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

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

APPLICATION OF MESQUITE SWD, INC. FOR APPROVAL OF A SALTWATER DISPOSAL WELL, EDDY COUNTY, NEW MEXICO. CASE NO. 20472

APPLICATION OF MESQUITE SWD. INC. FOR APPROVAL OF A PRODUCED WATER DISPOSAL WELL, EDDY COUNTY, NEW MEXICO. CASE NOs. 20313, 20314

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

VOLUME 1

May 31, 2019

Santa Fe, New Mexico

BEFORE: WILLIAM V. JONES, CHIEF EXAMINER
MICHAEL McMILLAN, TECHNICAL EXAMINER
BILL BRANCARD, LEGAL EXAMINER

This matter came on for hearing before the New Mexico Oil Conservation Division, William V. Jones, Chief Examiner; Michael McMillan, Technical Examiner; and Bill Brancard, Legal Examiner, on Friday, May 31, 2019, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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

FOR THE APPLICANT MESQUITE SWD, INC.:

DEANA M. BENNETT, ESQ.
SUSAN BISONG, ESQ.
MODRALL, SPERLING, ROEHL, HARRIS & SISK, P.A.
500 4th Street, Northwest, Suite 1000
Albuquerque, New Mexico 87102
(505) 848-1800
deanab@modrall.com
sbisong@modrall.com

FOR INTERESTED PARTY/INTERVENOR BAKER RANCH:

JAMES ROACH, ESQ.
300 Central Avenue, Southwest, Suite 1600W
Albuquerque, New Mexico 87102
(505) 243-4419

FOR PROTESTANT NEW MEXICO OIL CONSERVATION DIVISION:

DAVID K. BROOKS, ESQ.
ENERGY, MINERALS & NATURAL RESOURCES DEPARTMENT
OFFICE OF GENERAL COUNSEL
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
(505) 476-3415
david.brooks@state.nm.us

FOR INTERESTED PARTY BLACKBUCK RESOURCES:

ERNEST L. PADILLA, ESQ.
PADILLA LAW FIRM, P.A.
1512 South St. Francis Drive
Post Office Box 2523
Santa Fe, New Mexico 87504
(505) 988-7577
padillalaw@qwestoffice.net

FOR INTERESTED PARTIES SOLARIS WATER MIDSTREAM AND KAISER-FRANCIS OIL COMPANY:

JAMES G. BRUCE, ESQ.
Post Office Box 1056
Santa Fe, New Mexico 87504
(505) 982-2043
jamesbruc@aol.com

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EXHIBITS OFFERED AND ADMITTED

NOTE: Exhibits will be attached to the record upon completion of the hearing. There are no exhibits accompanying this volume at this time.

(8:29 a.m.)

EXAMINER JONES: Let's go on the record. We're back on the record. This is a continuation of the May 30th hearing. This is obviously May 31st, on a Friday. We've got what I believe are two matters to discuss today, five total cases.

First we would like to have a discussion about the -- whether to have all the matters heard together or have two separate -- two separate, complete hearings here.

So for Mesquite, Ms. Bennett, do you have a preference?

MS. BENNETT: Yes, I do. Good morning. Thanks for having us here today.

My preference would be to have two separate proceedings, and that is because the Mesquite issues are separate -- while they're similar issues, the Mesquite cases are separate from the Blackbuck and Solaris cases, and I think it would make a cleaner record for the Division if the cases were heard separately. Also, it will be easier to have a transcript of the proceedings. So I feel like overall that would be a more efficient process going forward for both the parties and the Division. And I'm also unclear how that would work in terms -- just logistically in terms of cross-examination and direct examination in terms of managing all of the parties that will be present and able to ask questions.

And then personally, I represent Mesquite and NGL in the protests of the Solaris Predator and the Mesquite -- I'm sorry -- and the Blackbuck Olive Branch. And so just for my own sanity, I would prefer to not have to switch roles midstream but keep the cases separate.

Thank you.

EXAMINER JONES: And for the record --

MS. BENNETT: I'm sorry. For the record, my name is Deana Bennett. I'm here on behalf of Mesquite SWD and NGL Water Solutions, and I'm at Modrall Sperling.

EXAMINER BRANCARD: Okay. So would you -- would you have a preference for the Mesquite cases to be separate hearings or combined into one.

MS. BENNETT: The Mesquite cases we would prefer to be combined into one, and we would ask that those cases be heard first, as this special docket was specially set for those three cases and not the other two cases. And we would ask that those case be heard first.

MR. BROOKS: Mr. Examiner -- Mr. Examiners, David Brooks for the Oil Conservation Division.

I disagree. The Division, I'm aware, has a very busy docket today, and anything that will shorten the proceedings, I would think, would be -- would help everybody. But specifically from the point of view of the Division, we intend to present essentially the same testimony in all five cases, and we see no reason why we would have to go through the repetition of going through it twice.

Thank you.

EXAMINER JONES: Mr. Bruce.

MR. BRUCE: Mr. Examiner, I mean, I think the Division could go through its testimony once and have it incorporated. I -- I think there are different issues between the Blackbuck, Solaris and the Mesquite, or at least it would be similar to have them heard in two groups rather than one.

EXAMINER JONES: Mr. Padilla.

MR. PADILLA: I don't really have a preference one way or the other whether you combine them all or not.

The fact of the matter is the Division is in all of these cases, so from that standpoint, it seems to me that there would be some unity in terms of the Division's case. And we did not enter appearances in the Mesquite cases, but if they're consolidated, I wouldn't want to have to go through repetition of my cross-examination in every case. And I think that I would try to inquire universally in all five cases why the Division has entered appearances in these particular cases in policy decisions that have been made by -- internally by the Oil Conservation Division and I think it's all the same. So from that standpoint, I think they should be consolidated.

But I think each individual party here, as far as NGL or Mesquite, they are separate. So in the interest of moving this along, I think they should be sort of separated but allow us to cross-examine on the Mesquite cases or the Solaris case, which we did enter an appearance on, and we're only entering an appearance in that case. But I think as the testimony develops, I may have more questions from a standpoint of cross-examination.

EXAMINER BRANCARD: Mr. Padilla, you're representing.

MR. PADILLA: I'm representing Blackbuck Resources.

EXAMINER JONES: Mr. Bruce, who are you representing?

MR. BRUCE: Solaris.

EXAMINER JONES: And, Mr. Brooks, you are representing the Division?

MR. BROOKS: Yes, sir.

EXAMINER JONES: Are there any other appearances, attorneys that are representing clients here today in these cases?

MS. BENNETT: Mr. Examiners, with me today is Mr. Jim Roach, and he's here -- he's an attorney in Albuquerque. He's not here to ask any questions or to present any evidence, but he represents the Baker Ranch. And the Baker Ranch is in support of Mesquite's application, and he and I have discussed the possibility of him making a statement on the record in support of Mesquite's applications -- the Mesquite-Baker applications. So while he won't be asking any questions or presenting any witnesses, he is here with his clients on behalf -- in support of Mesquite.

EXAMINER BRANCARD: But they didn't file a prehearing statement.

MS. BENNETT: He did file a prehearing statement and an entry of appearance and a notice of intervention out of -- for belt and suspenders.

EXAMINER BRANCARD: Okay.

MS. BENNETT: And I would also note that Mr. Bruce has entered an appearance in one of our Mesquite cases on behalf of Kaiser-Francis, and those issues have been resolved to my understanding, so I don't know that that's an issue today. But I would just point out that there was an entry of appearance -- or a question by Kaiser-Francis in one of the Mesquite cases, and that has been resolved.

Sorry. This is Susan Bisong. She's with me, at Modrall Sperling, today, and she's going to be assisting me on SWD cases going forward. She's a partner at Modrall Sperling here on behalf of Mesquite SWD.

MS. BISONG: Good morning.

EXAMINER BRANCARD: Good morning.

Well, I think the point made by counsel here of Mesquite about confusing the record is an important one. So if not all the parties are agreeable to combining all five cases, I don't think that's probably a good idea to do that. But it seems like we have an agreement to combine into two groups here the Blackbuck-Solaris case and then the three Mesquite cases.

From the perspective of the other parties, is there any position about which of those two groups should go together first?

Mr. Padilla?

MR. PADILLA: I don't have any preferences.

It's up to the Division what you want to consider first. I don't have my preference of Ms. Bennett going first.

EXAMINER BRANCARD: Mr. Bruce?

MR. BRUCE: I always like to go first.

(Laughter.)

MR. BROOKS: Mr. Examiner, in view of your ruling, we would request that -- we would make an alternative request that the Division be allowed, as suggested by Mr. Padilla, to incorporate by reference the testimony of our witness, since it will be the same in all cases, direct testimony, rather than having to get up here and repeat all the questions and repeat all the answers.

MS. BENNETT: Mr. Examiner, that's actually, I think, an efficient approach to this, is allowing each case to go forward on its own direct of our witnesses, because that's what I was concerned about, was the logistics of would each party put on their first witness and then have cross-examination of that first witness, so we'd first three witnesses for each party, and then we'd have three second witnesses of three geologists.

So just logistically I thought that the direct of the parties would be confusing if we combined the cases, but I'm not opposed to the Division's direct being consolidated and the cross of the Division's witness being consolidated, because I think that can then be easily excerpted from the transcripts and put into the appropriate cases and is an efficient way to go about the proceedings. But I was more concerned about our individual direct examination getting confusing and logistically untenable.

And in terms of the order, I guess as I mentioned at the outset, this special hearing date was set by Mr. Warnell for the Mesquite cases -- specifically for the Mesquite cases. The Mesquite cases have been continued at the Division's request two times and then unilaterally by the Division one time. So we are here today at the Division's behest, and so for that reason, I ask that the Mesquite cases be heard first, which has been the plan and it is, I think, the only real alternative given the way that the Mesquite cases have been continued unilaterally by the Division and the fact that Mr. Warnell specifically set this date for the Mesquite cases and not the other cases.

MR. BROOKS: I have nothing further.

EXAMINER JONES: Okay. I neglected to introduce myself. I'm William V. Jones. Bill Brancard, Chief Counsel for the entire Energy, Minerals Department, has graciously agreed to appear as a legal examiner today. And also we have Michael McMillan. He's another co-examiner. He's a geologist. So I wanted to get that on the record first.

And since we've got a different court reporter from yesterday, this would be obviously another prehearing transcript that would be included in all five of the cases which we are getting ready to call at least the first group of.

MR. BROOKS: Excuse me, Honorable Examiners. May I have a ruling on my request to present our case only once?

EXAMINER BRANCARD: Mr. Examiner, my recommendation would be that we proceed with the first group of cases, whichever one you want to do first, and then the Division would be part of that case. And at that point, I think, once the Division's testimony is complete in cross-examination, then I think it would up to decide when the parties are agreeable to allow that then. Without the testimony itself, I think it's a little hard to make a decision about whether to incorporate that into the next case or not. So I think in the absence of actual testimony, we have to wait.

EXAMINER JONES: Okay. We're going proceed with the Mesquite cases first. The Mesquite cases, as I understand it, are cases 20472, 20313, 20314, application of Mesquite SWD, Incorporated for approval of a saltwater disposal well. Two of the cases are styled "approval of produced water disposal well."

Call for appearances in all three cases for the Applicant.

MS. BENNETT: Yes. Good morning. Deana Bennett and Susan Bisong from Modrall Sperling for the Applicant, Mesquite SWD.

MR. BRUCE: Mr. Examiner, I'm entering an appearance for Kaiser-Francis Oil Company. I can't remember which specific case, but since they're all being heard, it doesn't matter. And no witnesses, just entering an appearance.

And since the Division will be testifying, I'm also entering an appearance for Solaris Water Midstream simply because I'm going to need probably to do some cross-examination.

MR. BROOKS: I cannot hear you, Mr. Bruce. Would you repeat your last sentence?

MR. BRUCE: That I'm appearing for Solaris in these cases even though I didn't prior previously enter an appearance because obviously this might be the only chance I get to cross-examine the Division's witnesses.

MR. BROOKS: Thank you.

I have no objections to that.

EXAMINER JONES: Mr. Bruce, would you mind coming up closer, if you have a chance?

Maybe we can make some room for Mr. Bruce.

Any other appearances in these three cases.

MR. ROACH: James Roach, in Case Number 20472, for Jesse Baker and the Baker Ranch.

EXAMINER JONES: Okay. Mr. Roach, which law firm are you from?

MR. ROACH: James Roach, Attorney at Law.

EXAMINER JONES: Okay. Thank you.

Will the witnesses for the Applicant --

EXAMINER BRANCARD: Mr. Padilla.

MR. PADILLA: We haven't previously entered an appearance in the Mesquite cases, but necessarily we have to enter an appearance now, as Mr. Bruce has done, simply because if the Division's going to present testimony and we only have one chance for cross-examination, then procedurally I should be allowed to cross-examine.

EXAMINER JONES: Any objections to this, to Mr. Padilla entering an appearance and questioning witnesses?

MS. BENNETT: None from me.

MR. BROOKS: None from the Division.

EXAMINER JONES: Okay.

MS. BENNETT: Thank you.

We have four witnesses with us here today on behalf of Mesquite.

EXAMINER JONES: On behalf of Mesquite, will the witnesses please stand and the court reporter swear the witnesses?

(Mr. Neatherlin, Dr. Zeigler, Mr. Reynolds and Mr. Wilson sworn.)

MS. BENNETT: At this time I'll call my first witness, Mr. Riley Neatherlin.

I also wanted to let the examiners know that with me today is Mr. Clay Wilson. He is the owner of Mesquite SWD, and he's here also here on Mesquite SWD, although he won't be testifying today.

EXAMINER JONES: I did spot Mr. Wilson in the audience.

RILEY NEATHERLIN,

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

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Mr. Neatherlin, will you please state your name for the record?

A. Riley Neatherlin.

Q. And for whom do you work?

A. Mesquite SWD.

Q. And in what capacity?

A. I'm the operations manager, chief operations officer. I do a little bit of everything.

Q. How long have you worked for Mesquite?

A. It's been around nine, ten years now.

Q. And what are your -- excuse me -- what are your responsibilities at Mesquite?

A. Helping oversee drilling operations, day-to-day operations, planning, permitting, anything of the sort.

Q. And are you familiar with the three applications, the two Laguna Salada applications and the one Baker application that are the subject of this hearing?

A. Yes, I am.

MS. BENNETT: I just realized I had intended to make an opening statement. Can I quickly make an opening statement, and then the others can make an opening statement if they'd like to?

EXAMINER JONES: Yes.

First of all, are these witnesses exactly the ones that you put in your prehearing statement?

MS. BENNETT: They are, yes. Yes, they are.

EXAMINER JONES: Okay.

MR. BROOKS: The Division has no objection to Ms. Bennett making an out-of-order opening statement.

MS. BENNETT: Yes. Yeah. I apologize. I had it right there in front of me, but I got so excited about calling Riley that I forgot to do it.

(Laughter.)

MS. BENNETT: So any objections from anybody else? No?

OPENING STATEMENT

MS. BENNETT: Okay. I think it's pretty obvious that this case and others -- these three cases, the Mesquite cases, and the other two cases that we're here for today have garnered a lot of attention both from the Division and from other SWD operators and other operators generally.

And the reason we're here today is because the five -- or the three applicants are here today because the Division has -- specifically with Mesquite, the Division denied two of Mesquite's applications, the Laguna Salada applications, which were submitted administratively. And the Division never actually denied the third application, the Baker application, but it was Mesquite's understanding that the Division intended to deny that application. And those were done based solely on the Division's 1.5-mile spacing requirement.

The important thing here is that there are no other SWD operators that are actually protesting Mesquite's application, not even SWD operators that may be within the 1.5-mile spacing. There are no oil and gas operators that are protesting Mesquite's applications. These wells are proposed on fee land, and the surface owners are supporting these wells. So the only party that's here today to protest these wells is the OCD.

And the OCD protest is based -- or sorry -- denial and protest today is based only on the 1.5-mile spacing requirement, and the 1.5-mile spacing requirement has no basis in the rules. It's not promulgated. Yesterday we heard Mr. Brooks say it's not a policy because it hasn't even gone through formal requirements for policy making, but yet this 1.5-mile spacing requirement is being applied mechanically as a per se rule.

There was no evidence in the denial that demonstrated any reason to deny Mesquite's application. There was no technical data, no studies. All that was included in the denial is a map that shows mechanically the proximity, which is going to be before you today, of the wells. That can't be the way a regulatory body works.

Last night as I was thinking through this, there is sort of a regulatory compact between regulated entities and a regulatory body, and that regulatory compact is an agreement where the regulated entity says, We agree to comply with your regulations, and the regulator says, We agree to let you know what they are, and we agree to apply them evenly and fair-handedly after notice. None of that happened here.

Mr. Brooks' email to me in another case I think sums this up. He sent me an email in one of the NGL cases, and his email reads and I quote and this will be in the evidence today, "Since the 1.5-mile distance is not a rule provision, it does not control, unless its propriety is shown in a specific case." He goes on to say, "The Division has power to issue rules or orders to regulate disposal of water to protect the environment. If either party were to demonstrate by technical evidence that both wells now proposed cannot be operated consistently with environmental protection, the Division should enter an appropriate order. Given that OCD has not" -- and here I'm quoting Mr. Brooks again -- "demonstrated by technical evidence that these wells as proposed cannot be operated consistently with environmental protection" -- and that's the end of my quote -- the Division's protest should be denied.

So before the hearing even begins, before we even get through all this testimony that I know everyone's spent a lot of time working on, I'd like to make an oral motion to dismiss OCD's protest. It lacks any basis in fact or law and should be dismissed, and it's inconsistent with OCD's own counsel's determination about the applicability of the 1.5-mile spacing requirement.

So I'd ask that this protest and the other protests be dismissed.

EXAMINER JONES: Do you have the denials as an exhibit?

MS. BENNETT: Yes, I do. Uh-huh. And I'm happy to point the examiner to those denials right now so that you can see. What the denials say is: The Division has sought to maintain a 1.5-mile spacing location spacing requirement. This is to protect against induced seismicity and protect correlative rights and minimize impact from pressure.

I'm paraphrasing here. It says that if Mesquite protests and if Mesquite files an application, the Division will protest -- which is exactly what's happened here -- and the Division will present evidence in support at that time.

We still -- today is the first time that we have gotten any evidence supporting the Division's denial of Mesquite's applications. It's completely -- it just doesn't feel appropriate to deny Mesquite's application, saying: There is a 1.5-mile spacing requirement that you never knew about. And guess what? We're not going to tell you about it now. We're going to give you a map that doesn't have a legend, doesn't have a key. We're not going to tell you when we came up with this rule, how we came up with it, and we're not going to let you protest it, because if you do, we're going to be there to contest you, and that's when we're going to present the evidence, that's when we're going to present the technical data.

That seems to me to violate the very heart of what this regulatory body is here for.

Mesquite isn't here to say that the Division lacks authority over the UIC Program. In fact, Mesquite has been complying with the 1.5-mile rule or requirement ever since it became aware of it. So this is not about Mesquite throwing sand in the Division's face. It's not about Mesquite calling into question the UIC Program. What it's about is complying with that regulatory compact and giving the regulated entities notice of what the Division intends to do so that they can comply with it. That's what they want to do. That's why they're here. They want to comply with the Division's regulations, but unless they know what they are, they can't do it.

And so that's why I think this protest should be dismissed and the applications be returned to the administrative application process and be approved promptly.

EXAMINER BRANCARD: I just have a question. I'm confused on where we are procedurally.

Mesquite applied administratively in these two cases.

MS. BENNETT: They did. And that was in -- Mesquite applied for all three of these cases administratively. The Salada was in July. And as I'll remind the examiner, it was on July 25th which is my birthday. And then they applied for the Baker in September. The Laguna Salada applications were denied administratively in December, December 13th, 2018. The denial said that the option available to Mesquite was to apply for an examiner hearing, and Mesquite did file applications shortly thereafter in January for examiner hearings. So these applications for examiner hearing have been pending since early January. That's the procedural process of how we got here.

EXAMINER BRANCARD: So you had a denial.

MS. BENNETT: Uh-huh.

EXAMINER BRANCARD: And that was when?

MS. BENNETT: For the Laguna Salada wells, that was July 25th, 2018.

EXAMINER BRANCARD: And then you applied for a hearing when?

MS. BENNETT: January. The denial came in December, and we applied for the hearing.

EXAMINER BRANCARD: Oh, the denial came in December.

MS. BENNETT: Yes. And we applied for the hearing in December -- I'm sorry. We filed applications for an examiner hearing in January.

EXAMINER BRANCARD: So are we here on an appeal of the denial?

MS. BENNETT: That's a good question. I wasn't sure how that works. I mean, in my view this is de novo, but at the same time, the denial needed to be supported by -- under Mr. Brooks' own email, needed to be supported by technical data to support a finding that the two wells could not be operated consistent with environmental protection, and that was never done. So in my view, any evidence that the Division intends to present today is a post hoc justification for the December denial, and we can't cure the December denial. That can't be the way it works.

If the Division wanted us to go to hearing -- wanted Mesquite to go to hearing, then that is obviously completely within the Division's authority, but at that point, it should be a hearing between Mesquite and, say -- Kaiser-Francis isn't protesting here, but let's just say they continued their protest. It would be a hearing between Mesquite and Kaiser-Francis where the two parties would be presenting their competing information, and the Division would be in the adjudicatory, fact-finding body role that it should be as opposed to the advocacy role that it's in now. So that's a long-winded answer to say, Heck if I know.

I don't know if we're here on the appeal of the de novo -- I'm sorry -- on appeal of the denial. I didn't see the process for an appeal of the denial in the regulations, which is why we chose to go this route.

EXAMINER JONES: You kept talking about denials, and you're going to present those as an exhibit; is that correct?

MS. BENNETT: That's right, except for the Baker well, which was never denied.

EXAMINER JONES: Okay. Okay. So the Baker well, what do you have on it?

MS. BENNETT: Nothing.

EXAMINER JONES: Just hasn't been acted on?

MS. BENNETT: It hasn't been acted on.

And so we affirmative- -- knowing that the issues were likely the same given its proximity to another Mesquite well, the Paduca 6, we affirmatively filed an application for hearing. And, in fact, in the Division's prehearing statement, our predictions were accurate because the Division's prehearing statement in Baker says that the Division has sought to maintain a 1.5-mile spacing distance. So the issues -- even though Baker was just not acted upon, the issues there were going to and have now raised their head.

EXAMINER JONES: On the Laguna Salada wells, were they -- did it say "denied" in this document that you're going to present --

MS. BENNETT: Yes, it did.

EXAMINER JONES: -- or did it say "cannot be approved administratively"?

MS. BENNETT: I believe it says denied. I'll double-check right now, but I'm almost 100 percent positive it says denied.

EXAMINER JONES: What exhibit?

MS. BENNETT: That's Exhibit D -- D1. It's behind Tab Number 1, and it's Exhibit D1 behind Tab Number 1. And I have that right here in front of me. It says, "Mr. Wilson, the application submitted on behalf of Mesquite SWD for approval of the Laguna Salada 13 and the Laguna Salada 19 are being denied." Then later it says, "However, should the Applicant seek approval of these applications through hearing, the Division will appear and oppose the approval of these applications based on the reasons previously provided, supported by the evidence and testimony offered in similar cases before the Division and the Commission."

And Mr. Brooks' email to me in the other matters is behind Tab E.

EXAMINER JONES: Okay. So the argument for the Laguna Salada is not exactly the same argument for the Baker, that this would be done de novo?

MS. BENNETT: Right.

EXAMINER JONES: Baker could be done today. Is that your statement?

MS. BENNETT: Oh, no. All three cases can be heard today if the Division denies my motion to dismiss. But that's what I'm asking for, is a motion to dismiss all three protests based on the grounds that the Division's 1.5-mile spacing unit -- or spacing distance is not a rule, cannot be applied mechanically and is not supported by any technical evidence or data.

EXAMINER JONES: Mr. Bruce, do you have an opinion on this?

MR. BRUCE: No.

(Laughter.)

EXAMINER JONES: And everybody agreed that Mr. Padilla could talk.

So, Mr. Padilla?

MR. PADILLA: We support the motion before the Division as far as the 1.5-mile finding rule is concerned. We just don't see any reason for applying a rule that's not supported by technical data or by appropriate rulemaking.

EXAMINER JONES: Mr. Brooks?

MR. BROOKS: Well, I think the motion to dismiss is not well-taken unless we -- it is very -- it is not well-taken on the grounds which are stated because how can you deny a motion on the grounds that there is no technical data to support the objection until we've been allowed to present our case? I think it's at least premature in that regards.

Otherwise, I would note that if they're confused about the subsequent rules, we're also confused about the procedural rules, because I have been an attorney for the Division for 18 years, and for 17 of those years, everyone, I think, assumed that if a permit was denied, it would go to hearing. If a permit -- if administrative approval was denied or not granted, it went to hearing, and the hearing was the hearing. It was the only -- it was not a de novo hearing. It was the only hearing. Because it was assumed, although admittedly there is nothing in the rule that says that, it was assumed that the director made these decisions about permits.

And a hearing by an examiner is a hearing by a deputy appointed by the director to hear evidence and make a recommendation to the director as to how to proceed. And it was assumed that if the director was unwilling to grant an application that had been granted, the director could reconsider after evidence was presented at a hearing. Whether you call that an appeal or simply an ongoing part of the permitting proceeding, I don't know.

But then the Commission announced a new rule in the Alpha versus Delaware case, which, in my opinion, was unsupported by any precedent, to the effect that administratively -- denials of administrative applications that had not gone to hearing could be reviewed by the Commission and should be appealed to the

Commission and were not otherwise reviewable. Now, how those two things parallel, I do not know, because the Commission has plowed new territory. And I think if I had Mr. Carr and Mr. Callahan [sic] and several others who have practiced their entire career before the OCD, they would at least verify my statement that everybody assumed the contrary before Alpha versus Delaware.

Now, if I'm called upon to testify, then I'm going to have to be disqualified as counsel for the Division because my credibility is put in issue.

Thank you.

EXAMINER BRANCARD: I mean, my suggestion to the hearing examiners is that we go forward with the hearing. There are, as Mr. Brooks has pointed out, significant procedural issues related to these permit proceedings in which we do them by notice and opportunity for hearing, which is not something that is laid out very specifically in the Oil and Gas Act. So if this issue does go up to the Commission, the Commission can try to deal with the procedural matters better than, say, the hearing examiners here. So we're going to get -- get to the issues here substantively in one of these hearings or the other, so my suggestion is to go forward with this hearing.

EXAMINER JONES: Okay. It does seem that

the Baker application was a bit -- the way it arrived was a bit different than the Laguna Saladas. But the motion to dismiss will be acted on after we hear all the evidence.

And prehearing statements -- our prehearing --

Mr. Bruce?

MR. BRUCE: I don't have anything to say.

EXAMINER JONES: Mr. Padilla?

MR. PADILLA: I don't have anything.

EXAMINER JONES: Mr. Brooks.

MR. BROOKS: Well, I've only addressed the motion to dismiss at this point, so I would reserve the right to do a prehearing statement before the testimony -- before the start of my case-in-chief, but I probably will not do one because -- unless there is a need created by the way the case is presented, I see no reason to.

EXAMINER JONES: Okay.

MS. BENNETT: Thank you.

And, Mr. Roach, did you have something you wanted to say or --

EXAMINER JONES: Yes. I'm sorry.

MR. ROACH: We support Mesquite's position on behalf of Baker Ranch. Mr. and Mrs. Baker are also here. We have dealt with Mesquite over a period of time. They have done very well. They're very friendly and cooperative with the landowner, with the -- and very eco-friendly to them, and we completely support their position as presented by counsel for Mesquite.

Thank you.

EXAMINER JONES: Thank you.

Ms. Bennett, please proceed with your -- Mr. Neatherlin.

MS. BENNETT: Thank you. I appreciate the ability to get that all on the record.

Thank you.

CONTINUED DIRECT EXAMINATION

BY MS. BENNETT:

Q. So, Mr. Neatherlin, thank you for your patience while we went through that.

So we were going through some of your background, and I was about to ask you if you were familiar with the three applications that were filed for this hearing.

A. Yes, I am.

Q. And does your area of responsibility include the areas of New Mexico that are the subject of these applications?

A. Yes.

Q. Have you testified before the Division before?
A. Yes, I have.
Q. And how about before the Commission?
A. Yes.
Q. And your credentials as an expert in drilling, completion, permitting and casing design matters for saltwater disposal wells were accepted as a matter of record; is that right?
A. Yes, they were.
MS. BENNETT: At this time I tender Mr. Neatherlin as an expert in permitting, casing design, drilling, completion and operation matters for SWDs.
EXAMINER JONES: Any objections?
MR. PADILLA: No.
EXAMINER JONES: He is so qualified.
MS. BENNETT: Thank you.
Q. (BY MS. BENNETT) Mr. Neatherlin, what does Mesquite want from this hearing?
A. We'd like our permits to be approved as soon as possible.
Q. That's a pretty succinct answer. Thank you (laughter).
But I guess what I was wanting for you to address is some of the frustrations that Mesquite has

felt over the past six to nine months in terms of the rule that you thought was in effect when you applied versus the denial email that you got and the implications for Mesquite as a company.

A. Well, I guess what we're seeking is just clarification, notification process of regulation. There's never been any official notice of spacing. The only thing that we've seen has been the area of review moved to a mile and -- yeah, a mile, and that's the only thing that we've really seen that's changed in the application process for the C-108. And we're just seeking clarification.

Q. And so it was your understanding, though, when you applied -- well, what was your understanding when you applied for the Laguna Salada well and the Baker well? What was your understanding of the spacing requirements at that time?

A. That it was a mile spacing.

Q. And so at that time, you hadn't had any indication or any knowledge of a change to a 1.5-mile spacing?

A. No. No, we had not.

Q. A moment ago I said that Mesquite is complying with the 1.5-mile requirement at this point. Is that accurate?

A. That is correct. Yes.

Q. And why are you doing that?

A. Because of these denials, because we're trying not to slow down the process so that we can keep moving to stay up with industry.

Q. And why can't you just move the Laguna Salada wells and the Baker well?

A. Because of the one-and-a-half-mile spacing. If we move them anywhere -- there is no room to move them now. We're boxed in from other operators on all sides.

Q. So when you applied for the three wells, you weren't boxed in, under your understanding of the rule at that time; is that right?

A. No. They're spaced a little over a mile of each other.

Q. If you wouldn't mind --

MS. BENNETT: And I've given all the examiners and the witnesses a packet.

Q. (BY MS. BENNETT) If you wouldn't mind just turning to Tab 1 and looking at Exhibit A behind Tab 1, can you explain to the examiners what that is?

A. This is our application for the Laguna Salada 13.

Q. And what is Exhibit B?

A. B is the application for the Laguna Salada 19

No. 1.

Q. And what is Exhibit C?

A. C is the application for the Baker SWD No. 1.

Q. And those three applications contain the application that I filed on Mesquite's behalf, along with the C--108s that were previously filed as administrative applications but that I refiled for this hearing. Is that how you see them?

A. Yes. Correct.

Q. Okay. Have you assisted with preparing other administrative applications for Mesquite?

A. Yes, I have.

Q. And about how many administrative applications have you prepared for Mesquite?

A. About a dozen or so.

Q. And has Mesquite had administrative applications approved?

A. Yes.

Q. About how many?

A. 15.

Q. So a moment ago, we talked about your understanding of the spacing requirement at the time you submitted these three applications, and your testimony was that you thought -- your understanding was that it was a one-mile spacing requirement?

A. Correct.

Q. Where did the one-mile spacing requirement come from?

A. I don't know.

Q. Is that in any of the rules?

A. Not that I'm aware of.

Q. It is on the C-108?

A. No.

Q. Were you involved in the SWD working group?

A. Yes.

Q. As part of that SWD working group, was there a discussion about spacing?

A. There was.

Q. And did the SWD working group discuss the one-mile spacing requirement that you can recall?

A. We discussed the one-mile area of review but nothing on a spacing basis for a notification of a one-mile buffer around each wellbore.

Q. Uh-huh. So in other words, the spacing requirement that you thought was in effect at the time wasn't even a formal spacing requirement?

A. Correct.

Q. You had no notice of that?

A. Yes, no notice.

Q. So the area of review that you mentioned a

moment ago, do you know if the area of review is codified or sort of described in the C-108s?

A. I don't think the one mile is. I believe it's a half mile that's required in the C-108.

Q. Yeah. If you look at your -- let's look at the first exhibit, Exhibit A, the Laguna Salada 13 application. And if you look back a few pages, the C-108 starts a couple pages into the exhibit. And if you look at Roman numeral V -- do you see that Roman numeral V? It says it starts "with attached map that identifies."

A. Yes.

Q. And after you read that, can you tell me what the area of review is?

A. It's a half-mile radius.

Q. And it is your understanding that that half-mile radius is also in the regulations?

A. Yes, it is.

Q. Did you comply -- so you don't -- you said a minute ago that you think the one-mile -- expansion of the one-mile area of review may have come from the SWD working group?

A. Yes.

Q. Did you comply with the one-mile policy for providing notice and identifying wells in your Laguna

Salada and Baker applications?

A. We did.

Q. Earlier today I said that you submitted the Laguna Salada applications for administrative approval on July 25th, 2018. Does that sound about right to you?

A. Yes, it does.

Q. And then you submitted the Baker application around September 27th, 2018. Does that sound familiar to you?

A. Yes.

Q. What is your understanding of the timeline for administrative approval?

A. It's a 15-day protest period and then as long as you have a complete application, that the C-108 can be approved administratively.

Q. Let's talk about the Laguna Salada 13. Do you know if anyone -- any other SWD operator protested that application?

A. Not on the 13, no.

Q. How about on the Laguna Salada 19? Did any other SWD operator protest that application?

A. No.

Q. How about on the Baker? Did any other SWD operator protest that application?

A. No.

Q. For those three wells, has any oil and gas operator protested those applications?

A. No, not that I'm aware of.

Q. And so there were no protests filed by email during the 15-day protest period?

A. No.

Q. Before these applications were denied, did you ever receive any communication from OCD that the applications were incomplete?

A. No.

Q. Did you ever receive any applications -- any communications from OCD asking for any more information?

A. No.

Q. So for the Laguna Salada, you received no communication from OCD that you recall asking for more information?

A. No, we did not.

Q. For the Laguna Salada 19, did you receive any communication from the OCD?

A. No.

Q. For the Baker well?

A. No.

Q. So what do you -- what's your takeaway from that? There were no protests during the 15-day period, and you received no communications from OCD that your

application was not administratively complete. What would you have anticipated the next step would be?

A. Approval of our permits.

Q. And they could have been -- the Laguna Salada permits could have been approved as early as August, right, at least mid-August, mid to late August in the protest period?

A. Yes.

Q. Did you hear from OCD in August about the Laguna Salada applications?

A. No, we did not.

Q. September?

A. No.

Q. October?

A. No.

Q. November?

A. No.

Q. So the first time you heard from OCD about the Laguna Salada applications was the denial you received on December 13th?

A. That's correct.

Q. The Baker application we discussed a moment ago was submitted around the end of September 2018. So based on your understanding -- and I understand, of course, that there are some delays in approving these

administrative applications. But in your opinion, when could it first have been approved?

A. Technically, it could have been approved in October.

Q. And how about -- did you hear anything from OCD about the Baker application in October?

A. No.

Q. November?

A. No.

Q. December?

A. No.

Q. January?

A. No.

Q. At all?

A. No. We still have not heard anything from them.

Q. So your Baker application was pending before OCD with no information to you at all?

A. Correct.

Q. During the same time period, you were receiving communications from OCD about other wells; is that right?

A. Yes.

Q. For example, you had some requests in for increased tubing size, as I recall?

A. Yes. We had some increased tubing sizes and some other wells we were permitting.

Q. Did OCD tell you about the change to the 1.5-mile spacing requirement in any of those communications?

A. No.

Q. So, again, the first time you heard about the 1.5-mile spacing requirement was in the denial you received on December 13th?

A. That's correct.

Q. Nearly six months after you filed your applications?

A. Yes.

Q. And what did you receive from OCD?

A. Just the denial of the two Laguna wells, stating that the -- the one-and-a-half-mile radius --

Q. Applied?

A. -- applied on there.

Q. Is that denial what we were looking at behind Tab D1?

A. Yes, it is.

Q. And if you could -- let's take a minute and just kind of review that denial email. What's your understanding of what that email means?

A. It says that the Division is going to deny our application because they're trying to maintain a one-and-a-half-mile radius around the Devonian wells to reduce interference, to extend operational life and reduce the potential for induced seismicity activity.

Q. And did OCD provide a map to you with that denial?

A. They did.

Q. And is that map behind the denial email --

A. Yes.

Q. -- marked as Exhibit D2?

A. Yes.

Q. Can you take a minute and orient the examiners to that map and show the examiners where the Laguna Salada wells are on this map?

A. They are the two yellow circles on the map.

Q. Let me back up a second. Did you create this map?

A. No. This was from the OCD in our denial.

Q. So you had never seen this map before you got it in the denial?

A. No.

Q. Are there circles drawn around the two Laguna Salada wells?

A. Yes, there are.

Q. And are they different colors?

A. Yes. There is a black one and a red-dashed one.

Q. Is there any some kind of legend on the map or any kind of key to tell you what those are?

A. No, there is not.

Q. And in your opinion, just based on what you know from the denial and extrapolating from the denial email, what do you assume those are?

A. I assume the black circle is a one-mile radius and that the red-dashed circles are a three-quarter-mile radius.

Q. And, again, this is the first time -- well, when you got the denial, that was the first time you'd ever seen a map like this?

A. Yes.

Q. And it was the first time you'd ever seen a map with a three-quarter --

A. Yes.

Q. -- what we're guessing is a three-quarter-mile radius?

A. Correct.

Q. Okay. Turning back to the denial email, when OCD denied these two applications, did OCD provide any technical study or data supporting this email?

A. No, they did not.

Q. The email and the map are the only two things you received from OCD?

A. Yes.

Q. You read from the denial a moment ago, and you read the language that said OCD is intending to propose the 1.5-mile requirement to address the potential for interference between wells. Did OCD ever provide you with any studies or data about interference between wells?

A. No, they did not.

Q. The OCD denial that you read a moment ago also talks about the risk of induced seismicity. Did OCD ever provide you with any technical studies or data about the risk of induced seismicity?

A. No, they did not.

Q. Do you see in the denial email where OCD states that "OCD will oppose your applications and will support the denial by evidence and testimony offered in similar cases before the Division and Commission"?

A. Yes.

Q. Did OCD provide that evidence and testimony in its denial email?

A. No, it did not.

Q. Did OCD provide this prior evidence and testimony to Mesquite at all?

A. No. We have not seen any evidence to support their denial.

Q. And have you seen any evidence to support a 1.5-mile spacing location requirement more generally?

A. No, I have not.

Q. Let's turn to Exhibit E. Exhibit E is an email from Mr. David Brooks, lawyer for OCD, sent to me and to others in a different case, right?

A. Correct.

Q. Sent sometime in February? Is that on --

A. Yes.

Q. Okay. Can you read the first few lines of that email to me, please?

A. "Since the 1.5-mile distance is not a rule provision, it does not control unless the propriety of its application in a particular case is shown. The Division has power to issue rules or orders to regulate disposal of" waters -- "disposal of wastes to protect the environment. If either party were to demonstrate by technical evidence that both wells now proposed cannot be operated consistently with environmental protection, the Division should enter an appropriate order."

Q. Thank you.

What does that mean to you, just as a layperson? I'm not asking for a legal opinion, just as

a layperson who is regulated by the OCD.

A. It basically says that since the 1.5-mile distance is not a rule, that approval or denial should be based on the technical evidence between the two wells.

Q. And so even though it's OCD's position that a 1.5 spacing can only be applied on a case-by-case basis supported by technical evidence, OCD did not provide you with any technical data?

A. No, they did not.

Q. Have you seen the Division's prehearing statements filed in these cases?

A. Yes.

Q. And can you turn to Tab F, please? Does Tab F have the three prehearing statements labeled F1, F2 and F3?

A. Yes, it does.

Q. Let's turn to Tab F3, which is -- and can you tell me what that is?

EXAMINER BRANCARD: Ms. Bennett, what are you looking at?

MS. BENNETT: Tab F behind Exhibit 1. It's the Division's prehearing statements.

I handed out a separate -- this is my packet of materials (indicating). That's the Division's packet of materials that you're looking at there. My packet is bound by a rubber band. That's the Division's materials. That's Mr. Brooks' materials that you're flipping through. What Mr. Jones is flipping through is my materials, and I handed a packet to each of you.

EXAMINER BRANCARD: But you're talking about the Division's exhibits.

MS. BENNETT: No. I'm talking about the prehearing statements that were filed in these cases that I've included as exhibits in my materials.

EXAMINER BRANCARD: Oh, okay.

MS. BENNETT: Thank you for that clarification.

So I did include the Division's prehearing statements in these three cases in my materials behind Tab F.

Q. (BY MS. BENNETT) So if you could turn to Tab F3?

MS. BENNETT: Mr. McMillan, do you need a copy of the exhibits? Did I fail to give them to you?

Apologies.

Mr. Brancard, did I not give you a copy?

EXAMINER BRANCARD: (Indicating.)

MS. BENNETT: Okay. Again, apologies for not handing out those exhibits earlier. I thought I had done that.

So if you look at Tab 1, which are the exhibits that Mr. Neatherlin is testifying about, behind Tab 1 are a series of subtabs, and Subtab F are the prehearing statements that the Division filed in these three cases. And F3 is the prehearing statement that the Division filed in the Baker case.

Q. (BY MS. BENNETT) Have you had a chance to review the prehearing statements?

A. Yes.

Q. You've seen them before today?

A. Yes, I have.

Q. I wanted to ask you about some language in the prehearing statement. Can you turn to the page that has highlighting there?

A. Uh-huh.

Q. And read the highlighted portion that starts -- that discusses the Division's desire to maintain a distance of 1.5 miles to minimize interference. Do you see that?

A. "The Division has sought to maintain a distance of 1.5 miles between injection sources based on a three-quarter-mile radius from the well surface location or" 7,200 -- "or 7,920 feet between the Devonian SWD wells."

Q. And then what does subparagraph one say in terms of one of the justifications for imposing this 1.5-mile requirement?

A. "In an effort to minimize interference between the wells in support of the effort to reduce the potential for induced seismic events and to optimize the operational life of these wells as a best management practice."

Q. And does the prehearing statement also identify the need to protect correlative rights and support production while preventing waste?

A. It does.

Q. And having reviewed all three prehearing statements, is this essentially the same language as in the prehearing statements for the Laguna Salada wells?

A. Yes, it is.

Q. And does it more or less track the language in the denial that you saw for the Laguna Salada wells?

A. Yes, it does.

Q. Now, Mesquite has retained technical experts that will be testifying here today; is that right?

A. Correct.

Q. And you've met with the technical experts?

A. Yes, I have.

Q. Will they be testifying today -- and I'm sorry.

Those technical experts have been retained to discuss the potential for induced seismicity; is that right?

A. Correct.

Q. And those technical experts have also been retained to discuss the potential for interference between wells; is that right?

A. Correct.

Q. And how about to discuss the geology of this area?

A. Yes.

Q. And they've modeled -- done extensive modeling --

A. Yes.

Q. -- for all three of these topics?

A. Yes, they have.

Q. Based on your understanding of what the witnesses will be testifying to today -- and I'm not asking you for any kind of an expert opinion. Just based on what you know the witnesses will be testifying to, do you know if the witnesses will be testifying -- what is your understanding of what they'll be testifying to in terms of increased or induced seismicity?

A. That there is very low risk for it.

Q. How about impact on correlative rights?

A. That there are none.

Q. How about potential increase for pressure?
A. There is very minimal pressure increase that could be seen from this.
Q. Now, we talked about how Mesquite has retained three subject-matter experts to provide data to the Division today. Did OCD -- before it issued its denial to you, do you know if OCD provided you with any technical data or studies that were prepared by subject-matter experts?
A. No, they did not.
Q. Between the time that OCD denied the Laguna Salada applications and today, has OCD ever provided Mesquite with any technical studies prepared by subject-matter experts?
A. No, they have not.
Q. One of the things I did want to talk to you about -- and I think this is sort of in your area of knowledge -- is the notion that the 1.5-mile spacing requirement is designed to minimize interference between the wells and to optimize operational life as a best management practice. What do you understand that -- what do you understand interference between wells to mean?
A. That the wells would be communicating with each other, and they would start seeing a pressure increase

because of their proximity to each other.

Q. And what's the practical effect of that pressure increase if two wells -- if their pressures start to communicate?

A. You'll see an increase in surface pressure and reduction in your injection rate.

Q. And so the amount that you can inject decreases?

A. Correct.

Q. What wells -- let's just talk about the Laguna Salada wells. What two wells are going to interfere with each other, if there is interference?

A. It would be the two Laguna Salada wells.

Q. And let's talk about the Baker well for a moment. With respect to the Baker well, if there is interference with another well, what will that interfere with?

A. It would interfere with our Paduca 6 well.

Q. So the wells that would be -- that may have potential interference are owned by Mesquite?

A. Correct.

Q. Operated by Mesquite?

A. Yes.

Q. And do you think -- in your view, is the practical effect, a slight reduction in injection rate,

is that a business decision?

A. Yes, it is.

Q. Has Mesquite analyzed that business decision?

A. Yes, we have.

Q. And Mesquite's willing to go forward with that risk of a slightly decreased injection rate?

A. Yes, we were.

Q. Do you think -- well, getting back to some of our original points, you're not saying that OCD doesn't have jurisdiction to regulate well design or mechanical integrity?

A. Not at all.

Q. And are some of those requirements and regulations in the C-108 also in the order that you receive from the Division?

A. Yes.

Q. Has OCD ever provided you or made available to you any sort of formal guidance document that sets out OCD's best management practices?

A. No, they have not.

Q. In your opinion, would you say that the regulations that OCD has duly promulgated include the best management practices or at least reflect operators' best management practices?

A. Yes, I would.

Q. And did Mesquite's application comply with the additional requirements under the regulations?
A. Yes, they did.
Q. And then once the order was granted, OCD would put in further protections based on the regulations. Is that accurate?
A. Yes.
Q. So I just wanted to also talk to you little bit about the 1.5-mile spacing requirement again. We talked about how the one-mile spacing requirement is not in the regulations, and you've never had formal notice of a one-mile spacing requirement; is that right?
A. That's correct.
Q. And the denial was the first time you'd ever heard of a 1.5-mile spacing requirement?
A. Yes.
Q. Do you know in the intervening months since your applications were denied, has OCD put anything on their website about the 1.5-mile spacing location?
A. Nothing that I've seen, no.
Q. Has OCD ever sent you, Mesquite, a letter, guidance document discussing the 1.5-mile spacing requirement?
A. Not until we got these denial applications.
Q. Did you ever see a notice in the newspaper or

in any other publicly available document that OCD was imposing a 1.5-mile spacing requirement?

A. No, I did not.

Q. So you essentially learned about it from this denial and had to then modify your behavior to comply with an unwritten rule?

A. Correct.

Q. Now, one of the things I'd like to understand is why -- we talked a little bit about the fact that you can't move these wells because they're boxed in. But why did you choose this location for -- let's start with the Laguna Salada wells. Why did you choose the location for the Laguna Salada wells? Are there oil and gas operators nearby? Did you have contracts? What caused you to choose those locations?

A. We had entered into some contracts with different operators in the area, and we chose those locations, one, because they're on fee land and, two, because of their close proximity to the operators' infrastructure. That way we're not having to have increased capital costs because they are -- they're farther away from where the production is.

Q. Uh-huh. And so you actually had contracts first and then applied for the applications?

A. That's correct.

Q. So these are applications that Mesquite -- or wells that Mesquite intends to drill --

A. Yeah.

Q. -- and intends to operate because you have these pre-existing contracts?

A. Correct.

Q. What's your understanding of what's happened or what will happen now that these applications have been denied on the production that was the subject of your contracts?

A. That there could be some slowdown of production. There could be some slowdown of bringing wells online and slowing down operators' programs to develop these acreage.

Q. And do the developers -- could they just truck this water someplace else?

A. General consensus is if they can't pipe this water, they won't produce these wells because of the economics.

Q. But that would be the other option, right, is trucking a long distance or trucking some distance across probably dirt roads or other roads to get to a permitted disposal well?

A. Yes. That would be the only other option.

Q. And -- but your wells are close by and

infrastructure wouldn't be that difficult to supply to get the production -- the produced water to your wells?

A. Correct.

Q. Did you conduct anywhere surveys or have any initial work that you did based on your understanding that the 1.5 -- one-mile spacing requirement was in place when you applied for these applications?

A. Yes, we did. We went out and surveyed the land and looked at existing applications and permits to make sure that we were a mile away from the existing either permits or wells in the area.

Q. And did you have surveys done?

A. Yes, we did.

Q. Okay. About -- and those surveys were done based on the 1. -- based on the one-mile spacing requirement?

A. Yes.

Q. And about how much does it cost to prepare an application for administrative approval?

A. Around $10,000 an application.

Q. Is any of that money that you spent on that -- in reliance on the one-mile rule, is any of that transferable to a 1.5-mile application?

A. No, it's not.

Q. So the money that you spent in reliance on the

one-mile spacing requirement is essentially just lost?

A. Correct.

Q. Would you have conducted the surveys differently if you had known that OCD was going to require a 1.5-mile spacing location?

A. Yes, we would have.

Q. I believe you mentioned that Mesquite actually moved the location of one of your Laguna Salada wells and even brought Laguna Salada applications based on discussions with another saltwater disposal operator; is that right?

A. That's correct. We had a third well permitted -- or were going to permit in the area and it was too close to another operator's existing permit. In private discussions with them, we dropped that permit, and they said they were okay with the other two.

Q. So as a competitor, you worked with your neighboring SWD operator to work out those issues as between the two of you?

A. Correct.

Q. Without any necessity for the Division to come in and kind of oversee your negotiations?

A. Correct.

Q. And that operator -- that SWD operator didn't even enter an appearance in this case, did it?

A. No, they did not.

Q. And it hasn't raised any concerns with your wells?

A. No.

Q. I think that's all the questions I have for you at the moment.

MS. BENNETT: Do you have any follow-up questions?

MS. BISONG: No.

Q. (BY MS. BENNETT) But before I pass the witness and tender your exhibits, I was wondering if you had anything else that you wanted to say that I didn't cover in my questions.

A. No, not really. We're just wanting again, you know, like I said earlier, to get clarification on what the regulations are going to be and how to go about it, and we'll play by the rules. We're not -- we're not trying to change the rules or do anything else, but just to have consistency across the board. That's all we're looking for so we can keep doing what we're doing; we don't have to come up here all the time.

Q. Thank you.

MS. BENNETT: With that, I have no further questions for Mr. Neatherlin, and I would like to move admission of the exhibits behind Tab 1 at this time into the record.

EXAMINER JONES: Exhibits behind Tab 1? Just all of Tab 1 then?

MS. BENNETT: All of Tab 1.

EXAMINER JONES: Any objection?

MR. PADILLA: No objection.

MR. BRUCE: No objection.

EXAMINER JONES: Mr. Brooks?

MR. BROOKS: Mr. Examiner, I have a question. Does that include the -- I'm not sure. There is a lot of stuff behind Tab 1 and I haven't gone through what it all is. Is there any -- does that include these denial letters -- so-called denial letters that you were talking about?

MS. BENNETT: Yes, it does, behind Tab D1.

MR. BROOKS: B1?

MS. BENNETT: D, as in dog.

MR. BROOKS: D, as in dog. Okay. Let me look for it.

EXAMINER BRANCARD: There are three applications --

MS. BENNETT: That's correct.

EXAMINER BRANCARD: -- A, B and C. And D is the denial letter -- supposed denial letter, an email from Mr. Goetze to Ms. [sic] Wilson, December 13th,

2018. And then E is an email from Mr. Brooks to Ms. Bennett, February 18th, 2019. And then F is the prehearing statement of the Division in one of these cases.

MS. BENNETT: In all three of the cases.

EXAMINER BRANCARD: All three of the cases.

MS. BENNETT: Uh-huh. F1 is the Laguna Salada 13, F2 is the Laguna Salada 19, and F3 is the Baker.

EXAMINER BRANCARD: Which are already in the record.

MS. BENNETT: They are already in the record, but I wanted to make sure I had them available for the witnesses today.

MR. BROOKS: Okay. I have no objection to anything in -- anything behind Tab 1, which I will refer to as Exhibit 1.

But in view of the -- assuming that D1 will now be admitted, I have a motion to make.

EXAMINER BRANCARD: Exhibit 1, Tab D?

MR. BROOKS: Yes.

Okay. Since this email clearly states, as Ms. Bennett has told us -- let's see. Where is the language about the denial? I saw it just a minute ago.

These applications -- it's in the middle of the second-to-the-last paragraph on the front -- well, there is nothing on the back. "Therefore, these applications are being denied for approval through the administrative review but remain available for hearing." Now, I don't know how that will be construed, but if it is construed that there is one proceeding and once the Division has denied the application, it has denied the application. Based on that possible construction, I want to make a motion to dismiss the applications now pending before us as to the Laguna Salada -- Laguna Salada No. 1 -- Laguna Salada 13 No. 1 and the Laguna Salada 19 No. 1 on the grounds that those applications were denied on December 11th, 2018 and de novo appeal was filed to the Commission -- or there has been no showing that any de novo application was filed to the Commission on or before January -- January 17th of 2019, and, therefore, there is no jurisdiction in this proceeding because of the Commission's holding of Delaware versus Alpha.

Thank you.

MS. BENNETT: May I respond?

EXAMINER BRANCARD: (Indicating.)

MS. BENNETT: Well, I would just like to clarify that the email says these cases can be set for hearing. It does not say these cases have to go to de novo -- application for a de novo hearing by the Commission has to be held. And, in fact -- I don't have those emails with me because I honestly didn't think this was going to be an issue today, but I'm happy to look through my e-mail. When I first submitted these applications, I acquired as to the correct approach, and I was told that the Division was considering whether these needed to go to the Commission, and, in fact, was considering make a sua sponte motion to submit these to the Commission. That was in January. These cases have been continued five times.

Mr. Padilla and Mr. Bruce are here on the exact same issue, denial of an administrative application. The Division has been well aware that these cases were set for hearing, that we have witnesses here, that we intended to proceed before a Division hearing. We were told to file applications, which I did, and so to now have to face this motion to dismiss based on procedural ambiguity, at best, but one I feel was resolved well before we came to this hearing, I think it untimely, and the Division has acquiesced in these hearings by continuing them at their own behest and by appearing today by filing prehearing statements in these cases that have no notion -- no mention of a denial -- I'm sorry -- of a dismissal based on lack of jurisdiction.

And to the extent that there is some sort of jurisdictional issue, we did file our applications with the Division on January 18th, which is slightly outside of the 30-day window, but I was under the impression, based on the email that my client received from the Division, that we were to file hearing applications, not de novo applications before the Commission. And at any time during the past five months, the Division could have made this motion to dismiss and saved us all this time and trouble, but they did not, and we're here today. All parties are here today before the Division requesting that the Division hear these cases, and there is no basis to dismiss our applications pending before the Division.

And I would suggest -- and perhaps the other counsel have the same impression for the other operators that are here -- that we're all in the same boat. If you dismiss -- and I shouldn't say that. We might not be in the same boat. But if you dismiss Mesquite's applications, then there is no review for the other operators here as well. So that can't be the answer.

Thank you.

EXAMINER JONES: Any other -- Mr. Bruce.

MR. BRUCE: Just briefly, I think, you know, an administrative application, whether it's denied or objected to by another operator, I think the only remedy available was to set it for hearing.

MS. BENNETT: This kind of hearing?

MR. BRUCE: This kind of hearing.

EXAMINER JONES: Mr. Padilla.

MR. PADILLA: That's my understanding of the procedure. I agree with Mr. Bruce. Even if you've been denied administratively or there is opposition to an administrative application, then it goes to hearing. That's been the practice here as far as I can remember. I've been here a long time.

EXAMINER BRANCARD: This is sort of the flip side of your motion to dismiss this application -- Okay? -- and to dismiss disapproval of the denials.

So perhaps the way this has been handled in the past -- again, there is no process set out in the rules for this. But the normal process in the past, I believe, is that when something was set for a denial as an administrative application, the Division would normally set it for a hearing. It seems like in this case, the Division denied it and through it back on the Applicant to set it for -- we can view that as a distinction without a difference, or we can simply view this as you have filed a new application before the Division. Okay?

MS. BENNETT: (Indicating.)

EXAMINER BRANCARD: And so if we treat this as a new application to be done at a hearing, which was your option, we have this -- I don't want to disparage our rules, but we have this unique process for injection permits that you can go administrative or you can go to hearing. It doesn't comport with how EPA does it, but that's how we do it here in New Mexico. So you have that option. So essentially I think we can treat this as a new -- it's not an appeal of the decision. It's a new application set for hearing before the Division.

And I think we have -- we have the Delaware case that has brought up the problem of what do you do to appeal from an administrative decision, and that's now in the courts to decide. That was not a situation of a denial in the Delaware. That was a situation of an approval that someone who had not protested came in over two months later and then went to a Division hearing examiner to throw out the original decision. Okay? And the Commission decided that's not your remedy. Okay? It could have been a Commission appeal. It could have been an appeal to district court. The Delaware case says it's one way or the other. It's not finding another hearing examiner to throw out the decision of the first hearing examiner. Okay? That was a true appeal.

But I think in this case, we can treat this as a new application for the Division. Instead of doing it administratively, you're now doing it through the hearing process.

And, Mr. Padilla, Mr. Bruce, were your cases also denials?

MR. PADILLA: Ours was an objection by three other parties.

EXAMINER BRANCARD: Okay. So you had an administrative case, but there are objections, and so it's going to hearing.

MR. PADILLA: My client got a letter simply saying you have to go to hearing. And I think that's the practice. I just recently had one not long ago, a disposal case into the Delaware, and we studied that very well. We filed the administrative application. It was denied. My client chose not to go there after looking at it just simply because we didn't think we could prevail in that in the Delaware. But we had the choice then of filing an application and proceeding as you are discussing at this point.

MR. BRUCE: And the Solaris case was

objection to my offsets.

EXAMINER JONES: Ms. Bennett, did you do a complete renotice for all the protected parties for this case?

MS. BENNETT: Yes, I did.

EXAMINER JONES: There you go.

Okay. So first questioning -- cross-examining the witness --

MS. BENNETT: I'm sorry. May I just confirm that my Tab 1 exhibits are admitted and that the motion to dismiss has been denied?

EXAMINER JONES: Tab 1 exhibits are admitted.

(Mesquite SWD, Inc. Exhibit Number 1 with Tabs A through F are offered and admitted into evidence.)

MS. BENNETT: And Mr. Brooks' motion to dismiss is denied, question mark?

EXAMINER ONES: Yes. The motion is denied.

MR. BROOKS: Thank you.

EXAMINER JONES: Okay. Mr. Padilla, any questions?

MR. PADILLA: I don't have any questions, but I just simply want to make sure that what Mr. Riley testified to in terms of the 1.5 regulation, his understanding of that, can be incorporated in our case or at least considered by the Division in ultimately deciding whether rulemaking should have -- should have occurred first before applying this 1.5-mile policy.

EXAMINER BRANCARD: Well, I think because of the outstanding issue about the fact that the Division's -- the idea that was raised earlier by the parties in the Division's testimony could be incorporated from one hearing to another, I think when we get to the second hearing, we can -- if you want to try to incorporate other people's testimony -- if we're going to incorporate one party, you want to have the option of raising that as a possibility.

MR. PADILLA: That's all I'm asking.

Thank you.

EXAMINER JONES: Mr. Bruce, any questions?

MR. BRUCE: Really just a statement that I believe the witness stated that there were no objections filed by other parties regarding the application, and Solaris did file objections to the Mesquite applications. I'd just point that out.

EXAMINER JONES: But Kaiser-Francis didn't?

MR. BRUCE: They were going to, but they worked out an agreement with Mesquite.

EXAMINER JONES: Okay. Mr. Roach, do you

have any questions for the witness?

MR. ROACH: No, I do not. Thank you.

EXAMINER JONES: Thank you.

Mr. Brooks?

CROSS-EXAMINATION

BY MR. BROOKS:

Q. Well, I just want to clarify the locations here. This map was prepared by our witness, and we will be using it as an exhibit. It's marked Division Exhibit Number 1, but I will not tender it for admission until the witness has identified it. I would just like for you to look at it and ask if you agree with the locations shown on the exhibit.

A. Yes. I agree with the locations on the exhibit.

Q. Thank you.

MR. BROOKS: I have no further questions.

MS. BENNETT: I'm sorry. I just had a follow-up question, which I can do in a minute. Sorry about that.

EXAMINER JONES: Mr. McMillan?

EXAMINER McMILLAN: I don't have any.

EXAMINER BRANCARD: Oh, I have a few questions.

CROSS-EXAMINATION

BY EXAMINER BRANCARD:

Q. Mr. Neatherlin, did you prepare the applications?

A. Not wholly. I assisted in them.

Q. Are there other witnesses testifying who prepared the applications?

A. I don't think. No.

Q. So you are the only witness who was involved in the preparation of the application?

A. Yes. Yes.

MS. BENNETT: That's correct.

Q. (BY EXAMINER BRANCARD) Okay. So to follow up Mr. Brooks' question, so then -- so there seems to be blue lines indicating a distance of between the two Laguna Saladas of 1.05 miles?

A. Correct.

Q. And you don't have a disagreement with that?

A. No, I do not.

Q. So just to clar- -- you've been talking about a the 1.5, three-quarter. What we're talking about here -- I get to ask the dumb questions -- is a -- am I correct, a three-quarter-mile area of review? But if you're going from the center point of two separate wells, it's 1.5 miles; is that correct?

MS. BENNETT: Well, I'll let Mr. Neatherlin testify about what he knows about that, but I think the real witness to address that question and the one we're all kind of grappling with is Mr. Goetze. But I'm happy to let Mr. Neatherlin testify because he has been trying to comply with that rule -- or that requirement on an ongoing basis.

THE WITNESS: So that's -- yes. That's our understanding of what the OCD is requiring now.

Q. (BY EXAMINER BRANCARD) And what you thought the previous requirement was based on the regulatory requirement -- minimum requirement of a half-mile area of review would give you one mile from each -- if you had two injection wells in that proximity, you now have to be at least a mile apart?

A. Correct.

Q. Okay. I wanted to clarify that.

So is it your assumption then that because of that area of review that you would be prohibited from having another injection well within a mile of your proposed injection well?

A. Our understanding was that if we were inside of that area of review -- if there was another operator inside of that area of review, then they would have the opportunity to protest our well, and then if we could work it out between two operators, then it would go to hearing to be resolved. So not that you couldn't even have the wells next to each other within the half mile, but if neither party protested it, then it could be approved.

Q. Okay. So in the application, is there a duration for this well?

A. Oh. In the application, did we put a duration in there for the life span of the well?

Q. Yes.

A. I don't believe we did.

Q. Okay. So you would be asking essentially for a permit -- and I'm not saying this is unusual -- that would be with no duration?

A. That's how every permit is -- yes. That's what we would be asking because that's how every permit is given. As long as the well is active, then the permit is active.

Q. So you could be putting in 40,000 barrels per day, which I believe is your -- the number you put in in at least the one application I looked at?

A. Yes. The number that we put in there is not a requirement. It's an estimation of what we expect the well to do commercially.

Q. Right.

At a certain pressure?

A. Under the injection -- under the max-allowed injection pressure, yes.

Q. And your normal permit that you receive, it doesn't give you a maximum disposal rate?

A. No, it doesn't. We're only regulated by the maximum surface injection.

Q. So with your application, do you include a model of where the produced water is going to go over a period of time?

A. No, we did not. We're not required to.

Q. Okay. So the agency has no idea over ten, 20, 30, 50, 100 years where your produced water is going to go?

A. That would be a question for the agency.

Q. But you're not telling them that?

A. No.

Q. Okay. And so were you also in charge of notice for this?

A. Not in charge for notice, no.

MS. BENNETT: That was me.

EXAMINER BRANCARD: Do we have any exhibits about notice.

MS. BENNETT: Yes, we do. They're at the end.

EXAMINER BRANCARD: Those are my questions.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. Okay. You were first too close to the Predator well? Is that -- is that what you said earlier?

A. No. It was the Intrepid SWD with our Laguna Salada 7, which is shown on the map in the red circle.

Q. Okay. So are you asking for a rate limit in this application?

A. No, I'm not.

Q. Okay. Are you asking for a volume limit in the application?

A. No.

Q. Are you -- are you in charge of the guys that take care of the wells?

A. Yes, I am.

Q. Okay. So if they seem -- the initial fluid levels on these wells, where does it -- where does it stand? Is it surface or what?

A. It depends on the well. It depends on the area. We have some that they go -- they go on a vacuum. We can inject into them all day, every day, and as soon as we turn them off, they go back on the vacuum. And then we have some that hold pressure. So it depends on the area as to how the well's going to -- where the fluid level stands.

Q. This general area here, what do you think?

A. General area here, wellbores are going to stand full.

Q. So it's normally pressured?

A. It becomes pressured, yes. It's a tighter area of injection. Yes.

Q. Okay. Have you -- but still you're able to get the rates into these wells. Otherwise, you wouldn't be -- you're assuming you can get the rates into these wells; otherwise, you wouldn't be drilling them?

A. Yes.

Q. And what tubing size are you going for?

A. We would be going for a 7-inch-by-5-1/2 tapered string.

Q. 5-1/2 inside 7-5/8 liner?

A. Yes. Correct.

Q. With a 39-pound liner?

A. Yes.

Q. Okay. Have you seen, in your experience, other Devonian wells being affected pressurewise by disposal from adjacent wells?

A. No, I've not. Not in the Devonian, no.

Q. Have you measured any of them to see?

A. Yes. We have our two Sand Dune wells that are just a little over a mile, I believe, and one of them injects about 30,000 a day. The other one does about 45,000 barrels a day, and we have not seen any pressure increase in those wells.

Q. Okay. You said you're going to have some more technical witnesses, so they'll probably talk more about this. But you're the -- you're the guy that would see things out in the oil fields?

A. Correct.

Q. This example you've quoted, you don't have that in an exhibit anywhere?

A. I do not. I wasn't planning on it being brought up. So --

Q. Okay. As I understand it, you filed these on Ms. Bennett's birthday --

(Laughter.)

Q. -- and then there was an SWD work group that fall after that, and you were part of the work group, right? Or you were invited to the work group?

A. Yeah. I don't know particularly if we participated in that meeting or -- off the top of my head, I can't say. We were involved with the work group.

Q. But some decisions were made. You were in communication with the people from the work group

anyway.

A. Uh-huh.

Q. And some decisions were made coming out of the work group as far as how to space -- initially space wells out. So your applications essentially got caught, because they were filed before that and they were not acted on until after that, is that correct --

A. Correct.

Q. -- the way you see it?

So would one mile satisfy you as far as -- is it the one-and-a-half you object to here?

A. I object to the inconsistency that we've had to deal with under the application process on this.

Q. Okay.

A. If the Division makes a rule for a mile, we're fine with that. If the Division makes a rule for a mile-and-a-half, we're fine with that.

Q. What would you say if you were the Division?

A. We need to make some rules.

(Laughter.)

A. You know, the argument can be made, in this case where these are lower-volume wells as opposed to the higher volumes wells, that the one mile is fine. I'm going to let the experts speak to that. But, you know, there are arguments that can be made on either case.

Q. Yeah.

But you picked your locations, got your right-of-ways, got all your surface permits and made all your plans, and then you get hit with this -- this decision. So is that -- that's your main objection, correct?

A. Yes. That's our main objection.

Q. Okay. Thank you.

EXAMINER JONES: I guess that's it for this witness?

MS. BENNETT: May I ask a few follow-up questions?

EXAMINER JONES: Yes.

MS. BENNETT: Thank you.

REDIRECT EXAMINATION

BY MS. BENNETT:

Q. Earlier Mr. Bruce, counsel for Solaris, mentioned that Solaris had protested probably the Laguna Salada 13 -- I'm not sure -- but do you know -- was that a full-fledged protest, or was that an untimely protest? Do you remember?

A. I don't remember. In -- in the questioning, I didn't think that it was an official protest. I knew that they had protested us, but I thought that it was --

my understanding was they had called us and said, "Hey, we're going to protest these wells, and then we discussed it and worked it out.

Q. And do you know if Solaris has entered an appearance in this case -- in any of these three cases?

A. I'm assuming they have. Until today, I had no knowledge of it.

Q. Okay. They actually hadn't entered an appearance in these three cases before today, just to clarify.

A. Okay.

Q. So Mr. Brancard asked you about the flow -- sort of the dispersion of water once it's injected into a well and asked you about whether, with your application, you supply any sort of technical studies with your application. And you said no; is that right?

A. Correct.

Q. And I believe your response was that that's because the regulations don't require it?

A. That's correct.

Q. And the C-108 doesn't require it?

A. Correct.

Q. You never got an email from the OCD saying your applications were incomplete because you didn't include a reservoir engineering study, did you?

A. No, we did not.

Q. If the Division were to enact a rule that required operators to provide a reservoir engineering study with their applications, would you do that?

A. Yes.

Q. In fact, you've done that for today, right?

A. Correct.

Q. And is it fair to say -- well, no, I'm not going to ask that.

Earlier you were asked about the volume limit, the injection rate, the injection limit.

A. Uh-huh.

Q. And you mentioned that Mesquite was seeking 40,000 barrels per day -- 40,000, yeah, barrels per day.

A. Yes. That's what we put in our application for expect injectivity.

Q. Now, is that rate controlled by forces outside of Mesquite's control, for example, the .2 pressure -- the wellhead pressure set at .2?

A. Yes. That's the only determining factor on the rate.

Q. Uh-huh. Who sets that .2?

A. OCD.

Q. So OCD has already set regulations -- or set standards that control the amount you can inject?

A. Correct.

Q. If you were asked to reduce your injection limit for this well rather than having an arbitrary spacing requirement imposed, would Mesquite be willing to discuss that?

A. We would.

Q. How about seismicity monitoring?

A. We would be open to that.

Q. In your opinion, would seismicity monitoring next to a well be a better indicator of -- a better ameliorative or protection for -- against induced seismicity, mechanical application of going 1.5 miles?

A. Yes, it would be.

MR. BROOKS: Was this witness qualified as an expert? I don't recall.

MS. BENNETT: No. As an expert in SWD operations, drilling, casing design. And I'm not asking him as an expert.

MR. BROOKS: I'd object to that last question and answer on the grounds that he's giving an opinion outside his area of expertise.

MS. BENNETT: That's fine.

Q. (BY MS. BENNETT) Mr. Jones asked you what you are objecting to in this matter, and you said that for these three cases, what you're objecting to is the sort

of backwards imposition of the 1.5-mile requirement on your current applications; is that right?

A. That's correct.

Q. And what you said is you would like the Division to make some rules on a going-forward basis; is that right?

A. Yes. I'd love for this to be written out plain as day. That way we can follow it from step A to step Z, turn it in and be done with it.

Q. And would you expect those rules to be based on technical data?

A. I would expect that. Yes.

Q. And operator input?

A. Yes.

Q. And input maybe from other agencies like the BLM or State Land Office?

A. I would expect so. Yes.

MS. BENNETT: Those are the only additional questions I had. Thank you.

EXAMINER JONES: Okay. Ten-minute break.

MS. BENNETT: Thank you.

(Recess, 10:10 a.m. to 10:28 a.m.)

EXAMINER JONES: Okay. Let's get back on the record and call the next witness, please.

MS. BENNETT: Thank you.

MS. BISONG: Thank you, Mr. Examiners.

On behalf of Mesquite, I'd like to call our next witness, Dr. Kate Zeigler.

KATE ZEIGLER, Ph.D.,

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

DIRECT EXAMINATION

BY MS. BISONG:

Q. Good morning, Ms. Zeigler.

A. Good morning.

Q. Can you state your full name for the record?

A. Kate Zeigler.

Q. Who do you work for and in what capacity?

A. Zeigler Geologic Consulting on behalf of Mesquite SWD.

Q. What are your responsibilities there?

A. I'm a geologist. I'm primarily focused on stratigraphy and the basin geology zone that Mesquite is interested in.

Q. Can you provide just a brief summary of your professional credentials?

A. So I have a bachelor's in geology from Rice University, a master's and Ph.D. in stratigraphy, paleontology and paleomagnetism from the University of New Mexico. I have my AIPG CPG licensure, and I've been working as a field geologist with my own company since 2009.

Q. And have you previously testified as an expert before the Division or the Commission?

A. Yes, ma'am.

Q. And were your credentials accepted as a matter of record?

A. Yes.

EXAMINER JONES: Any objection?

MS. BENNETT: Oh, she hadn't tendered her yet.

MS. BISONG: I haven't tendered her yet. I'm going to do that.

EXAMINER JONES: Okay.

Q. (BY MS. BISONG) Are you familiar with the applications filed by Mesquite -- or the three applications filed by Mesquite?

A. Yes.

Q. And are you familiar with the status of the lands where the wells are that are the subject of where those wells will be drilled?

A. Yes.

Q. Are you familiar with the drilling plans for the wells at issue?

A. Yes.

Q. And have you conducted a geologic study of the area embracing the proposed location of those three wells?

A. Yes.

MS. BISONG: At this time I'd like to tender Dr. Zeigler as an expert in geology.

EXAMINER JONES: Expert in petroleum geology?

MS. BISONG: Yes.

EXAMINER BRANCARD: Geology.

THE WITNESS: Or just geology, not petroleum geology. Oh, God.

(Laughter.)

MS. BISONG: Not a petroleum geologist. Just a geologist.

EXAMINER JONES: Okay. Any objections to Dr. Zeigler as an expert in geology?

MR. BROOKS: No.

MR. BRUCE: No objection.

MR. PADILLA: No objection.

EXAMINER JONES: Okay. She's so qualified.

EXAMINER McMILLAN: How about the guy in the back?

MR. ROACH: No objection.

Q. (BY MS. BISONG) Dr. Zeigler, could you turn to

Tab 2 of the exhibits -- the Mesquite exhibits?

MS. BISONG: I'll wait until everybody gets there.

Everybody have a copy?

Q. (BY MS. BISONG) Dr. Zeigler, could you please explain to the examiners what is behind Tab 2?

A. So there is a set of different exhibits here that include descriptions of the different stratigraphic units that are in question in these wells, as well as a generalized stratigraphic chart for the Carlsbad-Loving area that will show relatively the freshwater resources, known petroleum leasing areas and the target injection intervals, as well as a series of isopach maps and cross sections to show the target injection interval, the thickness of the different units that we're going to discuss so we have an idea of the geology in the area.

Q. And so we have -- behind Tab 2, there is a Tab A and then a Tab B. Let's start specifically with Tab A. This is for the Laguna Salada wells, correct?

A. Yes.

Q. And Exhibit A, behind Tab A, can you give a brief synopsis of what Exhibit A reveals?

A. So the first two pages are written descriptions of the different stratigraphic units in the injection interval area. So I didn't choose to describe all the rock units but simply the ones that are of importance of upper permeability barrier, which is the Woodford Shale, as well as the injection interval, which can include the Thirtyone Formation more to the southeast, but primarily the Wristen Group, Fusselman Formation and Upper Montoya Group, and then the Simpson Group, which we will talk about as the lower permeability barrier, and then the Ellenburger Formation below that. And so these are short written descriptions that describe the lithology of these different rock units so that we're all thinking about how they're operating both in terms of the injection interval and the different permeability barriers. And this information was compiled from different literature resources about the basin, especially Ron Broadhead's work in the area.

Q. Okay. And right after the stratigraphic unit descriptions, can you describe what the next page is?

A. So this is the -- this is the stratigraphic chart (indicating), and this is also compiled from Ron Broadhead's 2017 memoir where he compiled a large amount of information concerning the Permian Basin. And this is just to give a visual idea of where everything is located down below the earth's surface in the Carlsbad-Loving area. So this was based on data from NGL's Striker 3 SWD, as well as the Cedar Canyon SWD as reference wells to put this together. And it's simply to show, as we work from the surface downwards into the earth, that we're going to pass through the freshwater resources in the Carlsbad-Loving area, which are in, depending on exactly where you are, some part of the Chinle red beds or the Santa Rosa or the Upper Permian rocks. And those freshwater resources don't go much below 400 to maybe 700 feet at the most before you start having water quality issues that make it not fresh water.

And then below that, we move into current petroleum production zones or historic production zones in the Delaware Mountain Group, the Wolfbone, some in the Atoka and Morrow Shale. And then as we continue to go down in this area, looking at around 14,000 feet below land surface, we hit the Woodford, which is going to be acting as our upper permeability barrier to this target injection interval. And in this area -- we'll look at the isopach map in just a moment. But in this area, we're looking at about 100- to 150-foot-thick Woodford Shale, and then below that, the target interval that Mesquite seeks to inject into.

And here -- and Mr. McMillan has heard this before -- I'm going to note that driller lingo is different than stratigrapher lingo in the basin. So you'll hear drillers refer to, "We're going to inject into the Devonian." And really the Devonian encompasses the Woodford Shale. And so from a stratigraphic perspective, if I said the Devonian, I'm talking about the Woodford Shale. Drillers are talking about the limestones below that, which are actually -- if you add the Thirtyone, Lower Devonian, they're mostly Silurian in age. And so there is just a little bit of an awkwardness in nomenclature there. From this point forward, I'll refer the injection interval by driller lingo, referring to it as a Devonian, Siluro-Devonian.

So we go through the Wristen-Fusselman-Montoya as our target injection interval, and then below that sits the Simpson Group, which is going to act as our lower shale permeability barrier for the area. And then below that, our Ellenburger and on down to the basin.

Q. Thank you.

Looking at the Woodford, at the stratigraphic unit, how thick is that permeability barrier?

A. So in the area of the Laguna Salada wells, we're looking at about 100 to 200 feet thick, and we'll see that on the isopach maps as well.

Q. Can you briefly reiterate or describe the

properties of the Woodford that make it a good permeability barrier?

A. So it is a rock unit that is almost entirely a shale, and the shales generally are very low permeability. And so when we have that shale of that thickness, that's going to act to restrict both upward and downward mobility of fluids through there.

Q. The target injection interval that we see here on the stratigraphic chart, about how thick is that area?

A. So if we're incorporating the Wristen-Fusselman in just the Upper Montoya, so not including the full thickness of the Montoya in this discussion, we're looking at a target interval that can range from 1,100 to 1,200 feet thick in this particular area.

Q. And the Simpson stratigraphic unit, can you give us a description or tell us how thick the Simpson unit is?

A. In this area, it's on order of 250 to 300 feet thick, and it's mixed sandstone and shale. But in general, it's usually greater than 50 percent shale, which is going to help act as that lower barrier.

Q. Can you tell us what the next five pages of Exhibit A are?

A. So this is a satellite image of the Carlsbad-Loving area, and we're going to work through a series of isopach maps? And the -- the stratigraphic interval that we're in is down within the legend. It'll tell you which rock unit we're operating in.

And I apologize. We do need to change that to the title of the exhibits going forward.

So on here, there are some green lines cross-cutting to the southwest of Carlsbad and also a blue-dashed line. These are Precambrian/basement-penetrating faults that have been suggested or present through the Texas Bureau of Economic Geology database, as well as through Ron Broadhead's compilation of data in the area. And so we've put these faults on. We have found in other parts of the basin that sometimes the faults that are presumed to be there in these databases are not always actually there, but we chose to show them so that if they are, in fact, present in this area, they're shown on these maps.

Then we also have some purple lines. In the case of the very first one, which is the Ellenburger -- so now we're going to go from the bottom of the section back up.

EXAMINER McMILLAN: Can I make one quick comment?

THE WITNESS: Uh-huh.

EXAMINER McMILLAN: If you look at the legend, the fifth one down is the map you're looking at.

MS. BISONG: Correct.

THE WITNESS: Yes.

EXAMINER McMILLAN: Just to help people.

THE WITNESS: Thank you.

So in this first one, this is the Ellenburger. And because we're zoomed in enough, there is only one line of constant thickness that cuts diagonally across the southeast corner of the map. It has a 750 planted across that. So that's the estimated thickness of the Ellenburger at that point. And so the Ellenburger is going to become slightly thinner as we go to the northwest to the Carlsbad area.

So we also have on here purple well locations that are tied together with a yellow-dashed line. These are the reference wells that we used to construct the cross section that we will look at in just a few slides.

And then we have two yellow stars over just east of Loving. Those are the Laguna Salada 13 and 19 well locations. And the blue lines are simply to show you how we chose to project them into the cross section so you see where they set in the cross-section line. So when we're looking here at the Ellenburger for the Laguna Salada 13 and 19, estimated thickness in the Ellenburger is probably around 700 feet thick.

And then as we continue through, the next exhibit is the Simpson isopach. And there is a green line that runs right through Loving that has a 200 mark on it, and just to the southeast of it is the 400 isopach line, so showing you the thickness of the Simpson Group and with the Laguna Salada wells where they're positioned looking at a thickness of approximately 250 to 300 feet thick for the Simpson Group.

The next one is the Montoya, and on this one -- I'm sorry. We changed colors for our isopach lines. We were trying to keep isopach lines different by rock unit. The 300-foot-thickness isopach line runs almost right through the Laguna Salada 19 well. So for the Montoya, looking at an estimated thickness of around 300 feet for both of these wells.

The next one is a combined Wristen-Fusselman, so this would be the heart of our injection interval. And here our isopach lines are sort of a purple-blue color. And the 1,000-foot isopach line runs right through the middle of Loving from northwest to southeast, and then we have the 1,200 isopach line down to the southeast. So looking at an estimated thickness for the entire injection, not including the top of the Montoya, to be on the order of 1,100 -- or 1,050 to 1,100 feet thick in this area.

And then finally our Woodford Shale, and these are the pink lines. And we have the 100-foot isopach line to the northwest of Loving, and so as we're going -- we're thickening down into the Delaware Basin as we're going southeast, looking at an estimated thickness for the two wells for the Woodford Shale of about 100 to 150, maybe 200 feet thick locally. So those are the isopach maps.

Q. (BY MS. BISONG) Thank you.

Can you turn to the next page of Exhibit A and describe what the last page is?

A. So this is the cross section that we developed for the area. I should note it's difficult to find many wells that are deep enough to do reasonably spaced cross sections in the area, so we did the best that we could with what's out there. And what I've done is clipped out from the Mississippian Limestone down for each of these wells. Everything is hung on the bottom of the Mississippian Limestone. And so we're going from northwest to southeast across this cross section with the Laguna Salada 13 and 19 with the red arrows to show you where they fit between the reference wells that we've shown.

And our take-home point in this is showing the Woodford Shale with a reasonable thickness through the proposed location for both wells, as well a thick -- and here I'm switching to driller lingo -- quote, "Devonian section," which is that Wristen-Fusselman, and then showing your Montoya and your Simpson and your Ellenburger, which was -- the only well in the area that we were able to find that was drilled deep enough was pretty far to the northwest, but we're going to project these tops down to the southeast. And so showing that we don't see evidence of significant -- for example, significant fault offsets in the area of the two wells, that the thickness of the shale, the thickness of the target injection interval, they're fairly uniform through the area, so we don't anticipate any issues with the injection interval or the upper or lower permeability barriers.

Q. Thank you.

About how far is the nearest fault from the Laguna wells?

A. So if we look back at any of the isopach maps where we have the faults continuing in green and blue, we're looking at at least ten, 15 miles to the nearest projected fault trace, which is to the southwest of Loving and Carlsbad.

Q. Looking at the documents behind Tab B, these are basically the same documents we're looking at for the Laguna, but these are for the Baker area, correct?

A. Yes. And so for all intents and purposes, the first four pages, the written unit descriptions and the stratigraphic section will be similar. Other than -- because the Baker well is located a little further away, the depth to these units shifts a little bit as you move to the Baker well. So in the stratigraphic -- the depth -- projected depths to the top of the shale -- top of the Woodford Shale is a little bit deeper than the Laguna Salada wells. But for all intents and purposes, the stratigraphy remains the same for the two Laguna wells versus the Baker well.

Q. And the isopachs that were prepared for the Baker well, those are on the next six pages, correct?

A. Sure. Oh. Yeah, they are. The Upper Morrow snuck in.

So, again, if we start at the Ellenburger -- so starting at the bottom of the section again and working our way up -- notice we're now much more southeast than the two Laguna Salada wells. So now the map has shifted slightly to the southeast. And, again, green and blue are projected basement faults from the Texas Bureau of Economic Geology and Ron Broadhead's compilation work.

And then we'll go through the different isopachs. The purple circles are our reference wells that were used to create the cross section for the Baker well. The Baker well is the yellow star with the little high [sic] line that shows how we projected it into our cross section.

So here, looking at an Ellenburger that's a little bit thicker, we're moving a little bit deeper into the heart of the Delaware Basin here. And so we're moving towards 800 to 850 projected thicknesses for the Ellenburger.

As we move through into the Simpson, which is the next one, looking at about 700 feet thick Simpson Group projected for the Baker well, and that's the green isopach lines.

The Montoya is the yellow isopach line on the next figure and still holding steady at 300-foot-thick projected thicknesses.

As we move through the Wristen-Fusselman, the target injection interval, looking at a little over 1,400 feet thick for the target injection interval for the Baker well.

And the Woodford here, looking at probably around 180-feet-thickness. So your 100 isopach line is way up in the northwest corner, and your 200-foot-thick isopach line is down past the end of the cross section.

And then apparently we're jumping all the way to the Morrow. So here's the Morrow.

Q. In case you would like to know (laughter.)

A. In case you would like to know, the Morrow is a little over 600 feet thick here. I'm not really sure how the Morrow crept in. My apologies for that. But now we know about the Morrow.

Q. Can you tell us how far your fault is from the Baker well site?

A. So, again, looking at any of these isopach maps, we show the projected fault traces on all of them, and here we're looking at easily 15 to 20 miles from the nearest projected fault trace for the Baker well.

Q. And the final page of Exhibit B is also a cross section, correct?

A. Yes. And, again, in looking at deeper -- information for deeper wells -- again, we're a little restricted on the information that we've been able to find. And so here what we've done is taken four reference wells, the Mesquite, Baker SWDs, projected into the middle of this, and this was a previous cross section hung on the base of the Mississippian Limestone to show again the consistent thickness of the Woodford Shale as we move from northwest to southeast through the proposed area for the Baker well, as well as the thickness of the Wristen plus Fusselman-Devonian injection zone for this area, and then the top of the Montoya below.

And, again, we don't see -- there isn't enough offset among these wells to suggest that there is structure here that might affect any of the -- either the injection interval or either the permeability barriers.

Q. And I'm sorry if I missed this. Have you described how thick the Woodford Shale unit is?

A. Yeah. It's on the order of 100, 150 to 200 feet thick, and we can see that on the isopachs.

Q. Okay. And then the Simpson Group, how thick is that?

A. In this area, it's on the order of about 700 feet.

Q. Have you drawn any conclusions from these cross sections?

A. My impression from the cross sections for all three wells is that we have reasonably thick upper and lower permeability barriers, that we have a relatively thick target injection interval and that there does not appear to be any evidence of faulting or lateral pinch-outs or anything that might affect either lower or upper permeability barrier or the target injection area.

Q. In terms of permeability of the Woodford Shale, Simpson Group in the region of the Baker well, would you say it's similar from what you described with the Laguna wells?

A. Yes.

Q. Are you aware of any productive shales in the formation at issue?

A. For the injection interval?

Q. Yes.

A. None that have been shown to be reasonable productive units.

Q. And why is it unlikely that the Devonian unit is unproductive?

A. So if you look at various well log data for the area, there don't appear to be significant enough shale horizons that would produce. And if there are, they're very small traps that would take quite a bit of high-resolution imaging to be able to target effectively.

Q. Are you familiar with the prehearing statements that were filed by the Division for these wells?

A. Yes.
Q. And I believe they're Tab F to Exhibit 1. We'll just look at F1, which is the prehearing statement for the Laguna Salada 13. Do you see that?
A. Yes.
Q. And do you see where the Division is taking the position that a 1.5-mile spacing requirement is needed to protect correlative rights?
A. Yes.
Q. In your opinion, will the drilling of the Laguna Salada 13 well impact the correlative rights of mineral interest owners?
A. No.
Q. In your opinion, will the drilling of the Laguna Salada 19 well impact the correlative rights of mineral interest owners?
A. No.
Q. In your opinion, will the drilling of the Baker well impact the correlative rights of mineral interest owners?
A. No.
Q. In your opinion, is there a risk to freshwater resources if these wells are drilled?
A. No.
Q. Were the exhibits under Tab 2 prepared by you

or compiled under your direction and supervision?

A. Yes.

MS. BISONG: At this time I'd like to move for the admission of the exhibits under Tab 2 into the record.

EXAMINER BRANCARD: I'm sorry. Are you asking for B1 and 2 or --

MS. BISONG: Under Tab 2, I guess it would be 2A and B.

EXAMINER JONES: Any objections?

MR. BRUCE: No objection.

MR. PADILLA: No objection.

MR. BROOKS: Well, I have no objection to the admissibility of the exhibits. I think it's unfortunate that the exhibits are so poorly labeled that the only way to examine the witness concerning them is to take -- to take a copy of the page you're looking at and let the witness see it and be sure -- well, never mind. I mean, that's -- I like to see a presentation before the Division that has the pages of the collective exhibits numbered, especially when they're -- especially when they're not fastened together. But that's not really relevant, so I'm going to withdraw it.

EXAMINER JONES: The exhibits are admitted.

MS. BISONG: Thank you.

EXAMINER JONES: Please say again what those exhibits are.

MS. BISONG: Those are the exhibits under Tab 2, A and B.

EXAMINER JONES: Tab 2A and Tab 2B.

MS. BISONG: Correct.

EXAMINER JONES: Okay.

(Mesquite SWD, Inc. Exhibit Number 2 with A and B are offered and admitted into evidence.)

EXAMINER JONES: Okay. Mr. Bruce?

MR. BRUCE: I don't have any questions.

MR. PADILLA: No questions.

EXAMINER JONES: Mr. Roach?

MR. ROACH: No. I don't have any questions.

EXAMINER JONES: Mr. Brooks?

CROSS-EXAMINATION

BY MR. BROOKS:

Q. Now, I'm looking at the basic stratigraphic table, which you have here --

A. Yes, sir.

Q. -- and the Ordovician is the level immediately below what you said drillers called the Devonian, right?

A. What drillers call the Devonian.

Q. Well, please clarify for me because I'm not clear on this.

A. So if you look back at drilling records and even today, when people say, "We're going to have a saltwater disposal well and it's going to target the Devonian for injection," what -- and this -- if I can be a little geeky for a moment. This stems back to -- back in the day before we understood the age relationship of a lot of these rocks in detail, there was the assumption that the Wristen and the Fusselman were of some part of Devonian age, and then the paleontologists got involved. And it turned out that those are actually Silurian in age, but the language that had historically been used by geologists and drillers in the basin referring to the Wristen and the Fusselman as, quote, "Devonian" persists, even though from a straight geologic standpoint, they're not Devonian in age. And so if I were a stratigraphic purist, I would get very upset about this, and I would tell you the injection interval is actually Siluro to Siluro-Devonian.

But all of the language used in all of the C-108s and all the various paperwork, geo-prognosis reports, everything refers to the injection interval as the Devonian.

Q. Okay. Well, the bottom of the injection

interval is -- I see you don't have -- you have the Montoya in here between the Fusselman -- or the Montoya is in here. I assume -- did you prepare this --

A. Yes, sir.

Q. -- this exhibit or is this a printed --

A. I prepared this based on Ron Broadhead's stratigraphic chart for the Delaware Basin.

Q. Okay. It looks like the target injection interval is only the Silurian. It does not include any part of what you show as Ordovician, right?

A. Actually, if you notice, the Fusselman can also be Upper Ordovician.

Q. Oh. That's right. It brackets the Silurian and the Ordovician. And the Montoya is actually in the Ordovician, all of it, according to this chart, but it's not part of the target interval, correct?

A. Generally, what we have set up -- the message we have received from OCD is that anyone who is going to drill into the Montoya is not to go more than 100 feet into the top of the Montoya.

Q. Okay. Now, what is the thickness of -- hold on a minute.

Okay. The bottom permeability barrier in these locations is considered to be the Simpson, which is part of the Ordovician?

A. Yes, sir.

Q. And what is the thickness of the Simpson in this area?

A. So for Laguna Salada or for Baker or for all three?

Q. For Laguna Salada first.

A. Okay. So for Laguna Salada, it's on the order of 250 to 300 feet thick, and that's isopachs combined along with the few reference wells we had that go deep enough to show that rock unit.

For the Baker -- just to make sure I get you the right numbers. For the Baker, the estimated Simpson thickness is on the order of 700 feet thick.

Q. Okay. Now, you're talking about the Simpson only, right? Was your response as to the Laguna Salada the Simpson -- specific to the Simpson, 250 to 300 feet thick?

A. Yes. That's what you had asked for.

Q. So the permeability barrier is -- your opinion is that that's 250 to 300 feet thick?

A. For the Laguna Salada area.

Q. What about the Baker?

A. It's on the order of about 700. It thickens as you go to the southeast.

Q. Okay. Where are the control points?

A. So what we've done is used a combination of the isopach maps from the Texas Bureau of Economic Geology, as well as the reference wells that are shown in the cross sections.

Q. Well, how far is your nearest control point?

A. For the Laguna Salada, we're looking at -- for that one, it's spaced between the 301544407 to the west and the 301544054 to the east, and that span between those two reference wells is a little less than five miles.

Q. So the -- how does that -- what distance is it from the -- from the Laguna Salada projected locations?

A. So if you project them into the cross section, you're looking at probably a couple of miles from the projected location of the well to the reference, whether you go to the west well or to the east well. And so the two Laguna Salada wells are spaced near to each other.

Q. Did you say two miles?

A. From where they project into the line of cross section.

Q. To where they project into the line of cross section. Can you explain that?

MS. BENNETT: Can you identify that on the map by pointing to it?

Q. (BY MR. BROOKS) That's right. You need to

explain this to me.

A. Okay. So we have all of our reference in the purple dots coming across from northwest to southeast.

Q. Yeah.

A. And then the very two last wells to the southeast, the last two purple dots, that's the area we're going to focus in on on the cross-section line.

Q. Okay.

A. So just to the north of them are the two yellow stars that represent the Laguna Salada wells.

Q. Yes, ma'am.

A. And so the blue lines between the stars and the yellow-dashed line between the reference wells, that's how we projected the position of the two Laguna Salada wells into the line of cross section.

Q. Okay. So the distance from -- the distances from those -- along those blue lines -- the length of those blue lines shown on the map, if plotted on the ground or under the ground, would be approximately two miles?

A. Give or take, yes, sir.

Q. Okay. I think I now understand.

Okay. If we had to include the Ellenburger, would that function as a -- as a permeability barrier between what's above it and the

Precambrian?

A. I would be hesitant to include that as a permeability barrier. It can have a slightly higher porosity and permeability, so that's not a unit that anyone traditionally tends to think of as a lower permeability barrier.

Q. Slightly higher than what? The Simpson?

A. Yes, sir.

Q. Okay. Now, what about -- is there anything further between the target injection interval and the Precambrian that would provide additional insulation?

A. Not that I'm aware of.

Q. Okay. I think I have no further questions.

I do not understand your description of these maps. Maybe you can tell me so I can make some notes here. These -- one, two, three, four -- five maps --

A. Yes, sir.

Q. -- all look identical to me. I couldn't spot any differences, but you tried to explain that they were plotting isopachs from different locations; is that correct?

A. They're thicknesses of different rock units. So it's the same location. But it's like if I dug a giant hole in the ground and we started down at the

Ellenburger and we were to climb back up the hole, it would be how much thickness of each of those rock units we would basically climb through as we went through the Ellenburger on up through the Woodford Shale. So each of these maps is the same location, but the different colored lines that have numbers written on them -- and the Ellenburger is not the best one because there is only one isopach line. But let's pick one that's got more --

Q. Well, I never even identified what were the isopach lines actually.

A. So on each of them, there is -- so let's actually switch to Tab B, to that Morrow one, because that's super busy. And now I'm actually glad that it crept into things.

Q. That's under Tab B?

A. Tab B. And it's the figure right before the cross section. So we're doing the super wiggly one.

MR. BROOKS: Well, if nobody is confused about this except me, I don't see --

(Laughter.)

(Dr. Zeigler approaches Mr. Brooks.)

MS. BENNETT: Is it okay for her to approach?

THE WITNESS: Oh, I'm so sorry. Am I not

supposed to do that?

MS. BENNETT: Is it all right if she goes over and shows --

MR. BROOKS: I think we're running on a rabbit trail because --

MR. GOETZE: May I recommend we have a discussion on it later?

MR. BROOKS: I think that would be a good idea.

MS. BISONG: We are aware that they can be labeled better, and we will do that.

EXAMINER McMILLAN: As in earlier hearings, redo all of them and send them -- re-send them to all of the affected parties, as was requested yesterday, putting a header on the top.

Do you have any questions?

EXAMINER JONES: Well, I do, but I'm not the geologist, so go ahead. I'm like Mr. Brooks here. I'm confused.

MR. BROOKS: Well, your name is much more closely related to geology than mine.

MR. McMILLAN: Yeah, but I've been --

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. So going back to Laguna Salada, how much of the

Montoya do you think will act as a barrier out of the 300 feet?

A. So the Montoya is generally a fairly tight unit, and so it can, on its whole as a thickness, act as an additional part of the permeability barrier. But it's our understanding that saltwater disposal operators are not to go more than 100 feet into the top of the Montoya.

Q. Okay.

A. But it is a tight unit, so it will act as an additional barrier to fluid motion.

Q. Okay. Okay. So I'm going -- the question I'm getting is -- I'm going to the first page of Exhibit B.

A. Uh-huh.

Q. You're saying that the Wristen to the north targeted -- reservoirs are targeted for production are dolomitic with regular and fracture-related porosity. First of all, do you actually think the vugs are going to contribute to the porosity?

A. I think locally in the Wristen.

Q. Okay. Well, I've always been -- my knowledge of carbonates is that vugs have no permeability.

The other question I'm getting is --

A. I thought you said porosity. I apologize.

Q. The other question I'm getting is -- so the

primary porosity, which is going to contribute to the permeability, is going to be the intergranular porosity, correct?

A. Uh-huh, along with potentially some -- some localized fracturing within the unit.

Q. Okay. So based on that, do you think that the porosity and the associated permeability is going to be constant, or do you think it would be variable?

A. I think it will have some variability within it.

Q. Can you describe what that -- how do you envision that?

A. So just thinking about in any -- any reef system anywhere along like a shelf margin, we're thinking about not all reef-building structures and not introduction of granular material from the shelf edge is going to be identical everywhere, and so you're going to get lateral variation within these rock units simply by the nature of it being a complex environment. And then as we go through lithification and we bury it, you're also going to have differences in cementation, difference in dolomitization that are going to occur.

Q. Right.

So then what's going to happen to the diagenesis as it -- do you think it's going to create

little pockets of porosity and permeability?

A. I think that's a fair assessment.

Q. So do you believe based on the variability in the -- variability in the permeability, do you think that you're going to get a radial flow, or do you think you're going to get some form of a linear flow?

A. I think it's probably going to be more radial than linear.

Q. But you -- okay. Do you believe you're going to get the linear flow out of it, some characteristics of it?

A. There will be some linear flow depending on bedding planes, depending on fractures, depending on reef orientation, if you're in a reefal [sic] part of the system. But I think until we get a lot more data for the deep basin, it's going to be really hard to know for sure the patterns of diagenesis, the patterns of dolomitization that are going to control that behavior. This is flying blind a little bit in the deep basin.

Q. Yeah. Because, you know, I'm familiar with the Yeso.

A. Uh-huh.

Q. And, for instance, I remember one well that we did. And we drilled the well, and it was tight. And we were going to plug it. And the operator went in there,

put a big frac job, and it turned out to be a pretty good well because they were able to connect some of the permeability.

A. Uh-huh.

Q. Now, I realize it's a different system, but in terms of diagenesis, it's very, very similar --

A. Yeah.

Q. -- in that case.

EXAMINER JONES: Okay. Mr. Brancard?

EXAMINER BRANCARD: I just have a labeling question.

(Laughter.)

CROSS-EXAMINATION

BY EXAMINER BRANCARD:

Q. Okay. So stratigraphic chart (indicating). Maps (indicating).

A. Yes.

Q. The stratigraphic chart shows Precambrian, basement rock.

A. Yes.

Q. The maps indicate two different kinds of faults, Precambrian faults, basement faults.

A. Yeah. And we talked about this. This is because we're combining two different sets of data to create where we think the fault traces may be. The green lines are from the Texas Bureau of Economic Geology study, and the blue lines are ones we added and compiled from a lot of Ron Broadhead's compilations in the area, because we noticed that there are a lot faults that are shown in one data set, but there are some that don't show up in the other data set. So we chose to combine the two data sets to show all potential fault traces that anybody has ever thought might be in the basin. And so we kept them color-differentiated to keep the Bureau of Economic Geology fault lines separate from Ron Broadhead's projected fault lines.

Q. Okay. But geologically they're in the same --

A. Same deal, basement, Precambrian, granite, yes.

Q. Maybe that's another labeling thing.

A. Yes.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. Okay. Dr. Zeigler, so there is a degree of -- do you think there is a degree of lateral compartmentalization similar to what Mr. McMillan was talking about? Is it always that way in a dolomite?

A. The dolomitization process is maybe not as well understood as I think a lot of people feel like it could be, and I feel like we still see comments in literature that come out suggesting that you could have complete dolomitization of an interval, or you could have a sort of hodgepodge dolomitization of the interval.

And in looking at some literature last year for dolomitization in the Madera Group up by Socorro, it's not -- it seems like the jury is still out on how uniform that process can be through any given rock unit. And when we're dealing with these depths with as little data we have from reference well to reference well, it's hard to understand how that is changing over 500 feet or a mile or more miles.

Q. Okay. If you had your druthers, what kind of logging and sampling and coring would you ask for?

A. I would like continuous core.

Q. Wireline retrievable continuous?

A. Uh-huh. Everything you could get. Honestly, I think I'd prefer -- and I know we're working on this right now, but having deep wells that are -- more deep wells closer together -- I know that's not what you-all want to hear. But it's hard for us to say what's happening between two reference wells that are five miles apart. I mean, the thicknesses do not shift significantly over that distance, but lateral heterogeneity may be shifting in a way that we're not understanding the patterns of it, which is what Mr. McMillan was getting at. It's hard to understand the patterns of difference in these rock units when we have so few control points at depth to tell us what's happening.

Q. Okay.

A. And also the more you bury things, the more you compact and you run fluids through them and things happen.

Q. Okay. But before everything got changed, what kind of depositional -- what happened during the Devonian time? How did this rock get laid down?

A. So as we go through -- from the Bliss Sandstone through the Ellenburger on up to the Devonian, we're seeing basically -- as we're coming into the end of the Pennsylvanian -- or I'm sorry. Not the Pennsylvania. As we're coming into the Silurian going into the -- we have this fairly deep basin that's sitting there, and it has modern -- or not modern, but oceanic conditions, and you have, you know, your reefs going along the rims of it, and you're slowly acquiring this slimy mud and various fossil material in this basin, and that's just slowly accumulating over time, with the Woodford Shale representing that deepest, dark shale, the history of the deepest part of the basin, and the water level is the deepest.

Q. Okay.

A. And then as you go on up, we see that shore -- or that sea -- the sea retreats, and we get on up into all of the complexities of the Pennsylvanian and the Permian, especially the -- and the Rockies building.

Q. Okay. Is the higher-energy environment lower then in the middle of the section, that target interval, and you say it's getting quieter as it gets up towards the Woodford; is that correct?

A. Yes, sir. You're getting quieter, but you are, in some places, probably going to have -- like we see this a lot in the Bone Spring, where you get these little turbidity currents and other one-off events where you're moving higher-energy deposits out along the basin floor. But, again, I feel like because this is so deep and we know so little about it, understanding the geographic pattern of where those maybe higher-energy zones may be, I don't think we fully understand that like we do for the Bone Spring.

Q. Okay.

A. Yeah.

Q. The shale barrier in the Simpson --

A. Uh-huh.

Q. -- that was just another quiet deep ocean time?

A. That was actually mixed terrestrial to near shore. So the Bliss Sandstone is a sandstone that's more terrestrial in origin. And so as we step from the Bliss on through into -- through the Simpson to the Montoya to the Fusselman, we're seeing that slow inundation of that part of the continent with a shallow seaway, and that shoreline is going to fluctuate back and forth a little bit as we slowly flood that part of New Mexico at the time. And so we're transitioning from more terrestrial down into marine, into deep marine and then transitioning out as that sea level retreats.

Q. Okay. Is this a totally different -- well, I better not go there right yet.

Do you have any idea of tectonic stresses in the Devonian levels right now?

A. So the -- and this is something that Mr. Reynolds will get into a lot more. I don't want to steal his thunder.

Q. Okay. Okay. That sounds good.

These faults that you've got mapped on every one of these, including the Morrow, but did it actually go up through into the Pennsylvanian age, these faults?

A. So these faults have a complicated history. A lot of them started out as Precambrian structures during the rifting of Laurentia. And then as we slowly put North America back together again, we go from those faults being that original rifting structure. And then as we come into the Pennsylvanian to Early Permian and we go through compression that creates the ancestral Rocky Mountains, we reactivate a lot of those faults.

Q. Oh, okay.

A. So we don't necessarily change the orientation of them. I mean, North America is moving, so their relative orientation is changing. But the faults themselves are just being reactivated in a different sense of motion. So we go from extension and opening to compression. And then in basin and range time, we reactivate some of them again with the extension that's affecting North America after we built the Rocky Mountains.

So the faults are old. Most of them have been there a very long time, and they keep getting reactivated by these different stretch, compress, stretch.

Q. Are they normal faults?

A. It depends on what stress you're under. So ancestral Rockies, they would have been high-angle reverse faults. Basin and range, because now we're extending, we're going to go back to a normal orientation. So they're going to change depending on what's happening to this part of North America.

Q. Okay. Does that also imply that there is more child faulting or however you call it, the drag faults or the -- in other words, extensions of little faulting away from these big faults?

A. I think that's something where we would need a lot better three-dimensional seismic control to really understand where there are these smaller faults coming off the bigger fault, how they're oriented and how they act. But there doesn't seem to be -- at least in the deep basin data that we have, it's hard to see if and what is happening with anything off the big -- those big major faults.

Q. Do you think the only danger of injection-induced seismic would be if you're close to the big faults, or is there just as much danger if you're out away from these big faults?

A. I'm actually going to defer that question to Mr. Reynolds because he can show you some really cool data that shows how -- distance from faults and behavior.

Q. Yeah.

A. So yeah.

Q. Okay. Okay. The big -- I guess one of the big questions -- and you're a stratigrapher, I think. So the Devonian seems to just suck up water. Is it going

laterally, is it going vertically, or is it going both? From a stratigrapher's standpoint, is it so anticular [sic; phonetic] that it's just going out in little preferred high-permeability lenses, or is it just a big monolithic thing that's sucking it up like a big sponge?

A. Well, stratigraphers always hate to use the word "monolithic" (laughter).

Q. Engineers can say that (laughter).

A. So just my thinking of the depositional environment in the rock units, I think it's going to trend a little more towards it being what Mr. McMillan was getting towards, that it is a more heterogeneous thing. And we hear about some saltwater disposal wells that were expected to take a lot of water, but they unexpectedly don't. And so there is enough variability in the system that it's not easy to just say it's always going to behave this way. But I think until we have more data showing, at different parts of the injection interval, how different parts of the Fusselman acting, how are different parts of the Upper Montoya acting, it's really hard to get at what exactly is happening.

Q. Okay. Okay. And your answer to the question: Do you think the environment is protected by protection of fresh water, that was kind of confining protection of the environment to protection of fresh water. Is that

how you would view it, the environment is being confined to the protection of fresh water? I know the legal people will chime in on this, but just between you and me.

(Laughter.)

EXAMINER BRANCARD: We won't listen.

(Laughter.)

THE WITNESS: So I think -- and this is -- so my team does a lot of groundwater resource management for agriculture in northeast and eastern New Mexico, and I spend a lot of time thinking about the upper freshwater aquifers in the state -- in the eastern part of the state.

And what happens here is not only do we have a fairly shallow zone of freshwater groundwater resources, but if you look -- and we haven't spent time talking about the Morrow or the Strawn or the Bone Spring or any of these rock units that are between the target injection interval and the deepest we get fresh water out here. And by fresh water, we're trending toward what a cow is willing to drink, which pushes that envelope a little bit.

So when we look at these other rock units, you know, we go through a lot of variation in the rock types as we go up, and there are many other shale barriers that exist between that. So it's not just the Woodford we're hanging our hat on.

Q. (BY EXAMINER JONES) Okay.

A. It's everything upsection that helps protect those freshwater resources.

Q. And Mr. Broadhead, when you used -- did you talk to him --

A. I did.

Q. -- before you made this?

A. Yes.

Q. Okay. That's all the questions I had.

EXAMINER JONES: Any more for Dr. Zeigler?

MR. PADILLA: I don't have any questions.

EXAMINER JONES: Sorry. I'm sorry.

MR. BROOKS: Well, I have a lot of questions, but I'm not going to ask them. I'm done asking questions.

EXAMINER JONES: Okay. Thank you very much for coming.

THE WITNESS: Thank you.

EXAMINER JONES: Appreciate it.

How long will the next witness be?

MS. BENNETT: Probably a half an hour, maybe 45 minutes.

EXAMINER JONES: Let's keep going here

because if we break for lunch later, it will be quicker. It won't be so crowded out there.

MS. BENNETT: At this time I'll call my next witness, Todd Reynolds.

MR. REYNOLDS: Since I'm on the stand, I'll grab my jacket.

EXAMINER JONES: You don't have to.

MR. REYNOLDS: All right.

EXAMINER McMILLAN: I'm not the examiner.

EXAMINER JONES: He might disagree with me. It's getting hot in here.

TODD W. REYNOLDS,

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

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Please state your name for the record.

A. Todd W. Reynolds.

Q. And for whom do you work and in what capacity?

A. I work at FTI Platt Sparks. I'm the managing director and geologist and geophysicist. I'm here on behalf of Mesquite SWD.

Q. And you've previously testified before the Division and the Commission, right, or before the Division anyway?

A. I have.

Q. And were your credentials accepted as a matter of record?

A. They were.

Q. And can you just briefly give us an overview of your educational and professional background?

A. Sure. I received my bachelor's in geology and geophysics from the University of Texas in 1985. I started work in the E&P industry of the oil and gas business primarily interpreting seismic data, specifically looking for faults.

For the first, I'd say, 15 years of my career, we were working in the Austin Chalk -- fractured Austin Chalk trend, and seismic data was used extensively to locate fairly small faults, 50-foot faults because that was the target. I mean, the intended target was to try to intercept the fault with the wellbore because that was the fractured interval and that was the reservoir in that formation. So a lot of my career has been examining seismic data to identify faults. From there, we moved into the Gulf Coast and other areas. But, again, faults are something that you're always looking for because it may be the target or it may be the trapping mechanism for the reservoir.

I did that for 15 years and then formed my own company and spent the next 15 years developing prospects, seismic based typically, oftentimes 3D seismic data.

And then for the last five years, I've been at FTI Platt Sparks, and I've been introduced to the saltwater disposal world.

Q. And you've been in love with it ever since, a love-hate relationship, love-love.

A. No comment.

Q. No comment.

That was just between me and you, by the way.

(Laughter.)

Q. So are you familiar with the applications that Mesquite filed in these cases?

A. I am.

Q. Have you conducted a fault slip probability analysis related to these cases?

A. Yes. In addition to that, like Dr. Zeigler, I've created cross sections in the area to get myself on some level of comfort. Are there other faults out here that haven't been identified by the BEG or others? And you do that by constructing a structural cross section. I mean, a fault is going to typically reveal itself in a structural cross section because you can see a significant step up or step down if you have enough control points. There are quite a few control points down to the Mississippian, and typically these basement faults or Precambrian faults do penetrate all the way up to the Mississippian, and you would see some expression of those. So in addition to the FSP analysis, I did some localized mapping and cross sections around the location.

MS. BENNETT: At this time I'd like to tender Mr. Reynolds as an expert in geology, geophysics and seismic matters.

EXAMINER JONES: Any objections?

MR. PADILLA: None.

EXAMINER JONES: Mr. Brooks?

MR. BROOKS: No objection.

EXAMINER JONES: He is so qualified.

MS. BENNETT: Thank you.

Q. (BY MS. BENNETT) I'm going to take the questions that we've gone through a little bit out of order based on some of the material we've gotten today and some of the discussions we've had over the past couple of days.

So you're familiar with the prehearing statements that the Division filed in these three cases, right?

A. I am.

Q. And did the Division in those prehearing statements cite to an EPA technical work document?

A. Yes. I believe there was a citation to that.

Q. And have you reviewed that EPA technical work document?

A. I have.

Q. And did you review it even before this hearing?

A. I've not only reviewed that document, I've actually reviewed most of those case histories in greater depth. We've actually gone in and mapped those areas ourselves and using seismic data to do a deeper dive into most of those areas where there is a clear link between injection and seismicity to look for specific characteristics that are -- in most of those instances and try to use that as a screening tool to mitigate seismicity for -- for clients.

Q. And one of -- one of the things that you mentioned -- or that Dr. Zeigler mentioned in her testimony is the orientation of a fault. And I imagine you look at that in your screening process to decide whether there are faults of concerns in the screening process that you do?

A. That's correct. The first and foremost is to identify if there are faults of any orientation. And then once the faults are identified, the orientation is a critical component to determine whether it's a critically stressed fault or likely to slip.

Q. Now, before we get into the details of your fault slip probability analysis, did you identify any faults of concern -- any faults, period, within your area of review for these wells?

A. I did not. And, you know, what I use as an area of review, since they're somewhat -- I don't know that the FSP analysis is actually a requirement in New Mexico at this time, but as -- in lacking any guidance, I just used the same parameters that we use in Texas. When it's warranted, I look at a 100 square-mile area.

Q. And you just said when it's warranted. What makes the fault slip probability analysis warranted in Texas?

A. What will trigger the need for additional analysis is Texas is you take the saltwater disposal location, and you draw a circle around it. It equates to 100 square miles, which is a radius of 5.64 miles. That equals a 100-square-mile area. If you find a historical earthquake event within that circle, then you conduct additional scrutiny or screening that includes a structural cross section in two directions, a strike and dip, a structural map at the top of injection interval and a structural map at the base of the injection interval. You take the difference between those two. That gives you the isopach. And what that does is it shows how much lateral continuity there is for the injection interval over the -- over the study area. And it typically will reveal faults of concern.

In some areas, you have a lot of data points. The Delaware Mountain Group, we have lots of penetration, so the maps are very detailed with a lot of control points. Obviously, at the deeper depths, we have fewer control points. And so, you know, you're looking at different variables. And when you have -- when you have the luxury of having seismic data, you can answer a lot of those questions.

But to answer your question, I did not find any faults in that circle.

Q. But backing up even a step -- I think I might have jumped a step. You said you need to first analyze or assess whether there has been any historic seismic activity in the area. Did you do that assessment for the Laguna Salada wells?

A. Yes, I did, and I did for the Baker also.

Q. And what did you find in terms of historic seismic activity in the area of review for the Laguna

Salada wells?

A. I'd have to refer to my maps. I think it was the Laguna Salada; there was maybe a seismic event just outside the circle of both of those.

On the Baker, there was -- there were no events even close at all. I don't think there were even any on the map, which goes well beyond the circle, except for the -- the events recorded on NGL's system, which were maybe 25 or 30 miles away.

Q. Uh-huh. So then if there were -- if there was historic seismic activity, then you would look to see if there were faults of concern. So you did that here, too?

A. Yes.

Q. And did you conclude that there are any faults of concern?

A. In both of these applications, the Laguna Salada and the Baker, it's kind of hard to do the FSP analysis when there are no faults, but I did not find any faults. I did the analysis anyway, and I threw some hypothetical faults into the analysis just to calculate the pressure out to a fault that might exist five kilometers away.

Q. So you actually had to sort of gin up a model for this because there is no fault within the area of

review to do a fault slip probability analysis?

A. That's correct.

Q. And earlier, though, Dr. Zeigler testified that there were Precambrian basement faults. How far away are those?

A. I think you might see them on my maps when we get to those exhibits, but they're -- in general, the distance is, as she quoted, ten, 15, 20 miles away, and the pressure from the modeling would not have any effect on those faults.

And getting back to your other question, they're not optimally oriented. They're optimally oriented typically 90 degrees from the optimal orientation, which takes pressures in excess of 4,000 pounds to make those faults slip. And the .2 pressure limit that is placed on the well will not have an increase of 4,000 pounds right at the well. So some fault some distance away, that pressure is even less.

Q. So let's turn now to your exhibits, which are behind Tab 4. The first exhibit in Tab 4 is -- well, can you explain to the examiners what the first exhibit is? I'm sorry. These are behind Tab 3. I apologize. Behind Tab 3.

A. Gotcha.

Q. What's the first exhibit there?

A. A1?

Q. A1, yes.

A. A1 is an exhibit that's -- it's a schematic taken from the U.S. Geological Survey on their earthquake archive portion of the website. And it just -- it just kind of illustrates the differences in magnitudes of earthquakes, how frequently the small earthquakes occur versus the large earthquakes, you know, at what magnitude do humans feel it. Typically, this shows around 3.5, but I would push that down closer to 3, is what would be felt by humans. And as you see, when you get below 2.0, there's -- there are millions of those worldwide that typically are only known in areas where you have a seismic monitoring system close enough together where they can be detected.

Q. Now, are you familiar with Dr. Steven Taylor's study that he's prepared?

A. Yes, I am.

Q. And is that study actually behind the purple shade of paper saying "Seismic Catalog Analysis within 50 Kilometers within the Laguna Salada Well"?

A. Yes, it is. And at the bottom of it, it would be labeled "A2."

Q. And he's also prepared a similar study for the Laguna Salada 19 well; is that right?

A. Yes. And we can probably discuss both from one report.

Q. And if you could just give a very high overview of these studies, just sort of what Dr. Taylor does and the highest magnitude that he's encountered in his seismic monitoring.

A. Sure. So on the second page, there is a Table 2.

I believe his Table 1 is the USGS historical events that have been reported in the area.

The Table 2 are events that he has located and recorded on the system that NGL has installed out in southeast New Mexico and across the line over into Texas also. I believe he's -- he's located 13 events in the southeast New Mexico area, all of which have a small magnitude. That's going to be the column in Table 2 that is second from the right. So the magnitudes go from 1.25 up to, you know, a high of about 1.98, so below 2.0.

Q. Okay. I think that's good. Thanks.

EXAMINER BRANCARD: Can you let us know where you are.

MS. BENNETT: Sure.

THE WITNESS: Right here (indicating), second page of Exhibit A2.

EXAMINER BRANCARD: (Indicating.)

MS. BENNETT: Yes.

Q. (BY MS. BENNETT) And so just to review again, that second page has -- Table 1 is the historic figures of magnitude. Table 2 is the most recent figures of the magnitude that Dr. Taylor has measured in the area?

A. That's correct. I believe -- I'm not certain what Table 1 is. Just looking at the dates, they're all since 2011. But it's -- it's events that he's noted on his maps within 50 kilometers of these wells. Probably look to the maps to find out what the source -- source data is. I suspect it's USGS, though.

Q. And so now, unfortunately, I want to turn to another exhibit that's also labeled A2.

MS. BENNETT: And I apologize for the confusion, but I had to add exhibits this morning and couldn't redo the packets altogether.

Q. (BY MS. BENNETT) So this Exhibit A2 is actually a -- has a cover sheet for the EPA memorandum from the work group. It's immediately behind the USGS graphic, and it starts with "A Memorandum," sort of a cover sheet, dated February 6th, 2015. It looks like this (indicating). And then the next page of that is an excerpt from the EPA UIC technical work group report, and that is labeled "page B15." Do you see those two?

A. Yes, I do.

Q. And is it your understanding that it's this final work product from the National Underground Injection Control Technical Workgroup that's cited in the prehearing statements submitted by the Division?

A. I believe it is cited. Yes.

Q. And does this look like materials that I excerpted from the work group manual and work group final product?

A. The EPA work group, yes.

Q. Yes. Okay.

If I could ask you to look at Exhibit B15.

A. Also known as Exhibit X?

Q. Sorry. Yeah. B15, page B15. Sorry.

Page B15, it says "Figure B1" at the top, "Injection-Induced Seismicity Decision Model for UIC Directors." Do you see that?

A. I see that.

Q. Okay. Have you had a chance to review this decision tree?

A. Yes, I have.

Q. Can you give us a brief overview of what you think this decision tree is designed to do?

A. Well, I think it's designed to scrutinize saltwater disposal wells a little more closely than they were in the past. Oftentimes in the past, you know, permits were just walked through and let's put water in this formation, and as long as we're protecting the fresh water, that's really all that was looked at closely years ago.

Now there is the concern of induced seismicity, so we have other things that we're looking at such as faulting and how good of a formation is it to put water into, things like that. So this is kind of a decision tree to guide or assist UIC divisions in whether to grant a permit or not or whether to impose some other -- some other restriction on the application because there was some concern for seismicity. It might be monitoring. It might be reduced injection rates, or it might be some certain setback distance from known faults of, you know, some -- some specific distance.

And as you look at this, you know, there are exit points. If no concerns are identified, you exit and you just go to the regular process.

Q. So let's look at the first assessment that's done for new Class 2 oil and gas waste disposal wells. That's here in the upper -- in the upper corner. There is one for existing and one for new, and these are proposed new. So let's look at the initial assessment criteria that a UIC director would look at under the EPA

work group document that is cited in the Division's prehearing statements.

A. Okay.

Q. So would you mind reading what those assessment points are in this bubble right here (indicating)?

A. The upper right?

Q. Yes.

A. "Is there a history of successful disposal activity in the area of the proposed well?" The answer would be yes.

"Have there been area seismic events?" Well, what is going to be your area of review? In Texas, it's 100 square miles. And so here you would say -- under that standard, you would say no, there are none within that 100-square-mile area.

"Is the disposal zone in or near basement rock?" And the reason this is kind of focused on a lot of times and sometimes somewhat misguided is that many of the cases of fairly well-proven induced seismicity were into the Ellenburger or the Arbuckle, which sit directly on basement rock. They're both known to be fractured formations. And so there was a direct conduit into the basement rock. There was no confining layer at the base of the injection interval. The injection interval was -- you know, it was not the greatest zone for injection regarding seismic activity. It's a great zone for taking water on a vacuum because it's fractured and that kind of thing.

But -- so here, no, we're not sitting on basement rock, and we're really not near basement rock. We've got the Ellenburger. We've got the Simpson. We've got a tight Montoya section sitting above you, and we have a lack of faulting. Because in those areas -- even in those areas, all the other injection wells sit -- the disposal zone sits on basement rock. There is no induced seismicity except for the ones close to the faults. I mean, the fault is the problem. That's what's lacking from that first box, is there is no discussion of how close you are to faults. And that's really what should be in that first box.

So if there are no concerns identified, you exit stage left and go to the regular process.

Q. Okay.

A. And if this -- if this were across the state line, it wouldn't even have elicited the FSP response, but --

Q. And by --

A. -- we're proactive and did it anyway.

Q. And you mean these three applications?

A. That's correct.

Q. And that's because the disposal zone isn't in or near basement rock. There's been no area of seismic events based on the 100-square-mile area of review, and beyond that, there is no faults of concern?

A. Correct.

Q. Okay. Let's now turn to your FSP analysis, and that's about ten pages behind the EPA work group document, and that's marked A4.

A. Okay.

Q. Okay. Is this the fault slip probability analysis that you prepared for the Laguna Salada 13 and 19?

A. It is.

Q. And the first few pages are just sort of a summary, right, of your conclusions?

A. Yes. It kind of walks through the analysis and describes what's shown on the exhibits, but it's probably worth describing it in person rather than just saying, "Read this" --

Q. Yeah, exactly.

A. -- "we'll talk later."

EXAMINER McMILLAN: Is everyone on the page he's talking about?

MR. BROOKS: (Indicating.)

MS. BENNETT: Yes. Uh-huh.

EXAMINER McMILLAN: Okay. Sorry about that.

Q. (BY MS. BENNETT) So if you look at page 4 of 4 of your summary report, which looks like this (indicating), page 4 of 4, it says "FSP Analysis Findings and Conclusions." Do you see that?

A. Yes, I do.

Q. Could you briefly run through your findings and conclusions for the Laguna Salada wells?

A. Yes. There are no mapped faults in the 100-square-mile area of review, and that would include, you know, the ones that are noted by BEG and others. Plus, our own analysis found no evidence of faulting in the area. There are no historical earthquake events within the 100-square-mile area of review. And based on that, plus the analysis, this area represents a very low risk of induced seismicity related to SWD injection.

It goes on to say that we ran the model at injection rates over a 25-year period at constant rates, which is not typically what you see, so we kind of ran a worst-case scenario.

Q. Okay. And turning to the next page that's labeled "FSP Exhibit 1," says "FSP Data Worksheet" on the top --

A. Yes.

Q. -- looks like a figure, could you explain for the examiners what the FSP worksheet is?

A. Yes. This is just where I compile a number of the inputs that are necessary to run the FSP model. And, you know, we have top of the base of the injection interval. The model is run at a depth of the midpoint just because you have to calculate the pressures at some depth, and we've used the midpoint to do that.

And then there is also some other factors such as resistivity, formation temperature, salinity that all go into determining the viscosity of the fluid. Then there are compressibility formations, the fluid compressibility.

Aquifer thickness. I do not assume that the entire interval is going to take water. Based on log analysis that I've seen in the area, it's typically about a 50 percent ratio of rock within a defined interval that would be -- accept water -- have porosity and permeability that would accept water. So we have an aquifer thickness that we use for the model, porosity value, permeability.

The vertical stress gradient is just integrated from a density log. And minimal -- minimum horizontal stress gradient, basically that assumes a frac gradient of .67. So, again, being conservative, because I've seen quoted in some other cases over here a .75. So if it is .75 instead of the .67 that I used, you know, the likelihood of slip is even less, if you put a .75 in there.

"Initial pore pressure gradient" and then "azimuth of the maximum horizontal stress." This question came up earlier about the stresses in the injection interval. We derived this from the Snee-Zoback paper for the stress study for the Permian Basin. And at this location, we calculate this to be 45 degrees east of north.

Fault orientation is just dependent on each fault, so you can't put a constant in there. It's going to vary based on each individual fault. Faults out here are typically near vertical, so we assume a fault angle of 85 degrees but with a variance of 5 degrees. So if you go up to 90, you go down to 80. And that's what's in the right-hand column, is the variance that we use toward modifying the fixed variable. So we build some variation into the model to allow for the fact that we don't have a lot of data points out here. We can't just assume it's the same thickness everywhere.

Friction coefficient is .6, which is what you see typically assigned for a pre-existing fault or fracture, not facture. That's a typo. And, again, I go back to the .75 because that was quoted as a frac gradient for the formation. It shouldn't be -- the concern shouldn't be: Are we fracking the formation? The concern should be: Are there existing fractures already there, because those open at a much lower pressure. And that's one of the justifications for using a lower frac gradient of .67. It's the pre-existing fractures that you need to be concerned with.

So that's a long answer to what Exhibit 1 is.

Q. And I think that goes to a question I have, which is you took all that information into account when you did your fault slip probability analysis; is that right?

A. That's correct.

Q. And, I mean, I'm guessing that there is -- you know, your fault slip probability analysis identifies the distance between these two wells, but really what you're talking about there are geologic inputs and other -- the faults, for example, and their orientation, and that is -- at least to my untrained ear sounds like it's not -- that doesn't have a real correlation that I can find to the 1.5-mile spacing requirement. How do those -- how does the 1.5-mile spacing requirement, in

your opinion, take into account -- a per se mechanical application of a 1.5-mile spacing requirement take into account all of those things that you just went through with me?

A. It doesn't. And I've prepared an exhibit where I've created a grid of wells in a 1.5 spacing and then project a critically oriented fault right through that batch of wells. That 1.5-mile spacing does nothing to mitigate the risk for induced seismicity because it's only treating it as a two-dimensional problem drawing a circle around wells. It hasn't analyzed whether there is a fault of concern in the area.

And that's why this FSP software was developed. It takes into account the faults, the orientation of faults and the geographic position of every well, whether some are a half mile apart from each other or if some are a half mile away from each other. All of that is built into the model and projecting how much pressure is going to be seen at any fault in the model.

So, you know, just trying to push wells apart is not particularly a seismicity mitigating tool. It should be something more like pushing wells away from identified faults. Some -- some buffer zone around faults should be the real guidance that could be used to mitigate seismicity.

Q. Uh-huh. And you were here when Mr. Jones asked Dr. Zeigler a question along those lines, about what is the real concern here; is it the faulting? And she deferred that question to you. And it sounds like, in your opinion, that's what the concern is. Is when there is a fault of concern, then this deeper analysis needs to take place?

A. Absolutely. I mean, there was a line of questioning about how the thick is the Simpson. Well, it's 250 feet or 300 feet or whatever it is. But if there is a 400-foot fault, it doesn't matter. That's your conduit. Those layers, yes, that's an insurance policy. The more -- the thicker the confining layer is, that's great. But if there is a fault nearby that breaches that confining layer, it doesn't matter how thick that confining layer is. So that's kind of -- a false focus sometimes is, you know, are we far enough from the basement? Well, the question should be: Are you far enough away from the fault? Because if there is a fault nearby, that water or that pressure is going to get to the basement via that fault, not breaching through the confining layer.

Q. And when you say the concern is whether there is a fault nearby, you mean a fault -- do you mean a

fault of concern or just any fault?

A. Well, a part of the screening process is to identify any fault. And then the next step is: What is the orientation of that fault? We have actually conducted the FSP analysis at the DFW Airport and Fashing and Azle and all these other areas, and when you run the software, it's amazingly predictive. The peak in pressure from the wells, there is a -- there is a great time matchup to the data and the model, and so it's somewhat indicative that the model does have some value. And it can not only show problem areas, it can show -- you can use it to throttle rates back, keep those faults below a certain threshold. And so, you know, that's -- that's why we've gone to this extent, is to show that we don't believe this area is a risk relating to seismicity.

Q. And for the faults -- the Precambrian basement faults, what is the stress -- what's the orientation of those faults and the stress orientation that would be needed to create induced seismicity there? Are they pretty -- I don't know the right FSP analysis term, but are they pretty solid?

A. Well, it would probably be a good time to go to FSP Exhibit 2 --

Q. Thanks.

A. -- because off to the southwest, we see two faults that are noted by the BEG and were also noted by the Snee and Zoback paper. And in this particular area, the direction of the maximum horizontal stress is approximately 45 degrees east of north. And so a fault that has an orientation within 20 degrees of that would be one that I would consider a fault of concern. And we see one on this map. It's over to the west. It's the orange fault.

And not every injection well -- we did not go out and show every injection well beyond our arc. We just went out about -- a little bit beyond our arc. But for whatever reason, it did catch one over to the west near that fault. And I happen to know from having looked at that area previously, there are actually two wells next to each other right there. So that would be -- that would be a situation where it would be of greater concern. That fault is oriented very close and similar to the orientation of maximum horizontal stress.

And I will say, as Dr. Zeigler said that, you know, a lot of these faults were put on a map 30 years ago. Someone wrote a paper and they estimated where they thought faults were. We have found that a lot of times you've got 30 years of drilling and more data points out there, and you map it and you say, "That fault is just not there." My recollection of looking at that one is that it was -- there was not a lot of strong evidence that that fault really existed in that particular area. But that is a fault that's oriented and would be a fault of concern, if it existed oriented in that direction.

The green fault is the exact opposite. It is almost 90 degrees from the maximum horizontal stress. And so it takes, as I stated earlier, in excess of 5,000 pounds to cause slip on a fault that's oriented in that direction.

Q. If you don't mind, why don't you just take us through all of the slides in your FSP for the Laguna Salada real fast.

A. Sure. And I mentioned previously that there were -- I thought there were two earthquake events just outside the area of review. So there was one in 1974 on the west side just outside the circle. And then there is one in 2012 just outside the right side of the circle.

Q. And those are denoted by the blue circle with the blue circle inside of it?

A. That's correct, kind of the blue bullseye-looking symbol.

The NGL network did not detect anything on this map or has not since it's been running, so recent seismicity, no, even though obviously there is a lot of new injection out here.

But what this map depicts is my input data points. All the injection wells that were placed in the model are the injection wells within the circle, and then I believe we went out just a half-mile or so beyond the circle to try to catch a few more wells for the analysis. And so all of those wells are inputted into the model, and we also input the Laguna Salada wells at the proposed rate.

Q. What's the rate that you used for the other wells? Is it a historical rate?

A. If it was a well that had history -- actual injection history, we take the last -- the final rate reported and hold it constant over the life of the model, because, you know, we all know there is plenty of demand. If that well could take more water, they'd be taking it. So that's kind of an indication of what that well is capable of injecting. So it would not be -- it would not be a good valid input to just assume, well, let's just put up whatever rate it applied for, put that in and run it.

Q. For other -- the proposed wells and other proposed wells in the area, you used --

A. I used a higher rate. For some of the pending wells where I just didn't know what they were applying for, I used 30,000 barrels a day, which is again in excess of what most of the actual wells are injecting out here. And then for the two Laguna Salada wells -- and we'll get to a slide that shows what those volumes are, but those were input at 40,000 barrels a day.

So if we go to the FSP Exhibit Number 3, which I referenced earlier, that's where we derive the stress data for the area of review.

Exhibit Number 4, we need to provide a little bit clearer copy, but basically on the chart, the nomograph on the right, this is how we derive the viscosity. And that value affects how much pressure builds up and how quickly is the viscosity of fluids.

Exhibit Number 5 -- FSP Exhibit Number 5, here we have a map in the center part of the exhibit. It shows all the input wells into the model. And the FSP software is just not real graphically friendly, so you can't edit the font size or anything like that. But that's the input wells regardless of how far apart they are. It's -- you know, it's the actual distance that's between the wells that's put into the model. And as I stated earlier, we use the actual rates they've been injecting or assumed rates of 30- and 40,000 barrels a day.

Now, Exhibit Number 6 would be typically where I would put in the report some of the geomechanical details of faults, but there were none, so it's kind of a blank page. The one we presented yesterday was a more full package because it had some faults in the area of review.

Same thing with Exhibit 7. This would be where we would show the calculated pore pressure to slip at each of the fault segments. And I can tell you that it's around 1,500 psi for a critically oriented fault of 85 degrees dip. So just keep that in the back of your mind, 1,500 psi.

Exhibit 8 would be another analysis of faults in the area of review. With none in the area, there was nothing to review there.

Exhibit 9 is where we start showing what the pressure field will look like from the injection that's put into the model. And I had also mentioned earlier that I just put an assumed fault at some distance, five kilometers due west, from the Laguna Salada wells. That would be the little green line that you see that has a 326 next to it.

I also put a point near both of the wells to show what the calculated increase in Delta P pressure would be right at the wellbore at that point in time and just to see if we're staying under the .2 speed limit, if you will, or regulator.

So what this exhibit shows, if you look in the upper left -- excuse me -- upper right, it will show the pressure along each fault segment, which we don't have any, but the two points we have for this model is the fault, hypothetically five kilometers to the west, and then just what the actual BHP increase is of the wells. It's going to be that higher line. And this is at 2025, January 1st, 2025. We see that if there was a fault out there five kilometers away, it would be at 326 pounds, primarily caused by the wells south of it at that point. Those are the ones putting the most pressure on that assumed fault.

We move forward in the model to 2035, January 1, and as expected -- as you would expect after that much time and putting that much water, your Delta P right at the well is now at about 2,300 pounds, still below our .2 limit. So I just continued to hold the rates flat because we haven't maxed out yet. The hypothetical fault five kilometers to the west is at 814 pounds now.

And January 1, 2045, we see how the pressure field is growing from this group of wells. And so had we had a fault in the model, we could -- we could look at those faults, and based on their orientation, determine whether there was a likelihood to slip. And since we didn't, we've also created kind of a hypothetical model, which we'll show.

Q. But even here on this one at 2045, with these two wells spaced one mile apart, this increase in pressure on this hypothetical fault isn't --

A. Yeah. Even if those two wells were a mile and a half apart from each other, you're probably still looking at the same 1,133 pounds out there at that hypothetical fault, whether they're one and a half or 1.0 or whatever, because all the wells go into the -- into the calculation.

Q. Uh-huh. So Exhibit B is essentially the same as Exhibit A except for the Baker wells; is that right?

A. Before I answer, let me just check.

Q. Yeah. Yeah.

A. I believe it is the same type of analysis. It's the same report by Dr. Taylor and the same analysis for the Baker. We might turn to FSP Exhibit 2 within Tab B just to -- just to see where the Baker well is relative to any faults in the area. And I'm looking at this map here (indicating).

Again, we show the Baker well and existing injection wells -- excuse me -- existing deep-injection wells. We have not included the shallow in the model. And in this particular area, there is just not a lot of other wells. There was one other well to the northeast, and I think I may have picked up two wells outside the circle that went into the model.

The faulting is some considerable distance off to the southwest and northeast. And, again, these are -- these are oriented in a fashion that they're not necessarily in a dimension -- or an azimuth that would be considered critical.

You do see, with the pink, kind of fuchsia-colored bullseyes to the northeast, some seismicity that's been recorded on the NGL system. It's not as clear on this map, but you see all these little well sticks in the area and you'll see that there has been a tremendous amount of drilling and, you know, fracking of those associated wells which we've seen. That's another area we've studied, and we have found instances where you could date those to the actual day of the frac job. But USGS considers those to be typically not worrisome because they're kind of a short-term event and not a long-term situation. So, you know, that's one possibility of that seismicity. I haven't looked at that close enough to do that kind of analysis and compare when the frac dates were or anything like that. But I just point out, from looking at the map, it's pretty obvious there is a lot of activity right there.

Q. And just to remind everyone, Dr. Taylor's monitoring results didn't reveal any events higher than a magnitude of 1.98 or basically 2.0, right?

A. That's correct. And nothing in the area of what we would consider an area of review for this particular location.

And so, you know, we could go through it all, but it's basically the same conclusion as you walk through those, is to put a hypothetical fault out there some distance away. With it, since there weren't many wells in the area, it only reaches 184 pounds out to the west of Baker. So, again, I see this as -- absent any faults in the review area and no history of seismicity, it doesn't appear to be an area of great concern that injection would cause additional seismicity.

Q. So that's your conclusion for both sets of -- for the Laguna Salada wells and the Baker wells, that there is no risk of induced seismicity or little risk? I know I can't say no, or you can't say no.

A. I don't see the characteristics that are very common in the instances where we know there's a good --

a strong link between injection wells and seismicity. None of those characteristics are presented here.

Q. And earlier we talked about the prehearing statements that the Division had filed in these cases. Are you familiar with those prehearing statements?

A. I am.

Q. And do you recall that those prehearing statements suggested that a 1.5-mile spacing location is necessary to minimize -- and that's a spacing between wells -- that's going to minimize induced seismicity? Based on your studies, do you think a 1.5-mile spacing requirement is needed to reduce the risk of induced seismicity? Spacing between wells, I'm talking about.

A. No. I think there are much better mitigation strategies out there that could be applied. And if -- if an area is determined to be high risk, then certainly that 1.5-mile radius might be applicable in areas such as that. But just to broadly enforce something like that without any real evidence of faulting or historical seismicity or problems with the injection interval, it doesn't seem appropriate over a broad area. It may be very appropriate in specific areas.

Q. Would you say your conclusion, that it needs to be -- all these variables need to be looked at and it needs to be done basically on a case-by-case basis or,

you know, looking at the specific geography and the specific fault at issue, is consistent with the UIC work group manual that was cited in the Division's prehearing statement? Is that part of the approach they suggest, as you recall -- if you recall?

A. You're talking about the EPA --

Q. EPA, uh-huh.

A. Yes, because it is site-specific of whether or not a well is a risk of seismicity. Because on each -- if you're looking at an EPA paper, they quote about five examples, and on every one of those examples, the well is too close to the fault. In most instances, it's less than a mile from the fault. In several that we've reviewed, the DFW Airport one, for example, the well cuts the fault in the Ellenburger. So the day they turned the pumps on, the pressure was beyond the slip pressure. And that well -- the earthquakes showed up within 20 days. They didn't have to put a certain volume of water in the ground to increase the pressure, because when they flipped the pumps on, that pressure was seen at the fault because the fault was in the wellbore. And it was a 1,000-foot fault. It was -- you know, you hear this expression a lot of time, "Well, it was an unmapped fault. We didn't know it was there." The operator knew the fault was there because they had

3D seismic, and the Barnett Shale well was on one side of the fault and they drilled here (indicating), and on the other side of the fault, they drilled 1,000 feet deeper. So just -- if the screening process we have in place now in Texas would have been in place then, a simple cross section would have shown that this is a well that could have been prevented.

The same was true in Timpson, which was another case we looked at in East Texas. The well cuts a 400-foot fault in the wellbore, not in the injection zone, but it's in the wellbore. You know, it's harder to find vertical faults in a wellbore, but you can still find that relationship of it's 1,000 foot lower over here than it is over here. And the other was that well injected into a zone that never should have been approved. It was the James Lime and a shale interval, and that zone had no potential to accept water except through the fractures. And when the water goes into the those fractures near a fault, they go straight to the fault. And, you know, we did the FSP analysis on that particular example, and they injected for a period of time, and then they slowed down their injection. They had a distinct peak in their injection profile, and that's when the earthquakes were.

So, I mean, it's -- it can't be something that you just blanket and punish everybody. You need to identify the problem areas, and then when seismicity does occur, look at the wells where the seismicity is occurring. Can you identify a fault? Can you identify one well that particularly is maybe the problem well? And in most cases, that's what you'll find, is that it's not always this idea that all the wells in the basin are pressuring up the formation. That is true. That is happening. But in these examples that I've looked at, there is just simply a well that should under -- under good screening process, it shouldn't have been allowed, and it could have been prevented that way.

Q. It sounds like you've done a lot of work at looking at events that have happened and then been able to test those against the fault slip probability analysis and have seen -- been able to extrapolate some red flags from your work.

A. Yes.

Q. Are any of those red flags present here?

A. No. I mean, when some of these guidelines came down the pike in Texas in 2014, our firm dedicated about a half million bucks to researching all these other places it had occurred, looking for specific characteristics so that we could advise our clients. A lot of times when they come to us and they say, "I bought this 5-acre tract at the intersection of these two roads," we say, "Well, you should have come talked to us first because it just so happens there is a fault a half mile away from you."

So I think there are certain suggestions that we've made to Texas UIC of ways to screen and have -- would have caught situations like that and prevented it. And they're not costly. They're, you know, fairly straightforward things that can be done in advance that don't punish everybody but specifically try to identify a problem application.

Q. Thanks.

I think in the interest of time, we won't go through the hypothetical that you developed that shows 1.5 mile versus 1.5 mile because -- wells near a fault versus wells away from a fault just because we're running short on time.

A. If I may have one minute to describe it --

Q. Yes.

A. -- and if they would like it submitted for review later.

Q. Yeah. Uh-huh.

A. It was basically just a grid of 30 wells spaced 1.5 miles apart and then drawing a hypothetical fault through the batch of wells that's critically oriented to slip. And what you find is that, well, some of those wells are going to be too close to it on that 1.5-mile pattern, and by 2035, the fault is slipping.

And then I took the same 30 wells, but I deleted the ones that were within like a mile of the fault on either side of the fault -- and so that took the batch of wells from 30 down to 20, I believe -- and ran it all the way out to 2045 and no fault slip.

Q. Even though the wells in the second example were still 1.5 miles apart from each other?

A. Still 1.5 apart from each other and still injecting at the high rate of, I think, 30,000 barrels a day on all the wells in the model. So obviously you can eliminate ten wells, but, you know, that's ten wells that probably ought to be drilled somewhere else. And so in other areas, maybe the one-mile is appropriate in areas of no concern, because now we've got to accommodate for some wells that we didn't allow in another area.

Q. And so based on the hypothetical, what it revealed to you, as you mentioned earlier in your testimony, is it's the proximity to the fault and not the proximity to other wells that's the trigger?

A. Exactly. Simply checkerboarding the wells does nothing to reduce the risk of induced seismicity. It's limiting the wells that are allowed to be drilled near either known faults or faults that were revealed in the screening process. And as I described earlier, those cross sections and structure maps on the injection interval are the first screening tool.

If the UIC or a regulatory division is still concerned, they might ask the applicant to purchase a seismic line and show us there is not a fault. You know, we like your analysis, but there's just not enough data points at that depth. We're still concerned. You know, if you've ever looked at the grid of available TV seismic data, it looks like somebody dropped spaghetti on the floor. There are seismic lines all throughout the spacing that can be acquired to take all the guesswork out.

Q. Now, I know you haven't had -- I know these exhibits that were prepared by the Division haven't been accepted into the record yet, but I did just have a question about whether you had a chance to look through them.

A. Yes. I did earlier this morning.

Q. And I don't want you to talk about anything in particular in those exhibits, but just in your review of those exhibits, did you see anything that was site-specific to these sites of these wells?

A. No. Most of the -- well, all the literature that I saw was examples of some of the case studies or the cases around the U.S. where there is a pretty clear connection between injection and seismicity. I can see -- I didn't go beyond that. I think we know that that's a possibility. But a deeper dive into those reveal certain characteristics where it's most likely to occur, and I'm sure that's discussed in a number of these. I know it's discussed in quite a bit of detail in the full EPA report, about, you know, carbonates versus sandstones, known fractured formations, that kind of thing. But over and over and over, the common element is you need a fault.

And in the applications we're here talking about today, there is -- nobody -- and there is nothing in this book of exhibits (indicating) that has identified a fault in the area of these proposed wells. I did notice some these had some examples from New Mexico, and in general, it shows the same fault patterns that we've put on our maps. And I just do not see any site-specific reason or anything in these potential exhibits that are specific to this location. They're just kind of 30,000-foot looks at the subject of seismicity, which I think we all can see there are places where it is caused by injection and there are a number of places where it's related to other factors, oil field factors but not injection.

Q. Thank you.

Turning back to your exhibits, were the exhibits behind Tab 3 exhibits that either you prepared or that you have reviewed and are confident in their subject matter or were compiled under your direction?

A. They are.

MS. BENNETT: At this time I'd like to move that the exhibits behind Tab 3 be admitted into the record.

EXAMINER JONES: Any objection?

MR. PADILLA: No.

MR. BRUCE: No.

MR. BROOKS: No objection.

EXAMINER JONES: The exhibits behind Tab 3 are admitted.

(Mesquite SWD, Inc. Exhibit Tab 3 are offered and admitted into evidence.)

MS. BENNETT: Thank you.

I have no further questions.

EXAMINER JONES: Okay. Mr. Bruce?

CROSS-EXAMINATION

BY MR. BRUCE:

Q. One question: Looking at the Baker -- proposed

Baker well where you say there are no faults within 100 miles, is that a ten-mile -- like a ten-mile grid, or is it a circle?

A. The 100-square-mile area is a circle. It's a 5.64-mile radius --

Q. Okay.

A. -- and that equals 100 square miles.

Q. Okay.

A. The faults, I believe, on that map were 20 to 25 miles away.

Q. Okay. Thank you.

EXAMINER JONES: Mr. Padilla?

MR. PADILLA: I don't have any questions.

EXAMINER JONES: Mr. Roach, do you have a question?

MR. ROACH: No.

EXAMINER JONES: Mr. Brooks?

MR. BROOKS: I have no questions.

EXAMINER JONES: Mr. McMillan?

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. The question I'm getting is your EPA flowchart, did you look at -- the question I'm getting is what about Dagger Draw? How do you explain that?

A. How far away is that from here?

Q. It's like --

MR. CLAY WILSON: 40 miles.

Q. (BY EXAMINER McMILLAN) Okay. All right. That's 40 miles.

Then have you looked at that cause? And that's the classic example that I want to talk about in New Mexico.

A. Sure.

Q. That's the reason I'm bringing it up.

A. I have not done the kind of analysis I did at DFW and Timpson and all the Texas sites where seismicity has occurred and SWDs were potentially blamed on it. I've looked at every one of those. But the same kind of analysis could be done at the area you're talking about, and I have not looked at that one.

Q. I think it's safe to say that the operator drilled into the ground and he injected into the ground, and there has been known seismic events.

A. And there was probably a fault nearby, too, I would -- I would expect. I mean, that's kind of a classic no-no, is don't drill into the -- the basement formation, specifically in close proximity to faulting.

But to answer your question, I have not done a full-blown deep dive into that one. It could be done, but generally I like to get paid for it.

(Laughter.)

EXAMINER McMILLAN: Go ahead.

CROSS-EXAMINATION

BY EXAMINER BRANCARD:

Q. Well, speaking of not doing deep dives, I notice you didn't mention Oklahoma. Have you not analyzed what happened in Oklahoma?

A. I mean, I did mention Oklahoma in passing in that the problems there were the Arbuckle, which is kind of an equivalent to the Ellenburger in Texas. The problems, you know, were faulting and injecting into a fractured carbonate near faults.

Again, it's -- it's kind of the classic characteristic you see over and over and over on these problematic areas, is -- well, for example, the Gulf Coast of Texas, most of the injection goes into sandstone formations, clastics. And those are subdivided by shale layers typically, you know, 100-foot shale sand and sand, shale, sand, shale. And so we don't get -- and there are hundreds of injection wells that are located near faults, cut faults and faults oriented optimally to slip, and there is no seismicity. And part of that is faults don't behave as conduits like they do in a carbonate.

In a carbonate, a fault can be a sealed

fault, but oftentimes, they're fractured, and they are the conduit to the basement or to a problem, you know, a stressed interval. So, you know, there is an example of wells in close proximity to faults and there's never been any problems, and it's a characteristic of the formation that the injection is going into.

But, you know, I didn't -- I didn't not [sic] mention Oklahoma on purpose, but because -- and I will mention it in more detail now. Unfortunately, Oklahoma tends to be what we create the guidance and the rules based on, because both Texas and New Mexico has probably said the same thing, "I don't want to be the next Oklahoma." I've heard that a number of times at the UIC. But a number of times, I've told them, you know, you've got to look at the formation. It's not just draw a circle around the map and apply a rule. It's a four-dimensional problem. You have to look at, you know, what's going on at the depth that you're injecting at. Do the faults penetrate that depth, and were there other activities occurring that might have been related to the seismicity?

In Oklahoma and the Barnett Shale area, those faults are highly conductive to the point that most producing wells that cut those faults in the Barnett or the formations above them have tremendous saltwater-production problems, because there is salt water -- just tremendous amounts of salt water coming up the fault plane and being produced in the Barnett well or wells above the Arbuckle or in south Texas.

The Eagle Ford sees the same thing. If an Eagle Ford well is in close proximity to one of these faults that penetrates the Edwards, they make a tremendous amount of salt water. So it's -- it's proof that you have a conductive fault.

And Zoback has speculated or theorized that a conductive fault is indicative of a critically stressed fault because it's open, and it's allowing fluids to move along that fault.

And so there are factors that you can look at, and I've suggested this to UIC and presented a paper on this at AAPG, is that in the Barnett Shale area, the focal points of seismicity are near the Barnett wells that make the most water. There is a bullseye of seismicity around these Barnett Shale wells that are producing anomalous volumes of water, which is indicative that there is a conductive fault there, and, you know, just things like that that can be identified to say, "Hey, that's probably not a good place for us to put a saltwater disposal well near those wells," because it's just a cycle. You're injecting the water here.

It's pushing water toward the fault that's producing it, and you're sending it over here, and you've just got this cycle going on.

The effect of that water moving up and down the fault plane actually changes the coefficient of friction on the fault, and it makes it slip easier with no pressure increase at all.

Q. So I guess I'm confused here because your documents -- your testimony has focused almost entirely on the location of faults and prior seismic events, which is what this FSP model analysis focuses on. And now I hear you saying that it's the formation that's the issue such as in Oklahoma.

A. Well, that's just one of the factors. The Arbuckle or the Ellenburger is not a problem when it's properly or far enough away from the fault. But as you get closer to a fault, there is more likelihood of fracturing that can come off of that fault that would be -- the fluids can get into that fracture system and then get into the fault. And the reason I say that is that's more likely to happen in a carbonate versus a clastic sequence where the faults are typically sealed because there are sand-shale sequences that seal them.

Q. So would your conclusion then for these wells that it would be fine for them to inject into the

Ellenburger?

A. For these wells?

Q. Yes.

A. Of course we're not asking to do that, but it is fine to inject into the Ellenburger if you've appropriately screened the area and determined that there is -- there is not a faulting concern in the area. Because, for example, in the DFW area, there's -- it's in the order of thousands of injection wells which don't cause any problems, but there is a handful that are too close to conductive faults that cause a problem. And that generally is -- whether it's the Ellenburger or any other carbonate.

And that is one area of concern in the Devonian here, is that you would like to identify faulting because it is a carbonate also. It doesn't quite have the fracture history that the Ellenburger and the Arbuckle and some of those formations do, but there is some remote potential for that.

Q. So if the focus is on faults -- I think I understood you to say that we do have an issue here with unmapped faults anywhere, and that's really something that should be of concern to the program.

A. There are methods to map them, though. I mean, a lot of these research papers, unfortunately, rely on -- even the Snee-Zoback paper on the stress for the Permian Basin relies on a fault trace grid that was generated in 1990. So obviously there is much more data and better data to determine where those faults really are today.

And, you know, if an area of concern is identified, there might be a requirement that an operator or an applicant consider demonstrating with a seismic line that there are no faults of concern in the area. But the first step would be cross sections and mapping and things of that nature. If there are enough data points to alleviate that concern, that may be the end of it and determine, yeah, there is a fault or no, there is no evidence of faulting.

If a concern remains, then the step that would answer the question is a -- is a 2D seismic line or two across the area to prove that there is not any faulting here within -- within a distance that the pressures could reach. So we're talking about 18 -- $15 million wells. To go out and buy a couple of seismic lines to be able to drill that well and prove that it's not in a bad area is not an unreasonable expense for an operation of that magnitude.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. You would need to reprocess it, wouldn't you, to focus on those depths?

A. It would depend on the vintage of the data. There are a number of -- obviously, a lot of the newer data is 3D, and that tends to be more expensive and beyond the budgets of what most saltwater disposal operators want to incur. But there is a lot of high-quality 2D data out there that can see the type of faults that we're talking about that would be of concern.

Q. The stress that's relieved when these seismic -- these movements happen in the basement rock, is it higher -- closer to the fault, or is it higher away from the faults?

A. Well, the energy released is right at where the slippage occurs, and as you get further away from it, it becomes, at these magnitudes, not detectable. So that's why, you know, a lot of the USGS points are typically in the higher-magnitude range because they just don't pick up the smaller events because their recording devices are so far spaced apart that they're not going to identify a 2.0 magnitude event like Dr. Taylor's system would.

Q. Okay. So if injection into a basement happened a long ways away from these faults, the faults are acting as an area that can relieve the stress, but you might get a bunch of little, bitty faults then, right, just little, bitty seismic movements that would relieve stress in the adjoining and the basement rocks; is that correct?

A. Yeah. I think that's going on all the time without injection.

Q. Okay.

A. And that's probably a good thing because we don't want to see an accumulation of stress over a long period of time without some movement and then you end up having a much larger event like you see on the San Andres fault, where it's stuck and it builds up, builds up, builds up, builds up and then it moves and it's more catastrophic. So a bunch more smaller events that none of us ever knew happened is a good thing.

Q. So the big movement happens where it has happened in the past, at the fault? You don't start new faults this way.

A. Well, generally, it just takes a big fault for a big event.

Q. Okay. Do you know if you -- if you drill from the driller's term "Devonian" into the Ellenburger that

you get a lower pressure if you get loose circulation or anything in the Ellenburger?

A. There are areas where the Ellenburger is more like a .43.

Q. So sometimes you do?

A. Sometimes. A lot of times that's in areas where the Ellenburger has had some historical production or something of that nature.

But, you know, the pressure regime out here is fairly complex. And in the studies we've done, we believe that is part of the cause of the seismicity, is that we have normal pressure generally in the Delaware Basin down through top of Wolfcamp and then it gradually starts building to an overpressured environment of about a point -- up to a .75 --

Q. In the Pennsylvanian?

A. Yeah, and into the Mississippian. And then it dramatically drops off to normal pressure again from the Woodford down. And that also illustrates how good of a seal the Woodford is, because you're not going to have that sharp contrast in pressure gradient without some permeability barrier.

And from the studies we've done, there was a series of earthquakes that occurred near War-Wink in the '70s and '80s when -- for the -- a study that was conducted for the WIPP project to determine whether seismicity was of concern before they disposed of nuclear waste out here. They picked up over 1,500 seismic events around War-Wink, a cluster of them, and then they went away over time. And what they found -- and the multiple authors have concluded this, and I'm seeing the same thing in the Delaware Basin now on the Texas side -- is there was an -- there was an activity flurry of Wolfcamp development and overpressured formation development at that time period. As they drew down the pressure in those formations, they had this clustering of seismicity widespread, not focused along any specific fault.

And we're seeing the same thing in Reeves County now. Seismicity is popping up in areas long before any injection has taken place in the Delaware Mountain Group in those areas, but wells are being brought online and extracting fluids and dropping the pressure. So it's a stress change.

Q. Uh-huh.

A. It's a stress change in a rock down close to where the depths are where there is faulting. And the injection that's taking place up in the Delaware Mountain Group, there is no faulting at that depth.

Q. You were talking about this 100-square-mile

circle. And these faulting data that you would need to screen -- in other words -- back to the question Mr. Brancard asked. Is this data -- it's not public yet then, right? You would have to get the seismic and process it and come up --

A. Yeah. If you were pushed to the point of requiring a seismic line to prove or disprove the existence or nonexistence of a fault, that would be an expenditure, and that would be -- the seismic -- the company you buy the seismic data from, they're going to want you to treat that as confidential. You would probably have to show it to the Division under seal and not be released in the public record because they don't like to do that. But they might allow you to sanitize the seismic line and cover up the shock [sic] points and cover up the shock [sic] points on the map, show it to the regulators to prove your point and then put it in the public record.

Q. Okay. You said basically the stress regime out there is northeast-southwest, and you showed a schematic with a bunch of lines kind of northeast-southwest. Are you basing that on existing faults or the assumption --

A. No. That is typically stress measurements taken from wellbores.

Q. Okay.

A. And it rotates around. As you get over near Carlsbad, it's more maybe 30 degrees, but as you get over toward the Texas border and Winkler County, it's rotated to about 90. And then when you get into Texas, it's rotated all the way around to 135. So it's changing, and typically you can determine what the distress direction is from breakouts in wellbores. You'll get kind of an elliptical shape to a wellbore that will determine the stress direction in that area in that specific formation.

Q. Uh-huh. So if they've done that, then they probably know the stresses in the -- in the deepest part of that well, too. I mean the Simpson and these lower-sealing zones. So you think the Simpson is a pretty good seal then --

A. Yes.

Q. -- the Montoya and Simpson?

A. Yes, I do.

Q. Thank you very much.

A. Sure.

EXAMINER JONES: Is that it?

MR. BROOKS: I would like to ask a couple of follow-up -- well, do you -- I would like to ask a couple of follow-ups.

EXAMINER JONES: Okay.

CROSS-EXAMINATION

BY MR. BROOKS:

Q. Basically your conclusion is that induced seismicity is no fault, no problem, right?

A. In general, that's correct. I've not seen a case of induced seismicity where there was not a fault at issue.

Q. But you said the available mapping data -- fault-mapping data is not very good. At least that's the conclusion I got from what you said.

A. I think -- yeah. What we both stated is a lot of faults that are depicted aren't there. In some instances, you do find that those faults exist at or near where they're shown on a map, but -- and again -- yeah. Since that was kind of a regional look, I'm fairly certain they didn't detect every fault either in the right location. And that's why a screening technique of, you know, building structural cross sections and actually mapping the site-specific formation in the site-specific area has the ability to reveal those faults. Because these fault traces that we're relying on on these maps, they did not go into the level of detail that we go into in this 100-square-mile area. Generally, those were papers done 30 years ago. They may have had 30 log data points, and they say, "Well, it's quite a bit higher here than it is over here; there must be some faulting in here." We've got a lot more data now to be able to look at well log data, penetrations to the formations where we can identify whether there is a problematic fault or possibly identify that the fault that's shown on the map just isn't there.

Q. But you didn't have very much penetration data on the deep part available as to these particular locations, did you?

A. I think there was better data and penetrations more numerous around the Laguna Saladas than the Baker, was my recollection. But from the cross sections that I drew in a strike and a dip direction, there was no evidence of the kind of step-up you see over to the area to the north -- or actually to the east where there's -- we had some applications that we presented in the area of maybe Sparrow and a lot of NGL wells over there.

There's -- there's a north-south trending fault trend, and then with the cross sections that I've conducted over there, it clearly steps up 4-, 500 feet. There is no doubt that there is faulting in that area. And that's how quickly it reveals itself. Just with a couple of cross sections, you see that yes, there is a fault here.

Q. Where is this you're talking about?

A. Let's look at one of these exhibits. I think I can get really close to it.

Q. This is one of your hypothetical --

A. No. It's a real one.

Q. One of your -- but is it related to this -- to the area under discussion?

A. No. It's on one of those maps.

Q. Yeah.

A. But it's off -- far outside the area.

Q. I don't want to go -- I do not want you to go into it any further at this point.

If you were to rate your conclusions that there are no faults in the Laguna Salada area on a scale such as people in interviews are required to write -- are often asked to relate to, high confidence, intermediate confidence or low confidence -- of course, the margin is very high or very low -- what would you say about your conclusions?

A. In the area of the Laguna Salada, the cross sections that I looked at -- basically, you had a well at this end. I think it had five wells on the cross section, and the dip rate down that cross section was just constant. There was no clear step up, step down. So I would say based on the data available to me, with an intermediate level of confidence, I can say there is no faulting in that area of those wells.

Now, we've got more and more injection wells coming into play here, and as we get those data points, those data points themselves will determine whether they we're right.

Q. And, of course, as you say, a 3D seismic is the gold standard.

A. Sure.

MR. BROOKS: Okay. No further questions.

EXAMINER JONES: That's it for this witness?

MS. BENNETT: Well, if I could just ask one clarifying question.

EXAMINER JONES: Okay.

REDIRECT EXAMINATION

BY MS. BENNETT:

Q. And I think you just touched on this. You did do your own cross section for this very area, right?

A. Yes.

Q. And so did Dr. Zeigler?

A. She did. Her cross sections are stratigraphic, so they're focused on continuity and thickness of the zones. So they don't reveal the type of structural implications I'm talking about because they're not a structural cross section, but they do give some insight into the fact that there is not drastic changes or changes in thickness, even though a stratigraphic cross section sometimes can reveal whether or not you're close to a fault because the thicknesses change abruptly on one side or the other.

Q. So we're not really looking at an unmapped area here per se. What we are looking at is an area where there are specific data points. They may be limited, but you took those specific data points for this specific site and you created a cross section and an isopach based on those data points for this specific site, and that is what your conclusion is based on?

A. That's correct. And even those fault traces that have been drawn 30 years ago, they relied upon the data they had at the time, and they said, "We think there are faults in this area, this area and this area." We have a considerable amount of data that's been added to the record since then to show where we believe faults are or that aren't.

Q. Thank you.

EXAMINER JONES: Okay. Let's break for --

Thank you very much, Mr. Reynolds.

Let's break for lunch and come back maybe at 2:15.

(Recess, 12:54 p.m. to 2:15 p.m.)

EXAMINER JONES: Let's go back on the record and continue with Mesquite's cases.

MS. BENNETT: Thank you.

MS. BISONG: Good afternoon. On behalf of Mesquite, I'd like to present our next witness, Scott Wilson.

SCOTT J. WILSON,

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

DIRECT EXAMINATION

BY MS. BISONG:

Q. Mr. Wilson, can you state your full name for the record?

A. Scott James Wilson.

Q. And who do you work for and in what capacity?

A. I work for Ryder Scott Company. My title is senior vice president, and I've worked there for 20 years. I'm here on behalf of Mesquite SWD.

Q. What are your responsibilities?

A. My primary responsibilities are doing technical studies on oil wells. I prepare reserve reports for SEC filing, financial entities. I also do simulation work. I teach classes in nodal analysis. Pretty much anything that anyone wants that is within my area of expertise, I'm willing to do.

Q. And you have testified before the Division or the Commission before, correct?

A. I have.

Q. And were your credentials accepted as a matter of record?

A. They were.

Q. Are you familiar with the applications -- the three applications filed by Mesquite?

A. I am.

Q. Have you conducted a petroleum engineering study related to these three applications?

A. I have.

MS. BISONG: At this time I'd like to tender Mr. Wilson as an expert in petroleum engineering.

EXAMINER JONES: Any objections?

No objections?

He is so qualified.

MS. BISONG: Thank you.

MR. BROOKS: I never object.

EXAMINER JONES: Mr. Bruce, any objection to --

MR. BRUCE: Absolutely not.

EXAMINER JONES: You saw "Ryder Scott" in the name and said, "That's it" (laughter).

Q. (BY MS. BISONG) Mr. Wilson, you were here earlier when Dr. Zeigler testified earlier about the locations and the proposed injection zones for these three wells, correct?

A. Yes, I was.

Q. Your exhibits -- or the exhibits that you've prepared are behind Tab 4, which is in front of you; is that correct?

A. That's correct.

Q. And can you turn to Tab 4 for me?

A. (Witness complies.)

Q. And your study includes the Baker well and the two Laguna Salada wells?

A. It does.

Q. What information did you consider when you put together your study?

A. I looked at the locations of the proposed wells. I placed them in a reservoir simulation grid around the nearby offsets and other wells that we are familiar with. I also considered the completion sizes, the tubing sizes that were planned, and have included as Exhibits A1 and A2 a description of the nodal analysis that describes why the larger tubing size is preferable over the smaller tubing size.

Q. Can you briefly describe for everyone what a

nodal analysis is?

A. Sure. A nodal analysis is a technique of identifying the pressure losses within a system, and the technique is where you incorporate the capacity of the injection zone to absorb fluids at different pressures. You also couple that with different tubing-size models, and with the coupling of those two systems, you can identify the net effect of the overall system and the resulting injection rates and pressures.

Q. In addition to the nodal analysis, you did a reservoir study?

A. I did. That follows -- it's probably Exhibit A10 forward -- actually, A9 forward.

Q. Okay. And before we start going through your exhibits, can you just briefly summarize your conclusions with respect to your reservoir simulations?

A. The reservoir simulation studies showed that at the proposed injection rates, even at the maximum proposed injection rates, that the area of influence around each of the injection wells does not extend more than a mile over 20 years depending on the thickness of the zone primarily. The wells to the southeast are the thickest zone, and at the same injection rate as the wells to the northwest, the area of influence is larger in the northwest. But, in general, the interference between wells remains small until you get 30 or 40 or 50 years out.

Q. And can you also briefly describe the results you found in your nodal analysis?

A. The nodal analysis clearly shows that the larger pipe size you use, the less energy is used up in friction and other irreversible losses.

Q. Turning to your exhibits, at Tab 4, the first -- can you just tell us which exhibits are part of your nodal analysis?

A. Exhibits A1 and A2 are the nodal analysis exhibits.

Q. Can you explain what Exhibit A1 tells us?

A. Sure. Exhibit A1 shows that the red curve there with the triangles represents the hydraulics of the 7-inch-by-5-1/2-inch tapered string tubing. Now, the line is difficult to see, and it has green boxes. So if you connect the green boxes, that would represent the line that is relevant for the 5-1/2-inch tubing throughout. And it shows -- this image shows that with the 7-1/2 -- or 7-inch-by-5-1/2-inch tubing, the injection rate would be predicted to be roughly 48,000 barrels a day. And with the smaller tubing, you would get 7,000 barrels a day, but just the magnitude of the change in injection rate based on the tubing string for this particular well. And this well specifically was the Alpha well, where we did a detailed analysis on that well. But the same concepts are relevant. And actually the deeper the well, the more extreme the difference in the cases will be. And this well was only at 13,000 -- well, about 13,80 [sic]. So for a deeper well, the difference in the friction drop will be even larger.

Q. And turning to Exhibit A2, can you describe what you see in this exhibit?

A. Sure. A2 just shows the summary from the prior plot. And it says if you're using tubing ID with 5-1/2-inch OD, which represents a 4.7-inch ID, the injection rate is roughly 37,000 barrels a day. Now, the joint tubing that's represented by the 7-inch plus the 5-1/2, the tapered string, is that upper triangle to the right, and that says under those conditions, you'll have as much as 48,000 barrels per day.

The blue inset table shows, based on the need for injection in the area, how many wells you would need under both of those scenarios. For example, if the area of disposal capacity was 400,000 barrels a day, you'd need 11 wells with 5-1/2-inch tubing, and you'd only need eight wells with the 7-by-5-1/2-inch tapered string.

Q. So in the case with the two Laguna Salada wells

and the Baker well, pursuant to your analysis, is it more advantageous to have a larger-size tubing?

A. Yes. It's better to have the larger tubing.

Q. And why is that?

A. Primarily because you use less horsepower driving the fluids into the formation, because frictional losses are basically wasted energy, and so you basically have to pay for electricity, fuel, gas, things like that in order to push the fluids down the small piece of pipe and fight the friction of going down that smaller piece of pipe. So it's good for the operator, it's good for the environment, it's good for everyone if you don't lose energy due to things that are unnecessary.

Q. Turning to the exhibits in your -- I'm looking at Exhibit A4. We do not have an A3. But jumping to A4, can you describe that next exhibit?

A. Exhibit A4 specifically is a map that shows the two Laguna Salada wells. They're highlighted in the center of the figure. There is a callout that shows where those wells are, and there is a gray circle that represents a one-mile radius around each of those wells. It's also fairly clear what a mile is because these are section lines, and those are two-mile. So that's Exhibit A4.

A5 shows where those two wells appear on Dr. Zeigler's structure map. And actually this is a thickness map. It's a Silurian-Devonian thickness map at those three locations -- at those two locations. And you can see the structural contour just to the left of the large yellow box that says "1,000 feet." And then there is another structural contour immediately below the large yellow box, and it says "1,200 feet." So just visually those two wells are going to be roughly 1,000 feet, maybe a little more, in thickness. So that's Exhibit A5.

Q. And just for the benefit of the examiners, tell us which isopach we're looking at.

A. This is the Silurian-Devonian isopach, and I've left the original title blocks and depth scales and length scales on here for reference.

Q. And you can tell by looking at the legend --

A. Yes. And actually immediately above the top of the graph, it says the words "Silurian-Devonian Isopach."

Q. Turning to Exhibit A6, can you describe what's in this exhibit?

A. This is an image -- a map image of the locations of Baker well. This is a slightly more zoomed-in image than the last image that was similar to this. This well is offset by the Paduca well. There is a one-mile radius shown by the gray circle there. This is also a boundary basically between Eddy County and Lea County. So that's for location purposes. But there are not a lot of wells in this area, so there is not much to see here.

Q. Turning to Exhibit A7, please describe what we see here.

A. A7 is similar to A5 in that it takes the well that we're discussing here, the Baker and puts it onto an isopach map that shows the thickness of the Devonian-Silurian at this location. And you can see, the Baker well to the far right is denoted by that blue star, and it's just off of the 1,400-foot contour. And up in the title bar of the exhibit, it says, "The Silurian-Devonian thickness at the Baker well is 1,400 feet."

Q. Exhibit A8, tell us what this exhibit is.

A. This is basically just showing that the area is developed heavily. All of the little white marks on this aerial photograph are wellbores or surface locations, surface pads. And so the area of interest is fairly well developed. It's flat. There is not a lot of terrain, things like that. It's basically a location map.

Q. I don't know if you can point us anywhere on this map where the wells of interest are.

A. Probably the best way to do it is to compare the road that cuts through there. And on A7 and A8, if you set them next to each other, you can kind of see the road following the same path through the area.

Q. The Del [sic; phonetic] Highway?

A. Yes.

So Exhibit A8 covers -- really it covers -- you can see on the far right-hand side the Texas boundary, and also Texas is on the south. And then over as far as -- I don't know. Is this Carlsbad? You guys know the towns better than I do. The far left-hand edge is potentially Carlsbad.

Q. Moving along to Exhibit A9, can you describe what we see in Exhibit 9?

A. Okay. So Exhibit 9 is the first of the grid plots that represents the simulation grid I built to model the performance of these wells and the offsets. This is a three-dimensional reservoir simulator. The Silurian-Devonian zone was mapped into the simulator based on the geologic maps provided by Dr. Zeigler. I then at each -- as each well is proposed, I look at the lat/long of the well. I compared it with the maps, and I identify where in the grid that would physically sit.

So then I say -- for example, the Laguna Salada 13 and 19, they're in certain grid cell locations. So I triangulate the grid cell locations and place them into the grid.

That little patchwork, the darker grid that you see there, is designed in order to try to get additional detail for the individual wells. And so wells of interest, I'll put a tighter grid around those wells so that you can see the response a little bit more accurately. Because the larger grid is only four cells per mile, so if you count four of these little cells in any direction, that's a mile distance. The finer grids are eight cells per mile, so it gives you twice as much detail.

Q. Can you tell us what the key in the bottom right-hand corner is?

A. Yes. That's the depth key. And the top item is 19,229 feet. And that's to the far right. It's off the scale on this image because we're only looking at the northwest corner of the overall grid. And you can see the red color here is roughly 13,000 feet. So the Laguna Salada wells are somewhere between the red color and the purple color below them. So they're mapped into this grid at roughly the depths that they're expected to fall on the maps from Dr. Zeigler.

Q. Let's move to A10. I think you can just go through the exhibits and finish describing --

A. Sure. So A9 leads to A10. The colors in A9 represent the depths of the formation. So if you look at A10, it's the wire-frame grid. And it's a little more difficult to tell what the depths of the individual wells are in this situation. But the inset image that's dark shows that to the west, the thickness is very small. Whereas, you almost double in thickness to the east. It also shows that the overall formation dips from shallow in the west to deeper in the east. So I've mapped the original map from Dr. Zeigler and then embedded that into this grid mesh in order to model it more accurately. So that's what's shown in A10. It also highlights the wells of interest.

A11 is the thickness of those zones. So now the color scale represents thickness. And the thickest zone here is roughly 1,900 feet, which is off the right side of the scale. The thinnest zone is the 797, the dark blue, which is on the left-hand side of the scale. And then the rainbow colors that phase up -- or downward from there are shown at the exact well locations, as best I could.

So, for example, the Baker well is in a reddish-orange color, so you can expect it to be roughly

1,300 to 1,400 feet thick. So that's Exhibit A11.

A12 is the pressure. So this is the first what's called dynamic property in the grid. Dynamic properties change over time. And so the initial pressure in the grid is based on the depth of the individual grid cell, the fluids that are in that cell and any capillary pressure effects that might affect the particular cell. So this one shows the pressure you'd expect to see in any of these zones.

So, for example, the Baker well location is in a greenish-yellow color. So I would expect it to be roughly 7,500 psi, which is the difference between the green title -- or the green legend area and the orange legend area. So that's the initial pressures.

And if you look quickly at A13, that shows the pressures after 20 years. So when you turn the grid on and start injecting fluids into, as you'd expect, the pressures in the grid increase. And so flipping quickly between A12 and A13, you can see which cells have changed color. And the ones that change color are usually the ones that have the highest injection and the thinnest zones. So material-balancewise, the grid honors the injection volumes and the formation response to the injection of those volumes.

Q. And let me stop you really quick. For each of

the wells that are shown in Exhibit A13, are you
injecting the same amount of barrels per day in each
well?

A. Yes. For this particular run, I injected 40,000 barrels a day into every well that didn't currently exist.

Q. For a period of 20 years?

A. Yes. This is shown at 20 years. And the reason to do that would be just to measure the worst-case scenario more than anything else.

So A14 shows where the fluids go during those 20 years. So the blue color -- the dark blue color there is the background fluids that were in the formation originally. The other colors, meaning light blue, red and green, are tracking the path of the injected fluids. And the upper graph shows the overall scale -- well, sorry -- the three wells in consideration. The lower two graphs show a detailed image of the wells in question so you can look exactly at which ones have fluid that have actually interfered with each other and which ones have not at that period in time.

And, again, the fine grid here is eight cells per mile, and the rough grid is the four cells per mile.

But you can see that there are roughly circular injection patterns around each of the injectors, and the fluids basically move radially away from the injector toward the other lower pressure areas. And you can see, with the two Laguna wells, at 20 years, they still mostly have circular injection patterns. But we ran this forward to 100 years yesterday to see when those patterns would be potentially distorted, and at 100 years, they have started to distort. And you can imagine. The Laguna 13 is injecting more to the north and the Laguna 19 is injecting more to the south once they start to interfere with each other. But it took 100 years before I could see something that was worth looking at. So that's Exhibit A14.

A15 is now very similar, just I've now turned off the background color so that you can see just the new fluids that have gone into these grid cells. And you can see the Laguna Salada wells are in that little cluster to the left. Whereas, the Baker well and the offset Paduca well are to the right.

And at 20 years, they're finally starting to slightly interfere with each other. There is a low probability operationally they would be affected. But what they will do after your 30 and 40 and 50 is it will become slightly more difficult to inject into these wells because of the proximity to each other. But you could say the same for if you had one well in the middle of the state, it would never interfere with any other well. So if any wells -- in this grid, if any well is in the grid, it's going to see every other well. It's the magnitude of that effect that it has. And that was kind of the whole point in doing the simulation, was to quantify the magnitude of the effect. So that's Exhibit A15.

A16 is what we call a mechanistic model. It's testing two wells next to each other that are hypothetical. So in the first trial, I put two wells one mile apart and saw how they acted as we injected 40,000 barrels a day into each one. And you can see that image on the lower left. And the image you see is at 20 years. That's the profile of injection at 20 years for those two wells.

Now, if there were -- if there is only one well there, there would be a high probability it could produce at -- sorry -- it could inject at 40,000 barrels a day for probably 20, 30 years before it would start to push back on itself basically. But if you have two wells that are only a mile apart, you'll lose roughly 3,000 barrels a day of injection off of the 40,000 barrel-a-day assumption, and that's at 20 years.

So in terms of trying to quantify the magnitude of the operational effect of putting wells close together versus far apart, that's what you see in the upper right-hand corner, those three lines. The blue line indicates the impact of wells that are two miles apart. The first red line, working your way down, shows the impact of the wells that are a mile and a half apart, and the last one down shows the impact of wells that are one mile apart. And as you can see, at 20 years, the impact of those three different scenarios is fairly difficult to see. So that's Exhibit A16.

Exhibits A17 through, I think, 21 show a time series of the saturation of injected fluids in the upper right -- sorry -- upper left, and in the lower right, it shows the pressure profile of those same wells. So each of these steps shows what those two conditions look like at a point in time. So the first Exhibit A17 shows before any injection, and the upper left graph looks dark because there is no new saturation of fluids in the formation. The pressure profile is very smooth and flat. There is no bumps in it because that's how it naturally occurs in the formation.

Now, if you turn to A18, that's after one year. And you can see each of those little bars in the upper left graph represents injection of fluids, and you're changing the saturation in the cell most proximal to the injection well. At the same time, you've increased the pressure. You can notice around the wellbores that little yellow color that's starting to appear, that's a slightly higher pressure around those wellbores as you inject fluid into. That's after one year.

Exhibit A19 shows after two years, it's more of the same. The injection radius is starting to grow. Those little blue feet around each of the bars on the upper left-hand graph shows that the saturation is beginning to increase more than one cell away from the injection well cell but not to a great extent. The amount is fairly low because the height of those bars represents the amount of that parameter.

The pressure points -- the increasing pressure points in the grid are starting to show up in this yellow color on the lower right-hand graph, but you can see they haven't gone above the pressures in the lower sections of the formation because it's all yellow.

Okay. After ten years, the effects are as you'd expect, more pronounced because we've been on injection at 40,000 barrels for ten years. And you can see that we've now moved maybe three cells away from each of the injection wells. The overall pressure gradient has climbed where there are clusters of wells. But if you look to the far left on the lower, right-hand graph, there's an individual well there that's kind of by itself, and that well has not really pressured up the formation very much because it doesn't have any wells near it. So the pressures in the formation rise, as you would expect them to. And so operators will say, "Well, if I have an opportunity to drill into a virgin reservoir at the corner of the state, that might be better than next to a bunch of other wells that are already existing." But they have to weigh that against where the demand is and where all their facilities are and things like that. So the intent of the simulation study was to try to quantify some of those effects.

The last slide in that series is Exhibit A21, and it really shows you more of the same. The circles of influence are growing, as you would expect, on each of the wells. The overall pressure profile continues to rise. We never go above fracture pressure on any of these wells because the defined simulation model is to operate them up to injection pressure -- maximum injection pressure and then let the rate fall, as they are unable to meet that new pressure increase. So the model automatically cut-rates back as you hit the maximum injection pressure. And you'll see that in one of the last slides I have.

So Exhibit A22 shows a little more detail on these specific wells. And so the tough part about this particular figure is I had to rotate the whole thing to bring the Laguna 13 and 19 to the front of the image. So you can see in the upper left-hand graph is those two green high spots that are denoted by Laguna 19 and 13, and that's the injection pressure at that location after 20 years. And you can see in the lower right-hand graph, also in the lower right-hand corner, the Laguna 13 and 19, the pressure profile around those wells -- oh, sorry -- the saturation profile around those two wells.

Okay. So that's the end of the grid images.

Exhibit A23 is just a plot of a certain parameter over time. And this set of plots was built in a previous simulation model to represent typical injection rates in this grid. I also have observation wells in the grid so that you can have a judgment of the overall pressure regime in the larger scale. So the observation wells are those horizontal lines that are denoted by the callout and the arrows. And basically, if you're in the corners of this very large grid, it almost doesn't recognize that there are pressure changes in the system. I think if you're looking at fractions and decimal places, you'll see them notch up to a hundredth and thousandth of a psi, but you can't see them on these scales.

(Pause in proceedings while the court reporter has a coughing attack.)

A. Okay. So we're still on A23, and that shows pressure on the left-hand axis, the bottom-hole injection pressure. Then the y-axis shows time and days. And for reference, the middle of the graph is ten years, and the right-hand edge of the graph is 20 years.

So Exhibit A24 shows the injection rates. And although it looks like a lot of horizontal lines, that just shows that very few of these wells have reached the maximum injection pressure. And I have a few wells -- I can count six here -- that are injecting less than 40,000 barrels a day. Those are wells that currently exist and have a history of injecting at a certain rate. And so I've typed in that rate and let them continue to operate at those conditions.

Now, the other thing to note here is we do -- let's just test whether the simulation is working or not. And you do see that, in this case, the Striker wells and the Alpha wells, on the upper right-hand side of the graph, are starting to see the maximum injection pressure, and the injection rates are starting to fall off. And as you would expect, those two wells are in a thinner zone, so their ability to inject more is evidenced in the -- in the simulation model. So that's Exhibit A24.

Q. Can I stop you really quick?

A. Sure.

Q. On Exhibit A24, I just wanted to confirm that where you see -- the fall-off is right -- right around 20 years; is that correct?

A. That's correct. It goes from 40,000 barrels a day at 6,000 days to 39,500 barrels a day at 20 years.

And then Exhibit A25 is -- actually, this did not have to do with my simulation study. This is the public data that I've pulled on active injectors in this area of the state. And I don't want anyone to get confused by the size of these bubbles, so I want to clearly describe what these bubbles represent. The size of these bubbles means the cumulative injection into those wells. It does not represent the distance the fluids have moved. That would be a different calculation. This is simply the cumulative injection.

So if you look, the big red bubbles on the west side are, based on this data, the most injection you've seen in any injectors in that zone among wells that are still characterized as active injectors. And the stars that are denoted to the center south of the grid are the three wells in question here today.

Q. So, Mr. Wilson, in your opinion, what does your study show with the pressure in the injection zone?

A. My study shows that if you honor the maximum injection pressure, as the simulation study does, it's physically impossible to go above frac pressure assuming that the .2 pressure gradient at the surface honors frac pressure. And when the wells do reach that maximum pressure, the rates will drop off accordingly, and the operators will see an increase in injection rates based on that.

The simulation study also shows that due to the thickness of this formation -- you know, it's hard to visualize what 1,400 feet thick is, but that's roughly 110-story-tall building. So that's the thickness of the injection zone we're injecting to. You can push a lot of water into that thickness of a zone without it really going very far because it's spreading out in a vertical distance.

Q. Does your study show how far the fluids will travel when they are injected?

A. They do. The saturation profiles, all the pictures with the black background, show a circle that represents the fluids that have moved into the formation based on the injection.

Q. And have you concluded approximately how far they will travel in about 20 years?

A. Yeah. In this case a good example would be Exhibit -- well, even Exhibit A16, there are three images there all showing injection at 20 years. And then the circle that's not black -- it's got a green center and then orange, then blue -- that represents the radius of injection. And you can see in the lower left, those wells are a mile apart and they haven't yet touched each other. So in that scenario, it would probably take 30 years before they touch each other because that's radial, and it's going to grow with the square foot of time as opposed to time, because that outside ring takes up more space than the inside rings.

Q. Does your study take into account that any injection zone, the permeability and porosity are not -- they're not equal throughout the formation?

A. Actually, this grid does have uniform porosity throughout.

Q. Okay.

A. It has changing thickness and pressure and depth, but we don't actually have enough data yet to identify tangible differences in permeability or

porosity. I think over time, as the dynamic, the
time-based data, is collected, we will be able to refine
the grid to show differences in quality of each
individual location.

**Q.   And based on the nodal analysis that you did,
have you reached an opinion on the likelihood of the
three proposed wells reaching a pressure that would
create fractures in the formations?**

A.   Yes. Based on the nodal analysis, the
requirement that the wellhead pressure not be above .2
times the well depth implicitly requires that the --
that the well not be above frac pressure. So the higher
the injection rate, the lower the bottom-hole pressure
that is delivered, and with smaller tubing, it gets even
worse. So, in general, as long as operators honor their
maximum injection pressures, they won't go above frac
pressure.

Q.   Thank you.

**Based on your study of the formation and
the modeling that you performed for this application --
or these three applications, what are your conclusions
concerning these applications' overall potential to
impact the formation?**

A.   These wells are very similar to other wells
I've studied. The formation is very thick, is able to

accept fluids very readily, and I would not see any problem with any of these permits given the constraints that we've seen. In general, they don't affect the wells near them for at least 20 years, in some cases, even longer. So the operators have made their own decisions as to whether it makes sense to drill these wells, and I honor those business decisions.

Q. I think you've already covered this, but in your opinion, will the volumes potentially -- will the volumes potentially injected into the formation affect the potential formation fracture pressures?

A. No. In paraphrasing your question, do the volumes that have been injected into the formation cause it to fracture? And the answer would be no because we're injecting -- we're injecting the maximum injection pressure, so regardless of the amount of volume that's going in, the fluids enter at below fracture pressure. So the entire system pressure will rise, but it won't rise above fracture pressure.

MS. BISONG: At this point in time, I would like to ask for the exhibits under Tab 4 be admitted into the record.

EXAMINER JONES: Any objection?

MR. BROOKS: No objections.

MR. PADILLA: No objection.

EXAMINER JONES: The exhibits under Tab 4 will be admitted in all three cases.

(Mesquite SWD, Inc. Exhibit Number 4 is offered and admitted into evidence.)

MS. BISONG: I have no more questions on direct.

EXAMINER JONES: Mr. Padilla?

MR. PADILLA: I don't have any questions of Mr. Wilson.

MR. BRUCE: No questions.

MR. BROOKS: We have one question.

CROSS-EXAMINATION

BY MR. BROOKS:

Q. You know, the permits require the -- that the fluid remain in the injection zone, which it either will or will not. What assumptions did you make in this regard?

A. In the grid I have, it's the single zone, so it's the zone -- it's the Devonian-Silurian zone. The assumption I make is that the .2 pressure gradient that is the requirement for the maximum injection pressure is honored, and when that is honored, by definition, the theory is that it will not go above frac pressure going up or down.

Q. So your model does assume there is no migration

outside the injection zone?

A. That's correct.

Q. Okay.

CROSS-EXAMINATION

BY EXAMINER BRANCARD:

Q. Thank you for the exhibits. I love color.

(Laughter.)

EXAMINER JONES: You should have been a geologist.

Q. (BY MR. BRANCARD) First, they confuse me, too, so Exhibits A14, 15, 16. Okay? You made the statement about A16, that it showed those three little Pac-Man things at the bottom, that it shows that there is no contact after 20 years one mile apart, 1.5 miles, two miles apart. Is that correct?

A. The fluids that are injected are not shown to basically touch each other even on the one-mile case. And realize that the pressures are going up. So these are -- Figure A16 makes it looks like it's either a color or a black because you can track the molecules that are injected and move away. But ahead of those molecules are the water molecules that are being pushed also away from the formation. And as -- as the existing water that's in the formation is pushed away, it will raise the pressure. So the pressure increases much more uniformly than is shown here on these black images on Exhibit A16. The saturation says, "Yeah, those wells aren't going to touch each other, but they will both see a little saddle of pressure because they're going to be peaks." And then the pressure will drop between the two. It will also drop moving away from them to the outside. But no, the injected fluids won't have actually connected at that time.

Q. So then why on A14 and A15, when you are specifically looking at the Laguna Salada after 20 years, you have those two connecting?

A. That's a great question. The reason is that these two -- Exhibit A16 is that little mechanistic model. I introduced that slide saying it was a mechanistic model and these are not real wells in the grid that I have here. These are the wells that are off to the side, and potentially the zone there was slightly thicker, because the grid goes from 700 feet in one corner to 1,400 in another. And these wells, like the Baker and Paduca, also don't touch, on Exhibit A14. So I think the right analogy to make would be that the image seen in Exhibit A16 looks more like the Baker and Paduca than the two Laguna wells.

Q. Because the zone is shallower?

A. Yes. It's thicker. Shall- -- depth is not important but thickness is. And the reason is is that if you're injecting -- let's say we have a box of water that's as big as this room and you push it into a layer that's this thick (demonstrating), it's going to go really far. But if you push it into a layer that's as thick as this room, it only goes as far as the room.

Q. Okay. But we have to deal with the Laguna applications, which are a little more shallow -- given the spectrum here, they're on the shallower end of the zone --

A. True. True.

Q. -- and, therefore, will come into contact much sooner than your model?

A. Yes. And that's actually shown in my Exhibit 24, because actually the Striker and Alpha wells are even worse. They affect each other even sooner than the Laguna wells would affect each other. So if you go to Exhibit 24, you'll notice the Striker and Alpha wells start to drop off a little because they've started to touch each other.

Q. So the wells that are graphed in A24 and A23, they're all -- are those the wells that are shown on these inverted bar graphs here on A21?

A. Yes.

Q. Okay. And so what you're showing on A21 is

existing wells?

A. And permits. Basically, every time I do one of these studies, I just add every well that is involved. I haven't taken any out yet. So if a permit gets pulled, I'll have to remove it. But so far I just keep adding new wells as they come up.

Q. So it doesn't simulate a scenario where, you know, if we had -- if we went with the one-mile setback, presumably this whole area could be just flooded with wells?

A. Yeah. And -- well, it would. If you took this entire grid and put a well every mile, yes, you'd pressure it up pretty quickly. But at the same time, my assumption here is you're injecting 40,000 barrels a day, so the combination of those two events is pretty low probability. Because, first of all, the pace at which development is happening, people are able to choose where they put their wells, and prudent operators are picking the optimal locations to put their wells, which would be the thickest zones, lowest pressures. And so there are certain cases where like, for example, the Alpha and Striker wells -- I just heard at lunch, the Alpha well is doing great even though my simulation model says it should be doing poorly because it's in a thin zone. So there are more layers of detail we need to start integrating into the simulation that honors the changes in porosity and permeability, but as of now, it's a uniform grid and it's attempting to model the zone of influence of wells in different physical locations as best I could.

Q. But you're not modeling a scenario of wells in every section?

A. No. No.

Q. And, I mean, while I think people are making business decisions, if they weren't making business decisions to put wells within a mile of each other, we wouldn't be here.

A. True. But in this case, if you look at the Baker and the Paduca wells, they're kind of down there by themselves, so potentially if another operator had the option to put a well anywhere in the basin they chose to, they probably wouldn't put them right next to those two unless there was a business reason to do that. But if I were to build a grid with an injector on every section and turn them all on at 40,000 barrels a day, the whole grid would pump up very quickly. But that wouldn't honor the reality of the situation the way things are playing out.

Q. That may be true, but the reality is we have to regulate as if that could happen.

A. Yeah, I guess.

Q. And so -- so, I mean, would the conclusion be that there is some distance, assuming you could put a well in every section or two or three or four, that there would be some distance that would be sort of optimal that you wouldn't want to go closer than?

A. I think the standards that looked like it was falling out of the prior permits was a mile, and so far I see no tangible benefit to going longer than that. I haven't -- I haven't been asked to evaluate the detriment to going closer to that. You would think if you put two wells immediately next to each other, they would each have half the injectivity that they would have if they weren't next to each other. So that's the extreme case. You would certainly not want to do that because you would get half injectivity. But a mile apart seems to give enough -- you know, in terms of business planning, it's roughly 20 years before you'll see the effect of it, and in the business planning I'm familiar with, that usually is long enough.

Q. Right. And I appreciate you modeling this out for 20 years, but as I discussed with the first witness, there is no application for a 20-year permit here. It's for infinite --

A. True.

Q. -- until the apocalypse.
So I'm glad you looked at one little factor for 100 years, but nothing else you've looked at is for 100 years.
A. Yeah. I agree that in the grand scheme of things, if the entire basin was drilled up on one mile or mile and a half, for that matter, maybe two miles, operators would have difficulty injecting at the rates they're injecting at. The injection rates would fall off.
The other thing to think about at that point would be that -- I don't know what the exact section count would be, and then if you multiply that section count by 40,000 barrels a day, you would be talking about tens of millions of barrels a day of injection, and I don't think the supply is out there to do that. We'll stop drilling, water producers. I think we're going to flatten out eventually. I can't predict exactly when.
Q. Yeah (laughter).
A. I know we're up to about 550 now -- 550,000 a day. I looked at that just a few days ago.
Q. Well, I don't think a decade ago we would have predicted we were going to be in this situation.
A. No. And starting in 2012, it started to notch

up, and it notched up again, and you're up to 550. So it's not something you can ignore because in the long run, maybe 2 million a day needs to be injected. But I can't see 10 million a day. That's overkill potentially.

Q. Thank you.

CROSS-EXAMINATION

BY EXAMINER JONES:

Q. I guess just quickly, I'm trying to better understand the total porosity versus effective porosity out here. Did you -- what porosity did you use for the model?

A. I used 10 percent porosity throughout the grid.

Q. Okay.

A. But I would like to double-check that because that's not in any exhibit.

Q. Does that mean effective porosity or total porosity minus some kind of, you know -- that's effective porosity, I take it?

A. Yeah. That's the -- that's the input porosity that I provide. The model does honor pore volume compressibility.

Q. Okay.

A. And so as you go to higher pressures, it'll squeeze down a bit. And that's actually what gives you the ability to push more fluids in because basically the rock contracts and the water that's already there contracts and it pushes it out.

Q. Have you seen any core porosity versus log porosity plots out here? They wouldn't correlate anyway, would they, in this carbonate?

A. I don't think so.

Q. Okay. The saturations are totally 100 percent water in the formation?

A. They are, yeah.

Q. You're not putting any -- any oil or gas in your model?

A. No. No.

Q. Okay. The mobility ratio then between your injected fluid and your displaced fluid is one to one, right?

A. Exactly. And I have -- I have perfect square real perm curves such that it just goes out evenly.

Q. Okay. Has there been any temperature surveys that you've seen that confirm the thicknesses -- the net thickness that you're --

A. In injecting into?

Q. Yeah.

A. I have not seen one. And it is a formation and it's open hole, so --

Q. Yeah.

A. And it's an expensive well, so maybe people are hesitant to do that.

Q. Yeah. Speaking of that, pressure transient models are testing -- frequently look for barriers. You can see a barrier on them. Is there a way you can design a pressure transient test in one of these big high-rate wells and actually look for potential faults out there?

A. All day long. You can do it very easily.

Q. Okay. Could you do it without shutting the well in totally?

A. No.

Q. Just change the rates?

A. No.

Q. Could you change the rates from one constant rate to another constant rate?

A. Potentially, but I would not --

Q. You don't trust that?

A. I don't trust that because you still have fluids that are moving. You'd have water hammer, and your gauges are just not going to catch it.

Q. Yeah.

A. I think the cheapest -- between you and I, the cheapest way to do that is to have a high -- a high-sensitivity surface gauge and just do a short fall-off. You can probably do it in six hours. Just have a really good surface gauge and watch the pressure fall off for six hours. You'd get a pressure, you'd get a perm, and you might get boundaries. And it's a very tight system, so if ever there was a case where you could see boundaries and high-quality reservoir data, it would be these wells.

Q. Okay. Okay. So seismic might be cheaper than that or not, or they could both correlate and look for the same thing maybe.

A. I think a pressure gauge is about as cheap as it gets.

Q. Yeah. Except there are a lot of tanks involved with changing and shutting the well in for a while.

A. For six hours.

Q. Okay. This simulation model you did, most of us don't have that available, and I guarantee you we don't have it here at the State. So is there any little analytical model we could use, and what could we get from that?

A. The Department of Energy has a program called BOAST, which is a reservoir simulator, and it's potentially available.

Q. Okay. Is this like an implicit, explicit

model, compressed model that you're using?

A. Yeah. Yeah. And actually I swapped out solvers in the grid once I get to the bigger time steps.

Q. Okay. Have you seen or heard of any -- they talked earlier about the FMIs and the potential stress direction which could come from an oriented array sonic or an FMI. But if you had that through your net pay down into your Simpson or whatever the name of that lower confining layer that we're all kind of concerned about -- I'm interested to know if you have seen a stress contrast between the net pay and that supposed confining layer and what it would be as compared to, you know --

A. I think that's going to be outside of my area of expertise because I specifically model the wellbore tubulars and then the reservoir simulation model.

Q. Okay. Did you tie your nodal model with your simulator? Is it all tied together?

A. Oh, yeah. They're all tied together.

Q. I don't have any more questions.

EXAMINER JONES: Anybody else?

Go ahead.

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. So you're saying that the Alpha -- was that the

well that was outperforming?

A. I just heard that today. I predicted that it would be doing poorly because it's in a thin zone and apparently it's doing great.

Q. Do you have any ideas -- any speculation, or is it impossible to tell?

A. I don't particularly like to speculate. I do have a friend who is also looking at injectors in this area, and he finds that there are sweet spots -- let's put it that way -- that inject better than other areas. And so I think as time goes on -- you know, the production plot for the area is fairly steep in terms of the volumes that you're injecting, and so, you know, a year from now, people will be very excited about where they chose to put their wells and others will be less excited. And I'm guessing it's not going to have much to do with how close they are to other wells.

EXAMINER JONES: Okay. Any more questions for this witness.

MS. BISONG: I have a follow-up question, just a couple.

REDIRECT EXAMINATION

BY MS. BISONG:

Q. Mr. Wilson, you don't see any issues of fracturing in your model, and that's assuming all the

wells are injecting 40,000 -- all the wells in your model injecting 40,000 barrels per day for 20 years because all those injection wells are constrained by a maximum injection pressure, correct?

A. Correct.

Q. So it essentially doesn't matter how close they are together in terms of fracturing pressure? You won't see that because the wells are limited in the injection pressure, correct?

A. Correct. The natural reaction of the simulator and the real well to reaching a maximum injection pressure is the rate starts to fall. Once you -- so the pressure comes up. You hit the maximum injection pressure. You lock out that pressure, and then the rate starts falling. So those curves coincide.

Q. And just to sum up, if wells are one mile apart versus 1.5 miles apart, it wouldn't matter in terms of there being enough fracture pressure because all of the wells are limited by their injection pressure?

A. True. They're all limited.

Q. Thank you.

MS. BISONG: Nothing further.

EXAMINER JONES: Thank you very much.

So is that the case-in-chief for Mesquite?

MS. BENNETT: Yes.

EXAMINER BRANCARD: I think you have another exhibit that involves notice.

MS. BENNETT: Oh, yes. I do have another exhibit that involves notice, and it's the affidavit that I prepared. It's behind Tab 5, and it's an affidavit prepared by me. And what that shows is that I actually sent out letters to all the affected parties notifying them of this hearing -- well, of the original hearing, but it's been continued a number of times since then. Also I also published -- we published as a matter of course.

So for the Laguna Salada wells, the notice materials show a -- show proof of notice and sent it out for certified mail. And for Mr. Brancard's information, we have a software program that takes care of our certified mail for us these days. So rather than having all the green cards comes back to us, the vendor provides us with a sheet that looks like this (indicating), and that sheet tabulates -- tracks where mail has been delivered and when. And so this is a functional replacement for the green cards so that we don't have to make copies of the green cards.

I will say that for the Baker well, I did not publish. Even though I almost always publish as a matter of course, I did not publish for the Baker well, and, unfortunately, one letter was lost for the Baker well, and that was to ConocoPhillips. And so if we need to continue the Baker well for notice purposes only, that's fine, but I feel like ConocoPhillips probably had actual notice of this hearing today by virtue of their attorneys being part of the docket, but that's neither here nor there. Not this docket but the general docket for the 30th and the 31st. But I'm happy to continue the Baker case for notice purposes only, if I need to publish in the newspaper just to need to cure that one notice party that did not get notice of my application. ConocoPhillips did get notice of the original administrative applications, though.

EXAMINER JONES: Okay.

EXAMINER BRANCARD: Okay. So why didn't you do a newspaper notice for Baker?

MS. BENNETT: For Baker?

EXAMINER BRANCARD: Yes.

MS. BENNETT: Well, it was an oversight on my part. They're not required for hearing examiner hearings unless a party doesn't get the certified mail, and so they're not -- publication is not required for examiner hearings. It's only a backup method in case letters are returned or they're undeliverable. And in this case, usually my practice is to publish every time regardless for a belt-and-suspenders approach, but in all honesty, I just overlooked it for the Baker well.

EXAMINER BRANCARD: So for the Baker well, you initially filed as --

MS. BENNETT: As an administrative application.

EXAMINER BRANCARD: -- an administrative application where publication is required.

MS. BENNETT: And it was done.

EXAMINER BRANCARD: Oh, it was done.

MS. BENNETT: Yes, it was.

EXAMINER BRANCARD: So the question is: Did you do it for the examiner hearing? And you're correct. It's not required.

MS. BENNETT: Okay.

EXAMINER BRANCARD: And I don't need to be annoying about this, but I find that everybody does this at these hearings and it's really annoying to me personally, which is can you just sort of go through these and let me know what I'm looking at here?

MS. BENNETT: Certainly.

EXAMINER BRANCARD: So there is a definition of who is required to give notice.

MS. BENNETT: Uh-huh.

EXAMINER BRANCARD: And that would

involve --

MS. BENNETT: That's affected parties, as defined by the regulation. And affected parties is any tract -- and I'm going from memory here. I can look it up in the rule if you'd like. But we actually have landmen and title folks who compile a list for me, but it's based on the AOR, which is a one-mile AOR. So parties within that one-mile AOR are identified and are given notice.

EXAMINER BRANCARD: Parties being?

MS. BENNETT: Affected parties. And the affected parties -- let me just pull up my regulation right here.

EXAMINER BRANCARD: These are operators?

MS. BENNETT: Some are operators. There are also landowners and mineral interest owners.

Affected person is "an operator, working interest owner, mineral estate within a half mile or a mile."

EXAMINER BRANCARD: So can you just confirm that this is what this is?

MS. BENNETT: Yes.

EXAMINER BRANCARD: So you followed that definition?

MS. BENNETT: Yes.

EXAMINER BRANCARD: And it also says "BLM, State Land Office."

MS. BENNETT: Yes. We are required to supply notice to BLM and the State Land Office when their minerals are -- or surface is within a half mile. Minerals, I think is the rule, actually. And so we would have followed that here as well.

In fact, if you turn back to the applications, which are behind Tab A, the applications each contain a map that shows the area of review. And so just looking at the very first application, which is the application for the Laguna Salada 13, if you go back about 10 or 12 pages in that, you'll see some colored diagrams that look like this (indicating) with a Midland Map and a one-mile -- a two-mile radius a half mile -- or a one-mile radius. So the applicant figures out the area of review and then identifies who within that area of review is entitled to notice.

And so if you go about three more pages in there, you'll see a chart that looks like this (indicating), and that chart is entitled "This is the Wells in the Area of Review."

Then there will be another chart that will identify the affected area -- the affected parties within the area of review. That's this page (indicating). It's about one page from the back of that application, and this shows the offset owners who were identified and the surface -- the offset operators -- excuse me -- and the surface owner who were provided notice for this application, which is the Laguna Salada 13.

And each one of these applications has this type of information in it.

EXAMINER BRANCARD: Okay. Excellent.

MS. BENNETT: And that's done as part of the administrative process and also part of the hearing examiner process.

EXAMINER BRANCARD: Okay. And so the surface owner is just the surface owner where the well is located.

MS. BENNETT: That's right. I misspoke a moment ago when I was saying that there might be adjacent tracts that get notice. It's just the surface owner where the well is located.

EXAMINER BRANCARD: It doesn't matter how far the produced water is going. You only give notice to the surface owner. Okay. That's my own pet peeve. Sorry.

MR. BROOKS: And that's what the rule says.

EXAMINER BRANCARD: That's what the rule

says.

MR. BROOKS: But I recognize there is an argument that could be made that the decision requires further notice, but that's not my argument to make in this case.

EXAMINER BRANCARD: Well, thank you.

MS. BENNETT: Sure. I would ask that Exhibit 5 be admitted into the record.

EXAMINER JONES: Any objection?

MR. BROOKS: No.

EXAMINER JONES: Exhibit 5.

MR. PADILLA: No.

MR. ROACH: No.

MR. BRUCE: No.

MS. BENNETT: Thank you.

EXAMINER JONES: Exhibit 5 is admitted.

(Mesquite SWD, Inc. Exhibit Number 5 is offered and admitted into evidence.)

MS. BENNETT: Thank you.

EXAMINER JONES: I'm trying to get this closed out by 4:00 today, and we've only got 30 more minutes.

I assume that you would want to make an opening statement, like you stated before, and --

MR. BROOKS: No, that's not necessary, but

I would like to have a break before we have to put Mr. Goetze on for testimony. We cannot get through in 30 minutes. So what's Plan B?

EXAMINER JONES: Plan B is a new date, probably a new Friday.

MR. BROOKS: Well, that's possible. Mr. Goetze's testimony, I would think, would be very hard to condense into 30 minutes.

EXAMINER JONES: That might not be fair to Mr. Goetze to do that. It was not fair to make him sit here all day and be in preparation for today.

MR. BROOKS: Especially since he's the only witness we have.

EXAMINER JONES: So do any of the other attorneys have witnesses?

MR. ROACH: No.

MR. PADILLA: Not today.

(Laughter.)

EXAMINER JONES: But if we continue, you might, huh, because you just made an appearance today?

MR. BRUCE: I won't have any witnesses.

MR. PADILLA: I wouldn't want to go today. If the Division has a 30-minute problem, I wouldn't want to be prejudiced by the same fact.

EXAMINER JONES: Yeah.

MR. BROOKS: Well, I don't know what your constraints are that requires 4:00, so I'm in no position to argue this.

EXAMINER JONES: Well, it's Friday and --

(Laughter.)

MR. BROOKS: I recognize that, but the preference at OCD for going late as necessary to finish a matter --

EXAMINER JONES: Do you think you could get done in one hour?

MR. BROOKS: Mr. Goetze?

EXAMINER JONES: Even if we started in ten minutes?

MR. BROOKS: With cross-examination, I think not.

MR. GOETZE: No.

EXAMINER JONES: We wouldn't be done by 5:00 anyway.

MR. BROOKS: So we would request the matter be continued -- we would request to start today and go as far as we can. And if there is --

EXAMINER JONES: Do you want to have a break and talk to your client?

MR. GOETZE: Yes. I'd like to talk to my lawyer.

(Recess, 3:31 p.m. to 3:41 p.m.)

EXAMINER JONES: We're back on the record.

Thank you for putting on this case, the Mesquite cases. We're going to continue these three cases and the Solaris and Blackbuck cases to a further docket.

This docket's adjourned.

MR. GOETZE: Wait, wait.

EXAMINER BRANCARD: On the exhibits, Mesquite mentioned you wanted to clean some things up.

MS. BENNETT: Oh, we're happy to do that. We understand that the exhibits may need to be cleaned up, but that's all I would be doing. I would like to make it clear that neither Mesquite -- I'm hoping that this is accurate. Just because we're continuing doesn't give either Mesquite or the Division or anyone else the opportunity to create new exhibits between now and the continuance date. The exhibits are what they are at this point, well, except for I will -- and if it's the Division's preference for me to clean them up after so there are no concerns about the changes that we've made to the exhibits, I'm happy to do that, too. But that is all I would be doing, is changing the headings and making some of the legends more prominent, and whatever Mr. Brooks would like me to do.

MR. BROOKS: Hopefully, on those exhibits under tabs where the pages are not numbered all the way through, you will insert the page numbers that are continuous throughout the exhibit.

MS. BENNETT: I certainly will.

EXAMINER BRANCARD: So maybe at the start of the next hearing, you can present that --

MS. BENNETT: I certainly will.

EXAMINER BRANCARD: -- to make sure nobody objects to --

MS. BENNETT: Definitely.

EXAMINER BRANCARD: We had this discussion already with the court reporter about preparing the transcript and we will use the exhibits we have now, but it seems like if you clean them up, then we can use those in the next --

MS. BENNETT: I certainly will. And I appreciate the Division's patience with me as we work through getting them to be more legible and more helpful for the Division. That's our hope.

EXAMINER BRANCARD: Mr. Jones, did you want to discuss any possible dates?

EXAMINER JONES: Well, off the record -- I better do this off the record.

(Recess, 3:43 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 11th day of June 2019.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2019
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