

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

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

APPLICATION OF MESQUITE SWD, INC. TO CASE NO. 16308
AMEND ADMINISTRATIVE ORDER SWD-1696
FOR A SALTWATER DISPOSAL WELL IN EDDY
COUNTY, NEW MEXICO.

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

July 12, 2018

Santa Fe, New Mexico

BEFORE: MICHAEL McMILLAN, CHIEF EXAMINER
 DAVID K. BROOKS, LEGAL EXAMINER

This matter came on for hearing before the
New Mexico Oil Conservation Division, Michael McMillan,
Chief Examiner, and David K. Brooks, Legal Examiner, on
Thursday, July 12, 2018, at the New Mexico Energy,
Minerals and Natural Resources Department, Wendell Chino
Building, 1220 South St. Francis Drive, Porter Hall,
Room 102, Santa Fe, New Mexico.

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

1 APPEARANCES
2 FOR APPLICANT MESQUITE SWD, INC.:
3 JENNIFER L. BRADFUTE, ESQ.
4 DEANA M. BENNETT, ESQ.
5 MODRALL, SPERLING, ROEHL, HARRIS & SISK, P.A.
6 500 4th Street, Northwest, Suite 1000
7 Albuquerque, New Mexico 87102
8 (505) 848-1800
9 jlb@modrall.com
10 deanab@modrall.com
11
12
13
14
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1 (2:40 p.m.)

2 EXAMINER McMILLAN: I'd like to call Case
3 Number 16308, application of Mesquite SWD, Incorporated
4 to amend Administrative Order SWD-1696 for a saltwater
5 disposal well, Eddy County, New Mexico.

6 Call for appearances.

7 MS. BRADFUTE: Mr. Examiner, Jennifer
8 Bradfute and Deana Bennett on behalf of Mesquite SWD,
9 the Applicant.

10 EXAMINER McMILLAN: Any other appearances?
11 Please proceed.

12 MS. BRADFUTE: Mr. Examiner, I'd like to
13 open by making a short statement. Mesquite SWD has
14 filed this application. This well has been drilled.
15 It's a Devonian saltwater disposal well, the Mesaverde
16 SWD #3, and no tubing has been installed in the well.
17 But because it is a Devonian disposal well, it is a very
18 expensive well to drill. So it's an \$8 million well
19 that is sitting without tubing, and there are operators
20 in the area who have had to shut in wells because
21 they're waiting for disposal in the area.

22 So Mesquite would like to respectfully ask
23 for an expedited order in this matter if it's possible.
24 We understand there's been a past issue at the Division
25 that's created a lot of conversation in Devonian cases

1 with increased tubing requests. So we're happy to
2 respond to any questions that the Division has as it
3 processes this order, but we do request an expedited
4 order if possible.

5 EXAMINER McMILLAN: Please proceed.

6 MS. BRADFUTE: Thank you. I'd like to call
7 my first witness, Riley Neatherlin.

8 EXAMINER McMILLAN: Would all the witnesses
9 please be sworn in?

10 (Mr. Neatherlin, Mr. Nave, Mr. Wilson,
11 Dr. Zeigler, Ms. Bilek sworn.)

12 RILEY NEATHERLIN,
13 after having been first duly sworn under oath, was
14 questioned and testified as follows:

15 DIRECT EXAMINATION

16 BY MS. BRADFUTE:

17 Q. Could you please state your name?

18 A. Riley Neatherlin.

19 Q. And, Mr. Neatherlin, who do you work for?

20 A. Mesquite SWD.

21 Q. And what is your position at Mesquite?

22 A. I'm an operations manager for Mesquite.

23 Q. And what are your responsibilities at Mesquite?

24 A. I'm in charge of the day-to-day operations,
25 planning and permitting of wells, completions of wells,

1 anything to do with the day-to-day and drilling and
2 continuing or keeping the wells operating.

3 Q. And have you previously testified before the
4 Division?

5 A. Yes.

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

8 A. Yes.

9 Q. And does your area of responsibility at
10 Mesquite include the areas of Eddy and Lea Counties in
11 southeastern New Mexico?

12 A. Yes, it does.

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

15 A. Yes.

16 Q. And are you familiar with the saltwater
17 disposal well which is the subject matter of this
18 application?

19 A. Yes, I am.

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

22 EXAMINER McMILLAN: So accepted.

23 Q. (BY MS. BRADFUTE) Mr. Neatherlin, could you
24 please turn to what's been marked as Exhibit Number 1 in
25 the packet in front of you? Is this a copy of

1 **Mesquite's application in this matter?**

2 A. Yes, it is.

3 **Q. Could you please explain to the hearing**
4 **examiner what Mesquite is requesting in its application?**

5 A. Mesquite is requesting the amendment of the
6 order from a 4-1/2 injection tubing inside of a 7-5/8
7 liner to upsize it to a 5-1/2 injection tubing inside
8 the liner, as -- as well as running a 7-inch tapered
9 string up inside the 9-5/8 to increase our injection
10 rate and decrease our surface pressure.

11 **Q. And is Mesquite also requesting, in paragraph**
12 **five of its application on the second page, to increase**
13 **its injection rate to a maximum of 40,000 barrels of**
14 **produced water per day?**

15 A. Yes, we are.

16 **Q. Could you please turn to what's been marked as**
17 **Exhibit Number 2? Does Exhibit 2 contain a copy of the**
18 **administrative order that's been entered for this well**
19 **SWD-1696?**

20 A. Yes. Yes, it does.

21 **Q. Could you please point out what is said in this**
22 **order concerning the size of tubing which has been**
23 **authorized by the Division for the well?**

24 A. It says, "Injection will occur through either
25 an internally coated 5-1/2-inch or smaller tubing inside

1 the surface and intermediate casing and a 4-1/2-inch or
2 smaller tubing inside the liner."

3 Q. So a tapered string tubing was approved in the
4 administrative order, correct?

5 A. Yes, it was.

6 Q. And Mesquite is seeking to increase the size of
7 tapered string tubing that it's using in the well?

8 A. Yes.

9 Q. And just for clarification, the tapered string
10 tubing that Mesquite is seeking authorization for is
11 7-inch by 5-1/2 inches?

12 A. Yes, it is.

13 Q. Has this well been drilled?

14 A. Yes, it has.

15 Q. But the tubing has not yet been installed in
16 the new well?

17 A. No. We have not done any completion work on it
18 yet.

19 Q. Can you please turn to what's been marked as
20 Exhibit Number 3? Is this document a diagram of the
21 wellbore showing the tubing that Mesquite is seeking
22 approval for in this case?

23 A. Yes, it is.

24 Q. And could you please explain what is shown in
25 this diagram to the hearing examiner?

1 A. It's a wellbore diagram showing the 7-inch to
2 5-1/2 tapered string inside the wellbore. It's got the
3 casing and tubing specs along the side.

4 **Q. Okay. I'm going to pass out to you what I'm**
5 **going to mark as Exhibit Number 25. Could you please**
6 **explain what is shown on Exhibit Number 25 to the**
7 **hearing examiner?**

8 A. This is a -- this is tubing specifications for
9 the 5-1/2 tubing that we're seeking to run in this well.
10 It's a 5-1/2, 20-pound P110 tubing. It's got a 5-1/2 OD
11 on the body. Coupling of it is 6.05. It's got an ID of
12 4.778 inches. It's got a burst of 12,640 pounds and a
13 collapse of 11,100 pounds.

14 Below that is a list of the wells that have
15 been approved through administrative order for 7-inch to
16 5-1/2 tapered strings.

17 **Q. Okay. And could you please explain Mesquite's**
18 **reason for requesting a larger tubing size for this**
19 **well?**

20 A. Our request to upsize the tubing is so that we
21 can maximize the well. I mean, these wells are very
22 expensive to drill. The more water we can get down one
23 well, the less wells we have to drill. The bigger the
24 tubing, it increases our injection rate, lowers our
25 surface injection pressure and allows us to really

1 maximize the reservoir.

2 Q. Mr. Neatherlin, are you aware of the fact that
3 other operators have presented cases in front of the
4 Division requesting larger tubing sizes?

5 A. Yes, I am.

6 Q. And are you aware of Black River Water
7 Management, LLC's cases presented to the Division?

8 A. Yes.

9 Q. In those cases, is it your understanding that
10 Black River Water Management, LLC testified that it was
11 able to reduce approximately 85 percent of the pressure
12 experienced at the surface when it increased the size of
13 the tubing that was used?

14 A. Yes.

15 Q. Okay. And it's the friction that's being
16 reduced?

17 A. Yes, the friction.

18 Q. Okay. Thank you.

19 You mentioned earlier on Exhibit Number 25
20 that there is a list of approved wells with the same
21 tubing sizes that Mesquite's requesting in this
22 application; is that right?

23 A. Yes.

24 Q. So the Division has already issued approvals
25 for 7-inch by 5-1/2-inch tubing?

1 A. Yes, that is correct.

2 **Q. And those wells are listed in Exhibit 25,**
3 **right?**

4 A. Yes.

5 **Q. Were those approvals made by the district**
6 **office?**

7 A. The 5-1/2 was approved before by the Division
8 or the Commission, and then the 7-inch tapered string
9 was approved by the district offices. Yes.

10 **Q. Okay. But Mesquite was asked to present this**
11 **request at hearing by the Division? It was required?**

12 A. Yes.

13 **Q. Can you please explain where these wells are**
14 **located?**

15 A. These wells are located in southeast Eddy -- or
16 southwest Eddy and east Lea County. I said that
17 backwards. Southeast Eddy --

18 EXAMINER BROOKS: I was thinking --

19 THE WITNESS: Yeah. Sorry.

20 EXAMINER BROOKS: -- that didn't sound
21 right.

22 (Laughter.)

23 MS. BRADFUTE: Thank you.

24 **Q. (BY MS. BRADFUTE) Please turn to what's been**
25 **marked as Exhibit Number 4 in the packet before you.**

1 Does Exhibit Number 4 contain a map or a diagram which
2 shows wells that have been proposed as Devonian
3 saltwater disposal wells and then existing Devonian
4 saltwater disposal wells surrounding the section for the
5 Mesaverde SWD #3 well?

6 A. Yes, it does.

7 Q. And could you please kind of walk through this
8 diagram for the benefit of the Examiner?

9 A. It's a four-township map consisting of wells
10 that are drilled or permitted Devonian wells in the
11 area. The red wells are proposed -- the red dots are
12 proposed and the green ones are existing Devonian wells.

13 Q. And can you please explain the spacing between
14 the Mesaverde SWD #3 well which is located in 24 South,
15 Section 13 --

16 A. Uh-huh.

17 Q. -- and where it's situated in comparison to the
18 next closest well?

19 A. The closest well to it is the Striker 2 SWD,
20 which is -- looks like it's a little over a mile --
21 maybe a mile and a quarter away from each other.

22 Q. Okay. But it's over a mile away?

23 A. Yes.

24 Q. Okay. Could you please turn to Exhibit -- the
25 second page of this exhibit, actually. Does the second

1 page of Exhibit Number 4 contain the data, the API
2 numbers, the well names, the type of disposal well for
3 all of the wells that are shown on the diagram that we
4 just discussed?

5 A. Yes, it does.

6 Q. And are there any productive wells within the
7 Devonian Formation located near the proposed well that
8 you're aware of?

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

10 Q. Could you please turn to Exhibit Number 5, and
11 could you please explain what that document shows to the
12 hearing examiner?

13 A. This is a designated Devonian pool map for the
14 area, for the same four townships that are shown on the
15 previous map.

16 Q. That were shown on the previous map?

17 A. Yes.

18 Q. And in this diagram, there are two red
19 triangles. Are those two red triangles Devonian pools
20 that have been designated by the district office?

21 A. Yes. The rectangles are --

22 EXAMINER BROOKS: I was going to say they
23 look like rectangles.

24 MS. BRADFUTE: Yes. Sorry. Thank you.

25 It's been a long day (laughter).

1 THE WITNESS: -- are designated pools.

2 Yes.

3 Q. (BY MS. BRADFUTE) And it's the -- they look --
4 the names are very difficult to read. It's the Paduca
5 Devonian wells there?

6 A. Uh-huh.

7 Q. Okay. And what is the distance between the
8 northern pool, the Devonian pool, and the Mesaverde SWD
9 #3 well?

10 A. It looks like just a little over three miles.

11 Q. Okay. So the Mesaverde SWD #3 well is not
12 located near an existing Devonian pool; is that correct?

13 A. No, it's not.

14 Q. Mr. Neatherlin, I want to kind of switch topics
15 a little bit now and talk about fishability in the event
16 there is a tubing problem or a fishing situation that
17 arises.

18 Does Mesquite work with a fishing tool
19 expert when considering whether it should increase the
20 size of the tubing that it installs in its wells?

21 A. Yes.

22 Q. In this case have you consulted with a fishing
23 tools expert to determine whether increasing the tubing
24 size would be a good choice?

25 A. Yes, we have, to make sure that we can get --

1 get the pipe fished if need be.

2 Q. And is that expert Mr. Steve Nave?

3 A. Yes, it is.

4 Q. And will Mr. Nave be presenting testimony today
5 about the fishability of tubing and other things that
6 might fall downhole?

7 A. Yes, he will.

8 Q. Could you please look at exhibits -- I just
9 want you to kind of flip through Exhibits 6, 7 and 8.
10 Are these exhibits documents which explain the different
11 kind of fishing tools that Mr. Nave has previously
12 testified about in other cases involving Mesquite SWD's
13 operations?

14 A. Yes, they are.

15 Q. And did Mr. Nave provide testimony in Case
16 Number 15654 before the Oil Conservation Commission on
17 behalf of Mesquite SWD?

18 A. Yes, he did.

19 Q. Was it Mr. Nave's testimony during that
20 proceeding that there would not be fishing problems with
21 5-1/2-inch tubing in these deep Devonian wells?

22 A. Yes, there was.

23 Q. Could you please turn to what has been marked
24 as Exhibit Number 9. Is Exhibit Number 9 proof that
25 Mesquite has notified all of the entities originally

1 notified in its administrative application, as well as
2 other parties located within a mile of the well location
3 about this application?

4 A. Yes, it is.

5 Q. And does it contain an affidavit that's been
6 prepared by Mesquite's counsel confirming that
7 notification was so provided?

8 A. Yes, it does.

9 Q. And if you could please look at the very last
10 page of this exhibit, is the last page of this exhibit
11 an Affidavit of Publication confirming that notification
12 was also provided in the "Carlsbad Current-Argus"
13 newspaper?

14 A. Yes, it does -- is.

15 Q. Mr. Neatherlin, were Exhibits 1 through 9
16 prepared by you or compiled under your supervision and
17 direction?

18 A. Yes, they were.

19 MS. BRADFUTE: I'd like to tender Exhibits
20 1 through 9 into the record.

21 EXAMINER McMILLAN: Exhibits 1 through 9
22 will now be accepted as part of the record.

23 (Mesquite SWD, Inc. Exhibit Numbers 1
24 through 9 are offered and admitted into
25 evidence.)

1 MS. BRADFUTE: That concludes my questions
2 for this witness.

3 CROSS-EXAMINATION

4 BY EXAMINER McMILLAN:

5 Q. Okay. Did you notice that NGL? Did you notify
6 them or the operator of the Striker 2?

7 A. That application was actually in before that
8 well was permitted, I believe.

9 Q. Okay.

10 A. I believe so.

11 Q. That's fine. Okay. That's fine.

12 So are you using flush joints?

13 A. On the tubing?

14 Q. Yes.

15 A. No. It's collar pipe.

16 Q. How did you select that instead of going with a
17 flush joint?

18 A. It's easier to anchor or liner to it as opposed
19 to just flush joint. It makes a better seal for our
20 liner or coating, I guess.

21 Q. I think we've added additional wording to
22 orders that says if there is -- the well to be shut in
23 within 24 hours if there are any problems. I'll have to
24 go back and look at that.

25 A. I haven't seen a new permit lately.

1 **Q. There is some new verbiage in there saying you**
2 **have to notify the district office within 24 hours.**

3 MS. BRADFUTE: If there is a tubing
4 incident?

5 EXAMINER McMILLAN: Yeah. If there is a
6 problem with the well, it has to be shut in. I'm
7 assuming you wouldn't have a problem with that. And you
8 can find the order.

9 MS. BRADFUTE: I'll look for one.

10 THE WITNESS: Yeah. If it's in there,
11 we'll abide by that.

12 EXAMINER McMILLAN: Do you have any
13 questions?

14 EXAMINER BROOKS: No questions.

15 MS. BRADFUTE: Mike, I have one follow-up
16 question.

17 REDIRECT EXAMINATION

18 BY MS. BRADFUTE:

19 **Q. In the event of a tubing failure, does Mesquite**
20 **operate other wells within the area where it can divert**
21 **produced water that operators need to dispose of?**

22 A. Yes. Our -- most of our wells are tied
23 together with pipelines, so in the event of having to
24 shut down a well, we can send water elsewhere, get rid
25 of it.

1 **Q. Does Mesquite have a system in place that**
2 **handles disposal in the event of a tubing problem?**

3 A. Yes.

4 **Q. Thank you.**

5 EXAMINER McMILLAN: Please proceed.

6 MS. BRADFUTE: I'd like to call my second
7 witness, Mr. Nave.

8 STEVE NAVE,
9 after having been previously sworn under oath, was
10 questioned and testified as follows:

11 DIRECT EXAMINATION

12 BY MS. BRADFUTE:

13 **Q. Good afternoon.**

14 A. Good afternoon.

15 EXAMINER McMILLAN: You have one more --
16 Exhibit 25 may now be accepted as part of
17 the record.

18 MS. BRADFUTE: Oh, thank you. Yes.
19 (Mesquite SWD, Inc. Exhibit Number 25 is
20 offered and admitted into evidence.)

21 **Q. (BY MS. BRADFUTE) Mr. Nave, could you please**
22 **state your name for the record?**

23 A. Steve Nave.

24 **Q. And who do you work for?**

25 A. Nave Oil & Gas.

1 **Q. And what is your position at Nave Oil & Gas?**

2 A. I'm president of the company.

3 **Q. And in your capacity at Nave Oil and Gas, have**
4 **you worked on fishing operations?**

5 A. Yes, ma'am. That's what we do primarily.

6 **Q. And could you give the hearing examiner just a**
7 **brief explanation of your fishing experience within the**
8 **basin?**

9 A. Okay. I started out, you know, roughnecking
10 and drilling wells and moved into the fishing tool
11 industry or part of the wing of the deal in 1980. I
12 started running fishing tools for Star Tool Company. I
13 stayed with that until 2001. I had acquired a position
14 in the company, and when we sold it to Smith
15 International, I stayed on with them for a while and
16 then left Smith International and started my own
17 company.

18 **Q. So you've been performing fishing operations**
19 **within New Mexico for many years?**

20 A. For -- since 1980.

21 **Q. Okay. And have you previously testified before**
22 **the Oil Conservation Division?**

23 A. Yes, ma'am, I have.

24 **Q. And were your credentials accepted and made a**
25 **matter of record?**

1 A. Yes, ma'am.

2 MS. BRADFUTE: I'd like to tender
3 Mr. Nave as an expert in fishing operations.

4 EXAMINER McMILLAN: So qualified.

5 Q. (BY MS. BRADFUTE) Mr. Nave, I'd like you to
6 turn back to Exhibit Number 6 in the packet in front of
7 you.

8 And actually I'd like you to look at
9 Exhibit 25, which is the loose paper right next to you.
10 And I'm going to first look at Exhibit 25.

11 A. Okay.

12 Q. Mr. Nave, have you previously reviewed the
13 specifications for the tubing sizes that Mesquite is
14 requesting in its application?

15 A. Yes, I have.

16 Q. And in your opinion, if tubing -- this size is
17 used, 7-inch by 5-1/2-inches, will it provide any
18 fishing problems in the event of a tubing failure?

19 A. Not in the casing sizes, as I understand. I
20 see no issues with it. No, ma'am.

21 Q. And what are -- what are the casing sizes?

22 A. As I understand it, we're talking about putting
23 7-inch tubing inside of 9-5/8-inch casing. The 9-5/8
24 is -- we're talking ODs here, 7-inch OD tubing inside of
25 9-5/8-inch casing, and 5-1/2-inch tubing inside of 7-5/8

1 OD casing.

2 Q. And in your opinion, does that allow for
3 sufficient clearance between the casing and the proposed
4 tubing in the event you need to fish something out of
5 the tubing?

6 A. Yes, it does.

7 Q. I now want to look at Exhibit Number 6. Is
8 this a document that you have previously testified about
9 before the Oil Conservation Commission?

10 A. Yes, it is.

11 Q. And does this document contain information
12 about overshot tools that can be used during fishing
13 procedures?

14 A. Yes, it does.

15 Q. Could you please briefly explain to the
16 Examiner how you would use an overshot tool to fish
17 something out of a tube?

18 A. An overshot is a tool designed to attach to a
19 smooth piece of the pipe from the outside. As the name
20 implies, it goes over the top of the tube, and it has
21 basically a slip assembly that bites into the metal and
22 creates a strong connection to the fish. That's kind of
23 an overview of what it does.

24 Q. Okay. And in your opinion, could an overshot
25 tool be used in a fishing operation, in this instance,

1 **using the specifications of casing and tubing that**
2 **Mesquite is requesting?**

3 A. Yes, you can. You're talking about two
4 different sizes of overshots. One is for fishing 7-inch
5 inside of the 9-5/8. That tool is an 8-1/8-inch OD.
6 It's readily available. The other for fishing
7 5-1/2-inch inside of 7-5/8 is originally a 6-5/8 OD
8 overshot with a maximum catch for 5-1/2. It can be
9 turned down to a little smaller if the casing weight
10 reduces the idea [sic] enough for it to be necessary.
11 So yes, overshot can be used in both situations to fish
12 tubing from those size casings.

13 **Q. Okay. Could you please turn to the next**
14 **exhibit, Exhibit Number 7, in the packet in front of**
15 **you? Does Exhibit Number 7 contain information about**
16 **releasing spear tools that can be used in fishing**
17 **operations?**

18 A. Yes, it does.

19 **Q. And could you please explain how this tool**
20 **would be used when you need to fish something out of a**
21 **tubing?**

22 A. This tool is basically the opposite of the
23 overshot. It goes on the inside of the pipe to be
24 fished and slips -- expands and bites on the internal
25 diameter of the -- so to be able to pick up on a broken

1 piece of pipe or whatever.

2 Q. And in your opinion, would you be able to use a
3 spear to fish something out of the tubing that's been
4 proposed by Mesquite in this case?

5 A. Yes, you can.

6 Q. Could you please turn to the next exhibit,
7 Exhibit Number 8? Does Exhibit Number 8 contain
8 information about a pressure pipe cutter?

9 A. Yes, it does.

10 Q. And could you please explain to the Examiner
11 how a pressure pipe cutter would be used in fishing
12 operations?

13 A. A pressure pipe cutter is a tool that is of a
14 size specific to run inside of the pipe that you want to
15 cut. You run it inside that string of casing. For
16 instance, the 5-1/2-inch tubing in this case, you would
17 run a 3-5/8-inch OD pressure cutter on a work string of
18 2-7/8 on the tubing down inside the 5-1/2 casing. You
19 start rotation on the tool, start pump pressure going
20 down the tubing that forces some knives out -- pushing
21 the piston down that forces the knives out and cuts the
22 5-1/2-inch casing in the tube so that it can be freed.
23 From -- from that point up, then you can latch on to it
24 with the overshot and pull it out of the well or
25 whatever the application would be. That is one of many

1 procedures that can be used to separate -- to cut
2 5-1/2 -- or to cut piping basically of any size, but it
3 works better in the larger sizes. These kind of cutters
4 can't be utilized in smaller -- can in some smaller but
5 not -- not a lot smaller operations than this.

6 **Q. Have you previously testified before the**
7 **Commission and the Division in other cases that it's**
8 **your preference to work in tubing with a larger diameter**
9 **so you can get more tools down there to work with?**

10 A. Yes, I believe I have.

11 **Q. Okay. And is that still your preference?**

12 A. Absolutely.

13 **Q. Mr. Nave, are you currently in the process of**
14 **working on a fishing operation with a well that has**
15 **tubing of 7 inches by 5-1/2 inches installed?**

16 A. We actually are on a well, a job. At current
17 time right now, I have a man on the job, and I believe
18 it's on the New Mexico side.

19 But anyway, they have 5-1/2-inch tubing --
20 in their case, it was casing. It wasn't tubing. But it
21 would be the exact same thing. It's a drilling
22 operation. They were running this casing in the well to
23 the cement. And they have round numbers, 12,000 feet of
24 7-5/8 casing set. They have like 19,000 feet of
25 5-1/2-inch casing that they run in this well, and then

1 they got it stuck before they got it to bottom.

2 During trying to free this, they parted the
3 pipe, pulled it in two at -- between 4- and 500 feet
4 from the surface, and that was up in the 7-5/8 casing.
5 As it turned out, it parted in a casing coupling, which
6 is 6.05 diameter.

7 There were several methods that we talked
8 about to get this -- to fix their problem, and with
9 well-control issues that they have, they opted to run
10 overshot. They wanted to use the overshot and tie the
11 string back together and then start trying to cut it.

12 And so they ran a -- the first thing we
13 done is left half of that collar, which is 6-inch OD,
14 and we went in and milled that away. It took about an
15 hour to mill that -- half of that 6-and-a-half inch --
16 or 6.05 collar away. Once they got that milled off, I
17 had a machine shop to build a top bushing to go in this
18 overshot where we could run that on 5-1/2-inch casing.
19 So we just screwed our overshot on the casing, run it in
20 the well then and latched on to the 5-1/2-inch tube, and
21 it packs off so it won't leak around there. You have a
22 rubber packoff assembly on it. And then they have well
23 control, and they also have full inside diameter on the
24 5-1/2 casing from the surface all the way back to
25 bottom. Basically, we just tied it all back together so

1 that they could try to work on getting it loose at the
2 bottom.

3 So it would -- by saying that there was --
4 that was one method. The other method that I suggested
5 to them to get this out of there would be -- what I
6 thought would be faster and more economical was to just
7 make a wireline cutter trip in with a jet cutter with
8 4-1/2-inch OD, flop it over then to the 5-1/2, run it to
9 the depth they wanted, cut it off, pull the wireline out
10 of the hole, run it in the hole, stick a spear in it and
11 pull it out of the hole and lay down and we're done.
12 But they had well-control issues and wanted to go about
13 it the other way.

14 Where that leads us to is that fishing
15 5-1/2 casing inside of 7-5/8 casing is the way to do it
16 if we have tools in the hole today.

17 **Q. It's doable --**

18 A. Doing just that.

19 **Q. -- you're doing it, and you're being successful**
20 **at fishing the casing out?**

21 A. That's from the outside. That don't mean you
22 have to fish it from the outside, but that is an option.
23 There are only two ways to fish it, one inside and one
24 outside.

25 **Q. Yeah. And you have felt comfortable with those**

1 **fishing operations?**

2 A. We can do it either way.

3 **Q. And in your expert opinion, is there an**
4 **unreasonable enhanced risk to the wellbore as a result**
5 **of using 7 inches by 5-1/2-inch tubing for the wells**
6 **proposed by Mesquite?**

7 A. In the well as prescribed, no, ma'am, I see no
8 problem.

9 **Q. And in your opinion, do see any concerns about**
10 **the ability to perform fishing operations if you use**
11 **tubing that's 7 inches by 5-1/2 inches?**

12 A. Not from a -- not from a fishing aspect. From
13 the -- the only consideration is that this is big stuff,
14 and you have to have big tools to work with, like big
15 surface equipment, drilling rig instead of a pulling
16 unit. But they know that.

17 **Q. And as long as an operator has access to a**
18 **bigger rig --**

19 A. That's correct.

20 **Q. -- there would be no concern?**

21 A. None whatsoever.

22 **Q. And that concludes my questions, Mr. Nave.**

23 **CROSS-EXAMINATION**

24 BY EXAMINER MCMILLAN:

25 **Q. Okay. So in your scenario, they had 12,000**

1 **feet at 7-5/8 casing?**

2 A. Yes, sir.

3 **Q. And then they had how many feet of 5-1/2?**

4 A. They had like 19,000 feet of 5-1/2. They were
5 running it from the surface all the way to TD in a
6 horizontal in the lateral.

7 **Q. Oh, okay.**

8 **And it got -- the casing part of it --**

9 A. It got stuck to start with down here somewhere
10 out in the lateral. It packed off. And they were
11 unable to move it and unable to get a good cement job
12 around it on account of it. So what they opted to do
13 was just cut it off, plug the bottom half of the lateral
14 and leave that in there and sidetrack it around and
15 drill your -- start over rather than trying to -- they
16 don't want to go to the trouble of trying to fish that
17 out of that out there. The well's never even been
18 completed out there. It's easier to go around it than
19 it is to fish it out. But then they parted it.

20 I guess where I'm going is while they were
21 trying to free that out there, they parted their pipe up
22 here at 450 feet from the surface, and that's where we
23 are -- we're latched on and doing the work. We're
24 getting ahold of the pipe. And just like any other
25 fishing operation, it's not a problem. Getting it to

1 free up out there at 19,000 feet out in the lateral can
2 be a significant problem. But you have to deal with
3 that as the problem is.

4 And in their situation, the best way to
5 remedy it is not to even attempt to fish it out there.
6 We can probably get it. I mean, it wouldn't be because
7 the tools are not capable of -- you're not capable of
8 fishing it in this. It's just that with the rig time
9 costs and stuff like that that it would take to fish
10 that out out there, they're better off to just leave it
11 and drill around it and carry on.

12 **Q. Okay. If it would be okay -- obviously someone**
13 **that's more knowledgeable is going to write the order.**
14 **Can we get a summary more or less of what you're saying?**

15 MS. BRADFUTE: Yes. We can provide, again,
16 an information request to provide a summary.

17 EXAMINER McMILLAN: Yeah, specific to that.

18 MS. BRADFUTE: Yes, absolutely. And I
19 just -- are you done with your questions?

20 EXAMINER McMILLAN: Yeah.

21 Do you have a problem with that?

22 THE WITNESS: No, I have no problem with it
23 at all.

24 EXAMINER McMILLAN: Okay.

25 THE WITNESS: All I need to know is what

1 you want.

2 EXAMINER McMILLAN: Okay. That's fine.
3 Someone better at this will write it.

4 REDIRECT EXAMINATION

5 BY MS. BRADFUTE:

6 **Q. Okay. Mr. Nave, just to follow up on the**
7 **Examiner's question, in your opinion, do you feel like**
8 **you can still perform fishing operations in the deeper**
9 **portions of these Devonian wells?**

10 A. Absolutely.

11 **Q. Okay. And you said, you know, it's a**
12 **significant operation to perform those fishing**
13 **operations because you're going to need a bigger rig and**
14 **it's going to have significant costs to perform those**
15 **fishing operations?**

16 A. That's correct.

17 **Q. But it's still your opinion that fishing**
18 **operations can be successfully done?**

19 A. Well, it's no different than any other fishing
20 operations on that part. If we had -- if they had 4-1/2
21 casing stuck in this well, it would be no different than
22 it is. Just because it's 5-1/2 in that size hole, it's
23 not making any difference to us. It would still be the
24 same situation.

25 **Q. And is the most significant challenge obtaining**

1 **a large rig in that situation where you're fishing --**

2 A. Yeah. And, I mean, you're going to need a rig
3 similar to what they're doing out here now, which is a
4 large drilling rig.

5 **Q. Yeah. Okay. Thank you very much.**

6 MS. BRADFUTE: And that concludes my
7 questions for Mr. Nave.

8 EXAMINER BROOKS: Questions?

9 MS. BRADFUTE: And I'd like to call my
10 third witness.

11 RE CROSS EXAMINATION

12 BY EXAMINER McMILLAN:

13 **Q. Is it easier for a 5-1/2 or a 4-1/2 to fish?**

14 A. No difference.

15 **Q. It doesn't matter? It's one and the same?**

16 A. Yeah.

17 **Q. Okay. Thank you very much. Nice presentation.**

18 MS. BRADFUTE: I'd like to call my next
19 witness, Ms. Zeigler.

20 KATE ZEIGLER, Ph.D.,
21 after having been previously sworn under oath, was
22 questioned and testified as follows:

23 DIRECT EXAMINATION

24 BY MS. BRADFUTE:

25 **Q. Could you please state your name for the**

1 **record?**

2 A. Kate Zeigler.

3 **Q. And, Ms. Zeigler, who do you work for?**

4 A. Zeigler Geologic Consulting on behalf of
5 Mesquite SWD.

6 **Q. Okay. And what are your responsibilities at**
7 **Zeigler Geologic Consulting?**

8 A. I am primarily a stratigrapher, so I spend time
9 understanding the stratigraphy of the paleogeography in
10 the Permian Basin and understanding how that SWD is
11 attempting to work in it.

12 **Q. And have you previously testified before the**
13 **Division?**

14 A. Yes.

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

17 A. Yes.

18 **Q. And are you familiar with the application**
19 **that's been filed by Mesquite in Case Number 16308?**

20 A. Yes.

21 **Q. Are you familiar with the status of the lands**
22 **which are the subject matter of that application?**

23 A. Yes.

24 **Q. And have you conducted a geologic study of the**
25 **area embracing the proposed location for the Mesaverde**

1 **#3 well?**

2 A. I have.

3 MS. BRADFUTE: I'd like to tender
4 Ms. Zeigler as an expert witness in geology matters.

5 EXAMINER McMILLAN: So qualified.

6 **Q. (BY MS. BRADFUTE) Can you please turn to**
7 **Exhibit Number 10 in the packet in front of you? And**
8 **could you please explain what this document is for the**
9 **hearing examiner?**

10 A. So this is a stratigraphic chart for the
11 Delaware Basin based on Ron Broadhead's recent
12 publication for all of the Permian Basin in southeast
13 New Mexico. And what this does is shows you not only
14 the age framework that we're working with but also the
15 nomenclature that we're working with. And this will
16 become -- this can be an issue in some cases because in
17 different parts of the section, the way that the
18 geologists refer to the units is different than the way
19 an operator would refer to the units. And I'll clarify
20 that when we get to the cross sections.

21 And on this, I've also shown, for example,
22 where the freshwater resources within the basin tend to
23 be located, which is near the top in the Triassic and
24 Upper Permian rocks, and then showing the target
25 injection interval for the Mesaverde well with both the

1 Woodford Shale as the upper permeability barrier and the
2 Simpson Group as the lower permeability barrier.

3 And in terms of the nomenclature
4 differences between geology and -- geologists and
5 operators, most operators out here refer to what are
6 actually Silurian-age rocks as the slur of the Devonian
7 package that they're injecting into, but we're actually
8 only working with Silurian- to Ordovician-age rocks. So
9 I'm just clarifying (laughter).

10 EXAMINER McMILLAN: I'm glad that someone
11 is. That's always been -- everything I've read, it's
12 always stated that -- so basically all you're saying is
13 it's a driller's term, the "Devonian"?

14 THE WITNESS: Yeah.

15 MS. BRADFUTE: That's right. That's right.

16 EXAMINER McMILLAN: That's the best way to
17 describe it?

18 THE WITNESS: So in a minute, I'm going to
19 switch from geology to operator, and I'm going to switch
20 nomenclature. That's all.

21 **Q. (BY MS. BRADFUTE) Could you please turn to the**
22 **next exhibit, Exhibit Number 11, and explain what this**
23 **exhibit shows to the hearing examiner.**

24 A. So this is just a summary, a brief description
25 of the lithology of all the different rock units that

1 are at consideration for these deeper injection wells
2 starting with the Woodford Shale, which is our upper
3 permeability boundary. And this is simply a summary of
4 descriptions from various literature sources, including
5 Ron Broadhead and the Texas Bureau of Economic Geology's
6 work in the basin.

7 And so the units that are of question here
8 include the Woodford Shale as the upper permeability
9 boundary. The Wristen Group, which is -- and this is
10 again where we get into some of that nomenclature
11 issues. This is, in fact, a Silurian unit and not a
12 Devonian unit. And so this is simply to summarize
13 quickly for you the lithologies of the different units
14 that are in play.

15 So in this particular well, the Woodford
16 Shale is their upper permeability barrier. We'd be
17 looking at injecting into the Wristen Group, plus or
18 minus some part of the Fusselman Formation, probably not
19 very much of the Montoya Group, and then the Simpson
20 Group, lower permeability shale barrier. And then I
21 also included the Ellenburger Formation description for
22 completeness sake.

23 **Q. I want to go back and cover a couple of fine**
24 **points. You said that the Woodford Shale is going to be**
25 **the upper permeability barrier. What do you mean by**

1 **that?**

2 A. So in this case, the Woodford Shale is
3 primarily an organic-rich mudstone and has a very fine
4 grain. The unit's porosity and permeability are less
5 than the fractured vuggy limestones and old stones that
6 are below them, and so this acts as an upper seal in
7 this area. It's anywhere from 150 to almost 300 feet
8 thick right here, where there is a facies variation and
9 gives us a real nice thick Woodford Shale locally in
10 this area.

11 **Q. And in your opinion, does the Woodford Shale**
12 **Formation basically prevent water or injected fluids**
13 **from flowing upward?**

14 A. From migrating upwards.

15 **Q. Yeah, migrating upwards.**

16 And then I wanted to focus on the Simpson
17 **Group, what you described as being the lower**
18 **permeability barrier. Could you please describe what**
19 **you meant by that to the hearing examiner?**

20 A. So the Simpson Group is not quite so simple as
21 the Woodford Group. It can seem more heterogeneous in
22 terms of the different rock types that occur in it, but
23 it's dominated by shale beds. So, again, it has this
24 fine-grain material that's not going to be as porous and
25 permeable. And in this part of the basin, the Simpson

1 Group can be 650 to 700 feet thick, and so it would be
2 preventing downward migration of fluids into the
3 Ellenburger and on down into the Precambrian Basin,
4 which is something we would prefer to avoid.

5 Q. Yes.

6 Could you please next turn to Exhibit
7 Number 12 and explain what this is to the hearing
8 examiner?

9 A. So this is a structure contour map on the top
10 of the Precambrian. And I apologize that the white
11 contour lines didn't show up very well in the printing.
12 But there are very fine, white contour lines in there
13 that have 1,000-foot interval markings on them, and
14 that's the top of the Precambrian Basin in the area.
15 And it also shows the location of -- Precambrian-
16 penetrating faults go through the thick black lines that
17 occur both to the southwest and to the east of the well
18 location. It has the county boundaries on it for Eddy,
19 Chaves and Lea Counties.

20 And sort in the south-center part of the
21 figure, there are a series of small wellbores shown.
22 The white wellbores are other wells in the area that we
23 use to develop the cross sections that we'll look at in
24 just a moment, and the green-colored wellbore is the
25 Mesaverde well.

1 Q. And could you please turn to what's been marked
2 as Exhibit 13? And this exhibit has two different
3 pages. I want to focus on the first page. Could you
4 please explain what this document shows?

5 A. So this is a north-to-south cross section
6 through the Mesaverde wells, so you are looking east
7 into Texas. And the red arrow's indicating the position
8 of the Mesaverde well. And this is a little different
9 from some of the cross sections that we've -- that we've
10 looked at previously in that for many of these wells,
11 from the OCD Web site, I was only able to capture the
12 very lowest part of the well logs. They didn't have the
13 upper part of the well logs available. And so in order
14 for me to extrapolate upwards where the Woodford Shale
15 is in this area, I went through all of the well files to
16 find the completion documents to find the picks for the
17 tops of those units and then place them above the well
18 logs that I was able to clip out to make the cross
19 section with.

20 And so where it says "extrapolated picks
21 from the well files," that's where I projected the
22 Woodford Shale and the Mississippian Limestone above the
23 segments of the well logs so that I was able to gain
24 access to.

25 And the point of the cross section is these

1 are all hung from land surface, and so we're looking at
2 starting at 15,500 feet below ground surface where you
3 would start to encounter the top of the injection
4 interval.

5 And so here's where we're going to make the
6 switch from the geologist nomenclature to the operator
7 nomenclature, in that here where I have Ordovician-
8 Devonian, this is referring to that thick package of
9 limestone and dolostone at the injection interval, even
10 though as a geologist, I would call this the
11 Silurian-Ordovician, but I'm switching to operator
12 language now for the name for the target interval.

13 **Q. And could you please turn to the second page of**
14 **this exhibit and explain what this second page shows?**

15 A. So this is a west-to-east cross section looking
16 north, and again the red arrow showing where the
17 Mesaverde log is. And as with the previous cross
18 section, for the Mesaverde well and the Sand Dunes #2
19 well, I extrapolated the picks for the Woodford Shale
20 and the Mississippian Limestone based on information
21 from other sources that I was not able to show
22 graphically in this particular case. But showing again
23 below ground surface how far down we would encounter
24 these limestone, dolostone sequences that are the
25 targeted injection interval.

1 And in both cross sections, another
2 important observation is in looking at the various
3 well-log data that is available for the deepest part of
4 the basin, the geology is very homogeneous. We're
5 seeing these limestones and dolostones. We're not
6 seeing a whole lot of variation in lithology or
7 thickness through the targeted injection interval.

8 **Q. Ms. Zeigler, what conclusions have you drawn**
9 **from your geologic study of the area where the well is**
10 **going to be drilled -- or completed?**

11 A. That we have a good, thick section of these
12 limestone and dolostone units that have good porosity.
13 You're looking at a total package thickness of anywhere
14 from 2- to 3,000 feet for this injection interval, and
15 it has a solid shale, upper permeability barrier, as
16 well as a lower permeability barrier.

17 **Q. And during your study of the area, did you**
18 **locate any productive shales within the injection -- the**
19 **targeted injection zone?**

20 A. No. There were none observed in the area.

21 **Q. And is it your opinion that the Devonian within**
22 **the area where this well will be situated is**
23 **unproductive?**

24 A. True.

25 **Q. In your opinion, will increasing the tubing**

1 size to 7 inches by 5-1/2 inches impact correlative
2 rights of any mineral interest owners?

3 A. No.

4 Q. And in your opinion, will the granting of
5 Mesquite's application be in the best interest of
6 conservation, the prevention of waste and the protection
7 of correlative rights?

8 A. Yes.

9 Q. Were Exhibits 10 through 13 prepared by you or
10 compiled under your direction and supervision?

11 A. Yes.

12 MS. BRADFUTE: I'd like to tender Exhibits
13 10 through 13 into the record.

14 EXAMINER McMILLAN: Exhibits 10 through 13
15 may now be accepted as part of the record.

16 MS. BRADFUTE: That concludes my questions
17 of this witness.

18 (Mesquite SWD, Inc. Exhibit Numbers 10
19 through 13 are offered and admitted into
20 evidence.)

21 CROSS-EXAMINATION

22 BY EXAMINER McMILLAN:

23 Q. I guess I'm at Exhibit 11. You didn't really
24 describe the Montoya, but isn't Montoya the lower
25 barrier?

1 A. So the Montoya in this area is actually still
2 primarily a dolostone, and it's only probably about 50
3 feet thick here and sits right over the Simpson Group.
4 So the first place you start seeing more terrestrial
5 sediments that are going to include your shales and
6 mudstones is in the top of the Simpson.

7 **Q. But the Montoya is dolomite tight?**

8 A. Yes. They generally are.

9 **Q. If it's tight, then it's not going to allow any**
10 **downward migration of the fluids, correct?**

11 A. True. However, in this part of the basin, it
12 is so very thin --

13 **Q. It's difficult?**

14 A. -- but we actually may be north of the
15 pinch-out of the Montoya Group where this well is
16 located. If you look at the Texas Bureau isopach map
17 for the Montana Group, the zero line is actually
18 projected through potentially just south of this.

19 **Q. I didn't know that. I thought Montoya was**
20 **actually in Chaves County.**

21 **So how -- what's the gross interval for**
22 **Devonian to the Ellenburger in the well?**

23 A. In terms of?

24 **Q. Just gross thickness.**

25 A. Gross thickness? So if we start at the base of

1 the Woodford Shale -- so I'm excluding that Devonian
2 unit. Sorry. I'm clarifying nomenclature.

3 **Q. I just call it the Devonian.**

4 A. So the classic Silurian-Devonian operator
5 terminology, we're looking at probably on the order of
6 about 2,500 to 3,000 feet all the way down to what
7 little Montoya is there, plus or minus the top of the
8 Simpson Group.

9 **Q. It's 2,500 to 3,000 from the Silurian-Devonian**
10 **to the Ellenburger?**

11 A. To the base of the Woodford Shale to the top of
12 the Simpson Group.

13 MS. BRADFUTE: And that does not include
14 the Simpson?

15 THE WITNESS: That does not include the
16 Simpson. If you want to include the Simpson, add
17 another 700 feet.

18 **Q. (BY EXAMINER McMILLAN) It's 25- to 3,000 feet.**
19 **Close enough.**

20 MS. BRADFUTE: Yeah (laughter).

21 THE WITNESS: We'll know more the more of
22 these wells get drilled.

23 **Q. (BY EXAMINER McMILLAN) Yeah. I just want to**
24 **make sure for clarity purposes that there is a big**
25 **interval.**

1 A. Yes.

2 **Q. There is a barrier, not a baffle?**

3 A. Yes.

4 MS. BRADFUTE: Yes.

5 **Q. (BY EXAMINER McMILLAN) That's the biggest**
6 **thing.**

7 A. Absolutely.

8 EXAMINER BROOKS: What he was just
9 suggesting reminds me of Mr. Carr's tract of 40 acres
10 more or less. He said, "Every tract in the world is 40
11 acres more or less. It's either 40 acres, or it's more
12 or it's less."

13 (Laughter.)

14 MS. BRADFUTE: It's more here.

15 EXAMINER BROOKS: I have no questions.

16 EXAMINER McMILLAN: Thank you very much.

17 THE WITNESS: Thank you.

18 EXAMINER McMILLAN: Let's take a ten-minute
19 break.

20 EXAMINER BROOKS: There's been a suggestion
21 that you need to clarify for the record what you want
22 from Mr. Nave. Maybe you-all can talk about it during
23 the break, and when we get back on the record, a
24 statement can be made about what this is to consist of.

25 MS. BRADFUTE: Mike, my understanding was

1 that you wanted a description of the current fishing
2 operations.

3 EXAMINER McMILLAN: Yeah, just current
4 fishing operations.

5 EXAMINER BROOKS: The one you're doing --
6 working on for another client right now.

7 MR. NAVE: Another client, yes, sir.

8 EXAMINER McMILLAN: Yeah. So we can have
9 something for the record that shows it has been done.
10 That's what I'm really after. Kind of make sense?

11 MR. NAVE: Does to me.

12 MS. BRADFUTE: Yes.

13 (Recess, 3:32 p.m. to 3:39 p.m.)

14 EXAMINER McMILLAN: Back on the record.

15 MS. BRADFUTE: During the break, Mr.
16 Examiner, there was a discussion about the statement
17 that you requested earlier on in the hearing from
18 Mr. Nave. It is my understanding that we are going to
19 provide an affidavit from Mr. Nave that explains the
20 current fishing job that he is doing right now involving
21 similar tubing sizes that are at issue in this
22 application.

23 EXAMINER McMILLAN: Yes. Okay. Thank you.

24 MS. BRADFUTE: And I would like to call my
25 next witness, Mr. Wilson.

1 EXAMINER McMILLAN: Please proceed.

2 SCOTT WILSON,

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

5 DIRECT EXAMINATION

6 BY MS. BRADFUTE:

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

9 A. Scott Wilson.

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

11 A. I work for Ryder Scott Company.

12 Q. And what is your position at Ryder Scott?

13 A. I'm a senior vice president.

14 Q. And what are your responsibilities?

15 A. I teach classes in nodal analysis. I do
16 simulation studies, and I do technical consulting.

17 Q. And have you previously testified before the
18 Oil Conservation Commission?

19 A. Yes, ma'am.

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

22 A. Yes, ma'am.

23 Q. And are you familiar with the application
24 that's been filed by Mesquite in this case to increase
25 the tubing size and injection rates?

1 A. I am.

2 **Q. And have you conducted an engineering study**
3 **related to this application?**

4 A. I have.

5 MS. BRADFUTE: I'd like to tender
6 Mr. Wilson as an expert witness in petroleum engineering
7 matters.

8 EXAMINER McMILLAN: So qualified.

9 **Q. (BY MS. BRADFUTE) Could you please turn to what**
10 **has been marked as Exhibit Number 14 in front of you,**
11 **and could you please identify what this document is for**
12 **the hearing examiner?**

13 A. This is a graph that represents the injection
14 rate versus wellhead pressure that you would see in a
15 typical well completed with 5-1/2 by 4-1/2-inch tubing.
16 That's the red line.

17 The blue diamonds are actual measured data
18 from the Sand Dunes #2 well, which is fairly close to
19 this well. It's three to four miles away. And the
20 green line represents what this well would do if it had
21 7-inch by 5-1/2-inch tapered string in it.

22 **Q. We're going to come back to this exhibit in a**
23 **moment, but I would kind of like to turn to Exhibit 15.**
24 **And my understanding is that Exhibit 15 relates to the**
25 **chart that you were just discussing, correct?**

1 A. It does.

2 **Q. And could you please explain what Exhibit 15**
3 **is?**

4 A. Exhibit 15 is a classic nodal analysis plot
5 with total liquid rate across the bottom of the x-axis
6 and flowing bottom-hole pressure and injecting
7 bottom-hole pressure on the y-axis.

8 The analogy to describe how this works is
9 like you have a bucket and you put it on a pile of sand,
10 and then you fill that bucket with water. So the black
11 line -- the black-dashed line represents how much water
12 would drain out of the bucket if it has a small hole in
13 the bottom. And as the bucket fills up, more water will
14 drain out of the bucket. So that's how the reservoir
15 acts as you push more fluid into it.

16 The other two lines represent the fluids
17 that are filling up the bucket. So if you have a faucet
18 above that and you're filling it up slowly, it looks a
19 little bit like the orange line. So you're filling
20 fluids in. You have a lot of pressure drop through the
21 valve in the faucet, and you'll have a static fluid
22 level that will take small amounts of fluid and also at
23 low pressures.

24 If you open up that valve, you're taking
25 away some of that friction, and the fluid level in the

1 bucket will go up and cause the hole to drain more
2 fluid, and it will cause a new equilibrium to be set.
3 So that's what nodal analysis is.

4 **Q. Exhibit 15 is a diagram that shows the nodal**
5 **analysis that's been performed for this case?**

6 A. It is, with two different tubing sizes.

7 **Q. Okay. And the blue line is the 7-inch by 5-1/2**
8 **inch?**

9 A. Correct.

10 **Q. And the orange line is 5-1/2 by 4-1/2-inch**
11 **tubing, which is what has been previously authorized by**
12 **the Division?**

13 A. Yes, ma'am.

14 **Q. I want to now flip back to Exhibit Number 14.**
15 **Does Exhibit Number 14 provide a summary of what your**
16 **nodal analysis shows?**

17 A. It does. This relates to all pressures and
18 measurements at the surface. So on the left, the y-axis
19 is wellhead injection pressure.

20 **Q. Okay. And based on your nodal analysis, what**
21 **observations have you made concerning increasing the**
22 **tubing size for this well?**

23 A. If you use larger tubing sizes, you have less
24 frictional pressure drop.

25 **Q. Could you please turn to Exhibit Number 16?**

1 **And the title of this exhibit is "Increased injection**
2 **rate per well equates to fewer injectors," correct?**

3 A. It is, yes.

4 **Q. Could you please explain to the hearing**
5 **examiner what this graph shows?**

6 A. This graph is a different visualization of the
7 prior exhibit, Number 15, and it shows the two solution
8 points at 41,000-barrels injection per day and roughly
9 an average tubing size of 2.67 for the first string.
10 And then -- that's the upper, right-hand point. So
11 that's the predicted performance of that well at 1,700
12 psi injection pressure.

13 And then if you make the tubing smaller,
14 which is the x-axis -- so as you go to smaller tubing
15 sizes, your injection rate decreases, and that one shows
16 29,000 barrels a day.

17 **Q. So is it your opinion by increasing the tubing**
18 **size for the Mesaverde SWD #3 well, there will be less**
19 **need for additional wells within the area?**

20 A. That's correct. The table inset shows at
21 various total injection demand how many wells you will
22 potentially need to meet that demand. And so at 100,000
23 barrels of injection per day, you need four wells with
24 the smaller tubing description, and you'd only need
25 three wells with the larger tubing description.

1 **Q. Okay. Could you please turn to the next**
2 **exhibit, Exhibit Number 17, and could you please explain**
3 **what this document shows?**

4 A. This document is fairly complex. It shows
5 along the x-axis injection rate in barrels per day. The
6 y-axis shows either surface- or bottom-hole injection
7 pressure. And starting at the top, the light blue
8 dashed, the dot line, shows the fracture pressure
9 predicted potentially using a .45 gradient and .2-psi-
10 per-foot surface pressure requirement.

11 And the blue-dashed line that angles up
12 from the left to the right is the reservoir performance,
13 the injection performance at various injection rates.
14 And you can see at zero injection, it's effectively the
15 reservoir pressure of 7,750 under these conditions.

16 And then on the far right side, of 50,000
17 barrels a day, you can see we're about halfway to the
18 fracture pressure -- predicted fracture pressure. So
19 that -- in order for that blue-dashed line to actually
20 intercept with the fracture pressure, I'd have to expand
21 this scale out to 100,000 barrels a day or --

22 **Q. Okay. And here, Mesquite is seeking a maximum**
23 **injection rate of 40,000 barrels per day; is that**
24 **correct?**

25 A. That's correct.

1 **Q. And so at 40,000 barrels per day, when I look**
2 **at the dark blue line in comparison to the lighter blue**
3 **line, you're nowhere near the fracture pressure point?**

4 A. There is still a couple thousand psi
5 difference. Yes.

6 **Q. So in your opinion, is there any risk of**
7 **creating fractures within the formation if the Division**
8 **allows an injection rate of 40,000 barrels per day?**

9 A. No. There is no risk of that. And there is --
10 a second reason for that is the maximum wellhead
11 injection pressure is 3,324. So if we were to try to
12 exceed that, the flow rate would drop, so we'd never get
13 above that pressure.

14 **Q. And I know when I look at the bottom part of**
15 **this graph, you have an orange line, kind of a turquoise**
16 **line, a red line, green line, purple line. Could you**
17 **explain what those lines represent?**

18 A. So those four lines represent the frictional
19 pressure drop at various injection rates. So starting
20 at the top with 4-1/2-inch ID tubing, it exerts a
21 frictional drop of -- say at 50,000 psi -- almost 5,000
22 psi of friction. The 5-1/2 by 4-1/2-inch tubing has a
23 frictional pressure drop of roughly 3,000 psi.

24 The reservoir, when it's being injected, at
25 40- to 50,000 barrels a day, has a pressure drop of

1 1,500 psi. And then the last one, 7-inch by 5-1/2-inch
2 tubing has maybe 750 psi frictional pressure drop at
3 those rates.

4 Q. So there is less friction when larger tubing
5 sizes are --

6 A. Yes, ma'am.

7 Q. Okay. Could you please turn to the next
8 exhibit, Exhibit Number 18, and explain what this
9 document shows to the hearing examiner?

10 A. Exhibit 18 shows the map that was presented
11 earlier in one of the prior exhibits of a four-township
12 area. That's with the subject well roughly in the
13 center. To the right, that big, red box is a simulation
14 grid with the wells placed approximately at the same
15 place as they are in reality.

16 Q. Okay. And so the red box over here, you're
17 just making a diagram representation to show that those
18 wells have been plotted into your modeling software?

19 A. That's correct.

20 Q. Okay. Could you please turn to the next
21 exhibit, Exhibit 19, and explain what this document
22 shows?

23 A. Exhibit 19 shows that same grid. And the view
24 there is of the pressure -- injection pressure and the
25 reservoir pressure. And so on right-hand side, I have a

1 contour grid that shows the blue as the original
2 reservoir pressure and the red hues as the increased
3 pressure in the reservoir at those locations. It's
4 difficult to read that contour map, so I plotted it in a
5 different way. It's basically the same data but plotted
6 three dimensionally so you can see how much of that red
7 is actually the higher pressure. So it shows that the
8 highest pressure at ten years after injecting 40,000
9 barrels a day is roughly 9,500 psi.

10 **Q. Okay. And by pressure increases, it's not the**
11 **same as how far the fluid is going to migrate within the**
12 **formation; is that correct?**

13 A. That's correct. It's like you can hear a
14 person speaking from miles away, but you can't actually
15 touch them. So that's the fluids that have gone into
16 the formation in this grid I've shown on the next
17 exhibit.

18 **Q. Okay. Let's turn to that exhibit, Exhibit**
19 **Number 20. Could you please explain what this document**
20 **shows?**

21 A. So this shows the actual saturation of the
22 injected fluid versus the native fluids in the reservoir
23 at the same time point. So at ten years out, the fluids
24 have moved that far away from the well, as indicated by
25 that little contour map.

1 **Q.** And were you present earlier for testimony
2 related to where the next closest well was located in
3 comparison to the Mesaverde SWD #3 well?

4 **A.** I was present. Yes.

5 **Q.** Okay. And on here, on the left-hand grid, it
6 looks like the Mesaverde well is located next to this
7 little rainbow circle?

8 **A.** That's correct. It's in the center of that
9 circle.

10 **Q.** And then the next closest well was the well
11 that was previously discussed, correct?

12 **A.** Correct.

13 **Q.** Just over a mile away?

14 **A.** It is, yes.

15 **Q.** Okay. And you can see that that rainbow
16 circle, which is the area where fluids are migrating to,
17 is still a decent distance away from that closest well?

18 **A.** Correct. And it's even larger than you would
19 expect because that's a radial space that's growing.

20 **Q.** Yeah.

21 **A.** So your distance is going to be a square of the
22 volume that goes into that. So if I doubled the volume
23 inside that little cone, it would only move that
24 distance a little ways.

25 **Q.** Interesting. Okay.

1 **Okay. Could you please turn to the next**
2 **exhibit, Exhibit Number 21, and identify what this**
3 **document shows?**

4 A. Okay. So this document shows the pressure
5 impact at various locations over time. And this is
6 running for 20 years, so 7,300 days. And so the maximum
7 bottom-hole injection pressure is that red-dashed bar at
8 the top.

9 The bottom black bar, which is about 7,500
10 psi, is the original reservoir pressure. As you can
11 see, even at great distances away, the pressure impact
12 is seen because of the big, continuous grid, but the
13 magnitude of those differences is very small and
14 probably not measurable in most cases.

15 **Q. And, Mr. Wilson, could you turn to Exhibit**
16 **Number 22 and explain what this document shows?**

17 A. So to test whether injection into this well
18 would affect other wells, I arbitrarily turned on the
19 two closest wells to this well at about five years into
20 the life of this well and then injected also at 40,000
21 barrels a day, and these are the two profiles that I
22 arrived at after 20 years of injection for the first
23 well.

24 **Q. So in your opinion, will the use of 7-inch by**
25 **5-1/2-inch tubing have a significant impact if there are**

1 **additional existing injection wells within the area?**

2 A. No, not at these distances.

3 **Q. And based on your study of the formation and**
4 **the modelings that you've performed for this**
5 **application, what are your conclusions concerning this**
6 **application's overall impact on the formation?**

7 A. This -- this increased injectivity is entering
8 a very large structure and so the pressure dissipates
9 easily. It takes a long time for the fluids to move far
10 away from this well, since it is such a thick zone. So
11 it won't necessarily affect any of the offset operators
12 to a great extent.

13 **Q. Okay. And it will not have a significant**
14 **impact on pore pressure?**

15 A. No. The overall pore pressure picture is shown
16 on Exhibit 21. And after 21 -- after 20 years, the
17 increase in average grid pressure is only -- it's that
18 dark black line you can't see. It moved off of the
19 space there.

20 **Q. And in your opinion, will injecting into this**
21 **well at the proposed amount significantly impact other**
22 **injection well operations in the area?**

23 A. No. It should not affect them significantly.

24 **Q. And in your opinion, will the granting of**
25 **Mesquite's application be in the best interest of**

1 **conservation, the prevention of waste and the protection**
2 **of correlative rights?**

3 A. Yes, it would.

4 **Q. And were Exhibits 14 through 22 prepared by you**
5 **or compiled under your supervision and direction?**

6 A. Yes, they were.

7 MS. BRADFUTE: I'd like to move the
8 admission of Exhibits 14 through 22 into the record.

9 EXAMINER McMILLAN: Exhibits 14 through 22
10 may now be accepted as part of the record.

11 (Mesquite SWD, Inc. Exhibit Numbers 14
12 through 22 are offered and admitted into
13 evidence.)

14 CROSS-EXAMINATION

15 BY EXAMINER McMILLAN:

16 **Q. So I'm asking you -- referring to Exhibit 21,**
17 **so that I'm understanding this, the black line**
18 **represents the bottom-hole pressure?**

19 A. The black line represents the average reservoir
20 pressure for the entire grid.

21 **Q. Average. Okay.**

22 A. And that's labeled at the very bottom of the
23 inset legend.

24 **Q. Okay. And then where's the -- where's the**
25 **5-1/2-inch tubing on this?**

1 A. This -- this grid was modeled at 40,000 barrels
2 a day --

3 **Q. Okay.**

4 A. -- and the 5-1/2 would not achieve that kind of
5 rate, so this is the result of 40,000-barrels-a-day
6 injection on three wells.

7 REDIRECT EXAMINATION

8 BY MS. BRADFUTE:

9 **Q. So this chart assumes that there are three**
10 **wells injecting 40,000 barrels per day?**

11 A. That's correct. And you can see that impact.
12 The little red line that kicks up right at the
13 beginning, times zero, that's the first well that goes
14 on injection. And the pressure comes up to about 9,700
15 pounds and then continues across to the right.

16 Now, at roughly 1,800 days, you see two
17 more lines kick up from the big grouping near the
18 bottom. Those are the second and third wells that go on
19 injection, also 40,000 barrels a day. So they were able
20 to make the same rate even though the well next to them
21 was injecting at that rate.

22 CONTINUED CROSS-EXAMINATION

23 BY EXAMINER McMILLAN:

24 **Q. So you're saying 40,000 barrels is never really**
25 **going to reach the maximum injection pressure?**

1 A. No, not in this case.

2 **Q. Is that the point of this?**

3 A. Yeah, that's mostly the point.

4 The other point is that you don't see a lot
5 of pressure distances away from these wells because the
6 magnitude of volumes aren't large enough to make a
7 difference. The structure's just so big.

8 **Q. Exhibit 17 just shows the pressure drops with**
9 **the different tubing sizes, right?**

10 A. Correct.

11 **Q. And then what does Exhibit 15 show?**

12 A. Oh, Exhibit 15 is the classic nodal analysis
13 plot. That's the plot that you use to kind of generate
14 all the rest of the subplots. And that shows the
15 reservoir IPR curve and the two tubing hydraulics curves
16 as single-well head pressure. So that's kind of the raw
17 materials to build the rest of the analysis.

18 **Q. Okay. What reservoir parameters did you use?**

19 A. On this one -- the values on Exhibit 15? The
20 reservoir pressure is 7,750 psi. The permeability was
21 7.2 millidarcies, and that was the match parameter I
22 used to match the Sand Dunes well. And then the kh --
23 the resulting kh is 10,800. And this is all listed in
24 the upper, left-hand corner of that image.

25 **Q. Okay.**

1 A. And that was roughly 1,500 feet of thickness.
2 So if the thickness was greater than that, it would
3 actually just improve these numbers, and the formation
4 would be able to take even more.

5 **Q. Okay.**

6 EXAMINER BROOKS: No questions.

7 MS. BRADFUTE: That concludes my questions
8 of this witness.

9 EXAMINER McMILLAN: Thank you very much.

10 THE WITNESS: Sure.

11 MS. BRADFUTE: And I'd like to call my last
12 witness, Sue Bilek.

13 SUSAN L. BILEK,
14 after having been previously sworn under oath, was
15 questioned and testified as follows:

16 DIRECT EXAMINATION

17 BY MS. BRADFUTE:

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

20 A. Susan Bilek.

21 **Q. And, Ms. Bilek, who do you work for?**

22 A. New Mexico Tech.

23 **Q. And what is your position at New Mexico Tech?**

24 A. I'm a professor of geology. I specialize in
25 earthquake studies.

1 **Q. And could you just briefly explain what you do**
2 **when you study earthquake studies for the hearing**
3 **examiner?**

4 A. Sure. So in my job, I teach classes on
5 seismology, earthquakes, and my research involves doing
6 earthquake location studies so locating earthquakes,
7 determining size of earthquakes, relating them to
8 faults.

9 **Q. And have you previously testified before the**
10 **Oil Conservation Commission?**

11 A. Yes.

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

14 A. Yes.

15 **Q. And are you familiar with the application**
16 **that's been filed by Mesquite in this case to increase**
17 **the tubing size?**

18 A. Yes.

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

21 A. I have.

22 MS. BRADFUTE: I'd like to tender this
23 witness as an expert in seismology.

24 EXAMINER McMILLAN: So qualified.

25 **Q. (BY MS. BRADFUTE) Ms. Bilek, could you please**

1 **turn to what's been marked as Exhibit Number 23 in the**
2 **packet in front of you, and could you please identify**
3 **what this document is for the hearing examiner?**

4 A. This exhibit outlines some of the results and
5 parameters I used in the study looking at the potential
6 for slip on faults in the area due to injection.

7 **Q. And was this study conducted using the Stanford**
8 **University fault slip model -- or the Fault Slip**
9 **Probability [sic] tool?**

10 A. Yes, it was.

11 **Q. And what is this tool commonly used for?**

12 A. This tool was developed to look at the -- to
13 estimate the probability of slip on a given fault due to
14 injection, so it allows you to define a model where you
15 can put in faults. You can also put in geologic
16 parameters. You can build a hydrologic model, and then
17 with given rates of injection, look at the probability
18 of slip on the fault.

19 **Q. Okay. And has this tool been accepted and**
20 **relied upon by other seismologists?**

21 A. Yes. This tool was -- the methodology was
22 published in 2016 in the "Journal of Geology," which is
23 a peer-reviewed, well-respected journal on earth
24 sciences.

25 **Q. And I want to focus on the first page of this**

1 exhibit. Could you please walk through the first page
2 for the hearing examiner and show -- explain what is
3 shown in the diagram on the right-hand side and then on
4 the table on the left-hand side of this page?

5 A. Sure. So I ran a number of -- 240 simulations
6 with this tool where I put in the location and an
7 orientation of faults in the area of interest but then
8 modified things like the background stress conditions,
9 modified the dip of the fault and then defined a
10 hydrologic model and then ran simulations to see what --
11 at the injection rates given, what would be the
12 probability of slip on the faults that I put inside the
13 model.

14 So what's shown here on the right-hand side
15 is just a graph of the different simulations, the number
16 of simulations there on the y-axis. On the x-axis is
17 the fault slip potentials. This is the number that you
18 determine -- you estimate from this tool for a given
19 fault, so you can estimate the probability of slip on
20 that fault.

21 So you can see that the vast majority of
22 these 240 simulations produced a fault slip potential of
23 zero in the fault that I put into the model. And a
24 handful of them had higher fault slip potentials largely
25 due to the orientation of one of the faults in the

1 model, which we can go into in a little bit.

2 The table that's on the left outlines the
3 parameters that I used in the model, so you can define
4 the orientation of the background stress field. And
5 those are the first two lines, SHmax and APhi. I
6 provide the range of values that I used in the
7 simulations, and these values are based on published
8 data for the given area.

9 So the SHmax, the orientation of the
10 maximum horizontal stresses, come from ranges in the
11 World Stress Map that has been published to southeast
12 New Mexico and West Texas.

13 APhi, again, related to the horizontal
14 stresses based on published data from Hurd and Zoback in
15 2012, again from southeast New Mexico and West Texas.

16 The next three lines detail information
17 about the hydrologic model that's used, and the values I
18 chose in here largely match what Scott presented in the
19 previous set of exhibits.

20 And then the final two relate to the fault
21 conditions. So, you know, we have mapped faults. We
22 know the orientation of the faults, the strike of the
23 faults, but the dip of the faults are not constrained.
24 So I used a range of values of fault dip that are
25 reasonable for faults in this area -- the uncertainty of

1 that.

2 And then the fault friction, I used a range
3 of values here that are what we would expect for the
4 rocks in this area. So those are again based on the
5 geologic conditions of the area.

6 **Q. Okay. And the majority of the models that you**
7 **tested led to a zero percent fault slip potential,**
8 **correct?**

9 A. Yes.

10 **Q. Okay. So that would be a likely zero percent**
11 **chance of creating a seismic event due to injection?**

12 A. Yes.

13 **Q. And if you could please turn to the next page**
14 **of this exhibit, could you please explain what this map**
15 **shows?**

16 A. This is the model geometry that I used for all
17 of the simulations. So what's shown on here, the black
18 lines are the locations of the Precambrian faults that
19 come from the Texas Geology Bureau -- the Bureau of
20 Economic Geology maps. These are what Kate had shown
21 previously. So these are the locations of the faults in
22 my model.

23 And then the squares with all of the
24 letters and numbers here are the locations of both the
25 Mesaverde well, which is the well of interest here, as

1 well as the other Mesquite wells that are in the area
2 that had applications previously.

3 Q. And so in this -- in this test that you ran and
4 all of the different simulations that you ran, you
5 entered injection rates for all of the wells that are
6 shown on this diagram?

7 A. Yes.

8 Q. So they would all be injecting at the same
9 time?

10 A. They're all injecting at the maximum rate
11 that's been applied for for the entire time period of
12 the simulation.

13 Q. And could you please turn to the next page of
14 this exhibit and explain what this diagram shows?

15 A. So this is the injection rates for each of the
16 wells on the previous page. The red line is the
17 Mesaverde well, and then the outer lines are the
18 injection rates for the other wells. And there are just
19 multiple lines. You can't see them all because some of
20 them have the same rates.

21 So this is done for about 40 years,
22 injecting at the maximum rate for 40 years of all of
23 these wells for all of the simulations. That didn't
24 change.

25 Q. Could you please turn to the next page of this

1 **exhibit and explain what is shown?**

2 A. This is the result for -- a representative
3 example of the fault slip potential simulations. So
4 I'll step through what the plot is here.

5 On the left-hand side, we see a list of the
6 faults. So I had four faults in the model that I had
7 shown in one of the previous slides. It outlines the
8 fault number and the fault slip potential that was
9 calculated for that particular simulation. And in this
10 case, all of the four faults had a zero fault slip
11 potential.

12 In the middle, you can see a cutout there
13 of the same geometry map that was shown before. There
14 are four faults on there, the westernmost one. There is
15 a tiny, little segment down here at the bottom,
16 left-hand corner of the box. That's fault number one.
17 And then faults two, three and four are the eastern
18 faults. You can see in the middle of that is the -- are
19 all of the wells that I have in the model, and I've
20 highlighted that Mesaverde well in there.

21 But, again, I put in that maximum injection
22 for all of the wells, so all of the wells are
23 contributing in here.

24 The colors that you see are the pore
25 pressures that you would expect based on injection from

1 all of these wells after 40 years.

2 **Q. Okay. And so what are your conclusions after**
3 **running these simulations shown here?**

4 A. So as I said, this is a representative handful
5 where all of those faults, we end up getting to zero on
6 the fault slip potential due to injection from these
7 wells, one of the main reasons that these wells are far
8 from these faults that are mapped.

9 **Q. Yeah. So a big part of this analysis -- or a**
10 **big part of your conclusions of analysis relates to the**
11 **distance of the proposed well from the known faults?**

12 A. Yeah. The pore pressures that are generated
13 from injection in these wells are not getting to the
14 faults -- the mapped faults in the time period that
15 we're looking at.

16 **Q. And if you turn to the next page of this**
17 **exhibit, could you please explain what that document**
18 **shows?**

19 A. This is another example -- or one of the
20 results of the simulation. And so I did mention at the
21 very beginning that there were some cases -- some
22 simulations where one of the faults had a
23 greater-than-zero fault slip potential that was
24 computed. And that's a case here. That westernmost,
25 little, tiny segment of a fault back there has an

1 elevated fault potential, 36 percent chance of slipping.
2 But I note that, you know, that happens starting at time
3 zero. This is not because of the injection. This is
4 because of the geometry of the fault and the stress
5 parameters that I used for that simulation.

6 So I tried a range of possible stress
7 parameters and fault frictions. And so for some
8 combinations of those, you get an elevated fault slip
9 potential in that westernmost fault. Again, you're not
10 seeing an increase of fault potential time. It turns on
11 when I start the simulation just because of the geometry
12 and the stress conditions during that simulation.

13 **Q. So is it your opinion that you are seeing some**
14 **fault slip potential in that particular fault due to**
15 **just the geologic conditions there and the stress**
16 **parameters you're putting in?**

17 A. Yes.

18 **Q. And those stress parameters have nothing to do**
19 **with the injection?**

20 A. Yes. They are background stress conditions,
21 background tectonic stress conditions. The orientation
22 of that fault is actually also different than the
23 orientation if you just look at the map. The strike
24 with respect to north is different than those
25 easternmost faults, which is why that one is getting a

1 certain stress condition turned on versus the other one.

2 Q. Okay. And those stress conditions -- that
3 fault slip potential would not change if injection
4 started in the area? It wouldn't decrease or increase
5 as a result of injection?

6 A. No, because that fault is still, you know, 30
7 kilometers away from the closest of the injection wells.

8 Q. Okay. Great.

9 Could you please turn to the next exhibit,
10 Exhibit Number 24? And this exhibit has two pages, and
11 I want to first look at the first page, which should be
12 an analysis, kind of a summary page document. Could you
13 please explain what this document shows?

14 A. So this is a prescription of the earthquake
15 catalog for this part of southeast New Mexico, and this
16 is based on analysis of catalogs of earthquakes from the
17 U.S. Geological Survey where they publish earthquake
18 catalogs for around the world but also based on data
19 that we have at New Mexico Tech. New Mexico Tech has
20 been operating a network of seismic instruments in this
21 area since the 1970s. And so we have a catalog of
22 earthquakes that go to even smaller magnitudes than the
23 U.S. Geological Survey can produce going back decades.

24 So this first page is just a list of the
25 earthquakes in the area within 25 kilometers, about 15

1 miles, from this well between 1962 and March of this
2 year. So this first page catalogs the 17 -- or sorry --
3 the seven earthquakes that occurred within 25
4 kilometers, about 15 miles, of this well since 1962.
5 The largest earthquake in this catalog is a magnitude
6 3.2 that happened in 1997. And that happened greater
7 than 20 kilometers from the well. And then this last
8 year, there were two earthquakes. Both of them were
9 less than magnitude 2. They were a magnitude 1 and a
10 magnitude 1.2. These are tiny earthquakes that no one
11 feels. We can record them because we have these
12 instruments -- these very sensitive instruments close to
13 this area.

14 **Q. Okay. And just for reference, you said that a**
15 **magnitude 1.2 earthquake is something you can't feel.**
16 **What would a magnitude 3.2 be like?**

17 A. So a magnitude 3 earthquake may be felt by
18 people, especially if they're indoors and not moving
19 around very much. It might feel like a truck driving
20 by.

21 **Q. But not a significant seismic event?**

22 A. No.

23 **Q. And can you please turn to the next page of**
24 **this exhibit and explain what this document shows?**

25 A. So this just shows in map form the previous

1 discussion, so we're looking at the earthquakes -- the
2 earthquake locations in this part of southeast New
3 Mexico going back to 1962 up through March of this year.

4 The circles are the earthquake locations,
5 and the size of the circle is related to their
6 magnitude. The color of the circle relates to when the
7 earthquake happened. Also included on here are the
8 locations of the wells. The Mesaverde well is the red
9 square. The other Mesquite wells in the area are these
10 gray squares. The stars are the seismic instruments
11 that New Mexico Tech operates within this area, and then
12 the red lines are these Precambrian faults. These are
13 the ones that end up in the model and the ones that Kate
14 also showed in her testimony.

15 **Q. So since in 1962, there have been seven**
16 **different seismic events within 25 kilometers of where**
17 **the well is located?**

18 A. Right. So that's within the dashed box around
19 the Mesaverde well.

20 **Q. In your opinion, does that amount to a**
21 **significant amount of seismic activity within this area?**

22 A. No. This is, you know, representative of the
23 background level of very small earthquakes. And, again,
24 we have these in our catalogs because we operate the
25 seismic stations very close to the area. If we didn't

1 have these stations there, you would never see these
2 earthquakes at magnitude 1 and 2 levels. The U.S.
3 Geological Survey, they'll produce catalogs going down
4 to magnitude 3-1/2 to 4, but we're seeing these
5 magnitudes at magnitude 1.

6 **Q. So what does this information tell you about**
7 **the suitability of the injection well using increased**
8 **tubing in the area?**

9 A. So the wells that are here are within -- are
10 further than 15 to 20 miles from these larger faults,
11 which there is not a lot of seismicity outside of these
12 faults, so it seems like a particularly good area to be
13 away from those faults and be away from a significant
14 earthquake-producing area.

15 **Q. And it's also very nice that New Mexico Tech**
16 **has several monitoring stations within the area?**

17 A. Right. And so these stations, again, have been
18 operating since the 1970s, so we actually have a very
19 good record of the seismic activity in this area. And
20 we continue to operate them, so they are still there,
21 you know, to keep monitoring these activities.

22 **Q. So what conclusions have you drawn from your**
23 **study of the area?**

24 A. That the seismicity within the area of the
25 wells is very small and very limited in number. And

1 then with the fault slip potential modeling, these
2 mapped faults are, again, far enough away from the area
3 of injection that the pore pressures are not continuing
4 to cause increased fault slip potential.

5 **Q. And were Exhibits 23 and 24 prepared by you or**
6 **compiled under your supervision and direction?**

7 A. Yes.

8 MS. BRADFUTE: And I'd like to tender
9 Exhibits 23 and 24 into the record.

10 EXAMINER McMILLAN: Exhibits 23 and 24 may
11 now be accepted as part of the record.

12 (Mesquite SWD, Inc. Exhibit Numbers 23 and
13 24 are offered and admitted into evidence.)

14 MS. BRADFUTE: And that concludes my
15 questions for this witness.

16 EXAMINER McMILLAN: I don't have any real
17 questions in this area.

18 Do you?

19 EXAMINER BROOKS: No.

20 (Laughter.)

21 EXAMINER BROOKS: As a matter of fact, I
22 don't have any imaginary ones either.

23 (Laughter.)

24

25

1 CROSS-EXAMINATION

2 BY EXAMINER McMILLAN:

3 Q. My question is: If you look at -- is the
4 faulting data raw because they actually injected into
5 the Ellenburger and slipped into --

6 A. Well --

7 Q. Is that a safe -- is that too generic?

8 A. I'm not sure I want to comment -- I don't know
9 the --

10 Q. You don't know. Okay.

11 A. I don't know the injection levels there, so I'm
12 not going to comment.

13 Q. Okay. They're actually injecting into the
14 Ellenburger and the Precambrian?

15 A. In -- in other places, injecting into the
16 basement -- the Precambrian basement has led to
17 increased seismicity in -- in other areas around the
18 country. So --

19 Q. Okay. Well, there -- there is the example of
20 the Dagger Draw -- injected into it. That's why I
21 picked it.

22 A. Yes. And so -- but I would suspect that that
23 is the reason, but I am not going to -- I haven't
24 done --

25 Q. That's fine. That's fine. Nice presentation.

1 **Great.**

2 MS. BRADFUTE: We ask that this case be
3 taken under advisement. That concludes my presentation.

4 EXAMINER McMILLAN: Okay. So Case Number
5 16308 shall be taken under advisement. Thank you very
6 much.

7 Nice presentation, everyone.

8 MS. BRADFUTE: Thank you.

9 (Case Number 16308 concludes, 4:21 p.m.)

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1 STATE OF NEW MEXICO
2 COUNTY OF BERNALILLO

3

4 CERTIFICATE OF COURT REPORTER

5 I, MARY C. HANKINS, Certified Court
6 Reporter, New Mexico Certified Court Reporter No. 20,
7 and Registered Professional Reporter, do hereby certify
8 that I reported the foregoing proceedings in
9 stenographic shorthand and that the foregoing pages are
10 a true and correct transcript of those proceedings that
11 were reduced to printed form by me to the best of my
12 ability.

13 I FURTHER CERTIFY that the Reporter's
14 Record of the proceedings truly and accurately reflects
15 the exhibits, if any, offered by the respective parties.

16 I FURTHER CERTIFY that I am neither
17 employed by nor related to any of the parties or
18 attorneys in this case and that I have no interest in
19 the final disposition of this case.

20 DATED THIS 23rd day of July 2018.

21

22

23 MARY C. HANKINS, CCR, RPR
24 Certified Court Reporter
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