and we'll go through the actual bankruptcies.

And maybe we've had -- I don't know. Maybe we have seven to ten -- seven to ten of those. They'll go through -- maybe they'll start out as a Chapter 11, and huge operators, D J Simmons, Vanguard, those big operators. And they'll sell off some of their assets. Some will emerge from bankruptcy as the same entity. Some of them will sell off their assets. And some will convert a Chapter 7 and not exist in the state anymore.

With the latter, those are the problems -- the problems that we see as a Division, the DC Energy, the Canyons, the Zerex [sic; phonetic], and they can have -- Marks and Garner. They can have very large well counts, and they won't sell off their assets. They will leave the State with 200, 300 wells that will be on our plugging list that we will ultimately be responsible for, or you will have operators who will emerge and continue to operate. So it's not -- it's not a -- unfortunately, it's not a clear answer.

We have a case -- well, I don't know if it's appropriate to talk about. But there is a case that the Division brought before the Division. I think it's going to go up before the Commission -- appealed to the Commission.

MR. BRANCARD: So maybe not talk about that.

COMMISSIONER BALCH: Because it's coming before the Commission.

Q. (BY COMMISSIONER BALCH) Well, actually you brought a case -- an example that is going to illustrate my concern, and that is the operator leaves and there are 200 wells and they're all put onto the plug list. But some of those are probably viable producers. So plugging them actually produces waste. Is there a mechanism for passing orphan wells on or selling -- reselling orphan wells to other producers?

A. I mean, if another operator wants to come in and take over those wells, we certainly would work with that new operator. Under our change-of-operator provisions, the operator trying to get rid of the wells would sign off on it. It would be the future duty of

the trustee in the bankruptcy to do everything within his or her power to sell off those wells in order to get the most money for the bankruptcy estate. So I think if there was an operator trying to get those wells, the trustee would sell off those wells in order to do his or her duty as the trustee to the estate. But yes, after the close of the bankruptcy, if some operator came in, we would certainly prefer to sign off on a change-of-operator as opposed to just plugging a well.
Q. Are there any horizontal wells in Exhibit 6?
A. There are not. There are not.
Q. And why just from 2014?
A. As opposed to going back to FY '12 or '13?
Q. '10 or whatever.
A. I just went back to '14. I pulled a number of invoices, and I worked with our administrative services division to pull all those invoices from a record-keeping perspective.
Q. Do you think the four-year sample here is representative of costs present and going forward?
A. No, actually. I believe that our costs will likely increase. Our well drilling is deeper. As I said, our reclamation fund has been very strapped, and we plugged a lot of shallower wells. As you mentioned with the 10,000-foot deep wells, those would be more

expensive. We see a lot of deeper wells. So I imagine those deeper wells would be more expensive, talking with certain -- certain other operators and plugging other types of wells.

We have operators in this one-to-ten range who just operate SWD wells, and it's not going to be -- it's not going to be an appropriate amount to plug an SWD well at $25,000, plus $2 per foot. So no. I think it's a gross under -- in certain cases. But, again, we find the difference in the reclamation fund, but we can't find an exact pinpoint amount for every single well, an individualized rule.

Q. And all of the concern about how the closure for horizontal wells -- deviated wells because really horizontal wells have become, starting in the early 2000s, more and more common. In fact, right now they're 90, 95 percent of all the wells that are drilled. So eventually these are going to start to come into the mix of wells that are being closed or abandoned. Maybe Mr. Goetze is the person to ask that question of.

A. Sure. I still believe we -- we plug the downhole part and wouldn't plug the --

Q. Wouldn't plug the horizontal?

A. -- horizontal. I had that concern a couple of years ago. And I reached out to some people in Texas, and I wanted to see if they had done any horizontal well plugging. And my understanding is we would worry about the vertical part and set the plug there.

Q. That would be roughly --

A. Yes. I think contemplate horizontal plugging in determining appropriate plugging costs.

Q. This might be a little bit back into some of Mr. Larson's questions, but is it fair to say that as a whole, the problems we have are more with the smaller side of the operator scale than the larger side? There aren't many Conchos or Conocos closing up shop and leaving you with abandoned wells that are not bonded?

A. I mean, from a -- so I believe I gave the statistics of operators out of compliance with our financial assurance rule. They certainly are the smaller operators. As far as operators going through bankruptcy, we do not see operators with ten wells who are going through a -- who file bankruptcy, or even 25 wells. That would be -- from historical practices, yes, that is the operator that is more likely to either be a sole proprietor or a smaller operator who will just walk away.

Q. Okay. How does an operator end up out of compliance? When do you pay the bond?

A. When do you -- when does an operator have to pay the bond?

Q. Yeah.

A. After a well is inactive for more than two years, they have to post additional --

Q. But there are two levels of bond, but everybody has to pay an initial bond?

A. Right.

Q. Right. And when is that collected?

A. In order to operate in the state of New Mexico, any private or --

Q. So how do you get out of compliance? You can't get out of compliance on that end?

A. Only after the two-year mark.

Q. So the two-year mark is when you have additional compliance?

A. Uh-huh.

Q. And that's when you have a hard time getting people to pay?

A. Correct.

Q. So my next question comes to the deadline for changes at the end of October 2018, so three months from now, basically, three-and-a-half months.

A. It would be like a Halloween trick or treat. I think it's a treat to us.

Q. There's a lot of operators, 600-plus operators.

A lot of oil wells, more than 100,000, right?
A. Active wells, I believe it's around 58,000.
Q. Okay. But total wells, it's a big number.
Is it possible, do you think, to rebond all those wells in that amount of time?
A. I do.
Q. I mean, are there a lot of bonding companies, or is it just one or two or three that show up over and over again?
A. We have usually about four, maybe sometimes five surety companies that we deal with routinely, and the average turnaround time is about -- no more than a few weeks dealing with the surety companies. There's also the opportunity to post a cash bond or a letter of credit, and that can be done very quickly with the bank.
Q. A letter of credit with the bank.
So that comes back to my other concern. The people that you're -- or the companies that you're going to have a large amount of problems with are the small companies, and they're the ones that may have a harder time dealing with the sudden change in their expenses for operating in just a three-month period. Is there a --
A. Well, again, it's 50 -- 56 percent or so of the operators would have -- if they're in the one-to-ten

category range, they would have no change in financial assurance.

Q. No change from the previous?

A. Right.

Q. How does this work with drilled but uncompleted wells? So we sometimes run into this with shale development, which is a very big part of what we're doing in New Mexico right now. But if the price were to go down to $30 a barrel or something like that, there is a pretty good chance that a lot of wells would be drilled and not completed, and they could sit there until the price goes back up. Does this impact that type of a well, or is it only wells that are completed and are ready for production?

A. What do you mean as far as impact?

Q. So when the price dropped in 2014, 2015, we ended up with a surplus of wells that were already drilled but not completed in the shale plays in the back Penn and other places, thousands of them. And that inventory didn't start to drop until after the price had gone back up a couple of years later.

A. In order to drill -- for us to permit certain wells, you have to post the financial assurance before we permit the well.

Q. So it's before the permits?

A. Uh-huh.

Q. So those would be sitting there. But those are -- those are wells that could, very conceivably, wait a couple of years to be completed, but they're relatively low risk if they're not completed eventually. It just depends on the price of oil.

A. There would be no change, though, in our financial assurance rules.

Q. Except for the two years. Okay. So after two years, they would have to add additional assurance if they still haven't completed the well?

A. Uh-huh.

MR. BRANCARD: Is that a yes?

THE WITNESS: Yes.

MR. BRANCARD: Thank you.

Q. (BY COMMISSIONER BALCH) Going back to the issue of federal wells, I'm wondering if there is a way to not count the federal wells for your financial assurance numbers or levels on the table but still allow you to deal with them as necessary from the fund -- the reclamation fund. I'm not sure -- it seems like when Commissioner Martin was questioning you about that, that there was a tie between the count and then being able to -- and then excluding them from the reclamation fund altogether. Is that necessarily true, that you have to have it that way?

A. So I think you could have a problem with an operator having, say, 99 federal wells. We often have one or two state or private wells. The remainder are federal wells. And then the operator is indeed not compliant with our 5.9 inactive well rule. If we were to not include those wells, then we would put them into that much lower bonding tier.

Q. Uh-huh.

A. And then if you're suggesting then we would then use the reclamation fund to plug their 100 wells, we would then take on, say, a $3.5 million liability out of the reclamation fund when there are only -- and there would be no single-well bonds for those either because we don't require single-well bonds for federal wells.

Q. Well, I think most of those 99 wells would be plugged under the federal bond, right?

A. No. They don't actually have single -- all single-well bonds with the BLM. And so there generally isn't all federal bonding, so they will give us a grant sometimes. But if we use the reclamation fund to then plug federal wells, I think we could be ultimately subsidizing --

Q. How often does that happen, that you use the reclamation fund to plug a federal well?

A. Well, that's --

Q. Does it happen?

A. It does happen. But I think part of the limitations that we have had is the very limited funds available in the reclamation fund. Again, we wouldn't want to be reliant on a federal grant. We haven't always had a federal grant, but we wouldn't want to be limited if we could reach out to the BLM and say, We'd like to go plug these wells, do you agree, and this is a matter of public health, safety or the environment; I think we would like to go do that. And if it is, say, a $145,000 plugging job or restoration --

Q. Or an emergency environmental issue is probably more expensive. However, does this happen? How many have happened in that four-year period, from 2014 to 2018?

A. That we've plugged out of the reclamation fund?

Q. Uh-huh.

A. I couldn't speak on '14 and '15 off the top of my head. I know we plugged one out of the reclamation fund certainly in the past two years.

Q. So it's not a common occurrence?

A. Well, we had the BLM grant until '17.

Q. And the BLM paid for it?

A. Right.

Q. It's not a common occurrence, and then the BLM paid for it. So I guess I still don't see why you wouldn't be able to exclude the federal wells from the count for the purpose of establishing the bonding levels.

Here's the -- here's the other side of the coin. If you're that operator with the 99 federal wells and you have -- do you have to provide some assurance to the federal government that those wells are going to be plugged when they're abandoned?

A. I can't speak to the federal policies or procedures and what assurances they give. They post a minimal, in my mind, bond to the federal government.

Q. So they must have some kind of a bond with the federal government?

A. Right. I want to say maybe for -- if these were all wells in the entire -- I believe there is like a -- the Government Accountability Office came out with some report talking about the federal government's bonds and how they weren't sufficient to cover -- it'll be a good read during your lunch break.

Q. But if they are underbonded, then that's their problem when it comes to plugging the wells. It's not the State of New Mexico's problem.

A. Unless -- unless we wanted to protect the citizens of the state of New Mexico.

Q. Which does happen, on one occasion at least in the last four years but not every month or even every year.

A. Well, in '17 -- FY '17, again, we plugged -- Commissioner Martin can probably speak to this. Basically all the wells we plugged are federal wells.

Q. Did you get any money back from the federal government fund for those wells, or will you get money back eventually?

A. We did, but that may not always be the case. So if there were limitations placed on a federal agency or if there wasn't any priority, we could, as a state agency, make that a priority to plug those wells. So if we don't want to be relying on the federal government for monies to plug a well, we could take it upon ourselves to plug a federal well that was a problem well.

Q. It does seem like the exception, though, right? It's not a common occurrence? It has not been a common occurrence?

A. I don't -- I don't know that it has been a common occurrence, to get a grant to plug wells from the BLM, and I believe they're quite backlogged in their plugging.

Q. How far is New Mexico backlogged? Quite a bit also, right?
A. We had been extremely backlogged, but we have actually done a phenomenal job this year. We are on target to double our LFC [phonetic] performance measure. So we were asked to plug maybe 30 wells. We're on target to maybe plug 60 wells this year. So we would like to clear up that backlog significantly.
Q. How big is the backlog?
A. Well, we had 200 or so wells. But like I said, we stepped up our compliance efforts significantly, so now we have about 500 wells on that plugging list. So we can -- if we continue the rate of 60 wells a year, we will do a phenomenal job.
Q. Basically, orphaned wells that nobody owns or nobody -- is there no way the Division could auction those out, see if anybody wants to buy them, put that money in the reclamation fund? I know that's a complete aside, but I'm just curious.
A. No.
Q. Because I think that that exposes the State to possible waste for a well plugged -- could be liable to the producers. That's a different issue.
A. I won't say that the State can't, but the Division can't.

Q. How many changes-of-operator on new wells completed and ready for operation do you get every day, just a ballpark?

A. How many change-of-operators?

Q. Yeah. There was a question from Mr. Larson about how dynamic could you be about selecting these number of wells that an operator has?

A. They're usually handled on a district basis, but -- and it varies every day. But there may be -- pending at any time, it could be eight pending at any time.

Q. So eight or so changes a day maybe?

A. There could be. And that could be for various number of wells.

Q. So my computer programming skills are woefully out of date, but even now I can write a script that would read the database and make that list without a human having to do it and as often as you'd like, very quickly.

A. We'll hire you in I.T.

(Laughter.)

Q. I suspect that Mr. Goetze could do that, too. I mean, it's not hard to automate those kind of processes. The difficulty would then be you have to notice the operator that you're above or below a threshold, and you need to change your bonding. Right?

A. Right. We would be denying change-of-operator. We deny a lot of change-of-operators already because of bonding compliance issues or out-of-bonding compliance issue already with our existing rules.

Q. Well, it seems like you would want to have that number on the fly as something to look at?

A. The number of --

Q. Wells per operator, so you know if they're in compliance or not.

A. Right. If we add an additional measure --

Q. So when I'm looking at IPANM's proposed changes -- I don't think they're going to have a witness, so we just have to go with what they've presented here. But they're adding one more category, and they're changing some of the numbers, particularly on the lower level, for the bonding requirements. And I think Mr. Larson was asking that why can't you have more categories than -- I guess originally the OCD wanted three categories, and that was for simplification of keeping track of these bonding level requirements.

A. Right.

Q. I don't think it's very hard to track how many wells an operator has, very quickly, very automated.

A. I don't know that the tracking necessarily -- I mean, I guess we could automate it. But how many -- how much personnel time are we going to devote on a daily basis to tracking in and out of compliance? And I think the numbers that I had come up with, their ranges were 2.1 percent of operators in one category, 1.6 percent in another category. I'm not really sure -- I mean, we could come up with 15 categories if we wanted to.

Q. Sure.

A. But if we're managing that from an administrative standpoint, that would be really difficult for us. We are -- you guys just heard the spill rule. We are very extremely understaffed right now, and we just don't have the personnel to manage our existing duties facing the Division. So that's giving us more and more duties with less people.

Q. So how are -- how are these categories arrived at? I mean, were there some statistics done on the data set that you were examining to determine higher levels of this from different levels of wells?

A. Yeah. I mean -- well, we had to come up with what is -- what's the -- I mean, obviously $250,000 really isn't enough to cover all of an operator's wells. I mean, we have Hilcorp with 11,000 wells in the state. $250,000 is not going to be enough. If you have ten wells, $50,000 isn't enough to cover all your liability.

But that's kind of a risk that you're going take. An operator isn't going to necessarily post all of their additional single-well bonds that are required.

So even if -- you know, to your earlier point with Exhibit 6, you may have -- you may be overbonded by $800 or $1,000. But the Division may -- like with Jim Pierce in Exhibit 7, they have ten out of ten wells or nine of nine wells that are on a plugging list. So where does that difference come? And he has no additional financial assurance. That has to come from the blanket fund and our proposed $50,000 and IPANM's $25,000. So we'd be left with 25,000 or $50,000 to plug nine wells, grossly insufficient.

Fifty percent of all those operators are out of compliance are the ones -- the operators out of compliance with the financial assurance, those are in the one-to-ten category range, so we have to turn to the blanket bond for that difference. And then after we turn to the blanket bond, then we turn to the reclamation fund. And, again, that's just a downhole plugging.

Then to Commissioner Martin's point for any reclamation efforts, then we would then again turn to the reclamation fund to address those issues.

So when we looked at 56 percent of all

operators who would not be affected, we thought that was pretty reasonable, and we looked at how many -- how many operators -- how many operators have wells in the state and, again, those percentages that I kind of broke down earlier.

Q. So 56 percent would be included in A and B?

A. 56 percent would be -- 56.7 percent would be in A, and then in B, it's 23.6 percent.

Q. And for A, it's not changing from the previous?

A. Correct.

Q. And for B, it is going up 25,000?

A. Right.

Q. Okay. Thank you very much.

A. You're welcome.

CROSS-EXAMINATION

BY CHAIRWOMAN RILEY:

Q. Ms. Marks, I wanted to go over just a couple of definitions, really, with you, the new rule under "Temporary" -- under 19.15.2.7E.(3) that talks about temporary abandonment and the language was added of "temporarily abandoned status," for clarification. And you testified that was synonymous with a well being inactive; is that correct?

A. Correct.

Q. I know you have your book with you. Could you look over to 19.15.25.12 and 25.13? And just take a minute and kind of look at that, and then would you tell us what -- give us some clarification around the temporary abandonment status. And I think that might help us clear up some of this morning's discussion. In particular 13, what it takes to get a well to abandoned status.

A. Sorry. I was going back to the definitions and temporary abandonment.

Q. Oh, okay.

A. And then I looked at the definition of inactive well, yes, and then approved temporary abandonment in 19.15.25.

Q. 12, uh-huh. And 13 describes how you get that.

A. Okay. And, again, the key word here is -- which I think -- bless my attorney. The word is "approved temporary abandonment." And, unfortunately, the definitions in 19.15.2 are confusing, and that's rather unfortunate. But -- so approved temporary abandonment, the Division can place a well on approved temporary abandonment for up to five years. And procedurally an operator submits a Form C-103 and seeks approval for -- to place a well on approved temporary abandonment. The operator gives the district office notice that it would -- before working on a well. And the operator then has to perform an MIT test on the well.

Sorry, Madam Chair. Do you want me to go through the rule or --

Q. Well, so the purpose of that, putting a well into an approved temporary abandonment status, would you say that is -- so read through B.(1) through (4).

A. Sure. So the Division and the district office "does not approve temporary abandonment until the operator furnishes evidence demonstrating that the well's casing and cementing are mechanically and physically sound and in such condition as to prevent: (1) damage to the producing zone; (2) migration of hydrocarbons or water; (3) the contamination of fresh water or other natural resources; and (4) the leakage of a substance at the surface."

Q. Okay. So the point of the approved temporary abandonment status is for the operator to have an inactive well but to also be sure that it is not damaging water or doesn't have anything -- any service, all that stuff, to make sure that the well is mechanically sound?

A. Correct.

Q. Okay. And so an operator can ask for approved temporary abandonment status really at any time, correct?

A. Correct. It could be -- exactly.

Q. And so it's not really -- it doesn't have anything to do with the two-year time frame of an inactive well that's required. Extra bonding is required?

A. Absolutely correct.

Q. Okay. So what we are attempting to correct in the new rule is that in order for them to get that approved temporary abandonment status at any time, not to do with the two years, they have to get that additional bonding?

A. Exactly.

And I think it really addresses -- I was trying to -- maybe I wasn't as eloquent as I should have been. But it really addresses a concern, because we have, under Rule 5.9, that a well can become inactive and an operator may try to remedy that by placing it into approved temporary abandonment status. And in between that 15 months and two years, statutorily, we are prevented right now from requiring any additional bonding.

But if we're giving an operator a permit, basically, by telling them they can be in approved temporary abandonment status, that's good for five years. So if we allow that well to be in approved temporary abandonment status for five years but then comes two years and three days or three years and the operator fails to provide us the additional financial assurance, we have no recourse against the operator to then yank that permit that we've given them or to go do anything about that approval that we've given them. So, again, it's a permit that we don't have to grant them. It's something that we're trying give guidance to our districts and to operators to say, Listen, if you want that permit, this is something you need to do to get that permit.

And then since the well will -- I mean, MIT tests are expensive to run. So if you're going to want to place a well in approved temporary abandonment status for up to five years, they're going to need that financial assurance. At that two-year mark, it makes sense to get it to close that gap if they're doing it before that two-year mark anyway.

Q. Okay. Thank you.

And then if you can flip backwards to 19.15.25B [sic], which is "Wells To Be Properly Abandoned," I think that will help address Dr. Balch's question about DUCs. So on B.(1), it talks about "the operator shall either properly plug and abandon the well or place it on temporary abandonment status in accordance with 19.15.25 within 90 days after," and then number one, "a 60-day period following suspension of drilling operations." So wouldn't that then indicate that a DUC really falls into the same category as any other wells, being that they have to be in approved temporary abandonment status or plugged or producing?

A. It does.

Q. Okay. I think that's all the clarifying questions I have.

COMMISSIONER MARTIN: I have two more.

MR. BRANCARD: Go ahead.

RECROSS EXAMINATION

BY COMMISSIONER MARTIN:

Q. In the wells that the Commissioner was just referencing, those would never get to your inactive well list. The drilled and completed wells have to have produced for some period of time to get --

A. That's correct.

Q. So you have different ways to track these wells?

A. We can query those wells.

Q. Pardon me?

A. We can query those wells.

Q. Okay. One more. In the event that you have to plug a federal well because of the imminent threat to health and the environment, wouldn't you have -- this is a legal question. It may end up being rhetorical. I'm going to ask it anyway. Wouldn't the Division have a claim on the federal government for those costs, in theory, since they have a bond in place to cover that same cost, assuming they do?

A. I'll abstain from that right now.

Q. That's fine. That's all I've got. Sorry.

CHAIRWOMAN RILEY: No, that's fine.

Okay. Mr. Brancard?

MR. BRANCARD: Before the witness goes, before lunch, I have two requests of the Division.

MR. BROOKS: Okay.

MR. BRANCARD: First of all, your witness proposed new language for 25.12. Could we get that in writing so the Commissioners can see that?

And then the effective dates that are proposed for 8.14, those effective dates were in the original proposal submitted in March. Since we've delayed the hearing, I don't know if these effective dates are workable anymore. I was sort of running through calculations of if the Commission makes a decision today, issues an order next month and then the delay in filing for rehearing and the effective date for the "New Mexico Register," this rule likely -- if it is adopted, will likely not be effective until probably sometime in September.

MR. BROOKS: Yes. Mr. Brancard, I looked --

MR. BRANCARD: So you may want to look at those effective dates in 8.14.

MR. BROOKS: I did look at those proposed dates in preparation for this hearing, and I would have proposed changes except for the time for filing alternative -- required to file changes with our pre-hearing statement and that was after our pre-hearing statement was filed that I looked at it. It goes without saying that we cannot make any provision -- the Commission cannot make any provision before publication of the rule in the "New Mexico Register." So I believe the first of those dates is before. It will likely be published, although it is -- if the Commission were to issue an order today and get a final rule today, then it could still be submitted for publication by the date in September that's on the proposal. But otherwise, not. And I think those dates will have to be adjusted.

MR. BRANCARD: Yeah, because the July 24th date is not going to work.

MR. BROOKS: That obviously could not be

met.

MR. BRANCARD: So if, over lunch, the Division can look at that section if you have proposals for -- if you recommend, I think the Commission will likely look at those dates anyway.

MR. BROOKS: I think so, too.

THE WITNESS: I just think that -- I know that compliance, I mean, in that October 31st would not be an issue to Commissioner Balch's question for us, but we can come up with some other dates.

COMMISSIONER BALCH: Well, if we end up giving them five weeks, that includes being noticed by the Division that they need.

THE WITNESS: We'll think -- I'll think of something.

And I will just say, Commissioner Martin, it just bothers me. Of course, if someone asks me a legal question, even though I do try and take that hat off, I do think -- I think that -- and, again, I won't speak for BLM. But I think the statewide bond for federal wells is $25,000, and I believe a nationwide bond is $150,000. So even if we did make a claim and we had limited resources, our amount to recover could be pretty limited, if, again, the operator had limited resources. So going into the reclamation fund may be our only possible --

COMMISSIONER BALCH: So we have the reclamation fund to catch the overages for the State of New Mexico. There has to be something equivalent for the federal government as well. If it costs more than the bond, they must have some mechanism.

MR. BRANCARD: Possibly whatever Congress appropriates.

THE WITNESS: Yeah. I think it's on a Congress -- Congressional appropriation. We reached out --

COMMISSIONER BALCH: Seems like you could get more from them than they can get from their bond.

THE WITNESS: And some of it -- I mean, there is a -- there is a well now out there that BLM has a funding issue on. So it's sitting out there right now, and they're saying they have no money to plug -- to plug a well. So while we would like to say that the federal government has unlimited resources, I don't know that that is necessarily true, and they are tied to their appropriations that they have. And we wouldn't want to be reliant as a state on an appropriation or go up to the federal government for an appropriation, especially for health or safety issues.

MR. BROOKS: If I may address that issue, Honorable Commissioners. I don't know the answer either, but it seems highly unlikely to me that there are any circumstances in which the Division would have a claim against the United States for the cost of plugging a well in the absence of a specific contract --

COMMISSIONER BALCH: They can just ask nicely.

MR. BROOKS: -- contractual obligation on the part of the United States that was funded by an appropriation by Congress.

I would recommend that if the Commission feels it's necessary to have advice on that question, that they rely on Commission counsel because it is a legal question, and it's not one I'm prepared for address.

THE WITNESS: And I can see some immunity defenses being raised. I mean, I could see all kinds of problems being raised there if we tried to recover certain costs.

COMMISSIONER BALCH: Well, it still seems to be a pretty low percentage of the wells that you're closing that fall into that category, that we would not get paid back from the federal government, or you're closing federal wells overall.

COMMISSIONER MARTIN: Issue here, in

instances where a small operator has a disproportionate share of federal wells and has two state wells that remain federal wells and is penalized under this rule --

COMMISSIONER BALCH: He has to buy a $250,000 bond.

COMMISSIONER MARTIN: Right.

THE WITNESS: Well, we do have a number of operators who have a lot of federal wells.

COMMISSIONER MARTIN: Correct.

THE WITNESS: So that could have a significant -- I mean, it seems like a minor adjustment, but it would have significant impact to us.

CHAIRWOMAN RILEY: Do you have questions?

MR. BRANCARD: That's it for me. Thank you.

MR. BROOKS: I have nothing further of the witness. We have another witness.

THE WITNESS: I will say I believe Mr. Goetze will be quick, and I don't know if he is wanting to stay all day. He has been gracious enough to come in for this hearing. He has not been well. So I would kindly ask the Commission to hear his testimony now, as the deputy director and who truly cares about all of my people. I would ask that of the Commission.

MR. BROOKS: I would request that we ask

the witness what his preference would be.

EXAMINER GOETZE: I'm good for all day, folks. Choose as you see fit, but I appreciate the courtesy. But I do have an Excel file to look at.

MR. LARSON: You volunteered.

COMMISSIONER MARTIN: You were volunteered.

COMMISSIONER BALCH: I just looked at the most competent person I could find in the room.

MR. GOETZE: I will save that for my performance appraisal.

(Laughter.)

CHAIRWOMAN RILEY: Well, I can go either way. If you guys want to take a lunch break, we can.

COMMISSIONER BALCH: That's a preference for Mr. Goetze.

MR. GOETZE: I can do it either way. I have other duties assigned, so --

THE WITNESS: If he has no preference, it doesn't matter.

CHAIRWOMAN RILEY: Why don't we go ahead and take our lunch break. And you might want to confer with Secretary McQueen because he has a lot of that data already.

THE WITNESS: I'll be good to --

CHAIRWOMAN RILEY: All right. So let's

break, do an hour and 15 and come back at 1:30.
Is that good for you, Ms. Larson?
MR. LARSON: It is, Madam Chair.
I assume Ms. Marks is going to come back and present an additional exhibit, because I have a couple of follow-up questions for her.
CHAIRWOMAN RILEY: You do. Okay. Yes. Then we will not release the witness.
COMMISSIONER BALCH: She's going to come back anyway and give us a new Exhibit 4 and a new Exhibit 6. So --
COMMISSIONER MARTIN: You were close.
THE WITNESS: Darn.
CHAIRWOMAN RILEY: We are adjourned for lunch.
(Recess, 12:13 p.m. to 1:37 p.m.)
CHAIRWOMAN RILEY: Let's go back on the record, please.
So we were just working on testimony from Allison Marks. She was asked to prepare some things and bring back, which looks like that's been done, and then we also have some additional questions, I think, by IPANM's attorney.
Is that where we are with this witness?
MR. BRANCARD: I assume the questions are

on the exhibits.

MR. BROOKS: Well, these exhibits have got to be numbered and marked. Does everyone have copies?

THE WITNESS: They do. I distributed them to everybody.

MR. BROOKS: My copies are not marked.

THE WITNESS: No, I didn't mark them.

And I will note that there is a -- just -- in the Excel spreadsheet, because I love Excel, in the Difference column, per Commissioner Balch's request, the G equals F minus A, it's not A. It's minus C, but I added the column. So you can ignore the G in that formula, but the difference is actually correct. So it is F minus C.

REDIRECT EXAMINATION

BY MR. BROOKS:

Q. Do you have any other comments on the exhibits before I number them?

A. I can discuss the exhibits if you would like.

Q. Let's number them first because then we can discuss them by number.

Now, unless I'm -- unless I am contradicting some exhibit number that has already been assigned, I want to call the exhibit spreadsheet Exhibit Number 9 and this chart, Exhibit Number 10, and the proposed new language, Exhibit Number 11.

Can we proceed?

A. So on Exhibit 9, I was asked to add additional columns of what the proposed bond would be for each API and our plugging costs and what the difference would with each bond. I can recite that Commissioner Balch's language if necessary. So that is reflected in Exhibit 9.

And then I took the data from the Excel spreadsheet, and I believe I was asked to plot that similar to what was in Exhibit 4 in the packets, and that is reflected in Exhibit 10 to show the new bonding -- what the new bonding costs would be with our historical plugging costs. And that's the red line -- the red line here. And I think it demonstrates that the proposed $25- -- $25,000, plus $2 per foot is actually pretty dead-on point with the new --

COMMISSIONER BALCH: Are you sure you didn't curve it to get that 2-foot denominator?

(Laughter.)

THE WITNESS: I'm not that proficient in Excel.

COMMISSIONER MARTIN: It's pretty perfect.

COMMISSIONER BALCH: It's pretty good.

THE WITNESS: I think that this means that

I'm pretty perfect.

(Laughter.)

MR. BROOKS: May I ask the witness a qualifying question before I tender the exhibits?

CHAIRWOMAN RILEY: Mr. Brancard?

MR. BRANCARD: Go ahead.

COMMISSIONER BALCH: It's new exhibits so --

Q. (BY MR. BROOKS) Ms. Marks, were Exhibits 9, 10 and 11 prepared by you and, in the case of Exhibits 9 and 10, from information from Division records?

A. Yes, they were.

MR. BROOKS: And I will tender Exhibits 9, 10 and 11.

CHAIRWOMAN RILEY: Mr. Larson?

MR. LARSON: No objection.

CHAIRWOMAN RILEY: Okay. Those exhibits are accepted into the record.

(NMOCD Exhibit Numbers 9, 10 and 11 are offered and admitted into evidence.)

MR. BROOKS: Pass the witness.

CHAIRWOMAN RILEY: Mr. Brancard, is that appropriate?

MR. BRANCARD: Yes.

RECROSS EXAMINATION

BY MR. LARSON:

Q. Ms. Marks, looking at your Exhibit Number 9, go maybe a third of the way down the list of wells on page 1 to API Number 30-005-6391 [sic]?

A. 63191, did you say?

Q. 63191, yes.

A. Okay.

Q. And if I'm reading this correctly, we have a natural cost of plugging of 18,201.39 and a bonding level, under the proposed new rules, at $30,400, for a difference of 12,198. Am I reading that correctly?

A. You are. I mean, obviously there are a number of black and a number of red, and that's one of the -- an outlier, and then there is the $119,000 deficiency. So it's not going to be a perfect fit, but Exhibit 10 will show that it's a pretty good fit.

Q. We'll just say I cherry-picked this one.

A. Yes. Good cherry-picking (laughter).

Q. Wouldn't this be an instance, to particularly a small operator, where it would make more sense to do the bonding for the total depth rather than the 25,000 and $2 per foot, because you're tying up, essentially, $12,200 of the operator's operating cash?

A. I guess you could say -- by total depth, I guess you're going back to Exhibit --

Q. I'm just going off your numbering right there on Exhibit 9.

A. Right. I just want to clarify before I answer. So I presume that you would be looking at Exhibit 5. And which well is that? So you would be suggesting the zero dollars and then the $7.49 for total depth? Is that the question?

Q. No. I'm just looking at the numbers across your table there. It appears to me that at the new bonding level, it would have been $12,198.61 more than the actual plugging cost.

A. It is 12,000-or-so-dollars more, but I'm confused as to what -- how the calculation of total depth would be done, what the proposed bonding level is that you are suggesting.

Q. It would be whatever depth the well is.

A. Right. But there would still --

Q. That's in the Division's records.

A. But there would still have to be a cost allocated to that depth. We would still need a formula --

Q. That's true.

A. -- for that. And so what we did was determine an appropriate formula knowing that we have certain costs. Like I said, I pulled that invoice from our plugger, but we have certain mobilization costs and certain costs that we would expect in every plugging job. So if we took that $7.49 and then we had a very, for example -- you know, we can also cherry-pick out a really shallow well, for example, that 1,003-foot-depth well. And if we took that times 7.49, that would be $7,512 in bonding, where the actual plugging -- with the actual plugging costs of $146,000. So that would be grossly underbonded for us as well.

So, again, we have to -- we run a risk analysis for the Division, and that's where -- I think when Commissioner Balch asked us to run the best fit for that line. There is always going to be wells above and below it, but we came up with an appropriate formula, I believe.

Q. And getting back to a point that Dr. Balch hit on in terms of having realtime data of changes in operator well counts, looking at the Division's proposed tiers, the second tier is for 11 to 50 wells; is that correct?

A. That's correct.

Q. And what if an operator with 49 wells purchases five wells? Doesn't that automatically raise the blanket bond by $50,000?

A. Under our proposed rule, that is correct.

MR. BROOKS: I would object to that question because he said automatically raise their blanket bond. It should -- I think he meant to say -- I would ask him to -- would request the Commission to ask him to rephrase as: Does it increase the blanket bond requirement.

THE WITNESS: That's correct.

MR. LARSON: I'm fine with that.

MR. BROOKS: That's just in the interest of accuracy.

THE WITNESS: And so yes, it would increase their blanket bond requirements.

And I actually -- since I was working on these exhibits during lunch, I've actually decided -- since the -- since the Commission started raising inquiries on the whole federal wells and exclusion, I started to look at some of those numbers and how many wells would be excluded and started to just kind of randomly pick some operators, and it could -- it would -- it could really decrease the number of operators in certain tiers if we excluded those wells.

And I don't think the intent of the legislature when we did the -- when we brought the bonding bill before the legislature, coming before the

Commission, was to decrease the amount of bonding available to the Division given the deficiencies that we've had before -- when trying to recover funds from operators. We had noticed that there was significant decreases in blanket bonds available to the Division, and that testimony was provided to the legislature. And in response, we thought it was appropriate to bring that legislation before the legislature and, in turn, come before the Commission to increase the amount of -- in response to the Senate Bill and come before the Commission to increase our blanket bonds because we have had significant deficiencies when we try to recoup the amount of monies available to the Division. And the number of federal wells have always, historically, been included. I think that would have a significant net impact that was never contemplated. So I just wanted to point that out.

Q. (BY MR. LARSON) Does the Division have an approved list of plugging operators?

A. Of?

Q. Plugging operators.

A. There is an approved list of operators -- plugging operators that the Division can use pursuant to the price agreement that we go through under state law.

Q. So that grouping of potential plugging operators is to be done through price points?

A. We go up for competitive bid and whoever goes and bids. During the last bid proposal, Jamie [phonetic] Well Service and A Plus pluggers were the only companies that bid. We again tried to get more people to bid and -- I think I said earlier -- we just weren't very successful in those efforts. We would love to have more pluggers, to be honest. It just hasn't been very successful.

Q. Have you ever seen any data comparing industry plugging costs versus Division plugging costs?

A. I have -- I have heard, actually, that -- I've heard various stories, and I don't know if it would be appropriate to go into hearsay. But I've heard that -- I've heard -- I've heard that various operators, their plugging costs are astronomically high, and they wonder how we are able to plug wells so cheaply. But, again, that's just the downhole plugging costs. And when we want a plugger, what we require of an operator to go plug, that's to plug and restore a site. We just plug. We would love to restore every site. But I have heard stories about downhole plugging costs.

And, again, with advances in technology and wells being drilled deeper in the future, to Commissioner Balch's question earlier about the 10,000 feet, I would assume that many wells will be drilled deeper with increasing horizontal wells, with many more laterals. So these are a lot shallower wells in the data provided.

Q. So basically you have some third-end stories and no hard data?

A. Well, I could also -- I believe -- I believe the Division worked on a case with the Hinkle Law Firm on a plugging and restoration case, so we can go into restoration costs if you would like.

Q. No. I'm keeping it to downhole.

A. So, again, I do know what it takes for an operator to plug and restore a site in compliance with our rules, and those costs are higher than what our costs provided to the Commission are. So I believe the Division does an excellent job in getting sites plugged. Again, if anybody wanted to bid on plugging costs at a lower rate, we would be happy to do so. We try and plug wells for the lowest cost possible. We can only -- we can only go with whatever pluggers have bid on contracts.

Q. You mentioned this morning a scenario where, say, an operator has nine, 12, 15 wells. They all have become inactive. They've all come out of compliance, and they all leave the state.

A. Uh-huh.

Q. Is there any way to go after the operator to try to retrieve plugging costs?

A. Definitely. That's where we've really stepped up our compliance efforts to get operators back into compliance or address those operators from the onset as opposed to letting those operators fall into noncompliance and then just leave -- leave the state or just leave operations with the Division. They don't all leave the state of New Mexico. But we will get a plugging order, plug the well, and then we will file suit in district court for indemnification of the cost expended by the Division.

Q. Let's address a scenario of an operator who had 15 wells, basically leaves the state but is still the operator of record for those wells. So you get your plugging order from a Division examiner. You then go to district court to get a judgment. Do you then go to whatever state that operator may still be operating in to try to recoup from them?

A. So if the operator is under the same business entity, we could -- this remedy would certainly be available to us that we could do so.

If we have a parent company and there are subsidiary companies, I think we may have -- if there is a piercing-the-corporate-veil type argument or certain types of arguments that may be applicable, we'd have to examine that. But if it's all under one type of business structure, that remedy would certainly be available to us.

Q. Would you say the Division aggressively pursues those remedies?

A. I believe under Secretary McQueen, we have aggressively taken on compliance, and it has been very much to the benefit of all good operators in the state of New Mexico. Yes.

Q. Thank you, Ms. Marks.

MR. LARSON: That's all I have.

COMMISSIONER BALCH: Thank you. No follow-up. Thank you.

THE WITNESS: I'm sorry. I do want to -- that is not to say that Secretary Martin wasn't a fantastic cabinet secretary who did not support the Division. I have worked under fabulous cabinet secretaries every time I have worked at EMNRD. Secretary McQueen has been very supportive of our compliance efforts, too.

RECROSS EXAMINATION

BY CHAIRWOMAN RILEY:

Q. So do you know ahead of time how much a well is going to cost for plugging, and do you know ahead of time if you're going to have issues downhole?

A. We do not.

Q. Thank you.

CHAIRWOMAN RILEY: That is all I have.

Mr. Brancard?

MR. BRANCARD: No.

CHAIRWOMAN RILEY: So, Mr. Brooks, are you done with this witness?

MR. BROOKS: I am done with this witness, Madam Chair.

CHAIRWOMAN RILEY: All right. You may be released.

THE WITNESS: Thank you.

CHAIRWOMAN RILEY: Call your next witness, Mr. Brooks.

MR. BROOKS: Call Phillip Goetze.

PHILLIP GOETZE,

after having been previously sworn under oath, was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BROOKS:

Q. Good afternoon, Mr. Goetze.

A. Good afternoon, Mr. Brooks.

Q. I'm hopeful you are in satisfactory condition.

A. When you work with the Division, you're always satisfactory.

Q. I hadn't noticed. I mean I hadn't noticed myself. I don't mean that I hadn't noticed that you're not satisfactory with the Division.

Anyway, you are going to testify about the definition of the true vertical depth, correct?

A. That is correct.

Q. Is there anything else I need to ask you -- is there any other subject matter that you have been told you're to testify about?

A. No, strictly definitions and some colors [sic].

Q. Okay. Well, I'm going to ask you to look at Exhibit 1 -- OCD Exhibit 1, and that is the proposed rule. Do you have that in front of you?

A. Yes.

Q. Okay. On the first page, 19.15.2.7M.(6), that purports to be a definition of "measured depth." Is that a satisfactory definition of measured depth?

A. Yes. For its application and rule, it would be adequate.

Q. Okay. Then I will take you to the second page and ask you to look at 19.15.2.7(11), "true vertical depth," the definition. Is that a satisfactory definition of the term "true vertical depth" as used by petroleum engineers for industry purposes?

A. I will elaborate if my attorney wishes.

Q. Well --

A. At this point, it really doesn't qualify for a definition.

Q. Okay. Then tell me what's wrong with it and what needs to be changed.

A. The concern was raised about using the description as provided here as to assess the true vertical depth by using "a straight line perpendicular to the surface." There are other sources of information available which the Division obtains on a well, especially with regards to wells that are deviated or horizontal wells.

Q. Let me interrupt you here and ask another question. I didn't get really beyond plane geometry in my studies in mathematics, but I did study plane geometry in the university.

Perpendicular refers to two lines. And while it can be perpendicular to another line, it can't be perpendicular to something that's not a straight line, right?

A. That's correct.

Q. Okay. Is the surface of the earth a straight line anywhere that you know of, even in eastern New

Mexico?

A. No. There is some devi- -- some change in the surface elevation.

Q. So the term "perpendicular to the surface" -- not mathematically precise, correct?

A. That's correct.

Q. Go ahead and tell me how you would go about defining true vertical depth?

A. I went back and looked at what was proposed in the rule and what we have currently in rule, and I looked to modify the definition as we present it.

Q. Definition of?

A. True vertical depth.

Q. Okay. Proceed.

A. The definition I propose for 11: "True vertical depth means the distance from ground level of the surface location to a point in the wellbore which is the deepest subsurface depth drilled." True vertical depth for vertical wells is measured by using a straight line perpendicular to ground level to the deepest depth. Otherwise, true vertical depth is obtained for directional wells from the directional survey required under 19.15.16.14B or obtained from the directional survey for horizontal wells required under 19.15.16.15E."

Q. Well, conceptually, what true vertical depth is, is it not, is the vertical distance from the -- from the plane in which the surface of the well -- the surface location of the well exists to the plane -- to the parallel plane that intersects the deepest point in the well? Is that not a correct conceptual definition?

A. That is correct.

Q. Okay. And you're saying that that is properly measured and reported on the directional surveys required by the --

A. Yes. If I may refer to Exhibit 8, which I put together as a demonstration?

Q. You may. And I'm going to ask you to identify Exhibit 8.

A. Exhibit 8 is a generic figure showing the difference between a vertical well, a directional well and a horizontal well.

In the case of a vertical well, it is generally fairly easy to derive a true vertical depth with using the simplest information provided. We do get deviation surveys for our vertical wells. If it is such that it gets outside our standards, well, then we can ask for additional information. The big difference between true vertical depth and measured depth changes when you go to directional wells and very much the horizontal wells.

Q. And measured depth in most all wells is going to be a greater figure than true vertical depth, correct?

A. Generally, yes, that's true.

Q. But that's much more exaggerated in the case of the horizontal well where it may have 5,000 feet vertical depth and 10,000 or more feet horizontal depth?

A. That is correct.

Q. Or no. Like, 15,000 feet measured depth if it's a mile deep and two miles long?

A. That's correct.

Q. Okay. Now, to be really mathematically precise in here, vertical, to the extent we can apply plane geometry to a sphere, vertical -- a vertical line in the case of ensuring things in the earth -- in or on the earth is a line -- a line is defined by two points in plane geometry, right?

A. Yes.

Q. So the two points that define a vertical line are the point you're looking -- you're looking from in the center of the earth because that's what makes it vertical -- center of the earth.

A. The projection would be to the core, yes.

Q. Yeah.

So the lines that are shown as vertical on here are theoretically projected to the center of the earth, right?
A. Correct.
Q. And the dashed horizontal line that you draw from the base of the dashed horizontal line with two arrows on it, those lines -- for each well, those lines are perpendicular to the vertical lines, right?
A. The dashed lines, which represent the deepest locations, the deepest depth?
Q. Yes.
A. Yes.
Q. So what you have is a vertical distance from the deepest depth in the wellbore to the plane of the kelly bushing in the well?
A. Or ground level.
Q. Or ground level.
Usually you measure ground level in the kelly bushing --
A. That's correct.
Q. -- in the oil and gas industry?
And you're saying that that is the same figure that will be shown as true vertical depth on a directional survey prepared as we require them to be prepared?

A. That information will be available, yes.

Q. Okay.

MR. BROOKS: Now, I think the Commission is going to be asking us, as they did Ms. Marks, for some language that we're substituting, although we couldn't file it in advance because we were deadlined.

Is that a correct assumption, Madam Chair?

COMMISSIONER MARTIN: As far as I'm concerned.

CHAIRWOMAN RILEY: Yes.

MR. BRANCARD: Unless we come up with our own language.

MR. BROOKS: Pardon me?

MR. BRANCARD: Unless we come up with our own language.

MR. BROOKS: Well, I'd be very happy if you come up with your own language --

COMMISSIONER MARTIN: I'd rather see your suggestion.

MR. BROOKS: -- but I will supply my suggestion. My suggestion would be -- you want it in writing, I'm sure, so I'll get that.

But my suggestion would be that "the distance is the distance" -- "the true vertical depth is the vertical distance from the plane of the kelly bushing to the" -- "from the horizontal plane of the kelly bushing to the horizontal plane in the deepest point in the well."

Q. (BY MR. BROOKS) Is that a correct definition -- theoretical definition, Mr. Goetze?

A. Well, the kelly bushing is going to disappear, so you're going to have the ground level.

Q. Okay.

A. So --

Q. Well, what would you say? How would you precisely define the ground level in a well that is not drilling? I'm talking about your zero point.

A. The datum would be supplied in the C-102 as the ground level.

Q. Okay. So if we say ground level, that would be an unambiguous term that everybody in the oil and gas industry would recognize?

A. I believe so.

Q. Okay. So we'll say: "Ground level to" -- "the vertical distance from ground level to the plane" -- "the ground level at the surface location to the plane of the deepest point in the well."

A. That would be sufficient.

Q. "In the wellbore."

A. "In the wellbore."

Q. We used to say well, but now we say wellbore. That's fine with me. Okay. I will supply that definition in writing at the next break.

MR. BRANCARD: Madam Chair?

CHAIRWOMAN RILEY: Yes.

MR. BRANCARD: May I ask a question or two?

CHAIRWOMAN RILEY: Yes.

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. So in the documents that an operator provides, are they going to provide a depth in this -- are they going to provide the elevation --

A. Yes.

Q. -- of the ground level at where you're drilling from?

A. That's correct.

Q. That number, the elevation, will appear on which form?

A. The C-102.

Q. Okay. Are they then going to give you the elevation of their lowest depth?

A. You will get a survey that provides you a continuous measurement of both measured depth and true vertical depth usually done from a datum either selected by the drilling company or the client. So you get both the kelly bushing and the ground level in the most recent surveys conducted.

Q. What are they going to provide in the C-102?

A. The C-102 will have a surveyed location at ground level. And the kelly bushing and other measurements typically are not provided. Those would appear in the application -- application and permit to drill, in which case you would have the proposed depth, which would give you both the proposed vertical depth and the proposed measured depth.

Q. Okay. So you would have the proposed vertical depth in the APD?

A. You should have it.

Q. Right.

And you would have it as an elevation number?

A. You would have it as a datum -- zero from ground level.

REDIRECT EXAMINATION

BY MR. BROOKS:

Q. So if I may clarify, because we discussed this during lunch. If -- on the directional survey, the ground level is zero, right, zero elevation in the True Vertical Depth column?

A. Yes.

Q. And then the directional survey for each point that is included in the directional survey, each depth point, they would -- the survey would provide a datum, a number, which is the different -- the vertical distance, the difference in elevation, between the zero point, which is the ground level at the well site or the kelly bushing or whatever datum they use and the point that they're reporting for.

So if you drill down 100 feet, your true vertical depth is going to show 100 feet, but then if you drill horizontally, it's just going to stay -- it's going to go up and down, but it's going to stay basically the same. So when you get to the deepest point, wherever that is, it will show the maximum amount in that column, the difference between the elevation at the surface and the elevation at that point of maximum depth, correct?

A. Correct.

Q. Okay.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. That's in the directional survey?

A. Yes.

Q. That doesn't help us, because you have to provide financial assurance before you drill.

A. That's correct. And in most cases, you have to go back and correct because you may even have -- from the period of awarding of an APD, you may go back and change your design, which it happens. You may decide to go to a shallower zone, and you would have to have modify then also.

REDIRECT EXAMINATION

BY MR. BROOKS:

Q. And it may wander, right?

A. Well, yes.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. But I'm reading your proposed rule here.

A. Yeah, I know.

Q. And it focuses on projected depth for a single-well bond. So how do we find out the projected depth for true vertical depth?

A. It is available in the C-101 application permit to drill.

Q. And it would be listed as true vertical depth, or is it some number minus some other number?

A. No. It is listed as true vertical depth and measured depth.

MR. BROOKS: I take the witness' word for it. I don't have a copy of the form.

COMMISSIONER MARTIN: That's correct.

REDIRECT EXAMINATION

BY MR. BROOKS:

Q. Okay. Mr. Goetze, are there any other exhibits you prepared other than Exhibit 8?

A. No, there are no other exhibits.

Q. Very well. Was Exhibit 8 prepared by you using your expertise?

I didn't go into your credentials and get you qualified as an expert because somebody told me that wasn't necessary in a rulemaking proceeding. Plus, last time I did that, you testified to your credentials before -- in a proceeding before the Commission, and the Commissioners remarked that they had them memorized. And besides, Dr. Balch has already stated you're the smartest man in the room.

COMMISSIONER BALCH: In the audience.

(Laughter.)

MR. BROOKS: Thank you for that qualification, Dr. Balch.

But based on the testimony that the witness has given in previous proceedings, without prolonging this one, I would like to tender Mr. Goetze as an expert in the technical aspects of oil and gas drilling even though he's not a drilling engineer.

MR. LARSON: No objection.

MR. BRANCARD: As I said, Madam Chair, we have no experts in rulemaking. Everybody's entitled to their opinion.

MR. BROOKS: Well, that's what I was told you would say, so that's why I wasn't prepared to. But based on what I'm going to ask next, I wanted to establish that technicality.

Q. (BY MR. BROOKS) Now, Mr. Goetze, was Exhibit 8 prepared by you using your technical expertise and --

A. Yes, and referencing.

Q. Okay.

MR. BROOKS: I'll tender Exhibit 8.

CHAIRWOMAN RILEY: You tendered the exhibit?

MR. BROOKS: Yes, Madam Chair.

CHAIRWOMAN RILEY: Mr. Larson?

MR. LARSON: No objection.

CHAIRWOMAN RILEY: The exhibit can be accepted into the record.

(NMOCD Exhibit Number 8 is offered and admitted into evidence.)

MR. BROOKS: And I pass the witness.

Oh, before I do, let me say that at least from my perspective, I would be happy for the

Commissioners to ask him any question that they feel is appropriate to ask him or opposing counsel to do so, without committing myself as to who is the smartest person in the room, as I think he is one of them.

With that, I pass the witness.

MR. LARSON: And I appreciate the invitation, but I have no questions for Mr. Goetze.

COMMISSIONER MARTIN: Nor do I.

COMMISSIONER BALCH: Actually, I have a couple of comments for the purpose of the recent discussion.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. The projected depth of the well versus the actual touchdown, you're probably caught in the 50 feet, 100 feet, couple hundred feet maybe in a very deep well?

A. Maybe, unless someone changes their mind.

Q. So we're talking a difference in bonding between 50 to $500?

A. Yeah. Yeah.

Q. I'm not sure if that's something that we really want to incorporate in the rule, that you have to necessarily modify, or maybe language that makes you modify if it's more than so many feet would be a little more appropriate or something like that.

A. But I have had compulsory poolings where we say Bone Spring. They come in and make the application for the second and then, mysteriously, it turns into the third, and that's the case where you would want to rebond (laughter).

Q. But in most cases, the projected depth is going to be pretty close to TVD?

A. Oh, yes. The controls nowadays are so much greater that these folks know where they're going, and really this is -- actually comes out as a product of measuring while drilling.

Q. Again, I would say that maybe we don't need to rebond necessarily unless it's a dramatic change. More than 500 feet or something like that would be more appropriate.

The other thing is I don't think it is really the intent of this rule to dictate how TVD is measured by drillers. And I'm not sure how much into detail in the definition of true vertical depth we really need to go. In fact, I think that the definition under 11 there is fine if you strike the second sentence.

A. (Indicating.)

Q. And that would be: "A true vertical depth means the distance from the surface to a point from the wellbore which is the deepest subsurface depth drilled." And then you let best practices and industry tell you how that's done.

MR. BROOKS: Excuse me. May I make a point, or would you rather I wait until you finish your questions?

COMMISSIONER BALCH: I'm not ready to be cross-examined yet.

(Laughter.)

MR. BROOKS: Well, I was just going to make a suggestion. I wasn't going to -- I wasn't going to presume to cross-examine you, Dr. Balch.

Go ahead.

COMMISSIONER BALCH: Oh, that's all right. You were asking for clarification maybe.

MR. BROOKS: I think, in my point of view -- from our point of view, the definition would be sufficient if we struck the second sentence and put in the word "vertical" before "distance."

COMMISSIONER BALCH: So you don't like to define things with the word in the definition. So you don't want to define "true vertical depth" using the word "vertical." But I think that the understanding of "vertical" is pretty well known in the scientific community and --

MR. BROOKS: Well, the Commission can do whatever they want to do. I'm just making a suggestion.

COMMISSIONER BALCH: Generally, you don't want to define things using one of the words in your definition.

MR. BRANCARD: I would actually support Mr. Brooks' comments because if you don't include the word "vertical," the distance from the surface to the point in the well where the deepest subsurface drill is, you're just doing this and measuring that. You want to measure that (demonstrating).

COMMISSIONER BALCH: Part of the deepest depth. Depth is pretty well defined.

MR. BRANCARD: No. It just says "distance."

COMMISSIONER BALCH: Okay. Depth is probably the one that we need instead of "distance." "Deepest subsurface depth drilled." It says "depth" right there. I think depth is pretty well understood, also, as being measured in a line towards the center of the earth along the --

MR. BROOKS: Well, I would recommend to the Commission they use a more precise definition, but that is the Commission's prerogative.

COMMISSIONER BALCH: What's your opinion on it?

THE WITNESS: I like to keep it simple. When money gets involved and lawyers are attracted to it, there tends to be points of clarity.

COMMISSIONER BALCH: That is all I have. Thank you very much.

THE WITNESS: You're welcome.

CROSS-EXAMINATION

BY CHAIRWOMAN RILEY:

Q. Just to help clarify as to what goes into the original APD, definitely have -- if you wanted to adjust your plat, give you your ground elevation but also directional plans. And the directional plans call out at least what the proposed -- or your measured depth. And your vertical depth cannot be based on the eastings and -- what you're doing with your eastings, northings and get accurate measurement of that vertical depth.

So as to Mr. Brancard's concern about having that at the beginning, call out for or is required for that bond, we can look to the directional plan?

A. We don't always require a directional plan. Usually that's provided in more -- the BLM does have a predrilling directional plan requirement. Sometimes we do not get those. The tendency is now that the clients are -- operators are offering them more -- more and more? So you do have historically a better presentation. Again, there may be someone -- when you have people putting in horizontal wells -- it's only one or two or three -- the tendency is they will not provide that information. But it should be in the APD.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. Okay. I'm looking at the C-101 form. Okay? Box 15 says "ground level elevation."

A. Uh-huh.

Q. Box 17 says "proposed depth."

A. Uh-huh.

Q. How would they write the proposed depth?

A. They will probably put in a true vertical depth.

Q. So in other words, distance below surface?

A. TVD -- designated TVD. And usually they'll give us both because typically for the C-102 to be complementary to the 101, you have to dedicate the acreage. And so your footages, which are surveyed in longitude and latitude, have to conform to what's coming in with your APD. Without the 102 and the 101 together, you don't have an approved drilling plan.

Q. Okay. But that proposed depth on this form, does that equate to what this definition is asking for, which is the deepest subsurface depth?

COMMISSIONER MARTIN: Bill, do you have the C-101 and C-102 instructions?

MR. BRANCARD: I just have the form.

COMMISSIONER MARTIN: I think it maybe specifies it in there.

MR. BRANCARD: Okay.

Q. (BY MR. BRANCARD) It says, 17, "proposed total depth of this well." Is that what we're looking for?

A. No. That opens up the question, "total depth."

COMMISSIONER BALCH: Measures that depth?

THE WITNESS: Yup.

COMMISSIONER BALCH: Could be either.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I think in all cases, TVD is going to be measured from the location of the wellbore -- of the well at the surface, correct?

A. Correct.

Q. So if you have a situation where you're on a hill, the well is here, your TD is down here (demonstrating), it is measured from -- from the depth of -- from the point of the surface where the well --

A. Most of your references are back to the surface location for elevation.

Q. And that, I think, is where the definition is fine, if we just strike the second sentence.

CONTINUED CROSS-EXAMINATION

BY CHAIRWOMAN RILEY:

Q. So then will we need to add any measurements to our C-101 or C-102?

A. I did not consider the remodification of any forms for this.

MR. BROOKS: That matter is being considered by the Division, by the new horizontal well rule because the rule -- when the rule went into effect, we found that the existing forms -- or the forms we had previously developed -- the rules were not adequate so now we're working on the revision.

CHAIRWOMAN RILEY: And that could be included in the revisions?

MR. BROOKS: It could be, Madam Chair.

COMMISSIONER BALCH: Actually, I have one more question.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Where in the proposed rule is "true vertical depth" used besides in the definition of "true vertical depth"?

A. Only in the rule, I think. I don't know.

CHAIRWOMAN RILEY: Here it is right here. It's that same paragraph --

COMMISSIONER BALCH: Okay.

CHAIRWOMAN RILEY: -- that you wanted to move higher up.

I would tend to agree with moving it because I -- when I first read this, I thought there was a mistake, that we hadn't captured that. So I think putting it higher might help the reader.

COMMISSIONER BALCH: Thank you. I'm glad it's just used in one place.

CHAIRWOMAN RILEY: Mr. Brooks, do you have any redirect?

MR. BROOKS: No. Thank you, Madam Commissioner.

CHAIRWOMAN RILEY: We can excuse this witness.

MR. BROOKS: May I ask if it is still the desire of the Commission to have the Division submit a proposed alternative definition, or has the Commission reached conclusion and no longer needs it?

COMMISSIONER BALCH: We haven't debated it yet.

MR. BROOKS: Okay. I will submit it.

And I will add that I have been approached by someone requesting to make a public comment, and so I would ask that we take a recess before we ask for public comment in case this person actually does desire to make a public comment.

CHAIRWOMAN RILEY: Okay. Let me ask this question first: Mr. Larson, it would go to you next. Do you have anything more that you want to do?

MR. LARSON: I do not. The only thing I would have at this point is a closing statement.

CHAIRWOMAN RILEY: A closing. Okay.

So I think, Mr. Brancard, it's probably an appropriate point in this hearing to bring in public comment.

MR. BRANCARD: There are no more party witnesses, so I think it's a good point for any kind of public testimony.

CHAIRWOMAN RILEY: Okay. And you're asking for a break between --

MR. BROOKS: Yes.

CHAIRWOMAN RILEY: Okay. So let's take a break right now and come back at quarter till.

MR. BROOKS: That would be acceptable.

CHAIRWOMAN RILEY: Would that work for you, Mr. Brooks?

MR. BROOKS: Yes.

CHAIRWOMAN RILEY: We are off the record. Let's adjourn for 15 minutes.

(Recess, 2:31 p.m. to 2:52 p.m.)

MR. BROOKS: Madam Chair, Commissioners, I would like to make a brief closing statement at an appropriate time. I assume it would be after members of the public are given an opportunity to comment. However, that's all I have. I have no more witnesses and no more evidence to present.

CHAIRWOMAN RILEY: We're back on the record.

So I think at this point if we could do our public comments, public testimony. There are two that I see on the sheet that I find here. Larry Marker is the first one and Rory --

COMMISSIONER MARTIN: McMinn.

CHAIRWOMAN RILEY: -- McMinn. Okay. Thank you.

So let's start with --

MR. MARKER: Do I do it from here or at the table? Where do you want me to be?

CHAIRWOMAN RILEY: Well, probably where the court reporter can hear you best.

MR. MARKER: Will right here work?

CHAIRWOMAN RILEY: That's perfect.

MR. MARKER: What I'm going to do is I'm going to present some basic -- I'm going to read this prepared statement. But what I've done -- I'm a little bit nervous. I'm not the best communicator on the planet, so what I did -- I have it written.

CHAIRWOMAN RILEY: Could please state your name?

MR. MARKER: Oh. My name is Larry Marker.

Anyway, I'm out of Roswell, New Mexico. I'm representing myself, several other stripper wellers and then a little cooperative we just recently formed called the IPPC. That stands for Independent Petroleum Producers Cooperative. The main focus of our cooperative is to -- right now our main focus is to help with the administrative issues that smaller operators have.

Anyway, I've got these copies of what I'm going to say today. I've left spacing in them so you can make notes, and then I left a blank page on the back.

Do you want one, sir?

MR. BROOKS: Thank you.

MR. MARKER: Do you want one?

MR. LARSON: Sure. That's your last one?

Is that your last one?

MR. MARKER: I've got my own copy. I've been scribbling on it all morning.

MR. BRANCARD: Would you like to swear in the witness?

LARRY MARKER,

after having been first duly sworn under oath,

testified in narrative form as follows:

MR. MARKER: I'm going to go ahead and sit down.

Okay. You guys know all the other stuff and here we go.

In reference to the proposed amendments to the Commission rules of financial assurance, I am submitting these comments and request verbally and written to provide clarity and reference.

Number 1: Proposed amendment to Rule 19.15.8.9, Subsection C, Part 1. The OCD has proposed a single well financial assurance of active wells of $25,000, plus an additional $2 per foot of depth. We request the Commission to reconsider the amendment to require a single active financial assurance of $5,000, plus an additional $2 per foot.

(A) To require single active well assurance as proposed by the OCD will, for all practical purposes, end the entry of new operators into the industry. The value of entry level position in any industry is vital to the future of that industry.

(B) New Mexico operators commonly will have wells on both federal and state land. This level of assurance proposed by the OCD would be prohibitive in the event that an operator has several federal wells and one or two state wells.

Number 2: Proposed amendment to Rule 19.15.8.9, Subsection C, Part 2. We endorse the proposal presented by counsel for IPANM for the amended ratios as we referenced in the following excerpt from the pre-hearing statement submitted: $25,000 for one to ten wells; $50,000 for 11 to 99 wells; 100,000 for 100 to 149 wells; 200,000 for 150 to 199 wells; $250,000 for more.

The ratios of assurance as proposed by the IPANM will serve to satisfy the implementation of the changes enacted by the 2018 Legislature.

Number 3: The Oil Conservation Division proposed ratios of assurance as they have submitted in their pre-hearing statement would be detrimental to every aspect of the oil and gas industry in New Mexico.

(A) The independent operators, small, medium and large, have had three of the toughest years in the history of the industry and will be forced to commit already limited resources required for operations to comply with the massive increases in financial assurance as proposed by the OCD.

(B) Several methods of acquiring financial assurance are available. Each of these methods will require a substantial increase in operator investment under the OCD proposal.

Example -- and this is me -- I have on record 77 state wells. My existing blanket bond is $50,000. I am fortunate to have surety company participation. My conditions to have this bond is a 40 percent collateral and a 3 percent yearly premium. My actual cost is $20,000 cash held by the surety company and a $1,500-a-year premium charge. The OCD proposal would require I increase my blanket bond to $125,000. I would then have $50,000 cash held by the surety company -- it's a $30,000 increase -- and have a yearly premium of $3,750. That is a $2,250 increase. This is assuming that the surety company, after reviewing my financials, will be willing to accept the increased risk at the 40 percent -- excuse me -- 40 percent collateral or increase that as well. The surety company could also refuse an increased level of liability at any level of collateral.

(C) State statute allows for the use of an irrevocable letter of credit as financial assurance. This option is common. Lending institutions require cash or property to be encumbered as collateral. The encumbrance of assets, along with the reduction in the amount of credit now available to the operator, further restricts his operations.

(D) Cash is another form of assurance used to provide assurance. To increase the level of cash required to meet the OCD proposed ratios would be a challenge even for the most financially secure operators.

(E) Sale of assets to provide the additional resources would normally be an option. The dramatic increases of assurance proposed by the OCD has already seriously reduced the value of producing properties. Full implementation, if adopted, will further reduce the marketability of an operator's property.

The phenomenon of increasing regulation expense on operators can easily be examined right here in our own industry. The increased regulatory activity to include the latest round of bond reviews by federal agencies has depreciated the value of stripper wells on federal land to the point of making them nonmarketable.

Even the most aggressive buyers are not interested in stripper wells on federal land.

The proposed OCD amendment could conceivably result in financially destroying many small, medium and even some larger operators by forcing them to divert cash or other resources to the most nonproductive part of their business. The reduced value of properties and the reduction of available credit from already worried lenders is an additional negative result.

(H) The proposed OCD amendment will most likely result in an increase of the number of properties abandoned, also reducing the OCD's ability to market any of those properties -- excuse me; let me start over -- reducing the OCD's ability to market its already full portfolio of abandoned properties.

Number 4: The OCD proposed amendment to Rule 19.15.8.9, Subsection D, Part 1 has proposed a single well financial assurance in the amount of $25,000, plus $2 per foot for wells categorized as temporarily abandoned.

We respectfully request that the Commission consider the alternative of financial assurance requirement of a $5,000 base, plus $4 per foot of depth.

(B) The level of assurance we are requesting will more accurately reflect a practical level of assurance for the shallow wells abundant in southeastern New Mexico. The requested $5,000, plus $4 per foot will also provide the amount of assurance necessary for deeper wells.

(C) The more shallow wells are attractive to entry level operators, as well as small operators expanding their business. These wells also serve as a type of apprentice or incubation program for new operators. Shallow wells are traditionally less expensive to operate and have provided a foundation for some of the most successful operators in this region.

(D) The level of assurance as proposed by the OCD will be prohibitive to any operator attempting to purchase inactive wells with the intention of reworking them to bring them back into production further limiting potential.

Number 5: The evidence and exhibits provided by the OCD in the pre-hearing statement are informative and thorough. That material does not demonstrate that by implementing the ratios of assurance or the increasing -- or increasing the amount of assurance for the single-well bonds as proposed by the OCD will serve to produce any positive results. As a matter of practicality, the OCD amendment as proposed will further expose the OCD and taxpayers to even more liability and less income from the affected properties and operators. The obvious detrimental conditions created by massive increases of financial assurance make the OCD proposed amendments counterproductive.

Number 6: The evidence and exhibits provided by the OCD expose facts that will not be remedied by raising the amount of financial assurance.

(A) Exhibit 6, "List of Wells Plugged" provides a list of wells plugged by the OCD over the last few years. I can find -- or I have no information that these wells were plugged using funds obtained from forfeited financial assurance provided by the operators. To properly demonstrate that a simple increase of financial assurance will benefit, we must examine where the funds to plugs these wells originated.

(B) Without all the information required, I am left to speculate that most, if not all, of the 145 abandoned wells were plugged using funds procured from the Oil and Gas Reclamation Act or litigation, neither of which would be avoided by increasing the amount of financial assurance provided by reputable operators.

(C) My research did allow me to conclude that over 80 percent of the wells listed in Exhibit 6 were operated by out-of-state operators.

(D) Further research revealed that of the ten operators associated with these wells, two individual operators accounted for 100 of these wells, both out-of-state operators.

Number 7: Exhibit 7, "Rule 5.9 Compliance List" provides a list of wells in the category of inactive. Most of the wells listed are on the list because of reporting issues, waiting on repairs, et cetera.

I believe the OCD provided this compliance list to demonstrate the large amount of inactive wells and potential liability to the taxpayer. This list does serve that purpose.

Additionally, this list also provides more evidence that the majority of the wells that will eventually be plugged by the OCD will not be plugged using forfeited financial assurance funds. These wells, when plugged, will be plugged with money procured from the oil and gas reclamation fund. Again, the largest share of this future liability comes from out-of-state operators.

(B) The compliance list contains a list of wells owned by 136 individual operators or companies. These operators and companies have a total of 10,351 wells with 1,738 of these wells listed as inactive. Further investigation into this has led me to the conclusion that the number of inactive wells on state or private leases is actually 949. Most of these wells are classified as inactive because of late production reports, waiting on workover equipment, et cetera. These wells are normally inactive for a short period of time.

(C) The OCD requires financial assurance from the operator on wells that are on state or private leases. Of the 1,738 wells categorized as inactive, only 949 of these wells require OCD-administered bonds of any type.

(D) I do note that the OCD did plug nine wells shown as federal. These federal wells, by statute, could be plugged using the money procured from the oil and gas reclamation fund. This money is not relating to financial assurance provided by the operator.

The increase in financial assurance will not reduce the number of existing wells already abandoned by defunct operators.

The BLM -- I'm sorry.

(F) The BLM requires its own financial assurance for wells on federal property.

Number 8: These comments of conclusion are based on our perception of the issues of financial assurance based on my own experiences in this industry, the information I researched for this hearing and input from at least a dozen experienced independent operators.

(A) The increase of financial assurance will not be of benefit to the operators, the OCD or the taxpayers. The only people that will benefit from increase in financial assurance is the people that provide that assurance. There is no evidence provided to prove that a massive increase in financial assurance will improve this situation.

(B) The increase in financial assurance will not increase the amount of funds available to the OCD to plug wells. The only practical method available is to increase the funds available via the oil and gas reclamation fund.

(C) The natural course of business is that some operators will go broke. Also, no amount of financial assurance will completely protect us from people with nefarious intentions. Considering current bankruptcy laws and the cost of litigation, we need to adjust our policies.

We would be willing to support the OCD and modifications required to better use the oil and gas reclamation fund.

To summarize, myself, the members of the

IPPC and nonmember independent operators consulted respectfully request the OCC to consider the facts of the case and implement the amendments as we have requested.

Thank you.

CHAIRWOMAN RILEY: Thank you, Mr. Marker.

MR. MARKER: Am I done?

COMMISSIONER BALCH: You can be cross-examined, if you'd like to answer questions.

MR. MARKER: It doesn't bother me. Go ahead.

MR. BROOKS: No questions.

MR. LARSON: No questions.

CHAIRWOMAN RILEY: Questions?

COMMISSIONER MARTIN: No.

CHAIRWOMAN RILEY: I don't.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I've got a couple of questions.

A. Okay. Go ahead.

Q. First of all, thanks for coming here today. It's very important, I think, to hear the perspective of the stripper-well operators.

A. Yes, sir.

Q. They're a lot of, I think, a big chunk of production that doesn't get --

A. And I can promise you there is no place I'd rather not be (laughter), to be real honest.

Q. The individual bond --

A. Yes, sir.

Q. -- if you have a couple of individual bonds and then you end up with a few more wells, you can go to a bulk bond and pull back those individual bonds, right?

A. Yes, sir. You can do that. And my point is if a guy -- if a guy wants to get started in the oil and gas business, he'll pick up one or two wells, and if it goes pretty good, then he'll go buy -- you know, he'll go buy a blanket bond, which generally works. Typically, you have to be in the business quite a while to be able to get surety company participation. The only way I was able to accomplish that is at one point, I was actually at 100 percent collateral. Normally, a person wouldn't go through that process, but I went through it to build a relationship with the surety company because I knew -- down the road, I had intended on growing my business, and I could also see that eventually we're going to have to change the way we do business.

Q. Did you put up your wells as the collateral?

A. No, sir. The bank typically -- the banks I deal with won't --

Q. They know better?

A. They know better (laughter). I wasn't going to say it like that, but yeah.

Typically, on my surety -- my surety company requires cash. I'm still in the process of getting all of my federal bonds moved over to the surety company, but right now, the way I was having to do it, when I got started, I bought a couple of federal wells, and I thought life was wonderful. I went and put up a metal building. I got $25,000. I ran down and bought a CD and put my bonds up, and I was off and running.

It took me a little while longer to get a state bond of $50,000 collateral, but I was able to do that. And now my business has grown to the point where my balance sheet reflects enough that the surety company will ride with me. Most people don't have that option.

Q. So IPPC, that's your cooperative?

A. What we did --

Q. How many participants in there?

A. Right now we've got seven participants. We're probably going to max out at 20 participants.

Q. How many wells?

A. 5-, 600. Easily 5- or 600.

Q. So as a cooperative, you might be able to go for the bonding at the 250,000 level, the blanket bond.

A. It's kind of funny that you mentioned that. Right now we sat down -- we all sat down -- actually, we don't sit down anywhere together. We're typically running all over the place. We might run by a rig when we're working or whatever. But what we've decided as a group is there is no way any one of us can provide a full office staff for anybody. It just can't happen. And we're sick to death of waking up at 3:00 in the morning because we're six months behind on our reporting; Daniel's probably trying to avoid the phone or whatever. No. You know, me and Daniel actually have a relationship.

But what we decided is what we want to do is we want to change the way we do business. We want to stay current on our reports. We want this co-op to address any of the issues that the small independent operators have. Right now the biggest issue, the one that was biting the most of us and not so much on the state reporting as on the federal reporting, the ONRR federal reporting is just a nightmare. Okay? We've got a girl in place now. She's got everybody caught up. We're gaining new members. That's why we're growing slowly, to get everybody caught up. We charge a fee for that to the member, plus the monthly investment capital fee. Eventually, we will be able to roll that investment capital into retirement.

But my -- my personal goal -- and, of course, I'm not the full co-op. My personal goal and where we were headed for is I was researching the possibility of finding an underwriter so we can self-bond. That way all of the guys could get a surety company, because it made a massive difference in my life. And not everybody is going to be able to go through the struggles that I did to get a surety company relationship, especially now.

So our next -- our next idea -- and that actually is a good idea.

Our next idea is to figure out a way for bonding wells for the individual operators, you know, as well as everybody else. And I was talking to a couple of guys a while ago who are trying to do business differently than what we've done in the past. That's just the way it is. Things are different.

Q. So your group of stripper operators is averaging 70 to 80 wells apiece. So 600 wells --

A. I'm probably one of the more aggressive -- one of the more aggressive. I rolled into the industry about six years ago. I was tired of working in town. I wanted to get back in the oil industry and buying, selling, trading, swapping. And a lot of opportunity presented itself when the market cratered that normally would not have been there. I made a couple of pretty good deals, some rougher deals, whatever, but that's basically how I survived, and that's how I've grown my business basically debt free. So, you know, my balance sheet looks pretty sweet to a bonding company. And you and I both know my balance sheet and cash position probably are pretty bad.

The average stripper weller -- and I'm stalling because I was hoping Buddy would slip me an answer. But I would say -- we've got Steve here.

How many wells you got, Steve?

MR. OLDFIELD: 20.

MR. MARKER: He's got 20 wells. Two of those are state wells.

MR. OLDFIELD: Three.

MR. MARKER: Three of those are state wells.

COMMISSIONER BALCH: 17 are Fed?

MR. MARKER: And 17 are Fed.

MR. OLDFIELD: I've got eight federal, eight state.

MR. MARKER: Eight federal, eight state.

We've got -- we've got -- how many wells does Louis have?

MR. OLDFIELD: Probably similar to what I have.

MR. MARKER: Probably similar.

Q. (BY COMMISSIONER BALCH) So for your stripper wells -- just for your own 77 wells --

A. Yes, sir, my own state.

Q. -- what's your monthly production?

A. My wells are a little different because I have taken a bunch of properties that I continue to work on. And that's kind of my deal, is I take environmental issues that people normally wouldn't take. For whatever reason, my personality, I don't judge consequence real well, so I'm liable to jump into anything with both feet, which has made my dentist a lot of money over the years, but it hasn't served me too well all of the time.

But anyway, the average stripper well, I would say, is going to be somewhere between a half and a barrel a day.

Wouldn't you, Buddy?

MR. DeLONG: Uh-huh.

MR. MARKER: Realistically. I mean, we're all going to sit around and say, I've got 16 2-barrel-a-day wells. No, you don't.

Q. (BY COMMISSIONER BALCH) So what's your net out of that?

A. Right now --

Q. Let's say 30 barrels a month for one well at -- I think it was 60 the other day. But that's not the price you're going to get.

A. Yeah. That's not the price you're going to get. It gets really, really complicated really, really easy.

You can have as many wells as I have and sell six loads in a month, and then the next load, you might sell 12 -- the next month, you might sell 12 loads. Or the issue with a stripper well is you might have one well here making you a half a barrel a day going into that tank. And then you've got three wells over here. Each one of these makes a half a barrel, but they all go into the same tank.

And then I guarantee you, 30 percent of the wells that you're operating will break. There are only two kinds of stripper wells in the world: broken and breaking. There is no in-between. It's a constant.

Q. Right.

So let me phrase it a little bit differently. What's your break-even point? Half a barrel a day, right now it sounds like you can run a stripper well.

A. I can operate a stripper well at a half a barrel a day. Now, I'm a little, again, unusual. I've got my own pulling unit, my own water truck. I do all my own work. I'm the one-man pulling unit crew. Steve's another example of that. We can't -- we can't really afford to -- practically to pay somebody to come pull our wells and stuff, so there is a challenge.

What I would say -- and then we recently just had an increase in our electric price, which is more of a challenge.

If we could keep oil at $60 a barrel -- the advertised price of 60 bucks a barrel, that gets me, for the oil that I sell -- we're taking a $10 hit in southeastern New Mexico right now because of the pipelines and the trains and that various thing. So if you've got -- let's just go 70. If you've got $70 crude WTI, you take that $10 hit when you're going to get your reduction. You're going to get your reduction for sour crude or whatever. So if it's $70 crude, I'm confident my best crude I'm going to sell for -- you've got ten. That's 60. I'm going to get 75 percent. My average net revenue is 75 percent of, let's say, $57. That's what I actually bring -- that's what I actually have to pay my bills with.

Any amount of money that we take out of our cash flow, some months it's better than others. It's an ugly business, especially right now.

In February of 2013 -- I'm sorry. In February of 2016, I sold 22 loads of crude oil, and it did not pay my electric bill. That's ugly. It's gotten continually better. My best lease I sold -- when did I sell the -- like two years ago? About a year and a half ago. I sold my best lease about a year and a half ago. The down- -- the downturn lasted longer than what I had anticipated. I was a little too aggressive rolling in, so I ended up selling my best property to go ahead and get my debt taken care of. And I had some issues on some wells around Roswell that me and Daniel had worked on that I'm getting squared away.

Q. So you're 77 wells (indicating).

20 wells (indicating).

MR. DeLONG: 16.

COMMISSIONER BALCH: 16.

MR. MARKER: Those are -- his are federal and state.

Q. (BY COMMISSIONER BALCH) Federal and state.

And out of all the stripper-well operators, you know, what's a good average number, stripper wells?

A. Number of average -- average number of wells?

What's Daryl got?

We actually had two other stripper wellers calling [sic] in today, but one was so nervous, he got sick and had to go home.

MR. McMINN: Your question was what, Commissioner?

MR. MARKER: The average number of wells --

COMMISSIONER BALCH: I'm trying to figure out how many -- how many stripper wells you have to have to make a viable operation. It sounds like at least 16 or 20.

MR. McMINN: Not necessarily. I mean, it's not just -- they're not all just a half a barrel a day. I've got some that are three barrels a day and one that's five. But I guess to cut to the chase on what Larry was saying, half a barrel a day will net you $12,000 a year, and you figure you may spend $1,500 over the year's time on electricity -- on electricity. If you have ten of those and it's not something where you're totally away at a desk every day for eight hours, you're going --

MR. MARKER: There's no doubt it's a rough life.

MR. BRANCARD: Excuse me. Can we just get your names for the record?

MR. DeLONG: Buddy DeLong.

MR. OLDFIELD: Oldfield, O-L-D-F-I-E-L-D.
Q. (BY COMMISSIONER BALCH) So it's pretty variable, but more than ten?
A. Yes, sir, I would say so. Yes, sir. Typically, ten wells. If a guy comes into the business and he picks up less than ten wells and he stays that way for very long, he's typically looking to sell those wells and get out of it because it's more work than what he had anticipated. Or -- or he typically goes past that point and decides, Hey, this is something I want to do. Unfortunately, we haven't had a whole lot of people saying, Hey, this is something I want to do, in the last few years, but things are improving.
That's another reason for the co-op. A guy can walk in and buy four or five wells. He's never -- he's never going to get behind on his reporting. He's never going to have the regulatory issues that I had when I started. You know, getting behind -- the first red flag that I see -- and I've been told by other operators. When the OCD sees you get behind on your reporting, the red flag goes up. Then you're on the radar. I actually got into this business trying to fly under the radar. I just didn't do a very good job.
Q. I think however this turns out, you ought to talk to the OCD about getting your cooperative to be an

entity for the purpose of bonding.

A. And I will say -- and I'm not -- believe me. I mean, I'm impressed with, you know, the evidence today and all that. I'm not knocking the OCD at all. I've worked with the BLM. I love the OCD.

(Laughter.)

A. I mean, maybe that's not a popular thing to say. But Daniel has -- truly, Daniel and Keith, both, have gone out of their way.

MR. BROOKS: That's a popular thing to say around here.

MR. MARKER: Sir?

MR. BROOKS: That's a popular thing to say around here.

MR. MARKER: Well, the last 33 wells that hit my -- and the reason I'm showing 21 inactive wells on my inactive well list is in February, we put 33 inactive wells on my list, some wells I brought from a buddy and it's a long story. But I'm just going to tell you. Had Daniel not worked with me, that was another 33 wells that the OCD was going to end up with. Instead, we worked it out. He said, you know, You do your seven years of reporting, you get Johnny's [sic] reports current, you get all that done, and we'll let you -- we'll let you continue on.

I'm going to drop three more of them off of the inactive well list this month. I'm waiting on the right-of-way stuff from the BLM, or I would have had nine more off this week. But I'm still waiting on rights-of-way on wells that are 40 years old, but that's another story. And then me and Steve, we're going to check six more on the way home, see if I can call CV and have the meters put in. That'll be another six that'll be off the inactive list.

But that tells you the inactive list is basically pretty fluid. Now, you've got EP, Canyon, Cano and those people who are headed for a wreck. But typically, stripper wells, that list -- like I said, 30 percent of them are going to be off anyway. Normally, they won't hit the inactive well list unless you don't report them for 60 days. And you try to stay off the list. The ultimate goal is to not have anything on the radar.

Q. (BY COMMISSIONER BALCH) I think I also encourage you to shop the list of orphaned wells, see if you can acquire some of those.

A. Actually, another thing Daniel has done -- a friend of mine, the guy that actually ended up throwing up and had to go home, he was working with Daniel to buy some of those wells. Daniel actually has been marketing those wells. Him and Daryl come to an agreement. And then the deep rights operator apparently didn't want the deal to go through. You'd have to ask him the particulars. But Daryl was upset or was pretty frustrated.

The OCD has been trying to sell those wells. I believe we need to give them some -- well, maybe some help somehow or another. But I agree with you. There's opportunity there. Right now I'm kind of hamstrung. I've got another deal. I'm kind of hamstrung with what I've got going, but, you know, at the end of the year, beginning of next year, we've got several guys from the co-op that would look to drill.

Plus, with our co-op, like I said, if a guy has been thinking about getting in the oil and gas business, if he wants to pick up 10 or 15 wells, gets ahold of Daniel, talks to Buddy, gets with Mr. Fulton or whatever, they go check these wells and yeah, you can make a go of it, then they can get set up with the co-op, stake themselves a well if everything's good.

The problem that we have with the increase in bonding, that's going to be a challenge. We understand that the taxpayer needs to be protected. We completely -- we understand that.

You know, I can't tell you how many wells

I've wanted to buy or how many units I wanted to buy, and some big out-of-state -- some big out-of-state operator ended up with it. And I knew what he was doing. Worked the thing for six months or a year, decided he couldn't make any money, strips all the pumper jacks, takes the tubing -- takes the tubing rods and leaves. That was the lease that I was trying to get bought, but I didn't have the money to get it done because the guy overbid me. Now he's gone.

MR. DeLONG: And we're still here.

MR. MARKER: And then we drive by those daily.

I don't understand exactly -- there must be -- it must cost more to litigate those cases. I wouldn't want the challenge of trying to figure that mess out. I believe the OCD is qualified to take care of the situation. The people that would we have on staff -- and I say "we." The people we have on staff with the OCD are more than qualified to take care of the situation. We just have to give them the right tools.

As far as the assurance goes -- and obviously this is just my humble opinion. As far as the assurance goes, just giving somebody a bigger hammer isn't always the answer. Believe me. I'm from the bigger-hammer crowd. You know, get a bigger hammer. I really think that increasing the financial assurance to this amount is basically just saying, The state legislature told us to take it 250. And believe me. We appreciate the fact that you guys are considering -- I call them ratios. You call them -- we appreciate the effort that you guys are taking in this deal, but just to give -- just to put this into place, simply because the state legislature told us to, probably doesn't make a lot of sense because I really don't think the state legislature knows anything about the oil and gas business, for one. Just my opinion.

Q. (BY COMMISSIONER BALCH) Thank you, Mr. Marker.

A. Thank you.

CHAIRWOMAN RILEY: I don't have anything.

Mr. McMinn?

MR. McMINN: I don't know how I can follow that.

My name is Rory, R-O-R-Y, McMinn, M-C-M-I-N-N. I'm here representing an entity called Quatro Osos E&P, LLC. We are OGRID Number 372241.

We bought our first set of 17 wells in April of last year, operated those up until January, added enough more wells to get us a total count of 64. Our wells are located approximately 22 to 25 miles east of Roswell on a little San Andres trend. Our deepest wells are just barely over 2,100 feet deep. And we have three inactive single-well bonds posted, and those were part of a sell package when we closed on the balance of our wells the first of January.

The principals of Quatro Osos are four couples. My wife and I primarily do the operating of Quatros Osos because of our proximity to the wells. Our goal has been to take wells that have been -- the best term would be a total lack of maintenance, and so what we've done -- we were fortunate enough to gain the services of a pumper who was involved in cable tooling many, if not most, of the wells that we bought. So his experience in the field is great for us and gives us the historical connection that we need.

The issues that we have, as Larry has pointed out, revolve around just the normal course of business and expenses that you have to deal with. And so when financial assurance came forward and was first brought to our attention, it really caused great concern on our part because of the fact that all of our bonds, including our single-well bonds, are cash bonds. So all of the cash that we have in the bank to cover those bonds are encumbered by the State Land Office or the OCD, and we have no access to those funds. So we've taken working capital and moved it into the bond arena.

So out of the 64 wells that we have, 61 are producers, and we produce between 50 and 55 barrels a day. So we're averaging less than a barrel a day per well. Last month, we sold 1,417 barrels, and we've sold five loads so far this month. We rebuild four pumping units a month. A group out of Hobbs comes over. We just pulled a well yesterday, had to lay down a whole string of tubing and rods because of corrosion. And so our expenses at this moment are extremely high because of the fact that we're reworking these wells and trying to get these wells on a consistent basis. Consistency -- Larry's right. They're either broken or they're breaking, and so consistency is a problem. And Mother Nature is no great help when it comes to electrical storms and that kind of thing. We've burned up several control boxes, you know, at 12-, $1,300 apiece. So we count our pennies.

In essence, what I'm representing is a mom-and-pop operation. And I've worked for family-owned companies. I've worked for a large Australian company here in the United States. And so my experience in dealing with the large operations and a very large budget was great, but the freedom that I have in being able to go out and do what I do on a daily basis in the field, I can't get that and could not get that with any of the employment that I had prior. So at my age, I did not to want retire, and I wanted to continue to work. And so my partners agreed with that, and since I'm the one doing the daily work, it was real easy for them to agree to it.

And so the point that I would like to make to you is that we support the presentation as amended today by IPANM on the tier structure for the financial assuredness on the bonds. We also support the Independent Petroleum Producers Cooperative position in regards to the inactive well at $5,000 per well and $4 per foot.

The issue that I have is payback. So what is being proposed currently by the OCD to me takes a sixth of my annual income to recover that revenue. It's going to cost us out-of-pocket, in order to come up with the difference, just under $140,000 to post those additional cash bonds. That's my cash flow. You're taking cash flow for a couple of months out of our pockets. We amortize that, of course.

The other issue we have -- in addition to the fact that I'm not Devon, I'm not Concho, I'm not Marathon -- is I have no public money. Money that we put into the business, my wife writes a check out of a joint account. So any income that may come in, we're turning around and putting it back, and every month we add a little more out of our bank account in order to make ends meet, as do my partners. So we split things four ways. I have one CPA in Artesia who has a quarter of 1 percent that was bequeathed to her by her mother, and she'll never sell it. So other than that, there are four working interest owners. We have a 75 percent net revenue, which in the state of the things makes it difficult. On those state wells that have already been applied for, we have a reduced royalty that the State Land Office allows us to apply for, and that differential is phenomenal in the amount of income that comes in.

And so the concerns that we have are that the things that we hear being spoken by the OCD and personnel indicate to us that there is a negative bias towards the small operator, and that's very concerning to us because -- because of the fact that we believe that we are part of what made this state what it is in regards to operations. We wouldn't be here in many instances if we hadn't been in a position to take the wells that the bigger operators didn't -- no longer wanted to have, because they could not operate it with their overhead.

So being able to do what Steve and Buddy and Larry and others do keeps these things active.

We have depth limits on the wells that we have, so we're at the total depth of the wells. We can't improve our position any at all by drilling into the P3 or the P2, so we're producing what we have. We've accepted it as it is. We're -- we have the ability to generate a little cash flow on a monthly basis, but determining that we're going to have to come up with additional money is -- I mean, we've been -- everybody -- all my partners and I have been saving money since this first came through the legislature in order to try to be able to have it when the time comes in order to make the payment. We don't think it's a matter of whether this is going to get done. We think it's a matter of when it's going to become official. So we're trying to acclimate ourselves to that position.

One of the things that concerns me greatly about the presentation today, which was well done, by the way, and I failed to thank you-all for having this hearing. I mean, the legislature allowed you-all to have 250,000. You could have just gone 250,000 without having the hearing. But we appreciate the Secretary's position in wanting to consider a tiered approach. We appreciate that very much, and we are thankful to be able to participate in the hearing.

But the FTE count, the administrative burden statements, the lack of statistical data that's available through the OCD is of a cause of great concern. The State Land Office and the OCD are the repositories of all of the knowledge of oil-and-gas income, sales, acreage sales and everything for the State. If we cannot come to you-all to get statistics such as how many bonds have been redeemed on operators that have gone out of business, if you can't even tell us that number, then there's a problem.

So I'd like to make a suggestion in closing and that is, Commissioner Balch, who works for New Mexico Tech, which is crawling with ants named students that are technically oriented, and I think the reclamation fund money, you need to make a long-term arrangement for analysis through those students and gather the statistics from the data that you already capture that you don't know how to put together, because you get -- you have that data. I have no doubt. But you just don't know how -- you haven't been able at this point in time to disseminate it.

So I would recommend that some of that money is used for that because I think that the manner in which these kind of things, like financial assuredness, could be done in the future would be done upon accurate numbers rather than it costs an average of $33,000 to plug a well. Mine are between $8,200 and 10,000, what it costs to plug one of my wells. So $33,000 is ludicrous. I mean, paying the bonds, you know, the single-well bond -- I will plug three wells when this is implemented, if the single-well bond comes in, at $25,000 per well. It's cheaper for me to plug them than it is to pay $25,000 a well.

So we have wired two of the wells, put motors on two of the wells, are putting control boxes on two of the wells and stringing flow lines to two of the wells in order to try and activate them. But if it comes in at 25,000 and I don't have that done, I'll take all that equipment off and plug them because I can't afford to pay $25,000 per well.

So with that, I'll close and stand for any questions.

MR. BROOKS: No questions.

MR. LARSON: No questions.

COMMISSIONER MARTIN: No.

CHAIRWOMAN RILEY: I don't have any.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Do your number of wells and economic analysis fall pretty much in line with Mr. Marker?

A. It's all the same. Yeah.

Q. But you can do the same thing. If you have a $25,000 bond per well, after two wells, it makes more sense to have a blanket bond.

A. Forgive me?

Q. If you have two wells at 25,000, it makes more sense on your third well to have a blanket bond for 50,000?

A. Correct. Yeah.

Q. So I think you maybe understand that the quandary that we're facing here. You guys are -- you're the good guys. You're doing everything right. You're on the up-and-up and making sure you're responsible for your properties, and there are some people that don't do that. And, unfortunately, they make it harder for everybody else.

A. Right.

Q. That's why the OCD is asking for a regular surety. You guys aren't the problem. We want to make sure that we don't get rid of the good guys or the bad guys, right?

So is there maybe some compromise levels, somewhere in between the IPANM proposal and the OCD proposal that might bring a little more comfort to an operator like you?

A. Currently, we have about $7,200 on each well -- on each of the three wells that is held at the bank for bond. That's below our plugging cost, so it's easy for us to justify that. If we were to do the $5,000 and $4 a foot, we need -- "we" meaning the royal we in the room. It's your decision, not mine. But if that decision was made, it becomes -- it becomes a teeter-totter for us because it's just over that $10,000. It would be $13,000 or 13,5-, something like that, on a per-well basis we'd have to post. So if we did that, that would be -- each would be $30,000, still below the $50,000 blanket bond. But if -- if we do a $50,000 blanket bond, it's still cheaper for me to plug three wells than it is to --

Q. Now, is there a way that you could demonstrate to Daniel, for example, that your plugging cost is $10,000 -- 8- to $10,000?

A. That the plugging cost is --

Q. 8- to 10,000 and not 25,000.

A. Yeah. We can put an AFE together very easily.

Q. I don't know about you, but I haven't seen an AFE come in on target yet.

A. Well, we've -- we've -- you know, because of the way we operate, we don't AFE anything because, you know, what we're doing is maintenance -- maintenance, repair and operations.

Q. But you have a receipt from the same field for plugging a well, maybe, that shows that it's 8- to $10,000?

A. Yeah. You know, that can be done.

Q. So maybe the thing to do is for the individual bond, put a little language in there that allows for a variance if you can demonstrate that your cost is significantly lower.

A. We'd -- we would welcome that kind of change to it.

Q. Okay. Thank you.

A. Thank you.

CHAIRWOMAN RILEY: Are there others out there that would like to make a comment?

I don't have anybody else on the list.

So that concludes public comment time.

Any other matters of business we need to take care of before we close down and go into deliberation?

MR. BRANCARD: I believe the parties would like final closing statements.

CHAIRWOMAN RILEY: Okay.

MR. BROOKS: Do you want to proceed with those now?

CHAIRWOMAN RILEY: How are you doing?

(The court reporter responds.)

CLOSING ARGUMENT

MR. BROOKS: Madam Chair, Honorable Commissioners, I'm going to be brief here, just a couple of -- or just a few points I want to make.

One is that adequate bonding will prevent or will minimize the necessity to pursue litigation against operators in bankruptcy court or otherwise to recover costs of plugging. I led my witness through the provisions of the Oil and Gas Act on the subject of priority of funding plugging operations, and it's very clear that the -- to me and I would argue it should be clear to any reader that the legislature intended our primary resource to be financial assur- -- operator financial assurance that we're forfeiting.

First of all, we can't actually, in a practical manner, forfeit it until we plug the well because you have to prove damages to recover from the surety company, and we don't want to litigate with the surety companies. They usually pay up promptly.

So what we do is we plug the well, then we forget the bond, and then if the bond is not adequate, we've got to decide how we're going to get back the rest of the money, which we have a right to, from the operators, but we have to file suit. And it may be in bankruptcy, and there may be costs involved in that. There definitely will be some costs, and they may be large. And there is an uncertainty of getting your money back, because if it's in bankruptcy, you may not get it all, and if it's not in bankruptcy, you may find you get a judgment that can't be collected. We avoid all those problems if we have adequate financial assurance to cover the cost of the plugging.

The next point I want to make is about federal wells. I believe it is very unlikely that the State of New Mexico would ever, under any circumstances, have a claim or cause of action that could be enforced against the United States for plugging any well unless we had an express contract with the United States to bring that claim in a court of United States Court of Claims. I just don't think it would ever happen.

Now, we have worked the BLM, as Ms. Marks testified, since she's been in charge of that and before that, when I was in charge of it. And Ed Martin was in between us there. He was in charge of plugging operations before he left -- before he defected to the State Land Office. But under everybody that's been under it, there's been an effort to work with the BLM. Sometimes we've worked with the BLM successfully.

Sometimes we've not.

But the point is the State of New Mexico has an interest in getting wells that need to be plugged. If they are not plugged, they may affect correlative rights by reducing the production available from wells that are producing, and they may cause environmental damage from subsurface conditions. So the State of New Mexico has a responsibility to our citizens to see that wells are plugged when they need to be plugged, even if they happen to be on federal land and we are not able to make satisfactory arrangements with the United States Bureau of Land Management or if they're on tribal land and we're not able to make satisfactory arrangements with the tribe.

Now, contrary to what was suggested by the public commenters, I want to assure them that I don't know anybody at the OCD who has any bias against small operators. It is true that we have more noncompliant small operators than we have noncompliant big operators, but it's also true that the police pick up more poor people for vagrancy, back when that used to be allowed, than they do rich people for some obvious reasons.

We are sympathetic to the small operator, and the OCD staff would not oppose making some accommodations, including those suggested by Dr. Balch just a few minutes ago. But we do believe that the legislature has directed this agency, and we believe that the Commission should make it our general objective to get every well adequately bonded to the extent it's within our power to do so and it can be done without causing waste. For instance, in some situations where an operator could not bond a well, there might be waste issues, we would not object to adjustments for that. But to the extent it could be done so without waste, it should be, because the legislature has told us that and because it's to the interest of the citizens of the state of New Mexico.

Thank you.

CHAIRWOMAN RILEY: Mr. Larson.

CLOSING ARGUMENT

MR. LARSON: Madam Chair, Commissioners, IPANM acknowledges that the legislature has given the Commission a mandate to increase the blanket of single-well bonding requirements and also acknowledges the need to update bonding levels, which Ms. Marks has testified hasn't been changed since 1977. Nevertheless, the Commission afforded considerable discretion in establishing the tiers of blanket bonding maxed out to the cap of $250,000.

A significant number of IPANM's members are small independents who operate marginal wells on very tight operating budgets. Given that requiring IPANM's members to tie up significant amounts of what would otherwise be operating capital in Division cash bonds would place a substantial financial burden on them. Consequently, IPANM has proposed blanket bonding amounts that are different from those proposed by the Division, including a fifth tier intended to provide relief for the smallest operators, independent operators who have ten wells or less, as well as reduced bonding amounts for other tiers.

The first tier which IPANM proposes, which is $25,000, for an operator with one to ten wells would significantly reduce the financial burden on these operators and help them to maintain their financial viability. IPANM's proposed reduction would also make the bonding requirement less of a barrier to entering for entrepreneurial independents who would like to conduct oil-and-gas operations in New Mexico, particularly in the Permian Basin.

IPANM also requests reduction in the three tiers for the very same reasons. The reduced bonding amounts free up cash that the operators can utilize for operative costs and other expenses. Again, these bonding amounts will directly impact the financial viability of these operators to provide jobs and contribute millions of dollars of revenue yearly to the State of New Mexico. The amount of cash tied up in a blanket bond could potentially be a significant factor in the prospects for a small independent operator staying in or going out of business.

The bonding amounts in the proposed rules are insufficient to cover the Division's average plugging costs for the number of wells in any of the tiers. And, thus, the respective bonding amounts are not grounded to any plugging costs equivalency. Given that, IPANM believes that the Commission, in the exercise of discretion, should take into account the significant financial burdens that the bonding requirements would place on small independent operators and weigh those burdens against the regulatory issues raised by Ms. Marks.

And in sum, IPANM requests that the Commission adopt its proposed changes to the plugging financial assurance amounts proposed by the Division.

CHAIRWOMAN RILEY: Thank you.

Anything else we need to take care of?

MR. BRANCARD: No.

CHAIRWOMAN RILEY: Is there anything else before we close and go into deliberation?

MR. BRANCARD: You can't close the meeting. You deliberate in public.

COMMISSIONER BALCH: No matter how much you want to.

CHAIRWOMAN RILEY: Yeah, I know.

MR. BRANCARD: I think we're done, and I think the record is -- the Commission can always re-open the record if necessary.

CHAIRWOMAN RILEY: Okay.

MR. BRANCARD: At this point, you'll begin your deliberations today and tomorrow for the Commission meeting. So you can start the discussion and see how far you can get on this so far today.

CHAIRWOMAN RILEY: Okay. Is that okay with the Commissioners?

COMMISSIONER BALCH: Works for me.

CHAIRWOMAN RILEY: Are you okay with that?

COMMISSIONER MARTIN: I'm good.

CHAIRWOMAN RILEY: All right. Let's begin deliberations.

MR. BRANCARD: Mr. Feldewert?

MR. FELDEWERT: Madam Chair, members of the Commission, I'm sorry to interrupt. There are some other matters on the docket. Is it safe to assume you'll get to those in the morning?

CHAIRWOMAN RILEY: I believe you are safe in assuming that.

MR. FELDEWERT: Appreciate that. Thank you.

MR. BRANCARD: Mr. Brooks, did you submit another exhibit?

MR. BROOKS: I did. I think I handed copies to everyone, Exhibit Number 12, which is the proposed change in definition of the --

MR. LARSON: I don't think it was admitted into the record.

MR. BROOKS: Okay. I will then offer it as an exhibit.

CHAIRWOMAN RILEY: Do you have any objections?

MR. LARSON: No objection.

CHAIRWOMAN RILEY: Okay. So Exhibit Number 12 is admitted into the record.

(NMOCD Exhibit Number 12 is offered and admitted into evidence.)

MR. BROOKS: Okay. Thank you.

CHAIRWOMAN RILEY: Thank you.

(Open-session deliberations, 3:58 p.m.)

CHAIRWOMAN RILEY: Do you guys want to start this from the beginning, tackle the definitions first --

COMMISSIONER BALCH: Sure.

CHAIRWOMAN RILEY: -- because those ought to be fairly easy?

The first change is measured depth. Everybody comfortable with that change?

COMMISSIONER MARTIN: Yup.

COMMISSIONER BALCH: Yup.

CHAIRWOMAN RILEY: As am I.

Everybody okay with "temporary abandonment," adding "or temporarily abandonment status" for clarification?

COMMISSIONER BALCH: Is that additional language because of another OCD form?

MR. BRANCARD: I believe the phrase is used in the financial assurance rule because it's a phrase that's in the statute. So normally throughout the rules, we use the phrase "temporary abandonment." But in the financial assurance provision in the Oil and Gas Act, it uses the phrase "temporary abandoned status." So the attempt here is to try to make it clear that those two phrases mean the same thing. So it's used several times in the financial assurance rule because that's the phrase that's used in the statute.

COMMISSIONER MARTIN: I'm not sure that

they're the same thing in reality. I don't think all the temporarily abandoned wells have a temporary abandonment status.

COMMISSIONER BALCH: Status has -- notated as temporarily abandoned.

COMMISSIONER MARTIN: OCD has approved the temporary abandoned status.

MR. BRANCARD: But if I may, Commissioner Martin, these two phrases are different from the phrase "approved temporary abandonment," which is an entirely different concept under Rule 25. So, basically, "temporary abandonment" is another word for "inactive."

COMMISSIONER MARTIN: Yes. I agree with that.

MR. BRANCARD: So once you're inactive, not producing, the clock starts ticking. And then at a certain point, you have to get into temporary -- approved temporary abandoned status. Otherwise, you're not in compliance with Rule 25. So this definition has nothing to do with approved temporary abandoned. It's just "temporary."

CHAIRWOMAN RILEY: I think it's just a point of clarification. I'm good with it.

COMMISSIONER BALCH: I'm okay with it. I was just curious why we had to have it.

COMMISSIONER MARTIN: I'm good, too.

CHAIRWOMAN RILEY: Cleanup.

And the last one would be true vertical depth.

COMMISSIONER BALCH: I'm comfortable with the definition as long as you strike the second sentence.

CHAIRWOMAN RILEY: Did he keep the same --

MR. BRANCARD: OCD Exhibit 12?

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: Which is the same thing, I believe.

MR. BRANCARD: No. There is a difference in elevation.

COMMISSIONER BALCH: Ah, I see. "At the well's surface location." I actually like that. That's better. It matches my little diagram that I made.

CHAIRWOMAN RILEY: Wait a minute.

COMMISSIONER BALCH: The well could -- the touchdown point of the well could be at a higher elevation -- could have a higher elevation than the well, so it specifies it measuring from the well.

CHAIRWOMAN RILEY: Uh-huh. Okay.

COMMISSIONER BALCH: It's my job, of trying to find the exception to everything.

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER BALCH: Actually, I would move to adopt this language.

COMMISSIONER MARTIN: I agree. I second.

CHAIRWOMAN RILEY: So moved.

Okay. That was easy.

That gets us to 19.15.8.9.

COMMISSIONER BALCH: I'm wondering if perhaps we -- that's going to be the main part of the discussion.

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER BALCH: But we could clean up some of the other parts of it probably rather quickly.

CHAIRWOMAN RILEY: Are you saying you don't want to go in a linear fashion?

COMMISSIONER BALCH: I'm saying I want to skip ahead. I don't know. Well, there's the effective dates, but I think those are going to be driven by when we can get this processed. We can go linear.

CHAIRWOMAN RILEY: Okay.

COMMISSIONER MARTIN: Inclusion of federal wells may be a shorter discussion. Do you want to talk about that?

COMMISSIONER BALCH: I would like to talk about inclusion of federal wells.

CHAIRWOMAN RILEY: I don't know how short it will be.

COMMISSIONER MARTIN: Shorter than this one.

COMMISSIONER BALCH: It's how do you count the number of wells, right?

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER BALCH: One example was from the public commenter, with 18 or 19 wells, and two of them are state and the rest of them are federal. It puts them into a whole different category of compliance.

COMMISSIONER MARTIN: Right. I don't think we should include federal wells in the well count. It seems unfair and illogical to me.

Your turn.

CHAIRWOMAN RILEY: Wait. Who wants to go next (laughter)? Maybe I'll be the tiebreaker.

COMMISSIONER BALCH: No. Actually, I tend to agree with Mr. Martin. I'm just not sure how we -- how we address the other comments from testimony, that we may -- we will have to close up a federal well, plug it with no real guarantee that we'll get the money back. I think in general that's not the case. So I'm not sure how to address that, but I think it's a little bit unfair, and particularly unfair to this gentleman (indicating) on what he's doing.

COMMISSIONER MARTIN: I don't think he's the only one. I don't think it happens -- I'm not saying it doesn't happen. Okay? And so far it hasn't happened enough to justify penalizing all the operators that have a predominant number of federal wells, I don't think.

CHAIRWOMAN RILEY: I think our problem is we don't -- I don't know whether we have enough statistical data, really, to do that.

COMMISSIONER MARTIN: That's possibly true.

CHAIRWOMAN RILEY: I haven't been here very long, but I've done a lot of looking at those operators that are having issues with compliance and looking at their financial assurance situation, and it's fairly dire. And I don't -- the federal bonding at $25 for a statewide blanket bond --

COMMISSIONER BALCH: 25,000.

CHAIRWOMAN RILEY: -- 25,000 and 150,000 for a nationwide. Say you've got an operator who has operations across the nation, $150,000 is not very much money.

COMMISSIONER MARTIN: No.

CHAIRWOMAN RILEY: And so the reality is that the burden could truly come back to the State for federal wells if that's all there is to cover that.

COMMISSIONER BALCH: I think it actually could. When I was cross-examining Ms. Marks, I could not get a feel that that was a very common occurrence.

CHAIRWOMAN RILEY: Okay. But you also have to look, too, that the federal government has a different way in which they deal with inactive wells, idle wells, all that stuff. They do require permission to have a well shut in. It can require you to do MITs, but it doesn't require they do that very often. They have a temporary abandonment program as well, but what they call an idle well -- and I'm just -- I haven't worked in it in a while, but my recollection is it's a seven-year scenario, where it's not even considered idle until seven years.

COMMISSIONER MARTIN: That's right.

CHAIRWOMAN RILEY: So if you've had last production, you know, at some point and then you get an additional seven years before they're even coming to knock on your door. So they have a much less stringent procedure in dealing with these. And I don't know how active they're really being on that. In fact, I think they're getting a lot of criticism nationwide for lack of pursuing these idle wells.

COMMISSIONER BALCH: Still, if do you have to close -- if you do have to plug a federal well, you're not completely without recourse. You can take them to court and sue them. You can, Hey, we really need to close this, and then reimbursement is this for later on. And I think that that's -- the sense that I got was in most cases, that is what occurs and they did get the money back.

MR. BRANCARD: Well, I don't think that's what the testimony was. I think the testimony was that the agency was able to obtain a grant from the federal government probably for specific wells that the federal government wanted plugged. Basically, the State is basically acting as a contractor --

COMMISSIONER BALCH: Right.

MR. BRANCARD: -- to do these wells and using the State's contractor as a subcontractor.

CHAIRWOMAN RILEY: Correct. Bank.

MR. BRANCARD: Right? Because that was more efficient for the federal government to do it that way. So my sense from the testimony is they had to apply for that funding to get it in order to even do that. It wasn't, Oh, we went out and plugged your well; can you pay us? I don't know that that would work.

And, you know, legally, I agree with, you know, with Mr. Brooks, that I don't think the State really has much recourse. I mean, I can tell you, you know, on the mining side, there is a prohibition for duplicating federal financial assurance. So what the State has done is to get financial assurance that is payable to both the State and the federal government so both parties are covered by one bond. That's not what's happening here. You have federal BLM financial assurance and you have OCD financial assurance with two groups of wells.

COMMISSIONER BALCH: But I think that's part of what I'm wrestling with, is it -- it is two groups of wells.

MR. BRANCARD: Right. And here's the problem that, you know, the testimony brought up, is that we have a conflict -- maybe I shouldn't use it that way. We have a disconnect, perhaps, between what the Oil and Gas Act requires and what the reality is of the rules and what's happening on the ground. And what the Oil and Gas Act requires is financial assurance for every well in this state. Okay? What the rules require is every privately owned or state-owned wells. Okay?

So there is an obligation in the Oil and Gas Act that we kind of, sort of push to the side because the federal government has their own bonding program. So that's what the testimony was about, why federal wells have always been included, because there is actually an obligation under the Oil and Gas Act to bond all wells.

COMMISSIONER BALCH: So in a sense, all wells are bonded because the federal ones are bonded through the federal government.

COMMISSIONER MARTIN: That's absolutely right. And what we're talking about is taking them out of the well count for the purposes of obtaining a bonding level for a particular operator. Including those federal wells that are already bonded seems unfair to me.

COMMISSIONER BALCH: That's giving them double jeopardy. They basically have to bond twice.

MR. BRANCARD: Right. But as I think Mr. Larson's closing statement admitted, the blanket bonds don't cover the actual costs of that number of wells.

COMMISSIONER MARTIN: That's kind of a different question, I mean to me.

COMMISSIONER BALCH: That's -- I mean, that's not our place to tell the federal government what to do, right, when it comes to bonding their wells?

CHAIRWOMAN RILEY: Well, even the blanket bonds -- our blanket bond wouldn't cover -- 250,000 over

100 wells, if we're stuck with all of them, will not get you very far.

COMMISSIONER BALCH: My real concern is the prevention of waste. We had at least one piece of testimony from the public, Mr. McMinn, who said if this passes in this form, he'll shut in three wells.

COMMISSIONER MARTIN: I agree.

COMMISSIONER BALCH: Those are three wells that are making oil for the State of New Mexico.

CHAIRWOMAN RILEY: Is he going to shut those in, or is he going to shut in and then plug them?

COMMISSIONER BALCH: He was going to plug them, plug three wells.

CHAIRWOMAN RILEY: Put a bond on -- and so I come back and argue the other side of that, which is if you can't afford to fix them so that they do produce and then you can't afford to put a bond on them, then maybe they should be plugged.

COMMISSIONER MARTIN: But he's talking about plugging producing wells.

MR. BRANCARD: No.

CHAIRWOMAN RILEY: No, I don't think so.

COMMISSIONER BALCH: Doesn't matter if they're producing or not.

COMMISSIONER MARTIN: Or prospective

producing.

COMMISSIONER BALCH: He's got them temporarily abandoned for a reason, and that's because he hopes to put them in production later on. If he takes them out of that temporarily abandoned status now and puts them into plugged status, they will never produce another drop of oil.

COMMISSIONER MARTIN: Correct. And for the waste issue, you leave reserves in the ground.

COMMISSIONER BALCH: You leave reserves in the ground, which is waste. Then not only were -- nominally using correlative rights to produce the oil.

And the real issue for me for the federal versus state in the well count is exactly what Mr. Martin said. It's double jeopardy. They're paying bonding twice for the same well. Whether the federal bonding is inadequate or not, whether the state bonding ends up being inadequate or not, it just strikes me as unfair.

CHAIRWOMAN RILEY: I think this is going to reduce the amount of bonding that the State has available, perhaps even less than what we had before. It kind of flies in the face of what the legislature was looking to us for.

COMMISSIONER BALCH: Their idea is to

increase the amount of bond money available.

CHAIRWOMAN RILEY: Uh-huh.

MR. BRANCARD: I don't think it's going to reduce anybody's bond.

CHAIRWOMAN RILEY: I think just overall.

COMMISSIONER BALCH: It won't decrease anybody's bond. It will just keep it the same as it is. It won't increase as much as -- it may not increase as much, though, but it's not going to decrease it.

COMMISSIONER MARTIN: I don't think it'll decrease it. You still get that $250,000 tier.

CHAIRWOMAN RILEY: But there are fewer operators that fall into those categories.

COMMISSIONER BALCH: But no operator is going to be below the existing 50,000 blanket bond.

CHAIRWOMAN RILEY: True.

COMMISSIONER BALCH: So it's not going to decrease the amount of bond money.

CHAIRWOMAN RILEY: But you won't have as many -- yeah. I mean, you're not going to have as many operators that will post the 250, which is the max that they allow for it, so we won't have as many at that.

COMMISSIONER BALCH: It would have been nice to see an OCD economic analysis of what they expected to bring in from additional bond money.

CHAIRWOMAN RILEY: I can tell you it was only looked at from the standpoint of how we historically looked at these well counts. They don't even consider that.

COMMISSIONER BALCH: 56 percent of all operators produce less than ten wells, right?

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: So those aren't going to change. The 44 percent are already going to be carrying the burden. The 23.6 percent --

MR. BRANCARD: But if you make that one to ten just state or private, then it will go above 56, right?

COMMISSIONER BALCH: Actually, we already have some of the numbers. 23.6 percent were between 11 and 50. So that's 80 percent that are between -- that are already less than 50 wells. They're not going to see a large impact -- a large change from what they were already doing. So we're talking about maybe changing that order from -- the 20 percent are paying more than the 15 percent are paying more --

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: -- rather than a huge number of people paying more.

CHAIRWOMAN RILEY: Yeah. It would be nice to see those numbers, but I don't know them off the top of my head.

COMMISSIONER BALCH: Well, we're missing the 51 to 100 and more than 100 on the table. We could always pull back the witness and ask if they have those numbers.

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER MARTIN: I'm still opposed to it philosophically regardless of how the numbers --

COMMISSIONER BALCH: I don't think it's going to change as much as you may think. Only 45 percent are going to have any change, and only 20 percent are going to have more than the 25 --

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: -- the way it's proposed. We haven't talked about the numbers in the distribution either.

COMMISSIONER MARTIN: I think before we do this, we should get some more data to see what the impact to OCD is going to be by doing this.

CHAIRWOMAN RILEY: Okay. Well, we could call back our witness and bring in more data.

COMMISSIONER BALCH: Call back Ms. Marks?

CHAIRWOMAN RILEY: How do we want to see

this? Do you want to see it run --

COMMISSIONER MARTIN: Maybe we should let her do the research first. I doubt she has the numbers at her fingertips.

COMMISSIONER BALCH: She had two numbers at her fingertips.

COMMISSIONER MARTIN: Oh, yeah?

COMMISSIONER BALCH: She may have the others.

CHAIRWOMAN RILEY: As far as the percentages?

COMMISSIONER BALCH: Yeah. It's just a percentage for total number of operators that have less than 10, 11 to 50, 51 to 100 and more than 100, and then we can tell --

CHAIRWOMAN RILEY: But you need to know -- she's not going to have that until she runs those same numbers and excludes federal, because those will change, theoretically.

COMMISSIONER BALCH: That will change.

CHAIRWOMAN RILEY: So she would have to look at that, at an exclusion of federal.

MS. MARKS: It was a significant change. It was a very significant change, during my lunch break.

COMMISSIONER BALCH: We can put her back on the stand and verify what we want to ask her.

MR. BRANCARD: So you would like to recall Ms. Marks as a witness --

CHAIRWOMAN RILEY: Yes.

MR. BRANCARD: -- for the single purpose of discussing this?

CHAIRWOMAN RILEY: Yes.

(4:20 p.m.)

ALLISON MARKS,

after having been previously sworn under oath, was recalled, questioned and testified as follows:

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. So we would like the other two percentages. You gave us 56.7 for less than ten wells, right, of the total number of operators?

A. That's correct, 56.7 percent for one to ten operators.

Q. And 11 to 50 was 23.6?

A. 23.6 for the 11-to-50 range.

Q. And 11 to 50 was 23.6?

A. Correct.

Q. What's the number for the 51 to 100?

A. 48 operators, which is 7.8 percent.

Q. 7.8 percent.

And more than 100?

A. Sorry. There is a lot of talk.

In the greater-than-100, there were 72 operators, which is 11.7 percent.

Q. 11.7 percent?

A. And so during my lunch break, when the whole federal well issue came up, I started to examine a number of operators in those different -- in these other ranges, and I saw that it would lower -- significantly lower the number of operators in those higher ranges and bring them down into the other ranges because we have historically and always included federal wells in our well count.

And then I started to think about the increase in horizontal drilling and those wells penetrating and to state lease land and private lease land. And I brought up -- and I don't have it with me. It's 40 CFR 3103, I believe, the federal bonding rule, and it all addressed the surface bonding for the federal government and surface waters, everything surface.

So when we talked about the laterals and the horizontal laterals and anything affecting the lands Mr. Martin is responsible for, if we don't have a bond in place to address those wells, we would not have any monies available excluding those --

Q. So I think having -- having any part of a state-leased lender -- any part of state land on your lease could trigger you having a state bond, or it should?

A. Well, that would be a really interesting -- that would -- that would be a very large shift. And right now I can't pull that data because --

Q. I think what I'm going to ask of you is a little simpler.

COMMISSIONER BALCH: And after I ask it, tell me what you want.

COMMISSIONER MARTIN: Sure.

THE WITNESS: And just to clarify, when we switched over from two different systems, we had just looked at certain parts of it. Basically, it was a federal -- it was a mineral interest. It was surface ownership, and not all the interest ownership was properly kind of --

CHAIRWOMAN RILEY: Can you hold on just a minute?

Mr. Marker, could you please be quiet? We've got a court reporter trying to listen and capture this. So --

MR. MARKER: I'm sorry.

CHAIRWOMAN RILEY: That's all right.

THE WITNESS: -- all converted. So some of it would just affect federal surface mineral owners.

Q. (BY COMMISSIONER BALCH) I think I'm going to ask you something much more simple.

A. Okay.

Q. Given the table that's proposed by OCD, A, B, C D, for ranges and the percent of operators that you have, assuming everybody gets a blanket bond and nobody does single-well bonds, how much money is that in bond money total?

The next question is: How much do they get right now with the $50,000 blanket bond? How much money do they have in bonds at the 50,000 present level? So I want to know what the baseline is. The baseline is current day before we change the rule.

A. Can I ask a clarifying question?

Q. Sure.

A. Not all those operators do have blanket bonds?

Q. Just assume everybody has a blanket bond, to keep it simple. That'll give us kind of a benchmark. So that's a starting point.

The next question is: With these present levels here, what would the bond level be if everybody had a blanket bond?

A. That was the first question anyway, right?

Q. Yes.

And the third one is: For only state wells or wells that have part of a state lease or whatever, excluding federal only wells, what would those numbers be also?

A. That's one that's a lot more difficult to do, because we had an issue with older wells, and sometimes the data has come in based off of the mineral interest. Sometimes it would be based off of the surface ownership.

Q. How close can you get?

A. I couldn't -- I couldn't be certain, to be honest. We are actively working with our district offices to change all -- to accurately reflect mineral ownership and surface ownership of each well. So if you would like to know based off of surface ownership or mineral interest ownership --

Q. One or the other, right?

A. Well, like I said, I believe the federal government only requires bonding on surface ownership; therefore, leaving the liability to the State of New Mexico. I'd have to consult again. I believe, like I said, it's 40 CFR 3103, federal bonding requirements.

Q. So federal bonding is only for surface?

A. Surface. From the surface and then surface waters and --

Q. So they don't really plug a well?

COMMISSIONER MARTIN: They plug the lateral anyway.

COMMISSIONER BALCH: They just cap it.

COMMISSIONER MARTIN: They plug the vertical portion.

THE WITNESS: Right.

COMMISSIONER MARTIN: Right.

THE WITNESS: But then, again, if the lateral -- and say there was, on a lateral, and there was any sort of restoration type of activity or anything that we wanted to go into the blanket bond and it was on state land -- lease land, we could use that blanket bond to --

Q. (BY COMMISSIONER BALCH) Is there anything you can do to give us a feel for what the impact of removing federal wells from the count will be?

A. I will certainly try.

Q. Okay.

So the fourth thing would be to take IPANM's numbers and do the same exercise. We wanted to compare the level of bond money available to the OCD in those four scenarios. Does that capture what we want to see?

A. Okay.

COMMISSIONER MARTIN: Yeah.

You're good?

CHAIRWOMAN RILEY: All right. Thank you.

COMMISSIONER BALCH: Just to see what the real difference is, if it's pennies or depending on if it's billions of dollars.

COMMISSIONER MARTIN: But the real question -- there is a third point. What's the difference on the state and private well excluding the federal wells. If we increase bonding on that portion, then I think we let -- you know what I'm saying?

COMMISSIONER BALCH: I don't know what they have required. I don't think any of those scenarios increase it from the third -- just bonding levels -- increased.

MR. BRANCARD: Maybe.

CHAIRWOMAN RILEY: I'm sitting here thinking if we had another portion of our rules like 5.9, which is then --

(All parties speaking at one time.)

COMMISSIONER MARTIN: We do. We do.

MR. BRANCARD: So do you want to reserve this section for tomorrow and then --

COMMISSIONER BALCH: We'll have a lot more information to talk about levels after that.

THE WITNESS: Can I ask one clarifying question?

MR. BRANCARD: Yes.

THE WITNESS: On the federal -- the federal well excluded, my understanding is if a well is drilled on state trust land and it penetrates any federal mineral, it would require a federal bond. Correct?

COMMISSIONER MARTIN: I think that's true.

COMMISSIONER BALCH: Well, I think one way to look at it probably would be if the well has any state land in it -- state or private land in it, then -- I don't know.

MR. BRANCARD: Well -- no. Our -- our rules require that you need to get our bonding for a well drilled on privately owned or state-owned lands.

THE WITNESS: Right. But then with our new --

MR. BRANCARD: So the only thing we can exclude from that is something drilled on federal land.

COMMISSIONER BALCH: Okay. It probably simplifies your math.

CHAIRWOMAN RILEY: On federal surface? Is that what you're saying?

COMMISSIONER BALCH: Federal surface, yes.

Exclude federal surface. That's where the bond is.

MR. BROOKS: Madam Chair, I apologize to the Commission for leaving, but I was under the erroneous impression that the testimony and evidence had been closed.

COMMISSIONER BALCH: It was closed.

MR. BROOKS: Well, until Mr. Herrmann came upstairs and told me my witness was back on the stand --

MR. BRANCARD: But the Commission reserved the right to recall witnesses.

MR. BROOKS: But you don't need anything further from me?

COMMISSIONER BALCH: We just gave Ms. Marks some homework.

MR. BROOKS: I'm sure she can handle it.

(Open-session deliberations continue, 4:29 p.m.)

COMMISSIONER BALCH: I would like to bring up the concept of putting in a variance clause or a number in there for the case where you can conclusively demonstrate to the Division office that your plugging costs are going to be lower, that you could get a lower individual well bond.

COMMISSIONER MARTIN: I'm okay with that.

COMMISSIONER BALCH: That would be the

variance, so it's up to the discretion of the office. They can weigh any number of factors, including the viability of the operator, to whether or not they would grant that variance.

COMMISSIONER MARTIN: I'm good with that.

COMMISSIONER BALCH: So that would require variance language as part of or associated with 8.9C.(1) and D.(1).

CHAIRWOMAN RILEY: You have to keep in mind --

COMMISSIONER MARTIN: Yeah.

CHAIRWOMAN RILEY: -- that even though we're hearing more from the small operators today, that these also apply to the bigger wells and also apply to injection wells.

COMMISSIONER BALCH: There is absolutely no question for the wells that were closed in the last four years that the 25,000, plus $2 per foot fits extremely well, and that's a very good number. But I think you do want to allow the possibility, if someone can demonstrate that their 500-foot shallow wells only cost them $6,000 to close very reliably, they can get a variance.

COMMISSIONER MARTIN: Right. Right.

COMMISSIONER BALCH: It doesn't mean

they're going to get it. It means they can ask for it.

MR. BRANCARD: How about this as language: "As an alternative, an operator may propose an estimated cost of plugging a well based on actual costs of similar wells in similar location"?

COMMISSIONER BALCH: Uh-huh.

COMMISSIONER MARTIN: Sure.

COMMISSIONER BALCH: That would be good.

COMMISSIONER MARTIN: There could be other factors, too, if a well operator has his own rig, for instance.

COMMISSIONER BALCH: Exactly.

MR. BRANCARD: Well, but the problem is --

COMMISSIONER BALCH: They're not closing it in their case.

MR. BRANCARD: They're not -- remember, the financial assurance is designed to cover the cost if the State has to step in.

COMMISSIONER BALCH: As compared to what the State's cost --

COMMISSIONER MARTIN: But the State would not have to step in if it could compel the operator to plug his own well.

MR. BRANCARD: Right. But the financial assurance cost is not for --

COMMISSIONER MARTIN: The cost would be lower.

MR. BRANCARD: -- their benefit. It's for the State's benefit.

COMMISSIONER BALCH: I think the way Mr. Brancard wrote it is fine. That's probably going to be sufficient.

COMMISSIONER MARTIN: I'll think about it. Okay. I see what you're trying to do. I understand your point.

CHAIRWOMAN RILEY: The problem is that at the point we need the bond, it's going to be --

COMMISSIONER MARTIN: That's true. Yeah.

COMMISSIONER BALCH: It has to be a cost the State would incur.

COMMISSIONER MARTIN: That's true.

COMMISSIONER BALCH: I like putting the variance in because most of the rules we've done in the last seven years include that sort of language, and it allows exceptions for exceptional cases.

COMMISSIONER MARTIN: I agree.

COMMISSIONER BALCH: A variance for unusual circumstances, I should say. Exceptions are different.

CHAIRWOMAN RILEY: Yes, they are.

So there weren't any changes to D as far as --

COMMISSIONER BALCH: We talked about moving E above C.

CHAIRWOMAN RILEY: Making it C?

COMMISSIONER BALCH: Making it C and moving everything else down.

CHAIRWOMAN RILEY: Uh-huh.

MR. BRANCARD: Well, what -- okay. But would it be preferable to move E -- or at least after the first clause at E, starting with "the depth of a well," into C.(1) and D.(1)?

COMMISSIONER BALCH: Well, I think you could just change the language in C.(1) to "a one-well financial assurance amount, 25,000, plus $2 per foot of the projected length of a proposed well or the measured depth of the existing well." If you put that same language in C.(1) and D.(1), then you don't need E at all.

MR. BRANCARD: Well, would you have to say proposed -- you'd have to cover all the conditions, which is "the measured depth for deviated and directional and true vertical depth for vertical and horizontal." That's kind of a mouthful.

COMMISSIONER BALCH: In that case, I would just put it above C or put the same clause into -- you'd have to rewrite C.(1) and D.(1), which already have a different thrust. Becomes cumbersome, maybe.

CHAIRWOMAN RILEY: I think --

COMMISSIONER BALCH: I'm trying to figure out a way to move E above C.

I do have a question on 19.15.12. And there were some suggested changes to the language there, to 33-and-three-tenths. I don't know why they don't just say one-third.

CHAIRWOMAN RILEY: This is an I.T. issue, that it's hard for them to calculate that.

COMMISSIONER BALCH: Well, I would say we change it to say "one-third rounded to the nearest lower whole number," or round it down. If we take five wells, as the example, right, and divide that by three, you end up with 1.77. So you would round that. That would still end up being one well that you could plug. So I think "one-third of the well rounded down" would take care of it pretty clear.

CHAIRWOMAN RILEY: Allison isn't here. When she comes back, we might want to ask her because she worked this out with the capability of I.T.

COMMISSIONER MARTIN: Keeping I.T. happy is probably wise.

COMMISSIONER BALCH: Does she have language in there for rounding down?

MR. BRANCARD: I don't know.

CHAIRWOMAN RILEY: No.

COMMISSIONER BALCH: I think you need to round to the nearest whole number. I think they technically call it truncating.

MR. BRANCARD: So five would be one as opposed to two?

COMMISSIONER BALCH: Five would be one, yeah.

CHAIRWOMAN RILEY: I'm good with that.

COMMISSIONER MARTIN: I'm okay.

COMMISSIONER BALCH: Any fractional well, as far as I know.

MR. BRANCARD: I think you're correct, but figuring out whether you're rounding down or up is important. Right? Because if you have eight wells, that's 2.66. You can round that up to 3 or round it down to 2. Where do we want to go with that?

COMMISSIONER BALCH: Actually, I almost don't mind just rounding up. We do have to pick one.

CHAIRWOMAN RILEY: Using rounding rules, down if it's .5, up --

COMMISSIONER BALCH: Rounding to the -- I'd say rounding to the nearest whole number would take care of that. So 2.6 would become 3, and 1.4 would become 1. I'm comfortable with that.

COMMISSIONER MARTIN: (Indicating.)

COMMISSIONER BALCH: As long as we don't have fractional wells being temporarily abandoned.

COMMISSIONER MARTIN: Temporarily partially abandoned.

COMMISSIONER BALCH: So a little change in language, that would be just fine.

CHAIRWOMAN RILEY: Okay. So does that mean we're good with all of .12. Do you guys have any issues?

COMMISSIONER BALCH: Just the language we have to fix when we get a fresh version.

Do you want to incorporate the OCD language, which is "33-and-three-tenths percent for more than five wells"?

It might be worth -- at some later time when we can query Ms. Marks, but I would really change the language to say something more like "one-third of the wells rounded." It can go into "temporarily abandonment."

MR. BRANCARD: I would say B, "For more than five wells, one-third of the wells rounded to the nearest whole number."

COMMISSIONER BALCH: At this point, you don't even really need A because A would apply the same way.

MR. BRANCARD: Because then A, five wells would get to two.

COMMISSIONER BALCH: Yeah, I suppose. All right. Yeah. I would change the language from the 33-and-three-tenths, if we possibly can. That's not a third anyway.

CHAIRWOMAN RILEY: Technically, it isn't.

COMMISSIONER BALCH: It's off by .03333333.

CHAIRWOMAN RILEY: Which is, I believe, why I.T. had a problem with it.

COMMISSIONER MARTIN: I believe that's right.

CHAIRWOMAN RILEY: So can we please see the cleaned-up language on this, and then we'll make a final decision on 12?

COMMISSIONER MARTIN: Yeah.

CHAIRWOMAN RILEY: But conceptually, we're good?

COMMISSIONER BALCH: And I'm fine with 13, which is basically saying we're not going to approve it until you have the assurance.

CHAIRWOMAN RILEY: Uh-huh.

Are you good with --

COMMISSIONER MARTIN: Yeah.

MR. BRANCARD: Well, then the other issue which I requested a response, we didn't get, which is we need effective dates.

COMMISSIONER BALCH: You know, really, I didn't think the October dates were going to work because they were too close to the end of the rulemaking. But I'm wondering if you should not give a longer grace period for operators that are going to have to come up with another 40-, $50,000 to comply.

MR. BRANCARD: So I think the idea in 8.14 is that it becomes effective pretty close to immediately upon effective date of the rule for anybody applying for a new well --

COMMISSIONER BALCH: Uh-huh.

MR. BRANCARD: -- or deepen or plug back a well.

COMMISSIONER BALCH: Which is fine.

MR. BRANCARD: Right?

And anybody during that period now kicks into having to get temporary abandonment status.

COMMISSIONER BALCH: Originally, we gave them like six months.

MR. BRANCARD: Those are the two categories that it's effective almost -- almost immediately under what was proposed, but we could make it the effective date. And then they gave more months basically for everybody else, so all existing wells that transition over.

CHAIRWOMAN RILEY: So if you're changing your status, you have to do it right away.

MR. BRANCARD: If you're changing your status, the rule's effective when it's effective, or we could put another date on there.

COMMISSIONER BALCH: Well, a little grace period might not hurt, particularly for smaller operators that might have to cough up an extra large chunk of their capital. I would hate to have a situation where they're driven to walk away from their field because they can't come up with the money fast enough. So a reasonable amount of time I think would good.

MR. BRANCARD: I mean, based on the testimony, you know, 43-plus percent of operators, if they have a blanket bond, will have to increase that blanket bond.

COMMISSIONER BALCH: Uh-huh. Yup.

MR. BRANCARD: Okay?

And then everybody who has a single-well bond will either have to increase that single-well bond or get a blanket bond.

COMMISSIONER BALCH: Right.

And I hadn't realized how much a bond would cost. I was really glad that Mr. Marker had given that analysis. That's a third of the money, plus 2 or 3 percent per year in fees. So that would be pretty substantial, a cash bond. It's not a big deal if you're Chevron, which is I guess why they're not in the room.

MR. BRANCARD: So do you want to discuss that further, then, the transition dates?

COMMISSIONER BALCH: I have no problem making it effective immediately for new or change of status. But for existing bondholders or a different category, I think they should be given a reasonable time period to comply. I'm not sure what reasonable is. Three to six months seems like something that would be all right. The original rule -- rule was written in March or May?

MR. BRANCARD: It was submitted in March, and the hearing was supposed to be in --

CHAIRWOMAN RILEY: May 24th, I think.

MR. BRANCARD: -- May. So they were sort of assuming that July was probably when it was going to become effective.

COMMISSIONER BALCH: So they were giving six months from the time of the hearing -- six months from the time of the hearing today would be in January, end of December.

MR. BRANCARD: So if this became effective -- we could just make -- we could just leave the first date blank.

COMMISSIONER BALCH: Uh-huh.

MR. BRANCARD: Right? So when we submit the rule, we will know what the effective date is, and we can fill in the effective date. And the second date you can say is three months from now, so you can fill in that date --

COMMISSIONER BALCH: Or six months.

MR. BRANCARD: -- or six months or whatever.

COMMISSIONER BALCH: Okay. Is there a time period that gives you a feeling of justice being done?

COMMISSIONER MARTIN: I'm good with whatever you guys want to. Whatever grace period is acceptable, I'm agreeable. I don't have a better one.

CHAIRWOMAN RILEY: I think three months is --

MR. BRANCARD: The only thing is that if -- by my calculation, if it gets published in the "New

Mexico Register" on September 24th, three months from then is Christmas.

COMMISSIONER BALCH: December 24th.

MR. BRANCARD: Yeah.

COMMISSIONER BALCH: There goes the Christmas bonus.

We could do four months.

CHAIRWOMAN RILEY: That puts it into next year.

COMMISSIONER BALCH: Doesn't matter except bigger bond picture, I guess.

CHAIRWOMAN RILEY: Uh-huh.

COMMISSIONER BALCH: Really, the bigger bond pool just reduces the exposure of the reclamation fund, right?

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: Doesn't give you any money.

COMMISSIONER MARTIN: Right.

COMMISSIONER BALCH: It reduces possible expenditures from that other --

COMMISSIONER MARTIN: Correct.

CHAIRWOMAN RILEY: It can change our P&A program if we would have a better -- if we were juxtaposed better, we can get some of these abandoned wells off the books, and we'd have the funding to do it.

MR. BRANCARD: So four months?

COMMISSIONER BALCH: I'd say four months.

With that, I think we're waiting for Ms. Marks.

CHAIRWOMAN RILEY: Okay. So shall we adjourn until tomorrow and start this back up tomorrow?

COMMISSIONER MARTIN: That's what I would suggest, give her some time to look it over.

CHAIRWOMAN RILEY: Yeah. Okay. So let's adjourn. We're off the record. We'll start back up tomorrow morning at 9:00.

COMMISSIONER MARTIN: Sounds good.

COMMISSIONER BALCH: Sounds good.

CHAIRWOMAN RILEY: Thank you, everybody.

(Recess, 4:48 p.m.)

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

I, MARY C. HANKINS, Certified Court Reporter, New Mexico Certified Court Reporter No. 20, and Registered Professional Reporter, do hereby certify that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings that were reduced to printed form by me to the best of my ability.

I FURTHER CERTIFY that the Reporter's Record of the proceedings truly and accurately reflects the exhibits, if any, offered by the respective parties.

I FURTHER CERTIFY that I am neither employed by nor related to any of the parties or attorneys in this case and that I have no interest in the final disposition of this case.

DATED THIS 28th day of August 2018.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2018
Paul Baca Professional Court Reporters