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 NGL WATER SOLUTIONS PERMIAN, LLC TO APPROVE SALTWATER DISPOSAL WELLS, LEA COUNTY, NEW MEXICO.

CASE NOs. 20139, 20143

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

February 21, 2019

Santa Fe, New Mexico

BEFORE: PHILLIP GOETZE, CHIEF EXAMINER
MICHAEL McMILLAN, TECHNICAL EXAMINER
TERRY WARNELL, TECHNICAL EXAMINER
DAVID K. BROOKS, LEGAL EXAMINER

This matter came on for hearing before the New Mexico Oil Conservation Division, Phillip Goetze, Chief Examiner; Michael McMillan and Terry Warnell, Technical Examiners; and David K. Brooks, Legal Examiner, on Thursday, February 21, 2019, at the New Mexico Energy, Minerals and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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EXHIBITS OFFERED AND ADMITTED

(8:34 a.m.)

EXAMINER McMILLAN: So the first case we're going to call is Case Number 20139, application of NGL Water Solutions Permian, LLC to approve saltwater disposal well in Lea County, New Mexico.

Call for appearances.

MS. BENNETT: Good morning, Hearing Examiners. My name is Deana Bennett. I'm here on behalf of NGL, and with me today is Zoe Lees. And we've actually asked that these two cases be consolidated today. The two cases are 20139 and 20143, and those are the Asroc and Viper cases. And we have -- we do have witnesses for those cases, but I've consolidated the exhibits for those cases.

EXAMINER McMILLAN: Any objections to this?

MS. ANTILLON: Yes, Mr. Examiner.

Once again, my name is Andrea Antillon. I'm here on behalf of the State Land Office, and we don't have any witnesses to present today, but we would like to make a statement for the record.

EXAMINER McMILLAN: Go ahead.

MS. ANTILLON: The State Land Office is reviewing this application and in particular the Viper Saltwater Disposal No. 1 application, and we have some concerns with the saltwater disposal well spacing due to its close proximity to State Trust Lands.

EXAMINER McMILLAN: Okay. So do you have any objection to combining the cases?

MS. ANTILLON: Oh. No. I don't have any objection to that.

But I would like to clarify that our concerns are with Case 20143, not 20139.

EXAMINER McMILLAN: Okay. And if the witnesses would --

MS. BENNETT: Sure. I think there is another appearance.

EXAMINER McMILLAN: Another appearance?

MR. RANKIN: Thank you, Mr. Examiner. Adam Rankin with the law firm of Holland & Hart. We have entered appearances in both cases on behalf of EOG Resources.

EXAMINER McMILLAN: Okay. Phillip Goetze will be handling the cases.

EXAMINER GOETZE: So will the witnesses please stand up, identify yourself to the court reporter and be sworn in?

MR. DUNCAN: Neel Duncan.

DR. ZEIGLER: Kate Zeigler.

DR. TAYLOR: Steven Taylor.

MR. WILSON: Scott Wilson.

MR. REYNOLDS: Todd Reynolds.

(Mr. Duncan, Dr. Zeigler, Dr. Taylor, Mr. Wilson and Mr. Reynolds sworn.)

MS. BENNETT: Thank you.

At this time I'd like to call my first witness, which is Mr. Neel Duncan.

NEEL L. DUNCAN,

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

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Mr. Duncan, can you please state your name for the examiners?

A. Neel Lawrence Duncan.

Q. And for whom do you work?

A. Integrated Petroleum Technologies as managing director.

Q. And have you been retained by NGL?

A. I have.

Q. What are your responsibilities for NGL?

A. For drilling and development of SWDs in southeast New Mexico.

Q. And do your responsibilities include management and oversight of drilling SWDs in New Mexico?

A. Yes. Yes, they do.

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

A. Petroleum engineer, Texas Tech University, a long time ago. I worked for Mobil in West Texas and also in the San Juan Basin, drilled wells independent. I went to Russia. I was in Russia for 15 years as CEO of the first Russian-American joint venture and then the CEO of a gas POM entity -- no collusion -- and then worked for TNK-BP as the head of upstream gas development.

Later, I came back and became managing director of -- general manager for Oil Search Limited in Papua New Guinea, where we developed the assets to the PNG LNG Project with -- in anticipation of ExxonMobil. And I've been consulting in the U.S. now. I've done a lot of SWD work since 2014.

Q. Thank you.

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

A. Yes, I have, beginning back in the early '90s.

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

A. Yes.

Q. Are you familiar with the applications that NGL filed in these two matters?

A. I am.

MS. BENNETT: At this time I'd like to tender Mr. Duncan as an expert in operations and engineering matters.

EXAMINER GOETZE: He is so qualified.

MS. BENNETT: Thank you.

Q. (BY MS. BENNETT) Let's turn to Tab A, please, and let's start with Exhibit 1. Exhibit 1 is the Asroc application, right?

A. Yes, that's correct.

Q. And can you explain to the examiners what NGL seeks under this application?

A. We seek to drill and operate an SWD in this Fusselman Formation. We're also asking for a 7-inch by 5-1/2-inch tubing string in this well and a maximum injection rate of 50,000 barrels per day instantaneous.

Q. Did NGL propose to relocate the Asroc well?

A. Yes. We've worked hard with EOG to find a suitable location as to not inhibit their horizontal well placement.

Q. And so NGL has agreed to move the well based on those negotiations?

A. Yeah. The well's moved, and I believe all the C-102s were filed for that.

Q. And did the change in location change the

parties entitled to notice?

A. No, it did not. We took the notice much more than the rule requires, so if there is a small movement, it's not going to affect notice.

Q. And if you turn to Tab 2 -- or Exhibit 2 behind your tab, is that an affidavit of Chris Weyand?

A. Yes, it is.

Q. And is Chris Weyand a consultant for NGL?

A. Yes. He is a consultant that does permitting for NGL.

Q. And in his affidavit he states that he undertook an additional review once the location was changed to confirm that no additional notice was required; is that correct?

A. That's correct.

Q. And if you look at his exhibit -- behind his affidavit is Exhibit 2A, which is the updated C-102; is that correct?

A. That's correct.

Q. A moment ago the State Land Office indicated that it had some concerns with -- and I forget which case it was, but I have it in both affidavits -- with either the Asroc well or the Viper well. But does Mr. Weyand, in his affidavit, include information about how close the Asroc well and the Viper well are to state

lands?

A. Yes, he did.

Q. And that's in paragraphs 10 and 11 of his affidavit on pages 2 and 3?

A. Correct.

Q. And he testifies in his affidavit that the Asroc well is located over a half mile from State Trust Lands?

A. Yes.

Q. And over a half mile from state minerals?

A. Yes.

Q. And for the Viper well, it's approximately a quarter mile from State Trust Lands?

A. Yes.

Q. And over a half mile from state minerals?

A. Yes.

Q. Let's turn to Tab 3, please. Tab 3 is the Viper application, right?

A. Yes.

Q. And what does NGL seek under the Viper application?

A. Basically the same thing as the Asroc. It's to drill and operate an SWD well with the design such that it protects fresh water and we can install a 7-inch by 5-1/2-inch tubing string in the well and have the rate of 50,000 barrels per day.

Q. Did NGL propose to relocate the Viper well?

A. Yes -- well, we did. Yeah.

Q. And what prompted that change in the location of the Viper well?

A. Discussions with EOG, their land group and their well planners.

Q. So NGL has agreed to relocate the Viper well?

A. Yes, we have, and we filed accordingly.

Q. Did the change in the location change the parties entitled to notice?

A. No, it did not.

Q. And does Mr. Weyand's affidavit address that issue as well?

A. Yes.

Q. And does Mr. Weyand's affidavit also include a revised C-102 for the Viper well?

A. Yes.

Q. Can you please request -- explain NGL's reason for requesting a larger tubing size?

A. Well, we can get more rate with fewer wells, if you look at the -- in the bigger picture. It reduces friction, reduces horsepower requirements, plus power required to inject the water.

Q. When we were speaking, you mentioned to me that

it's also a greener process?

A. Yes, it is. If you use less energy, it's greener.

Q. So fewer emissions?

A. Yes.

Q. And more efficient?

A. Yes.

Q. And fewer service impacts? Fewer wells?

A. Yes. Much fewer wells with the large rates.

Q. Are you aware of any Devonian disposal wells for which the Division has recently approved the use of 7-inch-by-5-1/2 tubing?

A. Yes, Mesquite wells. There has been an OWL well and an NGL well.

Q. Let's now turn to Tab 4, please.

A. B4.

Q. B4 -- A4. A4.

A. Oh, A4.

Q. Is A4 a declaration obtained from Mr. Steve Nave?

A. Yes, it is.

Q. And who is Mr. Nave?

A. He's an expert fisherman, fishing meaning the recovery of things that have fallen in wells or things that have been stuck in wells.

Q. And has Mr. Nave previously testified before the Division?

A. Yes, he has.

Q. In his declaration, does he conclude that fishing operations will be possible in these wells if NGL is permitted to use the tubing it requests?

A. Yes.

Q. Will you please turn to Tab A5? Is Tab A5 an exhibit prepared by me identifying the parties to whom notice was sent and confirming that notice was, in fact, sent?

A. Yes, it is.

Q. And in Exhibit A5, you'll see that I have included the names and addresses of the parties entitled to notice. The page with the blue header is our delivery confirmation software. And then a couple of pages back is an Affidavit of Publication, and that's true for both Asroc and Viper. I have included our mailing information and our proof of publication for both wells in my affidavit.

A. Yes.

Q. Were the Tab A exhibits, 1 through 5, created by you or prepared under your supervision or direction or compiled from company business records?

A. Yes.

MS. BENNETT: At this time I would like to move to have the Tab A exhibits, 1 through 5, be admitted into the record.

MR. RANKIN: No objection.

EXAMINER GOETZE: Any objections?

MS. ANTILLON: No.

EXAMINER GOETZE: Exhibits A1 through A5 are admitted.

(NGL Water Solutions Permian, LLC Exhibit Numbers A1 through A5 are offered and admitted into evidence.)

MS. BENNETT: Are there any questions for Mr. Duncan?

MR. RANKIN: No questions.

EXAMINER GOETZE: No questions from EOG.

Okay. We'll go down the line here.

Mr. Warnell?

EXAMINER WARNELL: No, no questions.

EXAMINER GOETZE: I'll get started. I would like to have a request. Can we get something we can read?

MS. BENNETT: I will --

EXAMINER GOETZE: Try?

MS. BENNETT: -- try. Yes. Those are what we get from the newspapers.

EXAMINER GOETZE: I understand.

MS. BENNETT: So I will ask them to provide something --

EXAMINER GOETZE: We do look at them and compare them to the C-108s, and so these little details -- because if what's in here doesn't match your C-108, then we will have issues.

MS. BENNETT: Okay. I'll work on that.

EXAMINER GOETZE: Please.

CROSS-EXAMINATION

BY EXAMINER GOETZE:

Q. I will cut to the point that has come as a result of seeing the relocation of the wells. A prior case, Case Number 20235, the Javelina, we have taken under advisement. With the relocation of the Asroc and the Viper, we are now showing overlap with two wells of discussion, as well as the Tomahawk. How is NGL going to address this?

A. We will -- actually, Tomahawk will be moving. And that hasn't come in --

Q. That's a continued case?

A. Yes. It's a continued case. We're still working on Tomahawk. I think -- and --

MS. BENNETT: It doesn't show on this map, but we can check with the --

THE WITNESS: I think we're still okay with spacing. I know sometimes the GIS system doesn't always reflect the latest changes at the OCD, but we will work with you, Phillip, on that.

Q. (BY EXAMINER GOETZE) Let's sit down and let's verify them, because right now --

A. Yeah.

Q. -- from my calculations, we do have overlap of the three, one of particular concern, and that's the Asroc. And so we have it under advisement that it's not -- was not protested.

A. Okay.

Q. So let us take a look at that once again, and if we need to re-open it, we'll do so. But if not, let's resolve that difference. Okay?

MS. BENNETT: Uh-huh.

Q. (BY EXAMINER GOETZE) I guess one of the questions I have for, as we do in many of these cases, have you looked at the well design, and you are familiar with it?

A. Yes.

Q. And is it protective of underground sources of drinking water?

A. Yes, it is.

Q. Thank you.

And since you brought witnesses, I will talk to them more.

A. Yeah.

Q. No more further questions.

A. They're a lot smarter than I am.

EXAMINER GOETZE: Any questions?

EXAMINER McMILLAN: No. I don't have any questions.

EXAMINER BROOKS: No questions.

MS. BENNETT: Great. Thank you.

At this point, then, I'd like to call my next witness, Kate Zeigler.

EXAMINER GOETZE: It's Dr. Zeigler.

MS. BENNETT: Yes. I have that in my outline today for sure.

KATE ZEIGLER, Ph.D.,

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

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Good morning.

A. Good morning.

Q. Thanks for being here today.

Will you please state your name for the record?

A. Kate Zeigler.

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

A. Zeigler Geologic Consulting on behalf of NGL. I'm a free-range consulting geologist.

Q. And what are your responsibilities for NGL?

A. To review the stratigraphy and regional and local geology for the placement of these wells.

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

A. So I have an undergraduate degree from Rice University, a master's and Ph.D. from the University of New Mexico mostly focused on stratigraphy in New Mexico. And I've worked as a consulting geologist both in the Permian Basin, doing surface geologic mapping for independent small operators, as well as doing groundwater resource work in northeastern New Mexico.

Q. And are you -- you've previously testified before the Division?

A. Yes.

Q. And are you familiar with the applications that NGL filed in these two cases?

A. I am.

Q. Are you familiar with the status of the lands where these wells are proposed to be drilled?

A. Yes.

Q. And are you familiar with the drilling plan for these wells?

A. Yes.

Q. Have you conducted a geologic study of the area embracing the proposed locations of these wells?

A. Yes.

Q. And have you prepared similar studies for NGL's prior applications?

A. I have.

Q. And have those studies been submitted to the Division in support of NGL's prior applications?

A. Yes.

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

EXAMINER GOETZE: EOG?

MR. RANKIN: No objection.

MS. ANTILLON: No objections.

EXAMINER GOETZE: Dr. Zeigler is so qualified.

MS. BENNETT: Thank you.

Q. (BY MS. BENNETT) If you wouldn't mind turning to Tab B and explaining to the examiners -- well, Tab B contains your study behind a few different tabs. So if you could just briefly explain what your study is -- an overview of your study, and then we'll talk about each

specific part of the study individually.

A. Okay. So what I've done in these cases -- and this is what we'll walk through -- is looked at the stratigraphy in the area as it's been documented by various deeper boreholes that have penetrated close to basement where we can find them and have compiled that information, as well as using the Texas Bureau of Economic Geology's isopach data in order to constrain the thickness of the various units and to understand better how thick those units are and where they are in the subsurface.

Q. Thank you.

So B1 is a study -- is just a document that you've prepared that kind of outlines the stratigraphic unit descriptions, is that right, this --

A. Yes, the big, giant foldout.

Q. Actually, I was looking at this (indicating), the very first tab.

A. Apologies. Wrong one.

Q. And so that is a document you've compiled based on other resources?

A. Yes.

Q. So then now let's turn to the foldout chart. And can you let -- this is B2. Can you explain to the examiners why you've included this chart?

A. So I've included this in part because there are differences in the way that drillers refer to different units versus how geologists refer to those same units, and this is just in order to kind of keep things straight between driller terminology and geology terminology. This is compiled from Ron Broadhead's 2017 compilation of oil and gas resources in New Mexico.

And so you have your age on the left going through -- from the Triassic down to the Precambrian, since these are the units in question in most of the Permian Basin. And when you step over into the next column, we have the actual names of the stratigraphic units, and this is where things can get a little confusing in that a lot of our drillers tend to refer to things like the Woodford, the Thirtyone and the Wristen, combined as the Devonian, and yet those are different age -- or they have different ages associated with them. And so a geologist might refer to them in a different manner than a driller would.

And so here, when we talk about injecting into the Devonian, we're speaking to injecting into the Thirtyone, plus the Wristen, plus or minus part of the Fusselman. And you'll note that only the Thirtyone is actually Devonian where it's present in the Permian Basin. And so when we look at the Wristen, Fusselman, we're actually injecting into a Silurian-age unit.

And so I'm just clarifying that geologists are going to use different names for these units, and I will endeavor to stick with the driller lingo, since that's how most of this data is presented.

EXAMINER BROOKS: Which exhibit is this?

THE WITNESS: It's the big foldout chart that's behind B2.

EXAMINER BROOKS: B2. Thank you.

THE WITNESS: And then also on here just for reference, we showed the approximate depth of known freshwater resources in the Permian Basin, as well as current production zones and then showing the Woodford Shale as an upper permeability barrier to the injection interval and the Simpson Group as your lower shale permeability barrier just so you have a vertical visual of where these things are falling as you dig down into the earth.

Q. (BY MS. BENNETT) And so just so I'm clear, this shows NGL's target injection interval is well below the freshwater resources?

A. Yes, ma'am.

Q. And is actually below any petroleum zones as well?

A. Yes.

Q. And then there is a permeability barrier between our injection zone and the freshwater resources?

A. Yes.

Q. Great. Thank you.

Let's turn now to what's behind Tab B3. These are the -- there are ten pages to B3, and these are for the Asroc well. And you can see the Asroc well is identified by the green star in the middle of the page. Dr. Zeigler, could you walk us through these ten pages in B3 and explain these ten pages to the examiners, please?

A. So each of these is -- there are two isopach maps per rock-unit interval for each of these. And what we've chosen to do is the first isopach for each interval is simply the well location with the known estimated positions of different Precambrian or basement-penetrating faults from the Texas Bureau of Economic Geology data compilation, as well as the thicknesses for the different units. And so your first one, for example, is the Woodford Shale. So the red lines with the numbers on them are your isopach, your thicknesses of the Woodford Shale for that area.

And then the very second page is again the Woodford isopach, but now we've shown the wells that we've used to create the cross section that we will look at later, and you can see how we've laid out the line of cross section and how we've projected various wells into that cross-section line. And so for each unit -- stratigraphic unit, there are two isopach maps, one with just the wells and one with the cross-section line, because we felt like just having everything on one could sometimes get a little overwhelming.

So we start with the Woodford. We're going to go down through the section from our upper permeability barrier, which is our Woodford Shale. For Asroc, looking at a thickness of approximately 200 feet thick. And then if you step to the next isopach -- and you'll notice down in the key at the bottom, it has the rock unit, which stratigraphic unit we're working with on each isopach.

So as we step into the Wristen and Fusselman, you see Asroc sitting where it is, and we're looking at a thickness for the combined Wristen, Fusselman of approximately 1,550 feet, and then you have your line of cross-section again.

And then we step on through to the Montoya, looking at approximately 350 feet thick in the Montoya.

We step through two more pages into the Simpson, looking at approximately 900 feet thick of Simpson strata.

And then finally, step on down into the Ellenburger where we're looking probably at 600 to 650 feet thickness in the Ellenburger.

Q. On these isopach maps, are there fault zones identified on the isopach maps?

A. There are. We've combined a couple of different data sets here so that we have green lines as your basement faults. The blue-dashed lines are also indicated as Precambrian-penetrating faults. These are both from the Texas Bureau of Economic Geology, as well as some of Ron Broadhead's work, as well as the Snee and Zoback paper. And so we've tried to just compile as many potentially known fault locations that we could find in the data sets and constrain them as best we could.

Q. And so for the examiners, the green line here and these green lines, as well as the blue-dashed lines are the faults?

A. Those are all potential faults. Yes.

Q. Let's turn now to Tab 4 in Tab 4B. Can you explain what Tab 4 is, please?

A. So this is our cross section that we've developed using the wells that we could find in the area that did penetrate deep enough to show the Woodford Shale down into the, quote, "Devonian," which is your

Wristen and then your Fusselman and your Montoya and lucky enough to find some deep wells to the southeast that actually got all the way down to the Ellenburger.

And so this is to show the approximate thicknesses of these units as we travel from northwest to southeast, the approximate position of the fault that Asroc is sitting right adjacent to and then the position of some of NGL's other wells, which are the Jack Tank, McCoy West, McCoy Central and Minuteman, and then Asroc, with the red arrow, showing its position in relation to these other well logs, as well as the approximate trace of that fault.

Q. Thank you.

Let's turn now to Tab 5. Tab 5, like Tab 3, has ten isopachs, and this is for the Viper well. Are there any differences other than the well name and location between these ten slides and your prior ten slides?

A. Not significantly. The estimated thicknesses of the rock units don't shift too much between the Asroc and the Viper locations.

Q. Okay. Then with that, for efficiency sake, I don't think we need to walk through each one, but let's instead turn to Exhibit 6, please. And can you please describe what Exhibit 6 is?

A. So this is a second cross section that's going to look effectively identical to the Asroc cross section, since they are located close to each other geographically. And so again it's the same reference wells that we utilized going from northwest to southeast with the approximate thicknesses of these different stratigraphic units, as well as the position of the Viper well with its red arrow indicating where it would be projected into the line of cross section.

Q. Thank you.

What do the isopachs, along with the cross sections tell you about this area and the injection zone?

A. A couple of different things. One is that the thickness of the target injection interval is relatively consistent across this area. It is shifted by that approximate trace of that fault, but the thicknesses don't change much across the area. In addition, it helps us to project the potential depth to that rock unit. And it's a thick unit. We're looking at up to a combined thickness of 1,500 feet thick for that entire injection interval.

Q. And so that is the injection interval that has -- porosity and permeability is about 1,500 feet thick?

A. Yes.

Q. And in your opinion, will the drilling of the Viper or Asroc wells impact the rights of mineral interest owners?

A. It will not.

Q. And are you aware of any productive shales in the formations at issue?

A. Not in these lower formations, no.

Q. And I understand from speaking with you that it's unlikely that this Devonian area is unpro- -- productive. What is your -- what is that conclusion of yours based on?

A. In part because there have been -- in the exploratory wells that have drilled that deep, there have not been economically significant shows that have come from those deeper wells. In researching through Ron Broadhead's work in the area, there are concerns that if there are reserves in those lower units, that they're going to be difficult to target because they'll probably be small and constrained and that it would be difficult to target them in a way that would make them economically viable.

Q. In your opinion, is there a risk to freshwater resources if the Asroc and Viper wells are drilled?

A. There is not.

Q. And why is that?

A. In reference to Mr. Duncan's testimony with regard to not only the way that the wellbores are being constructed but also that we have not only the Woodford Shale as a significant permeability barrier at the top of the injection interval, but there are several other rock units above that that do have significant shale -- shale components to them that would act as additional permeability barriers above the Woodford Shale.

Q. And one thing I don't think we discussed is the permeability barrier below the injection zone. There is a permeability barrier below it as well, right?

A. Yes. The Simpson Group has a significant shale component that will act as a downward permeability barrier.

Q. Were the Tab B exhibits prepared by you or compiled under your direction and supervision?

A. Yes.

MS. BENNETT: At this time I'd like to move admission of the Tab B exhibits, 1 through 6.

EXAMINER GOETZE: EOG?

MR. RANKIN: No objection.

EXAMINER GOETZE: State Land Office?

MS. ANTILLON: No objection.

EXAMINER GOETZE: Exhibits B1 through B6

are so entered.

(NGL Water Solutions Permian, LLC Exhibit Numbers B1 through B6 are offered and admitted into evidence.)

MS. BENNETT: Thank you.

I have no more questions for Dr. Zeigler.

EXAMINER GOETZE: Mr. Rankin.

MR. RANKIN: No questions.

MS. ANTILLON: No questions.

CROSS-EXAMINATION

BY EXAMINER GOETZE:

Q. Thank you for the presentation.

I just have one quick question regarding the cross section. You identify a fault. Do you have any general comments? Is this a normal fault? Reverse? And how far up and how far down do we go? And then Part C of that question is: Does it represent a barrier, or does it represent a -- in your opinion?

A. So with regards to this fault, these -- given the lack of deep-penetrating boreholes very close to it, it's difficult to assess the complete dimensions of this fault. I think, in its latest incarnation, it may be a normal fault, but a lot of these faults have been active since Precambrian. And so we've had several different episodes of motion on them in different directions. I suspect that these are most active in basin and range as their final motion.

One of the features we see out here is at depth, there seems to be greater offset on them. But if you look at shallower stratigraphic units across this, the throw on the fault becomes lessened, and it's attenuated by the evaporites in the upper part of the sequence. And so in the lower part of this, given that we have attenuation near the top and we have evaporites that may be acting as a seal along parts of that fault, I suspect, at least once you start invoking motion where you're smearing those softer evaporites in the upper part, that's going to start to seal those fault zones, but I think it's difficult to assess at this point.

Q. Thank you.

EXAMINER GOETZE: I have no more questions for this witness.

Mr. Warnell?

EXAMINER WARNELL: No questions.

EXAMINER GOETZE: Mr. Brooks?

EXAMINER BROOKS: No questions -- oh, I have one about an exhibit.

CROSS-EXAMINATION

BY EXAMINER BROOKS:

Q. You referred to an exhibit that showed

freshwater resources in New Mexico, and I did not identify which exhibit that was.

A. So in B2.

Q. Okay. I had B2. Yes. This is the one (indicating)?

A. Yes. Yup. So up near the top, the blue box on the right-handmost column that shows freshwater resources in the Upper Triassic strata, which would be your Chinle, Santa Rosa and some of your Upper Permian, these are showing that in southeast New Mexico, the rock units generally tend to have fresh -- fresher water resources in them.

Q. Okay. When you say fresher waters, what TDS range are you talking about?

A. We're looking at some pretty cruddy waters out there.

Q. That's what I thought.

A. So we're looking at closing in on brackish-looking waters. Yeah. We've done a little bit of groundwater work down there, and it's some -- it's some pretty nasty water on a good day. Yeah.

Q. Okay. Thank you.

MS. BENNETT: Thank you.

EXAMINER GOETZE: Mr. McMillan?

CROSS-EXAMINATION

BY EXAMINER McMILLAN:

Q. What's the lateral distance from the borehole to the fault?

A. For which?

Q. For both of them.

A. So Viper is -- if that trace of the fault is even --

Q. Kind of close?

A. -- kind of close, we're looking at about 2,000 feet off of Viper. And Asroc could be within 100 feet, could be off the fault. It's really hard to tell without being able to constrain that fault better. And I believe there may be more information coming from some of the --

MS. BENNETT: Yes.

THE WITNESS: -- next witnesses to speak more to that.

MS. BENNETT: Uh-huh.

THE WITNESS: So somebody needs to drill some horizontal wells to find that thing.

(Laughter.)

EXAMINER GOETZE: I believe we're done with this witness.

MS. BENNETT: Thank you.

At this time I would like to call my next witness, which is Dr. Steven Taylor.

STEVEN R. TAYLOR, Ph.D.,

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

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Good morning, Dr. Taylor.

A. Hi, Deana.

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

A. Steven R. Taylor, with a V.

Q. And who do you work for?

A. GeoEnergy Monitoring Systems.

Q. And what's your capacity for -- what do you do for GeoEnergy Monitoring Systems?

A. Mainly daily seismic monitoring of different stations around the United States and Canada. And for NGL, we do daily monitoring in southeastern New Mexico and monthly reporting.

Q. Do you have seismic tools -- measuring tools at any of the NGL wells?

A. Yes, we do. We have -- we have seismic stations at Striker 2, Striker 3 and Striker 6.

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

A. No.

Q. And could you please explain your educational and professional background to the examiners?

A. Right. I have a Bachelor of Science degree from Ohio University in geology from 1975, a Ph.D. in geophysics from the Massachusetts Institute of Technology in 1980.

I worked at Warren's Livermore National Laboratory from 1980 to 1991 and at Los Alamos National Laboratory from 1991 until I retired in 2006. And since then I've formed two companies, Rocky Mountain Geophysics and GeoEnergy Monitoring Systems in 2011.

Q. Are you familiar with the applications that NGL filed in these cases?

A. Yes, I am.

Q. And have you conducted a seismology study related to those applications?

A. I have.

Q. And have you conducted seismology studies related to NGL's prior applications?

A. Yes.

Q. And do you know if those studies have been submitted to the Division?

A. Yes.

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

EXAMINER GOETZE: EOG?

MR. RANKIN: No objection.

MS. ANTILLON: No objection.

EXAMINER GOETZE: He is so qualified.

MS. BENNETT: Thank you.

Q. (BY MS. BENNETT) So a moment ago we talked about the studies that you have conducted, and you have conducted studies in this area.

A. Uh-huh.

Q. And what sort of data do you rely on when you prepare studies?

A. We rely on data from the -- well, in southeastern New Mexico, the three Striker stations. And then we also will pull up data from the New Mexico Tech WIPP monitoring stations in the region and also the TexNet stations in PB, a lot of which is in northern Texas.

Q. And do you use any catalogs like the USGS catalogs?

A. We did as a background survey to look at historic seismicity. We did use USGS catalogs.

Q. And so is it fair to say that your studies are based on historical review through present?

A. Yes.

Q. Is your study attached -- is your study included in Tab C of the materials? It is. I can tell you that it is.

A. Okay. Thanks.

(Laughter.)

Q. And this is your seismic catalog analysis within 50 kilometers of Asroc and Viper SWD wells. And you have that in front of you, right?

A. Yes. Right.

Q. If you could, could you walk the examiners through your study?

A. Okay. Let's see here. There's -- well, first of all, just as a background in Figure 1, that shows the three Striker stations where NGL has contracted with us to install seismic stations, and that was in early September of 2018. And those are shown as the blue pushpins.

The green circles around each station is basically a -- shows a -- it's a ten-kilometer circle showing detection thresholds of magnitude 1 from the station, and the red line are detection thresholds for a magnitude 2 event occurring within 20 kilometers of each station.

NGL also operates four stations -- or we operate four stations for NGL in the Delaware Basin of

Texas, and those are shown as the yellow pushpins in Figure 1.

Q. And on the top -- immediately above the year one, there is some data there. Can you tell us what that data is?

A. Right. Table 2 is the -- the seismicity that we have recorded and located since installation of the stations in early September.

Q. And they range between 1.1 magnitude and 1.98 magnitude?

A. Yes.

Q. And if you turn to Figure 2, what does Figure 2 have on it?

A. Figure 2 shows -- we looked at historic seismicity from any catalogs we could find between 2010 and 2017, and those events that we found are listed in Table 1 of the exhibit. And then Figure 2, the red dots show the location of the historic seismicity listed in Table 1. And I should also say that in this figure, the Striker stations that we operate for NGL are shown as yellow pushpins, and the green pushpins are stations operated by New Mexico Tech and TexNet.

Q. Thank you.

And then Figure 3?

A. Figure 3 shows the location of events as red dots using -- that are listed in Table 2. And so those -- right. So this is basically the same as Figure 2, but it shows the recent seismicity that we've recorded since mid-September of 2018.

Q. And that recent seismicity is included in the in Table 2, right?

A. Right. Yup.

Q. And when we spoke yesterday about the magnitude of these events, we talked a little bit about the USGS and what the USGS typically records. Would these even fall within the USGS's parameters for --

A. None of these were reported by the USGS. They typically, with their backbone seismic network, will report anything greater than magnitude 2-1/2.

Q. 2.5, 2-1/2?

A. Yes.

Q. What do you conclude from your study?

A. Well, there is -- there is some seismicity in the area, but it's all very small. And, you know, at this point it might just be background -- background seismicity. It just wasn't observed because there weren't any stations in the immediate vicinity until mid-September.

Q. Given what you know about the depths and locations of the wells that NGL is proposing in these

two applications, in your opinion, is there a risk of felt-induced seismicity?

A. I very much doubt there will be any felt seismicity from any injection in this area.

Q. Were the Tab C exhibits prepared by you or under your supervision or compiled from your company business records?

A. Yes.

MS. BENNETT: At this time I would move to have Tab C exhibits admitted into the record.

MR. RANKIN: No objections.

EXAMINER GOETZE: No objections?

MS. ANTILLON: No objection.

EXAMINER GOETZE: No objections.

Exhibit Tab C is so entered.

(NGL Water Solutions Permian, LLC Exhibit Letter C is offered and admitted into evidence.)

MS. BENNETT: Thank you.

I pass Dr. Taylor for any questions that the examiners may have or Adam or Andrea.

MR. RANKIN: No questions from EOG.

MS. ANTILLON: No questions from the State Land Office.

EXAMINER GOETZE: Let's go down the line.

Mr. Warnell?

EXAMINER WARNELL: No questions.

EXAMINER GOETZE: Mr. Brooks?

EXAMINER BROOKS: No questions.

EXAMINER McMILLAN: Go ahead.

MS. BENNETT: And I would like to point out we also have another geologist to testify on the fault slip probability analysis.

CROSS-EXAMINATION

BY EXAMINER GOETZE:

Q. So just out of curiosity -- again, this is with the problems in Oklahoma. With the rise of information coming in, we're starting to see all sorts of things. Any conjecture, other than the fact up until now because of the scale in the detection now available, there's nothing there that gives you concern?

A. No. They're all very small.

Q. Okay. Other than that, no more questions. Thank you.

MS. BENNETT: Thank you.

Thank you.

At this time I'd like to call my next witness, Todd Reynolds.

I'm going to pass out a larger exhibit that Mr. Reynolds prepared. It's also in your materials but much smaller.

EXAMINER GOETZE: Font 2 is my favorite size.

MS. BENNETT: This is font 102.

TODD REYNOLDS,

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

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Mr. Reynolds, please state your name for the record.

A. Todd Reynolds.

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

A. I work for FTI Platt Sparks. I'm the managing director, but I'm basically a geologist and geophysicist.

Q. And what are your responsibilities with FTI Platt Sparks?

A. I conduct geologic and geophysical studies for clients and also studies in support for the engineering studies that we do for clients. We are -- we are a consulting firm.

Q. And have you been retained by NGL?

A. Yes, I have.

Q. Have you previously testified before the

New Mexico Oil Conservation Division or Commission?

A. Not in New Mexico but similar commissions in Texas, Louisiana, Pennsylvania and Virginia.

Q. What is your -- well, can you briefly give us a summary of your educational and professional background?

A. Sure. I received a bachelor's degree from the University of Texas in 1985 in geophysics in geology and have been in the exploration -- geophysics and geologic exploration business since then for 15 years with a small independent where our focus was primarily horizontal drilling in fractured reservoirs and also using 3D seismic data to define bright spots and gas reserves along the Gulf Coast.

And then the next 15 years, I had my own company. It was a consulting company. And then the last four-plus years with FTI Platt Sparks.

Q. Thank you.

Are you familiar with the applications that NGL filed in these cases?

A. Yes, I am.

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

A. I have.

Q. Have you prepared similar studies for NGL's prior applications?

A. Yes, I have.

Q. And do you know if those studies have been submitted to the Division in support of NGL's prior applications?

A. They have.

MS. BENNETT: At this point I would like to tender Mr. Reynolds as an expert in geology matters.

MR. RANKIN: No objection.

MS. ANTILLON: No objection.

EXAMINER GOETZE: He is so qualified.

MS. BENNETT: Thank you.

Q. (BY MS. BENNETT) Now, I'd like to turn to Tab D, and Tab D contains a few documents. Behind D1 is a USGS graphic that you and I discussed yesterday, and I was wondering if you could give the examiners a brief overview of this graphic.

A. Sure. This graphic just illustrates the different magnitudes for earthquakes shown on the left-hand side starting at a 2 and going up to a 10. And there is also kind of a cone pyramid-looking chart in the middle that shows the relative frequency of those type of events worldwide. As you can see, for magnitude events below a 2.0, there are over a million of those worldwide of that type of magnitude, so, you know, around 3,000 a day. And then as you go up, you see fewer events or fewer earthquakes at the higher magnitudes.

Also what you see on the magnitude scale is kind of a description of what happens when that type of event occurs. Generally anything less than a 3 is not felt. I think that's been redefined to more like around a 2.5. If it's shallow enough, it can be felt. But then you see the type of damage -- you really don't start seeing property damage until you get up into the magnitude 5 scale. For example, the -- some of the earthquakes in Oklahoma, there was a chimney that fell over in a 5.6 magnitude. But then when you get above 6, you're starting to see, you know, peril and damage and risk-of-life type events. So that's what this chart shows, and this is a source from the USGS.

Q. And so all of the -- all of the earthquakes or events that Dr. Taylor testified to were under 2.0?

A. That's correct. And absent NGL's recording system, probably no one even knew they occurred.

Q. Thanks for explaining that.

Let's turn now to Exhibit 2. And a moment ago, you mentioned that you prepared a fault slip probability analysis. What tool do you use for that fault slip probability analysis?

A. Sure. There was some software developed by

Stanford in conjunction with ExxonMobil and XTO. They jointly developed this tool for assessing the potential for slip along faults as a result of the volume of water that's put into the ground and the pressure that would be associated with that injection.

So what this tool does is you input the known faults in the area and the orientation of those faults, and then you also input the historical injection history on a monthly basis for all the wells. And then any proposed wells, you would put into the model, and you can put them in at an initial rate and hold them flat or build any kind of decline on the wells that you desire. And we'll see, with some of the exhibits, what information went into this model.

Q. And so you were in the room when Dr. Zeigler testified about the two faults -- or three faults really that are near the Viper and Asroc well locations?

A. Yes. These are faults denoted by a study done by the BEG some time ago, like 20 years ago. And so they're estimations of where they believe there is faulting in the area.

Q. And you took that information into account when you ran your fault slip probability analysis?

A. That's correct. Those are the faults that are input into the model.

Q. Let's turn -- well, so Exhibit 2 is your fault slip probability analysis for the Asroc well; is that correct?

A. Yes. Exhibit 2 is the entire report, which has some exhibits with it.

Q. And then Exhibit 3 is the FSP analysis for the Viper well?

A. That's correct.

Q. And both of those exhibits have a summary and then the slides that back up your summary. Is that a fair characterization of those two exhibits?

A. That's correct. And they will be virtually identical except for the names of the wells on the report. Because when we do this, we don't treat it as a subject well in a vacuum. We have to input everything in the area, including the other proposed wells, and so the model applies to both of the applications.

Q. Thanks.

And for that reason, I suggest, for efficiency sake, that we go through the Asroc slides and not the Viper slides because they're essentially identical -- or they are identical.

A. They are. They are.

Q. So let's look first at -- well, is there anything you want to say initially about the summary of

your FSP analysis before we turn to the individual exhibits that support it?

A. We can just address it page by page if you want.

Q. Okay. Thank you. Sure.

So turning to the first slide, which is marked Exhibit Number 1 at the top of the slide, and that's the blowup of the map that you have in front of you, is this exhibit.

A. Yes.

Q. So why don't you go ahead and explain this first slide to the examiners?

A. Sure. On this slide, what you will see is a 100-square-mile area around this cluster of wells that are located along this fault, and that's represented by the black-dashed line. That would be 100 square miles around all of these subject wells.

We also show the location of the subject wells and any existing injection wells in this depth interval that have injection and history, and those are shown by the inverted blue triangles with the five-digit API numbers by them.

Q. I'm sorry to interrupt you, but could you orient us as to where Asroc and Viper are on this map -- on this diagram?

A. Yes. Asroc is located more or less in the center portion of the map, near fault segment 9.

Q. Right about here (indicating)?

A. Yes.

And Viper is immediately south-southeast of that, near fault segment 11.

Q. Yeah. Right about here (indicating)?

A. Yes.

Q. Okay. Thank you.

A. Also denoted on the map is the single USGS event up to the northwest, with a 2.9 magnitude in 1984, up near fault segment 2. And then the recent seismicity that was testified to by Dr. Taylor is shown by the magenta bulls-eye symbols located on the map down near the Asroc.

I also want to point out the fault segments 1 through 17. And it's important that you segment the faults because the FSP software calculates the pressure to the midpoint of a segment. So if we just drew it as one fault, it's only going to calculate the pressure at one point along the fault. So we try to segment the faults so that there is a normal to a subject well that's nearby so that we're getting a true measure of the pressure along the fault nearest an injection well.

Q. And just so I'm clear again, this -- this sort

of straight up-and-down line here (indicating) is the same fault that Dr. Zeigler had on her exhibits in green, but here it's in sort of orangish?

A. Yes.

Q. And then this little triangle over here are the other two faults that she had in green?

A. That's correct.

Q. And each of -- the longish fault, you have identified 13 segments starting from north, working south, one, two, three through 13?

A. That's correct.

Q. Okay.

A. And then just in general, before we move off of this exhibit, the faults are generally north -- located or oriented north-south with the orientation of maximum horizontal stress being more or less east-west. That's a good thing. When the two line up with each other, that's when there is a higher risk for fault slip. So in this particular area, the stress orientation is north 75 degrees east or about 2:30 on a clock, so any faults that are oriented similar to that will be the ones with the higher risk of fault slip.

Q. So just to summarize, here we have more of a perpendicular pressure, so that's a good thing?

A. That's a good thing. That requires very high pressures to cause -- allow a fault slip.

Q. Great.

So now turning to slide two, what do we need to know about slide two?

A. Slide two shows many of the input parameters that are used in the model. If you see the upper panel, you see the stress information that is input, the reference depth for the injection, the orientation of the stress, vertical stress component, and the initial reservoir pressure gradient is shown on that tab. And the next tab over we use -- we input the hydrologic parameters, thickness of the reservoir, porosity, permeability. We use a more conservative approach and don't use the entire 1,500 feet. We use 900 feet because I believe that's more of a net number of injectable portion of the reservoir.

And then in the lower, left-hand corner is an exhibit from the Snee and Zoback paper that shows the orientation of the stress in the area we're talking about, which is north 75 east.

Q. Thanks.

And then Exhibit 3?

A. Exhibit 3, we start putting some of the information into the FSP model. There is a box in the middle that shows the input fault locations. You can see kind of the same shape. There is that V-shaped fault segment, and then there is the north-south-running faults. And then all the wells are noted by kind of a square-circle-looking symbol with an abbreviation for each of the wells. And on the right-hand side would be the injection history, a very brief history out here. The Madera and the Vaca -- Vaca Draw well, I believe is the name of it -- represent the historical injection volume. And then everything is held constant going forward for 25 years. So the proposed wells were input at 40,000 barrels a day for the model.

Q. And that's what you mean by held constant, is a constant injection rate?

A. Yes. And that's typically not what you see. You typically see the wells decline as -- as demand declines to dispose of water.

Q. So would you say your model is very conservative -- is conservative, then, in that it takes the approach of holding those injection levels constant over time?

A. That's correct. It runs more of a worst-case scenario.

Q. Then let's look at Exhibit 4, please.

A. Exhibit 4 is another figure taken from the Snee-Zoback paper. You'll recognize the faults, the

V-shaped fault and the north-south trending fault, with the arrow pointing to it showing area of review. And the Snee-Zoback analysis, what they did is they just took simply fault orientation and did not input any injection data or anything like that, but just, based on fault orientation alone, what are the faults that are higher risk in the area and what are the faults that are lower risk? And they color-coded them as green being the very low-risk faults up to the orange and red, which would be the higher-risk faults, and those would be the ones that run roughly parallel to the local stress in that particular area.

Q. Thank you.

And now it seems like we start getting into the meat of your analysis; is that correct?

A. That's correct.

So Exhibit Number 5 shows the fault segments, and they're all numbered. As you can see, faults 15 and 16 are a little higher risk because of the way they're oriented to the stress direction.

I've also input two faults that are not on any of the maps, and that's 18 and 19. And those are hypothetical faults that were placed at the position of the recent seismicity recorded by Dr. Taylor. So it's just -- hypothetically, let's assume there is a fault there so that we can calculate the pressures at that point. So it doesn't represent that there is faulting there, but it's the only way I can get the FSP model to tell me what the pressure is at that point, is to put a small fault there.

Q. That seems very helpful.

And I'll just let you walk through the next exhibits at your pace.

A. Sure.

So Exhibit Number 6 just shows all of the faults, and it shows the variability of the inputs. The inputs were listed on, I think, Exhibit Number 2, but we varied them plus or minus 10 percent to see what effect that would have on the potential for slip. Again, we see the two -- the three faults, orange and yellow, which is that triangle fault out to the east, being the higher risk, but most of the other ones, the green ones, are well out there to where a 10 percent probability to slip, you're looking at over 2,000 pounds, most of them around 4,000 pounds.

Exhibit Number 7, we just look at some of these faults individually. So if you look at the left-hand column, we've got highlighted fault 15, which is probably the highest-risk fault. And then if we look in the lower, right-hand corner, we have a sensitivity analysis for that fault with the vertical line at around 1,200 pounds representing the pressure that it would take for that fault to slip if you didn't vary the inputs. And then when we vary the inputs by 10 percent, it's represented by these orange bars. So you can see that it could go as low as 750 pounds, or it could be as high as over 2,000 pounds, depending on that variation in the -- in the inputs. Now, that fault's quite distal from any of the wells we're talking about.

We do -- Exhibit 8 is the same look at fault 16, same type of analysis.

Exhibit 9 is for fault 14, and now we're starting to look at faults that are more north-south oriented.

And then Exhibit 10 is for fault 1. And faults 1 through, I believe, 12 or 13 are all pretty much the same, so they would all have the same type of analysis. And you can see on this one, even with the variability of the inputs, we're still talking about over 3,000 pounds to slip, but with no variation, it's over 5,000 pounds, so very high pressures.

Exhibit 11, we start walking through a time sequence of what does the pressure front look like in the area when you put all of these wells in, and it also will show the pressure at the fault segment through time. And it's kind of hard to read, but we have a table that recaps it at the very end. So at 2020, you see that the pressures are quite low, I think 93 pounds down to the south, and that's the highest you see. But that's the one where wells are closer to the fault.

Q. And, again, this represents all of the wells that were in your overview?

A. That's correct. To just put the subject wells in, that would not be a valid model.

Q. So this includes proposed wells -- as many proposed wells as you know about?

A. As the ones I know about.

Q. Yeah. And currently injecting wells?

A. That's correct.

Q. And it assumes 40,000 barrels?

A. That's correct.

Exhibit 12 is just looking at the next time period, 2025. As you would expect, the cloud is growing. The pressure in the area would be growing. And then the upper, right plot plots all of the faults with those blue lines with the little Xs on it. It shows the pressure seen at the midpoint of those faults through time all the way out to 2050. The lower, right-hand box that kind of looks like the Jamaican flag, with the green, yellow and the red, just shows that none of the faults ever get up into the high fault slip potential range of -- you know, 1.0 would be that the model says it's going to slip, and, you know, the percentagewise is on the left-hand column of that graph. So they're all staying down in the green area.

Q. Yeah. So I see that now. It was a little hard for me to follow at first. But that's on the bottom axis, right? The lower axis shows --

A. That's correct.

Q. It's not even close to the top of the green through 2050?

A. No. And there is a vertical green-dashed line that represents the time that we're looking at at that point.

Q. Okay.

A. So that line will move as we go through the sequence of charts or exhibits.

Exhibit 13 is for 2030, the same analysis.

Exhibit 14 is for 2035.

Exhibit 15 is 2040.

Exhibit 16 is 2045, and then we turn it off at that point and don't look beyond that.

Q. And even at 2045, the pressures are relatively low even on the two -- on the segments that you said were the most vulnerable that are quite a ways away from

Asroc and Viper?

A. Yes. I mean, it's well below the pressures that are calculated that would be needed to slip. And the table will look at -- actually, that's in the report. So if we back up to the report --

Q. And that's the white paper?

A. That's correct.

Page 5 of the report shows all of the fault segments and shows the calculated Delta P or pressure increase needed to initiate fault slip with the inputs fixed. The next column shows, if you vary the inputs, what's the lowest pressure on those varied inputs that would allow fault slip. And then the last column is the Delta P that's calculated at 2045. And as you can see, the most vulnerable fault is F15, which would be anywhere from 750 to 1,150 for fault slip, and it's only showing 489 pounds.

Now, some of the other ones that show higher pressures -- for example, fault F9 reaches over 2,000 pounds of pressure, but that's one that takes 4,400 to 6,000 pounds to slip, one of those north-south oriented faults.

Q. Uh-huh.

A. Exhibit 17 is a step-back look to see if we can explain the seismicity that has recently occurred. And so if we look at those two fault segments that I mentioned previously that were just the short segments, those were located at the points of that recent seismicity. And as of January 1st, 2019, the software is calculating there is no pressure change at this point. So there doesn't seem to be any real correlation to induced seismicity as a result of saltwater injection.

Exhibit Number 18 kind of addresses this concept of, well, if we have more devices listening, we're probably going to hear more events and record more events. This was taken from -- in the War-Wink area over in Ward and Winkler Counties, Texas. Between '75 and 1980, there was a 12-station seismometer array out in this area that was looking for seismicity to evaluate a nuclear injection site -- or a nuclear disposal site over in New Mexico. So it was put up to determine if there was any seismicity in the area where that site was proposed, and what they found was -- they recorded over 1,000 events in the War-Wink area during that time period, and the purple line on this graph represents injection in the area. And as you can see, that didn't begin until 1984. So, again, there was no -- no real strong correlation to saltwater disposal injection. The only correlation that you can see was there was -- there a ramp-up in a lot of development in the overpressured sections, Wolfcamp and below, during that period of time, and so -- there are even some papers written by professors out of UTEP that associated it with possibly extraction-based seismicity in that area. The key point there was there was no injection at all in the area at that time, so it's kind of hard to say that there is a correlation between that.

Exhibit 19 is a similar analysis to that War-Wink analysis. It's a 100-sqaure-mile area around the Pecos town site where there's been a fairly recent increase in seismicity. The same curves apply on this chart. The purple is injection. And you can see over time, injection has just been increasing pretty steadily out here, but you see a fairly rapid ramp-up in extraction and production starting in 2017. The red-shaded area is all magnitude events, and this is down to .2. I mean, just very small events. So that's represented by the shaded red area. The red bars are magnitude events of 2.0 or greater, but what we see is that even in that area, it's starting to drop off, similar to what you saw in the War-Wink area.

Exhibit 20 is a mud-weight distribution chart that shows that we're dealing with a fairly complex pressure environment where we have normal pressure above -- you know, above the Wolfcamp and then you start getting into a more overpressured section. And then it drastically drops back to a normal pressured section again below the Woodford. And a lot of this seismicity that's being recorded over in Texas now, around Pecos and back during the War-Wink time, seems to be coming from that overpressured section, is where it's coming from.

And then Exhibit 22 is a similar graph, 100 square miles around the subject well that we're talking about today.

Q. Exhibit 21?

A. 21. Excuse me.

Same type of graph, and it's a 100-square-mile area around the Asroc, Viper wells. And you see the seismic events on the bottom. Again, if not for the NGL network, they wouldn't be on there because I wouldn't have a source to put them on there. But we're seeing kind of similar characteristics of what you saw at War-Wink and around Pecos.

And the last exhibit, Number 22, shows that we're dealing with the same kind of overpressured environment in that section immediately above the injection interval. The injection interval is a normal pressure environment.

Q. Thank you.

And then behind Tab 3 are the same slides for the Viper well?

A. It's exactly the same. Yes.

Q. What conclusions have you drawn from your study with respect to the probability of slip?

A. The good thing is the faults are oriented in such a fashion that it takes an extremely high pressure to initiate fault slip. And by running the model, I see that the only faults that come close to that are quite a ways off to the northeast, and virtually the wells we're talking about here, you could put them in the model or pull them out of the model. They'd still see that same pressure on the fault in the northeast. It's more related to the wells that are nearer to that fault. And I think that was one of the blue triangles. One of the existing wells is the closest one to that currently.

Q. And given what you know about the depths and locations of the wells in this application, in your opinion, is there a risk of felt-induced seismicity?

A. There is always a risk of felt seismicity but probably not as a result of being induced. I mean, there's natural seismicity. There was the 2.9 event or whatever in 1984, which really couldn't be correlated to anything. It was an inducing event, but no, there doesn't seem to be a strong correlation that it would be as a result of saltwater injection.

Q. Were the Tab D exhibits prepared by you or compiled under your direction and supervision?

A. They were.

MS. BENNETT: I, at this time, would move to have the Tab D exhibits admitted into the record.

EXAMINER GOETZE: EOG?

MR. RANKIN: No objection.

MS. ANTILLON: No objection.

EXAMINER GOETZE: Tab D, D1 through D3, are so entered.

(NGL Water Solutions Permian, LLC Exhibit Letters D1 through D3 are offered and admitted into evidence.)

MS. BENNETT: Thank you.

And I have no further questions for Mr. Reynolds.

EXAMINER GOETZE: EOG?

MR. RANKIN: No questions.

MS. ANTILLON: No questions.

EXAMINER BROOKS: No questions.

CROSS-EXAMINATION

BY EXAMINER WARNELL:

Q. I have a question, Mr. Reynolds.

A. Sure.

Q. On the NGL network, the three wells, those are Striker wells, I believe?

A. As far as where they have the seismometers located?

Q. Yes.

A. I believe that's correct.

Q. And can you point those out to me here on your big exhibit?

A. Yeah. So I believe, just looking back at Dr. Taylor's exhibit, that they're located at Striker 3, Striker 2 and Striker 6. And so if we look at Exhibit 1 from my report, some of those will be on the map. Some of them will be so far west that they wouldn't be on here.

Q. So that might be the Striker -- I don't see the Striker 3. I see the 2 and the 6.

A. Yeah. The Striker 2 is on here, which is located on the far --

Q. Far west?

A. Yeah.

And the Striker 6 is actually right near fault segment 5, just east of it. So the Striker 3 is too far west.

Q. Okay. If some of your calculations were off

and there was -- recreated a fault slip, what would that mean?

A. Well, that's why we vary the inputs. And also the fact that NGL has been kind of a forward-looking company more so than most of the saltwater disposal operators I see, they will be in a position to detect any clustering or, you know, seismicity activity that might be increasing or showing up, and then they would be in a position to, you know, alter rates and change the rates on the injection. The FSP software, the good thing about it is, if you run it and it does slip, you can rerun it with different rates and different, you know, parameters -- not parameters but just different injection rates that can anticipate the pressure more, you know, quickly to keep it from building up too much at a point some distance over to a fault. So there is always that potential for them to react if they start seeing some seismicity. And I think I basically say that in the report, is that at this time, there doesn't appear to be any reason to rate-constrain any wells, but at a point in time where seismicity did occur, the model could be rerun and help identify wells that might be reduced.

Q. And you could ratchet back on your rates?

A. That's correct.

Q. Okay. Thank you.

EXAMINER GOETZE: Go ahead.

EXAMINER McMILLAN: Go ahead.

CROSS-EXAMINATION

BY EXAMINER GOETZE:

Q. Just one question. In your decision to break up this larger fault into segments, what was your criteria?

A. Mainly to try to have a centroid normal to a well so that if -- if I have a well here (indicating) and I put the segment here (indicating), I'm not getting a true measure. I want to get that closest distance to the fault so that -- so that I'm reading the pressures, you know, more accurately.

Q. So it would be based upon what we have as well locations currently -- proposed well locations --

A. Correct.

Q. Okay.

EXAMINER GOETZE: No further questions of this witness.

Thank you.

EXAMINER McMILLAN: I don't have any questions.

EXAMINER BROOKS: I don't have any.

MS. BENNETT: Well, good news. I have one final witness, only one final witness. So at this time I'd like to call my final witness, which is Mr. Scott Wilson.

SCOTT J. WILSON,

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

DIRECT EXAMINATION

BY MS. BENNETT:

Q. Good morning, Mr. Wilson.

A. Good morning.

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

A. Scott Wilson.

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

A. I work for Ryder Scott Company, and I'm a -- senior vice president is my title, and I do consulting projects.

Q. And have you been retained by NGL?

A. I have.

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

A. Yes.

Q. Can you briefly remind us of your professional credentials?

A. I have a petroleum engineering degree from Colorado School of Mines. I have a Master's in Business from the University of Colorado. I started working for Atlantic Richfield Company in Denver, then Alaska, then Dallas. In 2000, I started working for Ryder Scott Company as a consultant.

Q.   When you previously testified before the Division, were your credentials accepted as a matter of record?

A.   Yes.

Q.   Are you familiar with the applications that NGL filed in these cases?

A.   I am.

Q.   Have you conducted a petroleum engineering study related to those applications?

A.   Yes.

Q.   Have you prepared similar studies for NGL's prior applications?

A.   I have.

Q.   And have those studies been submitted to the Division in support of NGL's prior applications?

A.   Yes.

MS. BENNETT: At this time I would like to tender Mr. Wilson as an expert in petroleum engineering matters.

EXAMINER GOETZE: EOG?

MR. RANKIN: No objection.

EXAMINER GOETZE: State?
MS. ANTILLON: No objection.
EXAMINER GOETZE: He is so qualified.
MS. BENNETT: Thank you.
Q. (BY MS. BENNETT) Let's turn now to Tab E. You were here when Dr. Zeigler testified about the locations and proposed injection zones for these two wells, right?
A. Yes.
Q. And Tab E contains the study that you prepared with respect to those two wells --
A. Correct.
Q. -- based on the locations that Dr. Zeigler testified about and the locations you know about?
A. That's correct.
Q. And your study has two parts, right, a nodal analysis and reservoir simulation?
A. That's correct.
Q. What information did you consider when you put together your study?
A. I used the well locations. I used some step-rate tests on similar wells in the area. I've been working in this area for about a year and a half now, so I've looked at several wells in the area and calibrated the nodal analysis against existing wells. And the simulation work is very similar to what Todd Reynolds --

where we take prospective wells and place them in a simulation grid and then forecast forward what will happen once the -- injection.

Q. What is a nodal analysis exactly? Can you summarize that for us and what the relevance of that is?

A. Sure. A good analogy is supply-and-demand curve because the supply of fluids is the injection volume going into the well and the demand is what the reservoir will take away, and there is a balance between those two. And when they balance, that becomes the rate that the well will take.

Specifically to this case, the size of the tubing represents a restriction to flow. So if you use very small tubing, it's difficult for the water to get to the bottom of the well with any pressure left. So that's part of the supply. So the larger the tubing you use, more effectively you can deliver the water to the reservoir.

Q. And so your nodal analysis really was focused on the benefits of using a larger tubing size?

A. It was.

And using another analogy, it would be like a car. If you have flat tires, there is a lot of resistance to flow, and it's difficult to move. And to get from one place to another, you need more horsepower because you're driving on flat fires. The larger tubing is a more efficient way to get from one place to the next.

Q. Can you just briefly walk through the first three pages of your exhibit? I think those sort of reflect your nodal analysis. And let the examiners -- sort of explain to the examiners what you are looking at here and what your connections are.

A. Sure. The first exhibit shows a classic nodal analysis plot with the liquid rates running across the x-axis. That's liquid injection rates. And then the pressures are on the y-axis. The green curve there represents how the reservoir reacts to fluids as they're injected. The two curves that start at 8,000 psi on the left and then work their way down are the tubing hydraulics curves. And so that's two different wellbore configurations. And this one shows that the 5-1/2-inch tubing would potentially be able to inject 37,000 barrels a day, while the 7-inch-by-5-1/2-inch tubing would able to inject 48,000 barrels a day. That shows the magnitude in this particular well of what the larger tubing size would help.

Exhibit 2, same well, just a summary of the information. It says, "As the tubing size gets larger, you're able to inject more in any individual well." And the little inset table says if your intent in the area is to dispose of 100,000 barrels a day, if you use small wellbores, you'll need three of them. If you use larger wellbores, you'll only need two. So there is a decrease in the well count if you're able to inject more into each well.

The third exhibit just shows the frictional pressure drops that occur in the different-size pipe. That's the labels off to the lower right. It also shows the permitted maximum injection rate. That's the blue curve -- the blue horizontal curve that runs across at 8,600 psi. And then the curve that starts at 6,000 and inclines up and to the right is the actual injection pressure at different injection rates, showing, as you're approaching the maximum injection pressure, you can kind of predict off the scale. Maybe it would be at 100,000 barrels a day or something like that, but you're still pretty far from it at 50,000 barrels a day. So that's Exhibit 3.

And that's kind of the end of the nodal analysis aspect of it.

Q. So did your nodal analysis indicate that increasing the tubing size to 7 inches would not significantly increase reservoir pressures?

A. The reservoir pressure is a function of injection rate, and so if you are able to inject at a higher rate, your reservoir pressure will go up. But if you have fewer wells and your net injection rate is the same -- you know, it's the same effect. You just need fewer wells to get there.

Q. I think a moment ago you testified, though, that increasing the tubing size would reduce fiction?

A. Yes. Actually, you're gaining on horsepower. You don't -- you don't lose pressure in the tubing, and that's the primary benefit. The net pressure that arrives at the surface -- I mean at the bottom-hole location is going to be a function of the injection rate. And so that's, by definition, already below fracture pressure. So there is never an opportunity to get above fracture pressure as long as you're maintaining the maximum injection pressure at the surface.

Q. So increasing the tubing size would not cause fractures in the formation?

A. No. No, because you're constrained by the same limits that you would be on smaller tubing sizes. You're just wasting less horsepower.

Q. Thank you.

Is there anything else you'd like to say about your nodal analysis before we turn to the next

part of your exhibits?

A. No.

One -- one small addition in my background is I do teach classes in nodal analysis. I've done that since 1990. And this is very -- water injection wells are some of the easiest wells to model because it's single-phase, the fluids are easy to model. So this is pretty solid analysis in terms of predictability.

Q. Thank you.

So now let's look at Exhibit 4, and can you explain why you've included Exhibit 4 in your packet of materials?

A. Exhibit 4 is just to get an idea of the general layout of the area, kind of a big-picture view of where these injectors are. And then later there is a simulation grid that represents roughly the same area.

Q. Okay. And then Exhibit 5?

A. Exhibit 5 is a similar plot just showing the exact locations of the wells that we're looking at here, the Asroc and the Viper. It also has a one-and-a-half-mile radius around these wells showing the offset wells.

Q. Great.

And then I think the next few slides really take us into the heart of your reservoir simulation

analysis, right?

A. They do, yes.

Okay. So slide six is the first view of the simulation grid. The first time I did this a year ago, the grid was already simple. I had a few wells in it. It was a flat grid. I was lucky enough that Dr. Zeigler gave us structure maps. She also gave us structure thickness. And so I implemented those into this grid, and, ever since, we've been adding wells to it and watching how the grid responds as you inject water into the grid.

So Exhibit 6 shows the general picture where the grid is. I apologize that it's hard to tell the labeling on some of these wells. I zoomed in as best I can to show which wells are where, but they are approximate locations because I have to fit within the specific cells. So they're not necessarily perfect, but they're as close as I can get.

Q. The Asroc and Viper wells are sort of in the middle in this area right here?

A. Exactly. They'd be roughly in the center of this image. And I do have some zoom-ins a little later that show more detail.

Slide seven?

Q. Yes.

A. Okay. Slide seven slows a clear view of that same grid mesh. It shows kind of where the wells penetrate the mesh. This is also an inset image that's a slice across the mesh that shows that it gets thicker going to the -- I guess to the west. Going from east to west, the zone gets a little bit thicker. It's hard to tell looking at the grid, but if you look at the cross section, you can see it.

So then slide seven [sic] is actually an image of the thickness. So the color there represents the thickness. And you can see the dark blue in the upper right -- oh, sorry -- upper left is the thinnest of the structure, and then in the upper right is the thickest. And that gets up to roughly 1,800 feet thick. The wells that reference here, the Asroc and the Viper, are right about in the middle and are about 1,500 to 1,600 feet.

Q. That's the injection zone -- the thickness of the injection zone that we're talking about right here?

A. Correct.

Q. Uh-huh.

A. I did not model anything else. This is just the zone of reference.

And because the permeability in this is so high, I did not have any layering. I just had one big layer, so the good news is the grid runs very quickly so I can model things fast.

So then part nine shows the pressures that are equilibrated in that grid. And the initial pressure is basically a function of depth, so the deeper you go, the higher the pressure is going to be. It says "capillary pressure" here, but that's not really necessary. It's all single-phase water.

So this is the -- okay. So that should be -- actually, it looks like slides 9 and 10 are the same image. So what's happening there is that's the pressure at 20 years. And you can see that in the upper, left-hand corner, the time stamp there. So it's at 7,300 days or 20 years. So this is the pressure distribution at the end of the life. And the pressure distribution at the beginning of the life, you'd have to go back to the first set of slides. Okay. So effectively slides nine and ten are the same thing. They're the 20-year image of the life. So perhaps we should mark out the words "initial pressure of distribution" on that slide nine. And that's for the 20-year distribution. Sorry.

Okay. Slide ten is the pressure at 20 years. And you can see, compared to the offsets, the red color where you're at 6,000, 7,000 psi. You get up into the 8,000 and almost 9,000 psi right next to the wellbores. There is another image of this later on slides 12 and 13.

So Exhibit 11 is showing the -- the spread of the injected water at 20 years' time, and this is -- you can see the small circles around each wellbore location, and that represents the movement of the exact injected water into the grid at those time periods. And this is a large view that shows kind of the wells in this particular model and how far out they go. You can see the ones that are super close to each other might start interfering with each other maybe after 20 years, but you can see the ones that are widely distributed are -- they probably don't even know the other wells exist based on the pressure distributions.

Exhibit 12 is a zoom-in of the same thing, and this is the first one where we can see the wells that are referenced here. The Asroc is roughly in the middle of the figure, slightly to the right. The Viper is immediately to the south of it. And you can see the Falcons in there, the Javelin, the Patriot. Those are some of the offsets.

But the way to read this figure is that the cell that the wellbore goes through immediately, the saturation of injected fluids in those cells is fairly high. It's probably 70, 80 percent. But then as you move away, those purple colors and the darker colors represent a lower saturation of injected fluids. So it's basically a way to map how far this goes through.

And then the other slides are not here, but that's okay.

Q. Oh, did I leave out a slide?

A. Yeah. It's okay. We'll go with these.

Exhibit 13 shows a pressure profile over time for this suite of wells. And you can see at the very bottom, the horizontal lines are observation wells in the network, and they don't see any pressure response due to injection in this block of wells. Each of the injection wells does see a significant increase of pressure as you push water into it.

And then the next slide, Exhibit 14, shows that it doesn't really affect any of the wells until some 15, 20 years out, and they start to interfere with each other a little bit because the offset injection and the general increase in pressure around the wells causes the injection rates to drop off. Now, these injection rates are still maintained below the maximum permitted pressure, and because you have that pressure limit, you just to have start dropping your rates down as you can't push more fluid into the well.

Q. Thank you.

If you could summarize the takeaway from your study, what would that -- what would the takeaway from your reservoir simulation study be?

A. The big picture is this is a very thick, moderately high-permeability zone. It's capable of taking large amounts of injection over long periods of time. The wells that are permitted here, we turn them on at 40,000 barrels a day and let them run for 20 years, which is kind of the worst-case scenario or the best-case scenario, depending on perspective. And so it's showing that they don't necessarily interfere with each other to any great extent. And once they do, the downside is that the operator will just decrease the injection rates they're putting into those wells because they'll be at the maximum injection pressure.

Q. Did you consider whether the volumes potentially being injected into the formation will reach fracture pressures?

A. Implicitly, I do, because I set the pressure in the -- in the model at the permitted maximum pressure. And so once the well can no longer inject at 40,000 barrels a day at that pressure, it just automatically ramps down. Because in the simulator, you either set the pressure or the rate because one is defined by the other, and then the secondary phase will adjust accordingly. So I could have set the pressure and seen what these wells would inject, but if I had done that, they would start off injecting 70,000 barrels a day or something like that. That wasn't -- we have two constraints, so it's honoring both constraints.

Q. Based on your study, is it your opinion that these two wells wouldn't create potential formation fracture pressures as you've modeled them?

A. Correct.

Q. Were the Tab E exhibits prepared by you or under your supervision or compiled from company business records?

A. They were.

MS. BENNETT: At this time I'd like to move the exhibits behind Tab E into the record.

EXAMINER GOETZE: EOG?

MR. RANKIN: No objection.

EXAMINER GOETZE: State?

MS. ANTILLON: No objections.

EXAMINER GOETZE: Exhibit E is so entered.

(NGL Water Solutions Permian, LLC Exhibit E is offered and admitted into evidence.)

MS. BENNETT: Thank you.

I have no further questions for Mr. Wilson.

EXAMINER GOETZE: EOG?

MR. RANKIN: No questions from me.

EXAMINER GOETZE: State Land Office?

MS. ANTILLON: No questions.

EXAMINER GOETZE: I'll start on the end. Mr. Warnell?

EXAMINER WARNELL: No questions.

EXAMINER BROOKS: No questions.

EXAMINER GOETZE: No questions. Okay.

CROSS-EXAMINATION

BY EXAMINER GOETZE:

Q. Just one query. Based on your simulation reservoir modeling and assuming the parameters of the wells being operated over 20 years at the 40,000 barrel-per-day prediction, how far out will the pressure wave or the difference in between the actual well fluids and formation reach out from the well, roughly?

A. Sure. Figure 12 is probably the best one to look at for that.

Q. And not knowing the size of your cells.

A. These are half-mile cells.

Q. Okay. Very good.

A. So you can count the cells. Say, the Falcon. You draw the line down from the Falcon, and there is the Falcon cell itself, and then it looks like three past that is the volume that movement occurs.

Q. Okay.

A. And I was thinking of how to describe this in terms that are more natural. And pressure is best represented by sound. So if all of us in this room started yelling loudly, they might be able to hear us outside. They couldn't necessarily feel us or touch us, but they could hear us. And so the injection into the Falcon well will create pressure waves that will go for miles, but the actual fluids that go into the pressure into the Falcon well only go a short distance. And so pressure represents sound, and the fluids represent the actual physical being. And so the physical movement of fluids in 20 years is roughly a mile, maybe a mile and a half, depending on the flow rates and the thickness.

Q. Oh, yeah. Oh, I mean, not everything is going to have the same permeability and porosity.

A. True.

And up in the south -- up in the northeast corner, it's thinner, so if you're trying to inject 40,000 barrels a day there, it's going to go a little farther.

Q. Yeah.

A. But the bad news there is that you probably won't be able to get 40,000 barrels a day into it because it's thinner. So it kind of self-corrects.

MS. BENNETT: And I believe we do have those more descriptive exhibits in the Sidewinder case, which we'll be presenting after this one. So we do have those pressure exhibits in the Sidewinder packet.

THE WITNESS: Good.

EXAMINER GOETZE: No more questions for this witness.

I think we should take a break. I think everyone's had enough science.

MS. BENNETT: Before we take the break, though, I would like to ask that these cases be taken under advisement.

EXAMINER GOETZE: We still have someone else who would like to make a speech, so I'll let them --

Do you have input that you wish at this time or -- I mean after the break.

MS. ANTILLON: Okay.

EXAMINER GOETZE: Otherwise, everyone is going to revolt, and you'll have sounds in here.

EXAMINER BROOKS: That could be heard for miles.

EXAMINER GOETZE: Let's take, what, 15, ten?

EXAMINER McMILLAN: Yeah, 15.

EXAMINER GOETZE: 15.

(Recess, 10:15 a.m. to 10:25 a.m.)

EXAMINER GOETZE: Let's call the hearing back to order. So we are back on the record and still on Cases 20139 and 20143.

At this point we're back to the representative for NGL. And you're done with presenting your case?

MS. BENNETT: Yes. I am done presenting my case. Thank you.

EXAMINER GOETZE: So we go to EOG. Do you have any statements or any questions?

MR. RANKIN: No statements on behalf of EOG. No questions.

EXAMINER GOETZE: How about from the State Land Office?

MS. ANTILLON: The State Land Office would just like to say on the record that we are reviewing this application, and we do have concerns with the well spacing and the fact that there is a close proximity of the saltwater disposal well, Viper, in Case 20143, to State Trust Lands.

EXAMINER GOETZE: So with that, you would like to have both taken under advisement. However, since the State has entered an appearance --

I guess the question to the State would be: Do you feel at some time you're going to provide some sort of statement or opportunity for discussion of the well or --

MS. ANTILLON: Yes.

EXAMINER GOETZE: Off the record for Mr. Brooks.

(Consultation with Examiner Brooks off the record.)

MS. ANTILLON: The State Land Office doesn't object to this being taken under advisement. We are proceeding with a technical review, and we will be happy to apprise the Division of the results of that review, and we will consider an appeal if we have any concerns from that review.

EXAMINER GOETZE: Okay. So you will consider de novo at that point in time?

MS. ANTILLON: Yes, that's correct.

EXAMINER GOETZE: So you want to say?

MS. BENNETT: At this time I would request that Case Numbers 20139 and 20143 be taken under advisement.

EXAMINER GOETZE: Very good. Both cases, 20139 and 20143, are taken under advisement.

MS. BENNETT: Thank you.

(Case Numbers 20139 and 20143 conclude, 10:30 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.

DATED THIS 27th day of March 2019.

MARY C. HANKINS, CCR, RPR
Certified Court Reporter
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2019
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