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

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

APPLICATION OF MESQUITE SWD, INC. TO AMEND APPROVALS FOR SALT WATER DISPOSAL WELLS IN LEA AND EDDY COUNTIES.

CASE NO. 15654
ORDER NO. R-14392

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSIONER HEARING

November 9, 2017

Santa Fe, New Mexico

BEFORE: DAVID R. CATANACH, CHAIRPERSON
ED MARTIN, COMMISSIONER
DR. ROBERT S. BALCH, COMMISSIONER
BILL BRANCARD, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Thursday, November 9, 2017, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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EXHIBITS OFFERED AND ADMITTED

(9:04 a.m.)

CHAIRMAN CATANACH: Okay. Next order of business in this meeting is the -- I will call Case 15654, which is the de novo case of Mesquite SWD, Inc. to amend approvals for saltwater disposal wells in Lea and Eddy Counties, New Mexico.

At this time call for appearances in this case.

MS. BRADFUTE: Mr. Chairman and Mr. Commissioners, Jennifer Bradfute and Sarah Stevenson on behalf of Mesquite SWD, Inc.

MS. KESSLER: Mr. Commissioner, Jordan Kessler, from the Santa Fe office of Holland & Hart, on behalf of Black River Water Management Company, LLC.

MS. BRADFUTE: Mr. Chairman, we have five witnesses here today.

MS. KESSLER: No witnesses.

CHAIRMAN CATANACH: Can I get the witnesses to stand up at this time and be sworn in?

(Mr. Neatherlin, Mr. Wilson, Dr. Zeigler,
Dr. Bilek and Mr. Nave sworn.)

CHAIRMAN CATANACH: Ms. Bradfute, you have a procedural -- do you want to talk about that?

MS. BRADFUTE: Absolutely. Thank you.

So, Mr. Chairman and Commissioners, we did file a brief -- it's more of a legal brief -- yesterday with the Commission. It was noted that we were going to file some legal arguments in this matter in Mesquite's pre-hearing statement. These arguments were made mainly to preserve our record and technical issues through the testimony presented through expert witnesses. However, I wanted to put more the technical legal points in a written document that could be incorporated into part of the record, and we thought that was a more efficient way to address those points.

CHAIRMAN CATANACH: So we don't need to make a ruling on this?

MR. BRANCARD: What's the point of this document? Are you asking for the Commission to do something?

MS. BRADFUTE: In the proceedings below, an email from the BLM was considered. That email from the BLM had not been served on Mesquite or myself. I was counsel for Mesquite in the proceedings below. And the BLM did not enter an appearance in the case or appear on the record during the hearing.

In the Division's order, there are three paragraphs that address that email as though the BLM had been a party to the case, is kind of my interpretation. It may not have been the Division's intent, but that's definitely incorporated as one of the reasons in Mesquite's application. And since BLM had not appeared on the record, there were concerns. There was no opportunity to confront BLM's statement. It was a pretty short email, about three sentences. And BLM also didn't have a representative present to benefit from the testimony that had been presented from Mesquite's expert witnesses.

And so what we're asking is that the BLM email not be considered by the Commission in these proceedings. Technical questions that are raised by that email will be addressed in the testimony presented by experts, but it's a hearsay statement, and BLM has not entered an appearance in this case and is not a party.

MR. BRANCARD: Mr. Chairman, this is a de novo proceeding, not a record-review proceeding, so I don't know that this document really means anything to us, since the BLM is not in front of us, or at least we don't know whether the BLM email is in front of us.

CHAIRMAN CATANACH: So it's your recommendation that we don't have to take any action?

MR. BRANCARD: Yes.

CHAIRMAN CATANACH: Okay. You may proceed.

MS. BRADFUTE: Thank you.

If I may, I'd like to make a brief opening statement about the case in this matter to provide you-all with some background as to what Mesquite is asking and the Division's proceedings before and why we are here today.

OPENING STATEMENT

MS. BRADFUTE: The Applicant in this matter, Mesquite SWD, is requesting to amend several administrative orders that were issued by the Division which requires the use of 4-1/2-inch tubing in each Devonian saltwater injection wells. This application only involves Devonian and Devonian-Silurian injection wells that are used to inject produced water into those formations. So it does not involve injection wells into the Delaware Formation, which I know has been a hot topic of the Division and the Commission.

In this application, the only item that Mesquite is asking to amend or change is the tubing size. And they're only asking to change that tubing size by 1 inch, from 4-1/2 inches to 5-1/2 inches.

Previously, before Mesquite filed its application with the Division, the Division had administratively approved the use of 5-1/2-inch tubing for one of Mesquite's well, the Vaca Draw well. That well is not at issue in today's proceeding. That well has been drilled with 5-1/2-inch tubing, and the Division did not indicate any problems with the use of that tubing size in that well.

But based on that administrative approval, Mesquite proceeded to order additional tubing for its operations in several others wells that it was planning to drill. So that tubing was purchased, ordered based on prior actions taken by the Division.

Mesquite then requested administratively to amend several saltwater disposal orders that had been entered by the Division. And it originally did that by contacting engineers and then exchanging emails with the Division with that request. There were some concerns posed by the Division in response to that request. The original concern was the fishability of tubing. If there is a tubing failure in the wellbore or if tubing breaks, is it able to be fished out of the wellbore? And that was the initial concern expressed by the Division.

The Division asked that the matter be set for hearing. And so we filed an application and the matter was set for hearing, and that hearing was held on March -- I believe it was March -- in March of 2017, March 30th of 2017.

During that hearing, Mesquite presented

testimony about the fishability of tubing. They had an expert who has performed fishing operations in the field since 1980, and that expert presented adequate testimony that tubing was able to be fished out in the event of a failure through several different well-recognized, often-used procedures. And that testimony was well received by the Division. I think later it was referenced in other cases involving tubing questions that proceeded before the Division, and it was referenced favorably in those cases.

During the Division's hearing, the Division examiners had questions about other issues, other issues related to increased injection rates, into pore pressures and reservoir pressures. And they asked Mesquite to provide additional engineering data, which was provided in response to an information request and received on the record.

On July 21st, 2017, the Division entered an order. And I think it's important to give this background. I realize it's not a record review, but it will give you context as to why we're here and why we have so many witnesses to present to you today and the information that you're going to kind of receive and contemplate when you're ruling on this application.

The order first found that the Division

approved and recognizes that the Devonian and the Devonian-Silurian Formations are the preferred formations for injection right now. The Division wants operators to move away from Delaware disposal wells, and the Devonian Formation is the preferred formation to go ahead and perform those operations in.

The Division, however, found that Mesquite's application would set a precedent by which the Division would have deemed a best management practice. This finding was somewhat curious because the Division had, in 2016 and 2017, not only approved the use of 5-1/2-inch tubing for Mesquite but for several other operators administratively, without finding that those administrative orders would set a best management practice.

And so the question here is: What is different? Why is a higher standard being applied to Mesquite's application today?

The Division further found that Mesquite needed to present testimony as to the impact of other unidentified future wells and what impact those wells would have if they were drilled in close proximity to one another with 5-1/2-inch tubing. I'm unaware of a similar standard being applied in an administrative application that had been approved by the Division for other applications that have since gone to hearing.

In addition, the Division indicated that Mesquite should have presented evidence which established that its own regulatory notice requirements were sufficient, kind of placing the burden on the Applicant to say if additional notice was necessary or needed under the Division's regulations, though the Division is supposed to kind of indicate if additional notice is required. And prior to filing its application, Mesquite had reached out to the Division and confirmed that it should notify all of the original parties who were notified in the administrative applications, that that would be sufficient. No additional notice was indicated. Mesquite does not oppose giving additional notice. It just needs direction from the Commission of the Division as to what should be given.

The Division further tells that Mesquite should have presented evidence addressing any seismicity concerns with increased injection volumes, and the Division found that a committee needed to be created in order to create a best management practice for these tubing requests.

We've already addressed the BLM email. That was another big part of the order, that the BLM had issued an email to Mr. Goetze raising some questions about fracture pressures and if -- if these -- the use of this tubing would create pressure that would equal fracture pressures within the formation.

Today we're going to address a lot of these concerns that were in the Division's order. Mesquite wants to go above and beyond and show the Commission and the Division that the use of 5-1/2-inch tubing is a good practice in certain areas within New Mexico. And it's a good practice because you can increase higher volumes of produced water into these wells. Devonian wells are very expensive to drill. They're very deep wells. And so there is already an economic incentive to drill fewer of them, and they want to increase the amount of water they can get down each well, which will result in less surface disturbance within the area. And that's very important. They also want to reduce their friction amount that they see in the wellbore, which is a huge, huge burden to getting enough volume down these deep, deep wells.

We're going to present testimony to the Commission today from several different expert witnesses. You're going to hear from Dr. Kate Zeigler. She's a geologist. And she's examined what operators commonly refer to as the Devonian and the

Devonian-Silurian Formations. But she's going to provide a lot more context as to what specific formations geologists recognize that those formations include. She's going to testify that in the location where Mesquite's wells are located, there are two confining formations both above and below the Devonian and the Devonian-Silurian. This helps mitigate any concerns that fluids are going to be migrating up into productive formations or, you know, really far into where fresh water would be. And it'll also help mitigate concerns that fluids are migrating below into the base rock.

Ms. Zeigler will further testify that there is significant porosity and permeability within the formation, and this is important because this is something that is being recognized by operators in the field. The Devonian and the Devonian-Silurian Formations are good prospects for injection, and the permeability and porosity levels within these formations will help kind of confirm that that is what operators are seeing.

Finally, Dr. Zeigler will explain that Mesquite's wells are located far away from any major fault lines, which that is part of the concern when you're dealing with induced seismicity issues.

You're going to hear from a petroleum engineer, Scott Wilson, and he's going to testify that the use of 5-1/2-inch tubing will significantly help reduce friction in the wellbore and will not have a significant impact on formation pressure.

Mr. Wilson will further testify that the radial influence of these wells will not be significant and will confirm that a half-mile notification procedure should be appropriate, and that is currently what the Division's notification procedure is.

However, that being said, if a wider notification procedure needs to be followed, Mesquite can send out additional notices. It just needs to have the Division or Commission identify what that is.

You're going to hear from a seismologist who is a professor at New Mexico Tech University, Sue Bilek. And Dr. Bilek will tell you that based on her studies, there's not a history of high-background seismicity in the area where these wells are located. And she's going to further testify that based on known faults -- map faults and the locations and depths of these wells, there's a low probability that increased injection rates will result in felt induced seismicity in the area.

And what is very interesting about

Dr. Bilek's testimony is that New Mexico Tech University has had stations out in southeastern New Mexico since 1972 or around that time frame, and so they've been collecting seismic data for decades within the area.

Finally, we're going to go back to where this inquiry started, and you're going to hear from Steve Nave. Steve has performed fishing operations within the field since 1980. He's led teams who have performed fishing operations. And you're going to hear testimony that -- from him that 5-1/2-inch tubing is fishable in the event of a tubing failure through a variety of different methods that are well recognized that he's comfortable using and that other fishing operators are comfortable using

You're also going to hear that the tubing sizes requested in this case are very similar to tubing and casing sizes used in production wells, so in the event production wells or deep wells are drilled, they would pose equal concerns as those here in this application.

This evidence that you will hear today far exceeds any evidence that has been presented in the administrative applications or the other applications presented to the Division concerning tubing sizes, and it's going to confirm that Mesquite's application does not have an impact on freshwater resources. There is no increased chance that injected fluids are going to move between other formations and that the tubing design proposed by Mesquite is safe and adequate to prevent leakage.

Thank you.

CHAIRMAN CATANACH: Thank you, Ms. Bradfute.

Just one clarification, the Division did form a committee to look at some of the injection issues that are out there. It was not formed as a result of this particular case. It includes -- it was mostly formed to look at Delaware injection, but the committee's going to be looking at the tubing sizes in the process of their work, so just to clarify that.

MS. BRADFUTE: Thank you. I appreciate that.

CHAIRMAN CATANACH: You may proceed.

MS. BRADFUTE: We'd like to call our first witness.

RILEY NEATHERLIN,

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

DIRECT EXAMINATION

BY MS. BRADFUTE:

Q. Could you please state your name for the record?

A. Riley Neatherlin.

Q. And, Mr. Neatherlin, who do you work for and in what capacity?

A. Mesquite, SWD. I'm the operations manager for them.

Q. And what are your responsibilities at Mesquite SWD in operations and regulatory matters?

A. Dealing mostly with permitting and regulatory of our disposal wells, any compliance as far as annual testing, facilitating any workovers or remedial work that needs to be done with them.

Q. And do your responsibilities include the management and oversight of drilling the saltwater disposal wells?

A. Yes.

Q. And have you previously testified before the Oil Conservation Division or Commission?

A. Yes.

Q. And were your credentials accepted and made part of the record?

A. Yes.

Q. Does your area of responsibility at Mesquite SWD include the areas of Eddy and Lea Counties in southeastern New Mexico?

A. Yes.

Q. And are you familiar with the application that's been filed by Mesquite in this case?

A. Yes.

Q. Are you familiar with the saltwater disposal wells that are the subject matter of this application?

A. Yes.

MS. BRADFUTE: I'd like to tender Mr. Neatherlin as an expert witness in operations matters.

CHAIRMAN CATANACH: Mr. Neatherlin is so qualified.

Q. (BY MS. BRADFUTE) Mr. Neatherlin, could you please turn to what's been marked as Exhibit Number 1 in the exhibit notebook in front of you? And just briefly explain to the Commissioners what this document is.

A. Okay. This is our application to amend the disposal wells for 5-1/2 injection tubing in southeastern Eddy and Lea Counties.

Q. Has Mesquite previously received orders from the Division which approves the drilling of these wells?

A. Yes.

Q. Okay. And so Mesquite is just seeking to amend the tubing size to 5-1/2 inches for each of these administrative orders?
A. Yes.
Q. And were there any objections made by affected parties to the administrative applications that Mesquite made?
A. No.
Q. Were there any objections presented at the Division hearing in this matter in March of 2017?
A. Not that I can remember, no.
Q. And the Division did issue administrative orders approving each of the applications listed in the chart and paragraph one of this application?
A. Say that one more time.
Q. Yes. And the Division did issue orders, correct --
A. Oh, yes, approved orders.
Q. -- for --
Thank you.
If you could please turn to Exhibit Number 2, which includes Tabs A through H, and turn to Tab A and explain what this exhibit contains.
A. This is the administrative order for the approved -- these are our approved disposal wells with

4-1/2-inch tubing.

Q. Okay. And the rest of the tabs, B through H, do these tabs contain the other administrative orders for all of the wells which are the subject matter of the application?

A. Yes, they do.

Q. Were some of these orders originally issued to R360 or other operator?

A. Yes. I believe there are three or four of them that were -- that we purchased or we got from R360 Permian.

Q. And was a transfer of operatorship filed for these wells?

A. Yes.

Q. Could you please turn back to Tab A and look at the first order and point out to the Commissioners the language within this order which authorizes the size of the tubing that's at issue?

A. About halfway down the page, it says, "Injection will occur through internally-coated, 4-1/2-inch or smaller tubing and a packer set within 100 feet of the top of the open-hole...."

Q. So this is the language which is at issue in each of the orders today, correct?

A. Yes.

Q. How many wells does your application currently cover?

A. Eight.

Q. And have any of these eight wells been drilled already?

A. I believe two of them have been drilled and are in operation.

Q. Okay. And is Mesquite still seeking to amend the orders for those two wells that have been approved?

A. Yes, we are.

Q. And which wells are those?

A. That would be -- the Scott B and the San Dunes 2 are already in operation.

Q. And how would the tubing be changed in these wells since they've been drilled?

A. We would go in and unseat the tubing from the packer, trip the tubing out, lay it down and then run in with a full 5-1/2 string.

Q. And do you see any problems in performing those operations?

A. No.

Q. Could you please turn to what's been marked as Exhibit Number 3 in the notebook that's in front of you? And explain what that exhibit is to the Commissioners.

A. This was a spec sheet of the 5-1/2 tubing that we're looking to use in our injection wells. It goes through with the outside diameter of the coupling, the inside diameter of the coupling and then the total length of it. And then below that, we have the outside diameter of the tube body and the inside diameter of the tube body and then the inside diameter of the tubing after it's been lined. And then below that, we have the casing that we're using for our liners in these wells. It's a 7-5/8, 39 pound and then our -- the outside diameter, inside diameter for that casing string.

Q. And could you briefly explain to the Commissioners what type of cement program is going to be used in connection with this tubing and casing --

A. On all of our disposal wells, per order of the Division is that each string of our casing has to be cemented to surface. We put that in our application. And then either through visual inspection, upon cementing or afterwards, a wireline cement bond log ran through the liner to verify cement bonding across the cement -- or across the casing.

Q. And could you please explain Mesquite's reasons for requesting a larger tubing size?

A. This will allow Mesquite -- it will allow us to move more water at a lower surface pressure increasing the economics of our wells.

Q. And will the use of 5-1/2-inch tubing allow Mesquite to drill fewer wells within the area?

A. Yes.

Q. And will this result in a decreased surface disturbance throughout the area?

A. Yes, it will.

Q. Are you aware of any Devonian disposal wells for which the Division recently approved the use of 5-1/2-inch tubing?

A. Yes.

Q. And have you studied the Division's Web site and found those copies of such approvals which allowed the use of 5-1/2-inch tubing via administrative orders?

A. Yes, we have.

Q. Could you please turn to Exhibit Number 4, which has Tabs A through G in it, and turn to Tab A and maybe Tab B and briefly explain to the Commissioners what these documents are?

A. Tab A is an order that was given in 2000 for an injection well with 5-1/2-inch plastic-lined tubing. And then B is another one from 2014 that -- for another injection well that has 5-1/2-inch tubing in it as well.

Q. And let's go to Tab C and explain what this is to the Commissioners.

A. C is another order -- another administrative order in 2015 with an approved injection string of 5-1/2-inch tubing.

Q. Are you aware of other applications in cases that have recently gone before the Division which approve the use of 5-inch tubing?

A. Yes.

Q. Are you aware of an application filed by Black River Water Management Company which requested the use of 5-inch tubing?

A. Yes.

Q. And are you aware of the fact that Black River Water Management Company's application was granted to use 5-1/2-inch tubing?

A. Yes.

Q. Are you aware of any approvals given by the Division to use tapered string tubing sizes?

A. Yes, we are. All of ours have been approved for tapered string use.

Q. And for the benefit of the Commissioners and myself, what is a tapered string of tubing?

A. Tapered string is we're still sticking to the 4-1/2-inch through the liner string and then have a 5-1/2-inch tubing to the surface on that.

Q. Are you aware of administrative orders issued by the Division which are completely silent as to the

tubing size?

A. Yes. We have come across some that have no tubing size demanded -- or requirement on them.

Q. So the Division has been approving the use of a variety of different tubing sizes, correct?

A. Yes.

Q. Let's turn back to Exhibit Number 2 and start with Tab A. And I just want to quickly go through the approved injection intervals just to set some background information for other testimony that's going to be presented. Tab A is the order for the Sand Dunes SWD Well No. 2, correct?

A. Yes, it is.

Q. What is the injection interval that's been approved in this order?

A. It is from approximately 16,620 feet to 18,010 feet.

Q. And it covers the Devonian and the Silurian Formations?

A. Yes, it does.

Q. Could you turn to Tab B? This order relates to the Scott B SWD Well No. 1, correct?

A. Yes, it is.

Q. And what's the approved injection interval in this order?

A. 15,000 to 16,200 in the Devonian-Silurian Formations.

Q. Great.

And if you could turn to Tab C, and this order relates to the VL SWD Well No. 1, correct?

A. Yes, it does.

Q. And what's the approved injection interval for this well?

A. 15,100 to 16,300 in the Devonian-Silurian.

Q. And could you please turn to Tab B? And this is the approved order for the Station SWD No. 1 well, correct?

A. Yes, it is.

Q. And what's the approved injection interval for this well?

A. 16,470 to 17,975 in the Devonian-Silurian.

Q. And could you please turn to Tab E? This is the order for the Cypress SWD Well No. 1, correct?

A. Yes, it is.

Q. What's the approved injection interval for well?

A. It's 14,780 to 15,780 in the Devonian.

Q. And could you please turn to Tab F? And identify what the approved injection interval is for this well, which is the Gnome East SWD.

A. 15,550 to 16,550 in the Devonian Formation.

Q. Could you please turn to Tab G? Is this the order approving the Uber East SWD Well No. 1?

A. Yes.

Q. And could you please identify the injection interval for this one?

A. 16,390 to 17,500 feet in the Devonian Formation.

Q. And would you finally turn to Tab Number H? And this is the order for the Uber North SWD No. 1 well, correct?

A. Yes, it is.

Q. And could you identify the approved injection interval for this well?

A. 16,500 to 17,500 in the Devonian.

Q. And can you please explain to the Commissioners approximately where these wells are located?

A. They're pretty much all south and east of Carlsbad, New Mexico, in between -- pretty much in between Carlsbad and Jal, New Mexico.

Q. And are these spaced out, or are they located in close proximity?

A. All of these wells that we're talking about here are quite spaced out, anywhere from 5 to 15 miles a part.

Q. And are there any other injection wells which are injecting into the Devonian or Silurian Formations within the area?

A. None that are very close that I'm aware of.

Q. Are all of the wells which are the subject matter of this application isolated to what is referred to as the Devonian or the Devonian-Silurian Formations?

A. Yes, they are.

Q. And could you please explain to the Commissioners what is meant when we say that they're isolated to a single formation?

A. It's just specifically saying that our injection interval is isolated, one, from going up the casing with bonded cement and, two, drilling to the base of the Silurian and isolating our injection zone to those permitted footages.

Q. And did Mesquite SWD provide notification to all of the affected parties for its administrative applications of its application that it filed with the Division?

A. Yes, we did.

Q. And was that notice requirement "any affected parties within a half-mile location of the surface location for each well"?

A. Yes, it is.

Q. And did Mesquite provide proof of notification to affected parties when it presented its case to the Division?
A. Yes, we did.
Q. And did the Division's order find that notice had been given to those parties?
A. Yes.
Q. Could you please turn to Exhibit Number 5? Is this an affidavit confirming that notice -- additional notice had been provided to affected parties just for the Commission hearing as well?
A. Yes, it is.
Q. And at any time has the Division informed you that Mesquite needed to notify additional parties beyond those who have already been notified of this case?
A. No, it has not.
Q. At any time did the Division inform Mesquite that it needed to prove that the agency's notification regulations were sufficient other than in its order that it issued?
A. Would you state that one more time?
Q. Yeah. Did the Division at any time tell you that you needed to notify anyone else?
A. Oh. No.
Q. Were Exhibits 1 through 5 prepared by you or

under your supervision or compiled from company business records?

A. Yes, they were.

Q. And one final question, Mr. Neatherlin, are you aware of any negative impacts that this application will have on freshwater resources?

A. No. Not on fresh water, no.

Q. Why is that?

A. Because we're injecting anywhere from 14,000 feet to 16,000 feet below fresh water -- usable fresh water. We have three strings of casing that run through the freshwater zones cemented to surface and then our internally coated injection string acting as a fourth barrier between any produced water and fresh water.

MS. BRADFUTE: Mr. Chairman, I'd like to move that Exhibits 1 through 5 be admitted into the record.

CHAIRMAN CATANACH: Exhibits 1 through 5 will be admitted.

(Mesquite SWD, Inc. Exhibit Numbers 1 through 5 are offered and admitted into evidence.)

CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. Good morning, Mr. Neatherlin.

A. Good morning, sir.

Q. I have a few questions. Do you guys have any exhibits on how these wells are constructed currently?

A. As far as the wellbore diagram?

Q. Yes, sir.

A. We do. They are on file with the Division. They're in all of our applications that we turn in. We have to have a wellbore diagram form.

Q. But there are not exhibits here today?

MS. BRADFUTE: No, but all of the original applications are filed with the Division, and the Commission can take judicial notice of those applications which were approved.

Q. (BY CHAIRMAN CATANACH) Are all these wells constructed similarly?

A. Yes, they are.

Q. Can you just briefly tell us what kind of casing string you have in these wells?

A. We start off with a 30-inch conductor, to get started, and then from there, we run a 20-inch surface casing string down to the base of the fresh water -- well, below the base of the fresh water. And then we come back with a 13-3/8 casing string for the first intermediate, running it to the base of the salt and cementing there. And then from there, we run our second intermediate string with a 9-5/8 down anywhere from 100 to 200 feet into the top of the Wolfcamp and cement that string of casing back to surface. And then from there, we drill to the top of the Devonian and cement 7-5/8 liner. And then after that, that's the -- that's our last casing string that we run, and then the injection interval is open hole.

Q. Okay. So I had a question on the tapered tubing. On the orders that you referenced, it looks like it's just 4-1/2-inch tubing that's been approved?

A. Yes, sir.

Q. But you did say that you've been authorized to use a tapered tubing string?

A. Yes. The Division, both in Santa Fe and in the field offices, has -- well, we checked and got written and verbal verification from Santa Fe on running a tapered string, and it's fine as long as we are not running the 5-1/2 into the 7-5/8 line.

Q. So can you tell us what that tapered tubing string -- where these different sizes and where they're set?

A. So, for example, the Sand Dunes I believe are -- the 7-5/8 liner starts at about 11,000 feet. So from surface down to actually about 10,800 feet would be a 5-1/2 string. And then approximately 200 feet above our liner, we're having it cross over, and it goes from the 5-1/2 down to the 4-1/2, and then the 4-1/2 string runs through the 7-5/8 liner tying into our packer.

Q. So how -- approximately how much 4-1/2-inch tubing are you running in these wells?

A. Anywhere from 4- to 6,000 feet depending on the well.

REDIRECT EXAMINATION

BY MS. BRADFUTE:

Q. And, Mr. Neatherlin, just to confirm, that's been approved by the Division?

A. Yes, it has.

CONTINUED CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. So how much 5-1/2 would that entail about?

A. Remaining on the wells or to --

Q. Yeah. How much 5-1/2-inch tubing, the lengthwise?

A. Anywhere from -- we're running anywhere from 10- to 15,000 feet. Excuse me. We're not going 15,000 feet. Usually around 10,000 feet -- 8- to 10,000 feet on the 5-1/2 strings.

Q. And is that -- the two wells that are currently operating, that's the configuration of these wells right now?

A. Yes, sir.

Q. Are you injecting under pressure in those two wells?

A. Yes.

Q. Because a lot of times the Devonian will take water on a vacuum. But that's not the case?

A. It will take water on a vacuum. And most of these will take roughly about 3,000 barrels a day on a vacuum by themselves. But these wells, you know, we're trying to maximize the amount of water that we can get down these wells. We're shooting anywhere -- shooting for a volume of 30- to 40,000 barrels a day is what we're aiming for. But in order to do that, we have to have -- most of our wells right now have anywhere from three 700-horsepower pumps to 900-horsepower pumps to move that water -- move as much water as we can to inject into the well.

Q. So what's your current rate?

A. Some of these that we've been running are about 18,000 barrels a day. The Vaca Draw, the one that we have that has 5-1/2, I only have two pumps on it right now, and we're moving about 24,000 barrels a day. And it ranges -- we have one well that is a solid 4-1/2 string, one well that's a solid 5-1/2 string, and a few different ones that are tapered strings. But it also depends on the thickness of the injection zone and permeability for each specific well.

CHAIRMAN CATANACH: You guys have questions?

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. For the Devonian in New Mexico, what's the largest permitted -- is it 5-1/2-inch injection tubing?

A. The largest what?

Q. What's the largest permitted injection tubing?

A. The largest permitted in New Mexico we've seen has been 5-1/2.

Q. 5-1/2.

What about in adjacent areas, Texas, New Mexico?

A. I know of a well in Texas that has 7-inch injection string into the top of the Devonian, and it's a solid 7-inch string.

Q. In your opinion, is there any reason to limit the size of the injection string?

A. In my opinion, no, because we are not -- we're still remaining under the allowable injection -- surface-injection pressure, which is under frac gradient. So as long as we're constantly staying under that, we're not going to fracture the formation. All it is is -- all it's doing is it's allowing us to move more water at a lower surface pressure.

Because the tests that we run on our step-rate test, watching bottom-hole pressure as proposed to surface-hole pressure -- or surface pressure, we're seeing anywhere from -- as low as a change of 65 pounds per pressure downhole going from zero to -- for example, 35,000 barrels a day. Downhole -- on the last one that we did, on the Sand Dunes, we saw a Delta P of 65 pounds downhole as opposed to 3,200 pounds surface pressure. So you can see that all of that -- all of that pressure -- even through the 5-1/2 and 4-1/2 string, the friction on it, we're not even exerting that pressure downhole. So I don't feel that the size of the casing -- or the size of the injection string is going to cause any damage to the formations.

Q. Thank you, Mr. Neatherlin.

CROSS-EXAMINATION

BY COMMISSIONER MARTIN:

Q. On the two that are operational, did you testify -- and if you did, I apologize. Did you run a CBL on those?

A. Yes, we did.

Q. And you did circulate cement to the surface?

A. Yes, sir.

Q. And at what depth is the surface casing being set on most of these wells?

A. Typically -- I believe like the Sand Dunes -- I don't know off the top of my head, but I believe it's about 800 feet. We're setting it into the top of the Rustler, into the Rustler. Anything below that is nonpotable water.

Q. And what is your allowed permitted maximum injection pressure on those wells?

A. It depends on the well. It's .2 pounds per foot from the top of the injection interval. So we're looking at anywhere from 2,700 pounds to 3,700 pounds.

Q. And you're pumping at the max?

A. We're trying not to, no. No. And that's part of this, is we don't want to -- we want to lower our surface-injection pressure as much as possible. I don't want my guys working on 3,000-pound pumps. I'd feel safe at a lower surface-injection pressure.

Q. Okay. That's all I have.

CHAIRMAN CATANACH: Couple more.

RECROSS EXAMINATION

BY CHAIRMAN CATANACH:

Q. Mr. Neatherlin, how do you determine where to drill and site these wells?

A. A lot of it is just proximity to fields. Some of these have been in collaboration with other operators that have gone in and asked for disposal wells in this area that's going to be close to their field, and that's been the majority of these where we've been placing them. Some of it does go into looking at the geology on where we know the Devonian's been pinching out or where it's tight and where it's not interconnected and where we're going to be able to take the most water at the lowest pressures.

Q. So you said these are not -- they're isolated. They're not spaced together, your wells?

A. Our wells are not, no. They're not -- they're not spaced together.

Q. Are you guys drilling any wells where there are existing Devonian wells situated close to you?

A. I'm not aware of any that are close to us. There might be a few that have been drilled for production exploration, old plugged wells in the area of review, but none that are active -- of course, active-producing or injection.

Q. So if the demand for disposal in a certain area were great enough, would you drill maybe another second well in that area?

A. In reference to our wells, yeah. We have --

just within our company, we have just a practice management of trying to keep these wellbores at least a mile apart just because of the volume. We don't -- you know, like Jennifer said earlier in her statement, these wells are costly to put in. On a -- on a best -- best-case scenario, they're costly to put in, and we don't want to -- and we don't want to step on our own foot by overpressuring by putting wells too close to each other or having them communicate and having to deal with that.

Q. That's one of the Division's concerns with Devonian wells.

A. Uh-huh.

Q. But speaking of cost, did you drill these two existing wells?

A. We -- yes, we drilled them.

Q. How much did it cost to drill?

A. A lot. A lot.

Q. Do you know specifically?

A. Anywhere from 6- to $10 million per well.

Q. Okay. That's all I have.

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. I just have one question, just curious.

You can pick any one of these orders issued

to you under Exhibit 2. They all look pretty similar, and I guess the terms are pretty similar. But my question is: Is there a term in here, in other words, to allow to injection for ten years, 30 years?

A. The way that I understand the Division rules, as long as you are injecting into your well, as long as you don't have a cease of more than a year without any injection, then your permit is good until you either plug and abandon it or you fail on that stipulation from the -- that's already imposed from the Division of not injecting for more than a year.

Q. Okay. So these orders could be forever?

A. Yes.

CHAIRMAN CATANACH: And we don't put any volume restrictions in a normal SWD either. So it's just regulated by pressure.

MS. BRADFUTE: Could I follow up with a few questions?

CHAIRMAN CATANACH: (Indicating.)

REDIRECT EXAMINATION

BY MS. BRADFUTE:

Q. Mr. Neatherlin, is it likely that these wells would be plugged after the life of the tubing expires?

A. No. If the life of the tubing expires, we will change it out for new tubing.

Q. Change it out for new tubing?
A. Yes.
Q. Earlier there were some questions about tapered string wells. Are tapered strings preferable in your view?
A. No. No. We would prefer to have a solid, one-size string. It takes out any crossovers or changeover tools that are needed for going from one size of pipe to the other, as well as handling. It's just way easier if you have one string of pipe from top to bottom. You know, adding external components to it, injection string always typically be -- or typically the ones -- the components to fail in an injection string.
Q. And when you were preparing your administrative applications for these wells, you did work with a geologist, K. Havenor, correct?
A. Yes, we did.
CHAIRMAN CATANACH: Thank you.
MS. BRADFUTE: I have no further questions, Mr. Chairman.
CHAIRMAN CATANACH: Okay. This witness may be excused.
MS. BRADFUTE: Okay. Thank you.
CHAIRMAN CATANACH: You're too quiet over there.

MS. BRADFUTE: She's just keeping an eye on things.

We'd call our second witness, Dr. Zeigler.

MS. STEVENSON: She's going to bring a little show-and-tell.

CHAIRMAN CATANACH: Nice.

THE WITNESS: Like all good geologists.

COMMISSIONER BALCH: I'll just take these in my backyard.

MR. NAVE: She will make sure she takes them home.

KATE ZEIGLER, Ph.D.,

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

DIRECT EXAMINATION

BY MS. STEVENSON:

Q. Good morning. Please state your name.

A. Kate Zeigler.

Q. Dr. Zeigler, who do you work for?

A. Zeigler Geologic Consulting.

Q. What are your responsibilities?

A. I am the senior geologist at Zeigler Geologic Consulting, and we provide a wide variety of geoscience-related services to both rural New Mexico and to oil and gas.

Q. And will you please describe your educational background?

A. I have a bachelor's in geology from Rice University in Houston, Texas, a master's in paleontology from the University of New Mexico, a Ph.D. in stratigraphy and paleomagnetism from the University of New Mexico.

Q. Thank you.

Please describe your professional experience.

A. In terms of Permian Basin work, I've done quite a few surface geologic maps both for the State Survey Geologic Mapping Program for independent operators in the Basin who are looking at exploring prospects in the relatively shallow subsurface. And I've also done stratigraphic analysis on behalf of these companies for these prospects and have worked on stratigraphic analysis in the San Juan Basin as well.

Q. Are you familiar with the applications amending orders filed by Mesquite SWD in this matter?

A. Yes.

Q. Are you familiar with the status of the lands where the wells that are the subject of this hearing have been or will be drilled?

A. Yes.

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

A. I am.

Q. Have you conducted a geologic study of the area embracing the proposed location of the eight wells?

A. I have.

MS. STEVENSON: I would like to tender the witness as an expert in geology matters.

CHAIRMAN CATANACH: The witness is so qualified.

MS. STEVENSON: Thank you.

Q. (BY MS. STEVENSON) And, Dr. Zeigler, would you please explain what you brought with you today?

A. In terms of the rocks, there are four rocks piled in front of you. They do not need to remain piled. You can move them around as you please. The two smaller ones are fragments of dolostone, and I brought those so that you could see dolostone versus limestone. The sort of triangular web-shaped piece is a fragment of limestone that has significant fracturing running through it. And the platform upon which the others are stacked is a fragment of fossiliferous limestone that I'm using to show just the physical characteristics of the rocks that we're talking about today.

Q. Thank you.

Dr. Zeigler, will you please turn to Exhibit 6 and explain to the Commissioners what this exhibit is?

A. So this is a series of brief descriptions of the physical characteristics of the different stratigraphic units that are in question here. And I chose to begin our description starting with the Woodford Shale because that's the uppermost sort of permeability barrier that we're considering if we think about where fluids are going to go in the subsurface here.

So the Woodford Shale is an Upper Devonian unit, and it's pretty much organic-rich mudstone with some carbonate beds interbedded within it. And what's helpful about this unit is because it's predominantly a shale horizon, that means it has fairly low porosity and permeability, which allows us to consider it as a permeability boundary to prevent fluids from moving upward out of the units below it into the overlying units that are significant production units.

In this case what's interesting is the Woodford Shale, it's what's called unconformable on the rock units below it. And what that means is if you walked up and put your finger on the bottom of the Woodford Shale, the unit below it, there is significant time missing of that contact, and because of the time that's missing, that contact locally can have -- it's basically a karst surface, so you can have solution cavities and fissures that create significant porosity and permeability underneath that Woodford Shale.

Something that I would clarify at this point is geologists, when we think about Devonian strata in the Permian Basin, we think about it a little differently than how operators traditionally do. So when a driller says that they have drilled into the Devonian in the Delaware Basin, they're frequently actually referring to what are Silurian ash-rock for the Wristen Group, which we'll talk about in a moment. So the only true Devonian unit in terms of just stratigraphy that we have here is the Woodford Shale.

But from this point forward, I'm going to switch gears, and for further exhibits, I'll use the drillers' terminology just so that we stay on the same page with how operators think about the stratigraphy in the Permian Basin.

There is another Devonian unit in the Permian Basin, the Thirtyone Formation. This unit is only present right down in the very southeast corner of New Mexico and is not present where these wells are being considered. So it's included here for completion sake, but it's not at issue in terms of the rock units that we see in these wells.

So below the Woodford Shale and all of the wells that are at question here is a very quick package of limestone and dolostone that's comprised of the Wristen Group, the Fusselman Formation and the Montoya Group.

The Wristen Group is Silurian. And so in a lot of these wells, we refer to the Devonian-Silurian unit, and that's this Wristen Group into the Fusselman Formation. And the Wristen is quite thick. It can be from 0 to 1,400 feet thick. It's very deep in the subsurface in the Delaware Basin. It's very fossiliferous. It includes buildups of coral reefs -- coral reefs, stromatoporoids and other colonial vertebrate organisms which provide quite a bit of primary porosity for this well. And so the fossiliferous limestone that's at the bottom of the pile over there would be a good analog to what that rock unit would look like.

It also has significant fracturing and vug-space porosity developed within, and it's a good porous and permeable rock unit.

The Fusselman Formation, which sits below the Wristen Group, is Late Ordovician to Lower Silurian.

It's almost entirely dolostone. It can be up to 1,500 feet thick, and it has a primary crystalline -- primary coarsely crystalline porosity. It's also got vug space. It's fractured. It's brecciated. And so for these units, there is quite a bit of space that's both primary and secondary porosity and permeability.

Below that sits the Montoya Group, which is an old Upper Ordovician. Again, continuing our theme of thick dolostone sequences, at the base of the Montoya Group, there is a sandstone number, that Cable Canyon Sandstone. And this entire package is frequently up to 600 feet thick. Below that is the Simpson Group, Middle to Upper Ordovician, and this unit is another interesting unit in terms of the fact that it is not a giant pile of limestone like everything up above it, but it has thick sequences of shale. It can be up to 50 percent shale. And so once again, as with the Woodford Shale, at the top of the sequence we're considering here, that shale can act as a permeability barrier that would hopefully prevent fluid from moving downward into the deeper Ellenburger Formation and the Precambrian Basin, which is what we're seeking to avoid.

Beneath the Simpson Group is the Ellenburger Formation, which is up to 1,000 feet. And, again, limestone and dolostone both significant primary and secondary porosity, and that sits directly on the Precambrian Basin in much of this area where there is -- there is another unit that comes and goes in there, the Bliss Sandstone, but that is not always present in the subsea surface.

Q. Dr. Zeigler, into what stratigraphic unit will the eight wells that are the subject of this proceeding be located?

A. These will be primarily in the Wristen Group, the Fusselman Formation and potentially into the Upper Montoya Group.

Q. Please turn to what's been marked as Exhibit 7 in the notebook before you and explain to the Commissioners what this exhibit is.

A. So this an exhibit that is -- what we call a fence diagram, and it's developed from data from hundreds to thousands of individual wells that have been drilled through the Permian Basin. And you can see in the upper inset figure; it shows you how the lines in these fence diagrams are arranged between New Mexico and Texas. And the whole figure is kind of canted off to its side, so it might take a second to orient here to what you're looking at.

But what I wanted to focus in on in this particular case is sort of the right center part of the diagram here (indicating), where we're at that junction between sort of the Texas-New Mexico border. And what we're seeing here is the depth of the Delaware Basin. We have this very deep area here where we're depositing very thick sequences of limestone and dolostone, along with our Simpson Group down at the bottom and the Woodford Shale at the top. And this area is the deepest part of the Delaware Basin, is effectively where the wells in question are going to be situated. And so it's to show you the thickening of these packages as we come into the Delaware Basin off the western slopes and as we rise up onto the Central Basin Platform on our way into West Texas.

Q. And, Dr. Zeigler, there is a marker there on your desk, if you wouldn't mind circling for the Commissioners where on the map the wells will be located.

A. (Witness complies.)

Kind of in the heart of the deepest part of the Delaware Basin. Can you see that?

MS. BRADFUTE: Yes.

Q. (BY MS. STEVENSON) And can you please explain for us what the lines are on this diagram that say "Normal Fault?

A. So if you look both to the right and to the left of where I circled the deepest part of the Delaware Basin, there are vertical lines drawn across the fence diagram. These are representing where there are major fault or fault zones that penetrate all the way into the Precambrian basement and have been documented both in shallow seismic and other imaging and on the surface. The interesting part about where these wells have been located is they're in between these fault zones. So we have our western faults that are part of the Sacramento Mountains uplift and the Guadalupe Mountains uplift, and then we have the faults to the right which are the western edge of the Central Basin Platform. Those are the faults along which that Precambrian block was lifted up. So we're situated between those major faulted areas.

Q. Dr. Zeigler, please turn to what's been marked as Exhibit 8, and please explain to the Commissioners what this Exhibit is.

A. So this is a generalized stratigraphic chart from Ron Broadhead, a 2017 publication, that compiles all of the nomenclature that's used in the Permian Basin. The western left-hand stratigraphic chart is for the Northwest Shelf and the Central Basin Platform, so some of the rock unit names are not quite the same depending on where you are in the Permian Basin.

Where we are is in the right-hand chart, which is for the Delaware Basin. And effectively we're looking at -- I'll go ahead and highlight. We are looking at the portion of the section that is the Lower Paleozoic. So we're looking at -- you can see the Woodford Shale. It has a black-grayish box beneath it. That's representing the time that's missing at the bottom of the Woodford Shale. And then you have the Thirtyone Formation, the Wristen Group, Fusselman, Montoya, Simpson, Ellenburger, the Bliss where it's present, and the Precambrian basement.

A reminder that the Thirtyone Formation is present only in the very, very, very far southeast corner. So for the purposes of this, the Thirtyone Formation is not present in this sequence. But this is to show you both the ages and the names of the stratigraphic units in the area.

Q. Do you know if there is any oil and/or gas production occurring in the Devonian strata in the way operators use it, or is any of the older strata in this area?

A. Yeah. Here I'm going to switch gears and use Devonian to fit with the driller's lingo and not with the geologist lingo.

There are no known significant economic

reserves in these units in this part of the Delaware Basin.

Q. Dr. Zeigler, please turn to Exhibit 9 and explain to the Commissioners what this exhibit is.

A. So this figure is an isopach map for the Simpson Group, and the isopach map is showing you the thickness of that unit. And so there are very fine white lines that kind of curve and squiggle across the Permian Basin here, and those lines are contour lines of equal thickness of the Simpson Group.

The two lines of dots that are connected with lines, those are where the wells are that are in question both here and for future exhibits. And this is showing you that in these wells, if you were to drill all the way down through the Simpson Group, you would hit anywhere between 200 and 800 feet of Simpson Group. And the purpose of this is to demonstrate that there is a significant thickness of that lower shale, which would be acting as a permeability boundary at the bottoms of these potential wells.

Q. Does Mesquite intend to drill into the Simpson Group?

A. Not that I'm aware of.

Q. Dr. Zeigler, please turn to Exhibit 10 and explain to the Commissioners what this exhibit is.

A. So this is a structure map that's developed on the top of the Precambrian. There are also, once again, very fine white lines that are probably a little tricky to see here that are labeled with 1,000-foot intervals. These are basically showing you what the top of the Precambrian would look like if you could strip off everything that was above it and you could see, basically, the topography and the faulting and folding that's developed on the top of the Precambrian basement.

And so there are a few items here that are of interest. One is if you look at the depth -- so each of these numbers, 4,000 feet, 6,000 feet, et cetera, that's the depth from sea level down to the top of the Precambrian Basin. And so what we see here is the wells that we're considering here southeast of Carlsbad are really in the heart of that Delaware Basin. They're where the Precambrian Basin is sitting very deep below the surface.

The black lines that cut across the map, these are the fault zones that were shown on that fence diagram that we looked at earlier. So you have, to the west, this northwest-southeast trending fault that's sort of the easternmost expression of Sacramento Mountain structures and Guadalupe Mountain structures, and then as we move to the east, you're seeing the faults that are that western boundary of the Central Basin Platform and just showing the spacing of these wells, both the spacing out of them, and their proximity -- non-proximity to these faults. And so we're looking at anywhere from 15 to 18 miles between these wells and these major fault zones.

Q. So, Dr. Zeigler, there are no fault zones in the immediate vicinity of the proposed or existing well sites?

A. Not that have been documented, no.

Q. Please turn to Exhibit 11 and explain to the Commissioners what this exhibit is?

A. So these are also Precambrian structure contour maps that are zoomed out a little more so that you can see the bigger regional picture of what's going on. The one that we just looked at is zoomed in more focused on the area of interest here.

The first one is a compiled structure contour map from Broadhead 2017. And the green -- you can see our lines of cross sections are wells in green, sort of over in the lower right-hand corner of the diagram. The blue dots are individual wells that were used to construct the structured contour maps for New Mexico. And the red lines indicate the major fault zones that have been documented that penetrate all the way through the Precambrian Basin.

And so this is to demonstrate that the wells in question are centered between the major zones of faulting for the Central Basin Platform to the east and all of the structure that's involved in the Guadalupe uplift, the Sacramento Mountains uplift and features to the west so that you get a sense of that spacing.

The figure to the bottom is even more zoomed out. And, again, this is to simply highlight where the wells in question are are in relation to some of these bigger structural features that affect the Precambrian basement in this area, including the broad fault zone that isolates the Central Basin Platform from the Delaware Basin.

Q. Dr. Zeigler, please turn to Exhibit 12 in the notebook and explain to the Commissioners what this exhibit is.

A. So this figure is what's called a pinch-out figure, and each of the colored lines represents the point. If you were to go from the center of the Permian Basin in West Texas, if you were to travel up into New Mexico, at what point do these different rock units effectively pinch out to?

And so, for example, the Thirtyone

Formation, the pink arc that's down in the very far right-hand corner -- the lower right-hand corner of the figure, if you were to go anywhere to the west or north of that pink line, you would not find any Thirtyone Formation present. It has either hit the edge of the bathtub that it was being deposited in and, therefore, there is no more deposited, or it's been eroded out. And either way, there is no thickness of the Thirtyone Formation beyond that pink line as we go to the north or the west.

So the blue line is the furthest out that the Simpson Group is present in significant thickness. The yellow is the Wristen. The green is the Fusselman, and the red is sort of the Ordovician all lumped together.

And, again, we have all of our wells around the Carlsbad area shown -- the lines of the cross section that we'll look at in just a moment -- showing once again the Thirtyone Formation is not involved in this area. It pinches out before we get to where these wells are located and that we have -- all of the other stratigraphic units are present in some thickness where these wells are drilled.

Q.   Dr. Zeigler, please turn to Exhibit 13 in the notebook in front of you and explain to the

Commissioners what this exhibit is.

A. So the two pages here are a series of stratigraphic cross sections that were developed both from wells that are Mesquite wells and also from well data that we were able to find on the OCD Web site for this area that penetrate deep enough to be of interest. The first one is from west to east, and the second one is from north to south.

And on the first page, these are the geophysical logs from these wells so that you can see the data that came directly from the instruments that were run down the well with our picks for the top and bottom of the Woodford Shale and then having lumped together the limestone package below that as the Ordovician-Devonian. So we're sticking with the terminology used by the drillers.

And so showing the Woodford Shale as we go from west to east from just south of Carlsbad out into to the Delaware Basin, we see that plunge down into the Basin. We see this thick package of limestone that's Ordovician-Silurian-Devonian that sits beneath the Woodford Shale.

And then on the back side of that, what I've done is constructed what is called an interpreted stratigraphic diagram. And all I've done is taken the wireline squiggles and turned them into a lithology so that you see the limestone versus the shale. And this is to help visualize the Woodford Shale and the thicker limestone package below it so you can see what the rock types would look like if we could send a camera down the wellbore.

The second page is effectively that same two sets of data but reversed for the north-to-south cross section, again showing the drop-down into the Delaware Basin as we come south and then the geophysical logs on the back side that correspond to these interpretive stratigraphic sections.

MS. STEVENSON: And I'd just like to note for the record, Commissioners, you have four pages. Dr. Zeigler has front-and-back pages. So when she's mentioning two pages --

THE WITNESS: Sorry.

MS. STEVENSON: -- there are actually four pages to this exhibit, for the record.

Q. (BY MS. STEVENSON) And, Dr. Zeigler, if you would go into a little more of where you obtained the data used to create this exhibit.

A. So all of the well logs for these wells that are used are available from the OCD Web site. And some of these wells are Mesquite wells and some of them are other operators' wells that we chose to expand this cross section out so that we weren't just zoomed in on the area of interest, but we could expand out our view of what's happening in the subsurface.

So in the west-to-east cross section, the Scott B, the Moutray and the Cedar Canyon No. 1, as well as the Sand Dunes No. 2 and the Vaca Draw, these are all Mesquite wells. And the other wells in this figure are other operators' wells that we found that fall in line with this cross section and help to form it.

And then in the north-to-south one, these -- all of these wells are other operators' wells that intersect with the east-west cross section that includes the Mesquite wells. And so we chose these wells again to understand the profile of these rock units as we come into the area of interest both from the north and from the south.

Q. Dr. Zeigler, what conclusions have you drawn from your geologic study of the area where the wells are or will be drilled?

A. I think the biggest take-away point that I've gained from doing this study is that there is a very thick sequence of limestone and dolostone that is the interval of interest that has significant primary and secondary porosity and permeability and that it is bounded at the top by the Woodford Shale which presents a permeability boundary, and it is bounded at the bottom by the Simpson Group, which also offers a permeability boundary for fluids that are within that interval between those two units.

Q. Do you have any opinions on the capacity of the formation for injection of saltwater?

A. It has a significant porosity and permeability. Average porosity for many of these wells -- for many of these -- for these rock units, we see in many of these wells, is on the order of 5 percent, on average, but can be up to 15 percent or higher. And so there is significant porosity and permeability to accommodate fluids in these rock units.

Q. Is there any risk to freshwater resources by the injections proposed by Mesquite?

A. Not at this depth. Groundwater in the area tends to become less potable with depth, as we know, and frequently below 7- to 800 feet depth, the waters are not drinkable by either humans or livestock, which means that at average depths of 14,000 feet or deeper and with these permeability boundaries above it in terms of the Woodford Shale and other rock units, there's not significant harm that could be done to fresh water.

Q. Are you aware of any productive shales in the

formations at issue?

A. Not for the thick limestone package that sits below the Woodford Shale.

Q. In your opinion, will increasing the tubing size to 5-1/2 inches impact correlative rights of mineral interest owners?

A. No.

Q. And why not?

A. In the sense that this unit is not known as an economically significant productive interval, and for productive intervals above that, the Woodford Shale acts as a permeability barrier to protect those overlying reservoirs.

Q. In your opinion, would the granting of Mesquite's application be in the best interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. Were Exhibits 6 through 13 prepared by you or under your direction and supervision?

A. Yes.

MS. STEVENSON: I would like to move for the admission of Exhibits 6 through 13.

MS. KESSLER: No objection.

CHAIRMAN CATANACH: Exhibits 6 through 13 will be admitted.

(Mesquite SWD, Inc. Exhibit Numbers 6 through 13 are offered and admitted into evidence.)

MS. STEVENSON: Thank you. I have no further questions for this witness at this time.

CHAIRMAN CATANACH: Ms. Kessler?

MS. KESSLER: No questions.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Good morning, Dr. Zeigler. I don't have many questions, but I would like to talk a little more about the fault. Basically, what is the age of those faults?

A. So the faults that are at issue here have been around since Precambrian, so they're fairly old structures. And the last time that there's been significant motion on these faults was during the Basin and Range development, which is probably up to about 20 million years ago. So that would be the last major tectonic activity in this area.

Q. Do you know how -- so they're pretty much going all the way up the section of the Delaware except into the most recent formation?

A. And -- yeah. Uh-huh.

Q. So refresh me on the shallow stratigraphy. I

guess you have the stratigraphic diagram.

A. So Exhibit 8.

Q. For the Permian that --

A. Right. And these faults would penetrate up into the Mesozoic section that would sit above here that's not in these.

Q. Okay. Thank you.

CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. Dr. Zeigler, I wanted to talk a little bit about the barriers -- top and bottom barriers a little more. The Woodford Shale, is that present in all of these injections we see?

A. Yes, sir.

Q. And is this generally the same thickness, or is it --

A. Yes. For the most part, its thickness doesn't vary significantly. If you look to the cross sections on Exhibit 13, you'll see that the Woodford Shale, on average, is -- can be anywhere from 80 to 100 feet thick. At most, it's about 140 feet thick. But it doesn't tend to vary significantly in thickness compared to the rock units above and below it.

Q. That's predominantly a shale section?

A. Yes, sir.

Q. Okay. So the other, the bottom -- the bottom barrier that you discussed would be the Simpson?

A. Yes.

Q. And I was looking at the composition of the Simpson, and it's mostly limestone, dolostone, sandstone and some shale horizons. What would be the controlling factor in there? Would it be the shale sections that would be the barriers?

A. Yes. And if you look through the description, it's actually dominated by the shale beds, which make up 55 percent of the total thickness of the Simpson Group in any given place, and so the dolostone and limestone beds and sandstones become smaller components of that entire stratigraphic thickness. So when we think about how this rock unit would operate -- for example, if we switch gears a little bit and think of this in terms of the aquifer and aquitard, this unit, because it's dominated by those shale beds, it operates primarily as an aquitard. And the sandstone and the dolostone and limestone beds in it are not contiguous enough to operate as an aquifer, if that helps.

Q. You made a comment that the Simpson would be the lower barrier "hopefully." I just wanted to ask you about that.

A. I am confident that in this case, because if we look at the isopach map, we have anywhere from 200 feet to 800 feet thickness in the Simpson Group present where these wells are that there will be a significant enough thickness of the Simpson Group where these wells are located to act as that little permeability boundary.

Q. So that's between 200 and 800 feet thick?

A. Yes, sir.

Q. And the structure map had a lot of dots on it. Those are all Devonian wells?

A. No. These are -- these are simply wells that Ron Broadhead and other folks have used to construct a detailed Precambrian basement map. So these are all wells that have penetrated the Basin. So if we were outside of the pinch-out of these rock units, a lot of these wells up in the northern area, they will probably not intersect significant area of Devonian strata as you go into Chaves County and Roosevelt County simply because we've gone to the edges of the pinch-outs of those units.

So Precambrian -- wells that penetrate the Precambrian to the south that were used to construct these maps, those will have crossed through the full thickness of the Paleozoic sequence. It just simply gets to basement. But those wells are few and far between simply because when you're 20,000 feet or deeper, that's -- that's a hard deal to drill that deep.

Q. So the Division generally has a policy not to allow injection into the Lower Ordovician, Ellenburger and below. Do you concur with that?

A. I do.

Q. And, basically, to keep water out of the Precambrian Basin basement?

A. Yes.

Q. And is the Devonian thickness generally pretty consistent?

A. So in these -- in the wells that we were able to find that were used for the cross sections and even other wells that I looked at in the area, very few of them go any deeper than a total depth of 14- to 17,000. So we simply don't get to the Simpson Group in these wells. But the -- you know, if you look at isopach maps for these other rock units from the Texas Bureau of Economic Geology, a large Permian Basin study that they just did, the thicknesses through this area tend to be fairly consistent in the Delaware Basin.

Q. With high capacities --

A. Significant permeability, yes.

COMMISSIONER MARTIN: I don't have anything.

CHAIRMAN CATANACH: Bill?

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. Just one question. You stated -- your answer was that there are no hydrocarbons in the area below the Woodford Shale.

A. That are economically significant.

Q. Are there hydrocarbons in the Woodford Shale?

A. Yes.

Q. And those would be significant?

A. Yes, sir.

Q. But nobody's drilling in that area, right?

A. Not that I'm aware of.

RECROSS EXAMINATION

BY CHAIRMAN CATANACH:

Q. Now, there is Devonian production in isolated areas across the Basin, correct?

A. Yes. And these are either -- and this is where we get into the Devonian name problem, is that can refer to the Woodford Shale production from the Woodford Shale. If we're talking about the limestones below that that are sort of the Devonian-Silurian package, you're frequently looking at very small isolated traps that take significant ability with imaging to be able to locate them well enough to target them properly.

Q. All right.

CHAIRMAN CATANACH: Anything else?

MS. STEVENSON: We have no further questions.

CHAIRMAN CATANACH: Okay. This witness may be excused.

Do you want to take a break?

SCOTT J. WILSON,

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

DIRECT EXAMINATION

BY MS. BRADFUTE:

Q. Good morning.

A. Good morning.

Q. Could you please state your name for the record?

A. Scott Wilson.

Q. And, Mr. Wilson, who do you work for?

A. I work for Ryder Scott Company in Denver.

Q. And what is your position at Ryder Scott?

A. I'm senior vice president. I've been working there for 17 years.

Q. And what are your responsibilities?

A. My responsibilities include reserve appraisals. I also do technical evaluations. I do reservoir simulations, and during the slow season, I do training on -- analysis.

Q. And have you previously testified before the Oil Conservation Division or Commission?

A. Not in New Mexico.

Q. Have you testified before a similar commission in a different state?

A. I have in Alaska.

Q. And were your credentials accepted and made part of the record?

A. They were.

Q. Could you please explain your educational background to the hearing Commissioners?

A. I have a bachelor's degree in petroleum engineering, and I also have a master's degree in business from the University of Colorado. I've taken industry courses for roughly the last 25 years to stay up-to-date on my technical credentials.

Q. And could you please explain your professional background as a petroleum engineer?

A. I'm registered as a professional petroleum engineer in Colorado and Alaska, Texas and Wyoming. Do you have a specific --

Q. Well, can you give a little background on how long you've worked --

A. Ah.

Q. -- on petroleum engineering matters?
A. Sure. Right out of college in 1983, I started working as a petroleum engineer, and I've been gainfully employed ever since. I worked for Arco for 17 years and then Ryder Scott for now also 17 years.
Q. And are you familiar with the application that's been filed as Mesquite SWD in this case?
A. I am familiar with it.
Q. Have you conducted an engineering study related to this application?
A. I have.
MS. BRADFUTE: I'd like to tender Mr. Scott as an expert in petroleum engineering matters.
CHAIRMAN CATANACH: Where did you obtain your bachelor's degree?
THE WITNESS: Colorado School of Mines.
CHAIRMAN CATANACH: It's not New Mexico Tech.
THE WITNESS: Sorry.
(Laughter.)
COMMISSIONER BALCH: We'll let it slide this time.
THE WITNESS: We do our best.
CHAIRMAN CATANACH: He's so qualified.
MS. BRADFUTE: Thank you.

Q. (BY MS. BRADFUTE) Mr. Scott, can you please turn to what's been marked as Number 14 in the notebook in front of you? And can you please explain what this document is to the Commissioners?

A. This document is a -- a results document, a write-up on some step-rate tests that I was supplied back in May of this year. Mr. Neatherlin called me and asked me to help him evaluate the results of some pressure-testing that he was doing on some injection wells. And since I spent a lot of my time doing -- worked on nodal analysis and well performance, I felt qualified to do this study.

Q. And what information did you consider when you put this study together?

A. I had access to pressure tests, which are described in summary inside this document. I also had access to the wellbore descriptions that also went into this analysis.

Q. And can you please look at the first content page? It begins with "White Paper Discussion: Injector Performance Modeling." And can you look at Table 1 on this paper and explain what is included on Table 1?

A. Table 1 describes the three wells that I had specific data on. It also describes the tubing size that was in those wells at the time the pressure data was taken and the tubing depth. And it's probably good to introduce here that I tend to work in inner diameters because I'm doing evaluation of hydraulics relationships, and the fluids pass through the inner diameter. They don't really know what the outer diameter is. Unfortunately, most of the rest of this document is describing outer diameter, so when I say 4-1/2-inch ID, that is essentially the same as 5-1/2-inch OD.

Q. And why did you choose to study these particular wells listed within this table?

A. These are the wells that I was supplied to look at.

Q. Does one of the wells represent tubing that would have a 5-1/2-inch OD?

A. It does. The Vaca Draw well had 5-1/2 from top to bottom.

Q. And what was the OD for the Moutrap -- Moutray SWD 1? I slaughtered that.

A. Well, the number that's listed here is the ID, and that's 3.6 inches. And so I would need to know the weight of the pipe to identify the exact OD, but it's probably 4-1/2.

Q. Okay. And would the Paduca SWD 1 have been a tapered screen tubing scenario?

A. Yes. And based on this, it's probably a 5-1/2 to 9881 and 4-1/2 to 17284.

Q. Did you draw any conclusions within this White Paper study that you performed?

A. I did.

Q. And could you summarize those for the Commissioners?

A. Sure. The last page of that same exhibit describes a "Review of Completion Options," and it shows what the injection rates would be at fixed wellhead pressures assuming different tubing sizes were placed in these various wells. So that's Table 5.

Q. And the top of the page begins with "Review of Completion Options"?

A. Yes.

Unfortunately, these figures got a little lighter than I expected, but, in general, they show the nodal analysis results from each of those analyses that shows the intersection points between the injection reservoir performance and the tubing hydraulics for the tubing size.

Q. And did you analyze any step-rate test when you were performing this study?

A. I did. Actually, that's the basis of the study. We started with actual data, which is listed starting on Table 2, and then using that actual data, we match a nodal analysis model to the actual data and then varied parameters within that model to see how it acted under different conditions.

Q. Can you please turn to what's been marked as Exhibit Number 15 in the binder? And explain what this draft shows to the Commissioners.

A. Okay. This is an example of the process I just described. Those little crosses -- there are six of those -- those represent actual measurements of the downhole pressure gauges. And so knowing those measurements and knowing the surface pressures that existed when those measurements were taken, we can correlate the tubing hydraulics such that they connect up together. So you have a good match between the physical model and the mathematical model.

The blue line with the circles on it represents the reservoir's ability to inject fluid at various flow rates. And at a zero flow rate, you're effectively looking at the reservoir pressure, what the natural static reservoir pressure is. As you inject more and more fluid, the pressure that the wellbore sees increases, as you would expect, as you try to push more fluid into the reservoir.

But you can see here that you can move

roughly 45,000 barrels a day for this reservoir sees a pressure of more than 9,500 pounds. That's the blue line with the red -- the blue line with the blue circles on it.

Q. And could you please turn to what's been marked as Exhibit Number 16 in the notebook? And explain what this graph shows to the Commissioners.

A. So this graph is effectively a summary of the prior graph. The red -- or the pink triangles represent the intersection points between what the -- what the -- the points on the other page represent. So as you increase the surface pressure, you intersect the IPR curve at different points, and this effectively says -- for example, at 1,000 psi surface pressure, you would expect to inject roughly 18,000 barrels a day. At a surface pressure of 2,000 psi, you would expect to inject roughly 30,000 barrels a day.

Q. And I should have started here. I apologize. But just for my benefit and for the benefit of the Commissioners, could you explain in basic terms what a nodal analysis is?

A. Sure. Starting back on Figure 15, that graph shows a single line running from the left-hand side upward to the right, and that represents the ability of the reservoir to accept injected fluids. You see several lines running from the upper left to the lower right, and that represents the ability of the tubing to deliver pressure at various rates to the downhole condition. A good analog for this is supply-and-demand curves, and where your supply-and-demand curves cross, that's the actual performance of that system. So we have a supply of water going down. So we have a demand of water that can be taken away by the reservoir. Where these two curves cross, that represents the conditions under which it's currently working.

Q. Can you please turn to what's been marked as Exhibit Number 17? And explain what this graph shows to the Commissioners.

A. So this is a subset of that -- of that nodal analysis that takes a specific condition, an injection pressure of 2992, so that's roughly 3,000-pound injection pressure, and then injects into the formation as it was matched using three different tubing sizes. And the three tubing sizes shown here represent 4-1/2-inch OD, 5-inch OD and 5-1/2 ID. Those numbers are labeled here on the figure as 3-1/2 ID, 4-inch ID and 4-1/2-inch ID.

Q. And your conclusion from this graph is that increasing the tubing size will decrease friction losses and conserve forced power, correct?

A. Yes, it will.

And the way you can visualize friction on this plot is on the far left-hand side, where all of those three curves intersect the y-axis, that's where no friction is existing because there is no flow rate. As the flow rate increases, the curvature downward represents the magnitude of the friction. So, for example, say at 30,000 barrels a day, the 3-1/2-inch tubing would have roughly 3,000 psi of friction pressure. The 4-inch ID tubing would only have maybe 1,500 psi of friction pressure. And the 4-1/2-inch ID tubing would have less.

Q. And are you familiar with Division Case 16720, which involved Black River Water Management Company?

A. I am.

Q. Are you aware of testimony that was given in that case which stated that friction in the wellbore was approximately 85 percent?

A. I am.

Q. And do you have any reason to question that percentage rate finding by Black River Water?

A. No. I would not question that.

And you can see that magnitude here. Let's say that their surface-injection pressure was 3,000 pounds. We're using up that much in friction very quickly. On this graph, you can see what 3,000 pounds looks like on here. It's one-and-a-half of these groups. So you build 3,000 pounds of friction, you know, easily within 20,000 barrels a day with the smaller tubing sizes.

Q. Could you please turn to what's been marked as Exhibit 18? And explain what this chart shows for the Commissioners.

A. So this chart shows some specific parameters like wellhead pressures, downhole injection pressures. Starting at the top of the graph, the 10,000 psi marker is a rough representation of the affected fracture pressure of this formation. And you can see that the injection pressure starting at 8,000 psi. That's the dashed blue line that starts on the left side and then angles slightly to the right. All the way up to 45,000 barrels a day, there is no -- that line has not yet intersected with the expected fracture pressure.

The green, purple and blue lines that are solid represent the frictional loss in the tubing at various flow rates. And you can see, for example, the frictional loss, theoretically, at 45,000 barrels a day and 3-1/2-inch tubing is 10,000 psi. So it's a nonsensical number because you can't push that much fluid down that size pipe. The 4-1/2-inch tubing, the losses are still significant. You still lose 3,000 psi or so at 45,000 barrels a day, but there's a lot less wasted horsepower there.

Q. And can you please explain in your own words what your nodal analysis indicated to you?

A. My nodal analysis was consistent with prior studies I've done. On injection wells, you experience only frictional losses, a negative consequence of increasing flow rates, and those friction losses are nonrecoverable. Once you lose them, they're gone. And so if you want to minimize horsepower and fuel use and things like that, the goal would be to have the fewest frictional losses in the lowest tubing.

Q. And in your opinion, will increased injection rates result in small or large reservoir pressure?

A. The analysis I did showed that this reservoir has high productivity/injectivity. And so the increase in reservoir pressure would be very small given that it's a high-permeability system and it's areally very extensive.

Q. Could you please turn to what's been marked as Exhibit Number 19? And explain what this chart shows to the Commissioners.

A. Okay. So this is changing gears. This is past the nodal analysis part. We did a small reservoir simulation study on a uniform grid that represented this injection structure. And I used roughly the values that I had matched on the nodal analysis work. And so what this shows is kind of a cross section across the reservoir looking from the injection well on the left-hand axis or the distance from injector noted to be zero and then showing four time slices.

So at zero years, that's one day of injection. So we have an injection pressure at 20,000 barrels of water per day out of 8,400 psi. That's the -- actually, it's 8,300 psi. That would be the little blue diamonds. And so if you move away from that well maybe even a couple hundred feet, you effectively get back to reservoir pressure.

Now, after a year of injection, you can see that your injection has affected the reservoir to a certain extent. But at, say, 40,000 feet away, which is a long way, there is no recognition that injection has ever happened in that well.

One way to picture this -- and I was thinking about this earlier today -- is a physical thing that represents this pressure profile. And if you're making ice cubes in a freezer, once they freeze, it kind of climbs to a little peak right in the center, that's what this pressure profile looks like. Right where you're injecting, there is a little higher pressure than everywhere else, and then it distributes uniformly away from that.

Q. Can you please turn to what's been marked as Exhibit Number 20? And explain this chart to the Commissioners.

A. Okay. I wanted to test two different injection rates under the same circumstances. So this figure is identical to the prior figure except for a higher injection rate. And you can see, if you compare the two figures back and forth, that there is a larger impact by injecting more, but you can see that it's still small in comparison to where the potential fracture pressure would be, which would be basically double in scale off the page. It would be at 10,000 psi or more.

Q. So the fracture pressure, to get a fracture of the formation, would be off this chart? It's not even comparable?

A. Yes. It would be at 10,000. And this chart only goes from 8,000 to 9,000. So it would be double this scale.

Q. Okay. Go ahead.

A. If I had scaled these graphs on that scale, it would be difficult to see the pressure change out in the far -- because they would squeeze down.

Q. Does anything in this chart give you a pressure profile for a half-mile radius surface location of the wells?

A. It does. But the scale here is on 10,000-foot increments, so you would have to look at basically a quarter of the -- of the first little marker there. You go to 2,200 -- 2,500 feet, and that would tell you what the pressure would look like at one-half mile away from the injector.

Q. And could you please turn to Exhibit Number 21? And explain what this exhibit is to the Commissioners?

A. So these are 3D pressure profiles on a grid representation, and this is the same data as we saw in the prior lot. It's just a three-dimensional visualization of the same thing. So the graph that's in the upper left-hand corner shows injection at 365 days. So the injector is in the corner of that little box, and the pressure has climbed right next to the injector, and then it moves in a radial fashion away from that well, just as dropping like a food color or something like that into the center of a swimming pool. It slowly moves away from the center of this injection.

The next plot in the center is 366 days, where I tested what would happen if I drilled another well one mile away from the original well. So you can see there is an instantaneous spike where I'm injecting fluids, but it doesn't affect the overall profile much other than appearing right next to the injector -- the second injector.

And then the last curve in the lower right-hand corner represents both of those wells operating for a 20-year time frame and what the pressure profile would look like under those conditions.

Q. And this chart assumes that there are uniform layers, correct?

A. That's correct.

I have run cases where the reservoir was more complex, and it did not make a difference at any of the results because the permeability is so high. It just washes through the whole thing.

Q. Okay. And here there would be between 1,500 to 3,000 feet of permeable formation?

A. Yeah. This case was run with 1,500 feet as kind of a conservative case. If the overall flow area was 3,000 feet, the results would look half as interesting as these do. The response would be half as big.

Q. Could you please turn to what's been marked as Exhibit Number 22? And explain what this chart shows to the Commissioners?

A. Okay. So this is yet another view of the same study. This one -- the x-axis represents time. So at any point in time, you can look at various observation points in the grid and tell where the pressures would be at those times. And as you would expect, the points closest to the injectors see a sizable increase in injection pressure, but the farther away you get from the injectors, which is the graphs or the lines that are on the lower part of the y-axis, those are still not affected to any great extent.

Q. And does this information about pore pressures provide any insight concerning the radial resource that these wells might have?

A. Yes. This is a modeling study that represents what the pressure effect will be at all points away from these injectors. So it shows that roughly two to three, four miles away from these injectors, you probably won't get above 8,500 psi in ten years of injection.

Q. And your study shows that adding a second injection well one mile away from an existing Devonian injection well will not create any materially adverse pressures in the area?

A. No. And since the -- since the wellhead pressure limitation is set below fracture pressure, it's physically impossible to get above fracture pressure on any location, because what will ultimately happen is if you build up pressure next to your wellbore, your injectivity will drop, and you just won't have enough pressure to push more fluid in the well. So it's kind of self-correcting. If the well's capable of injecting 40,000 barrels a day at original reservoir pressure and then you increase the reservoir pressure due to offset injection, the injectivity of that well will decline. So, in general, you just -- it corrects itself. You just can't get above those pressures.

Q. And how do these factors impact when you're looking at the radial influence of fluids within the formation?

A. I'm sorry. Can you rephrase the question?

Q. Yeah. Did these factors or your analysis have any -- do they give you any understanding of how fluids migrate within the Devonian --

A. Yes. The simulation work, since it's all -- since it's all one phase, water, it's difficult to track any individual molecule of water as it's moving from the injector away from the injector. In a normal reservoir simulation where you have a water flood or gas flood, you can actually watch the flood front move forward. Here it's more difficult because you don't get -- the new water doesn't look any different than the old water.

You just see a pressure response. And that pressure response is very contiguous and continuous because the permeability is so high. It's a very smooth and discreet pressure response.

Q. So in your -- and in your opinion, is it more important to look at the pressure responses here? Does that give you some indication about what's going on in the formation?

A. Absolutely. That's your only way of tracking where the fluids have gone because the pressure will respond. There are fluids that have gone a certain direction.

Q. And based on your study, is it your opinion that a half-mile notification requirement is sufficient for Mesquite's application?

A. Yes. The half-mile captures the lion's share of the pressure change near these injectors.

Q. And all wells within the formation are -- within these formations based on your -- are typically cemented?

A. Oh, absolutely.

Q. And wells drilled within a half mile are more likely to be impacted by the pressure; is that correct?

A. Yes, because they're closer to these wells.

Q. Is there any incentive for operators to want to

locate their wells further than half a mile apart or a mile apart?

A. From a technical standpoint, if someone was injecting at a location, I would try to site the next injector as far away from that location as possible because that would give me a longer period of time before I ever recognize that other injection was happening. So from a purely technical standpoint, people would distribute their injectors evenly and widely dispersed.

Q. And based on your study of the formation and the modeling that you've performed for this application, what are your conclusions concerning Mesquite's request on the overall -- overall formation in the area?

A. Concerning the 5-1/2-inch tubing?

Q. Yeah.

A. The loss of frictional pressure, the number of increased wells needed to put away the same amount of injection all drive a person to think the best opportunity is to use larger tubing because there is less waste of horsepower and potentially fewer wells needed to accomplish the same injection.

Q. And there'll be relatively minor impacts on the formation pressure, correct?

A. Correct.

Q. And in your opinion, will the volumes being injected into the formation cause the formation to reach a potential fracture point?

A. No. Since the wellhead pressure is set as a maximum that is already below fracture pressure, it is physically impossible to get above fracture pressure while maintaining that constraint.

Q. In your opinion, would the granting of Mesquite's application be in the best interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes, it would.

Q. Were Exhibits 14 through 22 prepared by you or under your supervision or compiled from company business records?

A. Yes, they were.

MS. BRADFUTE: I'd like to admit Exhibits 14 through 22 into the record.

CHAIRMAN CATANACH: Exhibits --

MS. KESSLER: No objection.

CHAIRMAN CATANACH: -- 14 through 22 will be admitted.

Ms. Kessler, any questions?

MS. KESSLER: No questions. Thank you.

(Mesquite SWD, Inc. Exhibit Numbers 14

through 22 are offered and admitted into evidence.)

CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. Mr. Wilson, I'm trying to follow the pore-pressure scenario. Are you saying that you can't map that waterfront in this reservoir?

A. You can't, but -- and I say that because the tools we use in petroleum engineering to do these kind of calculations as a reservoir simulator. And then you inject the fluid, and then it moves out from where it was originally started, and there are fluxes across the cells and things like that. But if you're injecting water -- you already have water in the reservoir -- it's difficult to track which molecule was there originally and which one got injected.

Now, there are terms like "diffusion" that can account for that, and you can actually watch an individual molecule move through the -- through the formation, but you would have to trace that molecule.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Right. That's exactly it. You add a tracer for a small amount of gas or something like that --

A. Exactly.

Q. -- and do it.

Have you tried anything like that?

A. Oh, tracers? I recommend tracers in a gas injector well --

Q. Well, I know. But you [sic] don't think a real tracer. I'm talking about in this simulation, a fake tracer.

A. Oh. No. And I can turn on red and blue water in this particular simulator, and I -- I just hadn't done it on this particular case yet. But we -- it hasn't been a big study.

CONTINUED CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. So in terms of analyzing these Devonian wells at different, various injection rates, how does the Division know that that water is not going to go more than a half mile within a 20-year or 30-year time frame? I mean, is that something that we just -- we can't determine?

A. No. It can be determined. If you have a specific set of -- like a scenario. Say we're going to inject 30,000 barrels a day right here for X number of years. You can easily model that and see exactly where the fluids go, where that molecule goes. But the part of that that's less interesting is what happens to the pressures because you can map the farthest extent where that molecule went, and it might be a mile, it might be two miles, it might be half a mile. But as you look at the pressure profile for that, it's going to be a nice continuous phase. It won't be a discrete boundary where these fluids go, because you're transmitting that pressure to all those water molecules that are in front of it. It's like you're getting off of -- let's say you're going into a mall and there are people coming into the mall, and it gets more and more crowded. The mall will become more crowded and you'll be able to track individuals who came into the mall, but there are some people who are leaving out of other doors, and at the end of the day, the crowdedness of the mall is going to be a function of how fast that pressure dissipates, not necessarily where each individual went when they came in.

Q. Do you know what the water saturation is in the Devonian?

A. I think I ran this set -- well, it's effectively 100 percent, because it's -- you're talking about porosity or saturation?

Q. Saturation.

A. Okay. So I ran this at 100 percent water saturation assuming there was no free gas, there was no oil. Maybe we're talking two different terms.

Q. So when you're injecting water, you're pushing everything -- it's already in the reservoir pushing that water immediately out?

A. Forward, yes. Absolutely. You're pushing more water into a structure that already has water, and the existing water just gets moved farther away. And that's how a waterflood works. The difference there is you're moving an oil phase ahead of the water phase, so it's easier to track that injection front.

Q. How did you determine the initial reservoir pressure of the Devonian? You said 8,000, right?

A. Yes. If you turn to, I think, Exhibit 14 and turn two pages in -- that's actually not a good graph. Let's go to 15. 15 is a little better. So Figure 15 has a blue line with blue circles that goes through those little crosses, the block crosses.

Q. Uh-huh.

A. And those are measured values. And so the theory is that if you extrapolate those back to a zero injection rate, you'll hit the reservoir pressure. And so that's a fairly conclusive measurement on the reservoir pressure for this particular test at this particular time.

Now, if I was doing this on an ongoing

basis, you wouldn't need these -- you wouldn't need these downhole bombs [sic]. You could get live reservoir pressures on an injection well by just doing a simple falloff test at the surface, because falloff tests are one of the most dependable methods of calculating bottom-hole pressures over a pressure decline system.

Q. So 8,000 is not a direct measurement? That wasn't directly measured by any --

A. I would say no. It was not directly measured as a static pressure. It might have been measured and I didn't use it.

Is that true?

MR. NEATHERLIN: We did get static pressure.

THE WITNESS: Yeah. Yeah. And I had -- I had six points that were within 20 percent of zero injection rate, so I just extrapolate it back.

Q. (BY CHAIRPERSON CATANACH) How did we determine the parting pressure on this formation?

A. I just used the .2 gradient that apparently is standard practice here.

Q. So it's likely above .2?

A. Oh, here?

COMMISSIONER BALCH: Don't be so sure.

CHAIRMAN CATANACH: Well, I know. Well -- but this isn't Delaware.

COMMISSIONER BALCH: So nobody's done any mechanical tests on the rocks. Nobody knows for sure what it is.

THE WITNESS: I didn't look at that.

Q. (BY CHAIRMAN CATANACH) You just used .2 as a parting pressure?

A. I did. And actually it was irrelevant in this study because I never got to that pressure. All of the data I worked with was below that pressure.

Q. So the half mile, you said, would take the lion's share of the increase in pressure; is that correct?

A. I did say that, yes.

Q. So it does go further out than a half mile, though, the pressure increase?

A. I think if you look at Figure 20, that shows the pressure over different distances. So yes, there is a measurable pressure difference of roughly 50 pounds as far away as ten miles. But that only happens after 20 years of injection, and it's only 50 pounds.

Q. So you're saying that injection at 40,000 barrels a day over a period of 20 years has virtually no effect pressurewise on this reservoir?

A. It has the effects that are shown on these figures.

Q. But very small pressure increases?

A. Yeah. It's a -- you know, it's a half-a-mile-thick reservoir. It's high permeability. It just kind of disperses.

Q. That's all I have.

CONTINUED CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. So do you know if any core was taken in any of these wells?

A. I'm not aware of any core taken on any of these wells.

MR. NEATHERLIN: Uh-uh.

COMMISSIONER BALCH: So no opportunity to do a mechanical test on the rock?

MR. NEATHERLIN: No.

Q. (BY COMMISSIONER BALCH) I'd like to talk a little bit about your simulation model.

A. Sure.

Q. You used one massive layer, or did you use --

A. Yes. This is one 1,500-foot thick layer.

Q. What's your approximate gridlock size?

A. The gridding I originally used was 52 feet per cell, so it was a nice even hundred cells for a mile.

And then I looked at another exhibit that was presented, and it showed a longer distance here. So I said, I better make this thing bigger. So I then added 99 more cells that were larger so that I could cover a 15-mile square, but I still had high resolution in the center. And that's why the data points here are kind of concentrated near the edge on Figure 21. They're concentrated on the edge, and they get wider as you go further out.

Q. When you look at the log data, do you see any significant variability in porosity-permeability as you go down that 1,500-foot section?

A. Yeah. There is variance in those logs. But the theory is that if you have a high perm vuggy system, the water will find that system, and it'll continue to move out into the farther reaches until it finds a different high perm vuggy system, and then it'll move through that one. So it's a large fairly contiguous zone, and the geology was described earlier.

But the results I saw from my testing of the individual well tests, the step-rate tests, there is a fairly consistent KH on that big block of rock. And you would think that if there is a lot of diversity, like tight sections, high-perm sections, you'd see a larger spread of results. So this looks high perm throughout.

Q. Very good. Okay.

Have you done this similar kind of exercise with a larger tubing? I think you mentioned casing of 7-3/8 in Texas.

A. I actually won an award 15 years ago for upsizing tubing at the Prudhoe Bay field because we went from 7-inch to 7-5/8-inch and almost doubled injectivity of the gas injectors there.

Q. So you would expect something dramatic if you went larger than 5-1/2 outer diameter?

A. Here the rates that we're talking about, your -- basically, your frictional drop starts to drop off exponentially because friction is a bunch [sic] of velocity square. And 5-1/2 is a good-size tubing, and if someone went to 7-inch tubing here, they would decrease their friction even farther. But then you start to get into issues of availability of hardware and things like that. But 5-1/2 is pretty standard.

Q. In a larger -- tubing?

A. Yeah.

Q. That's all I have.

COMMISSIONER MARTIN: No questions.

MS. BRADFUTE: That completes my questions with this witness.

CHAIRMAN CATANACH: Okay. This witness may be excused.

Break now?

COMMISSIONER BALCH: Sure.

CHAIRMAN CATANACH: A ten-minute break.

(Recess, 10:04 a.m. to 10:16 a.m.)

CHAIRMAN CATANACH: Call the hearing back to order at this time. We'll turn it back to you.

MS. BRADFUTE: Okay. Great. I'd like to call my next witness, Dr. Bilek.

SUSAN BILEK, Ph.D.,

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

DIRECT EXAMINATION

BY MS. BRADFUTE:

Q. Would you please state your name for the record?

A. Sure. Dr. Susan Bilek.

Q. And, Dr. Bilek, who do you work for?

A. I'm a professor at New Mexico Tech at Socorro.

Q. And what is your area of specialty?

A. I'm an earth seismologist.

Q. Have you previously testified before the Oil Conservation Division or Commission?

A. No.

Q. Could you please provide the Commissioners with your educational background?

A. Sure. I have a Bachelor of Science degree in geosciences at Penn State University and a master's in -- a master's and Ph.D. in earth sciences with a specialty in seismology at University of California at Santa Cruz. And then I did a postdoctoral research fellowship at the University of Michigan also dealing with seismology problems.

Q. And could you please describe your professional background to the Commissioners?

A. Sure. I've been a professor at New Mexico Tech since 2003, and so my teaching areas are in seismology, geophysics. My research areas are in the study of earthquakes.

Q. And are you familiar with the application that's been filed by Mesquite SWD in this matter?

A. I am.

Q. And have you conducted a seismology study related to this application?

A. I have.

MS. BRADFUTE: I'd like to tender Dr. Bilek as an expert in seismology matters.

MS. KESSLER: No objection.

CHAIRMAN CATANACH: Dr. Bilek is so

qualified.

Q. (BY MS. BRADFUTE) Could you please turn to what's been marked as Exhibit 23 in the exhibit notebook in front of you?

A. Uh-huh.

Q. And identify what this document is for the Commissioners.

A. This is the result of analysis that I did of the earthquakes in the area of interest in southeast New Mexico. So the first page is a summary of the earthquake catalogs in the area, and the second page is a map of those earthquakes.

So I'll start with the first page, just going through this. I worked with the catalogs of data from that span from 1962 all the way up to September of this year. And these are published catalogs, for the most part, with some unpublished data in the more recent time period. And the earthquake catalogs consist of the earthquake locations and estimate of the earthquake size, and they're based on the seismic data that has been collected from seismograph stations in the area that go back to the 1960s to '70s. New Mexico Tech has operated some of these stations since 1972.

Q. And what are these stations that you're referring to? Could you give us a little bit more

details?

A. Uh-huh. So the seismic stations in the area, they basically record ground motion. So they provide a continuous record of ground motion, so if there is an earthquake, we would see that ground motion on our seismic stations. And we can use data from these seismic stations to then estimate the location of the seismic activity, as well as the magnitude of that seismic activity.

Q. And if you can look back at Exhibit Number 23, about halfway down the page there, there is a statement, "Yearly summary of earthquakes." Could you explain this information to the Commissioners?

A. Sure. So I took the published and unpublished catalogs of the earthquakes and just focused on the area within 25 kilometers of any of the proposed wells here. And so there are a total of 15 earthquakes within 25 kilometers of those wells going back to 1962. The yearly summary of earthquakes just grabs out, in those different years -- or periods of years, how many earthquakes happened and then how many of those were larger than magnitude 2. And that magnitude difference, I just highlight, because the earlier catalogs, they contain the only earthquakes that are bigger than magnitude 2. Some of the more recent catalogs contain earthquakes that are even smaller than that.

Q. So I'm hearing -- has listed from 2005 to 2014 eight different earthquakes, and one earthquake was a magnitude greater than magnitude 2, correct?

A. That's correct.

Q. So those were smaller earthquakes that were captured?

A. Yes. Right. So seven of those earthquakes were -- had a magnitude less than magnitude of 2.

Q. And just for everyone's benefit, what does a magnitude 2 earthquake feel like?

A. So the earthquake magnitude scale provides information about the size of the earthquake, and we measure the amplitude of the ground displacements on those seismic stations. The scale is log rhythmic, so as you go up one whole number in magnitude, you're talking about a ten times increase in the ground motion. So a magnitude 2 earthquake is ten times smaller than a magnitude 3 earthquake. A magnitude 2 earthquake is felt by very few people. Largely, if they're indoors and very sensitive, they may feel that earthquake, but the magnitude 2 level largely is unfelt by people.

Q. What's a magnitude 3 seismic?

A. The magnitude 3 earthquake, the displacement of the ground motions would be ten times larger than the magnitude 2. More people may feel this earthquake. It may -- but they may not recognize it as an earthquake. Typically, reports are it feels like a truck is driving by a structure.

Q. And looking at the chart below this yearly summary of earthquakes, it lists -- there is a column that lists magnitudes.

A. Uh-huh.

Q. What is the highest magnitude that's listed?

A. So the largest magnitude within this box is a magnitude 3.2 earthquake. So, again, this would be a size that if someone felt it, they would think that a truck was going by. And that earthquake occurred in 1997. Since then, the earthquakes have been smaller.

Q. Are you familiar with Stanford University's fault slip probability tool?

A. I am.

Did you want to look at the map at all?

Q. Oh, yes. Thank you.

If you could turn to what I think is going to be page 3 or page 2 in everyone's exhibit, it's going to show a map. Could you explain what that map is for the Commissioners?

A. So this is a map of the earthquakes in this general area based on those catalogs going back to 1962.

So the earthquakes are the circles on the map. They're scaled by size. The circle size indicates magnitude, and the colors indicate a time period. So those scales are on the right there. So the green earthquakes are the oldest ones leading up into the -- for the most recent event. So the circles are the earthquakes.

The red squares are the locations of the wells being discussed today. The outline -- the dashed line there is the box that is 25 kilometers from these wells. So the table on the previous page includes those earthquakes that occurred within that box. Also included on here, the stars are the locations of the seismic stations that New Mexico Tech has operated for many decades. So we have stations recording ground motions in the area of these wells, and these stations have been there for -- since the '70s and '80s. So we've had long-term monitoring of this area.

The other thing on this map are the red lines. These are the locations of the faults that were discussed earlier from the Precambrian basement map that faults are taken from that --

Q. So this depicts that these fault lines are relatively a good distance away from where the wells are located, right?

A. Right. So the closest fault to one of these wells is about 26 kilometers away, so 16 miles or so.

Q. And are you familiar with the Stanford University's fault slip probability tool?

A. I am.

Q. And what is this tool used for?

A. So this tool is software that is used to estimate the probability of slip on a fault due to pressure -- pore pressure changes from injection of fluid.

Q. And has this tool been relied upon and accepted by seismologists?

A. Yes. So the tool has been made available earlier this year by the Stanford induced seismicity group. They have provided use documents for this that's being used. The methodology was also published late 2016 in "The Journal of Geology," which is a well-respected peer review journal in the field.

Q. And did you use the Stanford tool in your analysis on the area impacted by Mesquite's application?

A. I did.

Q. Could you please turn to Exhibit Number 24? And explain what this document is to the Commissioners.

A. So this is a one-page summary of the key parameters that I used in this fault slip potential software, as well as some details of the sources of the parameters that I used. And then the text at the bottom discusses the outcomes of the various models that I ran. So I can go through some of these key parameters so that the Commission -- Commissioners are aware of what these are and how I came about them.

Q. That would be helpful. If you would outline the key parameters that you looked at when you ran the tool. I believe the Division has previously expressed an interest in knowing what those parameters are.

A. Uh-huh. So SHmax is giving information about the azimuth of the maximum horizontal stresses in the area, so we need to provide some information about the background stress conditions of the area. I used this range here between 60 and 90 degrees for that maximum horizontal stress direction, and that's based on the data from the World Stress Map. It's a well-regarded publication giving stress orientations around the world. And I took the data that was contained in the area of southeast New Mexico and West Texas, so there are several data points there. And the azimuth ranged between about 60 and 90 degrees. So I did run it using that range of values.

Aphi here also provides some information about the stresses, giving information about maximum and minimum stresses also related to the fault environment and the types of fault that you have in that particular area. For normal faulting environments, the range of that parameter is between zero and one. I used these values here that fit within that range, and that also came from data in a paper prepared by Hurd and Zoback in 2012 again for this particular area, in the West Texas region.

The next three parameters relate to the hydrologic model that gets incorporated in the software, and so you could define an injection thickness for porosity and permeability. So for these parameters, I used, similar to Scott's modeling, conservative values for these.

Q. And you say conservative values. Injection thickness, is that the thickness of the formation?

A. Yes.

Q. And we've heard testimony today that that thickness has ranged either from 1,300 feet to 13,000 feet?

A. Right.

And then the last two parameters here are with regards to the faults. So, you know, the fault slip potential software requires that you put in locations of the known faults, and so using the locations of the faults that were in the previous map.

And so we have the orientations of those. We don't have great constraints on the dip of those faults. So I used a range of values as a fault dip.

And then the fault friction, I also used a range of values, so this is the friction on those faults. Between .4 and .6 is commonly used. On limestones, .6, .7 are typical values of fault friction. I actually used a range that even went lower, of .3. .3 would require a very high clay content in these fault zones, which there is no evidence for, but I was trying to expand the range of possibilities to be used with these models.

So with these different parameters, I ran 50 of these simulations, and the vast majority of those resulted in zero percent fault source differentials [sic] on those known faults that I included in the model.

If I chose the very low fault friction values, I could get a fault slip potential of 16 percent on one of those faults. But, again, the -- the only way I could do that is to have very low fault frictions. And then I tested other ranges of the permeability and porosity. It increased the pressure change on the fault, but they didn't significantly change the fault slip potential.

Q. And, again, in order to get the results where you saw something, some slippage, you would have to put in a value for rock that has a very high clay content?

A. Right. And there is no evidence for that in this area.

Q. Would you please turn to what's been marked as Exhibit Number 25?

A. Uh-huh.

Q. And explain what this document is to the Commissioners.

A. So this shows the geometry that I used for the model. The squares in the center show the locations of the wells, the eight different wells, and then the black lines show the location and orientation of the faults. And so these are again coming from the map faults we saw earlier.

Q. Could you please turn to Exhibit Number 26? And explain what that document is to the Commissioners.

A. So we are able to include the injection rates for the wells, and so what I did -- and this is injection rates for all of the eight wells. Several of them have the same values, so you don't see eight separate lines here. But I took the maximum injection rates that were included in the applications, not the anticipated, which were lower. But I took the maximums, again to have the most conservative possible estimates.

Q. Okay. Great.

Could you please turn to what's been marked as Exhibit Number 27? And explain what that document is to the Commissioner.

A. So this is showing an example of the output, which was the final summary of the fault slip potential software for a particular set of parameters. So I'll walk through what is in here.

On the left-hand side, it shows the different faults. So we had four faults included in here. And the numbers here are for -- I think these are the fault slip potential that is calculated for each of those faults. The middle panel, what we see is the geometry again. The four faults are in green here. The first fault is down in the very, very southwest corner of the box. You can barely see it, but it's in there. The middle section of that geometry are the squares showing the location of the wells. The colors in this panel are actually showing you the extent of the pressure change from those wells. And you can see, similar to Scott's testimony, these are not getting out very far to where the faults are 25 to 30 kilometers away.

The rightmost panel shows the pressure

change that you would see at the midpoints of these faults over time, so pressure change on the y-axis, time on the x-axis. As you get out towards the end of the 20 years that I ran, you start to see some small increases in pressure at the midpoint of these faults but very small amounts.

And then the bottom panel is just the graphical representation of the fault slip potential on each fault, what is the fault slip potential through time.

And so this is, you know, a very representative example of the majority of the runs that I did where the fault slip potential on those four mapped faults in the zone.

Q. Great.

A. I provide some of the key parameters that I used for this run here.

Q. Okay. Thank you.

Can you please turn to what's been marked as Exhibit Number 28? And explain what this exhibit is to the Commissioners.

A. So this is an illustration showing the typical values of coefficient of friction for different rock types. So this is from a published geology study where they did a variety of friction experiments in the lab, so looking for faults of -- to define [sic] the coefficient of friction for different rock types in the lab.

And so this is providing some justification to the idea that .4 to .6 to .7 are sort of reasonable values for most rock types and especially for the limestones and the dolostones that we're talking about in this area. To get to the lower values of fault friction of .3, you need to have very unique clays in there. So, again, I don't think that those are the expected values of fault friction in this area, but I chose to use them just to provide a more complete range of tests.

Q. Could you please turn to what's been marked as Exhibit Number 29? And explain what that document is to the Commissioners.

A. So this is the same as the two slides before, the output of the fault slip potential software, so it's the exact same geometry. It's exactly the same parameters that I used, but the only difference being the fault friction value. So here is the case where I allowed the fault friction to be .3, again a lower value than I think is reasonable here. But this was the way that I was able to see any increase in that fault slip potential on one of these faults, which is actually

Fault Number 1 in the southwest corner. So, you know, .6 -- .16 for fault slip potential on that particular fault in this scenario, again, with these very, very low friction values.

Q. And that Fault 1, you can just barely see it --

A. You can barely see it.

Q. -- in that left-hand corner -- far corner, ten and zero.

What conclusions have you drawn from your study?

A. So, you know, a few things. You're looking at the decades of earthquake catalogs in this area. We don't see a lot of regress in the area around these wells. We have -- New Mexico Tech has been monitoring earthquakes in this area for decades. We have stations right in the area of these wells, and we have not seen a lot of seismicity in this area. So there does not appear in this case to be seismic active. And then based on the fault slip potential models, there is very low probability of slip or earthquakes on these known mapped faults that go down into the basement.

Q. Were Exhibits 23 through 29 prepared by you or under your supervision or compiled from company business records?

A. Yes.

MS. BRADFUTE: I'd like to move to admit Exhibits 23 through 29 into the record.

MS. KESSLER: No objection.

CHAIRMAN CATANACH: Exhibits 23 through 29 are admitted.

(Mesquite SWD, Inc. Exhibit Numbers 23 through 29 are offered and admitted into evidence.)

MS. BRADFUTE: That concludes my questioning.

COMMISSIONER BALCH: Of course I have questions. Susan would be very disappointed if I didn't.

THE WITNESS: I know. I would.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Good morning, Dr. Bilek.

A. Good morning.

Q. So my first question is about the sensitivity of the -- network. You're talking about that, right?

A. Yeah.

Q. So in this area, what's kind of the detection threshold?

A. So, I mean, we are able to pick up -- wherever we have stations that are in this area, we're able to pick up earthquakes down to magnitude 0.

Q. And the location threshold would be a little higher than that because you need to get to more than one station?

A. Right. Yeah.

So to locate earthquakes, we need at least three stations -- data on three stations to locate them. Again, we've had these stations there in some form since 1972, '73 and have mapped them out. So they've been operating and locating earthquakes for decades.

Q. No indication that Westinghouse is going to take these stations out anytime soon?

A. No.

Q. No?

A. (Indicating.)

Q. So, basically, this -- this array basically divides seismic monitoring for these wells --

A. Yes.

Q. -- far into the future?

A. Yes.

Q. So what'll happen if something were to happen? You would notice it?

A. Yes.

Q. Great.

There is about a 19-4 [sic] event just

north of the box, probably at about 30 kilometers?

A. We can go back to the map, which was Exhibit 23. So you're talking north of the box?

Q. Right. Just north of the box.

A. Yeah. This was a magnitude 3-1/2.

Q. Three-and-a-half?

A. Yeah.

Q. Do you know if a fault plan solution was attempted on that?

A. No. So it becomes difficult to get the fault plan solutions for some of these tiny earthquakes, just not having enough measurements to be able to determine that.

Q. Nothing conclusive?

A. No. No.

Q. So the other big event on this map is probably 50 kilometers to the west. That's the --

A. Yes. Yes.

Q. 1992?

A. 1992, yeah. January 2nd.

Q. I remember that one.

A. Yeah. So that was a 4.6.

Q. Yeah.

A. And there were a few aftershocks that were 2, 2-1/2.

Q. And that correlates to the rock formed in system -- some faults?

A. It does.

Q. So it -- but it does indicate that there are probably some unseen faults that are on this map also, smaller-scale faults, like the --

A. Smaller -- right. But we have no -- we have no maps of those faults.

Q. Did you do any -- any kind of sensitivity analysis in your simulations to kind of -- I mean, if you did have a fault that was running -- mostly drilling faults are roughly northwest-southeast. If you had one of those running through that 3.6 event through this area, what would you expect the sensitivity of that kind of unseen fault to be?

A. Yeah. Certainly it's possible that there could be higher fault slip potential on those unseen faults. It depends a lot on the orientation of those faults. You can see even the fault in the southwest is a different orientation than these ones.

Q. Right.

A. So then you get into the details of the stress orientation, the background stress fields. The reason this fault in the southwest, even at the low friction values, has a higher slip potential is because of that change in orientation. So I would not feel comfortable saying what the details of the fault slip potential would be up here without knowing some estimate of that orientation.

Q. That's some kind of hypothetical orientation.

Most of your simulations that you presented in your exhibits were for 20 years. So I think you may have heard testimony earlier that these permits are open-ended.

A. Uh-huh.

Q. Could still be injecting in 40 years or 60 years. Who knows how much more shale they'll find down there. But did you run any longer ones to find out a sensitivity when you start to see a risk on these faults?

A. I didn't, because if you look at -- so it's such a small pressure change, but you do start to see a pressure increase out at 2036 and 2038. It's going to take a while, probably well more than an additional 20 to 30 years before you're going to get a pressure change on those faults that even starts to move that slip potential.

Q. Before you start to move any earth?

A. Yeah.

Q. Great. Thank you.

A. Thank you. Uh-huh.

CHAIRMAN CATANACH: I didn't follow that with any --

THE WITNESS: That's it.

COMMISSIONER BALCH: I really should have asked what I should have asked you.

CHAIRMAN CATANACH: Bill?

MR. BRANCARD: Sure.

CROSS-EXAMINATION

BY MR. BRANCARD:

Q. So, Dr. Bilek, this Stanford analysis seems pretty recent.

A. Yes. It was just made available on their Web site in March of 2017. They have -- as I said, they published a lot of the analysis or the technique in this paper in geology in December of 2016, and then the difference between that published paper and their model and software has been made available, I think, some of the details on the hydrologic model.

Q. Other than this -- what you presented today, have you applied this model anywhere else?

A. Personally, no, I have not.

Q. Okay. Have you seen other people apply it?

A. I am not a member of the Stanford induced seismicity consortium, and you need to be a member of some of the research. The results, they publish on their Web site and it's restricted access.

COMMISSIONER BALCH: Was it built in response to Oklahoma?

THE WITNESS: Yes. So that's where -- you know, they have -- they have applied it in other publications to Oklahoma, yes.

Q. (BY MR. BRANCARD) What I'm curious about is what -- and you may not be able to answer this. But what are the range of values that you've seen in the published reports using this --

A. Fault slip potential?

Q. Yeah.

A. Well, you know, they make available with the software some samples --

Q. Okay.

A. -- and yeah, they can get fault slip potentials to 100 percent. And it depends very much on, you know, the orientation of the stress fields and background orientation of the faults and the injection rates that they get -- that they used. So it does seem that they can -- you can exercise the full range of that fault slip potential.

Q. Okay. Okay. And it is largely related to proximity to faults?

A. Well, so you're solving for the fault slip potential on a fault, or you define or you allow it to put in some random fault rate. But we're not looking at the fault slip potential within that entire grid. We're just looking on the defined faults.

Q. Okay. Thank you.

A. Uh-huh.

CROSS-EXAMINATION

BY COMMISSIONER MARTIN:

Q. So proximity to the fault would increase the potential?

A. Yes. So these faults are between 26 and 30 kilometers away from the well or far from the wells. Yeah.

RECROSS EXAMINATION

BY COMMISSIONER BALCH:

Q. I think the Delta P, even fairly close to the injection wells, based off of earlier testimony by Mr. Scott, was a few hundred psi?

A. Yeah.

Q. What if you put those kind of numbers in there? What would you expect to see?

A. I think this would go up a bit but not much.

Q. Not much? Not dramatic?

A. Uh-uh.

COMMISSIONER MARTIN: I have one more question.

RECROSS EXAMINATION

BY COMMISSIONER MARTIN:

Q. As some of these variables or parameters, like porosities, for instance, increase or decrease, what does that do to the fault slip potential? In other words -- porosity results in more potential, generally speaking?

A. Yeah. I tested a few of those ranges, and in this case, it didn't change the model very much. You know, again, we are working with the geology that we have. I was taking the normal range of --

Q. Thanks.

COMMISSIONER MARTIN: Go ahead.

MS. BRADFUTE: Thank you.

THE WITNESS: Uh-huh.

MS. BRADFUTE: We would like to call our last witness, Mr. Nave.

STEVE NAVE,

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

DIRECT EXAMINATION

BY MS. STEVENSON:

Q. Good morning.

A. Morning.

Q. Please state your name.

A. Steven Nave.

Q. Mr. Nave, who do you work for and in what capacity?

A. I work for Nave Oil and Gas. I'm the president of the company.

Q. Okay. And what are your responsibilities?

A. We are a fishing tool company, and what we do is -- well, we fish. We get -- when people have problems with wells, we try to correct that problem. We design game plans and tool configurations to be able to recover the problem in the well.

Q. Would you please explain your background and work experience?

A. I started -- well, I went to school in Hobbs. When I got out of school, I started roustabout -- working for a roustabout outfit. When I finished that, I went to drilling rigs, roughneck, tool pusher, driller, that kind of stuff. And in 1980, I went to work for Star Tool Company, which was a fishing tool company, as a fisherman. I stayed with Star Tool until 2001. I became a partner in Star Tool during that time, and then we sold it to Smith International. I stayed with them for three more years and eventually left them and went on my own doing fishing tools exclusively from 1980 until present, basically.

Q. Do you have experience fishing from saltwater disposal wells?

A. Yes, ma'am, I do.

Q. And do you have experience fishing from saltwater disposal wells in the Devonian Formation?

A. Yes.

Q. Does your area of responsibility or work include Eddie and Lea Counties in New Mexico?

A. Yes, it does.

Q. Have you previously testified as an expert before the Oil Conservation Commission or Division?

A. I have.

Q. And as a fishing expert?

A. Yes.

Q. And were your credentials as an engineer accepted?

A. I suppose.

Q. Okay. Are you familiar with the applications filed by Mesquite in this case?

A. Yes, ma'am.

MS. STEVENSON: I'd like to move Mr. Nave to be an expert in fishing operations.

CHAIRMAN CATANACH: Any objection?

MS. KESSLER: No.

CHAIRMAN CATANACH: Mr. Nave is so qualified.

MS. STEVENSON: Thank you.

Q. (BY MS. STEVENSON) Mr. Nave, please turn to what's already been admitted as Exhibit 3. And this document is specifications for the tubing proposed for these wells. Have you seen this document before?

A. I have.

Q. And what are the specifications for the proposed tubing?

A. Well, we're talking about 5-1/2 body, which 5-1/2-inch is the outside diameter. That's the bulk of the pipe. It's typically range 3 to 5. It'll probably be 40 feet long and 5-1/2 inch. And the coupling screws it together in the middle, and that's going to be a little less than 6-1/8-inch OD, which is 6.104. This gives them the ID that -- that they're looking for to be able to get the volumes that you're wanting.

This -- this -- the top -- the top column there, the bottom one is the casing, which is 7-5/8-inch OD, 39 pound, which basically the OD of the casing don't have much concern to us once it's cemented in the ground. So the only consideration is the ID, and that's what room we've got to work with. That's 6-5/8-inch OD.

It looks like -- this is pretty standard type stuff that we work with.

Q. Okay. And on Exhibit 3, on this box that you just referenced, does it discuss the clearance between the tubing and the casing?

A. Yes, it is. It's showing the -- showing the clearance there of the collar and the body. That does matter, except that it's kind of relevant to what you're trying to do at the time, but it shows clearance that even on the couplings it's basically a half inch.

Q. And in your experience as a fisherman, is there sufficient clearance between the 7-5/8-inch casing and the proposed 5-1/2-inch tubing for fishing purposes?

A. Yes, there is. We do this on a fairly regular basis.

Q. And before we get into some of the other exhibits, would you explain to us the difference between overshot and spearfishing?

A. Okay. Overshot is simply a tool to catch on to the outside of the casing, and it's one of several. It's one of many tools. The overshot is the preferred method to catch from the outside. If you want to get ahold of the outside of a fish, overshot is what you want to do it with normally. It gives you the best strength and the most flexibility to be able to work with it after you get ahold of it.

The spear is basically the exact same tool except turned wrong side out. It catches it from the inside. And that's one of many tools that catches it from the inside also. So there is not a lot of difference in them except that one is working from the outside and the other one catches it from the inside.

Q. Mr. Nave, will you please turn to what's been marked as Exhibit 30 in the notebook before you? And can you please explain what this is to the Commissioners?

A. That's a Series 150 Overshot standard, National Oilwell manufactured overshot. It's just one of the manufacturers of several. It's a cut-away diagram showing the actual grapple inside, which is the part that actually causes the tool to bite on to the fish.

Q. Okay. And how is this used in the fishing procedure you just described?

A. This is the tool that goes -- you go over the outside of a fish, and that grapple has teeth on the inside of it that bites into the outer skin of the fish and it creates a very strong connection to that fish. And then the overshot being very flexible in that if this fish is stuck or something like that, you can run through the inside with electric line and what have you and have ID and everything where you can go deeper into it and free something up.

Q. Does this procedure work on 5-1/2-inch tubing inside of a 7-5/8-inch casing?

A. Yes, it can.

Q. And have you done that procedure before?

A. We have done that procedure before.

Q. Is the procedure any different if it were 5-1/2-inch tubing versus 4-1/2-inch tubing?

A. The only difference is the size of the tools that you have to run. So you get a little more versatility. You get a little more -- I mean, you can run smaller tools to get a smaller bite, but it's still the same application.

Q. Mr. Nave, will you please turn to what's been marked as Exhibit 31? And please explain to us what this is.

A. That is -- that is an Itco spear. That's one type of spear. That's what we were talking about. That's exactly the opposite of an overshot. That goes to the inside. Those little teeth you see on that, the grapple that you're looking at in the center, that bites the fish from the inside. Now, this thing does have a hole through the middle of it. You can get through the middle of one of those. The bigger the pipe, the bigger the hole, the bigger the tools you can get through that hole as far as wireline tools and stuff like that.

So I can kind of clarify by saying that if you're talking about spearing 5-1/2 casing, the idea of the spear is larger than it would be for 4-1/2 casing allowing for bigger tools to go through.

Q. Okay. And so this procedure, it works -- this spearfishing procedure works on 5-1/2-inch tubing inside of 7-5/8-inch casing?

A. Yes, it would.

Q. And you've done that before?

A. Yes.

Q. Can you please turn to what's been marked as Exhibit 32? And actually -- I'm sorry. Before we get there, could you please explain the abandonment procedure when you abandon a well?

A. Well, typically if you're abandoning a well, you're trying to plug and move away from it. There are certain procedures that have to be followed, as these guys are aware of, to get cement plugs in proper places. So the idea being to secure the well and make sure that nothing comes -- that no fluids can change places or go places you don't want it to, is what abandonment is.

Q. If you could look now at Exhibit 32, please, and if you could explain what it is.

A. That is a -- that's a hydraulic pressure pipe cutter. We use these to cut pipe in a well. Say the pipe is stuck on the bottom or something like that -- you can't move -- you can't move it; maybe you can't move it all at one time -- you can run this tool inside that pipe on a smaller work string. And hydraulic pressure pushes a piston down that actuates some harden knives that come out and, with rotation, will cut the pipe in two so you can pull that piece of pipe out of the hole in a shorter pipe or pump through it or whatever you would need to do. It's to separate pipe from the inside, is what it's for.

Q. So this will be used in the event of abandoning a well?

A. Sure. It sure can.

Q. And can you use this tool in the procedure you just described where there is 5-1/2-inch tubing inside 7-5/8-inch casing?

A. Yes, sir -- or yes, ma'am.

Q. Will you please turn to what's been marked as Exhibit 33? And please explain to us what this is.

A. That's just charts of casing dimensions. Typically, casing is considered from 4-1/2 to -- and larger. There is smaller casing, and there is larger casing. In this case what we're talking about here, 5-1/2, is typically considered casing, and in this situation will be used as tubing. 7-5/8 down there, when you get to 39 pound, is what we're talking about using for casing here. 5-1/2 that they're considering is actually 20 pounds per foot -- but it's the same diameter outside, just a little smaller inside.

Q. In your opinion, based on your experience, is there an unreasonably enhanced risk to the wellbore as a result of using 5-1/2-inch tubing with the clearance proposed by Mesquite?

A. I can't see why. What -- anything -- any flexibility that you would lose by going to that size on the outside diameter, you will actually gain more flexibility by being able to go to the inside to work. So it's still small enough to fish from the outside, but 5-1/2 is the standard for producing wells to work inside of, so there is so many more things we can do from the inside of 5-1/2 that you couldn't do in a smaller pipe that -- no, I can't see -- I can't see why it would reduce your challenges of being able to get it out.

Q. Okay. Do you see any concerns about the ability to perform fishing operations or the use of standard tools to withdraw or pull out tubing in this case?

A. No, ma'am. These tools are readily available and sitting on the rack now.

Q. Were Exhibits 30, 31, 32 and 33 prepared by you or under your supervision or compiled from your company's business records?

A. They were.

MS. STEVENSON: I'd like to move admission of Exhibits 30 to 33.

CHAIRMAN CATANACH: Any objection?

MS. KESSLER: No objection.

CHAIRMAN CATANACH: 30 to 33 will be admitted.

(Mesquite SWD, Inc. Exhibit Numbers 30 through 33 are offered and admitted into evidence.)

Q. (BY MS. STEVENSON) Mr. Nave, just a couple more questions. Will you please turn back to Exhibit 3? And flip to the last page of that exhibit, please. Will you explain to the Commissioners the clearances that are discussed on this page?

A. It looks like what we're -- what we're looking at there is -- it kind of goes back to what we were talking about before. These are standards that are pretty much accepted and we run into quite a lot in the business. In 5-1/2-inch, 15-pound or 17-pound or 20-pound casing, these are decimal equivalents of the clearance of the tubing collars for 3-1/2-inch tubing inside of 5-1/2. There is a lot of that that goes on. Basically, you're talking about that tubing collar that is 4-1/2-inch OD, and so that -- a lot of that is permitted and in the field in operation right now.

The second chart below is for 4-1/2 casing. 9.5, which is pretty much the thinnest 4-1/2 casing you can get, gives you a 4-inch ID. And if you run 2-7/8 tubing in it, that's 3-21/32 diameter collar. It gives you the .442 clearance on the -- on the collar. That -- that is close, but you don't have to -- in any of these situations, you don't have to fish the coupling only. I mean, you're seldom ever relegated to having to fish the outside of the coupling. If that was the case, we would be in trouble all the time. But we have to -- once in a while we'll get in a situation where we have a coupling or something that's too big, but we'll mill it off and fish the body just underneath. Or we'll make a cut just underneath it and spear it and pull it out of the hole, and then we can go back and get ahold of it.

But these are just for different weights, I suppose, for comparison to the other -- that 5-1/2, 7-5/8.

Q. That's right.

And in your experience and given your

expertise, would fishing the 5-1/2-inch inside the 7-5/8 be any more difficult -- or difficult to perform than the example that we just looked at?

A. It's actually much less difficult, and the reason is because when you start into these smaller things, then you get into a smaller -- you lose the ability to work from the inside out. You only can work from the outside in on the smaller -- smaller types of tubing.

Q. In your opinion, will the use of 5-1/2-inch tubing inside the 7-5/8-inch casing increase the chance that broken tubing cannot be fished out?

A. No. I don't believe so.

Q. And why not?

A. Well, because like I say, if it breaks, you still have the option to fish it from the outside. You have a better option to fish it from the inside. So much stronger tools are available to use for the bigger stuff. The outside, it's a little closer. You have a little less clearance, but like I say, you make up for it from the inside. And seeing how there is -- I bet 80 percent of the wells in the Permian Basin have 5-1/2 casing cemented in, and we fish inside of that all the time. So working from the inside of this is easy. Whereas, smaller is not so easy.

Q. Will the use of 5-1/2-inch tubing inside of 7-5/8-inch casing leave a large enough diameter to allow operators to plug and abandon the wells?

A. Absolutely. Looks to me like that.

Q. And, Mr. Nave, is the granting of this application in the interest of conservation and the prevention of waste?

A. I would think so.

Q. Thank you.

CROSS-EXAMINATION

BY CHAIRMAN CATANACH:

Q. Mr. Nave, in your experience, how common is it to see that type of configuration, 5-1/2 in 7-5/8?

A. Well, it's -- it's -- as far as 5-1/2 in 7-5/8, it's not necessarily that common that we see casing or tubing inside there like that, but we do this -- we see this kind of thing on a daily basis. Last night -- and I've still got the job going on now -- they had a rotary steerable motor twisted off. It's 5-inch OD inside of a 6-inch hole. That's standard practice. There is a tool to do that, you know, and we can catch that.

As far as the -- it just comes down to dimensions and what we've got. It would be no different if you decided to go with 7-inch and 9-5/8. There is a tool to push that, too, or 2-7/8 inside of 4-1/2. So as long as there is a certain amount of clearance, then it really doesn't change anything. But as far as do we run into this a lot, no, I haven't seen it a lot. But is it out there? Yeah. It's usually not casing, though.

When they're drilling the well -- they're running 7-5/8 casing while they're drilling it, and they're drilling out with a drill pipe that's 5-1/4 OD tool joints and 5-1/2-inch tools on the bottom of it. And we're able to go through that and catch stuff down in there, out in the laterals and stuff like that. So I can't see this being any different than those situations.

Q. In your experience, what do you see as the major cause of tubing failures? Is it just corrosion?

A. Typically, it's corrosion. Yes, sir. It's -- and in injection wells and disposal wells, it's -- it's not paying attention to a leak that causes the corrosion. The inside is typically -- it shows up on the outside long before anybody does anything about it. So if the -- if the leaks are spotted in time, then you don't have problems with the back side of that tubing.

Q. The fact that this tubing is plastic-lined, does that help to avoid that kind of situation?

A. Well, absolutely. The plastic lining keeps the -- keeps the acids and the fluids or whatever from eating it up and coming to the outside. Now, the outside of the casing or outside of the tubing is typically not coated with any kind here.

Q. So in a typical fishing operation, is an overshot more effective generally than a spear?

A. It only -- no. It's no more effective. It is -- it is preferred simply because you can do a little more through the inside as far as running electric lines, free point tools and stuff like that, cutters, other types of electronic logging tools and things like that. You can run through an overshot a little more readily than you can a spear because the spear reduces the ID that you're able to get the tools through.

Q. So on your -- I was reading your abandonment procedure. And on a spear situation, you'd be able to run tools through the spear and go down and set something above the packer and then perforate?

A. You can get -- okay. Through a spear, like I say, you're reduced in size, because it has to go inside, so that means the bit is smaller.

Q. Yeah.

A. So there are tools you can run through a spear. But in 5-1/2-inch, you can run quite a few tools through the spear because it's a larger spear. But yes, you just -- I mean, whatever you can do through an inch-and-a-half ID, you can do with 5-1/2, through the 5-1/2-inch spear. If you're talking about a 4-1/2 spear, you've got to be able to do it through a 1-inch ID. Maybe that answers your question.

Q. So if we had a situation where you couldn't pull the fish and you wanted a cement plug maybe up around the annulus of that tubing --

A. Uh-huh.

Q. -- you could do that through those tools?

A. Yeah. But then see -- and that's why it seems to me that even 5-1/2 is even better simply because then we treat it just like a wellbore that was drilled and 5-1/2 cemented in. We go through the inside, perforate it, set a cement retainer, squeeze it, whatever you need to do, and leave it all in there, you know. But you have a big enough ID then to be able to work through the bits and packers and all kinds of things.

Q. So you couldn't use an overshot where the coupling was, the part that --

A. That's correct. The overshot will not fit over the coupling.

Q. And I heard you say you've got to go in and mill the coupling?

A. Either mill it off or make a cut underneath it and pull it out and get the spear --

Q. And if you milled that coupling off, you could get into that 5-1/2 with an overshot?

A. That's correct.

Q. Okay.

CHAIRMAN CATANACH: Nothing further.

COMMISSIONER BALCH: No questions.

COMMISSIONER MARTIN: Me either.

CHAIRMAN CATANACH: Anything else for this witness?

MS. STEVENSON: We don't have any more questions.

CHAIRMAN CATANACH: That concludes your presentation?

MS. BRADFUTE: It does.

Would you mind if I made a quick closing statement?

CHAIRMAN CATANACH: Go ahead.

MS. BRADFUTE: Thank you.

CLOSING STATEMENT

MS. BRADFUTE: We want to thank you for taking the time to hear Mesquite's application today and all of their witnesses.

I think Mesquite honestly has gone above and beyond what other applicants who have sought 5-1/2-inch tubing have done before the Division.

They've put on a whole suite of experts who are not in-house. They brought them in separately and retained them for this matter.

And this case really comes down to one question, which is a bit of a pun: Is the Commission willing to give an inch? And we realize that that question --

COMMISSIONER BALCH: I think that just sums up her case.

(Laughter.)

MS. BRADFUTE: We need a little comedic relief, right, after sitting through five witnesses?

We realize that this question and inquiry is not without consequence. Operators are very interested in having increased tubing sizes within southeastern New Mexico. And operations are increasing within the state. We're going to have increased amounts of produced water both from the Wolfcamp and Bone Spring production, and that water needs to go somewhere. You heard testimony that Texas is looking at using tubing with a 7-inch OD. New Mexico should consider allowing the use of 5-1/2-inch OD tubing, and it has already approved the use of that tubing.

Here I think it's especially appropriate, in a case where we have shown that the area -- the geographic area is appropriate for these types of deep-injection wells. It's not located near known faults that are identifiable. The geology in the formation is suitable for injection. We know that. We know that on the conservative end, it's about 1,500 feet thick, but it could be up to 3,000 feet thick. It can hold a lot of water. And we know that by increasing injection amounts into these wellbores, there won't be a need to drill as many wells. So there's going to be less surface disturbances. And these increased injection rates are going to have minimal impacts on reservoir pressures. That's been established here not only in this case but also in Black River Water Management's case, 16720, before the Division.

In addition, we know that we have a model where we can look at induced seismicity. I know that that's a serious inquiry. But it's a peer-reviewed model that's been put out by academics. It's a model that's free to use for operators. And we have experts at New Mexico Tech that operators can use, that Mesquite here went to the extent of hiring and using to analyze when induced seismicity can occur. In this case it established through scientific evidence that it's unlikely it's going to occur.

So we ask that the Commission take this

application into consideration and that it issue an order in Mesquite's favor.

CHAIRMAN CATANACH: Thank you.

MS. KESSLER: Mr. Commissioner, I have a statement.

Black River Water Management Company is an affiliate of MRC entities and Matador. They were an intervenor at the division level of these proceedings, have themselves presented evidence at hearings to the Division related to 5-1/2 -- to the approval of 5-1/2-inch tubing. One of those applications was approved. The other is pending. They do not take a position on this application. They simply are an interested party.

CHAIRMAN CATANACH: I was going to ask you about the Black River Water case. Is it the same kind of well configuration; do you know?

MS. KESSLER: It's similar. There are two issues. Again, one was approved, and the other one is pending in front of the Division. They are -- I can't speak to where they're located with respect to these wells, but the configuration is similar, and they are asking for 5-1/2-inch tubing rather than tapered tubing.

CHAIRMAN CATANACH: Okay. Thank you.

Okay. So do I hear a motion?

COMMISSIONER BALCH: I move we move to closed deliberations.

COMMISSIONER MARTIN: Sure. Second.

CHAIRMAN CATANACH: There you go.

All in favor?

(Ayes are unanimous.)

(Executive session, 11:17 a.m.)

(Open session, 11:40 a.m.)

CHAIRMAN CATANACH: Commissioners, do I have a motion to go back into regular session?

COMMISSIONER MARTIN: So move.

COMMISSIONER BALCH: Second it.

CHAIRMAN CATANACH: All in favor?

(Ayes are unanimous.)

CHAIRMAN CATANACH: So I'll just state for the record that during the -- during the executive session, we deliberated on the merits of this case, and that was the only thing that was discussed. And at this time I will turn it over to Mr. Brancard who will announce a decision in this case.

MR. BRANCARD: Thank you, Mr. Chairman.

Based on the evidence today, the Commission will approve the application of Mesquite to have the tubing changed from 4-1/2 inches to 5-1/2 inches for the eight wells that are in their application.

The Commission is basing the decision on the evidence that was presented today, which includes the seismic evidence, the merits of the injection layers, the geologic evidence, the pore-pressure data, and the fishing testimony that was presented. In other words, this is based -- this decision is for these eight wells and does not really establish a precedent for any other wells in the future.

In addition, the Commission directs the Division to continue its work group on UIC Class 2 wells and looking at the various issues that have been presented by the increased saltwater disposal that's going on and possibly the need to develop new regulations.

CHAIRMAN CATANACH: Can we get you guys to do a draft order on this?

MS. BRADFUTE: Yes, you can.

CHAIRMAN CATANACH: Thank you.

MS. BRADFUTE: Sure, we can.

COMMISSIONER BALCH: Next meeting is the 4th?

CHAIRMAN CATANACH: The 4th.

MS. DAVIDSON: The 7th, December 7th.

CHAIRMAN CATANACH: If you could get that to us before that hearing, we can review it.

MS. BRADFUTE: Yeah. So kind of December 1-ish or --

MR. BRANCARD: Sure.

CHAIRMAN CATANACH: Yeah. That'll work.

MR. CLAY WILSON: Can I ask a question?

CHAIRMAN CATANACH: SURE.

MR. CLAY WILSON: On applications going forward, will we -- I know you said it will be on a case-by-case basis. So we can go ahead and fill it out with 5-1/2, and y'all will review that?

CHAIRMAN CATANACH: Well, we're not setting any kind of precedent that we have to go to hearing, but what I would recommend is maybe the same kind of evidence that you put on this case be included in any sort of administrative application.

COMMISSIONER BALCH: Until a precedent is set.

MR. CLAY WILSON: Attach it with the C-108?

CHAIRMAN CATANACH: Yes, sir. I think that would be very helpful and instrumental in getting that application produced.

MR. CLAY WILSON: Okay. Thank you.

CHAIRMAN CATANACH: That's that?

I'm sorry.

Are we done with --

MR. BRANCARD: Yes.

(Case Number 15654 concludes, 11:43 a.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.

MARY C. HANKINS, CCR, RPR
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