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

APPLICATION OF THE NEW MEXICO OIL CONSERVATION DIVISION TO AMEND RULES OF THE COMMISSION CONCERNING THE DRILLING, SPACING, AND OPERATION OF HORIZONTAL WELLS AND RELATED MATTERS BY AMENDING VARIOUS SECTIONS OF RULES 19.15.2, 19.15.4, 19.15.14, 19.15.15, AND 19.15.16 NMAC; STATEWIDE.

CASE NO 15957

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSIONER HEARING

Volume 2 of 4

April 18, 2018

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 Tuesday, April 17 through Friday, April 20, 2018, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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EXHIBITS OFFERED AND ADMITTED

(9:02 a.m.)

CHAIRWOMAN RILEY: Shall we resume from last night?

MR. FELDEWERT: Yes, ma'am.

CHAIRWOMAN RILEY: Did everybody get rest and good meals in Santa Fe?

RICK FOPPIANO,

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

CONTINUED DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Foppiano, last night we ended on NMOGA slide A65, and so I now want to move on to another topic, which is reflected in NMOGA slide 66.

MR. FELDEWERT: And, Madam Chair and the Commission, I believe it would be on page 12 of NMOGA's Attachment A dealing with what I would just call Subsection A(5).

Q. (BY MR. FELDEWERT) And, Mr. Foppiano, I believe these deal with the consent requirements that we referenced earlier and make sure they're carried over with respect to the filing of an APD in the drilling of a well?

A. Yes. We're just going to continue working our way through Part A of the horizontal well rules, issues that deal with spacing. And as you mentioned, this is a carryover from the existing rule basically restating the existing requirement, that an operator can't file an APD until they have the consent of at least one lessee or owner in each tract and then other [sic] parties in the spacing unit have been compulsory pooled. This was just -- other than just some minor adjustments to the language, this was intended to be the same requirement that existed in Part A of 19.15.16.15 of the existing rule.

There is, however, a NMOGA proposed change in Paragraph 5A.

Q. And that's highlighted in yellow, Mr. Foppiano, on Attachment -- NMOGA Attachment 1?

A. Yes. Yes. It's not an attempt to substantively change the impact of who receives notice in this particular instance. It's really an attempt to just clarify the notice by replacing the word "owner" with "unleased mineral interest in each tract." So it would read: "One lessee or unleased mineral interest in each tract."

And in our opinion, the term "owner" is defined in the Division rules and because of that definition, it could be construed to be more broad than what was really intended. So we think that the replacement of that with the phrase "unleased mineral owner" gets to the more accurate meaning of what that phrase is, and it uses a term that's commonly known in industry.

Q. So it would read: "Receive the consent of at least one lessee or unleased mineral interest in each tract." Right?

A. Correct.

Q. And the purpose --

MR. BRANCARD: Mr. Feldewert, that's what -- you just read correctly what's under his rule. He's saying replace with "unleased mineral interest owner."

THE WITNESS: Oh, I apologize. My slide is wrong then. What is shown here --

MR. BRANCARD: Actually, that makes more sense.

MR. FELDEWERT: I don't disagree with you. And I was noticing that last night, and I was thinking perhaps I was going to ask Mr. Foppiano.

Q. (BY MR. FELDEWERT) Our concern was having "owner" as a stand-alone provision, and it was because of the definition of "owner" in the Division's rules, correct?

A. That's correct.

Q. Possibly being too broad and creating an ambiguity?

A. Yes.

Q. If the proposed modification was further modified to add "owner" at the end of "unleased mineral interest," then that would limit -- in your opinion, would that limit the type of owner that's involved?

A. I think that would make it just as clear or more clear, because industry understands what unleased mineral interest owner is.

Q. Okay. So in other words, if we just -- on page 12 of NMOGA's Attachment 1, if we put the word "owner" between the highlighted word "interest" and the highlighted word "in," that would further provide some clarity?

A. I think so, yes.

Q. And avoid an ambiguity, in your opinion?

A. Yes.

Q. Okay.

A. Moving on to the next section, as we said, we've defined the criteria for standard horizontal spacing units, and if it didn't meet all that criteria, then it would be considered a nonstandard spacing horizontal unit. So this Section 6 describes the approval process and notice process and other things related to nonstandard horizontal spacing units. And the attempt was to keep the application requirements, notice requirements and approval process pretty much the same as they are for other nonstandard spacing units that are covered by Subsection B of 19.15.15.11.

Q. So this proration Subsection 6 adopts the existing notice requirements that are already in place for general nonstandard spacing units?

A. That's my understanding.

Q. Okay. And if someone protests, how is it handled, or if it's not protested?

A. If it's not protested, the intent was to allow the process -- allow the administrative approval process for unprotested applications.

Q. And that's how it works under the referenced rule here in slide 67?

A. Yes.

Q. Okay. And what happens if it's protested?

A. Well, if it's protested, the parties could decide to have a hearing or withdraw the application.

Q. Okay.

A. And I suppose I should make another comment, that we considered Mr. Brooks' proposed change there to 6A. Instead of it referencing paragraphs two through five, it would reference paragraphs three through five.

And I don't believe that that would present any problem whatsoever.

Q. Okay. All right. Does this also identify the tracts whose affected persons are entitled to notice?

A. Yes. And this section also describes the tracts whose affected persons are entitled to notice. And this, again, is a carryover from the existing rule. And as it's shown up here, it's the tracts that are excluded from the spacing unit if the spacing unit would otherwise be a standard spacing unit, except for the inclusion of such tracts or the tracts that adjoin the nonstandard spacing unit.

Q. And that's codified in Subsection A(6)(b), correct?

A. That's correct.

Q. Hold on one second.

There was a comment lodged by Jalapeno to this very provision in their modifications, Mr. Foppiano. And I'm on page 7 of their filing, and it was their comment six on this very section. And I'm going to read to you -- they raised a question to the Commission. Okay?

A. All right.

Q. And their question was -- and I'm reading now -- "How can a nonstandard horizontal spacing unit be

created if every unit proposed by an operator is standard?" Is it correct to represent to the Commission that every unit proposed by an operator is going to be standard?

A. I believe there are going to be many situations that operators are going to propose nonstandard units because they don't meet the criteria as outlined for standard units.

Q. So in other words, for a horizontal spacing unit to be standard, it's got to meet certain objective criteria, right?

A. That's correct.

Q. Okay. They also point out that Section 6(B) should be amended to add subsections, "to require notice all owners of interests within a nonstandard spacing unit." Okay?

A. Yes.

Q. Now, isn't it true that all owners, whether you're inside or outside of a nonstandard spacing unit, are going to get notice?

A. Well, you must consolidate the interest inside of the spacing unit that you propose, be it standard or not standard --

Q. Exactly.

A. -- before you can produce the well. So it would seem to me that there is a mechanism that that gets notice to parties that have not voluntarily agreed to pool their interest.

Q. So in other words, there are already mechanisms by virtue of the fact in the statutory obligation to consolidate the interest within a spacing unit, still going to get notice, correct?

A. Right.

Q. And is that why, then, what you're dealing with here is ensuring that certain parties outside that proposed nonstandard spacing unit will get notice?

A. That's correct. And as I mentioned, it's not a substantive change from the current rules.

Q. Okay. All right. Then if we go on to the next section, which would be the next page of NMOGA Attachment 1, we're on Subsection A(7) dealing with state, federal or tribal lands?

A. Yes. This is a paragraph that just relates to the situation where the spacing unit might include federal or State Land Office lands or even tribal lands, and it just -- it regurgitates an existing requirement about copies, but it also adds to it and makes it more clear. So it is a slight change from the existing requirement, and it just makes it clear that, basically, if your proposed spacing unit includes those lands from either of those entities, that they're entitled to a copy of the C-102.

Q. So it took existing language in the rules and provided it to horizontal wells?

A. Yes.

Q. Okay. All right. Next topic. We're on Subparagraph 8.

A. Yes. This is -- this is where the concept of every well has a spacing unit is stated. However, there are created exceptions for that basic requirement, as we talked about and we'll talk about a little bit more, related to infill horizontal wells and multilateral wells. So this paragraph just states that concept and notes those exceptions.

Q. Now, if I look at NMOGA's Attachment 1 -- and I'm on page 13, Subparagraph 8, NMOGA has proposed modification to that language?

A. Yes, we have.

Q. And what's the purpose of that?

A. Well, the language as proposed seems to create the impression that the exception is -- applies to all multilateral wells. And as you'll see later on, I don't believe that's correct. The exception to every well has a spacing unit applies to certain types of multilateral wells but not others. So we proposed some language, the addition of a qualifier there, to basically, what we think, make it more accurate as to the application of that exception.

Q. Okay. And, in fact, you're referencing, by virtue of that language, that certain multilateral wells that are identified under Subsection 9(A) --

A. Yes. And we'll talk about this in the next section. But there are really two types of multilateral wells that we believe are possible right now or could be drilled under these proposed rules or might be drilled, and so we tried to create some rules that speak to those situations. And they're described in the next section, in 9(A) and 9(B). So we feel like here -- since you'll see that there are some situations where those multilateral wells will either share the same spacing unit or they don't, then we just went ahead and put that reference in there for that situation where they share the same spacing unit.

Q. Okay. So then looking on this slide, A69, we have, then, two exceptions to the rule proposed where a horizontal well must have its own spacing unit, first being infill wells?

A. Correct.

Q. Let's talk about that next.

A. All right. So paragraph eight is -- since we were talking about infill horizontal wells, it's a good time to go ahead and cover that subject with respect to spacing. And as we saw in the definition, an infill horizontal well is designated as such by the operator on Form C-102. And the definition allows for it to be "dedicated to an existing standard or nonstandard horizontal spacing unit if the completed interval of the infill well is entirely within the boundary of the existing horizontal spacing unit." And we'll see a picture here of that in a minute.

The question arises: Why did the group bother with this situation? And there was a recognition that infill wells can be drilled under multiple scenarios, primarily two. They can be drilled under existing force pooling orders and joint operating agreements. And the key that we believe that is advantageous to preserve the opportunity to drill those infill wells under the appropriate agreements or orders is that in most cases and practically all cases that I can think of, they'll have the same interest as the existing well, and they can, therefore, be produced to a common battery. So there is a significant incentive for operators to drill infill wells because that eliminates the need for separate facility or surface commingling authority.

Q. Let me stop you right there. So right now, if they dedicate it as an infill well to the same spacing unit --

A. Yes.

Q. -- then surface commingling issues don't arise?

A. That's correct.

Q. But if the operator does not dedicate that second well to the initial spacing unit and instead has its own spacing unit, then we'd have two involved, right?

A. Yes.

Q. And then we'd have commingling issues that would arise?

A. Correct. Because every well would have its own spacing unit, that infill well would have a different own spacing unit. It might be exactly the same as the initial well, and it might not be. It just depends on the location of the completed interval. So this particular case just preserves that opportunity to actually drill infill wells inside that spacing unit.

Q. Okay. And it's the operator's option, right?

A. It's at the operator's option.

Q. Gives them the flexibility that they need to deal with a lot of different circumstances?

A. That's correct.

Q. Okay. I think you have an example --
A. I do.
Q. -- on slide A71.
A. Here's an example of an infill well or an infill horizontal well spacing unit, the same type of example I've been using before. In our case here, the target oil pool is under special pool rules of 80-acre spacing. The operator under these proposed rules elects to construct a horizontal spacing unit using pool rules, and in this particular case, the completed interval for well number one penetrates four 80-acre tracts, as shown.
And then the operator also desires to drill an infill horizontal well. This would be well number two, as shown. And it has a completed interval interval entirely within the horizontal spacing unit for well number one, and the operator designates it as an infill horizontal well. So it meets the criteria for an infill horizontal well per the definition.
In this particular case, then, both wells would share the same standard horizontal spacing unit of 320 acres.
Q. Now, the next exception to every well has its own spacing unit is certain multilateral wells, right?
A. That's correct.

Q. And that relates to the language that NMOGA has proposed for Subsection 8 to make it clear that it's only those multilateral wells described in 9(A)?

A. That's correct.

Q. Okay. And do you have -- I think you have it up here now, slide A73, that discusses those types of multilateral wells?

A. Yes. As I mentioned, the committee, you know, was aware that even though these are rare cases, they do exist, and it is possible going forward that there may be more multilateral wells drilled. So in particular when we look across the state line in the Permian Basin, this was as an issue that was tackled by the Texas rules. They called them stacked laterals or -- that's not exactly a multilateral well, but they did have some provisions in there for multilaterals also.

So the desire was let's try to get some concepts and some rules in place, at least starting, so we can provide some clarity to operators who want to drill these multilateral wells.

So these are spacing issues that are related to multilateral wells, and we identified two types of multilateral wells. Here's an example of a well, surface location that is outside the spacing unit. The lateral comes down and has a first take point over here on the left side and a last take point over here on the right side. And you see it's a pretty simple horizontal spacing unit consisting of four 40-acre tracts. And we can call that a standard spacing unit because it meets the criteria. So this is the first lateral that is drilled from the well, and it's drilled on a standard spacing unit of 160 acres.

So either -- probably later on, the operator decides to drill a second lateral out of the same wellbore as the first lateral, and so call it deeper, whatever, but we're going to say that it's in the same pool, because if it's in a different pool, that's just a different story altogether. But it's in the same pool as the lateral number one. And the completed interval, as you see, for first take point 2, last take point 2 is entirely within the boundaries of the spacing unit that was assigned for the first lateral. So this would qualify as a multilateral well under A(9)(a). This is what was intended with this language. And in this particular case, the wells would share the same horizontal spacing unit much like an infill well would do.

Q. Okay. So this would be an example of a multilateral well where it could be designated as an infill well?

A. No. This would just be designated as a multilateral well.

Q. Would this be an infill -- this could be an infill -- could it be designated as an infill well by the operator?

A. Well, the infill well case is more of a separate well, a separate surface location and separate well entirely.

This a multilateral well that's using the same surface location, same wellbore situation. So if there was a second well drilled like shown here, but it had a different surface location, that would be an infill well.

Q. So maybe I'm confused. I looked at Subparagraph 8 --

A. Yes.

Q. -- and you said that except for infill wells and certain multilateral wells --

A. Correct.

Q. -- would have their own spacing unit?

A. Yes.

Q. Is this an example where we have multilateral wells that could be designated as an -- as an infill well?

A. They wouldn't be designated as an infill well.

These would be multilateral wells that share the same spacing unit. This is one of two exceptions to the every well has its own spacing unit concept because in this particular case, this well has two laterals that share the same spacing unit.

Q. Okay. All right. And then you have an example of a multilateral well that would not, correct?

A. Yes. This is another example, and this is what is attempted to be described in 9(B). Same situation of a multilateral well. The first lateral is drilled, as shown in this spacing unit, first take point in this tract, last take point in that tract. So there is a standard spacing unit of 160 acres associated with lateral number one.

And then the operator desires to drill lateral number two, but he wants to go in the other direction. And so lateral two would be shown here, first take point 2, last take point 2. And you can see that the wellbore -- they're all in the same pool. We're not talking about different pools again. But you can see a number of issue that arise in this situation related to ownership, commingling, a number of issues here. And so we decided to at least lay out the requirement that in this case, this other lateral, this second lateral, would have to have a separate spacing unit, because, obviously, it's affecting lands that are owned -- could be owned by different people.

Q. Okay. Now, if I look at NMOGA's Attachment 1 on page 13, there is a language change in Subsection 9(A)?

A. That's correct.

Q. Would you explain that for us, please?

A. Yes. There was some discussion that was initiated from the OCD about the use of the wording "existing horizontal spacing unit" here in the context of where an operator may want to drill these laterals at the same time. And in that context, there was some potential confusion because there might not be an existing horizontal spacing unit if they're being drilled at the same time.

Q. Let me step back. Probably the best depiction of this would be the previous slide?

A. Yes.

Q. Okay. Go ahead.

A. So if these laterals were drilled once and then the operator flowed it back and then set a plug and then drilled a second one and then the intention was to go ahead and do all of that before the well was actually finally completed, then there could be some issue with the fact that there might not be an existing spacing unit for lateral number one when lateral number two is drilled.

So there was some discussion with the OCD about some additional wording or change to the wording to address that issue. And what we came up with is some language to replace the use of the phrase "an existing horizontal spacing unit" with a "horizontal spacing unit for the longer lateral," seemed to address that concern.

Q. And in your opinion, does that language change eliminate the potential for ambiguity?

A. I think it does. And my understanding is that the OCD is fine with that proposed change.

Q. Okay. Now, the next --

MR. FELDEWERT: Go ahead.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. What's the significance of "longer"?

A. In this case, if you drilled the second lateral longer than the first one -- in other words, it went over here into the next section -- it would have a spacing unit that could be bigger than the lateral for the first one. And in that particular case, you would set the spacing unit based on the longer lateral and then the second lateral would be entirely within that. So it eliminates a potential problem when you might have this second lateral longer than the first lateral and you drill them both at the same time. It's a rare situation of a rare situation (laughter). But it's worth clarifying now as opposed to later, I guess.

Q. All right. Because if you drilled lateral two first and then lateral one, lateral one would need a separate spacing unit because it's longer than lateral two?

A. No, if you drill them both at the same time. Once -- once a lateral is drilled and it starts producing, the spacing unit is set for that. Then if you do something subsequent to that -- an example here, if this lateral extended over here (indicating), that's a situation that is described by 9(B), where it's in a separate spacing unit. This is really meant to address the situation where both laterals are drilled at the same time. You just set the spacing unit based on the longer lateral.

CONTINUED DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. So if I understand the issue raised by the Division, that as your spacing unit, you really don't have an existing spacing unit -- and that was the problem where we had the word "existing" in there -- until you have drilled and completed an initial well.

So their concern, as I understand it, was that you may not have an existing spacing unit by the time you drill that second well, and, therefore, you wanted to get rid of the word "existing" and use other language to clarify the circumstances you see here on slide A73?

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. But it seems the concept is that you want to be able to drill within one spacing unit, right? As long as all the laterals fit in that spacing unit within the same pool --

A. Yes.

Q. -- then you're fine?

Like, if you go to the next slide, if you created that all as one 320-acre spacing unit, would these both be -- aren't they both dedicated to the same spacing unit?

A. Well, The problem is when the operator drills the first lateral and then starts producing it. The lands over here for the second lateral don't qualify to be in the spacing unit for the first lateral because they're not penetrated and they're not within 330 feet. I suppose they could pursue it as a nonstandard. But if the operator thinks they want to drill the second lateral but then decides later on not to drill the second lateral, that could be a mess.

MR. FELDEWERT: Same way -- if you go back to the first slide, slide 73. If they were to drill that blue lateral first, you are not penetrating the remaining intervals.

MR. BRANCARD: I see. Okay.

MR. FELDEWERT: So there may be an issue when we come up to the Division and try to create a spacing unit when your first well is only going to be the blue well. So I think that was the impetus for the language "longer lateral."

MR. BRANCARD: Your second lateral does not drain all the tracts.

THE WITNESS: The second lateral could be and more likely would be in a different bench. So it would be drilled in a formation that actually would have multiple targets like the 1st Bone Spring, 2nd Bone Spring, 3rd Bone Spring. Lateral one may be in the 1st Bone Spring. Lateral two may be in the 3rd Bone Spring.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Kind of brings up the issue of how are you vertically defining your pool for each of these individual horizontal spacing units, because you're going to have 15 feet of shale and have ten different

horizons?

A. That is a challenge. It was a challenge in Texas and a challenge in New Mexico also, particularly when interests get severed in the middle of that defined pool, and you're dealing with different laterals and different benches.

Here again let me emphasize everything I've heard. Multilateral drilling in New Mexico is not common at all. I think it's been tried. There are a number of challenges associated with it, and it just didn't appear, in the work group, to be a common or even -- it was just very rare. It's more on the experimental kind of side. And some of the witnesses behind me may be able to speak more technically to the challenges associated with multiwell -- multilateral wells.

It's been tried, but there are a lot of challenges associated with it operationally, because if you think about it, you have to shut off one interval before you can go drill the other lateral. And when you drill a good well and get 3,000 barrels a day, most often management is not real excited about shutting that in to go drill some more.

Q. Well, I think you're out on your decline curve a little bit before you do that.

A. You may wait longer, and then that actually presents some issues in and of itself from depletion and communication.

Q. So one of the things that we're challenged with doing is making a rule that will last as long as possible.

A. Yes, sir.

Q. So everything you just said about multilaterals, you could have said about horizontals in 2003.

A. Absolutely.

Q. So it's just a matter of technology catching up and being able to import some of those factory mining technologies to New Mexico. We've done something in that direction already with water management that is supposed to make those more possible. Maybe just the puzzle hasn't been completely solved yet.

A. From my experience in Texas, there was a lot of energy a couple years ago about multiwell -- multilateral drilling, and it seems like that energy, enthusiasm, has dampened quite a bit in favor of just drilling separate wells, which would be infill wells instead of multilateral wells. And I know Occidental has tried it and is not too enthusiastic about it because of the cost and the challenges associated with it.

So all we really tried to do with these proposed rules is capture what we think the situation is today with respect to multilaterals and put some regulatory sideboards around it and then get out of the way of it, realizing that that may be the prevalent activity five years from now and may require the rules be adjusted or changed.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. So speaking of what the future is, does this provision allow for more than two laterals?

A. Absolutely. It should allow as many laterals as --

Q. So perhaps it should say "a horizontal spacing unit for the longest lateral." Would that be more appropriate? That would allow for more than two wells.

A. Personally I can't speak for NMOGA, but that change doesn't bother me at all. "Longer lateral," "longest lateral" seemed to be very close to the same thing, but --

CONTINUED DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. If there are no more questions, then, we'll move on to Subsection A(10), which will start on page 13

of NMOGA's Attachment 1.

A. Yes. A(10) covers the issues related to spacing units for wells drilled in unitized areas. And the work group was advised that even though this is somewhat of an existing concept, that the OCD requires spacing units for horizontal wells even if they're inside of unitized areas. And because these rules define setbacks and other issues related to the boundaries of spacing units, we needed to put some language in here that didn't unduly restrict the ability to drill wells -- horizontal wells inside of unitized areas such as EOR projects.

So certain exceptions were created here in paragraph ten related to spacing requirements for wells drilled in unitized areas, starting off with: The rectangular shape requirement should not trigger a nonstandard horizontal spacing unit merely because of the way the spacing unit is shaped in the unitized area because it's a well drilled in a unitized area. So there is an exception here created for the rectangular shape requirement that we've already discussed.

Q. Mr. Foppiano, just to put specifics on it, that would be what I would call the exception to the inclusion of the proximity tracts, which is in Subsection A(1)(c), right?

A. Correct. Subparagraph C, yes.

Q. Okay. And it's also in Subparagraph C of 3, correct, for gas wells, same -- same provision, Subparagraph A(3)? They're both the same, A(1)(c) and A(3)(c)?

A. Yes. But I'm looking at the proposed rule and it says "paragraph two."

Q. Correct. That's one of our changes, isn't it?

A. Okay.

Q. If I look --

A. Oh, that's right.

Q. It's one of our changes. But you're right. You're looking at our page 14 and Attachment 1, and it has the change from two to three?

A. Yes. Yes.

Q. Okay. All right. Then the other provision you pointed out here was the -- I noticed a lot of discussion about this yesterday, about the current stranded tract prohibition for spacing units for horizontal wells, right?

A. Yes. There is an exception here also created for the fact that a stranded tract shouldn't trigger the nonstandard horizontal spacing unit situation for a well's drilled and unitized area either.

Q. Currently that's in (A)(1)(d) and A(3)?

A. Yes.

Q. All right. Now, with respect to -- there was another change that was important here for these unitized areas, right, reflected on slide 77?

A. Yes. There was discussion, when drilling in unitized areas, that why shouldn't the opportunities and reduced restrictions for wells in unitized areas, why shouldn't that also apply to drilling a well on a single lease -- a large single lease? And there was a fair amount of discussion about that, and there was unanimous agreement that there should be some language added in the proposed rules to expand this concept to what we call the area of uniform ownership or common ownership, which is intended to capture the single lease situation. So the language that is in the proposed rule does reference the area of uniform ownership concept.

Q. And when you say area of uniform ownership, you're talking about working interest, royalty interest and overriding interest?

A. Everything is common, override, royalty, working interest, everything.

Q. And the committee concluded, therefore, that it would be appropriate, as Dr. Balch was talking about yesterday, with providing operators with the flexibility to include those areas of uniform ownership as areas

that would not normally be subject to restrictions on horizontal spacing units?

A. Yes. Basically to treat those areas of common ownership just like it was a unitized area because of the fact that the interests were all common. So, you know, why have some unnecessary restrictions on that? Provide more flexibility to operators.

Q. Okay. And has NMOGA proposed some changes here to Subparagraph A(10) to effectuate that intent?

A. Yes. There was some discussion about the description of this area of uniform ownership. And so there are some minor tweaks to the language that NMOGA proposes and I understand that the OCD is okay with, where we would delete the phrase "all oil and gas mineral interests" and just replace that with "the mineral estate." And here again the intent is, to make it very clear, that all interests, royalty, override, working interests, everything, must be common in this area in order for it to be considered an area of common ownership.

Q. In fact, Mr. Foppiano, isn't "mineral estate" a defined term under the Division rules that includes all those interests?

A. I thank you for reminding me. It is, yes.

Q. Okay. And then the other change in here was

striking the current language of a "single lease or tract" and just putting in the language "an area," right?

A. Yes, that's correct. I'm sorry. I missed that.

Q. And what's the purpose of that, to change that language from "a single lease or tract" to make it -- is it more broadly --

A. Yes. I think there was some concern about the limiting nature of the phrase "a single lease or tract." Really what we meant to say was an "area." If this area has a common ownership, it should enjoy the same relaxed restrictions as a unitized area.

Q. And that would allow operators then to -- in your opinion, will that provide operators with some additional flexibility to put together their development plans in a fashion that will most efficiently and effectively develop that resource under that area of common ownership?

A. Yes. Because -- because as you'll see, this is more of a multiwell project approach today than what it was five years ago. This flexibility, we believe, allows operators to place these wells at more optimum locations on a single lease and prosecute more -- prosecute it more as a project than by a well-by-well approach.

Q. Before we leave this section on unitized areas, if I look at page 14 of NMOGA's Attachment 1, I think we've mentioned the changes there at the top dealing with mineral estate and changing typo and referencing the paragraph. But NMOGA has also proposed to strike Subparagraph B, correct?

A. That's correct.

Q. Now, first off, is Subparagraph B the provision that was proposed by the work -- that was proposed by the work group?

A. No.

Q. That was something that the Division added after the work group had completed their work?

A. That's correct.

Q. And did that work group -- I think you mentioned earlier, it included representatives from the BLM, right?

A. That's correct.

Q. Okay. Why has NMOGA requested the Commission to strike this Subparagraph B?

A. Well, first, we didn't believe that the OCD's rules should put some restrictions in place that the BLM may or may not want today, when the BLM, years down the road, may change their mind and decide, oh, yeah, this is not a bad idea; let's go ahead and allow that, and it's codified in OCD's rules. We felt like the BLM is perfectly capable of administering their own rules to operators regardless of what the OCD's rules would say here. So our belief is that this should not be in the OCD's rules because the BLM can change their mind and certainly has in the past as horizontal drilling has progressed throughout public lands.

Q. So the predicate here, Mr. Foppiano, is when one reads through this, this is purely a federal matter as referenced here in Subsection B, right?

A. Yes.

And they did bring this up in the work group. They had some reservations and concerns about -- about this particular issue about, but there was also recognition that when an operator approaches the BLM to drill a well on federal land, obviously they have to permit it appropriately through the federal permits, and if it involves communitization, then they have to approve the communitization. And they have ultimate power to approve what they want. So we just didn't feel like it was necessary to address it in the OCD's rules, and it could present a problem later on when the BLM comes to their senses and decides that it's okay.

Q. All right. Then I think the next topic, moving

on -- and we can stay on page 14 of NMOGA's Attachment 1. It would be Subparagraph A(11), which deals with existing and subsequent wells in horizontal spacing units. Why don't we talk about this?

A. This is a -- this is an attempt to carry forward some existing language and make it applicable in the horizontal world and work within these rules, but it really relates to the drilling of horizontal wells in spacing units that have other vertical wells, other horizontal wells where there is an overlap with an existing spacing unit.

So the language that we see -- this language really only kicks in when there are existing wells in the same pool located within the boundaries of the proposed horizontal spacing unit. In other words, the operator looks at their project; here's my completed interval, looks at what the spacing is going to be based on the criteria that's been outlined. And if that proposed spacing unit includes other vertical wells or a portion of another horizontal well or whatever -- in other words, there's that overlap situation -- then they would have to go to this provision to ensure that they comply with the notice requirements.

And we feel that by requiring notice, this is really designed to protect those owners in existing wells from any adverse impacts associated with the horizontal well that might be drilled in close proximity to their well. So that's really what it gets to.

It's interesting to note, though, that those existing owners, by virtue of that overlap -- and we'll see that in some examples here in a minute -- will be offered opportunities or will be subject to agreements that allow them to have a chance to participate in the proposed horizontal well by virtue of that overlap.

Q. Because you've got to consolidate your ownership within --

A. Yes.

A(12) of these rules already requires voluntary or compulsory pooling of those separately owned interests in that proposed horizontal spacing unit before the operator can produce that new horizontal well. So there's already a mechanism in place to force some conversation and entering into agreements to deal with these other interests in the other well.

Q. So do these provisions seem to expand the notice to those outside the spacing unit that's being proposed that may be impacted ultimately?

A. Not outside the spacing unit -- the proposed spacing unit.

Q. But within the overlapping spacing unit?

A. Within the overlapping spacing unit, yes.

Q. I said that wrong. Outside the overlapping area?

A. Yes.

Q. Okay. Do you have some examples of how this notice provision works in various scenarios?

A. Yes. This is -- this is my understanding -- and I will admit, this is rather tortuous language in this section.

Q. Okay. I'm going to stop you a minute. We're on slide A80 -- NMOGA slide A80?

A. Yes.

Q. Okay. Go ahead.

A. So let's look at an example of a well that might be drilled that would be covered by 11(b)(i). 11(b)(i) is a subsequent well in an existing spacing unit. So we have an example here. Target oil pool is a Bone Spring pool under statewide rules, and we're going to say it includes the 1st, 2nd and 3rd Bone Spring sections. And the tract size is 40 acres, and the completed interval penetrates four 40-acre tracts, as shown. So in this particular example, the standard horizontal spacing unit is 160 acres. But there is an existing vertical well located on Tract O, as shown by the green star on the slide. And it's completed in the 1st Bone Spring. The proposed horizontal well will be completed in the 3rd Bone Spring.

Q. Okay. Let me stop you right there. Under the current Division pool rules, those would be in the same pool, right?

A. In this particular example, we're going to say they're in the same pool.

Q. Even though they're in different benches?

A. That's correct.

Q. And isn't it true, Mr. Foppiano, there are a number of pools that have been designated by the Division that include different benches like this, the 1st Bone Spring, 2nd Bond Spring, 3rd Bone Spring, et cetera?

A. Yes.

Q. Okay.

A. So in this particular example, the horizontal well is a subsequent well with a completed interval partially in an existing well's spacing unit. That's how it's covered by 11(b)(i).

If the existing well is operated by a different operator -- this is an existing rule now, Subsection B of 19.15.15.12, covering special rules for multiple operators within a spacing unit -- already requires notice to that other operator -- an opportunity for protest to that other operator. So without any of this language, we already are falling into this requirement to give notice to that other operator if that is a different operator.

But 11(b)(i) additionally requires notice to and opportunity to protest by the working interest owners in Tracts M, N, O and P. So by virtue of that, they should capture the ownership in that existing well -- the working interest owners in that existing well and that existing spacing unit because that's in spacing unit -- or that's in Unit O, and O is part of the proposed horizontal spacing unit.

Q. Okay. So the primary differentiation between Subparagraph B(1) and B(2) is that B1 deals with a circumstance here where the completed interval is partially in?

A. Yes.

Q. Okay. And then B2 deals with a circumstance where the proposed spacing unit, completed interval is wholly within?

A. Yes.

Q. Okay. And you have an example of that?

A. Yes. I call it --

Q. I'm sorry. I'm sorry. You have another

example of B(1), right, where it's partially --

A. Oh, I do, yes, another B(1) -- or (b)(i). Target oil pool is a Bone Spring pool under statewide rules. Same as before, it includes 1st, 2nd and 3rd Bone Spring. The tract size is 40 acres. The proposed completed interval penetrates four 40-acre tracts, the standard horizontal spacing unit of 160 acres. But in this particular example, there is an existing horizontal well located in Tracts A, H, I and P, and it's completed in the 1st Bone Spring Sand. So the difference here is one dealt with a vertical well. This deals with an existing horizontal well, but the spacing units overlap.

The proposed horizontal well will be completed in the 3rd Bone Spring. So the proposed horizontal well is a subsequent well with a completed interval partially in an existing well's spacing unit.

Once again, if the existing horizontal well is operated by a different operator, I interpret Subsection B to trigger notice requirements to that other operator.

And then additionally, 11(b)(i) requires notice to and an opportunity to protest by the working interest owners in Tracts M, N, O and P, as well as Tracts A, H and I.

Q. So it expands the notice outside the

overlapping tract, which would be Unit P?

A. Correct, because -- because when this existing horizontal well (indicating) is drilled and if it's drilled in compliance with the rules and all the interests are consolidated in that spacing unit, then by virtue of that consolidation and this overlap, then all the working interest owners are entitled to notice in this existing spacing unit because of the fact that they're consolidated and they show up as owners here in this overlap spacing unit.

So according to what my land people tell me, this situation results in notice to all working interest owners in A, H, I and P, as well as the proposed spacing unit.

Q. Rather than just the operator?

A. Rather than just the operator.

Q. Okay. All right. So those deal with a "partially within" circumstance, (b)(i)?

A. Yes.

Q. Now, do we have an example of (b)(ii) where they are wholly within?

A. Yes. This is how I interpret 11(b)(ii) to apply. The situation here is a target oil pool. It's under special pool rules with 80-acre spacing. The operator elects to construct the standard horizontal spacing unit using the pool rules. And the completed interval for well number one penetrates four 40-acre tracts, making the standard horizontal spacing unit of 320 acres.

Then a second well is proposed, well number two. It is not designated as an infill horizontal well, but it has a completed interval in the same pool as well number one and is located wholly within an existing well's horizontal spacing unit. So I characterize this as the noninfill infill well situation. As you can see, the horizontal spacing unit for well number two exactly overlaps the horizontal spacing unit for well number one.

11(b)(ii) requires notice and opportunity to protest by the operator and the working interest owners in both spacing units here.

Q. Okay. Let me stop you right there. In this scenario, when they drill well number two, you've got a scenario where the operator chose not to designate it as infill well?

A. Correct.

Q. Okay. Now, why would an operator do that?

A. There just may be some contractual situations or other reasons that prevent it. But we wanted to make sure that if an operator did drill what otherwise would be an infill well but for whatever reason he elected not to designate it as infill well, that notice requirements would be triggered that would ensure correlative rights were protected for the owners in well number one.

Q. Okay. So is it possible, for example, then, you might be a Bone Spring Pool -- well number one will be in the 1st Bone Spring and maybe well number two is in the 3rd Bone Spring?

A. Absolutely.

Q. And are there scenarios, Mr. Foppiano, where, while it's the same pool, there may be a depth severance?

A. That's correct. There could be a depth severance between these two pools -- these two target zones that result in well number two actually having different ownership than well number one.

Q. So you may have -- be in a different bench; you may have different owners --

A. Yes.

Q. -- which give rise to all kinds of contracts, right?

A. Exactly.

Q. Is that why, then, it's nice to have this flexibility where you can choose not to designate it as an infill well and instead create a separate stand-alone

spacing unit for that second well?

A. That's correct.

And in discussions at the committee -- we've noticed this in Texas. They're struggling mightily with the particular fields that have depth severances, as you mentioned, these long vertical intervals, these defined pools that have very long vertical intervals. So the depth severances are creating huge headaches for the regulatory agency and operators. And, unfortunately, that seems to be the trend, that there is going to be more and more depth severances of these interests with these multiple benches. And so we wanted to make sure that the provisions in these rules recognize that and provided some protections. So we believe that does accomplish that.

Q. Is this an example of the circumstance where the committee and the Division chose to provide operators flexibility to deal with these circumstances, right? You can designate it as an infill well if your contracts allow that, or you can, when you have a unique circumstance like a depth severance, designate it as a stand-alone separate spacing unit?

A. That's exactly right. It does provide operators necessary flexibility to deal with these complicated land situations that we see today and we'll see more in the future.

Q. Now, if I look at page 14 of NMOGA's Attachment 1, I see some language change proposed by NMOGA to these little -- these subsections, (b)(i) and (b)(ii). (B)(i) is dealing with circumstances wherein the second spacing unit is partially within, and (b)(ii) being where it's wholly within. Would you please walk us through the rationale for these proposed language changes?

A. Yes. There are a number of changes you see there being proposed, and some of these were suggested to us by the OCD. Some of those NMOGA arrived at them themselves to further clarify the language in this provision.

Starting with (i), there is a change proposed to where it says "any subsequent well, horizontal or otherwise" and just change that to "a horizontal well." And we believe that confines that provision a little more to horizontal wells and makes it more clear that that (i) does apply to a horizontal well -- a proposed horizontal well.

And then moving down, we can see the language "pursuant to a Division order" that we've recommended be struck. I believe Mr. Brooks has already discussed that, and everyone agreed that's a useful --

useful change to make to allow operators to be able to prosecute these operations without forcing a regulatory proceeding, the issuance of an order, where there is an easier way to get that done.

And then continuing on, there is a proposed change. Since the rule requires notice to operators and working interest owners and it relates to something that the operator would have knowledge of and something the operator may not have knowledge of, which are privately transferred interests in another well between other parties, we wanted to make it clear that that notice provision extended only to interest owners of record or known to the applicant such that he wouldn't be required to go figure out any private transactions that are not recorded at the county courthouse. So that's the changes proposed to (i).

To (ii), a similar change mainly to clarify its applicability, that (i) applies whether that noninfill infill well is a horizontal well or a vertical well. This would apply. And we wanted to qualify that we're talking about an existing horizontal well that's in the same spacing unit -- I mean -- sorry -- same pool or formation as the proposed well. And then, once again, the changes to delete "pursuant to Division order" and qualifying that the owners need to be of record or known to the applicant. Those changes are also contained.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Maybe I'm being a little naive, but the way I read 11(b)(i), if you take out "pursuant to Division order," it makes it sounds like you can do it with the approval or, if you don't have approval, you just have to notice.

A. It's notice and no protest. And I believe the references in subsequent Paragraphs C and possibly D of this section refer to the administrative approval process and what happens when there are protests and that sort of thing. And so we interpret it, the way it's proposed, that we would give notice if there is no protest. Then you can proceed, or if you have the approval of all these parties or you have waivers of protest. And that's why the language that we proposed both -- in the proposed rule, with some minor changes that NMOGA has suggested, we think gets that provision down to something that is easier to manage for operators and also accomplishes the desired result.

Q. So really the implication is "after notice to, without any protest, all operators and working interest owners of record known to the applicant in the existing

new well spacing units"?

A. It's intended to mean after notice and no protest.

Q. Right now it just says "after notice."

A. I understand. But I think this has to be read in conjunction with the other paragraphs in this section about notice, and that's where it refers to notice, waivers and everything. That's an existing process that has been described, and we just thought it was useful to reference that process.

MR. FELDEWERT: So Mr. Foppiano put specific language to it.

CONTINUED DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. If we look at the next page, page 15, there is a subsection -- should be Subsection (d), not (e). 11(d), as in dog --

A. Yes.

Q. -- references a certain subsection of the existing Division rules which deals with notice, right?

A. Yes.

Q. And that's what you're talking about where they have to send it out, got a certain period of time --

A. Yes.

Q. -- which you have to wait, and if there is no

protest within that, then you can proceed?

A. It says it shall apply for those notices that are required in (b)(i) and (b)(ii).

Q. Okay. Gotcha.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Well, maybe that needs to be somewhere above (b)(i) and (b)(ii) because that's the definition of who you're noticing and what the notice procedure is if there is consent or nonconsent?

A. It could be restated here, but the desire was if there was a good procedure that was already described in the existing rules and we felt that was a good one, because we covered all the bases, then referencing it covered the same thing. I don't disagree with what you're suggesting. But I think the work group presented it as the more we can point it back to an existing process, the more it would be understandable and easier to use for operators.

Q. I guess I just feel like (b)(ii) also applies for (b)(i).

A. I'm sorry. I don't understand.

Q. So (b)(ii) is where you're pointing to the notice requirements.

A. Oh.

Q. I think that also applies to (b)(i).

A. It does. This is 11(a), (b), (c) and (d). So (c) and (d) apply to -- it's a subparagraph, so it actually --

Q. Okay. I think my -- this is not my area of expertise, but it seems like that should be above -- (d) should be above (b), re-ordered where you have notice reference before you get to (b). That way it's clear who you're noticing in (b)(i) and (b)(ii). Otherwise, you could read (b)(i) to -- perhaps naively and not having read the whole thing, you could read that far and say, "Well, I just have to notice; I don't have to have any other sort of approval."

A. I understand. I just -- I think what we were trying to do with paragraph (d) was to make it clear, because it does actually reference items (i) and (ii), and it says, "Those notices that are required under (i) and (ii)" -- the way you do that and the way those are handled are covered in Subsection B of 19.15.15.12.

Q. I'm wondering if you need to point (b)(i) -- (b) to (d) or have (d) above (b).

MR. BRANCARD: I think you need to make clear whether this provision replaces or supplements the 15.12 process.

MR. FELDEWERT: It brings in the provisions of 15.12.

MR. BRANCARD: It doesn't say that. It just says, "This is what you do for subsequent horizontal wells." It doesn't say, "In addition to 15.12, you have to provide the following notice."

THE WITNESS: It really doesn't matter because this already states "operators." And so it covers the notice provisions that would be required under Subsection B. So if it replaced it, it wouldn't matter because it covers the same people. In both cases, (i), the notice goes to operators. Whereas, in Subsection B, the multiple operators in a spacing unit is just the notice that goes to the other operator.

COMMISSIONER BALCH: It seems to me and maybe -- and I know that land law is not something that applies logic very easily. If you just made (b) (d) and -- moved (b) to (d) and then have everything above (b), it would be pretty clear.

THE WITNESS: I see your point.

MR. FELDEWERT: So now we're about ready to move on to a new topic, unless there are other questions.

CONTINUED DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Before we do that, Mr. Foppiano, just for the

record, do you believe that these changes that are reflected in Subparagraph A(11) are necessary to avoid confusion and better implement the intent of the committee and the Division in enacting these rules?

A. Yes.

Q. Okay. All right.

A. Do we need to talk about NMOGA's proposed changes to Paragraph (d) where we're proposing to delete nonconsenting owners? I don't believe we mentioned that.

Q. And where are you? I'm sorry.

A. This would be 11, Subparagraph (d).

Q. Oh, I'm sorry. Yes. I didn't see that.

What's the circumstance there?

A. Well, this was -- this was new language after the committee did its work and NMOGA reviewed it, and it's proposing to delete that reference to nonconsenting owners, where -- so the provision would read that all those notice requirements that are described in Subsection (b) would apply to all the notices that are required in (b)(i) and (b)(ii). And it wouldn't be to just nonconsenting owners.

It was felt that nonconsenting owners were still working interest owners in the spacing unit, and so they're covered under the requirements of (b)(i) and (b)(ii). And it was unnecessary to have this language in there for just specific to nonconsenting owners. But by deleting it, then that allows that paragraph to apply to all the notices that require -- to operators, working interest owners in (b)(i) and (b)(ii).

Q. So in other words, it's to clarify that the people -- the interests that you do need to notify are set forth in (b)(i) and (b)(ii)?

A. Correct. And the notice process is described -- that applicable -- is described in Subsection B in 19.15.15.12.

Q. And the concern was that the phrase "to nonconsenting owners" would create some ambiguity when you looked at what would have been in B and also what's in (b)(i) and (b)(ii)?

A. Created ambiguity, and it also was unnecessarily limiting because it left out "operator." We think deleting it just makes it more clear.

Q. Okay. Anything else on this?

A. No.

MR. FELDEWERT: Any other questions from the Commission before we move to setbacks?

Q. (BY MR. FELDEWERT) Okay. Then our next topic as we move, then, through Attachment 1 is on the bottom of page 15. We're on setbacks now --

A. Yes.

Q. -- which now is another different major topic, right, Mr. Foppiano, as reflected in your slide B6 [sic]?

A. Yes. As we mentioned -- we just finished talking about all things related to spacing issues for horizontal wells.

Q. Let's advance one more there.

A. Okay.

Q. There you go.

A. And that was in part A. And now we're going to talk about Part B, which is all things related to setbacks. And I have some pictures here to describe what the setbacks are and how they work. We call this the dual setback type of rule because there is a different setback for one side of the completed interval than another, and we'll talk about that.

And because this section also deals with setbacks, it covers the approval process for both orthodox and unorthodox locations, as well as the tolerance for as-drilled horizontal wells and even -- we even get into discussing setbacks in unitized areas and basically exceptions to that, basically how the setback works for drilling unitized areas.

So I'm going to cover Sections B(1) through

B(4) much like I did in spacing, talk about that conceptually.

And the setbacks here are all defined in relation to the boundary of the horizontal spacing unit. And so we're talking about moving back from that, and we define those in relation to the completed interval, both objected and as-drilled. So where the completed interval is, there is a certain setback in relation to the nearest boundary line of the horizontal spacing unit.

As I mentioned, we described these as dual setback rules, and this is a concept that has become quite common in Texas for horizontal drilling in these unconventional reservoirs, to recognize that the drainage from the heel and the toe or the first take point and last take point is far less than the drainage from the side of the completed interval. And not only Texas but other states have recognized the need for less setbacks for first and last take point than for the side of the horizontal -- horizontal well.

So the setback described here for horizontal oil wells would be 330 feet, and that's measured in the horizontal plane and perpendicular to the completed interval, and 100 feet from the first and last take point measured in the horizontal plane.

And I'll stop here in a minute and explain why some of this language shows up in here about horizontal plane and perpendicular and stuff like that.

There was some discussion in Texas and may have been in New Mexico that a setback could actually be interpreted to apply in a vertical sense to a boundary of a spacing unit where the top of the pool could be interpreted as being the edge of the spacing unit. And that was unique and creative, but it was actually argued in Texas. And so in this particular case, the OCD offered that there was some discussion in New Mexico, and we wanted to be very clear in this wording how that setback actually is measured. And so that's where the phrase "measured in the horizontal plane" comes from. We want to make sure it's not interpreted to be measured in a vertical sense at all.

And then perpendicular to the completed interval is just how the setback applies. It only applies to the size of the completed interval because there is a different setback for the first and last take point.

Different setbacks for horizontal gas wells. It's 660 feet and also measured in the horizontal plane and perpendicular to the completed interval, and 330 feet from the first and last take point, measured in the horizontal plane. And as you would imagine for these horizontal spacing units, there would be no internal setbacks that would apply. That's also an existing rule.

The surface location. This is where New Mexico continues to lead the way ahead of Texas, how they deal with surface locations. And there are no rules in New Mexico governing surface locations. So these proposed rules carry forward an existing concept that basically this is a legal issue for the operator about where this surface location is. He must have all the legal rights and authorities with whatever agreements he needs to have to be able to put that surface location outside of the lease in which he's going to develop. And that's something that operators recognize, and it is -- my understanding, it's even been litigated recently in Texas. So it is -- there was very little discussion about the fact this is not really a regulatory issue as much as it is a legal issue for the operator.

So these rules just clarify that surface locations can be anywhere outside the setbacks. They can be outside the spacing unit, what we call off-lease. And, once again, just the recognition that this is primarily, if not purely, a legal issue between the operator and other parties.

Q. So now we get to NMOGA's proposed change. If I look at Attachment 1 and I go over to page 16 -- and I'm at Subparagraph B(3). We see NMOGA's proposed change to the -- to the rule, right?

A. Yes.

Q. Okay. And what are you trying to accomplish here?

A. Well, actually, the committee's version language was intended to be real clear about this, but on further reflection -- I believe Mr. Brooks caught this -- it needed some tweaking to be as clear as possible. And then NMOGA looked at that and decided that yeah, let's make this abundantly clear about what we mean about the location of the surface.

So what we have come up with is language -- and it's my understanding the OCD finds this acceptable -- that we would delete this language, "farther from the horizontal spacing unit boundaries than the applicable minimum setback" and just basically say what we really mean, which is "the surface location may be located anywhere inside or outside the boundaries of the spacing unit," period.

Q. Was it the "farther from" language that was creating some concern?

A. I'm sorry?

Q. Was it the "farther from" language --

A. Yes. It was -- there was some potential ambiguity created by that language, and we felt like there was an opportunity to make it more clear than what the committee had come up with.

Q. And in your opinion, does that eliminate the ambiguity in the current provision?

A. Yes, it does.

Q. Then if we move on to Subparagraph --

COMMISSIONER BALCH: I'd like to ask a couple of questions, if that's all right.

CHAIRWOMAN RILEY: Sure.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I think that it's important to know the difference between each well's individual horizontal spacing unit and then the discussion of a larger unitized area. Within that larger unitized area, would it make sense to have these setbacks at all, or would it really be at the discretion of the operator?

A. Mr. Commissioner, I'm going to get -- there is a setback exception to accomplish exactly that, to where the setbacks would be redefined --

Q. Okay.

A. -- for wells in the unitized area based on the boundaries of the unitized area.

Q. So on setbacks in general, B(1)(b), the take points, the change to 100 feet on the take points, that's new. That's different from what it was before. Is there going to be some discussion by a later witness or by you on the justification for moving that? I know you made a comment on it that other states are doing this, but that's not necessarily good enough for our record, to make a change like that.

A. Absolutely. I have some actual examples of what that means and how it's interpreted to apply, and also I have a little bit of testimony. It's my opinion. But we have technical witnesses behind me that are going to talk specifically to that issue, about drainage from the first and last take point areas as opposed to the drainage from the completed interval.

Q. All right. Thank you.

CONTINUED DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. So now, if there are no other questions about knowing the dual setback provisions that are on B(5), this deals with unorthodox well locations, right?

A. Yes. I've got some discussions on unorthodox locations, and then I have some pictures to show you how these setbacks actually work as we've described.

So starting with what is described in B(5), when -- an unorthodox location is when any part of a well's completed interval is projected to be closer to the outer boundary of the horizontal spacing unit and allowed by applicable rules, or the directional survey shows the as-drilled location of the first and last take point is too close to the boundary of the horizontal spacing unit, or the directional survey shows the as-drilled location of the well's completed interval exceeds the tolerance.

So here's an example, a picture. I'm showing a spacing unit, as shown here (indicating), outlined in red dash and then the first take point here and the last take point there (indicating). And the question I put up here is my completed interval's projected to be orthodox. In other words, is my first take point and last take point or my completed interval too close to this boundary line as described by the setbacks?

So the way to analyze this situation is we take a completed interval and draw a 330 box, with the long sides 330 feet because that's the applicable setback, 330 feet from the sides of the completed interval parallel to the completed interval, and then the short sides right through the first and last take point. And then, secondly, we'd draw a 100-foot circle around the first and last take points. We draw a 100-foot circle around the first and last take points to see whether we're in compliance with that particular setback.

And then at this point, all we have to do is look to see if any part of this box goes beyond the boundary of the spacing unit. Then that is an unorthodox location as projected.

So you can see this compliance box of 330 and 100 circles essentially follows the completed interval. So as an operator turns this completed interval to where it's north, south or east and west, that box just stays along with it, and if any part of that box moves too close or crosses over that boundary line, that's an unorthodox location.

Q. So this would be an example, for example -- this would be an example of transverse -- what some people call a transverse well?

A. This would be an example of a transverse well, yes, and how the setbacks described actually work in that context.

Q. And then if I move from slide 90 to slide 91, you've taken that same box and make it into a more

traditional lay-down format, right?

A. This is more what we see in the Permian Basin, an east-west type of completed interval. The first take point is shown here on the left side and the last take point on the right side. There, again, we draw the box, 330 from each side parallel to the completed interval with the long sides and then the short sides through the first and last take point. Draw 100-foot circles around the first and last take point. And then in this particular case, since no spacing unit boundary falls within inside the area described in this box, this is an orthodox location.

Q. Okay. So this would be -- deal with Subparagraph 5(A), where I have -- this is my plan; this is my projected --

A. This is projected.

Q. Okay. And then you have some slides that deal with Subsection 5(B)?

A. Which is the tolerance.

Q. Which is the tolerance. Okay.

A. Before we go on, I just want to make another comment on this in relation to the Commissioner's questions.

This box, as described, is really an attempt to forecast or roughly represent what might be a drainage area. And it recognizes, as you mentioned before, that the reservoir, the drainage, is essentially created by the hydraulic fracturing that goes on all along this completed interval.

As you'll hear from subsequent witnesses, we're really only going to drain this area that we frac. Since we're creating our own reservoir, there is horizontal development in unconventional shale reservoirs characterized by extremely low permeability, very discontinuous. And so by having less setbacks at first and last take points, then, from the side of the completed interval is a recognition of what we understand and what we believe is the drainage more likely from a horizontal well completed in that. And to not have less setbacks for first and last take point -- for example, to stay with 330 from first and last take points, you'll also see from a subsequent witness that that creates the potential for significant reserves to be left in the ground and unrecovered by a horizontal well.

Q. And, Mr. Foppiano, I know we have another witness, but you've been involved in these horizontal development projects, right?

A. Yes.

Q. In your opinion, do the drainage patterns for

horizontal wells support the closer setbacks for the first take point and last take point?

A. Yes, I believe they do.

Q. And in your opinion, will the adjustment of the setbacks for the first take point and the last take point assist in preventing waste?

A. Yes.

Q. Okay. Let's move to Subsections (5)(b) and (c), which gets to my directional surveys, right? So I have my plan, planned it orthodox, and then now we've got to look at the as-drilled.

A. As you mentioned, (5)(a) is intended to deal with the projected situation, and (5)(b) and (c) speak to the as-drilled situation. And the current rules do provide that an as-drilled horizontal well is unorthodox if it meets two tests. One, the completed interval goes more than 50 feet from its projected path, and the other is it's located closer to the outer boundary than allowed by applicable rules. In order for it to be unorthodox, it must meet both tests.

We added language to clarify how this tolerance works for approved unorthodox locations, and that was much like for directional wells. We came up with a percentage.

Q. So that's a circumstance where my projected

location showed I was going to be unorthodox, so then I go to the Division, and I get approval for a nonstandard location?

A. Yes.

Q. Okay.

A. And, of course, we recognize that when an operator does get that approval for a nonstandard location, if this default tolerance somehow doesn't work, then they should request in their nonstandard location authority a different tolerance. So there is that opportunity to have that adjusted if it doesn't work. But it does at least provide a default for how that would work in the previously approved unorthodox location situation.

It's also important to note that the proposed rules only allow tolerance in the 330, 660 direction. They allow no tolerance for first and last take point. And you might ask why. Because most of these wells, if not practically all of them, are being cased and cemented, and first and last take point is defined as the location of perforations, the first perforations and the last set of perforations. Those are controllable and well known to the operator, and it's not the same justification for the -- drilling the location of the wellbore as it is for where you're going to perforate in this wellbore. So the operator should know where you're going to perforate, and there shouldn't be a tolerance allowed for that. So this clearly states there is no tolerance for that first and last take point.

Q. Okay. So let me put a specific language on that. That would be in Subparagraph (5)(b), right?

A. That's correct.

Q. And Subparagraph (5)(c), that deals with your first bullet point here, where you get a 50-foot tolerance, but you may drift a little bit. And your point here in the first bullet point is that if your as-drilled is more than 50 feet and closer, then you're unorthodox?

A. Yes.

Q. And that's reflected in Subparagraph (5)(c)?

A. Yes.

Q. Do you have some slides to show the importance of having this requirement, that now I'm going to be more than 50 feet, but it also has to be closer?

A. Yes.

And, once again, this is building on the existing rule of 50-foot tolerance, but I want to show an example of how this actually works.

Here is a spacing unit, again, outlined in red dash, and for purposes of this discussion, we're drilling in an east-west type direction. So the orthodox area in yellow is really 330 from the side and 100 from the -- or 330 from the north and south boundaries and 100 from the east and west boundaries. So my proposed well -- you see the surface location, SL, as denoted here -- is actually off-lease, outside the spacing unit, and the well is drilled such that the first take point is planned to be right here in the upper left area, orthodox area, and then it's planned to be drilled in a straight line all the way over to the right at the last take point, as shown. So this is the projected location of the well's completed interval from first take point to last take point.

Now, the well gets drilled. The surface location didn't move, and we did a good job of hitting the first take point. But shown in green dash here would be the actual wellbore track that is defined by the well's directional survey.

So this presents us with a couple of tolerance situations here. The first one, situation number one, in blue dashed circles, this would be where the as-drilled completed interval is more than 50 feet from the projected location, but it doesn't encroach on the outer boundary of the spacing unit. It actually moves more orthodox. And so that would be a well drilled in tolerance.

Secondly, here is a situation where the as-drilled completed interval is less than 50 feet -- this is situation number two -- from the predicted location, and it is, in fact, closer to the outer boundary of the spacing unit than 330 feet. It just barely gets over that line. But because it's less than 50 feet and it's not -- because it's less than 50 feet, it is a well drilled in tolerance. It meets that test.

So the conclusion is, under the proposed language, that this as-drilled completed interval is orthodox.

Q. Now, with respect to the deviations that we see under the circles labeled "1," Mr. Foppiano --

A. Yes.

Q. -- that would be more than 50 feet?

A. Correct.

Q. Okay. And if you didn't have the additional requirement that it be closer than [sic], one could interpret the rule as requiring a nonstandard location?

A. Correct.

Q. In your opinion, is a nonstandard location approval needed from the Division in circumstances like depicted here in the circle labeled "1" on slide 93?

A. No, because you're not encroaching on anyone. It's not in a nonstandard location.

Q. There are no corrective right issues, is there?

A. No.

It might be an issue of needing to update the Form C-10- -- I mean the directional survey because of the deviation from the projected location, but that's just a paperwork issue.

Q. And then, for example, in your circumstance of circle number two where it actually deviated more than 50 feet, got outside that line, you would be encroaching towards the adjacent spacing unit, right?

A. If situation number two was more than 50 feet and encroaching, it would be beyond the tolerance, and it would be in an unorthodox location. Yes.

Q. And that's where you get a nonstandard location?

A. Yes.

Q. For your as-drilled?

A. For your as-drilled.

Q. Okay. Now, do we have a witness from Chevron today that is going to explain why these deviations occur when drilling?

A. Yes. Even though this is really an existing rule, we thought it would useful to have a drilling engineer explain why wells can't be drilled, essentially, exactly straight -- they do wander -- and why tolerance -- having a tolerance is really necessary from a standpoint of prosecuting drilling near the boundary lines at orthodox locations.

Q. Okay. Then in connection with this, if we look at Subparagraph B(6), it deals with approval of variances, correct?

A. Yes.

Q. Go ahead.

A. So B(6) is really the paragraph that states the district office can go ahead and approve the C-102 for wells that are drilled within the tolerance.

Q. Okay. And looking at this language here of B(6), did NMOGA see a concern with respect to the first sentence that has resulted in us proposing the elimination of that first sentence?

A. Yes. The first sentence, in our opinion, created an ambiguity about the situation where a well's projected location was, say, 75 feet, whether or not the district office could approve that. And that would be 75 feet but moving more towards the orthodox area.

Q. In other words -- go back to previous slide. In a circumstance where, number one, you'd be more than 50 feet moving away from the outer boundary, right?

A. Yes. And in situation number one, with this first sentence here, it seemed to create an ambiguity about the district office's authority to handle that. And after much discussion at NMOGA, we decided that it would just be more clear to delete the first sentence because the second sentence, we think, really states what is intended, that if the horizontal well's projected location was orthodox and the variance was more than 50 feet and the as-drilled location is unorthodox, then it requires nonstandard location approval authority from -- with notice and all that sort of stuff in Santa Fe. So we felt like deleting that first sentence really clarified the district office's authority to handle all of those situations that were within tolerance.

Q. Okay. And in your opinion, is it necessary to eliminate that first sentence to avoid any ambiguity?

A. I believe so, yes. And it is my understanding the OCD has no objection to that.

MR. FELDEWERT: Any questions about that from the Commission?

CHAIRWOMAN RILEY: Do you have any questions on that?

COMMISSIONER BALCH: Not at this time.

Q. (BY MR. FELDEWERT) Now, the other aspect of

B(6), Mr. Foppiano, is the provision allowing a tolerance for a previously approved nonstandard or unorthodox locations?

A. Correct.

Q. Okay. And is that reflected in slide -- do you have any discussion on that reflected in slide 95?

A. Yes. This is just an example of how we interpret this. The way that's written, the well would be in violation of its NSL order if the as-drilled completed interval was closer than the lesser of 50 feet or 25 percent of that previously authorized distance. So I have an example of how that would work.

In this particular example, the approved unorthodox location is 100 feet from the spacing unit boundary, and that means that the as-drilled completed interval can't be any closer than 75 feet because it gets a tolerance of only 25 feet here instead of 50 feet. So, essentially, the tolerance is adjusted the closer and closer the wellbore is approved to be to the horizontal -- to the boundary of the horizontal spacing unit.

And this is just a recognition. It doesn't say it in the rule. But, obviously, if that didn't work for a particular operator, I would imagine they could just request a different tolerance and provide justification for that, along with the application for their NSL order.

Q. In your opinion, does the existing 50-foot tolerance provide the flexibility needed to handle challenging drilling -- challenging drilling environments here in New Mexico?

A. Yes. And I will have a further witness that will talk about those challenging environments.

Q. And the modification to that existing 50-foot tolerance that the committee and the Division has come up with for previously approved nonstandard locations, in your opinion, does that strike a reasonable balance between those drilling issues and protecting correlative rights?

A. I believe so, yes.

Q. I want to go to a comment that was filed by Jalapeno on this particular provision. And I'm looking at page 10, and I'm reading from their comment 12 on this B(6) provision. Okay?

A. Okay.

Q. And in this verified pre-hearing statement, they make the representation that the rule -- proposed rule "allows horizontal well operators to encroach much closer to survey boundaries than vertical well owners are entitled to." Okay?

A. Yes.

Q. Is that correct, Mr. Foppiano?

A. No, it's not.

Q. Do the same tolerances that we see here in B(6), do they also apply to vertical and directional wells?

A. Yes. It's 50 foot.

Q. Okay. And is it true that with respect to this, that the rule does treat horizontal and vertical wells uniformly?

A. With respect to tolerance, yes.

Q. With respect to that 50-foot tolerance. Okay.

Because, in fact, don't we see a similar -- if someone would look, would they see a similar foot tolerance in the provisions of the rules dealing with vertical and directional wells?

A. Yes.

Q. Okay. All right. Next topic would deal with --

MR. BRANCARD: Mr. Feldewert, do you have a citation for that rule?

MR. FELDEWERT: Yeah. If we go to -- if you go to -- I'm afraid you're going to have to go to the Division's proposed rule and go to page 6. And on page 6 for vertical wells, it's under A(3). And then on page 7, under "Directional wellbores," it's under B(3). You'll see the 50-foot tolerance.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. So are you saying, then, that if your drilling location is more than 50 feet and it triggers -- it puts you from orthodox to unorthodox, you then have to follow the unorthodox well application process?

MR. FELDEWERT: If you're close --

THE WITNESS: You have to meet two requirements. One is more than 50 feet, and the other is encroaching on the outer boundary.

Q. (BY MR. BRANCARD) Right. In other words, you go from being orthodox to unorthodox?

A. Correct, if you meet both tests.

Q. Right.

MR. FELDEWERT: All wells have a 50-foot tolerance, whether it's horizontal, directional or vertical.

Q. (BY MR. BRANCARD) Once you do, then you have to follow the process for an unorthodox well?

A. Correct.

MR. FELDEWERT: If you deviate from that and are closer.

COMMISSIONER BALCH: So it's asking for

exception after the fact.

MR. BRANCARD: Yeah.

COMMISSIONER BALCH: You don't have any choice about it.

MR. BRANCARD: Yeah.

COMMISSIONER BALCH: You don't have any control. You want the order [sic] to be in tolerance.

MR. FELDEWERT: Stuff happens.

COMMISSIONER BALCH: Yeah.

THE WITNESS: In fact, what happens today is oftentimes we drill our wells moving 50 foot farther away from that 330 setback. Because of the ambiguity, we find ourselves today -- application because of the 50-foot tolerance. So the operators were very interested, on the committee, to clarify this tolerance and how it works for the district office, for the operators, for everybody.

MR. BRANCARD: It's not just an approval. It's an approval of going through the unorthodox well process.

MR. FELDEWERT: Yes, sir. Yes.

MR. BRANCARD: Which is clear in the other rules you cite but not in this.

MR. FELDEWERT: Which one are you referring to? I'm sorry.

MR. BRANCARD: If you look at -- looking at "directional wellbores," if it's the same.

Yeah. On page 7, it says, "The well is then considered unorthodox and you have to file an application to follow the process under 15.13C."

The rule here for the horizontal wells is not that explicit. It doesn't say it's unorthodox and you have to file the process under 15.13C.

THE WITNESS: You know what's interesting is my recollection is that language was in here at one time.

CONTINUED DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. I mean, the contemplation, Mr. Foppiano, was to get the approval that you would need is you'd have to follow the unorthodox process?

A. Yes. Yes. The language, I believe, says, "The operator shall obtain approval from the Division Santa Fe Office for the as-drilled location." So it contemplates that, but I take your point. It doesn't specifically reference those procedures.

MR. FELDEWERT: Yeah. I'm not aware of any other way to do it other than going through the nonstandard location. Certainly, the intent was --

MR. BRANCARD: Well, it just says

"approval" here.

MR. FELDEWERT: Yeah.

MR. BRANCARD: Stamps approved, you know.

THE WITNESS: Santa Fe will tell us how to do it, I guess.

COMMISSIONER BALCH: You don't want to end up with a case where they're routinely denying the applicant to drill there.

THE WITNESS: Yes.

MR. BRANCARD: I mean, that's my real concern, is if you put this back on the Division, what's the process and standards the Division has to apply to the situation?

THE WITNESS: The intent of the committee was that it would have to go through just as if you projected that location to be unorthodox. Depending on the adjoining spacing units you were encroaching upon, that would trigger the notice to those affected persons, 20 days protest -- opportunity to protest. If no protest, then it could be approved administratively.

Clearly, I agree with you. The expense -- these wells -- these wells are very expensive, and operators avoid as much as they can getting into that situation of having to repermit their well after they've drilled it.

MR. FELDEWERT: So I don't think we have -- there is no objection to, you know, carrying that same language into these provisions to make it abundantly clear that you have to go through that process.

MR. BRANCARD: Yeah. We're sort of getting the theme for a lot of these questions that we have existing rules for wells, and now we're adding new rules and how do they mesh.

THE WITNESS: Yes. Yes.

As I mentioned, my recollection is at one point, our version had a reference to that, and I'm not sure what happened to it.

Q. (BY MR. FELDEWERT) Okay. Then we go to B(7).

A. Yes. Remember, we're in the setback section, so we needed to create some -- put some language in here creating -- or dealing with the situation of wells in unitized areas or areas of uniform ownership.

(The court reporter experiences computer difficulty.)

CHAIRWOMAN RILEY: Let's take a ten-minute break.

(Recess, 10:47 a.m. to 10:58 a.m.)

CHAIRWOMAN RILEY: All right. Let's resume, please.

MR. FELDEWERT: Madam Chair, members of the

Commission, I believe we are on slide A96, dealing with now Subparagraph B(7) of the proposed rules on page 17.

Q. (BY MR. FELDEWERT) Mr. Foppiano, can you please discuss with us the purpose of Subparagraph B(7) on page 17 of the proposed rules?

A. Yes. Just like what we did for spacing, we felt it was necessary to describe how these setbacks should work for horizontal wells drilled in unitized areas or areas -- or the single-lease areas of common ownership situation.

And, basically, much like the way it works today, the setbacks would only apply to the outer boundary of the unitized area or area of uniform ownership, not the wells assigned or dedicated spacing unit. And that's really just a reflection that when we file our C-101s and C-102s for these wells, that we have a put a spacing unit around them, and that will arguably be a lot less than the unitized area boundary or the area of common ownership boundary. And we don't want the setback to apply to that spacing unit. Rather, we need it to apply to the outer boundary of those entities. So this is just a reflection of the current practice.

Q. And what happens if you have uncommitted tracts within the unitized area -- or within the unit -- the

unitized area?

A. It also deals with the situation where you might have a voluntary unit that has uncommitted tracts. And so the way it's described in these proposed rules is those setbacks would apply also to the outer boundary of those tracts. So an operator would have to locate his well in recognition of that.

Q. And that's reflected in the last clause of Subparagraph B(7)?

A. That's correct, yes.

Q. Now, before we get to NMOGA's proposed change, let's skip ahead real quick to slide 97. Does that provide a picture of what you're talking about?

A. Yes. This is just an example of a horizontal well that might be drilled unitized area or area of uniform ownership. Here we have -- as we mentioned, the rules provide that the standard spacing unit provision still apply, except for the rectangle requirement. We've already been through that. And now the setback requirements still apply, but they would only apply in in relation to the outer boundaries of the unitized area or the location of the uncommitted tract or partially committed tract, not the outer boundaries of a spacing unit that would be assigned to this well.

Q. Okay. Now, I see on page 17 of NMOGA's

Attachment 1, under B(7), that there has been some proposed language change, but this is similar to what we discussed before, right?

A. Yes. This is just to make this language consistent for the exception language applicable to drilling unitized areas and spacing issues associated with that.

Q. Okay. All right. Then the next big topic, I believe, Mr. Foppiano, if I look at slide 99 -- and then I'll move on to another part of the rule -- is Part C dealing with allowables, which begins on page 17 of the proposed rule?

A. Yes. This would be the section that deals with all things related to allowables for horizontal wells, and, essentially, it assigns capacity allowables to horizontal oil and gas wells, meaning it removes any restrictions that might be applicable based on depth-bracket yardsticks or GOR limits and that sort of thing.

Currently, as we know, allowables for these horizontal wells are based on the allowable for a standard spacing unit for a vertical well in the same pool. And if your project area has multiple or vertical well spacing units, then you get a multiple allowable. So these proposed rules provide for capacity allowables for horizontal oil and gas wells. And also, additionally, in the rare situation that there might be a top allowable oil well in the same pool that a horizontal well would be or would be drilled in, then it would enjoy the same treatment. It would also enjoy a capacity allowable. We think that's a very rare case, but it makes sense to provide that opportunity in case it does.

Also, the language provides that no GOR limits would apply for horizontal wells.

Q. Now, I want to focus here on the fourth bullet point, if any top allowable wells in the same pool as the horizontal well, they get a capacity allowable as well.

A. Yes.

Q. Where is that reflected in the allowable provision?

A. It's the second -- I'm reading C(1). It's the second sentence, "If any nonmarginal proration unit exists in the same pool as a horizontal oil well, the division shall assign to each oil well located in the unit an allowable equal to its productive capacity...." But we are proposing a slight change to that.

Q. Okay. Now, there is a comment filed by Jalapeno in response to this provision, 15C, in which

they represent to the Commission that the rule does not treat horizontal and vertical wells uniformly when it comes to this proposed allowable provision. Is that correct?

A. I don't believe that's correct.

Q. In fact, you have taken vertical wells into account in proposing this allowable?

A. Yes, as I just discussed.

Q. And if a horizontal well is in the same pool as a vertical well that is able to produce at the allowable, it would likewise, then, have a capacity allowable?

A. Yes.

Q. Okay. Now, do we have a witness that's going to discuss the rationale for this change in the allowables?

A. Yes, we do.

Q. In your opinion, Mr. Foppiano, do the horizontal wells being drilled in New Mexico and Texas today target low-permeability reservoirs?

A. Very low-permeability reservoirs, yes.

Q. And I lump Texas into that because they, likewise, have modified their allowables to be essentially the equivalent of what is being proposed by the Division and the committee here?

A. Yes. I was involved initially in that Texas rulemaking where they were essentially confronted with a similar situation. Operators were running into issues with allowable constraints on horizontal wells and to the point of where they were discouraging -- nonoptimum development was being created there.

And actually the Railroad Commission approached industry and said, "Look, let's consider some changes." And the result of that, there was a lot of discussion about allowables. And this would be primarily the situation in the Permian Basin they were trying to address because that's where the activity was and that's where the allowable issues were being created. And there was discussion of eliminating allowables for horizontal wells in Texas. But because of some land-lease contractual language, there was a desire to not eliminate totally allowables; instead, to arrive at a fixed allowable that was set intentionally so high as to not present any practical restriction at all to horizontal oil and gas wells.

And, quite frankly, it was amazing that -- it's 100 barrels per acre assigned to a well. So for a long horizontal well with ten acres assigned to it, it's 1,000 barrels a day, a fixed allowable. So they intentionally set those allowables so high -- and gas is unprorated in Texas anyway, so it didn't matter for gas. But for oil, they intentionally -- industry wanted that. The Railroad Commission agreed to it, and that's what is the rule over there today for these unconventional resources.

And, quite frankly, even if that wasn't enough for the situation, to make sure that allowables didn't present any problems for horizontal development, they created very long balancing periods so that you could overproduce and then underproduce, and you would have much longer balancing periods to play with. And if that wasn't good enough, then they streamlined the procedure to get overproduction canceled. So they set their scheme up to actually plan for these horizontal wells to be better and better as time went on and to remove the allowable constraints in a practical sense.

Q. And was that done, Mr. Foppiano, because of the nature of the reservoirs that are targeted by horizontal wells today?

A. I believe it was. And it was also a recognition that arbitrary constraints were restricting -- unnecessarily restricting horizontal development and in some cases causing waste.

Q. So similarly here, the committee and the Division proposal, the proposal is to assign what would

be an allowable equal to the amount of oil each well could produce, right?

A. Yes.

Q. Okay. And in your opinion, is it appropriate to eliminate what I think everybody concedes is at this point artificial production allowables?

A. Yes, I believe it is.

Q. And in your opinion, is it appropriate to eliminate any GOR limitations on those production allowables?

A. Yes, I believe it is.

Q. And in your opinion, will the elimination of these arbitrary production allowables harm the reservoir?

A. No.

Q. Or cause waste?

A. The elimination of those allowables?

Q. Yes.

A. No. It will not cause waste.

Q. Okay. And in the event, Mr. Foppiano, that there are some unique circumstances, where, for example, a horizontal well is drilled into a different type of reservoir than what's being targeted here today, how could those be handled with respect to allowables and the issues that are created by those unique

circumstances?

A. Well, you know, the unique circumstances, if there was a situation where there might be some correlative rights issues associated with the elimination of the allowables, we feel like can always be addressed with pool rules and where operators can come in and say, "Well, we do need an allowable for the wells to prevent waste and to protect correlative rights." And it would be applicable to the wells drilled in that particular pool.

But for the vast majority of horizontal wells being drilled, as the testimony that follows me will illustrate, is drilling wells with very limited drainage and there are really no concerns about the correlative rights associated with unlimited production from those wells.

Q. And was it the goal of the committee and the Division, when they put this rule together, to come up with a rule that would apply to a majority of the circumstances that we see today with respect to horizontal wells?

A. Yes.

Q. And do you believe that this provision that's been developed by the expertise of that committee meets that goal?

A. I do.

Q. Okay. Then I think we have one more topic to discuss, right, unless there are any questions.

Okay. Then if we move to the last topic, I think it's reflected on your slide A102?

A. Yes. We're in the last section of the horizontal rules, Part D, dealing with other matters that -- miscellaneous matters, so forth and so on. And starting with directional survey requirements in D(1), because we define horizontal wells now to be a separate type of well and not a type of directional well as they are today, we needed to restate the directional survey requirements that would apply to horizontal wells. And there is no substantive change from existing requirements.

There was a slight change because the OCD and the work group wanted the ability to specify the format of these directional surveys that are filed primarily in recognition that a lot of this data is becoming more and more digital. And so the OCD wanted to be able to specify how to file this data for directional surveys and get it digitally. So a slight change was made there to allow that authority to be clear.

And as Mr. Brooks mentioned, there was a recognition that survey companies haven't been approved by the OCD in a very long period of time, and so that language was adjusted to reflect today's practice.

But the point is that there are no substantive changes from the existing requirements for horizontal wells with respect to directional surveys.

Q. And the Division still has to approve the format on these directional surveys, correct?

A. Yes.

Q. Then the next topic under Subparagraph D would be D(2), downhole commingling?

A. Yes. There were a number of downhole commingling situations that were presented and discussed, and it was decided that these needed to be specifically addressed in these rules.

As I already mentioned, the horizontal wellbore that goes from one pool to another pool in the same formation could arguably trigger the downhole commingling requirements, and so specific language was put in here to address that and confirm that that does not trigger downhole commingling requirements.

And also when we had multilateral wells that have laterals in the same pool and dedicated to the same horizontal spacing unit, we wanted to make clear that those also do not require downhole commingling authority to be produced.

Q. And is that accomplished in language that's proposed under Subparagraph D(2)(a)?

A. B, as in boy, yes. Oh, I'm sorry.

Q. D, as in dog. So if I'm looking at page 18 of the Division's proposed rules --

A. Sorry. I'm looking at the wrong one.

Q. What you just referenced here in your first two bullet points on slide 104, does that accomplish what's in Subparagraph D(2)(a)?

A. Correct, D(2)(a).

Q. Okay. And then the multilateral provision that you just discussed, is that set forth in Subparagraph D(2)(b)?

A. Yes, that's correct.

Q. And in your opinion, does this provision avoid unnecessary administrative applications where Division oversight is not needed?

A. That's correct.

Q. Then move on to Subparagraph D(3).

A. Yes. D(3) is a requirement that I believe Mr. Brooks has already discussed. It's -- just wanted to be clear about how these rules work with respect to other existing provisions in the statewide rules or pool rules, and so it is as it is. Everything that was in effect on 2/1/2017 would not apply to horizontal wells, but any -- any subsequent pool rules or amendments to statewide rules that are adopted obviously would prevail over these rules.

Q. And why is that appropriate?

A. Well, the -- there wasn't much in the way of pool rules that were created addressing horizontal development except for Purple Sage; Wolfcamp. So it was felt like there was an appropriate provision to make sure that nothing in the existing pool rules that was really designed for vertical wells would present a problem for horizontal wells. So this provision essentially overrides those -- any conflicting provisions. However, recognizing that once these rules are in place, they certainly should be amended by subsequently adopted pool rules because then they could be done -- that could be done in contemplation of these rules.

Q. Okay. Now, do you agree with the observation made earlier with respect to when Mr. Brooks was testifying that rather than use the February 1st, 2017, that you could substitute "date of adoption"?

A. I believe that would be more clear and eliminate the ambiguity that Mr. Brooks identified.

Q. The other important item, if I look at NMOGA's

Attachment 1 and I look at the proposed change that we ask to be considered for Subparagraph D(3), it adds an additional sentence dealing with the absence of the density restrictions, right?

A. It does.

Q. Okay. And that is in the existing rule?

A. Yes.

Q. And was it the intent of the committee and the Division, Mr. Foppiano, that that provision remain and be carried over to the current rule?

A. It was, yes.

Q. And it was just inadvertently left out?

A. Yes. That's my discussion with Mr. Brooks.

Q. And is this a good place to put it, in your opinion?

A. I think so.

Q. Okay. And then finally we get to the last topic, which is the transitional provisions, which is under D(4).

A. Yes. And this basically, as Mr. Brooks explained, just clarifies the situation with respect to orders and things that relate to previously approved project areas and converts those to spacing units. So those wells that are drilled in those areas would be able to be properly regulated under these rules.

Q. And then what about with respect to previously approved project areas that does not conform to criteria, your next bullet point?

A. Oh, I'm sorry. If the previously approved project area does not conform to the criteria for a standard horizontal spacing unit, then this language just clarifies that it's already approved as a nonstandard horizontal spacing unit.

Q. So in your opinion, is that appropriate?

A. I believe it is, yes.

Q. And why is that?

A. Well, because we want to make sure that project areas come out of this, if these rules are adopted, as either standard or nonstandard horizontal spacing units, so, as I mentioned, they can be properly -- they can enjoy all the benefits under these rules and be handled appropriately.

Q. Isn't it true, Mr. Foppiano, that if there is a previously approved project area, that that was either done by agreement by the parties or by a creation of a nonstandard spacing unit by the Division?

A. That's correct.

Q. And so we just want to maintain that existing approval was either done by the parties or by order of the Division as we move forward with these rules?

A. We don't want these rules to create any ambiguities with respect to those prior approvals.

Q. Okay. Now, Mr. Foppiano, have you had a chance to review Marathon's proposed language?

A. I have, yes.

Q. And do you have any opinions on that?

A. I understand the desire to make the rules clear in the situation that they describe. However, I'm not -- I'm still not entirely comfortable with what they recommended as a solution. But I don't believe there was any intent by the committee to create any rules that would prevent what Marathon has proposed, and even there is some debate whether the existing rules allow what Marathon is proposing to accomplish. So I would be interested in trying to find a solution, and I'm not sure the solution that they presented doesn't have unintended consequences or makes it more complicated than is necessary. There might be better solutions. So I think it's a problem that should be addressed.

Q. Okay. With respect to the well that's been proposed, were those -- does this proposed rule -- do you agree with Mr. Brooks that this proposed rule embodied the technical expertise that was put together from this committee?

A. Yes.

Q. And do you believe, Mr. Foppiano, that it modernizes the horizontal well rules with the information that we have gathered since they were last revisited almost six years ago?

A. I believe it does, yes.

Q. And do you believe, Mr. Foppiano, that these rules have been designed and developed by the committee to deal with a majority of the circumstances under which horizontal wells are drilled today in New Mexico?

A. And our current understanding of horizontal wells, yes.

Q. In your opinion, will these proposed rules, with NMOGA's modifications, promote the efficient and effective recovery of oil and gas by horizontal wells?

A. Yes.

Q. And will these proposed rules, with NMOGA's modifications, prevent waste?

A. Yes.

Q. And in your opinion, will these proposed rules, with NMOGA's modifications, protect correlative rights?

A. Yes.

Q. And do you ask that the Commission adopt these rules with NMOGA's proposed modifications that are identified in Attachment 1?

A. I do.

Q. Were the pages that comprise NMOGA's Exhibit A, Mr. Foppiano, prepared by you or compiled under your direction and supervision?

A. Prepared by me.

Q. Almost solely by you?

A. Solely by me, being self-employed (laughter).

MR. FELDEWERT: I would move the admission of NMOGA Exhibit A, which contains slides 1 through 106.

CHAIRWOMAN RILEY: So moved. So accepted. Thank you.

(NMOGA Exhibit Letter A, pages 1 through 106, are offered and admitted into evidence.)

CHAIRWOMAN RILEY: Does that conclude --

MR. FELDEWERT: That concludes my examination of this witness.

CHAIRWOMAN RILEY: Do we have any more questions from the Commission?

COMMISSIONER BALCH: Not at this point. We can go after the other attorneys.

CHAIRWOMAN RILEY: Okay. Let's get started. Do we want to start with OCD first?

Cheryl, do you want to go?

CROSS-EXAMINATION

BY MS. BADA:

Q. I just have one question. For the changes NMOGA's proposing to 19.15.16.15A(10)(b), did OCD --

A. Excuse me. Can I catch up to you?

CHAIRWOMAN RILEY: 19.15.16.

Q. (BY MS. BADA) 19.15.16A, the horizontal well, and it's A(10)(b).

A. A(10).

Q. A(10)(b).

A. B, as in boy.

MR. FELDEWERT: It would be page 14 of NMOGA's -- is that what --

Q. (BY MS. BADA) Do you know whether the OCD concurred with that proposed recommendation?

A. I believe the OCD did not concur with that proposed recommendation.

MS. BADA: That's all I have.

CHAIRWOMAN RILEY: Okay. Ms. Bradfute?

CROSS-EXAMINATION

BY MS. BRADFUTE:

Q. Good morning, Mr. Foppiano.

A. Good morning.

Q. I represent Marathon Oil in this matter. And I know we have previously discussed some of Marathon's

concerns about the proposed rule, but I wanted to briefly outline what Marathon's issues are in this rulemaking procedure.

Marathon's issues are limited to situations in which multiple wells are drilled within a relatively short time frame in a half section, typically, or a section and then completed together, simultaneously completed or completed within a relatively short time frame. And I wanted to discuss how that can be accomplished under the proposed rules and what barriers might exist under the proposed rules as amended by NMOGA.

I wanted to first focus on Rule 19.15.16.15A(1), which is located on page 10 of NMOGA's Attachment 1.

A. Okay.

Q. You testified yesterday and today that under this provision, each horizontal well will be dedicated to a separate horizontal spacing unit; is that correct?

A. With the exceptions that are identified in -- of the other Part A there.

Q. Great. And we'll get to those in a minute.

So the idea is that each well will get a separate horizontal spacing unit?

A. That was the idea, that each horizontal well would have its own spacing unit, being it standard or nonstandard, based on the location of its completed interval.

Q. Okay. And you testified yesterday that a key concept to this rule is to allow for overlapping spacing units?

A. That's correct, as they are allowed today.

Q. As they are allowed today.

In your opinion, as the rule is drafted, does that mean spacing units can overlap in their entirety so that you could have two or three spacing units that covered the exact same acreage?

A. Yes.

Q. If you wouldn't mind flipping to slide 57 of NMOGA's presentation.

A. Sorry. I have a hard time reading these numbers.

Q. That's okay. You're at 60. You just passed it.

A. Oh, I did?

Q. Yeah.

You're at 54.

Right there. Thank you.

So this area depicts what is a half section, correct?

A. Yes.

Q. Okay. And I know in this example it provides for 80-acre spacing, but I'd like to, for purposes of this questioning, assume that it's based on 40-acre spacing.

A. Okay. I have other slides that show 40-acre spacing. Would they be better?

Q. Oh. Do you want to go back to the prior slide?

A. (Witness complies.)

Q. 56. So right here, if you look at the south half of this section, that half section, and you look at the south half-south half, that 160 acres, you could have three or four different spacing units that all cover the south half-south half, correct, under the proposal?

A. For this particular well, this would be the spacing unit --

Q. For that well?

A. -- that qualifies as standard.

Q. Yeah.

A. Now, if you had another well, then it would -- the spacing unit for that other well would be based on its completed location in order for it to be standard.

Q. Okay. So let's assume that you have -- that you placed two Bone Spring wells within in that

160-spacing unit, that you drilled them close to the same time. Would both of those wells be dedicated to a separate spacing unit covering the same acreage?

A. It would depend. Under these proposed rules, if the second well was identified as an infill well and its completed interval is located solely within the boundary of this spacing unit at an orthodox location so proximity tracts wouldn't be an issue, then it would have the same -- it would enjoy -- or be dedicated to the same spacing unit as the first well.

If it was not an infill well, then it would have a different spacing unit, which may be exactly the same as what is shown here.

Q. Okay. Great.

Where in the rules does it state -- in the proposed rules does it state that spacing units can overlap?

A. It doesn't.

Q. It doesn't.

So it doesn't expressly provide for that in the proposed regulations?

A. It provides for it by the way the rules are all designed and explained, but it doesn't -- there is not a phrase in there that says, "Spacing units can overlap." By virtue of the fact that there are no density restrictions applicable to horizontal wells and the fact that every well has its own spacing unit, what necessarily flows from that is that things can overlap, and so that's what happens.

Q. And I agree with you in that concept, but looking toward ten years from now, you could see somebody in a district office, maybe with a different opinion, where there is no provision expressly allowing for overlapping spacing units that cover the same acreage. So, therefore, every well -- subsequent well within that acreage must be an infill well.

A. The present rules don't -- to my recollection, don't say anything expressly about overlapping project areas, yet that's common today.

Q. Okay. Do the present rules, to your knowledge, when you are outside of the compulsory pooling context, require the designation of infill wells?

A. I don't believe so, no. Well, outside of -- outside of compulsory pooling, I don't believe there is any requirement for the operator to designate it as such.

Q. Okay. Yesterday you testified -- well, actually, no.

First I want to turn to Subsection A(8), on page 13 of NMOGA's Attachment 1?

A. Yes.

Q. And you testified earlier this morning that Subsection A(8) provides two exceptions as to when a separate horizontal spacing unit needs to be created; is that right?

A. That's correct.

Q. And those two exceptions are limited to either when an infill horizontal well is designated or when, in certain situations, there is a multilateral horizontal well?

A. Yes. And taken along with NMOGA's suggested changes, it clarifies exactly which exceptions are available there.

Q. Okay. And yesterday you alluded to the fact that there are certain benefits to designating an infill well, and I wanted to see if you could elaborate on that and what the benefits of having an infill well are.

A. Well, the primary benefits that jump to mind for me right now are a couple. One, your agreements that are in place may require that if you drill additional wells to the same pool, within the same defined area, that those must be infill wells. So having that authority allows you to comply with those agreements.

Secondly, I can see where having infill

wells that are in the same spacing unit, the same area of interest as the other wells allows that production to go to a common battery and not be treated in terms of the surface commingling -- in a surface commingling situation. And so in many respects, it eliminates the need for separate surface facilities.

Those are the two that jump to mind right now.

Q. Okay. If you could jump to the next -- highlighted in yellow.

So what I would like everyone to do is kind of picture in this scenario drilling five wells across that half section, which is not an uncommon scenario in today's drilling environment, correct?

A. Yes.

Q. Could you explain to me, when there is no pre-existing well, no well has been drilled in that half section previously, how an operator under these proposed rules could propose five wells and use a zipper frac in order to simultaneously complete those wells at the same time?

A. I'm thinking of the -- well, they could propose all five wells assuming that all five wells are within the orthodox area that's outlined in yellow here. They can drill all five wells under five different drilling permits, and all five wells would have different spacing units even though those five wells would all be -- the spacing units would be identical to each other.

Q. Now, is that necessarily true if you have 40-acre spacing, that all of the spacing units would be identical to each other? Wouldn't you have a spacing unit covering the south half of that half section and potentially another spacing unit covering the north half of that section with center wells creating a spacing unit for the entire half section?

MR. FELDEWERT: You mean in the scenario where you have 80-acre spacing units?

MS. BRADFUTE: No, where you have 40-acre. Thank you for the clarification.

THE WITNESS: So if I may flip back to a previous slide that shows 40-acre.

Q. (BY MS. BRADFUTE) Absolutely.

A. So if I understand your question, it's basically when subsequent wells or additional wells are drilled in these other 40-acre areas -- I'm sorry. What was your question again?

Q. My question is: If you have five wells planning, right --

A. Yes.

Q. -- and you're going to propose all those wells

together --

A. Yes.

Q. -- you're going to complete all those wells together --

A. Yes.

Q. -- and there is no pre-existing well --

A. Correct.

Q. -- within the half section --

A. Correct.

Q. -- do you end up essentially with three different -- well, maybe five different horizontal spacing units, some of which differ in size?

A. Yes. That's how I interpret these proposed rules, that each completed interval for those five wells would define a standard spacing unit. You would have a standard spacing unit for each one of those five wells, and depending on the location of that completed interval, those spacing units might overlap, they might not. It would depend on where those completed intervals were located.

Q. And having those overlapping spacing units, in your opinion, wouldn't preclude simultaneously zipper-fracking them and completing them together?

A. I don't understand how it would preclude that. It might present some problems from the standpoint of commingling production in a common battery.

Q. And that was going to be my next question. So when you have a separate spacing unit for each well, even though they might be in the same 160-acre area, would you need single-well facilities for each well?

A. If the ownership was different from those wells, that's my understanding of the commingling. You would either have to have surface commingling authority to be allowed pay production back to those different wells, or you would have to have separate facilities to separately measure that production.

Q. Now, when you have -- when you create a 320-acre horizontal spacing unit that covers an entire half section and let's say the ownership is different between the north half and the south half --

A. Would that be like this situation (indicating)?

Q. That situation, yeah.

-- would you need separate facilities in that scenario?

A. Under these proposed rules, if you drill multiple wells that were designated as infill wells inside of this spacing unit and they complied with the definition of infill horizontal wells, then my understanding is no. They would all -- all the interests would be the same as common, so you would be allowed to produce all those to a common battery.

Q. Okay. So operators, in a sense, would be penalized when they want to propose five wells all at the same time and frac them all together just because there is not a first, initial well in the spacing unit which later triggers the infill well provisions?

MR. FELDEWERT: Object to the form of the question.

You said penalized?

Q. (BY MS. BRADFUTE) Well, you're going to end up -- let me rephrase. Strike that.

In a situation where you are -- there is no pre-existing well within the half section?

A. Yes.

Q. -- and you're proposing five wells -- five initial wells all at the same time --

A. Yes.

Q. -- you cannot have an infill well in that situation, correct?

A. Because of the definition of infill horizontal well, it references a previously drilled -- let me go back and look at that again.

Yes. Looking at page 2 of the OCD exhibit of the proposed rules, reading the definition of the infill horizontal well, which is H, and it references a previously drilled horizontal well completed in the same pool, yeah, that could present a problem if it wasn't -- if you're trying to drill an initial well and infill wells at the same time because there is not a previously drilled horizontal well.

Q. Yeah.

A. And, quite frankly, in my recollection of discussion with the work group, I don't think that scenario was actually discussed. But I don't believe, based on my recollection of the discussions around these kinds of things, that there would have been a problem with that.

Q. Yeah.

A. So this language, "previously drilled horizontal well," wasn't intentionally meant to restrict that simultaneous development situation that you're discussing --

Q. Yeah.

A. -- in my opinion.

Q. Could -- in your opinion, could the definition of "infill horizontal well" be amended to allow the infill well provisions to be triggered after a well has been permitted?

A. I think there is an opportunity to consider whether the phrase "previously drilled" might need to be revised to something like "permitted" or "proposed" or something like that. In thinking about that today, I think maybe there might be an opportunity to change that definition that might address what you're talking about so an infill -- an initial well can be proposed at the same time as infill wells, and the spacing unit can be defined, and that can all be simultaneously done.

Q. Okay.

A. I spent part of my career in the Piceance Basin, and we did simultaneous operations up there. So I'm familiar with what you're talking about, and I absolutely agree there are good and valid reasons to pursue simultaneous development, completion and drilling all at the same time. It's a very efficient way of accessing these reserves.

Q. Yeah.

If you look back at Subsection A(8) on page 13 --

A. Yes.

Q. -- could another alternative essentially be adding an additional exception as to when a separate horizontal spacing unit is needed under this provision?

A. I don't know, because if another exception was added, there might be a need to define a different category of wells. I can't answer your question as to whether or not that would address the problem without creating other problems for interpretation in the rules.

Q. Okay. But potentially another exception could be created provided that that exception was properly defined and placed into the rules?

A. I guess I don't understand what the exception would be.

Q. Could there potentially be an exception for contemporaneous drilling operations?

A. I don't know. I'd have to give that some thought. We spent a lot of time working on these, like 12 versions of this rule language that the committee went through, and if I learned anything, it was that we needed to think carefully about every word in here and make sure that it accomplished what we tried to accomplish without creating unintended consequences for other parts of the rule. So that's why I'm very hesitant to make such a substantive change or to say that I agree with a substantive change like that without giving it more thought. So I really can't answer whether that would work or not.

Q. Yesterday David Brooks testified that he desired to continue to work with Marathon and NMOGA to come together and hopefully draft some language that would address some of these consecutive drilling issues

that Marathon has raised. Were you present for that testimony?

A. I was.

Q. And do you agree with Mr. Brooks' proposal that he submitted to the Commission yesterday, that there be additional time to propose some language amendments to the proposed rules shortly after the Commission concludes accepting testimony in this hearing?

A. I certainly have no objection to NMOGA being involved in those discussions and trying to help arrive at a solution that works. And if additional time is required, then, yeah, that would be fine. But it may not be -- it may not take very much time.

Q. Yes. I agree. I agree. Thank you.

That concludes my questions.

CHAIRWOMAN RILEY: Next if we can hear from IPANM. Mr. Cloutier?

MR. CLOUTIER: Thank you.

CROSS-EXAMINATION

BY MR. CLOUTIER:

Q. Mr. Foppiano, thank you for all your testimony and hard work. It's very well done.

I just have a few questions on an issue I raised with Mr. Brooks yesterday that hopefully will close some of that loop.

You're familiar, aren't you, that the Commission has adopted various rules related to the design and construction of oil and gas wells?

A. Yes.

Q. And among those wells are, for instance, the casing and tubing and cementing requirements, correct?

A. Yes.

Q. And those construction and design rules, among other things, are enacted in discharge of the Commission's responsibility to protect correlative rights?

A. That's my understanding, yes.

Q. Okay. Does the proposed horizontal rule today, that you've been testifying about yesterday, today, in any way alter those design and construction rules previously enacted by the Commission?

A. I don't believe so.

Q. Do the -- does the horizontal rule that you're testifying about create any exemptions from these design or construction rules?

A. No, it does not.

Q. No further questions. Thank you, Mr. Foppiano.

CHAIRWOMAN RILEY: Jalapeno?

MR. HALL: Madam Chair?

CHAIRWOMAN RILEY: Yes. Do you have

questions, Mr. Hall?

MR. HALL: Thank you, very briefly.

CROSS-EXAMINATION

BY MR. HALL:

Q. Thank you, Mr. Foppiano.

A. Sure.

Q. My understanding on one issue is incomplete. Mr. Balch touched on it this morning. But in the process of designating a horizontal spacing unit, how do you go about designating the vertical component of that? Let me put that question into context.

You look at the rules. It refers both to pools and then formations. As I understand it, the rules as written now, there is a difference towards designating a vertical extent of a spacing unit by reference to the pool. Is that what the committee came up with?

A. Well, I believe the committee attempted to provide or suggest rules that worked within the current regulatory understanding of what a particular pool was, the upper, lower limits and how it was defined. And if it was defined by pool rules, then the rules were designed to work with that definition or if it's defined by some formation tops that the district office is aware of. So there was no attempt to do anything other than work within the current regulatory understanding of what the defined limits of approval, the vertical limits.

Q. All right. And so the procedure would be, going forward -- the current procedure, whether on a C-101, C-102, you designate that pool -- designate a pool, and you can refer to the pool code if one exists, correct?

A. Yes.

Q. Or wildcat?

A. Yes.

Q. Fill that in later?

A. (Indicating.)

Q. The other opportunity would be by a compulsory pooling application, correct, where you designate the formation?

A. That's my understanding, that yeah, an operator does designate a formation -- or formation or pools requesting the interest be pooled in. But I'm not a forced-pooling expert, so --

Q. Okay. But would it be permissible where you could designate a subdivision of a formation for a pool in a pooling context?

A. I don't know.

MR. FELDEWERT: Actually, I believe that calls for a legal conclusion, an application --

Division's statutory and legal authority for purposes of pooling.

Q. (BY MR. HALL) Let me switch subjects just a little bit. I'm thinking of many of the pools up in the San Juan that are approved for areawide downhole commingling, various formations. Do you see any impediments under the proposed rules for the destination of a horizontal spacing unit that would include more than one formation that's preapproved for downhole commingling?

A. My understanding is you have a spacing unit for that pool. So if you have multiple pools involved, you would have different spacing units because of the different pools. So I don't think these rules, in that respect, are disturbed, whatever the current practice is, with wells that are completed in multiple pools and downhole commingling. I don't know how the Division handles that now, but I would think this would be able to work within that.

Q. Okay. Thanks.

CHAIRWOMAN RILEY: Did we ever get someone here from Jalapeno that wants to -- it'll be tomorrow?

Okay. So back to the Commission. Do you-all have questions?

Any additional questions, Dr. Balch?

COMMISSIONER BALCH: Yeah, a few more follow-ups.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. On the -- on the downhole commingling, currently the way it's set up now is you can make a horizontal unit that crossed pool boundaries. And now you're -- in the rule, the way it's presented to us, that would not require downhole commingling requirements. The only thing that kind of jumped out at me from that was if you go to ONGARD or GO-TECH, which is the front end for ONGARD, production data, a lot of times that's presented by pool. Would that be simply apportioned by the Division? How would that be addressed? I have production by pool from a horizontal that samples two pools without commingling.

A. In the present situation, when two pools are downhole commingled in an existing wellbore, my understanding is that it would be handled the same way. If the production is assigned to one pool in that well, then that's how this would be -- this will be handled, in the same way. This language really does tell operators if you're going from one pool to another pool in the same formation, same correlative interval or whatever the language is in there, you don't have to go through the hoops of downhole commingling and everything else, however it's handled. I'm unclear. I would have to go back and review how the production is handled in the downhole commingling with two pools situation, however, that's handled. Seems like it could be handled the same way going forward. This just exempts that from being an application and notice and all that sort of stuff.

Q. I think I agree with Marathon, that there needs to be some sort of explicit statement somewhere that horizontal spacing units can overlap all around within the limits of offset restrictions. That's the fork in the rule. So I think I would be a little more happy with the rule if there was an explicit statement somewhere in that list of horizontal well constraints.

A. I don't think there would be any problem with that statement, and we may be able to offer a suggestion about the appropriate place to put that.

Q. And then similarly with multiple wells completed at once, the zipper frac is a really good example of that. I suspect that communitization would be one way to work around that, just turn the whole thing into a unit.

A. My understanding is -- and it's limited about the force pooling, but because the force pooling is linked to spacing units and we're defining spacing units here, the ability to create larger and larger units with these rules -- with these proposed rules, it's easier than it is today, but it's still limited.

In my investigation in other states, in my opinion, I think the more appropriate way of going forward is actually to allow -- have rules that allow for bigger and bigger units to be developed because, as you're going to hear in subsequent testimony, of this multiwell nature of how this resource is accessed now, and even now where it is accessed simultaneously. So I think the more the rules work in that direction, the more we're actually going to be preventing waste in a way that protects correlative rights.

Q. Well, I think you can certainly run into a situation where you're trying to zipper frac and your well spacing is going to be -- you want it to be infill --

A. Yes.

Q. -- or within a unit so you don't have those offset restrictions. Maybe you want the wells 400 feet apart --

A. Yes.

Q. -- instead of the 660. So I think that that does have to be addressed somehow in here, perhaps as

another category of drilling or completion.

A. And we're actually -- NMOGA is actually considering some language that I proposed this morning to make a slight change to the infill well definition that might alleviate the issue and make it clear that you can have an initial well with a proposed spacing unit and infill wells, and they could all be drilled simultaneously. And there wouldn't be this restriction around having to have this previous unit in place before you can have infill wells.

And as I said, in my opinion, there seems to be a lot of value in trying to make sure there are no artificial barriers to providing for simultaneous development.

Q. So maybe just a note, if it's okay, with the indulgence of the Chair, kind of in the past with rulemaking, a lot of times we'll get to the end of testimony, and then we won't close the record. We'll wait for some issues to be resolved. We may have follow-up questions that come up from those. For example, this would be Marathon and OCD and NMOGA getting together and coming up with language that addresses something like this.

A. Yes.

Q. It does extend the proceeding.

A. Yes.

Q. So if something can be done in the context of this week that would be satisfactory to all parties, it would be nice to present it before -- before we close -- won't close the record but close the hearing for a couple of weeks or a month or two months or however long it takes us to get back to it.

A. Okay. I will commit to assist on that effort. I'm self-employed and only working on one project, so -- (laughter).

Q. Just a note: We have a very busy schedule for the next couple of months, so I don't know when we could get back to re-opening testimony, for example, on this particular case. And there are a lot of parties, so sometimes it takes two months to get everybody back together.

A. I'll confer with my attorney, and we'll try to provide something and we'll work to get something as quickly as possible. I think there is a way to resolve it. It's just working around in my head, and I think there is a way to do it.

Q. That was all I had.

A. Thank you.

CHAIRWOMAN RILEY: Any questions?

COMMISSIONER MARTIN: I don't have any

questions.

CHAIRWOMAN RILEY: I have just one clarification, if I could.

CROSS-EXAMINATION

BY CHAIRWOMAN RILEY:

Q. Under "Unitized areas" there, when you-all added into that -- reading it: "For a horizontal well, the completed interval of which is located wholly within a unitized area or ... area of uniform ownership...." And it's going to be treated the same?

A. Yes.

Q. Did you-all have discussions in the committee about what would happen if -- because without that formalized unit, you could have the potential of companies selling off, you know, portions where then you now don't have that uniform ownership, and so then there could be conflicts in how that's treated after the fact and going forward?

A. Or -- and one of the examples that was offered, a Pugh clause on a lease operates to where parts of that lease that are undrilled can be leased and unleased, so they end up being different interests. That was actually discussed. But it was felt like in the interests of particularly multiwell horizontal development, if we're operating on a single lease and it's being developed, then we ought to allow as much flexibility for drilling on that single lease, recognizing that at some point down the road, there might be changes to that outer boundary such that it collapses down to the area that's developed by the horizontal wells.

And to me that's taken care of by the fact that even if that results in, say, an unorthodox location or a completed interval being too close to a boundary, that is an after-the-fact type thing. It happens already today, where interests are assigned or whatever for existing wellbores. And so no one on the committee was really uncomfortable with how that works. In fact, it happens in other states and everywhere else. So it was felt like this was a better way to do this, recognizing even that situation may occur. But somebody's going to be picking up that interest or that lease and would know that that's the location of that wellbore when they would buy that. It's all a matter of public record. So it was felt like that was -- that was okay even though that might happen.

Q. Thank you. That's all I have.

MR. BRANCARD: I just have a few questions.

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. I think I'll start in the back, D(1), the directional survey requirement.

A. Okay.

Q. It says you have to file the directional survey upon the well's completion. There is no deadline here. Obviously, that's the only way the Division is going to know whether you have moved from orthodox to unorthodox, but there is no deadline here.

I did note that in the -- for directional wellbores and deviational wellbores, there is a revision in here which you didn't copy, which says, "The division shall not approve a form C-104 for the well until the operator files the directional survey." I'm just curious as to why that -- that would seem to drive your wanting to get that directional survey in pretty quickly. Why wasn't that provision included with the horizontal wells? It seems like a pretty good provision from the Division's point of view.

A. I seem to recall that it was included at some point.

But to your point, our understanding is the requirement, when it relates to the well's completion -- and there are other rules that specify the deadlines for the filing of completion reports and actually, I believe, even defined completion -- that was adequate enough to understand that the directional survey had to be filed with the completion paperwork and what those deadlines were. So there didn't appear to be any misunderstanding with industry about what that meant.

Q. Well, but absent a deadline, absent a reference to another rule, absent a provision about the C-104, I mean it seems like this could be delayed, and it hurts the Division because they don't know when something has become unorthodox, which would trigger more notice and more requirements and need to be dealt with.

So I would ask whether you want to include that same sentence, which is (B)3 for directional wellbores, and is also, I think, in A(3) for vertical and deviated wellbores that requires -- it says that "the division shall not approve a form C-104 for the well until the operator files the directional survey." We ought to treat horizontal wells the same way we're treating vertical, directional and deviation.

A. My memory is getting slightly better (laughter). I think, with the changes that were made last year allowing C-104s to be filed so oil could be moved, that language was deleted so as not to conflict with those provisions and changes that were made last year. I could be wrong, but I think that may have been the reason why that language was dropped, so as not to be a conflict with the changes that were made that allows an operator to move oil prior to getting the final C-104.

CHAIRWOMAN RILEY: Under a test allowable.

THE WITNESS: Yes, under a test allowable.

MR. BRANCARD: This treats horizontal wells differently?

CHAIRWOMAN RILEY: No.

MR. BRANCARD: But this treats horizontal wells differently. That's correct.

MR. FELDEWERT: So to your point, Mr. Brancard, I'm looking at the proposed rule on page 7 --

MR. BRANCARD: Yes.

MR. FELDEWERT: -- are you talking about the last sentence, Subparagraph 4, top of page 7?

MR. BRANCARD: Yeah. And then Subparagraph (B)3, further down on that page, includes the same sentence.

MR. FELDEWERT: That being the language, "The division shall not approve a form C-104 for the well until the operator files the directional survey"?

MR. BRANCARD: Yes.

MR. FELDEWERT: My understanding is that it's not just our modification [sic], but that from our perspective, we don't have a problem with that, since it's in the existing -- it's an existing provision for both vertical and directional wells.

THE WITNESS: I think the only concern may be with that language in there for horizontal wells, does that remove the Division's ability to approve a temporary C-104 when the operator has not yet filed all the completion work, including the directional survey?

CONTINUED DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would that same concern exist, Mr. Foppiano, for directional wells?

A. Not so much. Because of the complex nature of the -- the more time it takes to get the directional survey information from the directional company for horizontal wells. We don't drill very many directional wells anymore. But for these horizontal wells, I've heard that issue more and more, that it takes more time to get this directional survey data from these companies. We'll be waiting on it, yet we're sitting there producing a well, and oil is stacking up. And that was the whole reason for the test -- the change last year, was to be able to get -- to move that oil off that lease before we have filed the completion paperwork, which would include the directional survey.

So my only concern is, does that -- the inclusion of that language for horizontal wells, does that take away that which was granted last year in the rules?

CHAIRWOMAN RILEY: We would need to take a look at this, and maybe we can do it over lunch. But I thought it was -- the C-102 was asking for the directional survey, it went together and had to be provided prior to getting test allowable approval and then completion --

THE WITNESS: You may be right.

CHAIRWOMAN RILEY: -- paperwork and further time to do -- to be turned in.

THE WITNESS: You may be right. My recollection may be incorrect.

CONTINUED CROSS-EXAMINATION

BY MR. BRANCARD:

Q. Okay. Bouncing backwards, then, to page 16 of your (B)3, the entire well -- this entire rule proposal is focused on largely, as I understood it, requirements dealing with the completed interval of the well, spacing, setbacks, et cetera.

A. Yes.

Q. But now on (B)3, we're suddenly dealing with the surface location of the well?

A. Yes.
Q. Okay. Now, you have -- again, my concern is other requirements in other rules, you know, in your basic drilling permit rule, Rule 14, that requires -- it does matter where you're located in the well --
A. Yes.
Q. -- in terms of notice to the municipalities, notice to other operators from the same quarter-quarter section. I want to make sure that those requirements are not being, sort of, removed from the horizontal wells here. Is that the intent, or --
A. No. In fact, the "Other Matter" section where we talk about potential conflicts, to the extent that those requirements aren't conflicted by anything that is presented here, then they would still apply.
Q. I don't know how necessary this subparagraph is, but I don't want to create confusion as to what the requirements are, trumps the other requirements for C-101 or --
A. This was beneficial, I think, to operators particularly in the Permian Basin because of the different way it's treated over in Texas. And it was felt like to make these rules as clear to everyone dealing with the surface location in this manner, clarifying how the rules apply to it, was of benefit

from industry side.

MR. FELDEWERT: Mr. Brancard, I'm not -- if you took a look at what the Division filed and answering the Commission, they did file some draft -- it's my understanding that they're looking at those forms to see how they need to be changed to accommodate these rules. All those forms still retain the requirement that you identify your surface location.

COMMISSIONER BALCH: The forms, as we mentioned, are something more malleable than the rule, so I would caution you again to not depend upon the form.

Q. (BY MR. BRANCARD) Well, that's a good segue to the next point, which is the whole issue that you're talking here about with Marathon about infill wells and A(8), the exception for horizontal wells.

I mean, my crude understanding of how we do spacing in New Mexico is that every well has to have acreage dedicated to it.

A. Yes.

Q. Yes. Okay.

So the spacing unit is the format in which acreage is dedicated to a well?

A. Yes.

Q. So how does that work then for an infill

horizontal well if you're saying it doesn't have to be part of the spacing unit, doesn't need a spacing unit?

A. I don't believe we're saying that for infill horizontal wells. It just shares the same spacing unit as the existing well.

Q. It says here, "Except for infill wells, every well shall be dedicated to a spacing unit." So that seems to imply that an infill well is not dedicated to a spacing unit. I mean, I think what you're -- maybe your point is that the infill can be dedicated to an existing spacing unit.

A. Yes. I see. We don't specifically say that with respect to infill wells, about -- that it's just dedicated to the same spacing unit as an existing well.

Q. Now, you're still going to have to -- for the infill well, once you drill, you're still going to have to file a C-102.

A. Yes.

Q. And it's going to have to say, "This is the acreage dedicated to this well."

A. Yes.

Q. And I guess you want to be able to say that acreage has already been dedicated previously to another well?

A. We felt like that when the operator files the

C-102 and designates that well, that filing is applicable to an infill well and then shows a spacing unit associated with that, that that would indicate that it is sparing the same spacing unit as another well. In fact, it may even show the location of the other well and its existing spacing unit. So it would seem like to me that when the operator files that APD for that infill well, that issue would be addressed.

Q. So, I mean, it seems like a complete nonissue for a standard horizontal spacing unit, right, because the standard horizontal spacing unit, as we discussed yesterday, and hopefully maybe the rule will be clarified, that all you have to do is show on your C-102, check the box that you have met the requirements that are in the rule?

A. You would also show the spacing unit.

Q. You would also show the spacing unit, right? So, I mean, you do the same thing for an infill well, right?

A. Yes.

Q. Okay. So there is really no difference.

But maybe what we're talking about is if you have a nonstandard spacing unit? Is that where the real issue is here?

A. No? I think it -- it really wouldn't matter whether it was a standard or a nonstandard spacing unit if you're dealing with an infill well.

Our -- our intent was the operator would file, in the APD, and identify this well as an infill well and then would also show on his C-102 the spacing unit for that infill well, and that would be the acreage that would be dedicated to it. And by virtue of the fact that it is identified as an infill well and the spacing unit that's shown in the C-102, that -- that would be in compliance with the fact that it's previously dedicated to another well. But it's still shown as an infill well and it has a spacing unit. It's just the same spacing unit that's dedicated to the first well.

Q. Okay. But if you had a nonstandard spacing unit and now you have -- that got approved --

A. Yes.

Q. -- okay, and now you're coming with an infill well --

A. Yes.

Q. -- I assume what your goal is is to not have to go through all the same notice requirements that you went through initially for the nonstandard?

A. I believe what was contemplated was that even though that's a nonstandard unit, it's already approved.

And so that is the spacing unit attributable to the first well, the existing well, and I'm just drilling an infill well on that. I've checked that box, identified it as an infill well and there's the spacing unit associated to it, and it can be standard or nonstandard. But there was no -- there was no thought that it should trigger additional notice or have to be repermitted as a nonstandard unit if there is already an existing well there, even though that spacing unit for that existing well is nonstandard.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I find that language in 8 to be a little bit unclear as well. I don't know how to address that except for perhaps start it with: "Each horizontal well shall be dedicated to a standard horizontal spacing unit or approved nonstandard horizontal spacing unit." And then have another sentence that says: "Infill horizontals and multilateral horizontal wells are assigned to the exiting spacing unit that are associated with," or some language like that. I don't know if that would be a way around it. But the way it's written, it does sound like you could have a case where there is not acreage assigned to that particular well.

A. I think the language you're suggesting would actually make it more clear. Yes.

MR. FELDEWERT: Mr. Brancard, with that, I'll address your concern about the lack of a affirmative -- shall dedicate a standard or a nonstandard spacing to horizontal well that you talked about yesterday.

MR. BRANCARD: Well, yeah. I mean, conceptually, I would love to see A(8) right at the beginning. That's where it is in the current rule. So it seems like a pretty basic concept to get out right at the beginning. So I think what Marathon is getting at here is that if you don't have the drilled initial well and you come with a second well, even though it's the same spacing unit, you're basically applying for a new spacing unit, which only matters if it's nonstandard because that's when you have to do the notice. If it's standard, it's checking the box. Right?

MS. BRADFUTE: Yeah.

MR. BRANCARD: So you would have to file -- even if -- if you haven't drilled it already and even if it's the same spacing unit, you're going to have to go through the whole same notice process on that nonstandard spacing unit.

MS. BRADFUTE: Another issue would be facilities and the benefits that you get from shared facilities for infill wells, when really this is a situation analogous to infill wells. It's just that you're drilling them all at the same time and completing them all at the same time.

THE WITNESS: Since we're discussing it, the idea that we're considering is changing the definition -- or proposing to change the definition of "infill horizontal well" such that the words "previously drilled," we would add, "or proposed." So you would have -- you would be able to propose an initial well and infill wells, and they would all be drilled simultaneously. And those other wells would be considered infill wells because it's a proposed spacing unit. The language "previously drill" I think is one of the things that presents Marathon some problems, because there has to already be a spacing unit out there and an existing well before you can have infill wells, and that may be unnecessarily limited.

MS. BRADFUTE: And, Mr. Brancard, the other issue is Division counsel may have a different view as to when you have overlapping spacing units, whether or not that second well is in a nonstandard spacing unit. So there could be differences of opinion for the second well in a spacing unit when you're drilling them both at the same time and whether a spacing unit can overlap entirely as to 100 percent of the spacing unit.

MR. BRANCARD: Are you saying that the second well, therefore, would not -- the first well could be standard and the second well could be --

MS. BRADFUTE: Nonstandard.

MR. BRANCARD: -- nonstandard?

THE WITNESS: I would not agree with that interpretation.

(Laughter.)

MS. BRADFUTE: I don't agree with the interpretation either, but there's --

COMMISSIONER BALCH: I think you're applying for a nonstandard unit in that case.

MS. BRADFUTE: Yeah.

COMMISSIONER BALCH: You would have to apply for a nonstandard.

MS. BRADFUTE: And so Marathon's objective is just to make it clear so people can operate.

MR. BRANCARD: And just to be clear, as I read the definition of "infill horizontal well," it doesn't have to be the same operator, correct?

THE WITNESS: I guess not.

COMMISSIONER BALCH: You have to have permission from the existing operator.

THE WITNESS: My understanding of voluntary agreements is that, in most cases, those would be the same operator if infill wells are being drilled. And under force pooling, my understanding is that would be the same operator because the force pooling designates the operator.

MR. BRANCARD: For the unit.

THE WITNESS: For the unit.

MR. BRANCARD: But if everybody starts filing simultaneously or you have a pooling order --

(Laughter.)

THE WITNESS: That's an interesting situation.

MR. BRANCARD: -- that might -- you know, that might be sort of the impact of what Marathon is looking at, that you could have several people coming in at the same time all claiming that same unit.

THE WITNESS: Yeah.

COMMISSIONER BALCH: They're going to work that out between the landman before they apply.

MS. BRADFUTE: Yeah.

MR. BRANCARD: One would hope. I think that's all I have.

CHAIRWOMAN RILEY: I have my rules up here so just to point out what's required when, the 45 days is just on your completion report, which is the C-105.

An order to get an allowable and your authorization to transport, which is a C-104, you have to have provided the directional survey.

THE WITNESS: Okay. Apologize. My recollection was wrong.

CHAIRWOMAN RILEY: Procedurally, where are we? Would this be a great time to break for lunch? Are we finished with --

COMMISSIONER BALCH: Do you have redirect?

MR. FELDEWERT: No. I have no additional questions. Well, let me double-check. I don't think I do.

COMMISSIONER BALCH: If he's switching witnesses, it's a great time.

MR. FELDEWERT: No, no additional questions.

CHAIRWOMAN RILEY: I guess Marathon and NMOGA could get together for lunch, and you can have this wrapped up by the time we come back (laughter). Just a thought.

It's 12:20-ish. Be back by 1:20.

(Recess 12:16 a.m. to 1:25 p.m.)

BRIAN TAYLOR,

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

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your name, identify by whom you're employed and in what capacity?

A. Brian Taylor, Occidental Oil and Gas. I'm an engineer design manager.

Q. How long have you been an engineer design manager for Occidental?

A. In my current position, three years.

Q. And have your responsibilities included the Permian Basin?

A. Yes, sir.

Q. Of both Texas and New Mexico?

A. Yes.

Q. Okay. When you say unconventional reserves, what do you mean by that?

A. Unconventional resources would mean shale intervals primarily in very tight oil reservoirs.

Q. Okay. Have you previously testified before this Commission?

A. I have not.

Q. If I turn to what's been marked as NMOGA Exhibit B, do the first two pages of that exhibit accurately summarize your educational background and work experience?

A. Yes.

Q. It indicates that you got a geology degree in 1979 from ASU?

A. Yes.

Q. What did you do after graduation?

A. I was hired by Schlumberger in the engineering training program for two years. I worked in Levelland, Ohio, and then in the research facility, in Tulsa. And I was assigned to the field and worked in the Permian Basin for approximately ten years, including Hobbs and Artesia, worked in Lea and Eddy and Chaves Counties, and then went up to Tulsa and worked in fracturing research up there for two years ago. And then I transferred to a few other locations, Houston, Texas and then California.

And then I went to work for an independent oil company, Crimson Resource Management, as a drilling and completions manager, and then I worked there until 2010. And then I went to work for Occidental, and they transferred me to Houston as their fracturing specialist in 2010.

Q. So does your experience as a fracturing specialist extend to horizontal well development?

A. Yes, sir.

Q. And when did that experience with horizontal wells start?

A. It started when I was with Schlumberger in 1998. I worked with Chevron in their horizontal drilling program in California.

Q. Okay. And then are those -- with respect to your work for OXY since 2010, has that involved hydraulic fracturing and stimulation for horizontal wells?

A. Yes, sir.

Q. Okay. And what -- you mentioned the Permian. Has your experience also included other areas where horizontal development has been utilized?

A. When I was with Schlumberger, I worked in the Antrim Shale, in the Black Warrior Basin and other areas, Oklahoma, western Kansas, south Texas.

Q. And, Mr. Taylor, are you a member of any professional affiliations or associations?

A. The Society of Petroleum Engineers.

Q. For how long?

A. 37 years.

Q. If I take a look at the first page of your biography here, your resume, under Exhibit B, at the top, it has a nice summary of your experience; is that correct?

A. Yes.

Q. And do you consider yourself an expert in the

areas identified therein?

A. Yes, sir.

Q. Okay. Would you please explain to the Commissioners what you intend to cover with them here today?

A. Yes. I would like to talk about general completion design in unconventional resource reservoirs, this is what the process is, how we plan our completions, how we plan well spacing, hydraulic frac treatments and that kind of process and workflow.

Q. And are you going to be talking about things that impact your completion process?

A. Yes. I'll talk about the fracture geometry, frac height, frac length, cluster spacing and well spacing, and just the general nature of hydraulic fracturing in these tight reservoirs.

Q. And will you be able to offer to the Commissioners an opinion of the potential drainage radius that you could expect from horizontal wells given the current completion techniques?

A. Yes. What I'll talk about is what our simulated frac lengths are and then also what we see from other development programs through the Permian Basin and what our normal expectations are for fracture -- and well spacing.

Q. Do you have attachment NMOGA's Attachment 1 in front of you?

A. Yes.

Q. Will you please turn to page 10 of that NMOGA Attachment 1?

A. Okay.

Q. Mr. Taylor, are you familiar with the Division and committee's proposal to allow operators the option to include unpenetrated proximity tracts in standard horizontal well spacing units under certain conditions?

A. Yes, sir.

Q. And one of those conditions is that they be located within -- within 330 feet of a horizontal wellbore?

A. Yes.

Q. And is that specific provision reflected on page 10 in Subsection A(1)(b)?

A. Yes.

Q. And if you go to page 11, is that particular provision also found within Subsection (3)(b)?

A. Yes.

Q. In your opinion, Mr. Taylor, is it reasonable to provide that option when you have offsetting tracts that are within 330 feet of the wellbore?

A. Yes.

Q. And is that what you're primarily here to explain? Why?

A. Yes.

Q. Why don't you start with just a general brief explanation of the producing mechanism that is utilized for horizontal wells and how that perhaps is different from maybe more tradition or vertical wells?

A. Well, the more traditional vertical wells are completed in permeable formations, so the hydrocarbons and water flow through the matrix of the rock due to pressure going from high pressure to low pressure. In an unconventional reservoir, that movement doesn't exist. The reservoir permeability is so low that the fluid does not move through the rock.

And so in a vertical well -- you can drill one vertical well and it'll draw from a long distance because the fluids flow through the matrix of the rock under pressure.

In an unconventional reservoir, it will not flow, and so we have to hydraulically fracture every bit of the rock that it's going to produce. It just will not flow through the matrix of the rock. So every bit of the stimulated rock that we frac, that's where the production comes from.

So we drill long horizontals -- horizontal wells, and we put fracs all long those horizontal wells. And if we don't -- what we learned early on is that if they're spaced too far, that the wells don't perform very well. And if we put the fracs very close together, they perform a lot better. And so we know that we've got to frac everything that we want to produce.

Q. And it involves proppant concentrations, right?

A. Correct. We usually frac the wells with water, and we put in -- we've learned over the years -- we used to use coarse proppant and viscous fluids, and then we started evolving. We'll use less viscous fluids and smaller proppants and frac at high rates. And so -- because we've learned that the fracture -- just with trials, that the reservoir is -- the permeability is so low that the fracture does not need much conductivity. And so the reservoir sees it as infinitely conductive, and so you don't need a lot of conductivity. So the industry in general has pumped finer-mesh proppants over the years, so we've kind of learned that over the years.

Q. If I then turn to what's been marked as NMOGA Exhibit B1, which would be the first slide under Attachment B, is this an illustration that can help you explain in more detail how you fracture as you move along the wellbore?

A. Yeah. This is a graphical representation of a fracture simulation. And we have the computer simulations that help us describe fracture geometry that we can expect. So some of the terminology that I'll refer to, I want to explain here in these diagrams. The way you orient yourself here is this is the well projecting out (indicating). And this is 2D, so it makes it hard. But this is the well, and then the fracture goes on both sides of the well and grows perpendicular to maximum stress.

And so these color shadings represent concentrations of proppant. So the pink and the orange have the highest concentrations of proppant, which are closer to the wellbore. As the frac grows away from the wellbore, the proppant decreases, proppant concentrations. So the blue is the lowest proppant concentration.

Also, one of the terminology I'm going to talk about is frac length, but actually it's a fracture half-length. And so it's only the half-length of the fracture from the tip to the well. And so when we talk about half-length or fracture length, we're only talking about half. So in this case, the frac length arbitrarily could be like 400 feet. So that's the measurement from the well to the frac on the one side. So, actually, your fracture is growing 800 feet wide, but we're only going to talk about the half-length.

Also, we'll talk about frac height, and that's just the top and the bottom of the frac. So here's the top of the fracture, and here's the bottom (indicating).

The other thing is fracs tend to grow up. The stress in the formations decreases with -- as you go toward the surface, and so the stress at the top of the frac is lower than at the bottom. And so when we drill these wells, most of the frac height is above the wellbore, and it grows down very little. But this can be altered and be different when the stress profile is different. So one of the things I'll talk about is the stress profile and how much frac height we get.

The other thing I wanted to explain here is the cluster spacing. That's the distance between perforation clusters, is what that is referring to. And that's where the frac fluid leaves the wellbore, starts creating individual fractures. And so we've evolved. We used to have 2- to 300 feet between clusters, and now we're down to 50 feet of cluster spacing just because the wells -- the more clusters we have, the high rates the well's capable of producing.

Q. And on that point, then, what you found is the drainage flows out -- I guess it would perpendicular to

the wellbore, either up or sideways, but you don't get much drainage between the clusters?

A. It can be perpendicular, or it can be oblique. It depends on the direction azimuth of the maximum horizontal stress and also the direction of the well.

And so in the southeast New Mexico, we've looked at wells drilled east-west, north-south and also at a diagonal perpendicular to the stress, and the wells in southeast New Mexico don't seem to be sensitive to -- we've compared production from wells and those orientations, and they all produce similarly.

Q. So if I look at your diagram on slide 1 on the right-hand side, we see three clusters, right?

A. Correct.

Q. Okay. Is it true that you've found you don't get much drainage between those clusters?

A. Yes. The permeability is so low. And, again, all we have is computer simulations to describe it, but we don't think we'd get much drainage between the fractures, and that's why we decrease the cluster spacing as to get that oil. Before, when we had higher cluster spacing, we weren't draining the oil.

Q. Have you found -- now, do your clusters always look like this -- not like this, nice and symmetrical?

A. Well, these simulations are based on log data, and we make the assumption that the reservoir is homogeneous in its reservoir properties and geomechanical properties. What we find is, of course, it's a natural material, and it's not homogeneous. And so these fracs can grow in different lengths. So one cluster -- or one stage, we may have very long fracs, depending on the geomechanical properties.

And the other thing that can happen also is that direction stimulation shows the fracs to be symmetrical. One side of the well, the frac is the same size as the frac on the other side of the well. And we know that this probably doesn't occur all the time either because -- because it's a natural material, there may be geomechanical weaknesses to one side of the well that we don't know about, and so you may get more frac length on one side of the well and less on the other side of the well.

And so if we simulate 400 feet of frac length, we know that there may be some variation of that along the well, because we'll have something on the order of 4- to 500 fracs along the well that's about two miles along, and the geology can vary quite a bit over that two miles. And so we may get fracs that are 200 feet. We may get fracs that are 600 feet or larger. And that may be just due to the asymmetry and geomechanics of the property.

Q. So let me ask you this: If I'm looking at one of those clusters, maybe the center one, you have your warmer colors and you have your blue on the outside.

A. Uh-huh.

Q. Are there times even in the low-permeability environments where the drainage could extend beyond the area in blue?

A. Correct.

Q. What would cause that?

A. Like I said, the properties -- the rock properties on the geomechanical properties, put that into the fracturing simulator, and then if those rock properties change, then the geometry of the frac could change. And so the frac height could decrease, which would mean that for the same volume of frac fluid and slurry that you pump in there, you may get longer fracs, and then also just the heterogeneity in the rock.

Q. Okay. With this in mind, then, are there factors that you look at to help you design your completions?

A. Yes. We look at the previous wells and see if we're communicating between wells. If we hit the other wells with our fracs -- we know there is some of that, and it's kind of hard to tell. Does it happen one frac out of 500 or one frac out of 50? We don't know the frequency because all we have is the pressure response on the two wells. And so we don't know where along that well you had communication or how many different fracs communicated. We just know that a certain percentage may be longer than your predicted average.

Q. Anything else about this slide?

A. No, sir.

Q. We then move to the next slide. We then move to what's been marked as NMOGA Exhibit B2. What does this assist in explaining?

A. This is a graphical representation of the log data that was collected from a pilot hole. We typically drill pilot holes to describe the rock and with some frequency. It depends on how much geologic variability you have in an area, but we may want to drill a pilot hole every four sections. And it may vary, like I said.

But in this case, then we'll run -- get multiple different types of logs to describe the reservoir. We want to describe the reservoir fluids. We want to describe the geomechanical properties, and we want to describe the lithology. And so we take all these and we do calculations. Our petrophysicists calculate oil in place, and then the engineers in our group look at the sonic log, which creates a -- creates a stress profile, and that describes the stress in each lithologic layer.

And so what we try to match up is -- the petrophysicist tells us where the oil is, and then we look at the stress profile and see what we can frac. So then we decide, Okay, where are we going to land the well? We want to land the well where we can make the most oil.

And so in this case here, you can see -- it's kind of a little hard to see, but there is an open wide area here. This is called a Poisson's ratio butterfly. So we look at that, and we see where the frac is going to go. So when we have these dark blue areas, that indicates our frac barrier, and the elastic properties are very different than in the rock above it. When this butterfly is spread open, then this is a good rock for fracking.

And so you can see in this case, the oil in place, in the green here in the second column from the right -- sorry. My pointer is not working that great. And then the Poisson's ratio butterfly looks like it matches well. So we can frac a lot of oil in this well. And so this is a very good tier one well because we can frac as much H as we can. We can frac and make oil -- a lot of oil, and so this is a good case.

So this is kind of how the process is. We determine where to land the well based on the elastic properties of the rock and where the oil is.

Q. And then the significance of the frac barrier, does that have an impact on your --

A. Yes. This case is a good case where we don't have very many frac barriers, but in some areas, you have more frac barriers and they limit your frac height, and so then you can't contact as much oil.

Q. Okay. Any more about this slide?

A. Well, I was just going to say, to finish that point, so you try to pick -- you may have so many barriers in here that you may have to make a choice of where do you land it and where are you going to make your most oil. So that's kind of -- we'll do multiple frac simulations to determine that.

One other thing I wanted to mention, in the pilot hole, we have to drill a pilot hole deeper than where we're going to target the landing point because we want to get elastic properties of the rock below the pay, as well as above the pay to describe the fracture geometry.

Q. Now, if I go to the next slide, which is B3, there is a lot of information on it. First off, these are examples of frac simulations, right?

A. Yes. These are more frac simulations. This is a half-length, half of a wing. They're one wing in a fracture, so it only represents one side of the well. And this is the stress profile here (indicating).

And then here's the drivers I want to talk about for well spacing. The contactable oil in place, reservoir properties, the frac geometry and the fracture azimuth, all those are taken into consideration when we space the wells. As far as the frac design drivers, again, the frac barriers are a big part of it, contactable oil that we can get and the frac height and the frac length.

Q. So if I look at the first simulation, which is slide 3 towards the top, what's the environment that you were able to simulate?

A. In this case I wanted to show the Commissioners a case similar to the log we just saw, where there are very few barriers or the stress profile is very homogeneous. And so you'll get a large frac height, so you'll be able to contact a lot of oil in place. This frac barrier [sic] right here indicates the landing point, so this is where we would land it. Your frac grows up, so we can contact a lot of oil in place. So you can see it doesn't grow down very much.

And then also here is the frac half-length.

In this case the fracture half-length is 310 feet -- or 325 feet, and then the frac height is top to bottom here. To the top is 310 feet.

Q. So that's a circumstance where you don't have any confining frac barrier to limit --

A. Right.

Q. -- frac --

A. Right. And this is what operators would really like to see. They can contact the most oil in this situation.

Q. Okay. And what are you showing in the second simulation here in the middle of slide 3?

A. This case here shows a little more heterogeneity in the downhole stresses. It's not as smooth like this line is. There are little barriers and layers in here that have higher stresses, and that inhibits the growth of the frac. And so here is where the well is landed right here (indicating), and then here -- these different colors represent proppant concentrations, and so the scale here on this plot is a little bit different than here (indicating). But most of the proppant in the simulators is towards the bottom of the frac. But that's what the colors indicate.

So in this case, the fracture half-length is 480 feet, and the frac height is 245. So the frac height is a little less in this case, and the frac height is longer in the case --

Q. Anything else about this exhibit?

A. No.

Q. And you have yet a third simulation, right?

A. Yes. This shows a third case that's even more heterogeneity in the stress profile. Again, the inputs for the -- the fracture simulator are the petrophysical reservoir data, geomechanical rock properties, downhole stress calculated by the simulator. Then we put the placement of the well based on the fracture azimuth and then also proppant slurry properties are part of the input to the frac simulator also. So then what we get out of it are the fracture half-length, fracture height and the fracture conductivity.

In this case, again, we have more heterogeneity in the stresses, as you can see by the stress profile. So the frac height is even more limited in this case, and the fracture length goes out to 750 feet. And so like it's been said previously and I think you'll hear again, these are very low-permeability reservoirs. They lack continuity, which means the properties of the reservoir rock change and are not continuous. And so these models represent the best we can get near the pilot hole, but the further we get away from the pilot hole, the rock properties could be different than what we assume.

Q. So let me ask you, Mr. Taylor, as we look at this and we have a scenario like we have here, we've got some frac barriers that limit your frac height, we're able to then, your frac length -- resulted frac length in this scenario is about 700 feet, right?

A. Uh-huh.

Q. Okay. And so if I had a wellbore, for example, that was within 200 feet of an adjacent tract, okay, under this simulation, my frac length would extend roughly what, about 550 feet into the adjacent tract, on average?

A. Yes. And the one thing that we do need to talk about is that -- and that's a good point -- we would frac into the adjacent tract.

But the issue here is we really don't -- this is a simulated proppant conductivity. And one of the things is the proppant may go out this far, but we don't know how far out it's effective. The proppant concentration may not be exactly as the simulator gives us, and from what we've seen, our effective propped lengths are less than the simulated propped lengths. And so that's one of the issues. Yeah, we may see our frac simulations are 500 feet or 700 feet. We may not drain that far. So that's where we kind of work an iteration of our workflow, or we look at what's been working in the past in previous areas. And when we communicate with the other wells next to the wells that we're fracking, we may find that the simulation isn't as good as in other areas, and so maybe we put the wells closer together than the simulation would indicate.

Q. So let me ask you, then, in your opinion, can a company predict with certainty the range of drainage for a particular horizontal well?

A. No, sir.

Q. And is it highly dependent upon, then, the particular low-permeability environment you're in?

A. Yes. It's part of the low-permeability environment. It's a part of the -- just the simulations and just the heterogeneity of the rock.

Q. I think you mentioned that that can change from pool -- or from formation to formation?

A. Yes. I work with engineers who work in all areas of the Permian Basin and some areas in Texas. We may only put three wells in a section because the fracs are so long because -- they go over 1,000 feet long because of the geomechanical properties of the rock. So we use these frac lengths to space our wells, and then we learn from the wells as we go how much communication we had and whether the simulation is believable or not.

Q. So what range radius does the company generally try to achieve with their completion techniques, or what do they try to assume based on these simulations?

A. Typically what we're doing, OXY is doing and other operators are also, we usually run the simulations, look for differences in the rock properties, but, in general, we're seeing effective frac lengths of 350 to 500 feet.

Q. And then do you design your well spacing based on those simulations?

A. Yes.

Q. Okay. If I then turn to the last slide here in the Attachment B, what do you show here?

A. This is two different development plans based on the fracture geometry. In the top case here, we don't have many barriers in the stress profile. We get a large frac height. So our frac length is shorter, and so we would develop this section maybe with six wells per section. Then the bottom is an area maybe where we get longer fracs, and so we would space it at four wells per section based on the longer fracs.

Again, I tried to demonstrate a little bit the asymmetry. So you may have gaps between the wells, so the oil companies try to minimize these gaps. And so we have to balance the willingness to accept some frac hits and communication between wells to avoid some of these gaps. And so we want to get as much oil as we can out of each section, and so we'll increase the number of fracs. We'll try to account for some asymmetry and put the wells as close together without overcapitalizing the investment.

Q. So if I look at the scenario there at the top, 904 feet between wells, so that's a scenario of a company that's assuming an anticipated drain radius of half-length of about 450 feet?

A. Yes.

Q. Okay. And then the scenario at the bottom, would that be a scenario where you may have some frac barriers?

A. Yes, sir.

Q. And in that scenario, you would be anticipating drainage from, if I did my math right, at 500 --

A. 500- --

Q. -- 25 feet?

A. Uh-huh.

Q. If I then turn back to the proposal on these proximity tracts as reflected on Attachment A, at pages 10 and 11, is it -- in your opinion, given what we know and what we've seen with these developments in

New Mexico, is it reasonable to require that tracts be within 330 feet before they qualify for inclusion in a standard horizontal well spacing unit?

A. Yes.

Q. Okay. And is it reasonable to assume, then, that offsetting tracks within 330 feet of a horizontal wellbore will contribute to the production from that wellbore in most circumstances?

A. Yes.

Q. And would that be the same whether you're dealing with an oil or gas environment?

A. Yes.

Q. Is that because of the nature of the reservoirs that you're in?

A. Yeah. Unlike a permeable reservoir where gas is produced a lot longer distances because of the lower viscosity -- liquids, in the unconventional case, the permeability is so low that the only thing that's going to produce is the stimulated rock. And so there is not going to be the big differences between drainage between the gas and the oil.

Q. And given this circumstance that we see with the environment in New Mexico and where these horizontal wells are targeting, is it reasonable, then, to allow these proximity tracts as an option but not mandatory,

for example, rather than seeking a nonstandard location?

A. Yeah. I think it's great, because we will produce from the offsetting tracts, and maybe a better development plan could be put together if the offset operator is brought into the development.

Q. And does it provide operators with flexibility to deal with various environments?

A. Yes.

Q. Okay. And are you generally familiar with the concept of correlative rights under New Mexico law?

A. Yes.

Q. Okay. In your opinion, does the option to include offsetting tracts within 330 feet of a horizontal wellbore provide yet another tool to deal with correlative rights?

A. Yes.

Q. In your opinion, should the Division adopt the -- or should the Commission adopt the proposal to allow operators the option to include horizontal well units -- to include within their horizontal well unit proximity tracts that are within 330 feet of the wellbore?

A. Yes.

Q. Were the pages comprising NMOGA Exhibit B prepared by you or compiled under your direction and

supervision?

A. Yes.

MR. FELDEWERT: I would move the admission of NMOGA Exhibit B.

CHAIRWOMAN RILEY: Yes.

MR. FELDEWERT: And that concludes my examination of this witness.

(NMOGA Exhibit Letter B is offered and admitted into evidence.)

CHAIRWOMAN RILEY: Do we want to go to the other parties?

COMMISSIONER BALCH: The Commission gets to go last.

CHAIRWOMAN RILEY: Dang it. But they said we could ask questions. I can wait until last.

COMMISSIONER BALCH: I've got a whole page of questions.

MS. BRADFUTE: No questions.

MR. CLOUTIER: No questions from IPANM.

MR. HALL: No questions.

MS. BADA: No questions.

CROSS-EXAMINATION

BY CHAIRWOMAN RILEY:

Q. So given your testimony about the half-lengths and being able to bring in the proximity tracts, how

does that apply, then, to the setbacks to outer background of your spacing unit? In other words, at 330 feet, there is a thought that at that distance, you could be actually producing from a proximity tract. Are we encroaching on the next spacing unit, that 330 feet, since that's the setback?

A. Yeah. I think that's why the new rule is a good rule. It offers the ability to bring in that tract. The parties would negotiate what those terms would be. But if they negotiated the terms -- we would share in the production -- then I think it's a good situation.

Q. Well, but this is actually different, though, because your setback to the next spacing unit, you have to be 330 feet away.

A. Right.

Q. So --

A. I think just based on the setbacks -- say if you had a large frac height situation, not too many barriers, 330 -- you may have a gap between the two sections. And so in that case, I think you may not be as effective in draining it. But then if you have a shorter frac height, more barriers and you frac -- you could possible frac over into the next section.

Q. So is 330 feet still appropriate for a setback?

A. Well, the thing is no number is the right number. But the 330 is good with what we know today as far as the normal frac lengths being 350 -- effective frac lengths being 350 to 500 feet. And I think we can space wells accordingly. If it's too close -- in the situation I described with the heterogeneous stress profile, if you put the well right on the setback line, it may be too close.

Q. All right. Thank you.

A. Uh-huh.

COMMISSIONER MARTIN: I don't have any questions. Go ahead.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Simulation is something I get to deal with quite a bit, actually, and I'm familiar with geomechanical earth modeling as well. The figures 2 and 3 -- I'm sorry -- slide B1, you're kind of showing two slices. Go back to slide 1.

A. Okay.

Q. Is this just for illustration purposes --

A. Yes.

Q. -- or are these 2D simulations done for each frac --

A. No. This is 3D.

Q. It's 3D, and you're just showing representative slices?

A. Yeah.

Q. How do they look on the toe and the heel going along the axis of the well?

A. Similar. I mean, we don't use the different properties along the wellbore unless we have information.

Q. What we're being asked to do with this change to the rule is to reduce the offset on the toe and the heel to 100 feet --

A. Uh-huh.

Q. -- from -- I think it's 330 feet now. So from your experience with these simulations, how far do you go out from the toe and the heel along the axis of the well?

A. The fracture geometry doesn't change. The only thing that would change would be depending on the azimuth that you drilled your well. If the direction of least amount of stress would lead to that, then, of course, it would reduce some of that from the toe, but, you know, if there is more perpendicular, then there would be a big gap, and it would be undeveloped.

Q. These are pretty -- these -- these models that you use, obviously when you're starting out in a new

area, you have maybe one pilot hole, maybe two pilot holes, and that's what you're building your whole mechanical earth model on.

A. Uh-huh.

Q. But as you get further into your development and you've got 50 pilot holes -- or is there some point where you stop drilling the pilot holes and --

A. No. We don't ever have 50 pilot holes. The areas we have are pretty much governed by our acreage that we have, so that may be limited to ten sections or something like that, and so we may only have two pilot holes. And so we use pilot-hole data, all the vertical well log data where we have penetrations that are deep enough, and then we try to calibrate that to build a GeoModel. And then we use our seismic date, will also help identify when we see like what we may describe as barriers, potentially maybe limestone in some cases. We can see that sometimes on the seismic and help map it.

Q. Might produce similar to the -- contrast on the seismic data.

A. Yes.

Q. So you use acoustic -- version to get the data between the wellbores?

A. Yes.

Q. When you're developing these resource plays,

people talk a lot about how -- you know, it's the same step out five miles or whatever. It's not like the old days where you -- where things are changing every borehole. I mean, how true is that?

A. The way I understood you say that, I would just say I disagree with that. I think they do change quite a bit along a 10,000-foot lateral.

Q. So if you have two -- two or three pilot holes in a ten-well development area --

A. Ten-well-or ten-section?

Q. Ten sections.

A. Okay.

Q. However many pilot holes you're going to have --

A. Right.

Q. -- in ten sections. Maybe a handful?

A. 2- of 3,000.

Q. Two or three.

And how much variability do you see in the stress field at the wellbores for those?

A. It varies. I mean, some areas are more consistent, and so it's more predictable. There are differences between the logs, as you know, and so you may have a log -- a sonic log on one well that looks -- has similar character, but it looks different. But you can tell if it's the same rock. And in other areas where you have more carbonate and debris flows or different geologic-type occurrences, maybe along the margins of a basin or a shelf, you'll see a lot of contrast with barriers, and then you have a lot more variability. And so you need more pilot holes in those kinds of areas.

Q. So do you do your shear sonics and work off your mechanical logs routinely or --

A. You know what, I'd give anything to have dipole sonic as much as possible because these synthetics, you lose some of the character.

Q. And then you can work up your mechanical logs and show your variations in the Poisson's ratio and other mechanical properties in the rock?

A. Correct.

Q. That's pretty industry standard, and you put a lot of money into these fields.

A. Yeah, it is. We always want more dipoles in my group, and, you know, that costs money. And so then it's always a discussion of how many pilot holes we'll get. So we try to get as many dipoles and as much data as we can. But it's a financial decision, and so we just have to make our technical case of how much value we can provide if we drill another pilot hole.

Q. So you're really trying to get at a couple of things. One's going to be frac height and frac length, but the other thing is going to be the orientation of the --

A. Uh-huh.

Q. -- of the stresses, right?

A. Correct.

Q. But you really do -- and I think I -- I think I heard you say and I want to confirm this. You said between stand-up and lay-downs, there wasn't a whole lot of difference?

A. We've compared fracture azimuth and well orientation in southeast New Mexico. We compared lay-down to stand-up and also to diagonally placed wellbores, and there weren't any differences in production.

Q. Nothing substantial?

A. Uh-uh.

Q. But the reality is stress orientation. What's really happening is what -- what you've kind of shown in B5, Exhibit 5?

A. Yes.

Q. Where the wellbore is not perpendicular to that --

A. Correct.

Q. -- stress, but the fractures are going to generate in that stress direction?

A. Correct.

Q. So the interesting thing about this kind of a portrayal of that, when you get to the end, your 330-foot offset may not even capture the frac length for a thin horizon.

A. (Indicating.)

Q. A 100-foot definitely would not. And if you look at the heel and the toe of those as the first take and the last take on the bottom figure in particular, you could have quite a distance inside your area where you're not making fractures and then outside of the heel where you are.

A. Uh-huh.

Q. More than 100 feet, more than 330 feet in some cases.

A. Right.

Q. So the question Chair Riley posed about is 330 really the right number as kind of an average catchall, or is it something that really ought to be addressed on a pool-by-pool basis?

A. I don't think doing it on a pool-by-pool basis would help you because the geology changes too dramatically in a short distance. And so I think you would have to -- it would be better for the Commission to try to come up with rules, which I think these rules were designed for, based on what we've learned already as an industry, and I think that's consistent with what the industry's learned so far.

Q. If you go back in the SPE literature, when people were really starting to look at the slickwater type of fracs -- we're talking mostly slickwater, right?

A. Yes.

Q. Everybody's gone away from the crosslinked gels, for the most part?

A. It depends on the rock, but the majority of them are -- the large majority of them are slickwater.

Q. So I did a little bit of a literature review on that, and the common thought is about 250 feet is your prop half-length. So it's a part of the reservoir that you're going to be accessing, kind of in general and the homogeneous world where your stress is fairly uniform.

A. Okay.

Q. So in that context, 330 sounds great. You've got it pretty well covered. But in the case that you're talking about, where you have all these flow barriers and you're ending up pushing the proppant out -- I mean, the same papers that I've read also say that they've seen tracers -- they've done tracer studies on proppants

and seen them 1,600 feet away.

A. Yeah.

Q. So, I mean, it's possible to get that. It's not the most common scenario and the most likely scenario.

A. Yeah. We have cases at OXY where we have radioactive tracers in the offset wells.

Q. Yeah. I think that there is going to be some level of communication.

A. I would say, to those concerns, that we haven't seen that in New Mexico. The cases I've told you about with the radioactive tracer in offset wells and the debris flows near the shelf margins, we don't see that in New Mexico. That's the Southern Delaware Basin in Texas and also the Eastern Shelf, Howard County over there, in the Midland Basin, Reagan County over there is typically where we see a lot of the geology I talked about. We don't see that in the benches that we've been developing.

Q. I saw a pretty interesting SPE talk a few years ago about controlling your fracture orientation by the timing of -- of your frac stages. So basically you're taking it down to the local change to the rock fabric from one frac stage to control the orientation to the next frac stage. In your simulations, do you try and

indicate what the timing of those stages ought to be?

A. No, because of two things. One, we don't have really good control on where the perforations actually are with the way that we're fracking operationally. And then also we don't feel like the frac placement is as accurate either due to irregularities in the rock and/or the stress profile immediately around the well. We think there are acute [sic] stresses we may have, and we may have some longitudinal fracs and then also maybe some inconsistencies -- mechanical inconsistencies. And so we think that that's pretty -- it's nice to think about, but it's impractical. It's not really practical.

Q. Is not practical, not to mention you have all kinds of field issues, sand and --

A. Right.

Q. You said you were going pretty fine on the --

A. Proppant.

Q. -- on the proppant?

A. Yes.

Q. So 20/40?

A. So yeah. And then the proppant here recently -- the industry, in general, has gone down to 100 mesh and 40/70 quite often --

Q. 100 mesh.

A. -- and then also decreasing qualities of proppant. Everybody was pumping Northern White because that's what was easy to get, and in a few trials, started getting sand that's lower in spec, less round, more angular, decreasing quality. And the permeability of these rocks is so low that the reservoir still sees these fracs as infinitely conductive, even with the -- like now they're scooping up sand in West Texas right off the ground or shallow mines. They call it local or regional sand, and it's cheaper. And a lot of wells are being fracked with that sand now.

Q. Well, really it has to do with transport being that -- getting it out, even with the slickwater, which has a low carrying capacity.

A. Right. Right. So settling rates become a factor. And we think that we also get maybe some proppant in the natural fractures that maybe open up. So the settling rates and getting finer mesh proppant into places the coarser mesh proppant couldn't go may enhance our oil recovery.

Q. I've certainly seen studies where either just even one or two props are enough.

A. Yeah. I think the proppant distribution is very -- not understood -- not well understood.

Q. So one of the reasons why we're asking these questions is the correlative-rights issue. So an

advantage of this proposed rule change is a lot more flexibility where you place your horizontal wells, including right up on the edge of your -- of your lease within 330 feet, if you're using the side offset, 100 if you're using --

A. Correct.

Q. -- to toe and heel, right?

A. Uh-huh.

Q. So you're reducing the amount of acreage that's not being seen by -- by the reservoir creation and the fracturing that you're trying to do. The problem there is that you might go in there and you design everything around the 330, and you get your offset production and offset tracts -- your proximal tract. You don't get something because it's 400 feet away, for example, from where you are, but then you end up with your second scenario, four wells per section, where your frac length is 7-, 800 feet.

A. Uh-huh.

Q. So you're shooting well into that next person's mineral rights --

A. Uh-huh.

Q. -- and there may be an after-the-fact attempt to get their correlative rights addressed.

A. Uh-huh.

Q. So I'm a little bit concerned about opening up that possibility.

A. I think that's the thought behind the new rules, though. I think the more that the operators can discuss those things beforehand and come up with -- and then the offset operator can make a decision whether he wants to drill his own well or participate, and put together a development plan jointly. I think that takes care of those correlative rights.

Q. But when you're starting out a new development and maybe you have four sections that you're going to put in, you don't have any wells, because it may end up being six wells a section or eight wells a section or four wells a section or something like that --

A. Uh-huh.

Q. -- and you may not know that for a little while into your development. You may be putting in infills or you may determine that you need to space your regular wells further apart.

A. Uh-huh.

Q. That's when the possibility that your frac length is impinging more than 330 feet may become an issue to a neighboring leaseholder.

A. Uh-huh. Right. I think all I can say is industry is working very cooperatively. It's been surprising to see how cooperative the industry has been. We communicate frac dates so we all know when each other is fracking and we're moving water between -- you know, we're cooperating with each other like I've never seen before. And I think that by having these proximity tracts, that it'll help the communication and working out these issues.

Q. So this is primarily operators that are both doing the same kind of thing, though, where they're trying to develop horizontal unconventionals? Is that what you're talking about, or are you talking --

A. No. I'm just talking -- like, our land department is talking to all the operators, so the offset --

Q. So that includes people that are potentially going to be force pooled and --

A. Yeah. I mean, I think that our land departments talk to the offset operators and try to bring their blocks of acreage into the development. I think it's an advantage.

Q. Is that what you were referring to about there is a greater level of cooperation? Less force pooling? Is that what you're saying?

A. I'm just saying there is so much better communication between the operators now that I think --

to say that they're going to be negatively affected, I think is just a choice they make, you know, if they decide not to participate or, you know, develop their acreage themselves.

Q. So if you have a joint operating agreement with people from this tract on the bottom --

A. Uh-huh.

Q. -- and then you figure out this is what's happening, so you are shooting off your boundaries into the adjacent properties. In this case, it would be the east and west sides of the north-south; is that right? After the fact, I mean, are you willing to try and bring those people in?

A. Oh, I don't know. These are hypothetical cases, so --

Q. Sure. That's kind of what we have to think about --

A. Yeah.

Q. -- what could happen, what are the possibilities.

A. No. I agree.

Q. I think it's interesting you're saying there is no advantage to going exactly perpendicular -- well, I guess the advantage is you waste less space on the north and south end of your wells in this particular case.

A. Correct.

Q. So it would be more efficient if you went with a diagonal?

A. I don't know that that's true, because you still have the corners.

Q. That's true.

A. So we've looked at it all kinds of different ways, and we feel like this is the most efficient way to get as much oil out of the section as we can.

Q. If you picked up the tracts to the south or north, you could put some lay-downs -- that area?

A. That's what I think. The purpose of all these companies is to put together bigger blocks of acreage, and some of these new rules would help put together a development plan where so you wouldn't have these gaps.

COMMISSIONER BALCH: I think that's all I have.

CHAIRWOMAN RILEY: Thank you.

Mr. Brancard?

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. You mentioned that certain things have evolved or changed over time, that the proppants are --

A. Selected.

Q. -- selected. You mentioned the spacing of the

fracking. Have you also seen a trend in frac length changing over time?

A. No. Frac length, I would say -- you know, it's more the geologic properties and the heterogeneity and the stress profile. I think one of the things different operators do -- there is no consistency in that in the industry. Some operators look at their reservoir properties and rock properties, and they make decisions based on different views. Their business plans are different. And so they may put a whole lot more wells per section than, say, another operator. So some operators may choose to put six wells in a section, and another operator may choose to put ten. So I think there is no industry convention as to what's done, if that's what you're talking about.

Q. Well, what I'm talking about is you have all these simulations where you're estimating --

A. Uh-huh.

Q. -- frac length. As you change the inputs such as the proppants, et cetera, are you seeing changes in predicted frac lengths?

A. It depends on the area, again. So if you have a homogeneous stress profile and you have a lot of height, a lot of times, if you pump more sand, you'll get more frac length and more frac height, then you can get more oil. In some areas that doesn't work. And so maybe in some areas the rock is so tight that you need more clusters -- tighter cluster spacing, and your proppant per cluster will be less. So it's distributed differently, but each area is different and each operator's thought process is different. But I don't think the frac lengths have increased over time.

Q. So what you're saying is that while you and your company focus on these simulations models to help drive your spacing theory, that other companies may be making the same decisions purely on their business plan?

A. And the quality of their acreage and how much oil you have in place. And contactable oil makes a difference, too, because you still have to pay for everything. So if your contactable oil in place is less, then you're going to have to manage your costs to make it a profitable well.

Q. Thank you.

RECROSS EXAMINATION

BY COMMISSIONER BALCH:

Q. Ultimately, you're driven by production, for almost everybody at the very end, right, whether you're producing it?

A. Well, it is right now because everybody's drilling the best stuff they have, but that decision process will change as we get into lower-quality rock.

Q. Where you start to stack multilaterals to catch more of your frac height?

A. Right.

CHAIRWOMAN RILEY: I think we're done up here.

Do you have more questions?

MR. FELDEWERT: I have some additional questions.

REDIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Taylor, I want to go back to what's marked as slide 1.

MR. FELDEWERT: And I know I had informed the Commission that we do have another witness to address the change for the setbacks and the first take point and the last take point.

Q. (BY MR. FELDEWERT) Mr. Taylor, if I look at slide 1 and I look at the distance between these clusters and how the companies have been decreasing the distance between clusters, that's because you're not seeing a lot of drainage between the clusters, correct?

A. And the wells produce better. Yes.

Q. And so, for example, if we pretended to miss the section line, looking at the right side of slide 1,

and that this was a 330-foot setback --

A. Uh-huh.

Q. -- and this was the last take point, okay, there would be nothing that would be draining that 330-foot setback?

A. Correct.

Q. Are you of the opinion that, therefore, because of the nature of these fracs, that that should be adjusted to get closer to that section line?

A. Yes.

Q. Okay. Now, if I then go to slide 5 -- you have to work in a number of different scenarios when you drill these horizontal wells, correct?

A. Uh-huh.

Q. And one of the concerns that operators have and I guess the Division has always had is if you increase -- if you increase the setbacks, okay, move them from, let's say, there to here (indicating), right --

A. Uh-huh.

Q. -- as you increase those setbacks and make them mandatory beyond what has worked for a long time, if you increase those setbacks, are you increasing the chance of waste?

A. Yes.

Q. And isn't most well development now based on -- the starting point for most development, isn't it based on the setbacks that have been used for quite some time?

A. Yes.

Q. Okay. And I know you weren't around when this was put together and I wasn't around when this was put together, but at some point, somebody decided that a number, 330 feet, was the balance between avoiding waste and protecting correlative rights.

A. (Indicating.)

Q. And in your opinion, has that balance been working all these years?

A. Yes. I think 330 feet is a good number.

Q. And, in fact, isn't there some synergy, then, between what we've proposed here, and that is including proximity tracts that are included within 330 feet -- and they have to be within 330 feet to be able to qualify to be included in that spacing unit, correct?

A. Yes.

Q. And is there some synergy that we had with the existing setbacks that were used all these years to balance that prevention of waste and protection of correlative rights?

A. Yes.

Q. And are you aware, Mr. Taylor, of any operator

throughout this process, when this committee was put together and all these technical experts brought to the table, is there anybody that has suggested that the setbacks that we've used all these years to strike this balance, that they should be changed?

A. No.

Q. And in your opinion, should we continue to work within these setbacks that operators have utilized all these years to strike that balance and just make these slight adjustments that we need?

A. Yes.

MR. FELDEWERT: Thank you.

CHAIRWOMAN RILEY: Any other questions?

MR. FELDEWERT: Okay. If we may, we'll call our next witness.

JOSEPH J. BEER,

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

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your name, identify by whom employed and in what capacity?

A. My name is Joe Beer. I work for Encana Oil & Gas. I'm a geologist. My current title is senior manager of geoscience and base asset development. I manage the geoscience for the Eagle Ford asset and the geoscience and development for our San Juan asset and our Wyoming asset.

Q. Now, when you say geoscience, what are you talking about here, Mr. Beer?

A. Well, I have geologists on staff, geotechs, and occasionally I'll have a petrophysicist of a physicist on staff as well.

Q. All on staff with the group you manage?

A. That's correct.

Q. Have you testified previously before the Commission?

A. No, sir.

Q. If I turn to what's been marked as NMOGA Exhibit C, I see the first page behind NMOGA Exhibit C is, I believe, your resume or your biography, correct?

A. Correct.

Q. And does it accurately summarize your educational background and your work experience?

A. Yes, sir.

Q. It indicates you got a master's in geology in 2006?

A. Correct.

Q. Did you -- what did you do after you got your master's?

A. I thankfully was hired right away by Encana. I had bills to pay.

(Laughter.)

Q. And since you were hired by Encana in 2006, what has been your primary focus in the oil and gas industry?

A. I started as a geologist. I have worked planning and executing both vertical and horizontal wells across a number of plays in the U.S. I also did a stint as a geologist but focusing on getting technical on geomechanics for a couple of years. And then I've also worked some exploration and new-plays work trying to get new plays and new ideas off the ground. And more recently, I've taken more of a manager role at the company, managing, basically, development programs, planning wells, executing programs in horizontal oil plays.

Q. So you've been -- have you been involved with horizontal well development?

A. Yes, sir, in Colorado, New Mexico, Texas, Louisiana, Mississippi, Wyoming.

Q. And if I look at your resume, I see a number of publications at the bottom, correct?

A. Correct.

Q. That includes publications on hydraulic

fracturing for horizontal wells?

A. Correct. Yeah, vertical and horizontal.

Q. Okay. And these have been subject to peer review?

A. Yes, sir.

Q. If I take a look at the top of your resume here, it lists a number of areas of technical expertise?

A. Uh-huh.

Q. And is that an area -- these areas that you list here, they include, do they not, hydraulic fracturing and stimulation and completion of horizontal wells?

A. Yeah, that's correct.

Q. Okay. And you feel you have -- is it your opinion you've got expertise in that particular area to assist the Commission with some of their issues?

A. Yes, sir.

Q. What do you intend to cover with the Commission today?

A. Today I'm going to show examples from the San Juan Basin in New Mexico where locally what we have found is that when we drill perpendicular to the maximum horizontal stress, we get much more effective and efficient drainage and development of the resource. We're going to show you that data, that result, and show why it's important for us to not drill parallel to the land grid in that area.

And then also as a part of that, I'm going to show some of the limitations of the current rule that keeps us from drilling in that orientation and how we like the new rule because sort of the combination of getting rid of the rectangular requirement and allowing the proximity tracts is going to be a big help for us to build the proper orientation to have a much more effective and efficient development in the San Juan Basin.

Q. Now, Mr. Beer, if I go to NMOGA's Attachment 1 and I go to page 10 within the rules of that are being proposed here today, you mention the elimination of the mandatory rectangular requirement that currently exists for spacing units. Is that reflected in what's been proposed as Subsection A(1)(a) on page 10?

A. Yes. A(1)(a) does not -- doesn't say anything about needing to be rectangular.

Q. Okay. And that is carried over for gas wells in Subsection (3)(a), correct?

A. That's correct.

Q. Okay. And are you also then familiar with the proposal to include these unpenetrated proximity tracts in a horizontal well spacing unit if they meet

requirements?

A. Yes. And I'll show some slides on that as well.

Q. Are you in favor of both of these changes?

A. Yes, sir.

Q. All right. Would you then turn to what's been marked as NMOGA Exhibit B1, which is the first slide? And we have it up on the screen here today, and explain to us what you're showing here.

A. We're going to start by talking about what nature gives us, and that is what dictates the orientation of the hydraulic fractures that we create. So one of the primary forces we need to overcome in order to create a hydraulic fracture is we need to overcome the compressive stress in the earth. If you imagine that you are a little cube of rock 10,000 feet in the earth, there is compressive force on you. In fact, you wouldn't want to be that. There is a lot force on that cube of rock.

So that cube of rock is 10,000 feet down. The biggest force is the weight of all the rock that's above you, and rock is really heavy. That would be maybe 11,000 psi acting from above. But also tectonics and the fact that you have neighboring rocks on each side of you and you can't bulge even though all that weight is on top of you. You're being compressed from the sides as well, and those forces could be 6- or 7,000 pounds acting on the side.

So when we create a hydraulic fracture, we use hydraulic force to open up a crack. And you can imagine that hydraulic force acts equally in all directions. What orientation is that crack going to open? It's going to open with, again, the smallest force. So in the picture up on the board, what the crack is going to want to do is open against the small arrow, so in and out of the page. That's where you're going to want to make width against that smallest force. So that's why we end up getting vertical planes oriented parallel to maximum horizontal stress because they like to open width against minimum horizontal stress.

Q. Anything else about this slide?

A. I don't think so.

Q. If I go to what's been marked as Exhibit B2, what does this illustrate for the Commissioners?

A. This is a compilation of data taken from the western United States just showing that the orientation of that maximum horizontal stress is variable depending on where you are. Tectonic forces, et cetera are acting in different orientations across, I'm showing here, a very regional look, but, in fact, when we collect this type of data to see what orientation stress is locally, we'll see this change very locally across the county, maybe across the township. And so we like to locally develop relative to the local stress orientation.

Also, the other thing we notice can't really be shown on this map, but we've noticed sometimes in plays that orientation changes depending on what formation you're in and depth. That can rotate also.

Q. Okay. Then if I go on to the next line, which is B3, what does this explain?

A. So I mentioned that nature dictates the orientation of the cracks because nature's telling you the orientation of that stress. So the choice we have -- as we develop our resources, we can choose what orientation to drill our wellbore. And in a lot of cases -- and certainly the case I'm going to show you today from the San Juan Basin -- when we drill our wells perpendicular to that maximum horizontal stress, we get clearly better well results. We're more efficiently creating a series of hydraulic fractures perpendicular to the wellbore, and it sets up the most effective and efficient drainage.

Q. Is that always the case, Mr. Beer?

A. No. There is more at play.

So I've been talking about stress and how that dictates how we want to open width and grow a crack, but there is more to it. The rock is heterogeneous. The rock can already be naturally broken up, and there could be natural fractures. It doesn't always have to be a simple plane or frac. So some plays maybe get a more naturally complex fracture created with more of this map view as X-Y complexity than other plays.

The other thing is, I showed that first original block, and I showed the two small arrows coming in from the side. Some cases, maximum horizontal stress might only be a couple hundred psi greater than minimum horizontal stress. In other places, it's going to be thousands of psi greater. So it's not just orientation, but it's the contrast of those two forces. Right? If you can imagine in an area that has much more contrast, it may be much harder to create X-Y complexity. So there is a lot variability there.

You know, the prior testimony said that in southeastern New Mexico the orientation didn't matter in well results. I'll show you today that in the San Juan Basin it does.

Q. Is the point here, though, with the proposed changes, Mr. Beer, that it gives operators the flexibility to orient their wells in a fashion that

makes the most sense based on the depositional environment they're in?

A. That's correct.

Q. If I then turn to what you've referenced here in the next slide, slide C4, have you done some analysis focusing on the San Juan Basin?

A. Yes, I have. So I'll walk through this here with the pointer.

First of all, in the San Juan Basin -- this is a map of basically the heart of the Gallup play in the San Juan Basin. And locally the data we've collected suggests that maximum horizontal stress is in this orientation (indicating). So when we create hydraulic fracture, they're oriented in this direction because they want to open up against this smaller stress in this direction (indicating).

So what you'll notice here is a series of wells that exist, and we've colored the map to have sticks that are drilled not perpendicular to that in red, so those will either be stand-ups or lay-downs. Those are the red wells. And then wells where we've managed to drill perpendicular to maximum horizontal stress are in blue. And we've plotted the production of the red wells versus the blue wells, and the blue wells win.

So if you look at the production plot here, we're looking at a plot of cumulative oil production. This is normalized to lateral length. So longer laterals are not getting an unfair advantage over shorter laterals in this plot. That's been taken into account, versus time. And you can imagine, through time, the wells make more oil through time.

And what we'll see here is that the blue well set across -- you know, you can see that they're drilled in the same geologic area, similar completion size and style.

Q. Now, are these Encana wells?

A. These are all Encana wells, same operator. The blue wells are outperforming the red group by 30 percent.

Q. Now, these were all drilled under the current regulatory environment, right?

A. That's correct.

Q. Okay. Now, were you able and why were you able to drill the blue sticks, we'll call them, in the orientation that we see?

A. As you can see on the map, these dark black outlines are federal units, and within the federal units, we were able to drill that orientation.

Q. Whereas, when you got outside the federal

units -- we see some of the red sticks -- they were subject to the existing rules, which require the lay-down -- the rectangular --

A. The rectangular rule, uh-huh.

Q. Okay. And in your opinion, is the -- in this particular area, is the ability to drill perpendicular to the local maximum stress direction -- does that assist in preventing waste?

A. Yes, definitely. The same exact wellbore, the same exact well costs, the same completion and engineering effort yielded 30 percent better oil. So apples to apples, that's less waste. That's 30 percent more oil in the tank and not stranded.

Q. Okay. And then when we look at the current regulatory environment outside of the circumstances you've been able to -- these are voluntary, right, as shown on here?

A. That's right.

Q. You've got to have people -- everybody agrees, or you've got to have enough acreage to create these voluntary units?

A. Right.

Q. Outside of the unique circumstances where you can create large voluntary units, under what circumstance under the existing rules are you able to

drill in the preferred orientation?

A. To my knowledge, Encana's only had one unique scenario where we were able to do this.

Q. Is that reflected on slide B5?

A. That's correct.

Q. And what scenario is that?

A. The interesting thing about this scenario is that we had large tracts, two stand-up 320s and we could drill this orientation of a wellbore. At the end of the day, we end up with a square or rectangular shaped spacing unit, and the wellbore penetrates both of the tracts making that up, and the wellbore is a 330 setback all the way around. So in this unique scenario, it worked.

Q. Now, when we get to the scenarios where you don't have 320-acre spacing units, then you run into problems?

A. Yeah. Then we have problems.

Q. And is that reflected, first off, if we go to what's been marked as slide B6?

A. That's correct.

Q. And why don't you, starting on the left -- first off, is this a scenario where you're dealing with areas where you've got 40-acre existing spacing units?

A. That's right. So the next two slides will show a series of four sections split into 40-acre tracts. We'll show a red wellbore, and we've colored the tracts yellow where the wellbore has penetrated those tracts.

Q. And what problems do you run into when you start applying the rules as they currently exist to your desire to drill in a -- preferred orientation?

A. I think it's easier to start on the right here, actually, with this right example. There is a way to thread -- thread the needle here with the wellbore and avoid these inner corners on a stair-step and obey a 330 setback. Only about 30 percent of the time can you thread the needle through there and avoid those inner white points both above and below the well. And so you can get a standard location because the well obeys all the setbacks.

Q. And would this be a standard spacing unit?

A. This is not a standard spacing unit because it is not rectangular.

Q. So you'd have to go get regulatory approval?

A. That's correct.

Q. Okay. Then as you move to the scenarios -- remaining scenarios, it becomes even more problematic, right?

A. That's right. So if you take the exact same wellbore and just scooch it to the left a little bit, you can imagine that you get closer than 330 feet to these points. Now you no longer have a standard location because you're not obeying the 330 setback at every one of these interior points. And you still do not have a standard spacing unit. As you can see, all your penetrated tracts do not form a rectangle.

Q. So you have two issues, then. You've got a nonstandard location. You've got a nonstandard spacing unit. You've got to figure out a way to get regulatory approval for all that?

A. That's correct.

Q. And the same with respect to the scenario on the left?

A. Yeah. That was sort of a silly picture. That's a pretty tough well to drill, but it's mathematically fun to look at.

(Laughter.)

Q. Do you agree with the observation made by Mr. Brooks when he testified that under the current rules, while you might be able to thread the needle in certain circumstances, it's really impractical to develop in this type of orientation under the current rules without having to come to the Division each time and getting approvals for either a nonstandard spacing unit or a nonstandard location?

A. That's right.

Q. And if we then look at the proposals that have been put together by the Division and the committee to address some of these concerns, are they reflected in slide B7?

A. That's correct.

Q. Okay. Would you explain to us how they cure these issues?

A. Right. So now we're no longer hung up on needing our spacing unit to be rectangular, and the other thing that we have at our disposal is the ability to bring in a proximity tract. So if our wellbore is within 330 feet, we can choose to bring that in. I've seen that in green now in these examples.

If we walk through this and start on the right again, this is now problem solved for this one. This wellbore always obey the 330 setback, and so it was always a standard location, and it continues to be a standard location.

Our problem before is that it was not rectangular. Our penetrated tracts did not form a rectangle, and that was a problem. Now, that is not a problem. So if you just basically looped in all of these yellow penetrated tracts, you would have a standard spacing unit.

Q. Go ahead. I'm sorry.

A. On to the middle example now. Remember our problem here was that we did not have a standard location because we weren't obeying the 330 setback at these interior points? Now when that happens, we can bring in these proximity tracts shown in green, and now if we form our spacing unit and loop in the green and the yellows, we obey all the 330-foot setbacks and say we have a standard location. And also we have a standard spacing unit, because it's not a problem that it's not rectangular. And even if you could magically drill this well (indicating), it's going to work fine, too.

Q. So is it important to have both of these proposed changes in these rules to accommodate what you're doing with respect to the elimination of the mandatory rectangular requirement and then the allowance of the ability to bring in proximity tracts that are within 330 feet?

A. That's correct. They work together.

Q. And that way you avoid either having to come back for a nonstandard location or a nonstandard spacing unit?

A. That's correct.

Q. Now, if I turn then to the last slide, B8, does

this give an example of how they can work out to fully develop areas?

A. That's correct.

So what I'm showing here is a real example from Encana's acreage position in the San Juan Basin. And a geologist on my team basically put together a development plan for how we could tackle development of our acreage position here. This is a nonunitized area. And so what is an efficient way to go develop this? And I know one of the concerns is that when you drill at an oblique angle, it's maybe not efficient, that you strand corners. And I think what this shows is that you can have a very efficient development plan laid out with drilling 45 degrees off of the land grid.

Q. And, Mr. Beer, in your opinion, should the orientation of a well be dictated by, you know, mandatory rectangular requirements?

A. No, I don't think so.

Q. And in your opinion, are the current requirements for a mandatory rectangular spacing units creating unnecessary burdens both on operators and then also on the Division?

A. Yes.

Q. And in your opinion, will the elimination of that particular requirement then give operators the

flexibility needed to give these development plans to efficiently and effectively drain oil and gas reserves?

A. Yes. It would be helpful.

Q. With respect to the inclusion of the -- the optional inclusion of the proximity tract to a wellbore spacing unit, does that provide operators another tool to deal with their neighborhoods?

A. Yeah, that's correct.

Q. And, in fact, do you think it's -- in your opinion, is that a useful tool?

A. I think it's a very useful tool.

For example, if you look at the map, I can imagine getting along with the neighbor and being able to unstrand this corner.

Q. And not only does it give you an additional tool, as you've identified, will the ability to bring in proximity tracts within 330 feet avoid both the Division and operators with a regulatory burden associated with nonstandard locations to drill these -- did you call them transverse wells? How did you describe them?

A. Yeah. They're transverse to stress, so we call them transverse wells.

Q. So in other words, if they didn't -- if they didn't eliminate the rectangular requirement and did not include the provision for the inclusion of the proximity

tracts, would you be able to do the development plan that's shown on slide 8 without having to come back and get numerous nonstandard locations?

A. No. That would be difficult. Like I mentioned on slide 7, 30 percent of the time, you can thread the needle and not have to bring in proximity tracts. The problem is that sets you on a very specific well spacing pattern because you can only thread that needle on what the map dictates there and not on what the reservoir dictates and what the company believes is the appropriate spacing. So we would have to basically come up an entirely different development plan here, and it wouldn't just be the nice, efficient pattern drilled at the spacing that the operator would prefer from a performance standpoint.

Q. So finally, Mr. Beer, is it your opinion that the Division should adopt the provisions involved with well spacing that are reflected on pages 10 and 11 of NMOGA Attachment 1?

A. Yes.

Q. Were the pages comprising NMOGA Exhibit C prepared by you or compiled under your direction and supervision?

A. Yes, they were.

MR. FELDEWERT: Madam Chair, I would move into evidence NMOGA Exhibit C, which contains Mr. Beer's resume and slides 1 through 8.

CHAIRWOMAN RILEY: These exhibits are accepted for the record.

(NMOGA Exhibit Letter C, pages 1 through 8, is offered and admitted into evidence.)

MR. FELDEWERT: And that concludes my examination of this witness.

CHAIRWOMAN RILEY: Questions from the other parties?

MS. BRADFUTE: No questions.

CHAIRWOMAN RILEY: Questions, Mr. Hall?

MR. HALL: No questions.

MR. CLOUTIER: No questions.

MS. BADA: No questions.

CHAIRWOMAN RILEY: That takes us to the Commissioners.

COMMISSIONER BALCH: I always have questions.

THE WITNESS: That's fine.

COMMISSIONER BALCH: I'm tired of everybody looking at me funny.

(Laughter.)

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Okay. So I'm impressed, actually, a geologist in geomechanics in one package. Normally I give that to my geophysics students, do the rock physics modeling.

A. Oh, yeah.

Q. You do a similar process to what Mr. Taylor described in your development, tech models and all that?

A. Yeah. And that's one piece, right? We also -- it's not just modeling, but it's watching performance and doing real trials, trying a tighter spacing, trying a looser spacing, see -- once you get too tight, the well should tell you that. The performance should decline. If you're too -- if you're too loose and the wells don't communicate, they don't talk at all, you understand that you're probably stranded. So it's more than simulation. It's real field trials as well.

Q. That's kind of what went into your Figure 8.

Is this something that you really want to do? Encana wants to do this, or is this in process or just a hypothetical?

A. This is a hypothetical development plan, but this is exactly how we have laid out our development plan for our unitized areas.

Q. So this looks like -- I did a calculation of

about 600-foot offset on the wells?

A. Between these wells?

Q. 600 on each side, each well, so 1,250 between wells?

A. Yeah. Yeah. That's exactly right. Our current well spacing is 1,200, so effective half-length of 600.

Q. Which is more than twice what's in the past rule and the proposed rule, 330-foot setbacks?

A. Right. So the play right now is maybe this is a conservative development program. The play right now has trials anywhere from 800-foot well spacing to 1,300-foot well spacing.

Q. You could go in and infill these perhaps with the new wells?

A. You could, or stagger over the top with a second bench.

Q. I like the sound of that.

A. Uh-huh.

Q. You saw 30 percent better production from -- max stress versus stand-up and lay-downs, which is not exactly the observation we had for the Permian Basin. And I was a little disappointed that your map didn't include the Permian Basin for the regional stress orientations.

A. It's a tiny dot.

Q. But I have a feeling I kind of know what it is down there.

A. Uh-huh.

Q. I was a little bit -- so you don't see that same kind of effect where basically the frac wings are going off in the right direction no matter how you orient the well. Where do you think your extra 30 percent is coming from? Is it just the fact that you're picking up those tails from things of the toe and the heel?

A. I'm not sure why. I mean, I've done just the simple math of draining a parallelogram versus draining a rectangle, so it could be a simple trigonometry theorem. And these frac wings are just so planer that you truly are dictated by a rectangle having higher area than a parallelogram. That could be.

Q. What's the -- what's kind of a ratio between the minimum and maximum horizontal stresses in the San Juan for what you're looking at?

A. Yeah. That's a good question. I'm not sure I can quote a psi now, but I can say that the microseismic we've seen suggests it's very planer fracs.

Q. Okay. So a pretty high --

A. High enough to cause a very planer frac.

Q. Which may or may not be the case --
A. For other areas.
Q. -- for other areas?
A. Yeah, that's correct.
Q. So your comparison between the -- you had some stand-up, lie-downs [sic], and then you had some diagonal wells. Those were done over what time period?
A. Oh, in the last six years.
Q. I know it's a pretty new play.
A. Yeah. Right.
Q. Yeah.
Did you -- I mean, obviously, as you're going through that play, you're developing and involving your completion techniques. You may go to closer frac stages. You may go to more frac stages per closer -- same thing.
A. Right.
Q. More frac stages per -- per unit length, or you may use standard -- in the Permian Basin, as Taylor had indicated, gone to finer and finer prop sand. Are these still slickwater, or are they crosslinked gels?
A. These are all done with a nitrogen foam.
Q. Nitrogen foam.
A. It's an underpressure reservoir.
Q. Okay.

A. And so we found that if we use nitrogen foam, that helps not just flood out the reservoir energy. So these are a little bit different design than --

Q. So these aren't geopressured?

A. No. These are underpressured, actually.

Q. Interesting.

So has that -- that process evolved over those six years? Are they doing the wells different than the older wells?

A. Yeah. But that bias was sort of taken out of the well set that we used here. The range of proppant and job size is all very comparable. They're all nitrogen jobs. So we try to take that out for an apples-to-apples comparison.

Q. Okay.

A. But yes, frac design does continue to evolve and along -- along a lot of the same themes, tighter staging, tighter clusters. That's a trend that we're applying in this basin as well.

Q. So you're working on just one oil plant there. I think I saw one gas rig drilling up in San Juan right now, and that's pretty much it.

A. That's right. I think you'll see a lot more activity pick up in the summer months in the Basin.

Q. Yeah.

So the offsets that are in the proposed rule -- the original rule is 330 all the way around. The proposed rule is 330, which already looks like it's not applicable to at least one of your developments, and then you have 100 foot on the first and last take --

A. Right.

Q. -- take points. Do you feel that's relevant to San Juan development?

A. I do. I think -- I think 330 is fair. That theoretically leaves us a 660-foot gap. That's not a bad gap. I think that balances waste.

Q. You could be -- you could be -- with the new rule, you could actually be 330 from the edge of your -- your area of development, whatever you have a joint operating agreement for or sole ownership of.

So the same question comes back that I asked Mr. Taylor at the end. If your frac wings are going greater than 330 and you're building your horizontal spacing unit such that you're right at the edge, you do open up the door for your neighbors to come in after the fact with a correlative-rights concern.

A. Yeah. I also sit at the table and see my neighbors drilling today and realize that they're within their rights to be within 330, and so it kind of goes both ways. And I think it's --

Q. What about nonoperating neighbors, though? I mean, those are the people that aren't going to have a recourse. They can't drill to take the oil that's under their land. I mean, they can't afford a $12 million well or whatever it costs you to drill those. What about those owners? What about those mineral right owners?

A. Yeah. I mean, I could understand. I think the problem is you have to draw a line in the sand somewhere.

Q. Somewhere, yes.

A. And, you know, the previous slides show the frac being more proppant concentration near wellbore, so that would be -- if you want to talk effective drainage, most effective to less effective to noneffective to what you don't break, it's hard to draw a line in the sand there somewhere.

Q. I have no idea about the transport of nitrogen from frac compared to slickwater. And crosslink, slickwater, I have kind of a feeling in my head. With slickwater, about 250 feet --

A. Yeah.

Q. -- is your expected maximum prop line [sic] of your fracture under a homogeneous scenario, a little bit less with a crosslinked gel. I have no idea what a

nitrogen foam does.

A. It's hard for me to conceptualize, too. I picture shaving cream, but it's hard for me to imagine the comparison there.

Q. Yeah. Huh.

Also, one of the advantages of using water is incompressibility, which is not going to be a nitrogen pump frac.

A. And frac efficiency is completely different as well, your leak-off as you pump.

Q. Interesting.

I think those are my questions. Thank you.

A. Okay.

COMMISSIONER MARTIN: I don't have anything.

CHAIRWOMAN RILEY: I don't have any questions.

All right. We're a little after 3:00. Shall we take a break, come back at 3:15?

(Recess, 3:03 p.m. to 3:17 p.m.)

T.J. MIDKIFF,

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

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your name, identify by whom you're employed and in what capacity?

A. T.J. Midkiff, reservoir engineering supervisor for Concho Resources.

Q. And, Mr. Midkiff, how long have you held that position?

A. Going on three years now.

Q. And what basins have you been responsible for?

A. Right now I currently work the Delaware Basin for Concho.

Q. And has that been your area of responsibility over the last three years?

A. Yes, sir.

Q. Okay. Have you testified previously before this Commission?

A. Yes, sir, I have.

Q. For the Commission?

A. No, not for the Commission. I'm sorry.

Q. For the Division but not the Commission?

A. For the Division, not the Commission.

Q. Would you outline your educational background?

A. I got a Bachelor's of Petroleum Engineering degree from Texas A & M University in 2007.

Q. Okay. And what has been your work experience particularly with respect to the horizontal well development in New Mexico since you graduated?

A. I went to work for XTO right out of college, working exploration in the Delaware Basin. I had the privilege of working with an exploration geologist right as -- plays like the Avalon horizontal development, the Bone Spring horizontal development right as those were taking off. And then from that point, I moved over to Concho Resources, after being there for almost three years. I went to work on the New Mexico Shelf property right as we were getting kicked off with horizontal drilling on that and then worked even in the Midland Basin drilling horizontal wells in the Wolfberry, Wolfcamp, Spraberry over there as well, before I eventually came back to the Delaware Basin.

Q. Now, with respect to your general job responsibilities with Concho, what are they?

A. Right now I supervise a team of engineers and technicians working on development in the Delaware Basin.

Q. When you say development, is that exclusively horizontal development?

A. Yes, sir.

Q. Okay. Do you consider yourself having

technical expertise in petroleum reservoirs and petroleum engineering?

A. Yes, sir.

Q. If I then turn to what's been marked as NMOGA Exhibit E, as in Edward, and I go to Exhibit E1, does this outline what you intend to discuss with the Commissioners here today?

A. Yes, sir.

Q. Okay. What are the main themes here, Mr. Midkiff?

A. I've got two main themes that I really want to communicate today that hopefully, if there are any lingering questions maybe after the fact, that you come back to these two themes. They should help answer a lot of your questions and hopefully set the stage for our discussion today also.

The first theme is really recovery factor. And if you look back over last few years in the industry, there's been a lot of innovation as far as technology, best practices that have greatly improved recovery factors within these reservoirs, within these resources. And we're at the point now where taking advantage of these best practices and technologies are causing us to exceed the allowables for an extended period of time. And if we are forced to stay within those allowables, then we will be creating waste.

Q. In your opinion, with the nature of the reservoirs being targeted by horizontal wells, do you need allowables to prevent waste?

A. Well, that leads into my second biggest takeaway. The nature of the reservoirs today, how different they are when the rules were originally put it place. The low permeability, discontinuous heterogeneous nature of the reservoirs really does not lend them to the need for allowables as they were originally -- so --

Q. If I take a look at what's been marked as NMOGA Attachment 1 --

A. Yes, sir.

Q. -- and we go to page 17 within the horizontal well rules, there is the whole section dealing with -- Subsection C dealing with allowables. Have you reviewed those provisions?

A. Yes, sir.

Q. And are you familiar with the Division and committee recommendation that horizontal wells be assigned production allowables?

A. Yes, sir.

Q. And are you familiar with the provision to eliminate any artificial limitations due to GOR issues?

A. Yes, sir.

Q. Okay. Do you support these provisions?

A. Yes, sir.

Q. Okay. Then let's start with your first topic that you mention, and that is the nature of what used to be known as -- or I guess known as conventional reservoirs.

A. Yes, sir.

Q. Those are the ones -- Mr. Midkiff, you mentioned these allowables were developed, presumably?

A. Yes, sir. Yes, sir.

Q. Okay.

A. Well, I think to understand why allowables are not necessary today, the best place to start is why were they applicable at one point. And very simply, what you had was high-perm continuous reservoirs, again, where a single completion could affect very large areas through the matrix. Right? And so you saw even drive mechanisms such as are represented here.

Q. And you're looking at slide 2 of Exhibit B, right?

A. Yes, sir.

You saw drive mechanisms such as like a water drive, you know, where water could push oil through a reservoir. You saw things like a gas cap expansion drive, where gas could accumulate and help maintain pressure within the reservoir. Now, again, those drive mechanisms were dependent upon things like high permeability and continuous reservoir so those cumulations and those movements through the matrix could occur. And the allowables helped mitigate any sort of waste or correlative rights issues by helping manage the withdrawal of hydrocarbons from those situations.

Q. Now, what you describe here on Exhibit E2, are these the type of reservoirs that are being targeted by horizontal wells today?

A. No, sir, not typically.

Q. And are they -- in your opinion, the reservoirs being targeted by horizontal wells, are they, say, different --

A. Very different.

Q. -- different animals?

A. Very different, yes, sir.

Q. Okay. If I turn to what's been marked as NMOGA Exhibit E3, does this help explain some of the differences?

A. Yes, sir.

And, again, leading off with making the same statement again about unconventional reservoirs: They're low permeability -- very low permeability.

They're discontinuous, and they're heterogeneous. As many people have pointed out over the last couple of days, we have to create the reservoir when we frac. We do not drain in any sort of meaningful distance through the matrix. We create the reservoir.

And I'd like to point down at the pictures at the bottom of this slide, on slide 3. And if you can imagine, just think of the -- kind of the orange spots on those two different pictures as maybe being the distribution of hydrocarbons in the reservoir. And if you think about what's going on today and what prompted horizontal development to begin with was the fact that it's very discontinuous and that what we need to do is maximize the exposure to surface area that we can create in the reservoir, whether that's with intense stimulation or whether that's with very dense drilling. We have to maximize the density of the surface area so that we can efficiently remove hydrocarbons from the reservoir.

Q. Mr. Midkiff, I have in my hand a piece of rock.

A. Yes, sir.

Q. Have you seen this before?

A. I have, yes, sir.

Q. What does this represent?

A. Wolfcamp -- it's a core sample from the

Wolfcamp.

Q. Okay. So is this rock the type of low-permeability reservoir rock that your company and other companies are targeting today --

A. Yes, sir, it is.

Q. -- in a horizontal well?

MR. FELDEWERT: Madam Chair, may I approach?

CHAIRWOMAN RILEY: Yes.

Q. (BY MR. FELDEWERT) Now, I handed that to the Commission. But that is the type of rock you're looking at, right?

A. It is, yes, sir.

Q. Okay. And you heard the prior testimony where you have to fracture it and create the reservoir within that type of rock?

A. Yes, sir.

Q. When you are developing that type of rock and we see that with these horizontal wells and we see the high productivity these horizontal wells, is that something that the Commission should be concerned about in the types of reservoirs that are being targeted by horizontal wells?

A. No, sir.

Q. If I turn to what's been marked as Exhibit

E3 -- or E4, does this help explain the basis for that conclusion?

A. Yes, sir.

So what we have represented here are two different wellbores. One of them would be a vertical well, what we've labeled a "conventional development." And what we've illustrated there is maybe 50 foot of perfs in a conventional pay zone.

And then right next to that, where we've labeled "unconventional," would be a horizontal drilled in zone. And what we've illustrated is the multifrac, multi -- the complex fracturing that we need to initiate within these reservoirs to make them productive.

And what I wanted to do -- I feel like an important perspective to think of when we think about allowables -- because we typically hear very big production rates when we hear about horizontal wells. We'll hear 3,000 barrels a day, 2,000 barrels a day, 4,000 barrels a day. But what does that really mean?

So if you look down in the table in the bottom right, if you take that 50-foot perforated interval and you think about, you know, what could have been a typical production rate for a horizontal well, 150 barrels of fluid per day, and you break that down on a per-foot basis, you're flowing roughly 3 barrels -- 3 barrels per day, per foot.

Now, on an unconventional reservoir, where again we hear this big rate of 3,000 barrels a day, now that's spread over 4,400 feet of treated lateral. Whenever you break that down on a per-foot basis, you see a number of .7 barrels per foot per day.

So it's even less, actually, through the matrix in a horizontal well than it was in a -- in a -- in a conventional well. And if you think about even that .7 barrels per day, let's take that now -- and that's just taking the lateral and dividing it out by its length. Let's now go the half-lengths. Let's assume 100 feet on each side, maybe 50 to 100 feet of H that goes along with it. So it's a very, very slow seep, and the cumulative effect of those very, very slow seeps together give us these really big rates. So that's just an important of kind context to have when you think about horizontal production rates.

Q. So is it proper -- oozing out of pieces of rock like that?

A. Yes, sir, a very, very slow ooze.

Q. Let me ask you: What's the harm with just continuing the current circumstance where we have these artificial allowables or these artificial GOR limitations? What's the problem with continuing that?

A. Well, if we do that, we will not, again, take advantage of the best practices and new technologies that we are using now to greatly improve the recovery factors within these resources.

Q. Does it also affect the economics with companies that are looking at these types of reservoirs?

A. Yes, sir, it does. Absolutely.

Q. If I turn to what's been marked as E5, does that help explain what you're talking about?

A. It does.

Another very basic but very important concept to understand why this is important to us, the techniques that we use, again those technologies and best practices that we use to develop these resources, are very, very expensive, very expensive. I mean, we're -- anyway, they're very expensive. And those early production rates are very important to us to make these economics attractive.

Q. Okay. Why don't you explain to us what you're showing, starting on E5, starting on the left?

A. So the left plot, what I've got represented there is, on a y-axis, just again, that would be a daily production rate. And on the x-axis, just time. And what I'm representing is basically three different types of maybe production for the same well. Number one would be a completely unrestricted production. Number two would be maybe subject to some sort of artificial allowable, and then three may be subject to an even more artificial allowable.

And in the direction of that red arrow, what I'm indicating is as we -- as we extend the time that we get to recover the -- the -- the investment, we decrease -- we increase the time to get paid back, we are decreasing our rate of return, decreasing our net present value and really decreasing the incentive to even develop it.

And I can tell you, even within Concho, it is very competitive for those investment dollars. And if there is some sort of artificial restriction within my company that causes economics in another basin for no other reason than allowables to make their economics better investment within our company, we'll shift to that direction.

Q. And so what would we lose, for example, investment, in New Mexico?

A. You would probably lose it in the Midland Basin.

Q. Which is where?

A. In -- in -- on the Texas side.

Q. The big state of Texas?

A. Yes, sir.
Q. Does scenario number one, which is no curtailment, does that give you the best chance of having favorable economics in a number of --
A. Yes, sir.
Q. Thereby promoting development?
A. Yes, sir. Absolutely.
Q. Now, that all sounds great, but let me ask you this: Has the company seen any negative impacts from producing horizontal wells after -- like that which is being proposed by the rules?
A. No, sir. That is something that we have -- we have obviously looked for. And we have produced unrestricted, and we've seen no negative effects nor can we come up with any sort of reason why we could anticipate any sort of negative effects.
Q. If I turn to slide 6, is that an example of what you're talking about?
A. It is.
Q. Mr. Midkiff, this has a lot of information on it.
A. Yes, sir.
Q. So I want you to put this in perspective and explain to us the colors and the graphs before you start telling us the conclusions that you draw.

A. All right. Absolutely.

Q. Okay.

A. So to understand, you know, kind of the cumulative effect of all these practices and technologies coming together -- and this is just an example of a project that we have done down in the southeast corner of New Mexico and the southeast corner of the Basin within New Mexico. And what we're showing is how has this more dense development where we've taken advantage of the more simultaneous development and the more completions, how has that impacted the recovery from the reservoir.

So I want to start off by talking about this top left plot, which is a rate/time plot, again the rate on the y-axis, time on the x-axis. And what I've got represented there, the black line represents the total oil production from this project. The orange line represents the GOR from this total project, and then the green line represents the calculated allowable based off of the current rules. And so what you can see from that plot is that this project has produced above its allowable for a significant amount of time, and we've seen no negative effects from that.

Q. Now, is it helpful to point out that this initial chart deals with the Upper Avalon?

A. Yes, sir. That is -- that is important. And I wanted to start there, one, because whenever we think about the allowables, one of the important issues there is GOR. And the Avalon produces one of the highest GORs in the Basin. So I wanted to attack that issue straight on for you and go to the place you might be the most curious about. And so, again, that's why this example is so important.

Q. Now, you mentioned that you have eight wells per section, if I'm -- this is -- this would be a traditional 40-acre oil pool, right?

A. Yes, sir.

Q. And that roughly translates, then, to two wells per spacing unit?

A. Yes.

Q. Which is then contributed to exceeding that allowable then, right?

A. Yes, sir.

Q. Okay. And what do you see now -- when you look at the data, what do you see with having a length -- a period of time here of exceedance of the allowable and the increase in GOR?

A. Okay. Well, let's move over to the top right plot to -- to -- to look at next. And what I've got represented on there is two lines, and they're labeled, actually, down here in this bottom left. The colors are consistent all the way through. So what I wanted to do was make a comparison of somewhere where we had one well per spacing unit versus two wells per spacing unit so four wells per section versus eight wells per section equivalent. So the green line represents the four-well-per-section development, and then the black line represents the eight-well-per-section.

And in the top right plot, really all that we're indicating at this point is that we've seen really no difference in the decline characteristics between those two developments.

If I move down to the bottom left, that is a cumulative oil plot over time. And what I'm indicating there is, if you look at the eight-well-per-section development and you think about that in terms of recovery per section -- so this is grossed up on a total project basis.

And I forgot to point that out up there on the top right. That was an average profile per well, in the top right.

The bottom left is actually total recovery for the section. And so what you see is, with that eight-well-per-section recovery, it's already recovered within less than two years probably more than what that four-well-per-section recovered over its life. So we've already significantly improved our recovery factors in a short amount of time.

Q. Mr. Midkiff, what would the GOR history look like over time for two wells versus four wells if the higher GOR breakout was causing an issue?

A. Well, if there was any sort of issue that would be related to GOR breakout as in -- you know, a lot of people think about that in terms of maybe like a two-phase flow issue, where my gas was flowing preferential to my oil and, therefore, pinching out my oil.

One of the things I might see on this black line, the eight-well-per-section development, is I might see a higher decline from that, and that's clearly not indicated at this point.

And one of the things you also see, if you look down at this bottom right plot, this cumulative GOR versus cumulative oil, when you think about recovery in terms of oil per gas, again, looking for that preferential flow of gas, I don't see anything abnormal in the relationship of my oil recovery relative to my gas recovery.

Q. Anything else about this particular slide?

A. No, sir.

Q. Okay. And if we move on to what's been marked as E7, now we have what looks like similar data. But do we have a different area, or what's the difference here?

A. This is a different project in the Avalon. Again -- and, again, I really wanted to give you multiple examples here just to highlight -- because of the high GOR in this area, to highlight there is a nonissue.

So it's the same story, exact same layout and flow on this slide. If you look over in the top left corner, y-axis total production for the total project. I see the black line is my total oil production. The orange line is my GOR, and then the green-dashed line would be the calculated oil allowable based off of that. And so what you see there is that we again have been produced above the allowable for a significant amount of time.

Q. Without any impact on the recovery?

A. Again, without any sort of negative impact on our recoveries.

Q. Okay.

A. So move to the top right, and again you can see a very similar decline profile relative to the four wells per section. Again, look down in the bottom left. You see already a higher ultimate recovery, a more improved recovery factor. And then in the bottom right, that there is nothing abnormal happening with my oil relative to my gas production.

Q. Then if I move on to the next slide, E8, you now have a different formation, right?

A. Yes, sir.

Q. And what are you showing here?

A. Well, this is a project from the Wolfcamp A and same workflow here. One of the things that's important about the Wolfcamp and thinking about in terms of the current allowables, the way the rules work, with the reducing GOR -- that's why we saw the reducing oil allowable on those previous plots. With the Wolfcamp, we have very high production rates, but due to the nature of the reservoir -- and I've got a slide coming right behind that that'll explain that -- we don't see the reducing oil allowable, but we do see still a significant amount of overproduction just with the depth bracket allowable from the Wolfcamp.

Q. So is this a circumstance where you don't have any increase in GOR, but you have increase in the rate of production above the allowable?

A. Yes, sir.

Q. Okay. And what do you see here?

A. Well, exact same story as before. We see the high initial rates. If we look over at the -- the different development that I've shown now in the top right is not an eight-well versus four-well. It's actually a 16-well versus eight-well, so even more dense development. So it would be four wells in a proration unit equivalent. And whenever you look at those two lines relative to each other, again, nothing early on is indicating any sort of negative effects on the rate/time plot. And look down on the cumulative plots, and we're already producing -- or already showing indications of higher recovery. And then with the GOR, we have not seen any sort of abnormal breakout of GOR that would indicate any negative -- negative effect on the reservoir.

Q. That's shown on the bottom right-hand corner in this exhibit?

A. Yes, sir.

Q. Anything else about this exhibit?

A. No, sir.

Q. Now, did you examine this from a -- I think you told me a bubble-point perspective; is that right?

A. Yes, sir.

Q. If I turn to what's been marked as slide 9, E9, how does your analysis change here?

A. Well, again, really hammering on this bubble-point and GOR issue, you know, there's been some talk over the recent years about maybe the effect of bubble-point pressure on ultimate well performance, so, again, I wanted to attack that head-on for you.

So I chose two reservoirs that really bookend that issue, the Wolfcamp A, where I've got a reservoir pressure that is significantly greater than my bubble-point pressure, and then the Avalon Shale, which has a reservoir pressure which is very close to my bubble-point pressure.

Q. And is this in New Mexico?

A. This is in New Mexico down in the southeast corner. Yes, sir.

Q. Okay.

A. And so what I want to point out is up in the top left, again just a rate/time plot. And what I'm indicating -- the orange line represents the Wolfcamp, and the green line represents the Avalon, and the first thing to point out is -- and these are -- these are very typical wells for these reservoirs in this area. What I want to point out is how similar, actually, the declines have been throughout their life so far.

And then if I take that and I move directly below that to a GOR versus time plot, what do I see is my Wolfcamp GOR remained flat. Again, because my reservoir pressure is so much higher than my bubble-point pressure, I see my GOR remain flat. Whenever I look at my Avalon, I immediately see this breakout in my GOR. I immediately see this movement to a two-phase flow where my gas does move preferentially to my oil, but if I move back up to that very top plot, I see that it has not had any sort of negative effect on my oil decline curve, that my oil is still following that same trend as the reservoir that didn't see that GOR breakout.

And the point of being here, as others have testified, that my -- the permeability within my fractures is basically infinite compared to the matrix. So this phenomenon is happening in the mat- -- not in the matrix -- in the fractures where it's a nonissue. And any sort of alternative to this production style would be to produce these reservoirs at such a slow rate that basically they'd be uneconomic to develop because the Avalon immediately dropped it below your bubble point. There is no point in trying to keep -- trying to suppress that GOR. This is the only way to economically produce that reservoir.

Q. So if dropping below the bubble point were the issue in the Avalon in these horizontal wells, what would that green line in the left-hand corner look like?

A. If there was a negative effect, it might be attributed to two-phase flow pinching off oil. Again, you might see a higher decline on that green production curve indicating some sort of negative effect on the -- on the oil production.

Q. And you haven't seen any indication of that --

A. No, sir.

Q. -- in your studies?

A. No, sir.

Q. In your -- first off, in your opinion, the types of reservoirs that you've studied here, are they the type of reservoirs that are being targeted by horizontal wells in New Mexico?

A. Yes, sir. Absolutely.

Q. And in your opinion, are these targeted reservoirs, are they rate sensitive at all?

A. No, sir.

Q. And in these targeted reservoirs -- in these reservoirs targeted by horizontal wells, does the increasing GOR that occurs -- is it impacting production at all?

A. We have not observed that.

Q. And in your opinion, will unrestricted production from these reservoirs harm the reservoirs and result in waste?

A. No, sir.

Q. Okay. Now, you pointed out there's no harm here from exceeding the allowables or the GOR limitations. Aside from the economic issues that you raised, is there harm that occurs in another form by continuing with these artificial restrictions on the production from horizontal wells?

A. Yes, sir.

Q. Okay. What are they at a high level, before we go to each one?

A. Primarily, waste. We would be -- we would -- we would not develop these reservoirs at the density that would properly optimize the recovery factor of hydrocarbons.

Q. And is there also an impact on the completion technologies that would be utilized?

A. Yes, sir. Absolutely.

One of the -- one of the techniques that typically doesn't get associated with this, but we have examples -- and I'll show you here in a second -- where simply making changes to completions have taken us from being below the allowable to above the allowable.

Q. And if we continue with these artificial restrictions on production from horizontal wells, is that going to affect the incentive and ability to

develop various benches within the same pool?

A. Yes, sir.

Q. Okay. And all of these things that you just listed, this well density, the completion technology, the development of various benches within the same pool, all of these advances increase the production from a spacing unit, right?

A. Yes, sir.

Q. Okay. And in your opinion, if we maintain those arbitrary restrictions on production, there would be no incentive to utilize those devices to increase production in a timely fashion?

A. Exactly. Yes, sir.

Q. All right. So I want you to first then turn to the impact it would have upon what operators are doing with well density. Okay? If you turn to what's been marked as E10, does that help explain that?

A. It does. What I wanted to do was really pull out some slides from investor presentations that really show that this is something that the industry is in agreement upon, that we are all saying together. So I pulled a number of those slides together.

The first one we're going to start off with is a slide that EOG put out for an investor presentation. They're really talking about their Eagle

Ford asset. But why it's important is because it really tells the whole story of why we're doing what we're doing. So I'm going to walk through what is shown here.

They show two different developments, one with two wells per section and one with 16 wells per section. And if we walk through this table at the bottom and we look at maybe what changed for them as they tried these two different developments, you can see that one of the things that happened for them was as they went tighter and put more wells per section, their recovery per well actually went down. But because they had more wells in the section, the ultimate recovery and the recovery factor within that section went up significantly, and ultimately they were able to create much more value out of this section due to that technique.

Q. And is this incremental recovery, or is this accelerated recovery?

A. The majority of this is incremental recovery.

Q. Okay. Anything else about this slide?

A. No, sir.

Q. What are we showing on the next slide, 11?

A. Well, I've got a slide, again, from a number of operators. The top left would be from WPX, and you've got Cimarex. You've got Concho down on the bottom left and then Devon in the bottom right. And you see comments associated with what we've pulled out here. We're confirming 15 wells per drilling spacing unit, and we're testing 12 wells per section, and we're maximizing asset value. This is the major evolution that's happening right now in the industry.

And I really want to call your attention down to the bottom right slide where Devon has put together, basically, this diagram showing all the different benches and the potential development that might exist within these benches. It's huge. Okay? And this might even, honestly, be underselling. There is a lot of development to be had, I believe.

And one of the most important things to take away is: How many of these different benches actually show up under the same pool? If I look at, like, the Leonard in the Bone Spring and look at all the different benches and development and the density that's represented there, those would all be, right now, operated or governed under the same pool. So this simultaneous development of these resources would put us significantly over the allowables.

And think about the examples I showed you earlier and how far we were above the allowables. It was nowhere near some of these densities.

Q. All right. So is there any real consensus yet within the industry about what density should be at various locations?

A. There's not. It's one of the most difficult problems to solve, and we are all working towards figuring out what the optimum development is. What's most important is that we don't have any sort of artificial restrictions on us as we try to determine what is optimal.

Q. Because allowables are based on a spacing unit?

A. Yes, sir.

Q. Eight wells within a spacing unit?

A. Yes, sir.

Q. And isn't it true that each well within that spacing unit in that pool must currently share whatever artificial allowable is assigned under these depth bracket charges?

A. Yes, sir.

Q. Under GOR limitations?

A. Yes, sir.

Q. So this is not -- allowables aren't well by well. Allowables are the spacing unit -- right?

A. Exactly.

Q. And your point is that if we have a well in its spacing unit that is meeting or close to the current

artificial allowable, there would be no incentive to add an additional well?

A. Exactly.

Q. Because you'd have to curtail that well to bring it down within the allowable?

A. Yes, sir.

Q. Okay. Now, in addition to well spacing, you mentioned that there had been some advances in completion techniques?

A. Yes, sir.

Q. Making them more effective?

A. Yes, sir.

Q. If I turn to what's been marked as slide E12, is that reflective of what you're talking about?

A. It is. Again, I chose an area of the Basin that has seen a significant amount of testing and evolution on this front, down in that southeast corner of New Mexico where we've seen, again, a lot of development within the Avalon and the Wolfcamp. And so I chose -- I chose kind of a small area to eliminate any sort of geologic variances that might occur over an even larger area.

And if you look at the top left plot, what I'm representing there is y-axis represents the six-month cumulative oil production, and maybe that would be a proxy for ultimate recovery. And then on the x-axis, I've got the proppant loading, which, as you increase proppant loading -- so as I increase the intensity of my simulation, I see that my ultimate recovery is trending upwards to the right. And I see that same thing exists both within the Avalon and the Wolfcamp.

Q. Is the Wolfcamp shown in the bottom, left-hand corner?

A. In the bottom left, yes. Same trend, increase in proppant loading, increasing ultimate recovery.

Q. Again, is this incremental production, or is this acceleration production?

A. This is incremental production.

Q. How do you know that?

A. Well, next slide.

Q. Okay.

A. So one of the ways to analyze this is to again look at gas relative to my oil production. So what I've chosen here are two wells closer to the -- I guess more in the western side of the Basin. These are Avalon wells. And what we did was we had two different completion techniques that were applied here. And if you look at that bottom left table, which the main variable I would point out there is the cluster spacing, 100 foot versus 50 foot. And I've got diagrams kind of representing what does that look like roughly right next to it, just more completions in one well and less completions in the upper well.

Q. And let me stop you right here. What I see is blue lines and green lines. If I look in the upper, left-hand corner of this exhibit, does this identify what's associated with the blue line and then the green line?

A. Yes, sir. It's important to note that these wells are right next to each other. They were roughly 1,300 feet apart, and the blue well was actually completed first.

Q. If I look, then, at the bottom, left-hand corner of this exhibit down here, Exhibit E13, the Patron Federal 33 1H, what color is that?

A. The 1H relates to the blue line.

Q. Okay. And then the 23H [sic] is the green line?

A. The 2H goes with the green line.

Q. The 2H goes with the green line.

Okay. And what do you see here as you increase the cluster spacing --

A. Well, as we decreased --

Q. -- or decrease cluster spacing?

A. -- the cluster spacing, what I look at -- if I look at that green line relative to that blue line, again what I see is that I'm making much more oil relative to my gas production. If it was simply acceleration, I wouldn't see this. What this indicates is that I've actually created a bigger tank. Right? So I'm not drawing it down as fast because I've basically created more access to more reservoir. So I'm not seeing that GOR break out nearly as fast.

Q. So you're contacting more of that chunk of rock that we see up there at the table?

A. Creating more reservoir, yes, sir.

Q. Anything else about this slide?

A. What I really want to point out is -- you know, there's been a lot of talk about, you know, the efficiency of the development, and I really want to point out the cluster-spacing change. Again, we went from a 50-foot cluster spacing to 100-foot cluster spacing. A 50-foot change has created a significantly better well. And you'll see more indication of that on the next slide. But that's just important to think about. Even at 50 feet, we're seeing improvement. And we're even going down to the point at 50 foot to 20 foot, we're seeing significant improvement in there in some places.

Q. If I then turn to the next slide, does that show the impact relative to what would normally be the allowable for this?

A. It is. Yes, sir.

Q. Okay. What's slide E14?

A. So these are the same two wells from the previous slide. And there's a lot going on up in this plot in the top left. Again, it's a rate/time plot. The green line is the same green line from the previous plot. That's the 2H, the well that had the bigger completion. The blue line is the well that had the older-style completion. And what's important to -- and a dashed line for each represents the calculated allowable based off its depth bracket.

And what you see is for the older-style completion, it was only above its allowable for a short period of time, and it quickly fell below it. But if you look at the newer-style completion, just simply that completion change for an offsetting location put it significantly above its allowable for a significant period of time but also recovered a significantly higher amount of resource.

Q. And would you -- I think you've calculated down in the bottom, right-hand corner that you saw a substantial increase, right?

A. Yes, sir.

Q. Would companies be incentivized, for example, to do the green line if we might not have these artificial restrictions on production?

A. We would not be -- we would not spend the money for that development if we did not get to produce it.

Q. Because you've got to your curtailment below the --

A. Exactly.

Q. Okay. Now, you touched on this earlier. You mentioned the benches. So we've talked about well density. We've talked about the impact that these curtailments have and the completion enhancements. Then you have the issue of bench development within pools, right?

A. Yes, sir.

Q. If I turn to what's been marked as Exhibit E15, would you please explain to us what this shows?

A. Well, this is a type log from the Avalon in the Red Hills area, the southeast part of New Mexico, part of the Basin within New Mexico. And this is just the Avalon. So earlier I mentioned the Leonard and the Bone Spring all being within the same pool. This is just a fraction of that even. And what you see is a type log. And with the red histogram, what we've indicated is the number of different productive landings that we've observed within this reservoir.

So the important thing to take away from this is we're still trying to figure out how many different landings are within this and what is the optimum spacing within the wells to actually recover all of this 1,000 foot of productive hydrocarbon that we've observed just within the Avalon.

Q. And that Avalon bench that you put on here that you indicated earlier, this is just a portion of what is now an exiting pool?

A. Exactly. Yes, sir.

Q. Again, allowables are based upon spacing unit and pool?

A. Yes, sir.

Q. Not benches?

A. Exactly. Yes, sir.

Q. Not benched within a pool but the pool as a whole?

A. Yes, sir.

Q. And is it correct, Mr. Midkiff, that operators can target each productive bench within a pool individually with horizontal wells?

A. Yes, they can.

Q. Which then results in stacked horizontal wells?

A. Yes, sir.
Q. Within the same spacing unit?
A. Yes, sir.
Q. Within the same pool?
A. Yes, sir.
Q. Okay. And is it your experience, then, that the stacked laterals within a spacing unit in a pool will increase the total production from that pool?
A. Yes, sir. Absolutely.
Q. And if we maintain the current restrictions with allowables on horizontal production from the pool, you wouldn't be able to develop each one of those benches until one of them had been depleted, right?
A. Exactly. Yes.
Q. This phenomenon that you see, is this limited to just the Avalon, or do you see benches like this, for example, within pools of the Wolfcamp Formation?
A. In other formations.
But I want to add a point on to what you just said --
Q. Uh-huh.
A. -- and that's that it's not so much that production might be delayed from some of these benches. Production might become uneconomic to actually develop in these benches if we aren't allowed to do it at the

same time. That's a very, very important concept to understand, that a lot of this stuff, it only works if we're able to develop all the different benches in all the different spacing at the same time. So --

Q. And I want to make sure it's on the record. This is not unique to the Avalon?

A. It is not, no, sir.

Q. It extends to the Bone Spring?

A. Bone Spring, Wolfcamp, yes, sir. I can't think any sort of -- I can't think of a productive formation in New Mexico that doesn't have --

Q. Now, if you were not -- didn't have these artificial restrictions in place, how would you go about developing these various benches?

A. We would put wells on top of each other. We would put wells very close to each other areally. We would put as many wells in there that we could to maximize -- maximize the well.

Q. Yes, sir.

Do you have an example?

A. Yes, sir.

Q. Let's turn to what's been marked as slide E16.

A. Yes, sir.

Q. Is this an example of stacked development within the same pool, in the same spacing unit?

A. Yes, sir, it is.

Q. All right. Starting -- first identify where this data comes from and then walk us through each of these charts.

A. Okay. So if you look at the bottom right, I've got a locator map for you. And what I wanted to show you that we chose examples from across the Basin. So this is -- they're either Avalon or 2nd Bone Spring examples for this scenario. And, again, that's important because it's really the place where we have the most productive intervals to find within a single pool.

And if you look at the upper left plot, you can see from the little diagram down in the bottom left corner that these wells are roughly 1,500 feet apart, and they're in the same pool. And there are four different lines on these plots. And I know it's confusing. But what the different lines represent, the top line -- the total oil one -- the blue line represents the total of the black and the green line. Okay? And the dashed line represents the calculated allowable from that spacing unit. So what you see is, when you add those two wells together, the second well was really what took it over the allowable in that top left example.

Q. And if the company was -- if the companies continue to be restricted by these artificial allowables, again, you wouldn't do that?

A. No, sir.

Q. You would have to refrain --

A. Yes, sir.

Q. -- from drilling and completing --

A. Yes, sir.

And one of the things that is important to note is that -- I put this in here as a representation. I've actually normalized these for time to show how we would develop them going forward, which would be simultaneous.

Q. Now, you have some other examples here, right?

A. I do, another 2nd Bone Spring example in the top right. Again, you see that total oil production. You even have the one well by itself with the ability to exceed the allowable early on. But both of the wells together significantly exceeded the allowable for an extended period of time. And then same thing in the bottom left, another 2nd Bone Spring example where an individual well by itself was capable of producing above the allowable and the second well stacked on top of it roughly 500 feet away, but it's significantly above the allowable again.

Q. What's the advantage of being able to develop these benches, maybe not simultaneously but with stacked laterals within the same pool, within the same spacing unit? Does it help with surface issues?

A. Oh, absolutely. There are operational efficiencies that we gain outside of just the downhole reservoir efficiencies. We gain cost advantages when we complete. We minimize our surface disturbances, among other -- we get to build more efficient facilities. There are a number.

Q. Have you also observed that there is a benefit in -- from production in targeting these benches relatively close together time?

A. Yes, sir. Absolutely.

Q. What does that result in?

A. Well, I assume you're referring to any sort of simultaneous development that promotes better recovery factors.

Q. You're the one that told me about it.

A. Yeah. Absolutely. I'm making sure that's what you're asking me about.

Yes. The simultaneous development, I think that's an issue that most people are familiar with in the industry now, that whenever we drill a well, we produce it. We actually create a low-pressure environment. And it may not be in the matrix. It may just be in the fractures. It's probably just in the fractures. And we'll try to initiate a new fracture offset to that. Those fractures tend to link up, and it's hard to stimulate new reservoirs. So, ultimately, the resource that could be developed is now uneconomic to develop because we can't really stimulate enough of it to make it economic.

Q. And those would be the benches within the same pool --

A. Yes, sir.

Q. -- same spacing unit?

A. Yes, sir.

Q. In your opinion, Mr. Midkiff, are these current allowables, GOR limitations impeding these types of enhanced development techniques that you just reviewed?

A. Yes, sir.

Q. And in your opinion, is there any reason to restrict production from these horizontal wells using either an artificial allowable charts or GOR limitations?

A. No, sir.

Q. Will allowing horizontal wells to produce at capacity, in your opinion, is that going to cause waste?

A. No, sir.

Q. In your opinion, it does not at all harm --

A. Due to, again, this low-perm, discontinuous, very heterogeneous nature, you don't affect any sort of meaningful amount of matrix when you stimulate and when you produce. You create the reservoir when you frac, and it's that -- that gives you -- that very slow seep over a large area that gives you the big rates. You're not damaging the matrix of the reservoir.

Q. Is there any concern about the impact on your proppant or fracture-cluster effectiveness if you produce at capacity?

A. I have -- we've actually observed operators that have produced in excess of 10- to 15,000 barrels of fluid per day, okay, and have observed no negative effects from that type of flowback, very high, very fast. We've seen nothing to indicate there was anything negative occurring to the reservoir.

Q. In allowing horizontal wells to produce at capacity, do you negatively impact correlative rights, in your opinion?

A. No, sir.

Q. Why is that?

A. Well, again, because we're not draining through the matrix. We -- our stimulation is controlled where we're able to drain, and if our stimulations are controlled, then we are not going to be -- we should not be promoting any sort of correlative-rights issues.

Q. And when I look at the language, then, that is proposed in the rule at page 17 under "Allowables," in your opinion, should this mission adopt that language?

A. Yes, sir.

Q. And will that assist in preventing waste and protecting correlative rights?

A. Yes, sir.

Q. Were the pages comprising NMOGA Exhibit E prepared by you or compiled under your direction and supervision?

A. Yes, sir.

MR. FELDEWERT: Madam Chair, I would move admission into evidence of NMOGA Exhibit E, which contains slides 1 through 16.

CHAIRWOMAN RILEY: The exhibits are accepted to the record.

(NMOGA Exhibit Letter E, pages 1 through 16, is offered and admitted into evidence.)

MR. FELDEWERT: And that concludes my examination of this witness.

CHAIRWOMAN RILEY: Open this up.

OCD, do you have any questions?

MS. BADA: No questions.

MS. BRADFUTE: No questions.

MR. CLOUTIER: No questions.

MR. HALL: No questions.

COMMISSIONER MARTIN: I don't have any questions.

CHAIRWOMAN RILEY: Commissioner Balch?

COMMISSIONER BALCH: Of course I have questions.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I'm sorry. I didn't catch your name.

A. T.J. Midkiff.

Q. Okay. You're with Concho?

A. Yes.

Q. Because it skipped over the Chevron. The first time you didn't have your resume in --

A. Oh, I'm sorry.

Q. Thank you, Mr. Midkiff, for your testimony.

A. Yes, sir.

Q. These are -- a lot of these are pretty new plays, so you don't have anything except for that projected decline of the well. I think it's all hyperbolic, right?

A. Yes, sir.

Q. So you're -- trying to figure out what this well's really going to be doing in 25 years is still a little bit of a guessing game --

A. Absolutely.

Q. -- although I think that, generally speaking, people are finding these wells are lasting longer than they expect --

A. Yes, sir.

Q. -- at higher production rates than they expected?

A. Yes, sir.

Q. All right. So having said all of that, it's really hard to tell long term what potential formation damage could occur from changing or varying your production practices --

A. Yes, sir.

Q. -- over a six- to 12- or 15-month time period, as we have them right now. Okay. Sorry. So that's a preamble.

A. Okay.

Q. So disregarding the fact that I'm not sure the depth-bracket allowables have meaning for anything, there is something that needs to be considered. We're writing a horizontal rule that's not just for shale development.

A. Yes, sir.

Q. Granted, that's the biggest use. Most people are going to be doing that kind of development. You're looking at 500 wells a year in New Mexico for the next umpteen years. Nobody knows for sure.

A. Yes, sir.

Q. But there are still people down there that are drilling horizontal Brushy Canyon.

A. Yes, sir.

Q. There are people that are drilling horizontal wells in stacked-type plays like Blinebry, Prumpertive [phonetic] Wash, Tubb --

A. Yes, sir.

Q. -- things like that. These are conventional type --

A. Yes, sir.

Q. -- horizontal well applications. So we still have to make the rule apply to them as well --

A. Yes, sir.

Q. -- or at least be useful to them.

So one possible impact, especially when you're looking at Section A on well spacing -- I'm sorry -- on the allowables -- it's not Section A. It's C.

A. Okay.

Q. Allowables is that you're taking any -- any producing wells that are in the same formation -- now, granted, that's not going to have as much impact on these existing conventional-type plays, but in some places, it might, where you are then lifting that kind of automatic allowable from the conventional wells, as well as the nonconventional wells you're drilling now.

A. Yes, sir.

Q. And especially if you think of the case of somebody out there who is drilling a Blinebry-Tubb-Drinkard Wash -- I'm using that because we had a case last year that was doing exactly this.

A. Uh-huh.

Q. -- then you're suddenly impacting a lot of vertical wells that are potentially in that same pool.

A. Yes, sir.

Q. Or pools, in this case, because you're combining three pools into the play. That's where I'm wondering if there is a possible impact on allowables or the necessity of allowables.

A. Let me -- let me, first off, address one thing. In one of the original applications of horizontal wells, one of the things that I observed -- and it goes back to one of my first slides, right, where I showed the decreased production rates through the matrix, actually, with the horizontal well. One of the things that was observed early on was in places where water coning was an issue, the application of a horizontal well actually decreased those production rates through the matrix and actually helped those more conventional reservoirs produce.

Then I move on to something like the Blinebry, which I've personally worked. And yes, those are vertical wells, but similar to like the Wolfberry, that's a very thick section, right, where what we do is we go in and we put a lot of stimulations very close together because it's, again, a very low-permeability, discontinuous reservoir. Right? And the nature of that, we have to go and put that very intense stimulation on that. Now, it's vertical, but we're basically using a horizontal development technique to do that. Right? So, again, those characteristics --

And the hearings that I've been involved in, that I know of that have occurred recently on this subject, we actually, in some of the reservoirs you just mentioned, we sought to change the allowable, and our objective was -- we actually came and asked you for unrestricted allowables. And what we ended up settling on was an allowable that would just -- we asked for the allowables to go away, and we ended up settling on a number that we felt would be unrestrictive. So it was the same objective. We just kept the number.

Q. So still have an allowable, just higher than what you could possibly produce?

A. Correct. Exactly.

Q. Kind of on that same note, all the examples you gave were showing production over the allowables?

A. Yes, sir.

Q. So there is a way around that right now --

A. Yes, sir.

Q. -- with the existing rule and could potentially be a way around that going forward. It's just a matter of turning in a C-102 or something like that. I'm not --

CHAIRWOMAN RILEY: Your 102 is your plat.

COMMISSIONER BALCH: C-104. I don't know. That's not my side of the thing.

Q. (BY COMMISSIONER BALCH) But there is a way around it now, and we're already doing that.

A. Yes, sir.

Q. So in a sense you're already unrestricted in regard to that, except for it's an extra paperwork step by the time you want to do it, which is pretty much every well.

To your knowledge, has anybody ever been

turned down for one of those?

A. Not to my knowledge. I'm not expert on that, so I apologize.

Q. I think that the depth-bracket allowables are kind of funny.

My only real concern -- the only thing that I saw in that part of the regulation -- N.12 [sic], I think it was -- is the protection of the formation and protection of correlative rights, so producing somebody else's oil that's across your leaseline. So, similarly, you may only be producing from the fractures, but if your fractures are going off into somebody else's lease, then, essentially, you are depleting their matrix to some degree, at least the pressure in their matrix, which contributes to the potential of future production.

A. So one of the biggest challenges -- you just highlighted the biggest challenge that we have as operators. We look to squeeze or maximize the recovery factors from this reservoir. And one of the really important concepts to understand -- and previous testimony refers to this -- is that our recovery factors degrade as we move away from the well. So I may have a fracture that goes out 300, 400 feet, but I may only be producing a half a percent of the oil out there.

And that's one of the things that the --

you know, we, as industry, have gotten together and talked about this. We all understand that. And we've all looked at each other, and based off of our experience, the places where we've actually drilled and have empirical data to present, where we simulated it, we feel that that 330-foot number gives us a good balance between me having to be so far off a lease line that I've now created a lot more waste on my -- on my acreage and the ability to -- well, really just that, basically the ability to maximize recovery and still not impede on my neighbor. We, as an industry, feel like that is a good number.

Q. So you feel like that. Is there -- do you have any paper references you can give us on that?

A. Well, what I can show you is that the development in a lot of these reservoirs is going tighter than that spacing. So we think there is significant amount of oil left to be had at even tighter development than what we're proposing as a setback.

Q. I'm looking at your Eagle Ford example where you've got the ten to 16 wells --

A. Yes, sir.

Q. -- that will increase your recovery factor by 2 percent.

A. Yes, sir.

Q. That's by section, right?
A. Yes, sir.
Q. So that's improving your EUR by increasing the density of your wells.
At some point you're going to find a place where you no longer see that improvement in recovery.
A. Absolutely. Yes, sir.
Q. Do you have a sense what that might be in the Wolfcamp in New Mexico?
A. No. We think we're getting close, but we don't know what that is yet. No, sir. That is still going to be a very intense process, and that is what I spend most of my days on, is trying to solve that problem.
Now, I want to also point out that the 2 percent recovery factor increase was actually a 33 percent recovery factor increase. We improved the recovery by a third.
Q. And presumably the EUR will go up accordingly?
A. Yes, sir.
Q. We have to wait and see on that and make sure the decline rates follow that trend past six to 12 months.
A. Well, and to go back to that Eagle Ford example, again, we're okay if we -- some of these reservoirs -- you know, there are so many things that

spacing depends upon --

Q. Right.

A. -- reservoir characteristics. Even the economic criteria for the old operator can dictate what might be the proper spacing. So there is actually a point in this development where we might be okay in some of these reservoirs, where I start to degrade my individual well performance, as you saw in that EOG example, but I'm ultimately creating more value, ultimately creating -- ultimately recovering more resources.

Q. Essentially, you're improving the reservoir that you're creating.

A. Exactly. Exactly.

Q. It's interesting to note. It's still in development, so the long-term ramifications -- I mean, we hope to do the best we can.

A. Yes, sir.

Q. But we do have to keep in mind that, you know, the price of natural gas could quadruple for some reason in the next five years, then suddenly you're drilling tight gas up in San Juan again like crazy.

A. Yes, sir.

Q. Those wells are going to follow the same rules as these wells that you're talking about today.

A. Yes, sir.

Q. You have to understand that we're trying to try and guess what the broader impact of the rule would be on not just the unconventional resources, which we definitely want to see developed to their best possible potential to reduce the waste, but we want to make sure we're preserving everybody's correlative rights. But also we want to make sure we don't do something that has unforeseen consequences five years down the road when technology or economics prices change.

A. Speculating on -- or looking forward, I think the industry would -- right now we can't come up with a reason that would cause damage within the reservoir if we go too dense on the development. What we can come up with is reasons where we spent too much money to get the resource out. So that's an economic waste on the operator at that point, not necessarily damage to the reservoir.

Q. You were here for the previous two witnesses?

A. Yes, sir.

Q. So the San Juan example, they're underpressure.

A. Yes, sir.

Q. The Permian Basin, I think all of that stuff is geopressure.

A. Yes, sir.

Q. That's the initial driver of your production.
A. Absolutely.
Q. So the maintenance of that over -- the appropriate way to drain that geopressure was pushing the oil out your matrix into those cracks, is probably going to have an impact on the long-term recoverables.
A. Yes, sir.
Q. But in San Juan, they're underpressure.
A. Yes, sir.
Q. So they have a completely different scenario. So we also have to balance these two --
A. Yes, sir.
Q. -- two types of development.
A. Yes, sir.
Q. Do you think -- so the reason why I mention that example is you're going to be pumping earlier up there in the San Juan than you would be --
A. Yes, sir.
Q. -- in the Permian Basin.
A. There are some places in the Delaware Basin where we have to go immediately to artificial lift.
Q. Okay. Immediately.
A. Yes, sir.
Q. A lot of times you're flowing for the first -- you're flowing until it's paid off, maybe even?

A. That would be an exceptional case. Yes, sir.

Q. So when you start to apply that pressure to that -- the fractures, that back pressure -- and granted, you're not going to -- nobody has a good submersible that goes all the way out to the tail of one of these two-mile-long horizontals, but you are going to be having an impact on -- to some degree, on those fractures and whether or not you have the ability -- I think right now you don't have the ability to pump those things closed, but the long-term, if you're pumping them full out, you may be closing down fractures earlier than you would want to or damaging your proppant, things like that. It could cost -- you're calling it -- I wouldn't want to call it formation damage because you basically created the reservoir --

A. Yes, sir.

Q. -- but at the same time, you're diminishing the ability of that reservoir to produce for a longer period of time --

A. Yes, sir.

Q. -- even though you created it.

A. Well, so we have -- we have observed that. And one of the things to -- to know is that we're -- there is experimentation that goes on frequently. We pump proppants a lot as an industry, and we calculate crush almost immediately. Okay? But the thing about that is even with that crush, we still have a pathway that's still infinitely more productive than the matrix. And so that still provides a good pathway for it, but it increases the economic incentive because now we've decreased our cost. So that is a common practice in the industry.

Q. Great. All right. Well, those are my questions and concerns.

CHAIRWOMAN RILEY: Mr. Brancard, do you have any?

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. I guess following up on Dr. Balch's questions, if you look at your charts on 5 --

MR. FELDEWERT: I'm sorry. Which one?

MR. BRANCARD: 5, E5.

Q. (BY MR. BRANCARD) Start on the right. Is this sort of a hypothetical industry projection, or is this based on actual results from wells?

A. Well, this would be -- well, this is a -- kind of a generic case that represents a typical investment for us. So the decline, the capital, all that that was used to assume the return of the rate or return of NPV were typical for the Delaware Basin.

And then the plot on the right, really what we're showing there is that ultimate NPV is an NPV ten, and that's typically the way that we -- that we measure present value. And it's something that I didn't highlight when I went through this, but really what we're just indicating there is the majority of the values direct very early in the life of the well. And that's why those early production rates are so important to us.

Q. But you might be -- I don't know. Would you be refracking the well at times?

A. You know, we hope not. It's very hard to -- I'm never going to say never. We always come up with some new technology that proves us wrong. But one of the things, as you kept pointing out, there is always more oil in there than we thought. So what you're seeing is operators nowadays really go push the extreme. You know, we're pushing very, very tight completions, very, very tight spacing because we want to know those answers as soon as we can so that, again, we don't come back and say, "Man, I wish I would have done this." We're trying to look back on the past -- you know, the past ten years. And every three years, we look back three years and say, "Man, we didn't know what we were doing three years ago." We're trying to apply that going forward, saying, "Hey, how do we climb the learning curve as fast as we can?" So that's why you see a lot of this aggressive spacing going on, is because we don't see negative effects from it. And what we don't want to do is look back and say, "Man, I left a lot in the ground."

Q. Do you have wells that are out 10, 15 years?

A. Not in these reservoirs. Well, you might in some of the Bone Spring-type stuff, but it would have been where it was maybe a little bit more conventional. But as far as the really unconventional stuff that's really the vast majority of the industry right now, no, sir. Fifteen years would be a very old well.

COMMISSIONER BALCH: Or 50 frac stages and 300,000 pounds of sand --

THE WITNESS: Exactly.

COMMISSIONER BALCH: -- in the Avalon 15 years ago when they were developing.

THE WITNESS: Those are the ones we're looking at, saying, "Man, okay, we're going to go restimulate that." And I've actually taken part in some of those projects and have been very successful because, again, there is a lot more in there than we ever thought.

Q. (BY MR. BRANCARD) But you haven't gotten to the

point of abandoning any of these?

A. No, sir, nothing -- nothing that was an economic success early on through the abandoned wells that weren't economic successes at times.

CHAIRWOMAN RILEY: Mr. Feldewert, do you have any more questions for this witness?

MR. FELDEWERT: I do.

REDIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Midkiff, when the committee -- you heard the testimony that when the committee was put together, their goal was to put together rules for horizontal development that would fit the majority of circumstances in which horizontal wells are being drilled, correct?

A. Yes, sir.

Q. Would you agree that the majority of the circumstances for horizontal wells being drilled are in reservoirs that are reflected in slide E3?

A. Yes, sir.

Q. Similar to the rock that we've handed to the Commission here today?

A. Yes, sir.

Q. Okay. And isn't it true that that's what these rules are designed to affect?

A. Yes, sir.

Q. And in the event, for example, that we find circumstances where horizontal wells are being drilled into reservoirs that are dependent upon a water drive or a gas cap expansion drive, you're aware of the fact -- and I think Mr. Brooks testified to this -- that you can always obtain exceptions --

A. Yes, sir.

Q. -- to the majority rule, right --

A. Yes, sir. Absolutely.

Q. -- where necessary to prevent waste?

A. Where it occurs, yes, sir.

Q. And then Dr. Balch asked you about setbacks, and you indicated to him that 330 is a good number, fair?

A. Yes, sir.

Q. And the industry thinks that's a good number?

A. Yes, sir.

Q. And he asked you about literature.

A. Uh-huh.

Q. Okay. Let me ask you something. The committee has been working on this rule for almost a year, right?

A. Yes, sir.

Q. Okay. And they promulgated a proposed rule that maintains, with the exception of the first take point and the last take point, the traditional 330-foot

setback?

A. Yes, sir.

Q. And by virtue of that fact, that was an industry-Division draft, correct?

A. Yes, sir.

Q. And if there was anyone who thought 330 feet should not be used as a setback and if that was the consensus, it would have found its way into the draft?

A. Absolutely.

Q. And in addition to that, there have been comments filed on this rule, and no one has proposed any necessary change to the 330-foot setback?

A. Not that I'm aware of.

Q. Even with all the knowledge that we have engaged with respect to this horizontal development, how far out our proppant is going and what we think the drainage radiuses are --

A. Yes, sir.

Q. -- is it your opinion that we should maintain that traditional 330-foot setback?

A. Yes, sir.

MR. FELDEWERT: That's all the questions I have.

COMMISSIONER BALCH: 100 feet -- toe and the heel.

THE WITNESS: Well, the witness coming after me will provide great testimony on why that's a good number. And I support that number just as much as I support the 330-foot number. It's just as valid. It's just as technically valid, and you'll see that shortly.

MR. FELDEWERT: Thank you, Dr. Balch. I didn't mean to exclude that.

COMMISSIONER BALCH: Thank you.

MR. FELDEWERT: I have no more questions of this witness.

CHAIRWOMAN RILEY: Okay.

It's 4:25.

MR. FELDEWERT: I have another witness that should not take any more than an hour. We can go ahead and put the Chevron witness on. I wanted to get Mr. Midkiff done so he could leave. But we can certainly put on the Chevron witness that deals with the 50-foot tolerance, if you'd like to hear that.

CHAIRWOMAN RILEY: It's an hour?

Is there anyone that conflicts with this schedule for this evening because that puts us past 5:00?

COMMISSIONER MARTIN: I'm okay.

COMMISSIONER BALCH: I'm always sensitive to Florene.

CHAIRWOMAN RILEY: Yes. It's a long day.

MS. DAVIDSON: For all of us.

MR. FELDEWERT: I will say my examination is not going to take an hour. I'm anticipating --

CHAIRWOMAN RILEY: The whole thing?

MR. FELDEWERT: I think the examination will be a half hour, if I recall.

CHAIRWOMAN RILEY: Should we run it to 5:00 and call it an evening and finish in the morning? Will that work?

MR. FELDEWERT: It's entirely up to you. We can see where we are at 5:00.

COMMISSIONER BALCH: Sure. We can always cross tomorrow.

RODERICK C. MILLIGAN,

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

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your full name, identify by whom you're employed and in what capacity?

A. Roderick Milligan, Chevron Corporation. I work as a characterize and define drilling and completions engineer.

Q. Have you had an opportunity to previously testify before the Commission or the Division?

A. No.

Q. If I turn to what's been marked as NMOGA Exhibit D, as in dog, does this first page contain a summary of your educational background and work experience?

A. Yes.

Q. And is it accurate?

A. Yes, sir.

Q. And it reflects that you joined Chevron immediately following graduation in 2011, correct?

A. Yes, sir.

Q. What has been your primary focus in the oil and gas industry since you began your career in 2011, Mr. Milligan?

A. Well, I started off as a drill-site manager working in East Texas, Oklahoma and New Mexico and also West Texas. So I pretty much, you know, ran the rigs, did the directional work for it and then execute the plan. Went into the lead and, you know, did some design work and some planning work for Chevron. This is mostly in Texas and New Mexico. And I did some horizontal wells and also some vertical wells, but the mass majority of them were horizontal wells.

Then I became a project execution engineer, where I pretty much developed a master development plan for the Hayhurst in the New Mexico area. That was pretty much Eddy County. I looked over the design work, the bit design, the casing design, the cement design; I drilled a saltwater disposal, did some vertical wells. But like I said before, the mass majority of the wells were horizontal wells.

And then I'm currently working as the characterize and define completion and drilling engineer, where I pretty much come up with full development for certain areas in Texas and also New Mexico, where I go over the entire design and how we're actually going to execute the development area.

Q. How many horizontal wells do you think you've been involved with in terms of drilling?

A. A little over 100.

Q. Including areas of New Mexico, right?

A. Yes, sir, the majority of them in New Mexico.

Q. Are you a member of any professional affiliations or associations?

A. The Society of Petroleum Engineers.

Q. How many years?

A. A little over five years.

Q. Do you consider yourself, Mr. Milligan, to have

expertise in the drilling of horizontal wells?

A. Yes, sir.

Q. Are you prepared to share that expertise with the Commission?

A. Yes, sir.

Q. What do you intend to cover with the Commission here today?

A. Well, the big portion of this -- of my testimony is going to talk about the difficulties of actually drilling a horizontal well, some of the things that you may run into and the reason why we can't necessarily stay on this straight line that we have on our plat as our actual directional plan. And we'll go over the testimonies and also we'll talk about some of the design work and some of the considerations that we take into consideration for BHA, or bottom-hole assemblies, that we put in the hole.

Q. Okay. And will you be offering an opinion on the necessity of maintaining a reasonable drilling tolerance?

A. Yes.

Q. I want to take advantage, Mr. Milligan, of your expertise and ask you a couple of questions about some of the definitions that have been proposed by the Division and the committee. So I'm looking at NMOGA

Attachment 1, and go to the drilling and production portion, 19.15.16 of the definitions of that section. It would be the first page of it in those provisions.

Have you reviewed the definitions for the first take point and the last take point?

A. Yes, sir, I have.

Q. And in your opinion, do those definitions accurately define, for example, in a manner that engineers and geologists and others work on horizontal drilling, that they will understand these terms?

A. Yes, sir.

Q. Okay. And have you reviewed the proposed definition of the multilateral well on the second page of this section?

A. Yes, sir.

Q. And do you believe that that's a definition that those engaged in the drilling of horizontal wells can understand?

A. Yes, sir.

Q. Now, I want to turn, then, to the issue of drilling dollars.

A. All right.

Q. And that is reflected on Exhibit Number 1 at page -- NMOGA Attachment 1 at page, roughly -- at page 16. Can you turn there for us, please? So it would be

third to the last page of Attachment 1. Are you familiar with the 50-foot drilling tolerance projected well with respect to the horizontal plane as reflected in these proposed rules at Subsection B(5)(c)?

A. Yes, sir.

Q. And are you aware that that exists under the current rule drilling tolerance?

A. Yes, sir.

Q. Do you support the Division's and the committee's decision to retain the 50-foot drilling tolerance for a drilling location?

A. Yes, sir.

Q. And in addition to that, are you familiar with the proposed modification to that 50-foot drilling tolerance for previously approved unorthodox well locations?

A. Yes, sir.

Q. And is that modification -- if you look at page 17, is that reflected in the last portion of Subsection B(6)?

A. Yes, sir.

Q. And do you believe that's a reasonable drilling tolerance when you have an approved location that is moving closer to the offsetting line?

A. Yes, sir.

Q. Okay. All right. Would you please then -- we're going to turn to what's been marked as NMOGA Exhibit E1, and we have it up here on the screen. Is this an actual plat of a horizontal well?

A. Yes, sir. That's one of the plats that we actually submitted.

Q. Your company submitted?

A. Yes, sir.

Q. Okay. And where is this located?

A. This is in south Eddy. You can kind of tell -- the plat gives you pretty much all the information, but this is in south Eddy of New Mexico.

Q. Okay. And this would be what people like myself would consider to be roughly, what, a two-mile well?

A. Yes, sir.

Q. Which equates to what in terms of vertical length of a wellbore?

A. Depending on where you start from your surface location, a two-mile well can be about 10,000 -- about a 10,000-foot lateral.

Q. Would you use this to explain what you address as a drilling engineer when you're trying to implement this plat and the location?

A. Yes, sir.

All right. Everybody pretty much has the slides right here, but it may be a lot easier to look on the paper. But I'll kind of point this out. Right here is our surface location. If you see here, this is our first take point. So from our surface location, you know, the drilling engineer has to come up with a plan to actually hit this first take point, and from that first take point, you have to drill about 10,000 feet to the north and hit this -- and actually penetrate here (indicating) and hit this last take point. So that's pretty much the plan. You know, stand on this line right here and not deviating at all and penetrating this first take point, hitting this last take point from this surface location.

Q. Okay. Now, if that's your goal, if I then turn to what's been marked as slide D2, does this help identify how much you take into account?

A. Yes, sir. So starting off with our surface location, we have to come up with a directional drilling method. That's what we'll pretty much cover. Like the bottom-hole assembly, we call that the BHA design and help us get to those -- hit those first take points and those last take points. We'll talk about the drill string components, the stabilizers and the motors that we use and some of the problems associated with directional drilling.

Q. Okay. Let's turn to the stabilizers and the motors that you use. Does that help, if we turn to slide 3, in that discussion?

A. Yes, sir.

Some of the methods that we actually use or some of the tools we use to get to that first take point and also to the last take point, you know, you have your rotary assemblies. You use a bent mud motor. That's considered the conventional way of drilling. And then you have rotary steerable. They consider it fairly new technology. It's actually not new, but it's used a lot more often. Currently, depending on the size of your play and depending on, you know, the thickness of your formation that you're trying to drill, you know, you consider running a rotary steerable system versus a mud motor or a conventional way of drilling.

Q. Are there disadvantages over, you know, one versus the other, advantages and disadvantages?

A. Yes, sir. With a rotary steerable system, you have a lot more control over whether your well is going to deviate. You have a lot more control as far as it goes up and down. But as far as the robustness of the rotary steerable system, it has a lot more moving parts, and due to those moving parts, you have less reliability on those rotary steerable systems than you do the bent mud motor, which has fewer moving parts to it.

Q. Is the bent motor a little more robust then?

A. Yes, sir.

Q. Less mechanical issues?

A. Yes, sir.

Q. Now, do these -- just using these tools, does that allow you to get to your location? Are there issues that arise?

A. Yes, sir. There are always issue that may arise. You know, you may hit some geological anomaly. The rock properties may change. You may hit some soft formations, some hard formations. You may even run into some natural fractures that may kind of push you away from where your actual plan is, and you start drilling in the sense to get back to the plan. So with the bent mud motor, you'll have issues. Also, with rotary steerable systems, you'll have issues in actually drilling that hole.

Q. But these are tools that are available to try to keep you on line?

A. Yes, sir.

Q. Then do you have to take into account -- for example, if you use your bent motor, how you're going to -- your build rates and things of this nature?

A. Yes, sir.

Q. If I turn to the next slide, does that help explain what you have to calculate?

A. Yes, sir. So, you know, initially everybody has a plan to stand on that line and, you know, never deviating. And by all means, if we're ever able to do that, you know, that's a really good day, right? But we know we're going to run into some issues. So in order to correct for those issues that you do run into, this is pretty much one of the ways that we use to kind of tell us our deflection rate and how fast we can get back to the actual plan.

And in this calculation, if you look at the bottom, right here is your bit. This is the length from your bit to bend on your mud motor. And this bend right here (indicating) has a certain angle associated with it. And based on that, you get your build [sic] rate on how fast it'll take you to get back to target based on that angle. And that's just one component of the entire bottom-hole assembly that helps you -- pretty much tells you how long it'll take you to get back on actual plan.

Q. And are there other calculations that you have to take into account?

A. Yes, sir.

Q. If I go to slide 5, does that explain those?

A. Yes, sir.

Q. First off, why don't you orient us on the left-hand where it's showing 1, 2, 3.

A. All right. So right here you have your number 1. That's your bit right here. And number 2 and number 3, these are your stabilizers. We're using something called like a three point geometry, which pretty much tells us, you know, what's the angle that you can build at at the rate. So you have an angle per 100 feet that you can kind of build at to get back on target.

So using these three point geometry and depending on the placing of the stabilizers, depending on that bend of the angle of that mud motor and also depending on the placing of this third stabilizer, you know, the amount of force or the amount of weight on bit that you apply to this whole assembly right here gives you resultant force. Based on that resultant force, you have an angle associated with it, and these side forces are actually being applied to these three points right here (indicating).

Q. Now, are there certain things that impact -- first off, weight on bit is WOB on this slide 5, correct?

A. Yes, sir.

Q. And are there forces that -- are there issues

that impact your calculated side force?

A. Yes, sir.

Q. Does it help to go to the next slide?

A. Yes, sir.

Q. We'll go to slide E6.

A. So some of the issues that you may run into is -- you know, in an ideal situation, you know, you don't have any of these formation effects as far as soft formations, hard formations, natural fractures and thin laminate formations, and you also don't have the effect of wear on your tools.

So as you drill, you know, your bit wears out and your stabilizers also wear out, and that creates -- that gets you to a situation where you're -- if your bit is undergauged, then your stabilizer is also undergauged.

And then you also have your measure-while-drilling tool, or your MWD tool. You can see here the bit at the bottom. I kind of highlighted in this red box your MWD tool. The MWD tool is -- you know, kind of conventionally, it's about 40 to 60 feet behind the bit. So you're pretty much getting a delayed, you know, where you're actually at in the well. So you never know where you're at at the bit. You always have to figure out where you're at at the bit later on.

Q. Let's talk about each of these individually. I want to go back to the prior slide first. You have all these calculations that you take into account, right?

A. Yes, sir.

Q. And you think you've got it all figured out?

A. Yes, sir.

Q. And then you've got your tools and you're ready to go, and then things happen?

A. Yes, sir. So if we go just to the soft formations, sometimes, you know, you have -- you have washed out -- in the soft formations, kind of a washed-out little area, and -- let me go back to the last slide.

Q. Okay.

A. If you have a washout or you run into a soft formation, you know, this stabilizer may not be contacting the walls so you may not get the soft force that you're -- that you're actually -- that you plan on. This bit -- this bit right here may not be actually biting as hard, so you may not get the force that you actually want to kind of put you back on that angle to get you back on the plane.

Another issue is hard formations. So if you run into a hard formation, they may overcorrect for what you have planned as far as the angle that you need to get back on plan. So you may overshoot your plan whenever you're trying to get back on plan, and you may have to make another correction just because of that hard formation that you hit.

The other one is natural fractures. Natural fractures are pretty much all throughout the rest of the lateral, and you really -- you really can't anticipate. You don't know what this natural fracture is going to do. It will turn you in the right direction that you plan on going in, or it can turn you in the wrong direction, but you won't figure it out until you hit that natural fracture 40 feet -- 40 to 60 feet out, where you say, "Oh, I'm off plan; I need to make a correction because I hit a natural fracture."

Q. And all of those impact your calculations that put in for the side force, right?

A. Yes, sir.

Q. If I then go to the next slide, we have thin laminated formations. What are those?

A. Thin laminated formations, we have -- we have thin formations. Sometimes you get outside of that window of that formation and you hit a hard cap similar to like a limestone or something, and it goes back into like you hitting that hard formation. It may bounce you off, and then you're out of the plan again, and you have to overcorrect just to get back on the plan from that.

The worn stabilizers, like I said before, when we go back to the contact force, if you have a worn stabilizer or if you have a worn bit and it's not contacting that formation, and then again it goes back to the fact that you're not getting the angle that you designed or planned to have to correctly get back on plan.

Q. So you have these geologic unknowns that you encounter while you're drilling?

A. Yes, sir.

Q. And then you have these mechanical issues associated with your, one, stabilizer or your bits?

A. Yes, sir.

Q. And you try to anticipate those, but those happen even with all the planning you do?

A. Yes, sir. It's a lot better if you can kind of plan it out. You know, the more times you drill this area, you consider it a development area. But still -- still, in those formations, you may run into microfractures -- not microfractures, but natural fractures, or you may run into -- a vendor may give you a worn-out stabilizer, you know, that wears out a lot earlier than you anticipate. You may have to overcorrect for that. So there are multiple variables that come into play for this.

Q. And I want to turn to, more specifically, your last topic on here, on slide 6, and that is one of your measurement devices, and you mentioned that frequently. What's the issue there?

A. Well, the issue is there is no tool that's out there in the industry right now that has a MWD tool, measured-while-drilling tool, that's located on the bit. So, you know, although we would love to know, you know, exactly what happened, you know, instantaneously, we won't figure that out until we're about 40 to 60 feet, you know, past that point. And then you take a survey and you say, "Okay. I'm off plan. I need to make a correction." So you're never proactively, you know, fighting these issues. You're always doing it reactively, right?

Q. So you have a lag time in knowing you have a problem?

A. Yes, sir.

Q. Then you try to make your correction?

A. Yes, sir.

Q. Do you then have a lag time in knowing whether your correction worked?

A. Yes, sir, after you've made your correction in about a 40-to-60-foot window that you have to, you know, take into consideration if you actually made your correction and if it worked or not. And you never want to overcorrect, also. If you overcorrect, you create these massive doglegs, these really tight bends in your lateral, and you just can't get casing down.

Q. Okay. Now, Mr. Milligan, you've been drilling horizontal wells for a number of years?

A. Yes, sir.

Q. And you've worked with colleagues who have been drilling horizontal wells for a number of years?

A. Yes, sir.

Q. And would you agree with me that companies like Chevron have some of the best technology and some of the best experts in the world to do this kind of thing?

A. I would like to think so.

Q. With all these resources and all this expertise that you have available to you, are companies like Chevron able to go right down that dashed line from the first take point to the last take point?

A. No, sir.

Q. Are there always going to be deviations as you move down these -- these wellbores -- or as you attempt to reach out to these lengths?

A. Yes, sir, especially the further you move out.

This is assuming it's 5,000 foot, with a one-mile lateral. But the further you move out to the 10,000-foot lateral, then you have issues actually upon that weight on bit because of the friction that you've accounted for throughout the well. So you may not be applying the amount of weight on bit, so you may not get the corrections you plan on getting to get back on target.

Q. Okay. And I think you mentioned to me that it was like a pencil analogy that you --

A. Oh. Yes.

Q. I thought that was pretty good.

A. I mentioned to Mike that one of my other colleagues came up with this analogy of backing out of his driveway. And he has pea gravel in his driveway, and, you know, sometimes it just doesn't get that, you know, transaction. So he was sliding out. I don't know what speed he was pulling out of the driveway, but it seemed like he was going at a pretty fast rate. He wasn't able to, like, kind of control his car.

But I use the pencil analogy, also. If you assume that you had -- let's assume that we have about 25 foot of pencil, and I slide it on this carpet. The carpet has an associated friction factor that is applied to it, right? And the more -- the more pencils you put down on this carpet, the more, you know, amount of force you have to, you know, apply just to get -- you know, just to move the pencil and then apply weight on that. So the further you go out on this lateral, you know, you have the same associated effect on this -- on that bit and kind of controlling that well as you will if you had, you know, multiple amounts of pencils, you know, stacked up together and trying to control where that pencil actually goes.

Q. So with all those things that come into play here, you have a nice slide here that demonstrates an actually as-drilled lateral?

A. Yes, sir.

Q. And that's slide D8?

A. Yes, sir.

Q. Okay. Now, would you walk us through as-drilled lateral? First off, explain what the different colors show --

A. All right.

Q. -- and then what that little dashed red box is.

A. All right. So I think it would be a lot better if you read it off the paper, but I'm going to go on this slide right here.

So what this is is one of the wells that we actually drilled. And I kind of oriented it. I rotated, you know, this picture to the right so it could fit on this slide. But, you know, this direction right here, we're heading north. And this is west to north, so this is east. So if you can kind of look -- you know, this dashed -- this dashed red line right here, that's our 50-foot window east and west. And you kind of see there is -- there is a straight blue line that's running straight through, and this is our actual plan -- directional plan.

So we had a plan to, you know, hit this target and kind of drill all the way straight down. And this is just 5,000 feet right here. You know, I kind of put this in a box to kind of show that this isn't the full 10,000-foot lateral. And if you can see right here, below on the red, this is actually what we drilled. So these are actual surveys that we've drilled. The blue is the plan. The red box is the 50-foot window, plus or minus.

So if you can kind of look right here, you know, coming out -- coming from our surface location, we had a pretty good line right here, and we hit our first take point, and we were right on the line. And as we drilled a little bit further -- I don't think it was even more than 1,000 feet -- we start deviating from the actual line. So we start making some corrections throughout the well, and we were having a hard time getting back on the target line. You can kind of see right here. It almost teetered this 50-foot line right here.

And, you know, what reason we started to deviate from the actual plan, I'm not sure of, but we did -- we started making some corrections right here (indicating). Like I said before, due to some type of lag, you know, that 40- to -- 40- to 60-foot lag right there, we finally got our surveys to start going down, and we started going back to the formation, going to the actual target line.

So right here we have a good -- good 500 feet of good drilling. We're actually on the target line. And then we hit some type of anomaly again, and we deviate from the actual plan. We get to this point right here, which is about -- about 4,000 foot in depth, and we made our correction. And we probably hit some type of hard formation, and in making our correction --

The pointer kind of died. Yeah. It said two minutes. I didn't want to tell everybody, but --

MR. FELDEWERT: Let me see.

THE WITNESS: I thought we could buy some time and kind of hurry this up, but --

Right around here at 4,000 feet, we kind of of hit some type of hard anomaly, as you can see right here, and we overcorrected for our target line. After we've seen this overcorrection, we got back on line, hit this mid-take point and drilled 2,000 feet on the line. That's just the 5,000-foot lateral. That's not showing what we did, you know, throughout the rest of the well. But we did stay within this 50-foot window.

Q. (BY MR. FELDEWERT) If I look at what's been marked as D8, Mr. Milligan, does this reflect a typical type of drilling scenario that you see when you're dealing with these horizontal wells?

A. Yes, sir.

Q. And in your opinion, is it -- is it difficult to stay within that 50-foot box?

A. I believe it's reasonable.

Q. It's doable?

A. Yes, sir.

Q. Okay. But nonetheless, you're always going to have deflections that move you away from your target?

A. Yes, sir.

Q. And I believe you have some conclusions on the last slide, which is slide D9. Can you kind of walk us through how you put this together starting on the left?

A. Yes, sir. So in an ideal situation, we have, you know, zero tool tolerance. We also have to have zero geological anomalies. We have perfect execution of deflection, so we get -- we get to where we always say we're going to get, and we have continuous location awareness at the bit.

In actual situations, you know, tools manufactured are with tolerances. Geological anomalies do occur. You do have to make operational adjustment drilling parameters to meet the undesired deflections. And then you have the location of your MWD tool, which is pretty much about 30- to 60-feet lag behind the bit.

In conclusion, I believe operators do need this 50-foot tolerance just to manage the latent hole conditions that's in the well.

Q. And, Mr. Milligan, in your opinion, do the proposed tolerances for retention of a 50-foot tolerance and then an adjustment for that tolerance when you're dealing with a nonstandard location, does that strike a reasonable balance between protecting the rights of -- tracts and avoiding constant or unnecessary filings for nonstandard locations following drilling deviations?

A. Yes, sir.

Q. Were the pages comprising NMOGA Exhibit D prepared by you or compiled under your direction and supervision?

A. Yes, sir.

MR. FELDEWERT: Madam Chair, I'd move admission into evidence of NMOGA D, which contains Mr. Milligan's resume and slides 1 through 9.

CHAIRWOMAN RILEY: Those exhibits are accepted into the record.

(NMOGA Exhibit Letter D, pages 1 through 9, is offered and admitted into evidence.)

MR. FELDEWERT: That concludes my examination of this witness.

CHAIRWOMAN RILEY: Let me take a head count of who is going to ask questions.

MS. BADA: No questions.

MS. BRADFUTE: No questions.

MR. CLOUTIER: No questions.

MR. HALL: No questions.

COMMISSIONER BALCH: Just a couple.

CHAIRWOMAN RILEY: Commissioner Martin, do you have questions?

COMMISSIONER MARTIN: I do not.

COMMISSIONER BALCH: Everyone's staring at me.

(Laughter.)

CHAIRWOMAN RILEY: You have five minutes. Just kidding.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Thank you, Mr. Milligan.

This is an area completely out of my expertise. I think it's fascinating what the oil industry does routinely, threading the needle at 10,000 feet. It makes the space program look like a bunch of kindergartners, I think.

A. Thank you, sir.

Q. So in New Mexico -- you might have heard testimony earlier. In New Mexico, we allow you to be off site to put your well or spud your well.

A. Yes, sir.

Q. Does that help at all in hitting your first take point?

A. Yes, sir. If we're actually on location, then in order for us to hit our first take point, we actually have to back build [sic] a little bit. So we have to -- say if our surface location is right here, we have to build back here and then try to hit that first take point right here or whether it's right here. But we have to do some type of back build.

Q. So you're going like this --

A. Yes, sir.

Q. -- to get to it if you're within the lease?

A. Yes, sir. Because the kickoff point -- you lose some vertical section whenever you start kicking off, depending on the rate of angle that you're going to build. So if I build at 10 degrees, I lose about 573 feet. If I build at 12 degrees, I lose about 477 feet. That's the only mental math that I can do right now.

(Laughter.)

Q. So is it easier or harder to kick off from a vertical or a slightly deviated well?

A. It's a lot easier to kick off if you're deviating a little bit and just hitting the target instead of back building and then trying to move.

Q. So it's a real advantage to be able to be off site?

A. Yes, sir.

Q. I kind of had that feeling.

So how hard is it then to hit that first take point?

A. I mean, we -- you're still close to the surface well, so you have a lot more control over, you know, whether you're going to hit that first take point or not. So you still have good transfer on your bit. As long as you don't run into any anomalies -- geologic anomalies, so you have good build rates, you should just start, you know, moving in the right direction towards those first take points. It's usually the last take point that's the hardest to hit.

Q. So much harder to hit the last take point?

A. Yes, sir.

Q. Dead-on anyway.

A. Uh-huh.

Q. You probably have pretty good control of the measured depth but not kind of where it is on the horizontal and vertical?

A. Yes, sir. So the measured depth, we have a pretty good understanding. We can control that by just adding a couple of drill parts. But, you know, going in your azimuth, whether it's east or west and up and down, that's a lot harder to control.

Q. Okay. So you've been in on a number of these wells, 100 of them, I think you said, around?

A. Yes, sir.

Q. So that's quite bit of experience.

Those directional surveys --

A. Yes, sir.

Q. -- when they shoot them, I think we're specifying in this new version of the rule -- I'm probably in the old one -- 200 feet apart --

A. Uh-huh.

Q. -- shot points. Do you know if they make an

effort to put one of those right on the first take?

A. Yes, sir. So they'll take a survey every 200 feet, but whenever you hit the first take point, they have to take another survey. The way the plats work out, whenever you try to submit your C-102s or C-104s, you have to -- you have to spell out where is your first take point and where is your last take point as far as where your MWD tool took that survey at. So it's imperative for us to take our first take point survey. It's also imperative for us to take our last survey at the last take point. If not, then you just have to project ahead on where you think you're at.

Q. So I think you said pretty clearly in answer to Mr. Feldewert's query. It's pretty reasonable to stay within a 50-foot tolerance for the entire length of however long a horizontal well you're drilling?

A. Yes, sir, for at least 10,000-foot laterals. I mean, the industry is kind of pushing to go down to like 12,000 -- 12 -- you know, two 2-and-a-half-mile laterals. I still believe 50 feet, you know, is still reasonable, but they'll just have a lot more challenges staying within that 50 feet.

Q. It's really a function of that MWD tool being 40 to 60 feet behind the drill bit. So once you notice a deviation, it takes you, looks like, 7-, 800 feet to

get back on track --

A. Yes, sir.

Q. -- to deviate that well back?

A. It depends. It could take a little bit shorter, if you're getting the right deflection, if everything is going, you know, ideally, as planned and you don't have too much of a dogleg or you don't have too much of a bend in that well. If you have too much of a bend in that well, you start running casing -- your production casing down, you won't get to where you actually planned your production casing to get. So you'll lose some of that well. You'll lose some of the production off of that well because you didn't land your casing where you planned to.

Q. Out of those 100 wells, how many would you say were within the 50-foot tolerance? How many outside of it? How many have fallen outside of that 50-foot tolerance?

A. I don't think -- I don't think I ever went outside of the 50-foot tolerance because we understand that, you know, you have a 50-foot tolerance. We'll either trip out the hole, and we're going with a different assembly before we get that close. And if we do run outside the 50-foot tolerance, then our regulatory group would, you know, call whoever is in charge to get a variance so that we can perforate and produce out of that 50 feet. If not, we don't produce out of that zone.

Q. So how often does that phone call have to be made?

A. From my experience --

Q. Your personal experience, yeah.

A. Yeah. From my personal experience, I've never made that call.

Q. Out of 100 wells?

A. Yes, sir.

Q. So the 50-foot tolerance is pretty good?

A. I would believe so, at least for the 10,000-foot laterals that we've seen.

Q. So you can usually hit that first take point pretty good. I mean, kind of on average, how far off are you on the last take?

A. On the average, depending on, you know, how fast we drill, if there are a bunch of anomalies, on average, you can probably be about 20 to 30 feet off.

Q. That's horizontal or vertical, not lateral --

A. Horizontal.

Q. Horizontal?

A. Yes, sir.

Q. Thank you. Those are my questions.

A. Yes, sir.

COMMISSIONER BALCH: Right on time.

Mr. Brancard, do you have anything?

MR. BRANCARD: (Indicating.)

CHAIRWOMAN RILEY: All right. I think we'll dismiss for the evening and be back at 9:00.

MR. FELDEWERT: Madam Chair, just so everyone knows, we have one more witness. I anticipate an hour, maybe, at the most.

CHAIRWOMAN RILEY: Okay. All right. Thank you, everyone. We'll see you here at 9:00.

(Recess, 5:01 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 13th day of May 2018.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
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