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

APPLICATION OF DEVON ENERGY PRODUCTION COMPANY, L.P. TO REVOKE THE INJECTION AUTHORITY GRANTED BY ADMINISTRATIVE ORDER SWD-640, LEA COUNTY, NEW MEXICO.

CASE NO. 15397

REPORTER'S TRANSCRIPT OF PROCEEDINGS

SPECIAL EXAMINER HEARING

DOCKET NO. 13-16

BEFORE: Phillip Goetze, P.G., Hearing Examiner
David Brooks, Legal Examiner

March 29, 2016

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, Phillip Goetze, P.G., Hearing Examiner, and David Brooks, Legal Examiner, on 29, March, 2016, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Street Francis Drive, Room 102, Santa Fe, New Mexico.

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MR. EXAMINER: Good morning, ladies and gentlemen. This is the Special Examiner Hearing, docket number 13-16. We are here for case number 15397, application of Devon Energy Production Company, LP, to revoke injection authority, Lea County, New Mexico.

I'm the Examiner for today. My name is Phillip Goetze, and with me is legal counsel David Brooks.

At this point we call for appearances.

MR. BRUCE: Mr. Examiner, Jim Bruce of Santa Fe representing Devon Energy. I have six witnesses.

MR. FELDEWERT: May it please the Examiner, Michael Feldewert. I work with the Santa Fe office of Holland & Hart. I'm here on behalf of OXY, USA, Inc. We have two witnesses here today.

MR. EXAMINER: Very good.

What I would request is that the witnesses please stand, identify yourself to the court reporter, and we will have you sworn in.

MR. SCHWEGAL: I'm Steve Schwegal, geologist with Devon.

MR. BIHOLAR: Alex Biholar, geophysicist with Devon.

MR. BROUGHTON: Chris Broughton, reservoir engineer for Devon.

MR. JOHNSON: Kyle Johnson, drill engineer for Devon.

MR. HATHCOCK: Roy Hathcock. I'm the production engineering manager for Devon.

MR. WILBORN: Lorenzo Wilborn, production engineer with Devon.

MR. CLIFFORD: Thomas Clifford, engineer for OXY.

MR. COOPER: Wes Cooper, chief geoscientist with OXY.

MR. EXAMINER: Very good.

Go ahead and swear them in, please.

[Whereupon the witnesses were duly sworn.]

MR. EXAMINER: We would also ask you, when you do come up to testify that if you do have a business card, do give it to the court reporter so that she has an additional record.

And now to opening statements. Mr. Bruce?

MR. BRUCE: I wasn't planning on doing one but Mr. Feldewert indicated he was.

MR. EXAMINER: Well, let me do one thing. Before we proceed, we do have one item left unattended. We do have an order R14120, which was prepared for this case. We did go through some e-mails and we believe that they were delivered to you.

MR. BRUCE: That is correct.

MR. EXAMINER: And that we had a few that were embedded, that OXY said they were not going to waive their privilege. Do you have any problems with that?

MR. BRUCE: I'm not -- I didn't review them. I don't know which ones were embedded. Could we discuss that before you -- which ones were embedded.

MR. FELDEWERT: There was -- well, I can't tell you which ones. There were numerous ones that were embedded.

MR. BROOKS: Many of those instruments in the -- in the material that you gave to me appeared many times in those -- in various different files. Now, Phillip and I determined which documents we thought were privileged but we did not attempt to go back through the entirety of every file and identify every place where those documents would be.

MR. FELDEWERT: Because that would be a massive effort that we could not do in the timeframe we had.

MR. BRUCE: Okay. I think I have an easy way out of that, Mr. Examiner. My clients withheld their -- looked at a few of the doc -- or have looked at the documents. They said there was a couple of interests to them. We are not using those in our direct testimony and so maybe at the lunch break Mr. Feldewert and I could --

MR. EXAMINER: Have a discussion.

MR. BRUCE: -- have a discussion.

MR. BROOKS: That would be helpful.

MR. EXAMINER: All right. Well, then we will proceed on with the case.

MR. BRUCE: Mr. Examiner, due to the various motions and informal hearings in this case, I think the Division is fairly familiar with the claims of the parties.

Briefly, Devon encountered higher than normal pressures when drilling a well in the subject southwest corridor of section 34. At that time they contacted OXY regarding injection into OXY's nearby saltwater disposal well and OXY shut it in while Devon continued drilling. When OXY's well was shut in the pressures noticed in Devon's well dropped. Prima facie, there's something going on here, not to mention that those higher pressures were not encountered when the SWD well was drilled in the 1990s, nor was it noticed when a separate well in the southeast corridor of section 34 was drilled years earlier.

The Division, with respect to saltwater disposal wells or other injection wells, requires an operator to ensure there is no significant movement of fluids out of the injection zone, and I would also note that the Division must also protect freshwater sources. Those are founded in the statutes 70-2-12, and then of course in the regulations 19.15.26.10. The operator shall, as I said, make sure that there is no significant fluid movement. The operator shall report the failure of an injection well, which failure may endanger underground sources of drinking water, and the Division may restrict the injected volumes and pressures or shut-in injection wells that have exhibited failure under that regulation.

OXY, throughout this, has relied on the differences and the depths between the injection zone and the depth where Devon encountered the high pressures. However, as I said, something is going on and Devon will show how this could have occurred. Devon will show that the only source of that water flow that it noticed of that higher pressure is OXY's SWD well in which over 6 million barrels have been injected, and we believe the injection authority should be revoked or at the very least that well should be shut in until OXY can fix the problem.

Finally, depending on the area affected by the out-of-zone water flow, the drilling and operation of dozens of potential Devon wells will be affected adversely potentially causing waste and certainly impairing the correlative rights of the interest owners in these wells. And we ask, as a result, that Devon's application be granted.

MR. EXAMINER: Mr. Feldewert?

MR. FELDEWERT: Mr. Examiner, I've given you our exhibit notebook. It's the black notebook up there in front of you. On top of that are two printouts from the Division records. And I gave you those because this well has been permitted for dispose of the Bell Canyon since 1997 and we've had almost 20 years of disposal at perforations deeper than 5,355 feet.

The handouts I gave you are the Division records, and you have the well inspection history that goes back to 2002, always indicating that the equipment is in good shape, no issues. You've got the MIT, Mechanical Integrity Tracking Report. You can see the number of mechanical integrity tests that have been noted by the Division since 2002, always passing, never a failure in the well.

The only issue that's reflected in these records is a short period of injection over pressure on December 27th, 2004 when Pogo was operating this well. It was resolved within a week. The inspector came back on January 6th, 2005 and everything was okay. There's been no other issue with these wells for the last -- this well for the last 20 years.

Then comes along Devon in September of 2015, they're drilling a well and they hit a water pocket at 1800 feet. Okay. They jump to the conclusion that the cause of that is OXY's well and they file this application with the Division. If you turn to our Exhibit Number 29, this is a type log that we're going to discuss with you.

And you can see from this type log that there are numerous impermeable strata between the area of injection -- Exhibit 20 -- yeah, 29, and there's a bigger map in the back. You can pull it out if you want to. You don't need to now. But what the point is, there's no debate here that there were numerous impermeable strata zones, confinement barriers between the injection zone and 1800 feet up there in the Salado where they encountered their water pocket, including 3,000 feet of impermeable anhydrite. So recognizing this geology, Devon comes in and says, well, it's got to be your well. Your well must be conduit by which this water is migrating out of zone all the way up to 1800 feet.

We're going to present Mr. Tom Clifford here today. He's going to talk to you about the following events which have taken place since Devon's allegation. First off, the Division came back again and did another MIT test on the well. It passed. The Division does a Bradenhead test in October. There are no pressures recorded on the casing, thereby indicating no evidence of any fluid migration.

Look at our Exhibit Number 5. This is a current picture of the well. On the right-hand side OXY took the step, not required but they did, of putting on redundant pressure gauges on the casing annulus. They were installed in October, again, right after Devon's water encounters. They've had zero pressure readings since that time, again, indicating no evidence of fluid migration.

Devon says we want you to do temperature surveys, so OXY goes out and does temperature surveys on the well. That's our Exhibits 9 through 11, and they show no cooling trend above the injection zone. Again, no evidence of fluid migration.

OXY took another step. You're going to love this, Mr. Goetze. They did a radioactive tracer survey, something the EPA just loves. Okay. They did it for two days out there. They pumped a lot of that radioactive tracer stuff in there and checked for migration at various levels, indicates no channelling up of the water. The water is going out and down in the formation in which it's been approved for injection. Again, no evidence of fluid migration.

Mr. Clifford is going to get up here. He's going to show you our Exhibit Number 20. Our Exhibit Number 20 shows over the period of time that this well has been injecting it's been pressuring up. The zone has been pressuring up. It's more difficult now to inject water at the permitted pressure. You're not going to have a pressuring up of the reservoir if you've got the leak as they suggest, and they do nothing more than suggest.

Then we did a calculation of this. This is the second time I've been involved with this, this injection interval permeability. It comes out to be 2.44 millidarcies. That's matrix permeability is what they tell me and that's what they'll testify to. That's what you normally see for the Bell Canyon. It is not a fractured environment in which they were injecting.

Devon's theory of a water migration out of zone is nothing but a theory. It's nothing but conjecture. They have absolutely no evidence to support any problems with this well or any fluid migration out of zone. And for each of their witness that they put up there, ask them where is the evidence, not theory. Where is the evidence of fluid migration because it doesn't exist.

All they have is the fact that they hit a pressurized water pocket at 1800 feet. That's it. This region has seen isolated random instances of pressurized water pockets in the shallow zone. It's nothing new. It's unusual but it's nothing new and operators have known it for years.

Mr. Russ Cooper is going to testify and he's going to discuss how these isolated water pockets form in the salt section. He did a review of the salt section region, of the region. Not a very small finite area like Devon did, but it was a salt section region, a 12 township area and he found 22 instances in the records of report of instances of isolated random pressurized water pockets.

It doesn't happen very often. Very random, very isolated. There's no pattern to it, but it does happen. We're going to show you a couple of examples. He's going to walk you through a couple of examples, one of which is 3.5 miles away just off to the left of Devon's little finite study area.

And just off to the left of Devon's little finite study area is a developed field, lots of wells, large groupings of wells. And in that area there was one well that had a pressurized water pocket, just one, showing you how random it is, showing you how isolated it is, and showing you it can occur in one area and 300 feet away or 700 feet away, you don't hit it because it's isolated water pockets. So we have some other examples he's going to walk you through.

The mere fact that Devon hits another water pocket in this shallow salt section over 3,500 feet above the approved injection zone doesn't support shutting in this well, it doesn't support -- it doesn't show a migration of water, and it doesn't support hampering OXY's ability to operate in this area by now shutting in this disposal well that has been operating for 20 years. So since there's no evidence, and I'm talking about evidence, not theory. Since there's no evidence to support their migration theory, this application needs to be dismissed.

MR. EXAMINER: Very well.

Mr. Bruce?

MR. BRUCE: I call Mr. Johnson to the stand, please.

Mr. Examiner, all of Devon's exhibits are the lettered exhibits sitting there.

MR. EXAMINER: And you did that for the convenience so we wouldn't get confused; is that right? Thank you.

MR. BRUCE: You know I have problems with exhibits and I was thinking ahead.

THE COURT: Proceed.

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Could you please state your name and the city of residence for the record.

A. My name is Kyle Johnson. I live in Edmond, Oklahoma.

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

A. I am a drilling engineer for Devon Energy.

Q. Have you previously testified before the Division?

A. No, sir.

Q. Would you summarize your educational and employment background for the Examiner?

A. I have a bachelor's of science in petroleum engineering from Texas A&M University. I've worked full time in the industry since 2009, both for Devon Energy and Chevron in various capacities. I've worked as a production engineer, completions engineer, operations, and have been primarily a drilling engineer for the past four years. And I've got about three years' experience in the Delaware Basin itself.

Q. And are you familiar with the events involved in the drilling of Devon's North Thistle 34 State Com Number 1H well in section 34 of 22 south, 33 east?

A. Yes, sir, I was the drilling engineer for this one.

Q. And your area of responsibility at Devon includes this portion of Southeast New Mexico?

A. Yes, sir.

MR. BRUCE: Mr. Examiner, I'd tender Mr. Johnson as an expert drilling engineer.

MR. EXAMINER: Mr. Feldewert?

MR. FELDEWERT: No objection.

MR. EXAMINER: He's so qualify.

Q. (By Mr. Bruce) Mr. Johnson, if you could refer to Exhibit A, which is an eight-page exhibit. Did you prepare this exhibit for this hearing?

A. Yes, sir, I did.

Q. Okay. If you could refer to Exhibit A, and let's run through it, starting with page 1.

A. Okay. I'll just walk you through kind of the timeline of events that happened, or at least the significant ones. We were drilling in North Thistle 34 State Com 1H, which is roughly 1,350 feet away from the subject OXY SWD well. We drilled our surface casing or our surface hole, which was 17-and-a-half inches down into the rustler formation and set our 13-and-three-eighths casing to cover the freshwater bearing zones as we normally do. That was done without issue.

We drilled out of our shoe tract and performed a formation integrity test to 11-pounds-per-gallon equivalent. 11-pounds-per-gallon is the standard for the area. You never -- or I have never seen anything above that in my experience while drilling here, so that's the reason that we only test to 11-pound-per-gallon.

On September 3rd we were drilling ahead at 22:00. We took a kick at 1,820 feet, we shut in the well. And as per our well control procedures, we got a shut-in pipe pressure, which was 585 PSI running through the calculations. That came up to a kill weight mud of 16-pounds-per-gallon equivalent. Initially we suspected this to be H2S. Encountering isolated H2S in this salt section is not uncommon. It's not common, but it does happen occasionally as OXY has shown.

We performed the first circulation of the driller's method and confirmed that there was no H2S and this was strictly a water flow. Later that morning we confirmed that the nearby OXY SWD well was shut in at the time of the kick and they had a shut-in tubing pressure of approximately 620 PSI according to the person in charge of our operation out there.

If you'll go the page 2, this was a quick calculation we performed to see if this OXY SWD would be a potential source of this water. Comparing the two surface pressures, 585 PSI on our Devon well and 620 on the OXY SWD, we were drilling with a 9.8 fluid weight. We assumed that 9.4 fluid weight for the OXY SWD. This was based on a 1.13 specific gravity injection fluid, which is what we normally encounter with our Second Bone Spring and Avalon water that's injected on our wells.

Calculating at that same depth of interest of 1,820, we arrived at almost identical pressures at that depth; 1,512 for our well and 1,510 for the OXY SWD. This being a shut-in dynamic situation, the Utube calculations made sense that these wells could very possibly be in communication. Taking those pressures and converting them to an equivalent mud weight, you get a 15.98 on our well, a 15.95 on the SWD. So for all error intents and purposes, you would round up and call this a 16-pounds-per-gallon equivalent.

Moving on to slide 3, this is just a snapshot of our TODCO. These are just the different channels that are tracked while we were drilling. Up note is on the right. This just shows the instance when we took the initial gain.

The blue line, on the very right-hand track, shows our gain/loss meter. I've got it circled here where it shows we took a 30-barrel kick, we turned off our pumps, checked for flow, and confirmed that the well was showing. You could see the yellow line on the second tract from the left. You can see the flow decrease when we shut off our pumps, but the well is still flowing with the pumps off. At that point we shut the well in and went about our procedures.

Moving on to slide 4, over the next two days we made preparations to deal with this high pressure flow. On September 6th we began drilling ahead. We had weighted up to a 14-pounds-per-gallon fluid. The idea of this, we didn't weight up to a full kill weight mud, we were holding some pressure back at the surface utilizing a low pressure rotating head. Those rotating heads that we were using were rated to about 500 PSI. In reality, they have a working pressure of somewhere closer to 350. So with a 14-pounds-per-gallon fluid, that reduced our surface pressure within our operating margin.

At 20:30, I got a call from the person in charge on the rig and he informed me that the well was starting to flow harder, that he had to increase the back pressure that he was holding by approximately 200 PSI. This was getting above our comfortable range of using the rotating head so we made the decision to increase our mud weight to 15-pounds-per-gallon to decrease those surface pressures back to a tolerable level.

That following morning our person in charge on the rig visited the OXY SWD and determined that the well had begun injecting at some point earlier the previous day. At 9:00 AM, this was Labor Day, I believe, I called the OXY emergency line and talked to a few different people, but I requested that the well be shut in. OXY complied and shut in the well. I don't know exactly what time that was shut in. It was sometime in the morning.

At 1:00 o'clock on that afternoon of September 7th, I had a conversation with the PFC on the rig and he told me that the flow had decreased and the pressure that we were having to hold had decreased by about 200 PSI, so that sequence of events there showed me that we had communication with the well. The well had begun injecting. We had an increase in pressure and had to increase our mud weight. When we requested the well be shut in, that pressure decreased and the back pressure that we required to hold was decreased as well.

Going on to slide 5 here, from September 7th to the 11th we continued to drill ahead. We were having to change out our low pressure rotating head every 10 to 12 hours. It kept trying to blow out so we would have to shut in, replace the rotating head, and then continue on.

The final mud weight, when we reached the TD of this whole section, was a 15.3-pounds-per-gallon. We spotted a heavy 17-pounds-per-gallon pill hoping that this would kill the well and keep it from flowing on us. We stripped our bottom hole assembly out of the well not allowing it to flow. We then began running our 9-and-five-eighths intermediate casing.

At that point we had no ability to hold back pressure because we weren't circulating and we just had to allow the well to flow. During the 10-hour casing run the well flowed at approximately

1400 barrels of saltwater. We had trucks coming in and out hauling this water off, so we don't have an exact estimate, but 1400 barrels was the best we could come up with.

On September 11th we cemented our 9-and-five-eighths casing in place. We had talked with the NMOCD office and discussed that. They gave us permission to run an external casing packer and DV tool combination inside our surface casing. The idea of this was that when we performed our cement job, we didn't want the well to continue to try and flow on us and displace our cement or water down and give us a poor cement job.

So what we did was we pumped our cement job, inflated our external casing packer, and determined that we had good weight cement to surface. So instead of activating our DV tool and pumping a second cement stage we went ahead and canceled it because we knew that we had good cement. At that point, after setting the external casing packer, the well became static because we had everything isolated.

Moving on to slide 6, this was just the very initial review we did after the incident. We went back and looked at the mud records we could chase down that had availability to. Those are indicated with green circles. The ones with red dots are wells that we couldn't find mud records to right off the bat. The initial look was that none of the offset wells had encountered any kind of a high pressure flows, and the highest mud weight ever used in this section was a 10.4-pounds-per-gallon.

Moving on to the next slide --

Q. Wait, wait, just for a second just to orient the Hearing Examiners. Looking at this, section 34 is about in the middle of this land plat, correct?

A. Yes, sir.

Q. And the square around the well, that's OXY's SWD well?

A. Yes, sir, that's correct.

Q. And immediately to the west is the North Thistle 34 Well that you were drilling?

A. Yes, sir, in the blue circle there.

Q. And just for the record, the colored acreage is acreage in which Devon owns a working interest; is that correct?

A. Yes, sir.

Q. Okay. Let's move on to page 7.

A. So after the incident, we expanded our research. We were able to get data drilling reports from the OXY Diamond SWD itself, and we got some data from the nearby Humble State 1H, which is in the same section. Upon reviewing those reports, no abnormal water flows or pressure were encountered in either of those wells.

The OXY Diamond SWD was drilled in 1996. Mud weight through the interval of interest, which would be the 1800 down to around 5,000 feet, they did not encounter any water flows or any mud weight exceeding 10-pounds-per-gallon. We had a log header that we got for the Humble State 1H across the same section that showed a max mud weight of a 10.4-pounds-per-gallon for the open hole section of 363 down to 5300 feet and no water flows were noted. And also the fact that they were able to run logs would also indicate that they were not dealing with any high pressure water flows.

Upon that, that research tells me that this water flow and pressure house didn't exist in the section prior to 1996 and was created sometime after the SWD began injecting. We expanded our research. We reviewed a six township and range block area, which equivalents to 216 sections. Devon, within that area, has 163 wells. I reviewed all of those, and upon reviewing those I did not find any similar instances of high pressure water flows. We did have a couple wells related to H2S or air pockets, but I don't feel those were analogous to what we encountered on our well.

Going on to the last slide, number 8, just some of the concerns that we have with this situation. On the well that Devon-drilled, the North Thistle Well, our surface casing shoe, as I mentioned, we only performed a formation integrity test to 11-pounds-per-gallon. With continued injection and sustained pressure on that surface casing shoe, there's nothing to say that at some point something couldn't fail, either our casing or our cement, which could result in either a contamination of freshwater zones above our casing shoe, or even worse, an uncontrolled release of water flow to surface.

We had a second well planned on this same pad, which would have been the North Thistle 34 State Com 2H. We canceled that well due to the events that we saw on this one and moved the rig to a different section after we finished drilling.

Some of the other witnesses will show we had a lot of wells planned for this section in the future. Dealing with this water flow and pressure is going to definitely add a lot of costs to us, but more importantly it's going to be a safety environmental risk. In order to safely drill this, we'd have to test our surface shoe to a 17-pounds-per-gallon, at least by our -- Devon's well control manual, and that's really high and almost unheard of for a surface casing shoe.

And then the last thing is we really don't know the extent of this drilling hazard. There's no other surface hole locations that have been drilled since this North Thistle -- or, excuse me, since the OXY SWD began injecting within one mile of this. So, you know, theoretically the extent of this hazard could be up to a mile away.

Q. And will another witness show a future development in this section?

A. Yes, sir.

Q. Referring back to page 2 of your exhibit, Mr. Johnson, the pressures and the fluid weights and the depths, those are all -- that's all facts, isn't it? That's evidence?

A. Yes, sir.

Q. That's not theory?

A. Yeah, that's all facts. It's all

documented data that we have.

Q. And if you turn to page 4 of your exhibit where the back pressure increased by 200 PSI, and once the SWD well was shut in, it dropped 200 PSI. That's evidence, isn't it?

A. Yes, sir.

Q. It's not theory?

A. No, no. There's no doubt in my hind that the two were communicating at some point.

Q. And then if you move to page 7, you're talking about the drilling of the SWD Well and the Humble Well, which I believe is in the southeast corridor of section 34; is that correct?

A. Yes, sir.

Q. Those mud weights, those are reported data; is it not?

A. Yes, sir.

Q. It's data, it's evidence?

A. Yes, sir.

Q. It's not theory?

A. Correct.

Q. Mr. Johnson, was Exhibit A prepared by you or under your direction?

A. Yes, sir.

Q. And in your opinion, is the granting of

Devon's application in the interest of conservation and the prevention of waste?

A. Absolutely. Yes, sir.

MR. BRUCE: Mr. Examiner, I'd move the admission of Exhibit A.

MR. EXAMINER: Mr. Feldewert?

MR. FELDEWERT: No objection.

MR. EXAMINER: Exhibit A is so entered.

MR. BRUCE: And I pass the witness.

MR. EXAMINER: Mr. Feldewert?

CROSS-EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Johnson, how long did you say you've been a drilling engineer in this particular area?

A. I've worked for Chevron in this area for about two years, and then about a year with Devon.

Q. And in this -- let's just use your study area here, your A-6. How many wells have you drilled in this particular area?

A. I don't have an exact count, but I'd say 10 to 12.

Q. In the area shown on Exhibit A-6?

A. No. No, sir, not within that, but it would be within the six township and range block that I described on slide number 7.

Q. 10 to 12?
A. Yes, sir.
Q. And have you had any experience with shallow pressurize naturally occurring water pockets in this area?
A. No, sir, not previously.
Q. You agree that they do exist occasionally, correct?
A. Occasionally, when H2S is present has been my experience.
Q. Has been your experience?
A. Yes, sir.
Q. What experience do you have? I thought you said you hadn't encountered any.
A. Excuse me?
Q. I thought you said you had not encountered any?
A. Well, I've worked in groups with other engineers that have drilled wells in other areas and we -- we work closely together so I've heard them. And studying this incident, I've also reviewed wells that -- you know, especially OXY provided a list of 22 wells, and I noted on there that 15 of the 22 wells involved H2S.
Q. But not always? Not always, correct? H2S

is not always present when you hit these high pressured water pockets?

A. From what I've seen, H2S is always there. If there's --

Q. Well, you said --

A. If there is -- shallow water flows are typically much lower pressure than what we saw, much lower magnitude.

Q. I'm trying to understand, your testimony is that every time you hit a -- every documented report of pressurized water pockets being hit by operators involved H2S; is that your testimony?

A. No, sir, but that is what I've reviewed.

Q. Okay. With respect to your study, on Exhibit A-7 you suggest that on this exhibit that you examined an area of six townships, range -- involving six townships; is that right?

A. Two townships, three ranges, which comes up with six township and range blocks.

Q. Okay, thank you. Can you explain to us why Devon then limited its production of its records to only two township and range blocks?

A. We did provide all 163 wells, I believe.

Q. I don't think so.

A. I believe we gave a spreadsheet of all our non-productive time related to those wells.

Q. But you didn't give us all the information that you had on your six township block areas. Can you explain why?

A. I don't believe it was requested.

Q. It was requested.

A. Excuse me?

Q. It was objected to.

A. Excuse me. I don't understand the question.

Q. It was requested and it was objected to.

A. Okay. Not to my knowledge.

Q. Well, it's reflected in the Division records.

Okay. Did you -- you said here that you did an -- according to this exhibit, a further review of Devon-drilled wells; is that right?

A. Yes, sir, within this town -- six township and range blocks.

Q. You just looked at Devon-drilled wells, you didn't look at other records?

A. No, sir, because, you know, Devon-drilled wells are what we have the full reports to and what we have access to. We really don't have data to many of the other wells other than the public

information that's available.
Q. Oh, that's right, you have public information available. You didn't review any of that?
A. No, sir.
Q. Okay. And you didn't review any township blocks to the west or northwest of your study area?
A. No, sir.
Q. So if I look at Exhibit Number A-6, you didn't pay any attention to what's over just to the west side of your study area? You didn't look at anything to the west?
A. Not if they were not Devon-drilled wells, no, sir.
Q. Did you look at any Devon-drilled wells to the west?
A. Yes, sir. Yeah, they -- they were in that section. They would have been township 22, range 32 and 33, I believe.
Q. Okay. You just looked at Devon-drilled wells?
A. Yes, sir.
Q. Did you notice anything about the records when you looked at those Devon-drilled wells? Well, let me step back. When you say Devon-drilled wells,

are you talking about wells that just Devon drilled or does that include wells that Devon operates?

A. There -- there may be some wells that Devon operates as well.

Q. Did you look at those records?

A. Yes, sir. If we had drilling reports I did.

Q. You did?

A. Yes, sir.

Q. If you had drilling reports?

A. Yes, sir.

Q. You didn't look at the Division records relating to your wells that you operate?

A. No, sir, I didn't have time to review all that.

Q. You didn't have time? Is that what you said?

A. Yes, sir.

Q. If I look at your A-6, within the area you said that you examined, up there in the upper left-hand corner, do you see two well symbols that have Cloyd next to them?

A. Yes, sir.

Q. Did you look at the records for those wells?

A. Yes, sir, I did, as part of the data that OXY provided.

Q. You did? Part of the data OXY provided, right?

A. Yes, sir.

Q. And they showed they had encountered flowing water there, correct?

A. Sulphur water, yes, sir.

Q. When they were drilling?

A. Yes, sir.

Q. How come you didn't highlight those on your A-6?

A. Well, when I built this exhibit initially I did not have that data.

Q. Okay.

A. But I will note that those two Cloyd wells both refer to sulphur water or -- which would result from H2S pressurization and both of those wells were in the Castile. They're lower, much deeper than where we encountered flow.

Q. Well, let's go to exhibit -- I tell you what, let's not speculate. Let's go to Exhibit 31 in our notebook up there.

A. Okay.

Q. Go to the second page of Exhibit 31. When you did a study, did you look at any of these records?

A. Well, I looked at them after OXY provided this list of wells, yes, sir.

Q. But when you did your study, you hadn't looked at any of these records?

A. No, sir, I hadn't seen them previously.

Q. And the two Cloyd wells are the first two wells listed; is that right?

A. Yes, sir.

Q. These are all -- these are drilled back in 1930s; is that right?

A. Yes, sir.

Q. And they hit pressurized water pockets at 3,363 feet?

A. That's what it shows, yes, sir.

Q. You don't dispute that evidence, do you?

A. Only the fact that it was sulphur water, which indicates there was H2S. And if the records go back to 1937 then I would question their validity or how accurate they were.

Q. You got any more recent records on these wells?

A. No, sir, I don't.

Q. All right. Then I want you to go to your

A-1. Now, this is when you initially encountered your pressurized water pocket, correct?

A. Yes, sir.

Q. Were you aware -- and as you point out in here, OXY's well was actually shut-in at that time; isn't that correct?

A. Yes, sir.

Q. Were you aware that they were also pulling tubing on that date?

A. After the fact I was.

Q. So now you're aware that they were pulling tubing of that date?

A. Yes, sir.

Q. So they weren't injecting when you hit your water pocket? You also say that you suspected an H2S kick?

A. Yes, sir.

Q. Why is that?

A. Well, certainly I was not expecting to encounter any kind of water flow from the OXY SWD at this depth. So as I mentioned before, any time you encounter a kick, shallow like this, you're -- at least the first instinct, from what I've seen, is to assume that it's H2S because that is the majority of reasons for having any kind of flow at this level or

this -- this depth.
Q. Do you know how long OXY's well had been shut in when they observed that 620 PSI shut-in pressure?
A. No, sir.
Q. And do you know what date Devon's person in charge observed this 620 PSI shut-in pressure that you reference on here?
A. It would have been within a matter of hours of us taking that kick on September 3rd.
Q. How do you know that?
A. Just my conversations with the person in charge on the rig.
Q. Who is the person in charge?
A. His name was Mark Easley.
Q. Did Mark Easley go over and take a look at OXY's well; is that what you're suggesting?
A. Yes, sir.
Q. And he didn't tell you that they were pulling tubing?
A. He had mentioned that there had been a coil tubing unit on location, but there was no workover rig there at the time.
Q. Now, you say you suspected H2S, but I guess you didn't find any, correct?

A. No. As I mentioned, we performed the first circulation of our driller's method, which is a standard well control for Devon, and we got our bottoms up and determined there was no black water or H2S in that bottoms up. It was --
Q. Did you take a water sample?
A. They did, but it wasn't ever processed that I'm aware of.
Q. Why not?
A. I don't know. I guess we didn't think it would be coming to court, so --
Q. So you took a water sample for what purpose?
A. Well, we wanted to know what -- you know, what the source of this could be.
Q. So you take the water sample to determine the source of the water. And then what happened?
A. I'm not sure. I don't know what happened. It's hindsight 20/20, we definitely would have liked to have kept the samples because I think it would have shown --
Q. What happened to the water sample?
A. I couldn't tell you.
Q. Do you still have it?
A. No, sir, not that I'm aware of.

Q. How do you know you don't have it?
A. Because I asked him.
Q. Who did you ask?
A. The person in charge.
Q. This is Mark Easley?
A. Yes, sir.
Q. Did you ask Mark Easley what happened to it?
A. He said that it got lost. Either the -- our mud engineer had taken it for processing and we've just never seen it since then.
Q. I'm sorry, hold on. So you talked to Mark Easley about it, right?
A. Yes, sir.
Q. Asked him what happened. And he said what?
A. That the mud engineer had taken it for processing but we -- when we followed up with the mud engineer we didn't know where it was at.
Q. Who is the mud engineer?
A. I don't know his name.
Q. Does he work for the company?
A. He worked for M-I Swaco.
Q. I'm sorry?
A. M-I Swaco was our mud company.
Q. So is it your testimony that Mr. Easley

told you that he gave it to this mud engineer?

A. Yes, sir. Well, the mud engineer would have been the one that take -- would have taken the sample.

Q. Okay. But you didn't -- the company didn't secure it so that they could actually analyze the water?

A. Yes, that seems to be what happened.

Q. Okay. Are you familiar with the quality of OXY's water that they inject?

A. No, sir.

Q. Are you aware that that contains H2S?

A. No, sir.

Q. If it did contain H2S and this connection existed, as you would suspect or as you theorize, wouldn't you expect to see H2S in that water as well?

A. I mean, if they were indeed injecting H2S.

Q. Or water containing H2S?

A. Yes, sir.

Q. If it had this connection, as you suggest, you would have seen that in your kick, correct?

A. Not necessarily. I mean, it's -- it's likely, but I don't -- I don't --

Q. But you didn't see any H2S?

A. No, sir.

Q. That's one thing you're able to confirm?

A. Yes, sir.

Q. Now, I want to go to A-2, please.

A. Okay.

Q. What's the -- I didn't quite understand the source. You got OXY SWD, you got that column?

A. Yes, sir.

Q. And then you got a number there in the fluid weight, pounds per gallon of 9.4 with a little asterisk behind it.

A. Yes, sir.

Q. What's the source of that number?

A. Devon has other wells in the area that we inject water, that's produced water from the Second Bone Spring and the Avalon formations. The specific gravity of that water that's injected averages about a 1.13, so converting from a specific gravity to a fluid weight pound per gallon, that's how you arrive at 9.4.

Q. But you didn't have any evidence of OXY's actual water weight?

A. No, sir.

Q. And you didn't ask them for it?

A. Not at the time, no.

Q. You didn't ask them for it since, did you?
A. No, sir.
Q. If it was 9.7, would that make quite a bit of difference in your calculations here?
A. Potentially.
Q. Well, it would, wouldn't it?
A. Yes, but you've got to imagine the margin of error that you're dealing with here. You know, you're talking about a difference at this shallow of a depth, three-tenths of a pound.
Q. You don't think that's significant?
A. I think it is, yes, sir.
Q. A difference of three-tenths of a pound is significant?
A. Yes.
Q. Now, you say you did this Utube calculation balance. What does that mean?
A. Well, if you envision a U, surface pressure to surface pressure, and the idea being that if two wells are connected at the base of the U, the surface pressure -- or the pressure at that base of the U would be equal. And so what would be different between those two Us would be your fluid gradients and then your surface pressures.
Q. So are you assuming that -- normally don't

you do that within a particular wellbore?

A. Or you can do it between two wellbores.

Q. Okay. And you're assuming, therefore, that there's an open, uninhibited path between the two wells, right, to get your Utube?

A. Yeah, that would be your basic assumption. And, again, this was done --

Q. In other words, you don't account for, in your calculations, the distance between these two wells?

A. You wouldn't need to, no, sir.

Q. I'm sorry?

A. You wouldn't need to, being a static condition. Now, if it was a flowing condition you would expect there to be some kind of pressure drop. But knowing that both wells were shut in and you were dealing with a static condition, the distance between the two wells theoretically would not matter if they were connected.

Q. So you don't think it matters if there's 1300 feet of rock, salt, or anhydrite or whatever the material is between the two wells?

A. Not if it's permeable.

Q. And you don't account -- not if it's what?

A. Not if it's permeable.

Q. If it's permeable. Did you ascertain the permeability of the migratory pathway that you suggest exists?

A. No, we did not.

Q. So you don't account for any kind of friction in whatever zone you suggest is the migratory path in making these calculations?

A. Well, again, you would only be accounting for friction if you were dealing with a dynamic condition or a flowing condition. This was a calculation based strictly on static conditions.

Q. Isn't it true that the two wells had different pressures --

A. Correct.

Q. -- at the injection zone?

A. Oh, down lower?

Q. Yeah.

A. What are you referring to, different pressures?

Q. Well, isn't it true that OXY's well had a higher pressure at the injection zone than what Devon encountered when it drilled its well through the injection zone?

A. I would have to check those numbers to confirm that.

Q. You're not aware of that?

A. No. I mean, I know the pressure that we encountered when we took the kick in the injection zone.

Q. But you don't know Devon's pressure in the injection zone?

A. No. I know Devon's pressure, I don't know OXY's.

Q. No, no, I'm sorry. You don't know OXY's pressure in the injection zone?

A. Correct, yes, sir. Devon is calculated to be 2,894, I believe, PSI.

Q. And to the extent that there would be a difference in pressure, let's say the OXY injection pressure was higher than the pressure that Devon encountered at the same injection zone, the difference there would be because of the distance between the two wells, would it not?

A. If you're discussing a flowing condition, so I would have to really look at what numbers are being used, but if it's a situation where the well is injecting and it has a certain pressure then, yes, that would come into -- that would come into effect. Now, if it's static then I don't believe there would be --

Q. Didn't you see OXY's exhibits that they presented -- that they presented in this case?
A. Could you tell me which one you're referring to?
Q. Take a look at Exhibit 26. Have you seen this, Mr. Johnson?
A. Yes, sir.
Q. Have you looked at it?
A. Yes, I've looked at it.
Q. Have you studied it?
A. Yes, sir.
Q. So weren't you aware that OXY's injection pressure at the zone of injection was 3,274 PSI?
A. Well, I take that at face value. I don't know at what point this was taken. We've been given a variety of shut-in pressures, so depending on which one you select at random, you could come up with a variety of different shut-in bottom hole pressures.
Q. And your pressure is 2,894 PSI?
A. Yes, sir.
Q. And there's no debate there, right?
A. I wouldn't think so, no, sir.
Q. And would you agree that the difference between those two pressures would account for the

distance between the two wells, in part?

A. I wouldn't think so. I don't think that's a distance-related figure. If they are shut-in pressures, I don't believe that would be a difference.

Q. Okay. Now, the other thing that you noted here is A-4. This is the events on September 7th, correct?

A. Yes, sir.

Q. On Labor Day?

A. No, I don't believe September 7th was Labor Day.

Q. You don't think September 7th was Labor Day?

A. You're correct.

Q. All right. And you note this 200 PSI pressure drop. Why is that important?

A. Are you referring to the one that occurred at 13:00?

Q. Yeah. Why is that important?

A. It would be important because that was after the OXY SWD well was shut back in.

Q. And do you know when, as you suggest, the OXY SWD well was shut-in?

A. I don't know the exact time, no, sir. I do infer that it was sometime that morning, sometime between 9:00 AM and around 1:00 o'clock that day would be my best guess.

Q. And is that timeframe important to your proposition here?

A. I would say it is, yes, sir.

Q. Does it matter if it was five hours before you experienced the pressure drop?

A. I wouldn't think so. You wouldn't expect it to be instantaneous. I would -- I would almost assume there to be some time delay.

Q. What about 24 hours before?

A. Yeah, I don't know.

Q. Would that be of importance to your opinion?

A. It could be, yes, sir.

Q. How would it impact your opinion?

A. Well, if the well was shut in 24 hours before this took place then, I don't know, it would just mean that the -- the rocks probably tire a little permeability and you expect a longer time delay before you see that pressure response.

Q. So you think it would be a factor of the permeability of whatever pathway you suggest exists between these two wells?

A. Yes, sir.

Q. Okay. What if OXY hadn't shut in this well before the pressure dropped, what conclusion would you draw?

A. Well, I would have expected to see a pressure drop if they hadn't shut in their well. So if they had -- you know, if they continued injecting and we saw that back pressure decrease on its own then I don't -- you know, I wouldn't be as convinced that the two wells were communicating.

Q. You wouldn't have the evidence that Mr. Bruce was talking about?

A. Excuse me?

Q. You wouldn't have the evidence that Mr. Bruce was talking about?

A. Correct, yes, sir.

MR. FELDEWERT: Okay. That's all the questions.

MR. EXAMINER: Very good.

Redirect?

MR. BRUCE: Just a little bit, Mr. Examiner.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Could you turn to their Exhibit 31 again, the list of the wells.

A. Yes, sir.

Q. The second page of Exhibit 31. Now, I think you stated this in response to cross-examination, but there's two components to what is called the self section; is that what you said?

A. Yes. I think -- and I think Steve, in his testimony will show this, but there's the salt section and then there is the lower Castile section, I guess.

Q. Is there a difference between -- in one versus the other, are H2S flows more common than water flows or --

A. I would say in the lower Castile section you're probably more than likely to encounter the water flows and pressure associated with H2S.

Q. So in the Salado you're more likely to get H2S or is it the reverse?

A. I wouldn't say that you're more likely in one or the other. Steve or one of those guys could probably provide a little more clarity to that. It wouldn't be my expertise.

Q. But you looked at this data that OXY provided on this chart, correct?

A. Yes, sir, I did.

Q. And what numbers -- or what did you note regarding what OXY set forth regarding H2S or sulphur or black water?

A. Well, upon reviewing these wells, there's 22 wells on this list. Upon reviewing, discovered that 15 involved either H2S or sulphur water, black water. They also -- I mean, as we noticed, those Cloyd wells had to go all the way back to 1937 to find some of the status, so encountering this, in general, is fairly uncommon. And you'll note on this well -- on this list of 22 wells there's only four wells that have been drilled in the last 10 years, so -- and three of those wells on that list are also involving H2S. So, again, fairly uncommon to see it, in general, and very uncommon to see it without H2S.

Q. Okay. What about the last 35 well, did that encounter water or H2S?

A. It's noted, even on their exhibit, it notes that they encountered H2S and black water.

Q. What about the Anderson 35 5H well?

A. That was one well that, from what I've seen, did not show any indication of H2S. However, based on the shut-in drill pipe pressure they provided of 195 PSI and their fluid weight, that calculates to a kill weight mud of a 12.3-pounds-per-gallon. As you can note on our well, we had a 16-pounds-per-gallon kill weight, so it's a very large difference in kick intensity that you see there. And to note, that Anderson 5H that's given, that's actually the highest kill weight mud that I was able to calculate based on the data that I provided. So of all 22 wells at 12.3-pounds-per-gallon, kill weight fluid was the most used from what I could tell.

Q. And what about the Humble State Number 1?

A. This particular well encountered water at 1518. And upon my research from the NMOCD records, there was a surface casing leak at 1819 feet, so my assumption would be that the water was coming -- was freshwater coming from that surface casing leak up high.

Q. Okay.

A. This wasn't a very intense flow. They actually lost circulation while drilling that section. So, you know, if you lose circulation then the flow is not intense enough to even make it to surface.

Q. Would you say that OXY's chart is comparing apples to oranges compared to what happened to Devon's North Thistle Well?

A. Yes, sir, in my research, like I said, I did come across a couple wells that encountered H_2S, and I -- I didn't even consider them relevant for that exact reason, so --

MR. BRUCE: Thank you that's all I have, Mr. Examiner.

MR. EXAMINER: Very good.

Mr. Brooks?

MR. BROOKS: No questions.

MR. EXAMINER: Mr. Johnson, let's go to your Exhibit A-5. We have a five-day period where we have backflow when running casing. Approximately how many days into this five-day period was the first attempt to run casing? When did it occur?

MR. JOHNSON: It was on September 11th. It would have been the last day.

MR. EXAMINER: Okay.

MR. JOHNSON: So we were drilling ahead, drilling all the way to TD for the majority of those days. Then we tripped out of the well and began to run casing at that point.

MR. EXAMINER: Okay. So you did the whole thing in one fell swoop?

MR. JOHNSON: Yes, sir.

MR. EXAMINER: And as far as backflow, did you have any timeframe as to how much -- was there ever a point when there was no backflow out of the well?

MR. JOHNSON: Once we got casing in the bottom we had flowed back approximately 1400 barrels, we had a 15.3-pounds-per-gallon in the well, and just prior to our cement job was when the well was static, so the pressure has decreased enough to allow the well to be static with a 15.3 mud weight.

MR. EXAMINER: With casing in the hole?

MR. JOHNSON: Yes, sir.

MR. EXAMINER: No further questions for this witness. Thank you.

[Witness excused.]

LORENZO WILBORN

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

DIRECT EXAMINATION

BY MR. BRUCE:

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

A. My name is Lorenzo Wilborn.

Q. And where do you reside?
A. I live in Edmond, Oklahoma.
Q. Who are you employed by and in what capacity?
A. I'm employed by Devon Energy as a production engineer.
Q. Have you previously testified before the Division?
A. No.
Q. Would you please summarize your educational and employment background?
A. Yes, I received a bachelor's of science in chemical engineering at Washington University in St. Louis. And I graduated in 2009, where I then began working in the oil and gas industry at Schlumberger as a wireline engineer, and then joined Devon in 2014 where I've been a production engineer since.
Q. Could you describe a little bit what you did at Schlumberger?
A. Yes, I was a wireline field engineer primarily focused on wellbore integrity and case hole logging.
Q. And are you familiar with the production of engineering matters related to the application?

A. Yes, I am.

Q. And have you prepared exhibits -- what are marked Exhibits B and C for submission to the Division?

A. Yes.

MR. BRUCE: Mr. Examiner, I would tender Mr. Wilborn as an expert in production engineering.

MR. EXAMINER: Mr. Feldewert?

MR. FELDEWERT: Can I ask a couple questions?

MR. EXAMINER: Sure.

MR. FELDEWERT: Mr. Wilborn, you said you've been a production engineer since 2014?

MR. WILBORN: Yes.

MR. FELDEWERT: What was your area of -- what area was -- what was your area of responsibility?

MR. WILBORN: In the Delaware Basin, I primarily worked in the Todd area, which is a more mature section of the -- of what we call our basin area in the Delaware, Southeast New Mexico.

MR. FELDEWERT: Okay. That's all the questions I have. I have no objection.

MR. EXAMINER: Very good. The witness is so qualified.

Proceed, Mr. Bruce.

Q. (By Mr. Bruce) Could you identify Exhibit B for the Examiner and run through the various pages of the exhibits, Mr. Wilborn?

A. Yes. So after the issues that we encountered while drilling the North Thistle 34-1, I was asked to look at some of the publicly available data to determine if there were any issues that could be cause of concern -- a cause of concern in regards to well integrity.

The -- I first looked at the Diamond 34 State 1 since it was one of the only wells nearby, and the first thing I noticed that I wanted to investigate was, you know, where the top of cement was. I wanted to determine was any portion of that injection zone, was any of it unprotected by a -- by cement. And in reviewing the documents, it was on the NMOCD website, it was a little bit concerning because there wasn't a lot of consistency regarding where that top of cement was. However, we did eventually receive a bond log establishing the top of cement 5165, which did leave a section of the top of the Bell Canyon exposed to the -- to the production casing annulus.

Moving on to the next page, the main points in regards to the wellbore integrity that would cause me to have some concern, the 7-and-five-eighths intermediate casing set above the base of the salt -- and while I had mentioned the top of cement being below the top of the Bell Canyon, and the reason that this is concerning is because you have -- you have a permeable section that's exposed to this production intermediate casing annulus and also exposed to this -- this salt section.

In discussing this with some of the -- some of the geology and other disciplines, we determined that there was a fairly high likelihood that you could have decoupling take place within that salt section that could erode the mechanical integrity of the wellbore and provide an access point behind the intermediate casing and potentially establish a vertical conduit for flow.

On the third page it really just shows the bond log on the left in reference to the wellbore schematic on the right. You can see where the base of salt is, the free pipe amplitude on the CBL, and the reference of the top of the Bell Canyon which is also the top of the permitted injection interval.

The next thing I looked at was the

injection history from -- during 2004, as has already been mentioned, there was a compliance violation over -- an overpressure in the injection pressure. And, you know, it was noted that this was only a brief isolated event, but when you look at the evidence, I mean, these are -- these are actual numbers submitted to the OCD. It was highly concerning that similar volumes were -- were injected each month for that -- for the entirety of that year, including a month in February where more than 50,000 barrels were injected that month.

In that regard, in my opinion, I believe it's highly concerning that injection pressures above the permitted injection allowed is likely to have occurred more than just on an isolated event.

The other thing that I noticed, you know, OXY had provided the radioactive tracer survey that they had -- that they had conducted, which, you know, in many instances is reliable in establishing whether or not cross flow exists from a deeper zone to a shallower zone. But in this instance, because of the -- the uncertainty regarding the cross sectional area that you would have available for flow behind the intermediate casing, if they were indeed connected, leaves me to believe that you have very limited cross flow potential, but that doesn't preclude the ability to be hydraulically connected. And hydraulic connection would be the primary concern here, that if you were connected that you would have the potential to create -- to basically charge up that shallower zone where we encountered the water flows.

And the other -- and moving on to the next page, this is mainly just comparing the data that was supplied us and cross referring it with -- with other means of the same data provided. And the bottom line is that the -- that the data doesn't match one another. So, I mean, you know, there -- there are a lot of questions about evidence and data and why didn't you look at this data or that data. But one of the concerns that I have here is that the data that we were supplied wasn't really accurate or really meaningful in any way. It just tells us that it's inconsistent and can't be relied upon.

Q. And before you move on to that, part of this exhibit is an internal OXY e-mail; is that correct?

A. Yes, that's correct. There was an indication that there was an overpressured event, but yet that overpressured event was not reflected in the daily tubing pressure recordings.

On page 6, you can see in the remarks where on the daily -- the daily workover reports, the identified tubing pressures also did not match the supplied daily tubing pressures on the right.

The final thing that I reviewed was the Bradenhead test that was conducted back in 2002. So they applied 340 pounds on the production intermediate casing after what appeared to be a quick falloff after -- after pressuring up the backside. And when you account for that pressure applied on that -- on the annulus and the fluid gradient below it, looking at what pressure you would expect at the intermediate casing -- at the intermediate casing shoe is about 2600 PSI.

When you look at that pressure, based on the expected reservoir pressure at the top of the injection zone and back out the fluid gradient to the intermediate casing shoe kind of coming from the other direction, those -- those pressures are approximately equal. Which what that indicates to me is that you applied pressure at the -- at the Bradenhead and you applied just enough pressure so that you don't have leak off. And so of course it's going to pass because you have enough back pressure to hold that 340 PSI.

And in that regard I -- you know, I don't feel like this Bradenhead test or any of the subsequent Bradenhead tests that were conducted necessarily preclude the ability for there to be a hydraulic connection behind the intermediate casing.

And that was all I had.

Q. And were Exhibits B and C prepared by you or under your supervision?

A. Yes.

Q. And in your opinion, is the granting of Devon's application in the interest of conservation and the prevention of waste?

A. Yes.

MR. BRUCE: Mr. Examiner, I move the admission of Devon Exhibits B and C.

MR. EXAMINER: Mr. Feldewert?

MR. FELDEWERT: No objection.

MR. EXAMINER: Exhibits B and C are so entered.

Mr. Feldewert, your witness.

CROSS-EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Wilborn, I'm on your Exhibit B-2. Have you looked at the methodology where the casing shoe is -- intermediate casing shoe is set?

A. I have not. That would be a better question for the geologist.

Q. Well, you say here in your slide that I guess you created --

A. Uh-huh.

Q. -- that the intermediate casing set above base of salt. Do you see that?

A. Yes, based on the feedback that I received from -- from our geologist. Yes.

Q. But you didn't examine that?

A. Well, I looked at the log. I mean, you can -- you can see on the log that there's a clear marker for the base of salt.

Q. You don't believe that the intermediate casing shoe is set in an anhydrite zone?

A. That would be a better question for one of our geo guys.

Q. Okay. The injection zone shown on here the highest perforation is at 5,335 feet, correct?

A. Yes.

Q. And that's over 230 feet below the top of the Bell Canyon formation; is that right?

A. Yes.

Q. And you say here: "Based on these facts, lack of cement bond behind the production casing establishes conduit for fluid flow between the permitted injection zone and the base of salt."

Do you see that?

A. I do.

Q. You don't believe that there's a barrier at the top of the Bell Canyon that would prevent that migration?

A. I do believe there's a barrier at the top of the Bell Canyon that prevents that migration, but that doesn't really address the inference that I make.

Q. So you agree that there's a barrier at the top of the Bell Canyon that's going to prevent the migration?

A. Above the top of the Bell Canyon, yes. However, you don't have cement coverage in between the top of the Bell Canyon and the production casing annulus. In that regard you have -- you have an area that you don't have the mechanical and hydraulic isolation that you would hope to have by -- from your cement job. And that's generally why when you want to -- you know, when you look at a workover one of the first things that you're going to look at is where is my top of cement.

Q. Which is 65 feet below the top of the formation, right?

A. That's correct.

Q. So the water would have to go through the top of the formation in your theory, right?

A. That's -- that's correct, which is a lot easier to do considering in 1999 they hydraulically fractured that formation in that zone with 250,000 pounds of prothen.

Q. So do you have any evidence that the water is migrating out through the top of Bell Canyon?

A. Also, one of the problems with that is --

Q. My question to you is: Do you have any evidence of the water migrating to the top of the Bell Canyon?

A. I don't believe that you can make that inference based on the tools that were -- that the technology that we have and the tools that were run.

Q. Okay. And in order to get to the intermediate casing shoe in the anhydrite zone, you would have to go through the top of Bell Canyon, right?

A. That is correct.

Q. Have you looked at the seismic shot that Devon has presented to OXY?

A. That would be a better question for Alex.
Q. That might be a better question. My question is: Did you look at it?
A. Have I seen it?
Q. Yeah.
A. Yes, I've seen the exhibits that everyone has -- has prepared.
Q. And have you -- do you routinely review those types -- that type of seismic evidence?
A. No, I do not.
Q. So you don't know how to read it?
A. That would not be my area of expertise.
Q. Did you see any evidence of washout at the intermediate casing in Devon's seismic shocks?
A. Based on the -- I did not. I did not see that.
Q. Okay. I want you to turn to B-4. And at the bottom there you talk about -- your last bullet point. You talk about -- but you say: "This far-wellbore path." Do you see that?
A. Yes.
Q. What path are you talking about?
A. So the point that I tried to make with that bullet point is the fact that you -- when you conduct these logs you inject a slug of radioactive

material into the formation, and we're -- we -- I don't think there's -- there hasn't been any challenge to a near wellbore path. I mean, they have the -- OXY has cement coverage above their -- their perforation.

Q. Yep.

A. So the usefulness of this tool would be to identify channeling or near a wellbore fluid migration, which you're not going to see immediately above your perforations because you have cement coverage. So any hydraulic connection that there would be would have to take a path where the fluid travels into the wellbore, the radioactive tracer material becomes strung out by, you know, disbursing through the -- you know, the spaces.

And then eventually, you know, if you have enough cross flow to be identified by the tool and a high enough concentration of remaining radioactive material, which I believe both of those are unlikely, you're not going to see the radioactive tracer data in that --

Q. What is the -- but here's my question: What is the far wellbore path that you're referencing here? What are you talking about?

A. So the far -- and what I mean here is the far wellbore path means that you have -- that you would be establishing communication beyond the -- the sand face so you're not just having fluid migrate up the annulus in the immediate -- in the immediate depth above --

Q. So you're talking about away from the wellbore?

A. Correct.

Q. Okay. And you're suggesting that somewhere away from the wellbore there is a path of migration from the injection zone at 5,335 feet to 1800 feet? Is that what you're suggesting is a far wellbore path?

A. No, that is not. The far -- the far wellbore path that I'm referring to here just means -- it simply means that the fluid travels into the sand face before it would -- it would travel above the top of cement.

Q. So you're not suggesting that there's some far wellbore path in this zone --

A. No.

Q. -- of injection?

A. No.

Q. You're not suggesting that?

A. No.

Q. Okay. All right. Now, I'm curious about your exhibit --

MR. FELDEWERT: Is it C, Jim, the one that --

Q. (By Mr. Feldewert) Yeah, your Exhibit C. This was something new I guess you gave us last Tuesday.

A. Okay.

Q. You have there 340 PSI Bradenhead. Do you see that?

A. Yes.

Q. And then you have your arrow pointing, if I'm understanding it, down the backside of the production casing; is that right?

A. Yes.

Q. Okay. And what a Bradenhead test does is it measures the pressure on the production casing, correct?

A. In the annulus between the production casing and the intermediate casing.

Q. That's what a Bradenhead test does?

A. Yes.

Q. And so your whole exhibit here is dependent upon some 340 PSI reading during a Bradenhead test?

A. Yes, the documented PSI for the Bradenhead

test conducted in 2002 and the NMOCD --
Q. From the Bradenhead test?
A. Yes.
Q. And you said that the source of that is a 2002 reading by the Division?
A. A test conducted by whomever the operator was in 2002, whether it was OXY or Pogo.
Q. Let's go to OXY's Exhibit Number 3. Are you on Exhibit Number 3?
A. I am. Well, I thought I was.
Q. One more.
A. Yes, the one in 2002 under Pogo.
Q. And this is information about mechanical integrity tests?
A. Yes.
Q. Isn't that right? Which is different from a Bradenhead test, right?
A. It indicates run MIT and Bradenhead test, so there was a Bradenhead test conducted.
Q. Hold on. Let me catch up with you. Stay with me here. So this is a mechanical integrity test exhibit, right?
A. Uh-huh.
Q. And you're pointing to, in the middle, the bullet point that says on 2002: "Run MIT," that's a

mechanical integrity test, right?

A. Uh-huh.

Q. And a Bradenhead test. So they did both?

A. Correct.

Q. And then what are you focusing on after that? On this, are you focusing on the paragraph that says -- or the statement that says: "Casing held 340 PSI for 30 minutes."

Is that where you got your 340 PSI?

A. Yes.

Q. So you interpret that phrase "casing held 340 PSI for 30 minutes" as a Bradenhead test reading?

A. That was the way that I interpreted it.

Q. Did you look at the records from that test in 2002?

A. I did.

Q. Okay. If we go one, two -- it's the third page in. There's a Pogo test 3/26/2002, right?

A. Uh-huh.

Q. And you get that from the C-103?

A. Yes, that's where I got it.

Q. Now, if I go back to the first page of that exhibit, do you see the other summaries for those all point out that the casing held a certain pressure for 30 minutes?

A. Yes.

Q. So in other words, the one in '97: "Casing and packer held 500 PSI for 30 minutes."

A. Uh-huh.

Q. June of 2014: "Run MIT. Casing held 540 PSI for 30 minutes."

October 2015: "Run MIT. Casing held 580 PSI for 30 minutes."

Doesn't that look like an MIT test to you?

A. Yes, the -- the -- the dates you just mentioned do look like an IT test.

Q. So now we go to your 2002, the one that you focused on, and we see similar language.

A. Okay.

Q. "Casing held 340 PSI for 30 minutes."

And you don't think that's the mechanical integrity test reading?

A. I can't necessarily infer the intent of the people that wrote this documentation 13 years ago, but it's a possibility.

Q. It's a possibility, okay. But you haven't looked at the records?

A. Yes, I have looked at the records.

Q. At the Division records? Did you look at the Division records?

A. Yes.

MR. FELDEWERT: May I approach the witness?

MR. EXAMINER: You may.

Q. (By Mr. Feldewert) These are from the Division's website, Mr. Wilborn, the records you said you reviewed; is that right?

A. Yes.

Q. Okay. If you go over here to the first page it's what has been marked as OXY Exhibit 36 is the same C-103 that we see on OXY's Exhibit 3 of the third page, right?

A. Yes.

Q. And then behind that is the -- what do you call it, the next page is the chart; is that right, Mr. Wilborn?

A. Yes.

Q. And the next page is the back of that chart. Do you see that?

A. Yes, I see that.

Q. And as you point out, they did both the Bradenhead test and a mechanical integrity test. And do you see the -- do you see the start PSI on the last page of this exhibit at 340 PSI?

A. Yes.

Q. And then the finished PSI at 335?
A. Yes.
Q. Time, 31 minutes?
A. Uh-huh.
Q. And then it says: Casing 0 and surface 0; is that right?
A. I don't see what you're referring to.
Q. The last page, the last two handwritten entries.
A. Oh.
Q. Right? Do you see that?
A. Okay.
Q. Now, a Bradenhead test, isn't what they do is they open a valve to the atmosphere, right, and then they measure the pressure on the casing? That's what you do in a Bradenhead test, right? Is that right?
A. Yes.
Q. Okay. And do --
A. I misunderstood that, obviously.
Q. I think you did.
A. Okay.
Q. I think you did.
A. Okay.
Q. So you agree with me that there was another

340 PSI on the Bradenhead test?

A. Yeah, upon reviewing that.

MR. FELDEWERT: Okay. That's all the questions I have.

MR. EXAMINER: Mr. Bruce, redirect.

MR. BRUCE: No, I have no redirect, Mr. Goetze.

MR. BROOKS: No questions.

MR. EXAMINER: I have no questions for this witness, and I thank you for your testimony.

Let's go ahead and take a 15-minute break and come on back at 11:00 o'clock and we'll continue with your next witness.

[Witness excused.]

[Recess taken from 10:43 AM to 11:02 AM.]

MR. EXAMINER: All right. Let's go back on the record.

Mr. Bruce?

ROY HATHCOCK

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Okay. Would you please state your name and city of residence for the record?

A. Yes, my name is Roy Hathcock, and I live in Edmond, Oklahoma.

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

A. I work for Devon Energy, and I'm currently the production engineering manager for the Delaware Basin Assets.

Q. Have you previously testified before the Division?

A. No. No, sir, I have not.

Q. Would you summarize your educational and employment background?

A. Yes, sir. I have a bachelor's of science degree in petroleum engineering from Texas A&M University. I've worked for Pennzoil, and then after Devon acquired Pennzoil, with Devon the last 33 years in various completion and production engineering roles covering the Gulf Coast, Delaware Basin, East Texas, Gulf of Mexico, deep water Gulf of Mexico and the international assets.

Q. And does your area of responsibility at Devon include this portion of Southeast New Mexico?

A. Yes, sir, it does.

Q. And are you familiar with the production engineering matters related to this application?

A. Yes, sir.

Q. And have you prepared an exhibit for submission to the OCD today?

A. Yes, sir, I have.

MR. BRUCE: Mr. Examiner, I'd submit Mr. Hathcock as an expert production engineer.

MR. EXAMINER: Mr. Feldewert?

MR. FELDEWERT: No objection.

MR. EXAMINER: So qualified.

Q. (By Mr. Bruce) Mr. Hathcock, did you prepare or have compiled under your supervision Devon Exhibit D?

A. Yes, sir.

Q. Could you identify that for the Examiner and run through the various pages of that exhibit and explain what you see regarding temperature gradients and other matters related to these wells.

A. Yes, sir. Yes, sir, what we tried to do is take data that OXY had provided us and tried to compare that to data that we had ourselves from an offset well a few miles away and tried to compare the temperature profiles from both of these wells. So in Exhibit 1 is the first one, first slide, you'll note on the X-axis -- it's at the top of the chart, there is the temperature and degrees

Farenheit. The Y-axis is the measure depth going from 0 to 6,000 feet.

I have different markers that shows the key tubular depth related to the OXY well, the 10-and-three-quarter-inch casing seed at 823 feet, the 7-and-five-eighths intermediate casing seed at 4830, and then their 4-and-a-half packer that was set at 5317 according to the records that I had.

Also, I did denote the Devon kick at 1820 feet. So basically this is just trying to, at a very high level, show you the close correlation between the two surveys even though these wells were five miles apart.

Also, at the bottom you'll see the top perf and the red dashes. The kind of pink dots is the top of cement and the green dashes is the permitted top. So you can see the temperature change going into the -- into the formation and then it being a lot hotter as you get up to the top of the cement and then it dropping back and not really coming back to true gradient tube a little bit up the hole.

And I'd like to basically go to slide two, if that's okay with you, and we'll talk about this in a little bit more zoomed-in fashion. This is just the same plot that you saw previously but zoomed in from a 3,000 to 6,000 foot Y-axis and the emphasis of 80 to 90 degrees Fahrenheit.

But what I would like to note that there's -- looks like there's three gradient changes off of the baseline gradient, at least the baseline of our well. And so while it's not clear indication that there is flow, it certainly would suggest that there could be.

What I would like to draw your attention to is the difference in that blue line, the temperature line, from OXY's log. At the top of cement it's at like 5165 feet up to where it hits that gradient line is like 4713, so it's like 452 feet of off gradient temperature before it actually hits back to the gradient line. This could suggest that there is water movement. This log was one that was shut in, it was run after it was shut in.

I believe the information that was provided to us was this -- this log was shut in for 25 days and was run on December the 2nd. So anyway, we're seeing significant variances at the top of cement and the formation tops. So, again, an indication, not clearcut evidence. In Devon's defense, we relied heavily on information that OXY would give us to work with, so these were not our wells so it's just -- except for the one that we had, the baseline. So we did -- would like to note -- and I apologize, this may be slide 6 for you guys, but just to jump ahead because we did contemplate that some of these --

MR. FELDEWERT: Hold on. Hold on. I object to the introduction or discussion of Devon Exhibit -- or slide 6 on the grounds that it wasn't provided to us until 7:30 this morning for whatever reason. If you recall, Mr. Examiner, that this case was continued after we had given them our exhibits because they needed more time to examine and prepare for those exhibits.

And under that arrangement they were to provide us any new exhibits last week Tuesday. This was not provided until 7:30 this morning, so I object to the introduction of -- or any discussion for this particular slide.

MR. BRUCE: Mr. Examiner, I just received it late yesterday and I submitted it as soon as I could. It's one exhibit. When Devon objected to it several weeks ago they got about 40 exhibits that they had to look at. Over the course of one day, I don't think is too burdensome on them.

MR. BROOKS: Is this from the material that was produced pursuant to the motion to compel?

MR. FELDEWERT: No.

MR. BRUCE: This is from -- well, you can see this is a Devon well that is, I think, located to the south.

MR. BROOKS: Okay, okay. Well, it does appear to be late produced. Let's go ahead and hear the discussion of it and then we'll reserve a ruling on the admissibility. And if the ruling is not admissible then it will be limited.

This isn't a rebuttal evidence because they haven't put on any yet.

MR. BRUCE: No, it's not a rebuttal.

MR. BROOKS: Okay. Let's see what he's going to say on the basis of it, and it presumably will not be admitted into evidence.

You may proceed.

MR. HATHCOCK: Yes, sir.

A. So what I was saying was that we contemplated these gradient changes that we saw in slide 2, it might be related to formation events. So we looked at our neutron log in our well that we ran this baseline temperature survey and we saw no gradient variances where we saw these porosity formations. Like at 4800 feet would be the green arrow, and 4200 feet would be the blue arrow, and then 3500 feet would be the red arrow. So it just basically -- you know, we have porosity but we don't have gradient variances related to the porosity.

So going to slide 3, if we can -- so it's -- this is just compiling three shut-in passes, three logs that were run; one on the 10th of October, one on the 12th -- I'm sorry, the 2nd of December and the 17th of December. But the reason I wanted to show this is to show the similarity of the characters and the nuances that was happening between the 7-and-five-eighths casing and the top of the cement.

So all of them are somewhat similar. I did review their data on the injection temperature logs, did not see anything that clearly indicated from the injection side but it was more observed as a potential for the shut-in side of being able to see some type of communication.

And then slide 4 is the same slide but just with that baseline gradient added to it.

Q. (By Mr. Bruce) And what does that indicate to you?

A. I think that what it tells me is, is that you're not seeing a high differential pressure between your injection zone and what it is flowing to. I think the whole system is charged up. I try to look at things in ways that I can put my head around it, sort of like a garden hose where you have a hose end sprayer on it. You know, and you basically bleed off pressure and you can open it wide open and then as you close -- let off the handle everything just kind of pressures up and seals up.

So that's the way that I think. It probably has more flow if you were taking a relieving pressure off wherever the water has migrated up to. And as it pressures up, or if you're not bleeding off pressure, that rate of flow is much smaller, especially if it's been there for a long period of time. That's my take on it.

Q. And what is page 5?

A. Okay. Page 5 is -- I tried to pictorially just try to show, you know, we really -- we have no clear indication of what the leak path is. What makes sense to us is that before we drilled our well here there was no evidence of any geo pressured event. And over the period of about 20 years Pogo and OXY has used this SWD well to inject over 6 million barrels of water, so we're trying to think in our minds what could be the potential path for this water up to the 1820 feet.

So at the lower left I kind of listed, basically option one is a low top of cement which we did -- in January did in fact get the cement bond log that would indicate a low top of cement. If there was an intermediate casing leak without cement tying up into the intermediate casing, flow could come up that intermediate casing shoe between the production and intermediate casing up through a casing leak and charge up any permeable zone that would, for instance, be at the depth that we encounter with our drilling rig.

Another is that we -- this well was fracked at two different horizons, a fairly good size frac; 20 barrels per minute, 250,000 pounds of sand. In the timeframe that this was fracked it was usually some pretty high gel loadings, which means high viscosity. So we don't know what the geometry of that fracture looks like, but it could be that it's not contained.

Another is the high pressure permitted injection, higher than permitted injection that we know of in 2004. There's also an OXY, I guess, e-mail where one of their employees reference injecting at 2500 barrels per day at much higher than permitted pressures. And after a well work is performed, and I'll have to look back to see what exactly it says -- hey, let me -- let me pull that up because I do have that right here. I copied it.

It says -- it's in Exhibit 257: "As per my previous note, we were injecting above the permitted pressure on the Diamond 34 State 1 roughly 2500 barrels of fluid per day. We expect to be put down close to 1100 barrels per day after the workover is finished, so we decided to keep the wells shut in until Devon finishes their new well. We'd be looking for a total trucking cost of 60M. Thanks, and best regards. Sebastian."

Q. And is that a document that was turned over to Devon?

A. Yes. Yes, sir, it was. Yes. So it was indicated after this work that was done, and I assume it was work that was done around the second week of September according to the drilling reports that OXY supplied to us, and the injection rates were indeed 1100 barrels per day or lower. And so -- so anyway, that is -- that is a concern that we have that it could be higher than permitted injection pressures. Also, to the west of the OXY

SWD well --

Q. To the east?

A. I'm sorry, yes, to the east, the southeast corner of block 34; is that correct? It -- there is the CP Miller, Humble State 60 -- on X -- Humble State Number 1, and that well was drilled in the '60s. And there's two cement plugs that were spotted above this injection interval. I don't know the cementing practices, the plugging practices in the '60s, but if it were not a very good -- a very well plugged well there is a potential that that could be a path, or if one of those cement plugs had failed with time then there is a potential.

So, again, Devon doesn't know the path. Maybe OXY is seeing something in their evidence and investigation that would indicate what path is more likely, but I guess our gut tells us that our kick is directly related to the injection in this disposal well.

Q. There are potential ways where water can move vertically in this area?

A. Yes, sir.

Q. Mr. Hathcock, you have Devon -- or not Devon's -- do you have OXY's exhibit booklet?

A. Yes, sir.

Q. Could you turn to their -- let's see, what slide would that be -- their Exhibit 7?

A. Yes, sir.

Q. The second page of it.

A. Yes, sir.

Q. Is there any legible pressure line on this chart?

A. It's very hard for me to read, although I do see an increase to about 60 PSI about two-thirds of the way through the pressure test. Again, I would probably have to see the actual chart, but from the exhibit that I see here it does look like there was -- it didn't just ride on the zero PSI line.

Q. Okay. If we could move to their Exhibit 10.

A. Yes, sir.

Q. Looking at their -- the formations encountered, you see similar formations in Devon's offset well, do you not?

A. Yes, sir. I'm sure our geologists can speak to it more directly, but it appears that the geology here is very -- can be traced for long distances.

Q. And they're showing the temperature

gradient line. Did those show up in Devon's well?

A. No, sir. The variances that you're talking about?

Q. Correct.

A. No, sir.

Q. And then move to their Exhibit 20.

A. Yes, sir.

Q. What do these -- let me make sure I'm on the right one. So what -- what are the injection pressures and the injection rates that reflect this pressure or this injection?

A. Well, I guess some of the things that catch my eye, if you -- we talked about the violation in 2004. You can look, that they were injecting somewhere just under 70,000 barrels and then after that violation they dropped down to about 40. But if you look, in 2008 they went to a much higher rate again but then they dropped again.

What's interesting, more specific to us, is what happened around September 2015. You can see injection volumes around 40,000 barrels a day for --

Q. Per month or per day?

A. I'm sorry, per month, yes. And five -- five months there that are between 30 and 40,000 barrels per day, pretty high volumes when you compare it with some of the injection tests that they later presented in some of their exhibits. So I believe -- let me see if I can look at my notes. Yeah, on Exhibit -- can I reference one of their slides?

Q. Sure.

A. Their Exhibits?

Q. Sure.

A. I have it in slide 12, so I may have to basically figure out which one that is because I don't have the exhibit numbers. Yes, here it is.

Q. Exhibit 8?

A. Yes, sir. Yes, sir. So at Exhibit 8 it was -- so they were injecting at 1250 pounds at a half barrel per minute. And so just looking at what that would be, that would be about 720 barrels per day at a half barrel per minute. You know, when you look at it on a per month basis it's more like 22,000 barrels per day. It seems like in that 1250 pounds is roughly 210 pounds above what the permitted pressure is for this well, so --

Q. Okay. So they were injecting -- even at the rate set forth on Exhibit 8 they're injecting above the permitted injection pressure?

A. It would appear from their exhibit they were.

Q. And so when you're looking at the months running up to September 2015 they were injecting about -- more -- double what they were talking about here?

A. What that rate would. Of course, we don't have the pressures associated with it. And the pressures, like Lorenzo had mentioned that was given to us, were virtually two or three weeks of the same pressure. They really didn't tie much to what we understood was going on. It was hard for us to work with the data that was presented to us.

Q. Okay.

A. Again, and we were -- we're relying on their information they provided to us so we could try to understand how it affected Devon's well.

Q. I think we'll end with that, Mr. Hathcock. Was Exhibit D prepared by you or under your supervision?

A. Yes, sir, it was.

Q. And in your opinion, is the granting of Devon's application in the interest of conservation and prevention of waste?

A. Yes, sir.

MR. BRUCE: Mr. Examiner, I'd move the

admission of Exhibit D.

MR. FELDEWERT: I object to the last page of Exhibit D.

MR. EXAMINER: Is it slide 6?

MR. FELDEWERT: Slide 6, yes.

MR. BROOKS: I would sustain the objection to slide 6. It does not affect the admissibility of the rest of the exhibits.

MR. EXAMINER: Well, in that case we will include Exhibit D, slides 1 through 5 and 6 shall not be entered into the record.

Your witness, Mr. Feldewert.

MR. FELDEWERT: May I approach the witness?

MR. EXAMINER: Yes, you may.

CROSS-EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Hathcock, I'm going to hand you the well inspection history for this well. It was provided to the Examiners and taken out of the Division's records. Other than 2004, do you see any instance where, during those inspections, the Division indicated anywhere that the well was injecting above its permitted pressure?

A. Sir, I would love to make comment on that. If you want to give me time to read all this, I can.

Q. Well, I can represent to you -- let's make it easy. I'll represent to you that on that particular document that I handed you, the only instance of recorded injection above pressure is in 2004. And you don't have any information to the contrary, correct?

A. Not from the NMOCD but only from OXY.

Q. Okay. And can you -- and the only thing that you pointed to from OXY that in your opinion would indicate that they were injecting above pressure is Exhibit 8, which is the MIT surveys?

A. No, sir, I believe that there is an e-mail that I read to you, Exhibit 257, written by a Mr. Sebastian.

Q. And that's it?

A. I think that there is other e-mails that we received late last night that -- that would relate to the --

Q. Well, I'm not interested in what you believe, I'm asking you what you know.

A. What I do know is from what you have shared with us, and that there was a lack of pressure control monitoring equipment on your pumps, and there was a reference about lack of confidence in your lease operator taking accurate records and just repeating the same pressure over and over again. So, sir, with all due respect --

Q. But you don't have any of that here today, do you, what you suggested? I don't see any of that in what you provided to the Division, correct?

A. No, sir.

Q. Okay. If I go to what's been marked as D-1, which is your gradient shift slide.

A. Yes, sir.

Q. If I'm understanding you, the source of your -- let me make sure I understand. The baseline is the little squiggly gray line on here, correct?

A. Yes, sir.

Q. And the source of that baseline well is how many miles away?

A. Approximately five miles away.

Q. Is that an injection well?

A. No. It was a well that was originally completed in the Devonian, and we were going to use it as a science well to do some fracture diagnostics, so we did a baseline fiberoptic temperature survey.

Q. So you didn't do a temperature --

A. Yes, sir.

Q. -- survey? You did?

A. Yes, sir, with fiberoptics.

Q. Fiberoptics, okay.

A. Yes, sir.

Q. But you didn't actually do any temperature surveys on that well like we -- like OXY did?

A. Not in the same manner that OXY did, where they had a waterline tool that passed back and forth. Fiberoptics is a stationary line that sits there and takes readings every six inches.

Q. Okay. And if I look at your -- using that baseline, and I look at D-1, I see your temperature degrees in Fahrenheit is on the top axis; is that correct?

A. Yes, sir.

Q. And you've only, on this exhibit, identified what -- below 1800 feet only three areas where you suggest that there's a gradient change?

A. Yes, sir.

Q. So the remaining aspect of this exhibit reflects there's no gradient change, correct?

A. I would have to agree there.

Q. So whatever gradient change occurred for whatever reason it always went back to the normal gradient?

A. Yes, sir.

Q. Okay. And your gradient shifts, if I'm reading this correctly, are less than one degree?
A. That probably would be -- I would have to look at the data.
Q. Well, it's your -- it's your exhibit.
A. Yes, sir.
Q. Less than one degree, isn't it? If I'm just looking on here, I'm looking at your gradient shift here, below 1800 feet where you have your Devon kick shown here, as I view it, it's got to be less than one degree, isn't it?
A. I would reach the same conclusion as you.
Q. Okay. Are you aware that OXY did a tracer survey in addition to the temperature survey?
A. When was that done?
Q. Are you aware that OXY did a radioactive tracer survey in addition to their temperature survey?
A. Yes, sir.
Q. And you're aware of the results of those -- of that radioactive tracer survey?
A. Yes, sir.
Q. And it shows no upward channeling of the fluids, correct?
A. Yes, sir.

Q. Then if I go to Exhibit B-4, this is, I think, an exhibit you reference when you were pointing out the -- again, that blue squiggly line is the baseline?
A. The gray one?
Q. Yes, sir, the gray squiggly line.
A. Yes, sir.
Q. And that's from the well five miles away?
A. Yes, sir.
Q. Okay. And according to this, and according to your chart here, above the permitted top it looks like we have an instance where the water actually gets warmer. Do you see that?
A. Yes, sir.
Q. Okay. Not cooler? If water was channeling up as you suggest wouldn't you see cooling?
A. If it's coming from a deeper depth, wouldn't it be warmer water?
Q. I'm asking you. If the water is channeling up, it would be cooler.
A. I would think it would be warmer.
Q. Can you explain why your deviation there on one test is warmer, then on the other test it looks like it's cooler?
A. Than the baseline gradient?

Q. Yeah.

A. Well, all -- all that I can understand from this is that the one that is laid upon the -- or the gray line is -- is right next to, was a 25-day shut-in. The others were zero hour shut-ins and shut-in passes, so it -- there is a lot of movement of water and a lot of cooling and heating going on.

Q. But if I follow those lines all the way to the bottom, do you see how they go to the left?

A. Yes, sir.

Q. That means they're cooling. That means it's cool, right?

A. Yes, sir.

Q. And then as they're coming up it's getting warmer?

A. Yes, sir.

Q. So doesn't it indicate to you that the water that they're injecting is cool water?

A. At the sand face it is.

Q. And yet you show a line here, your gradient change, for whatever reason suddenly gets warmer?

A. Yes, sir. It might indicate that the water is not coming directly from the water that's injected but permeating through the top of the Bell Canyon and then working its way over to the intermediate casing.

Q. Do you have any evidence that the top of Bell Canyon is not a geologic barrier, Mr. Hathcock?

A. Sir, all I've got is what you've given me.

Q. And what you've studied?

A. Yes, sir. And the explanation of it getting warmer would make sense that that would be supporting that theory.

Q. Now, if I go to your Exhibit D-5, you have some interesting comments on there. I want to go over this with you. Okay?

A. Yes, sir.

Q. You have a bullet point there where you say: "Uncontained hydraulic frac treatment(s)."

Do you see that?

A. Yes, sir.

Q. You're talking about what Pogo did --

A. Yes, sir.

Q. -- when they drilled this well?

A. When they completed this well.

Q. Completed well, thank you.

A. Yes, sir.

Q. Back in 1997?

A. Yes, sir.

Q. And did you --

A. '97, and then 1999 was the latest -- later one.

Q. Did you calculate the fractured geometry?

A. No, sir, I did not. This was presented as a potential way that we could have expected a compromise.

Q. Okay. So you don't have any evidence of that, correct?

A. No, sir.

Q. And you're aware that the formation has actually been, I think as you put it, pressuring up?

A. Yes, sir.

Q. So that would indicate no clear indication of a leak, right?

A. It could be also a sign of a damage.

Q. Okay. Do you got any evidence of that?

A. Just my experience working with SWD wells.

Q. If I'm understanding your dashed blue lines here, would you help me out here?

A. Sure.

Q. Let's follow your little dashed blue line that goes, it looks like, to the outside of the intermediate casing.

A. Yes, sir.

Q. Okay. What are you suggesting there?

A. So what that concept is, is the fact that if you have undersaturated brine that's coming into contact with the salt and it's not a cemented barrier that it could basically decouple the formation to the cement and work its way up on the outside of the 7-and-five-eighths intermediate casing. That's a concept.
Q. Just as a concept?
A. Yes, sir.
Q. So that would be outside the intermediate casing?
A. Yes, sir.
Q. Would it be right next to the intermediate casing?
A. I would think so.
Q. Right next to it, right?
A. Yes, sir.
Q. Okay. And then the other one is inside the intermediate casing?
A. Yes, sir.
Q. And if you had that, wouldn't you expect to see some kind of pressure zone when you did a Bradenhead test?
A. Possibly. It all depends on what is in the annulus between the 7-and-five-eighths and the

four-and-a-half casings.

Q. Isn't that the purpose of a Bradenhead test, to ascertain whether there's fluid migrating up to the casing?

A. I would think, but was there any pressure applied to it? I don't know that there's not 14-pound mud on that backside where you'd see no pressure.

Q. And those Bradenhead tests were witnessed and approved by the Division. You're aware of that, correct?

A. Yes.

Q. Okay. Now, on your scenarios here, if I'm understanding it, the water here is being injected at 5335; is that 5330 or 5335?

A. That is our understanding.

Q. So to migrate, as you suggest, it would have to go out of the injection zone, it would have to first go through the Bell Canyon, correct?

A. Yes, sir.

Q. Above the perfs?

A. I think that you all's radioactive tracer works. It's pretty clear that there is no near wellbore channeling, yes, sir.

Q. You agree with that?

A. Oh, yes, sir.
Q. And then under your scenario it would have to go through the top of the Bell Canyon, right?
A. Yes, sir.
Q. And then it would have to go through the anhydrite zone that starts at the 5020?
A. I don't know where those zones start, but my understanding from other experts that are in the room that -- that the 7-and-five-eighths casing shoe is set in anhydrite or salt zone.
Q. In an anhydrite area, correct?
A. Yes.
Q. Okay. And you're not suggesting that there is evidence of any karsting or anything like that around the cement -- or the casing shoe, are you?
A. I'm not aware of any.
Q. You're not aware of any?
A. No, sir.
Q. Okay. Now, your other scenario on here that you just briefly talked about, it goes right through the Humble State; is that right --
A. Yes, sir.
Q. -- what you're suggesting?
A. Yes, sir.
Q. And do you have any evidence of that

pathway?
    A. No, sir. That well was plugged in the '60s and capped and it would require reentry to be able to understand if there's any pressure there or not.
    Q. Well, you would agree with me that the Division would have examined that well in 1997 when this disposal was first permitted, correct?
    A. I believe that they would have examined the data supplied to them, yes.
    Q. And would have done their own review, if necessary, of the well records and any review. You're aware of that, right?
    A. I would have every confidence they would have.
    Q. Okay. And then are you aware that the Division examined that wellbore again in 2010 when they authorized the change in the packet for this well?
    A. No, sir.
    Q. Would you turn to what's been marked as OXY Exhibit 24. There's a message down at the bottom of that from Will Jones. Are you familiar with him?
    A. No, sir, I'm not.
    Q. I'll represent to you that he's an engineer here with the Division. And it indicates in 2010,

he not only researched this well but also the area of review at the bottom. Do you see that?

A. The area of what?

Q. Of review --

A. Yes, sir.

Q. -- where the Humble State exists within the -- and the Humble State is within the area of review, correct, Mr. Hathcock?

A. Are you still on page 1 or on page 2?

Q. You're aware that the Humble State Well is within the area of review?

A. Yes, sir.

Q. All right. And if we go to page 2, at the top up there, and I've highlighted it for you, he says that all wells around the area appear to be plugged or cemented adequately. Do you see that?

A. Yes, sir.

Q. Do you have any evidence to indicate that the Division was wrong?

A. No, sir.

Q. And under your theory, if I'm understanding it through the Humble State Well, you have to assume that both of those plugs failed?

A. Yes, sir.

Q. And that the water would -- was migrating up that wellbore unimpeded?

A. That would be a possibility.

Q. That's what you would have to assume, right?

A. Yes, sir.

Q. And then wouldn't you also have to assume that that third well, that third plug, didn't fail?

A. That third plug would be up above.

Q. I'm sorry, from the bottom. We're working my way up.

A. I'm with you. The third plug --

Q. Go ahead.

A. -- I don't know about the third plug because we didn't see any pressure above where that third plug would have --

Q. Now, let me ask you, Mr. Hathcock, you're familiar with water flow. If it was going to those -- if those two plugs somehow magically failed and it was going up that wellbore, wouldn't it continue to go up that wellbore?

A. It could. It all depends on the crews that are spotting the cement plugs.

Q. And then for some reason, under your theory, it would just, what, magically exit the wellbore at 1800 feet, make a left turn, and come all the way back over; is that your theory?

A. My theory is that there are permeable streaks throughout this section that could transfer the flow or that pressure laterally. But that's not my testimony. You'll hear that from one of our folks that are here to testify for the commission.

Q. Did you do any calculations to determine whether that type of flow is even possible given the pressures that are involved with the injection?

A. No, sir, I did not.

Q. If this was a fractured disposal zone, as -- are you suggesting that, Mr. Hathcock?

A. I would have to assume, since it was hydraulically fractured, that it would be a fractured disposal zone.

Q. What type of permeability would you expect to see?

A. I would think that through the hydraulic fracture you would have probably in the range of Darcy's permeability but then when you contacted the formation you would go back to the normal formation permeability.

Q. Well, to support your theory here of this migratory path through the Humble State Well, what kind of permeability would you have to see within the disposal zone?

A. I don't think I'm qualified to make that determination.

Q. So you don't know?

A. No, sir.

MR. FELDEWERT: That's all the questions I have.

MR. EXAMINER: Very good.

Redirect?

MR. BRUCE: Yes, at this time, if I may, Mr. Examiner. I'd like to give Mr. Feldewert a little time to review those, Mr. Examiner.

MR. FELDEWERT: It's going to make it tough on you because I don't know, Mr. Examiner, if these fall within your rulings or not, but it's something certainly we could check. I mean, it looks like to me like certainly the last one, Exhibit J, would fall within the privilege, but, again, I have not checked to see what you've determined, as would Exhibit L.

MR. BROOKS: Yeah, I think we're going to have to -- I'm going to have to check this against my notes. And I would suggest, if it's okay with Mr. Goetze, if we take a lunch and recess now and we can get back to this after. Normally I would wait -- normally I wouldn't suggest that until the completion of this witness, but I really can't respond to that objection until I correlate with my notes.

MR. BRUCE: My only comment is this is clearly just factual and it's admissible, but --

MR. BROOKS: Okay. Well, I don't want to reverse rulings I just made yesterday, so I would like to check my notes.

MR. BRUCE: And that would be fast for us, so --

MR. EXAMINER: Seeing how this has been provided to us, let us take lunch and we'll take this under consideration and we'll continue with this witness when we get back. Let's get back here somewhere around 1:00 o'clock, if you could, folks.

MR. BROOKS: Can we make it 1:15?

MR. EXAMINER: We can make it 1:15.

MR. BROOKS: I know you don't want to go after hours and neither do I.

[Recess taken from 11:49 AM to 1:18 PM.]

MR. EXAMINER: Back on the record. And, Mr. Brooks, the floor is yours.

MR. BROOKS: Yes, I'm going to have to second guess my rulings of yesterday because I couldn't find these documents in these files, but I believe the documents marked -- well, one of them is marked J -- J, K, and L are the documents. Okay, J and K are the kind of documents that contain basically factual information and don't contain any material that indicates internally that they were prepared for purposes of litigation, so I would say the privilege does not apply to those.

Document L, on the other hand, I probably didn't designate as privileged since Mr. Bruce has it but I should have because this is clearly the letter from Mr. Clifford to Mr. Goddy and is clearly the type of communication that I think the privilege is supposed to cover. So I will rule out L and I will allow examination to be conducted on the basis of J and K.

MR. EXAMINER: And with that, we'll go ahead with your witness.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. Okay. Mr. Hathcock, I've handed you Exhibits J and K. Did you review the documents that were turned over to Devon yesterday afternoon about 2:00 or 2:30?

A. Yes, sir.

Q. And are these two of those documents?

A. Yes, sir, they are.

Q. Okay. If you would refer first to Exhibit K, can you identify who it's to and from, the date, and discuss what it talks about, pressures in the injection well.

A. Okay. It's from Paul B. Casares. I'm not very good at pronouncing Hispanic names, but please forgive me if I mispronounce that. Then Marshall A. Hedrick is who it's addressed to, reference the Diamond 34-1, dated Wednesday, October 7th, 2015.

Q. And the Diamond is the injection well?

A. Yes, sir. Yes, sir. So of course my interpretation to this is that they are having trouble exceeding the permitted injection pressure on the Diamond Well and that a Murphy switch needs to be installed to make sure that that pressure is not exceeded. And a mercy -- I'm sorry, Murphy switch that electronically can kill a pump until a lower pressure is seen, which then it automatically turns that pump back on. It allows it to work within a certain pressure range.

Q. And if you'll look at one of the -- maybe e-mails are hard to digest to me, but the second line says: The maximum injection pressure is

1020 PSI.

A. I would -- I would assume that that is -- what they're doing is telling him that's what our permitted pressure is. We're trying to control -- and I'm just guessing from the literature here, is that their pump is a distance away from the disposal well so there's frictional -- friction that takes place going through the pipes so they're trying to control the pressure at the well by controlling the pressure at the pump.

Q. And from the data you reviewed, the injection pressure limitation is about 1020 PSI?

A. That's what I've seen off the NMOCD website.

Q. And so, for instance, if you looked at their Exhibit 8 where they're talking about injecting at 1250 PSI, that would exceed the maximum allowed injection pressure?

A. Yes, sir.

MR. FELDEWERT: I'm sorry, exhibit what?

MR. BRUCE: 8.

MR. FELDEWERT: 8.

A. When you're pumping your temperature survey number two at 1250 PSI at half barrel per minute.

MR. FELDEWERT: Doing the temperature

survey?

MR. HATHCOCK: Yes, sir.

MR. FELDEWERT: Okay.

Q. (By Mr. Bruce) And when you look at most of these, they're exceeding the injection pressures.

MR. FELDEWERT: Objection to the form of the question. Lack of foundation.

Q. (By Mr. Bruce) Okay. Are they exceeding the permitted injection pressure?

A. My interpretation from this e-mail is they're not because they do have a higher pressure at the pump. But, again, there's a frictional loss between the pump and the injection well. What I sense is that by saying that they need to keep somebody there to make sure they don't exceed the pressure, they do not have --

MR. FELDEWERT: I'm going to object on lack of foundation.

MR. EXAMINER: Where are we going?

Q. (By Mr. Bruce) Are they -- Mr. Hathcock, from what you reviewed, they do not have a daily ability remotely to determine what is being injected, what the -- what the daily injection pressure is; is that correct?

A. That's what I would infer from the e-mails that I've read, including this one.

Q. Okay. And would that go back to your -- when you were discussing, I forget what exhibit it is now, that sometimes they're injecting 21,000 barrels a month and sometimes they're injecting twice that amount?

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

MR. BROOKS: Well, yeah, it was a leading question. Maybe you should rephrase.

MR. BRUCE: Okay.

Q. (By Mr. Bruce) Your interpretation was their maximum injection volume should be about 21,000, 22,000 a month; is that correct?

MR. FELDEWERT: Object to lack of foundation.

MR. BROOKS: I'm going to overrule that objection. I would sustain the objection to leading, but I don't really like to go there in this context because that's primarily when you're dealing with juries and we waste a lot of time if we force everybody to use the correct textbook way of asking questions.

However, you may rephrase the question.

Q. (By Mr. Bruce) What is -- your review of the data, what are the maximum injection volumes per month that are allowed in this OXY SWD well?

A. That's hard for me to -- to make that claim. I feel more comfortable with pressure than I am volumes.

Q. Okay. With pressure?

A. Yeah, but what I can say is that after they did their well work in September that their injection volumes on a monthly basis were greatly reduced. So what I might ask, if I was allowed, is how do -- how do they explain that they were injecting at a much higher rate before the well work than what they are after the well work.

Q. And I think -- what was your rough estimate of what they were injecting after the well work, per month?

A. I believe it was around 21,000 barrels per month.

Q. And before that, what were the approximate volumes they were injecting?

A. Close to 40,000.

Q. Would that indicate to you that they were exceeding the maximum allowed injection pressure?

A. Or they were injecting into a different horizon than just the permitted horizon. Again, we're relying on data that's not our data and we see a part of the picture.

MR. FELDEWERT: I'm not even sure what data they're referencing.

MR. HATHCOCK: Okay. You all's Exhibit 20.

MR. BROOKS: Well, you will have a chance to cross-examine later, Mr. Feldewert, recross on this line of questioning.

Q. (By Mr. Bruce) Go ahead, go to Exhibit 20, Mr. Hathcock.

A. Yes, sir. So in Exhibit 20, right before the Devon kick, we see three months where we're right at 40,000 barrels per day -- I'm sorry, for a month.

Q. Per month.

A. And then after the well work, of course there's only three months on this chart, but basically they were at the max, around 20, 21,000 barrels per month, showing a significant reduction. I think I went and looked at the NMOCD website and they have data through January. I think that it continues at this lower rate. There's nothing that's close to the 40,000 barrels per month that they were injecting before the well work.

Q. Does that -- could that cause a problem with the injection?

A. It could, yes, sir.

Q. Okay. Let's go to Devon's Exhibit J.

A. Yes, sir.

Q. Can you identify, was this one of your documents, e-mails that was turned over to Devon yesterday afternoon?

A. Yes, sir, it was.

Q. And, again, to and from, date, and could you summarize the contents of this e-mail?

A. Sure. It's from Lomar Smith at OXY to Omar Lisigurski, copying Thomas Clifford, referencing the Diamond 34 Number 1 SWD fall-off test document. And I didn't get much out of the first three paragraphs. What caught my eye was the fourth paragraph. If you don't mind, I'll read it.

Q. Go ahead, read it.

A. "The Diamond 34 Number 1 fall-off test was planned for 11/16."

And, again, this -- this e-mail was dated November 19th. So it was planned for 11/16, however, that was suspended after the well was shut in as a result from a tracer test. That's a different tracer test than what was presented to us that was run in December that we all said, yes, that's clear indication there was no channelling.

Okay. It goes on to say: "A fall-off test will be subsequent to actions to repair the well's casing issue."

Q. Okay. Mr. Hathcock, before you saw this e-mail, did you know anything about a casing issue in this well?

A. No, sir.

Q. OXY hadn't reported that to you --

A. No, sir.

Q. -- to Devon?

A. No, sir, no data that --

Q. Was there any filings with the Division, a sundry notice stating a problem regarding a casing issue?

A. I went to the documents that's filed in the NMOCD website last night, and the latest one was the well workover where they had the loose packer and the tubing and casing communication that they repaired in September. That's the only document that I saw.

Q. So there was no C-103 sundry notice reporting to the Division a casing problem?

A. No, sir.

Q. Was there any sundry notice reporting to the Division what action OXY intended to do regarding the casing issue?

A. No, sir.

Q. Was there any follow up C-103 reporting to the Division what OXY had done to repair the casing issue?

A. No, sir.

Q. Could that have acted as a conduit for fluids moving up --

A. Yes, sir. It's one of the options in option one that we could have had a potential casing leak, yeah. Of course, not having the transparency of knowing exactly what was found and -- and what they were working on if, you know, again conjecture --

Q. But they're the ones reporting a casing issue here?

A. On this e-mail, yes.

Q. Thank you, Mr. Hathcock.

MR. BRUCE: Mr. Examiner, I'd move the admission of Devon's Exhibits J and K.

MR. EXAMINER: And having gone through the process, Exhibits J and K are so entered. And you're done with the witness.

MR. BRUCE: I am.

MR. EXAMINER: You'd like to redirect, I'm sure.

RECROSS-EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Hathcock, would you go to Devon Exhibit -- I'm sorry, OXY Exhibit 20, where you were.

A. Yes, sir.

Q. Okay. And I'm understanding you're referencing -- you referenced previously the drop in volume there showing in September of 2015?

A. Yes, sir, September, October, and November.

Q. That's what you're referencing?

A. Yes, sir.

Q. Okay.

A. But also data that's not presented here, too, that's on the NMOCD website that's very similar to this data.

Q. It shows decrease in volumes in September and October?

A. And December and January.

Q. Okay. Now, would you go to Devon OXY Exhibit 27, please.

A. Okay.

Q. And if I'm looking halfway down there, do you see that the well was shut in on September 8th?

A. Yes, sir.

Q. And then it would continue to be shut in through the month of September?

A. Yes, sir.

Q. Okay. Couldn't that be part of the decreased volume?

A. I would expect so.

Q. Okay. So now, secondly, your suggestion that because of this e-mail from a Mr. Smith that there is somehow a documentation of a casing issue. You're aware, are you not, Mr. Hathcock, that there was MIT tests run on this well?

A. Yes, sir.

Q. After the Devon incident?

A. Yes, sir.

Q. And that there's a Bradenhead test run on this well after the incident?

A. Can you qualify what a Bradenhead test is?

Q. Are you aware of what a Bradenhead test is?

A. The -- what you're calling a Bradenhead, in my estimation, is not a test.

Q. Okay. Well, there was a Division witnessed Bradenhead test, correct, Mr. Hathcock?

A. Okay. Could you direct me to that test, please?

Q. You're not aware of a Division reference Bradenhead test?

A. I saw an MIT test.

Q. But you're saying you didn't see a Bradenhead test?

A. All I'm saying is that I would like to be refreshed, sir, with all due respect.

Q. Didn't you see our exhibits?

MR. BRUCE: I'd object to that, Mr. Examiner. Let him ask the question.

Q. (By Mr. Feldewert) Would you turn to OXY Exhibit Number 4.

MR. BROOKS: Since the matter was followed up there's no need for a ruling. My ruling would be that if you're going to ask him did he see it, an exhibit, you need to call his attention to what exhibit so he can look at it.

Q. (By Mr. Feldewert) OXY Exhibit Number 4, is that a Bradenhead test report?

A. Yes, sir.

Q. Is it witnessed by Bill -- somebody help me out, Sonnamaker?

MR. EXAMINER: Sonnamaker.

A. Yes, sir.

Q. (By Mr. Feldewert) And when was that done?
A. I was a bit confused, sir, because it says surface pressure -- surface casing is zero, but you all did not have piped or gauges on the surface casing. You had on the intermediate casing.
Q. I'm just asking you: Is that a Bradenhead test?
A. Well, based on the information here it was not applicable to what you are asking because you have gauges on the intermediate casing not the surface casing. This says surface casing.
Q. Is this a Bradenhead test?
A. Yes, sir.
Q. Okay. And then you're aware that there was a temperature survey done on this well, correct?
A. Temperature survey, yes, sir.
Q. On the OXY well, right?
A. There was three different temperature surveys.
Q. And then there was tracer surveys done on this well?
A. Yes, sir.
Q. And none on those indicate that there is any kind of a casing leak, is there?
A. None that we have seen, sir.

Q. Okay.

A. But it appears in this e-mail there was another tracer test that was -- because the date of this e-mail was done before the one that you presented to us, that could have indicated that there was a problem that you all fixed.

Q. That's your -- that's your conjecture?

A. Yes. Unfortunately, I can't ask you the question, sir.

Q. Well, you can't, that's correct. I'm finished.

MR. EXAMINER: Are we through? Okay, thank you.

MR. BROOKS: Nothing.

MR. EXAMINER: Well, I think we've taken this witness as far as we can with your subject matter. Let's move on to your next one.

Thank you very much for your participation.

MR. HATHCOCK: Yes, sir.

[Witness excused.]

MR. EXAMINER: Are you ready?

MR. BRUCE: I'm ready.

MR. EXAMINER: Proceed.

STEVE SCHWEGAL

after having been first duly sworn under oath,

was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Mr. Schwegal, could you state your full name and city of residence for the record.

A. Steve Schwegal from Edmond, Oklahoma.

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

A. Devon Energy as a geologist.

Q. Have you previously testified before the Division?

A. Yes.

Q. And were your credentials as an expert petroleum geologist accepted as a matter of record?

A. Yes.

Q. And have you prepared an exhibit for presentation to the Division today?

A. Yes, sir.

Q. And is that marked Exhibit E?

A. Yes.

Q. Would you please start with page 1 and discuss the contents of the various pages of this exhibit.

A. Sure. The first page is basically just a location map showing the Devon well, the Devon acreage in the small upper right corner with some of the general information on the OXY well.

MR. BROOKS: I'm sorry, is this witness -- did we qualify him?

MR. BRUCE: I'm sorry, we need to do that. I submit him as an expert petroleum geologist.

MR. EXAMINER: Well, that's good.

Mr. Feldewert?

MR. FELDEWERT: No objection.

MR. EXAMINER: Okay, he is so qualified. Now you may blaze into the examination.

MR. FELDEWERT: I was going to object when he offered an opinion.

A. Okay. In the upper right is just general information on the OXY well, kind of a zoomed out location map showing Devon's acreage.

On the left in the center is, in Petra, the software package we use, these are the perforations that were given for the Diamond 34 State Well. So if they're incorrect, I don't know anything more than what's in Petra.

As we've noted previously, none of the wells nor the OXY well that were drilled previous to the North Thistle 34 had any issues. You can see the location in the zoomed in map in the lower right. In the southwest corner of section 34 is the surface location of the North Thistle 34. And then you can see it drilled from south to north ending at the northwest corner of section 34.

About 1400 feet away is the OXY well completed in 1997. Because of the safety issues with drilling the 2H we decided to move the rig over to the east, and you can see the little blue dot in the lower southeast corner there, in the right-hand corner. We drilled the three follow-up wells, the 1H and the 2H, and then one well -- you can't see it going off to the south but all three of those wells had no problem in the shallow section.

I've also noted on here the state lease numbers for section 34 right in the center of the section, so you can see those are there.

Next slide is just zoomed in. There's a cross section that runs from west to east, and I'll talk about that on the next slide. The surface location, again, is in the southwest corner. The bottom hole location is in the northwest corner of section 34.

Q. (By Mr. Bruce) And let me just clarify, even though when you're looking at the Devon well, the bottom hole location, as mentioned on the cross section, is the data from the surface well?

A. Correct. The Petra software, for some reason, puts your cross section location at the bottom hole location but it really is starting at the surface and then extending northward from there.

As we've discussed previously, at 18, 20 feet mud weight was raised from 9.8 to 15.3-pounds-per-gallon with a 16-pounds-per-gallon kill mud weight. And it's interesting to note on the far east side, the Amoco Federal BG Number 1 had 9.6-pounds-per-gallon mud at 12,410 and 13,1 at 15,700 feet. So we're looking at 16-pound mud at 1820, and they drilled to 15,700 and still had not reached that mud weight that it took for us to kill the well.

Slide number 3 is a schematic cross section. The shaded in area, and I don't know if the version you have shows the transparency or not. It was meant to be transparent, but I think when we e-mailed it somehow -- does everybody got one with the transparency? I think you can pretty much read it anyway.

But the top of the Salado formation and the base of the salt or the top of the Delaware is shaded in blue. We contend that after injecting 6 million barrels of fluid down into the upper part of the Delaware that the water migrated up the Diamond 34 vertically from the injection perforations and then horizontally 1400 feet to the North Thistle 34 State Com 1H along an anhydrite bed. It's schematically drawn on there. It's not to scale.

In the Salado formation, quoting from a BEG study that was done, mud, silt, and sand deposited eolian and arid region fluvial processes are interbedded with halite and that provides a horizontal conduit for fluid migration. So anhydrite can have a lot of silt and mud mixed in with it so it can actually provide a conduit.

Oh, in the center is the blowup of the OXY well. I won't talk about that too much because we've talked about it pretty much already. There's a little box that shows -- the insert that shows the base of the salt at 5,044 and then the top of the Cherry Canyon and Bell Canyon down below that.

Okay. The next is a structure map of the Brushy Canyon.

Q. Page 4?

A. I'm sorry, yes, page 4. Lower Brushy Canyon, subsea structure, Devon has seven producers from the lower Brushy just to give you an idea what the structure looks like up shallow. I did not map anything shallower than that. You can see the 1H again with the surface location down in the southwest corner and again the OXY well. And you can see that the dip is essentially going up from west -- east to west. Sorry. This is in subsea depth, by the way.

Slide number 5 is down at the top of the Second Bone Spring. This is near to the objective where Devon normally drills our Second Bone Spring producing wells. That was the objective of the 1H well. As you can see, it was drilled from south to north because internal studies at Devon have proven that wells drilled toe up get better results due to gravity assisted draining. And we try to do that as often as we can throughout the Thistle area.

Slide 6 shows the lower Second Bone Spring sand net thickness with an 8 percent density porosity cutoff. Normally we would drill six wells per section, so, again, that's opportunities that are missing if we cannot go in and drill. The red lines show the thick trend going from north to south through the main part of the Thistle acreage and including section 34. And you can see the well is labeled there with that blue insert box.

Q. Okay. Mr. Schwegal, the North Thistle 34 1H is a Second Bone Spring sand well?

A. Correct. Yes, lower Second Bone Spring.

Q. And when you're talking development mode in the Thistle acreage, six wells per second, you're just looking at the Second Bone Spring?

A. Correct.

MR. FELDEWERT: Mr. Examiner, what's the -- I object at this point to grounds of relevancy. I don't see how these are relevant to the issue here today which is the disposal wells.

MR. BRUCE: Well, Mr. Examiner, what we're saying is the primary charge of the Division is to prevent waste. And what we are going to show is we think we're showing that there is a conduit for the water up to the zone. It is leading to drilling difficulties and safety concerns, and Devon plans to drill a lot of wells out here. And this is a waste issue, and that's what we're showing.

MR. BROOKS: Well, it seems to me there's some relevance.

MR. EXAMINER: We will let you proceed with this, but be aware of what Division has previously stated in its decision, especially with presentation of needs and various other operatives. So proceed with caution.

MR. BRUCE: This is pretty quick.

A. One more slide. I just picked one example of a different horizon that is not in development mode. This is the middle part of the Avalon where the other well was planned to drill. And as you can see, we were unable to drill that well, move to the east.

So on this slide, in addition to the thickness map -- or actually go to slide 8, that would be better. That shows the south to north cross section going through section 34.

And then if you go to slide 9 you can see the multiple horizons that have already been tested and the fact that, you know, if we are unable to drill we will certainly waste resource.

Q. (By Mr. Bruce) And finally slide 10, and there's actually two slide 10s. Could you explain that?

A. All that I did on slide 10 was to enlarge the text box in the southwest corridor so that my tired eyes could see it a little bit better. So what this is, is essentially a cartoon view of what could the damage be. We do not know the extent of the leak, if we can even drill another well in section 34.

I'd like to go ahead and paraphrase part of the little box and read some of it. This is from the National Research Council, and the title is the Waste Isolation Pilot Plant, A Potential Solution for the Disposal of Transuranic Waste, and it was done in 1996. Box 3.2, in that paper, is potential consequences of brine injection from petroleum recovery operations on repository flow.

And they say: "Although the permeability of halite in the Salado Formation is negligible, there remains some concern about flow through marker beds and other impurities in the formation." And that would be what I mentioned earlier, anhydrite beds that have silt or mud stone in them.

They go on to talk about two potential ways that injecting fluids can cause issues. The first one is water flooding, and we're not talking about that today so I'll just skip over that. The second one is disposing large volumes of brine that involve high pressure injection to the deep rock formation, so wastewater essentially.

They go on to say: "If there's a failure in the well casing or in the cement outside of the casing, fluid can leak into overlying formations and flow laterally along one of the many anhydrite layers in the Salado. One such recent occurrence, in the Rhodes Yates Field of Lea County in Southeast New Mexico apparently caused significant flow through the Salado (reported as an unexpected flow of 1,000 barrels per hour that was encountered by a well drilled in 1991). The unexpected flow through Salado was attributed to injection into old production wells in the Yates Formation 200 meters below or about 650 feet and 3 kilometers away from the Salado horizon in the well," so almost two miles away.

"The flow probably was transmitted through anhydrite marker beds."

Q. Okay. Finally, Mr. Schwegal, could you move on to OXY's exhibits in the booklet there in front of you, I think 32, 33, and 34. Could you discuss --

A. It's actually 32, 35, 36, 37.

Q. Well, those are the slide numbers.

A. Oh, I'm sorry. Oh, oh, oh, I'm sorry.

Q. We're talking about exhibit numbers.

A. Oh, I'm sorry.

Q. So if you could just go to Exhibits 32, 33, and 34. Could you comment upon the matters stated in those exhibits?

A. Let me find 32.

Q. And in the lower right corner 35 is where it says it.

A. Well, I'm actually going to try to lump together a couple of the slides, so I hope I can go slowly enough so that it's pretty much understandable. First I'd like to talk about the slide that's titled Development of Overpressure, and there's two cases shown; one where a permeable layer is deposited and water escapes, so there is no overpressure. And the lower one, which is of more interest to us, is where overpressure is developed by overburden. Now, remember, we're talking about 16-pounds-per-gallon mud weight at 1,820 feet.

Now, there are a number of other ways you can get overpressure in the subsurface; clay transformation, hydrocarbon generation, and H2S. And OXY did not present any -- present any slides on that, so I'm inferring that they're keying this on overburden as the -- as the cause of their pressure.

In order to do that you would need rapid deposition to trap water in those sands underneath. And to better understand what was happening in the Salado Formation 250 million years ago it makes sense to look at a modern analog. So we're talking about the uniformitarianism which was published back in the 1830s. It's nothing new, and the premise is the present is the key to the past, and it's really just one of the foundations of geology.

So if we look at the Persian Gulf sabkhas -- sabkha means salt flat -- we see there that there are -- it's slow deposition by annual wet and dry periods. So you get salt buildup in thin layers over time. Interestingly, precipitation is about 1.6 inches per year and evaporation is 2.4, so you're actually evaporating more than you're putting in there. You get a little thunderstorm, it wets everything, and then it evaporates. That cannot result in rapid deposition.

In addition, the ability to correlate these thin anhydrite layers over long, long distances is -- you know, it would make it very difficult to build up pressure in a small cell. We can carry these -- in fact, on OXY's -- let's see if I can find it in here. Yes, I'm sorry. It's number 32 but the second page. You can see the two well logs that are 7 --

MR. FELDEWERT: I'm sorry, which exhibit?

A. It's Exhibit 32, the second page. It shows the Anderson Number 1 and the Diamond 34 well logs. In those two logs that are eight miles apart essentially you can correlate marker beds as well as the overpressure depth over eight miles. Now, how you would develop overpressure in a local area when you can correlate these anhydrite, probably permeable beds over a long distance, it's hard to understand.

In addition, because there are not that many digital gamma ray curves, I looked around and found one down further to the south. It's an EOG well, the Jackson 3 State Com 1, and it's -- it's about seven miles away. And, again, I could correlate numerous thin anhydrite markers over 15 miles. So how you can generate overpressure in a small cell in beds that can be correlated for 15 miles is difficult to understand.

That's pretty much it.

Q. (By Mr. Bruce) Okay. So what you're saying is vertically the beds of salt and anhydrites are impermeable unless it appears in the wellbore?

A. Correct.

Q. But horizontally you can allow lateral migration?

A. Right. Yeah, there's like dust storms that occur. This was all an arid environment during the time and so there were dust storms that brought in impurities that could provide permeability.

Q. Does that make it hard to explain without a vertical pathway, as could be provided by the OXY saltwater disposal wellbore, why all wells drilled near that well had no issues until Devon's well?

A. That's right, yes.

Q. In your opinion, Mr. Schwegal, is the granting of Devon's application in the interest of conservation and the prevention of waste?

A. Yes.

MR. BRUCE: Mr. Examiner, I'd move the admission of Devon Exhibit E.

MR. EXAMINER: Mr. Feldewert?

MR. FELDEWERT: No objection.

MR. EXAMINER: Okay. Exhibit E is so entered.

And it is your turn, Mr. Feldewert.

CROSS-EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Schwegal, I think you have Exhibit 32 in front of you, the one you just looked at.

A. Yes, with the cross -- with the two wells, yes.

Q. So you've looked at this exhibit before, correct?

A. I've looked at this exhibit, yes.

Q. Would you go to the first page. Do you understand what's depicted on this exhibit?

A. Yes.

Q. Okay. Doesn't this exhibit then -- this exhibit depicts the fact that you had one well in a grouping of four and encountered pressure as what?

A. What it shows me is that that was the last well that was drilled in there. There could have been other issues with previous wells that we don't know about. And, in addition, they drilled that well with 9.8-pound mud when all the other wells around it were drilled with over 10-pound mud. So it's really maybe just an over -- an under balanced issue.

Q. You would agree with me that the Division records reflect that the Anderson 5H is the only one that encountered a saltwater inflow?

A. Yes.

Q. Okay. Of those wells, correct?

A. Yes.
Q. And some of these wells right next to it are only 300 feet away?
A. Yes, that's what it shows on the map.
Q. 730 feet away, right?
A. Yes.
Q. Much closer than the circumstance that we have between the OXY well and the Devon well, correct?
A. Yes.
Q. And would you agree with me that that saltwater flow was roughly the same distance below or in the salt as the -- as what would be 1800 feet at the Devon Well?
A. Yes. On the next slide you can actually see the correlation, yeah.
Q. Okay.
A. Over eight miles.
Q. So that's an example of where we have only one of four wells that encountered a water flow in very close proximity of one to another, correct?
A. Yes.
Q. In your exhibit -- I went through all your exhibits, and correct me if I'm wrong, but I think that they all assume that there was some type of

migration from the injection zone to 1800 feet,
right?
A. Correct.
Q. But none of your exhibits present any evidence of this --
A. That was presented previously.
Q. I'm sorry?
A. That was presented previously by --
Q. None of your exhibits --
A. None of my exhibits show that, no.
Q. It just assumes that there is some kind of migratory --
A. Yes, correct.
Q. And if I'm looking at slide 10 --
A. Uh-huh.
Q. -- your slide 10 references a Waste Isolation Pilot Plant study, right?
A. Yes.
Q. From 1996?
A. Uh-huh.
Q. And did you look at that whole study?
A. No, I did not look at the whole study.
Q. Did you look at the portion of that study that dealt with the Salado hydrology?
A. Yes.

Q. And are you familiar with -- that within that study it indicates that there are isolated occurrences of high pressurized brine?

A. What I recall is that they saw that there were fluid inclusions but they're millions of years old. They're not recently put into the formation. Other -- other brine, yeah, I didn't -- I don't recall that exactly.

Q. You don't recall the fact that that report identified that there would be isolated pockets of brine in the Salado area?

A. I think they were mainly associated with H2S.

Q. But they had water in there too, right?

A. Sure. Oh, yeah.

Q. Okay.

A. The combination of bacteria and anhydrite does generate water when there's a reaction.

Q. So you had -- they had pockets of pressurized water?

A. Related to H2S, yes.

Q. And then are you familiar with a subsequent study that was done by the Department of Energy in 2004?

A. No.

Q. You hadn't reviewed that?
A. No, I have not.
Q. Okay. So you're not familiar with what that study indicated with respect to the types of pressures that would be encountered in these isolated water pockets?
A. No.
Q. Okay. Would you agree that there are numerous impermeable barriers between the injection zone and 1800 feet where the Devon encountered their water pocket?
A. Yes.
Q. And would you agree with me that if you have -- an overpressurized zone does require some type of seal?
A. If you're continuously pumping 6 million barrels of water. I don't know that that's the case.
Q. If I have an overpressurized zone, like it's been reported by the Department of Energy and is reflected on a number of instances in the basin, that overpressurized zone of water requires a seal, does it not, to maintain its pressure?
A. It could be high pressure in this place and then slowly decline as you move out from where the

high pressure occurs.

Q. Okay. Well --

A. We were 1400 feet away from the wellbore.

Q. But to maintain the pressure, okay, that is observed in some of these pockets, you don't think that zone has to have some kind of a seal?

A. Not necessarily. If you're continually injecting water, no.

Q. If you're not continually injecting water. Let's say that these are naturally occurring water pockets, okay?

A. Uh-huh.

Q. That's what I'm talking about. When you have those naturally occurring water pockets and overpressurized zone in there, don't you have to have a seal there in order to maintain that pressure?

A. Yes, you probably would.

Q. You wouldn't have the horizontal migration that you talked about?

A. It depends. I mean, if it's -- if it's an H2S deposit that was recently developed then I don't know how much of a seal you would require laterally.

Q. Did you do any study at the depth that Devon encountered to ascertain whether that is susceptible to the type of horizontal migration that would be required under some of the theorys that have been presented here today?

A. No.

MR. FELDEWERT: That's all the questions I have.

MR. EXAMINER: Very good.

MR. BROOKS: Nothing, thank you.

MR. EXAMINER: I'm going to pass on questions of this witness, and thank you very much for your testimony.

MR. SCHWEGAL: Oh, sure.

[Witness excused.]

MR. EXAMINER: Proceed.

ALEX BIHOLAR

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your full name and city of residence for the record?

A. I'm Alex Biholar from Oklahoma City, Oklahoma.

Q. And for the Examiners, could you spell your last name?

A. It's B, as in boy, i-h-o-l-a-r.

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

A. I work for Devon Energy as a geophysicist.

Q. Have you previously testified before the Division?

A. Nope.

Q. Would you please summarize your educational and employment background.

A. I have a bachelor's of science in geo sciences as well as a master's of science in geo sciences from the University of Texas at Dallas. I've been working in the oil and gas industry now for a little over five years, coming up on five-and-a-half. I did that part split between SandRidge Energy and then also Devon Energy for the last three years.

During that time I have worked West Texas Overthrust, Mississippi and Lime Place, Central Basin Platform and most recently, for the last year and a half, the Delaware Basin of Southeast New Mexico.

Q. Does your area of responsibility at Devon include this portion of Southeast New Mexico?

A. Yes, it does.

Q. And are you familiar with the geophysical matters related to this application?

A. I am.

MR. BRUCE: Mr. Examiner, I'd tender Mr. Biholar as an expert petroleum geophysicist.

MR. EXAMINER: Mr. Feldewert?

MR. FELDEWERT: No objection.

MR. EXAMINER: So qualified.

Q. (By Mr. Bruce) And have you prepared two exhibits for presentation here today?

A. Yes, I have.

Q. And marked as Exhibits F and G, I believe?

A. Yes, sir.

Q. Could you refer to Exhibit F, identify that for the Examiner and discuss its contents.

A. All right. So Exhibit F, there's only one slide in Exhibit F, and it is an arbitrary seismic line that's drawn across one of the 3D seismic surveys that Devon has licensed over the Delaware Basin. And there's a lot of information on this slide, so I'm going to take my time kind of describing it and going through what some of the major points of it are.

You're looking at -- and I'm not sure everybody's familiarity with geophysics and seismic.

You're looking at the shallow section of the earth. This is a cross sectional view, and you're focused mostly on the Salado, the Castile, and then the base of the salt and everything underneath that, which would be your Bell Canyon faces.

Now, there's a couple of things in here that you'll notice. We often talk about this, Ochoan evaporate sequence and we kind of refer to it all as the salt, it's the salt sequence as though it's one and the same but it really isn't. When you -- when you talk about the Castile versus the Salado, the way that those rocks are made up, you're still going to find a lot more anhydrite within the Castile.

And in addition to that, the Castile is prone to deformation. Now, part of my role at Devon as a geophysicist, before every single well that we drill, we do a risk assessment in the near surface and we'll take a look at what are the possible near surface hazards. In the Delaware Basin there's several that come to mind. We get karst, particularly in the refill faces, we'll get -- but not just in the refill faces. We can actually get karst associated with some of the salt dissolution within the salt, particularly where we get freshwater flow that comes through to Capitan.

In addition to that, a couple of times we've had issues drilling through places where the Capitan formation has been deformed. An example of that would be towards the right of that cross section that's labeled Salt Deformation.

This is kind of typical salt pillar structures. Now, when we have gone back and looked at a number of the 22 wells that were provided for us, we saw that a large number of them that didn't have flows were in that Castile formation. And when you map up that trend, where that mobilized salt build occurs, a lot of those wells will line up across that point as well so it's not too much of a surprise that you could get water flows and pressurized water flows where you have the salt deformation because you are moving things around.

Now, if you look at where Devon got the water kick at 1820 feet in the Salado Formation, again, on that cross section the well furthest to the left is the North Thistle 34 State Com 1H. We're clearly within the Salado Formation. There's no contest there, but what you'll notice is the internal reflector package to that is on these very horizontally bedded reflectors.

Now, all that shows me is that we've got lithology that you map aerially for some extent away from this well. And any way that I look at this, any orientation through that 3D seismic volume, I can come to the same conclusion that these are mappable surfaces through there.

Now, we'll actually go through and do some attribute analysis on this and look at that near surface and pull up semblance, coherency, incoherence, whatever the flavor of the day is what we're calling that attribute to see if there's any disturbances within that rock. It looks at each seismic trace and the one next to it and sees how different statistically am I from the one next to me.

Now, if each trace says I'm not that statistically different from the one next to it, it means that the rocks structurally are not deformed. That's semblance in a nutshell. Now, what we see when we look through here is we don't see any semblance here. And I'm going to show an example in a second here where we were able to see such an incoherent event in the seismic data that actually was associated with the collapse feature that formed when water was allowed to migrate through the salt section and dissolve it out.

And when you got the dissolved salt and the shallow surface, anything that's in the subsurface and you have an open cavity, those tend not to stay open for very long and it's going to be prone to collapse. It's a risk that's associated with injecting undersaturated water into that salt layer.

And I guess one last thing on that, is we are looking at almost 3200 feet or greater than 3200 feet of impermeable strata. You know, it's salt and anhydrite. That's about as perfect of a seal vertically as you can geologically. Now, the problem with that is if you are encountering water, that water has to come from somewhere. Either it has to be deposited or it has to be placed there by some outside means.

And I think what Steve, our geologist's testimony earlier, he talked about why getting large volumes of water without the generation of H2S would be unreasonable. So that water had to come from somewhere, and I'm proposing, as with everybody else with Devon, the water was coming from this injection well.

That's all I've got for Exhibit F.

Q. Well, just a second. I just want to

confirm a couple of things.

A. Yes.

Q. When you're talking about the salt section, on your Exhibit F, the Castile is the orange acreage, the lower orange acreage?

A. Yes, sir.

Q. And that is more conducive to water flows?

A. Right, and that's more anhydrite rich.

Q. And then the yellow or greenish is the Salado?

A. Correct.

Q. And that is more conducive to H2S?

A. If there is anhydrite -- typically it would require anhydrites and then you need to have water or hydrocarbons moving through that anhydrite to generate H2S.

Q. Okay. Go ahead with your next exhibit.

A. Okay. So the next exhibit is Exhibit G, and I'll be quick on this one. I just wanted to show that there's a real risk to putting these unsaturated waters into -- into the salt section.

Now, on slide number 2 of that, you'll see just an index map of where we're looking. The Diamond 34 State is there up in the upper left-hand corner of the map. And towards the -- towards the southeast is the Jal Water System 2. We're going to be talking about that as an analog to what could be happening here at the Diamond 34 State 1.

So slide number 3 on there shows a screen cap from Google Maps that was taken very recently of what that well site looks like today. As you can see, there's a very large karst that has developed at that location.

Slide 4 is another view of that. It's a low angle aerial photograph that shows that same collapsed feature. It's about 60 feet across, maybe 60 to 70 feet across, and you can actually see this one in our seismic semblance. So this structure, it formed basically overnight in a catastrophic collapse sometime in 1998. And these sinkholes throughout this Ochoan evaporative sequences are not very common.

Now, this is a little bit circumstantial, but I present this because it is a real risk, and it's a risk that I know that we as an operator try to avoid because it will place the surface equipment at risk for damage or from any safety environmental standpoint.

But in addition to that, when you start to create these collapse features you're creating a

Betchel pipe that goes up into the near surface. Now, the problem with that is you're artificially increasing the vertical permeability which is going to allow waters to migrate vertically from one level to the next, which if you're going to the surface you would be going straight through the freshwater aquifers and potentially contaminating those.

Q. Now, referring back to your Exhibit F, how much seismic resolution do you have vertically near the wellbore?

A. Okay. So vertical seismic resolution, what we can and what we can't see with the seismic resolution, we're not going to be able to see water coming up the pipe. That's beyond the resolution of this data. We're going to be able to see features that would -- like, for example, a fault. We could see a fault if it was going to cut through that 3200 feet of rock and present a natural conduit. We could see something like that.

What we're not going to see is, like I said, a small collapse around the casing. That's not with the resolution or what seismic, as a tool, was used for. What it can see is the places like that 60-wide foot karst. We would be able to detect something like that.

Q. And then with respect to your Exhibit G, obviously the -- in this situation the water did migrate through the salt, correct?

A. Correct.

Q. Can you see any other reason than the wellbore itself?

A. Based on having 3200 feet of impermeable salts and anhydrites there has to be some conduit to allow that water to get there.

Q. Okay. And anhydrites, can anhydrites have impurities; mud, silt, stone, et cetera?

A. Yes, based on the depositional environment that was at the time in this part of the world, like Steve had mentioned earlier, you would be getting dust storms through there and you could possibly even be getting some fractured systems through those anhydrite beds which tend to be a little bit more brittle than the underlying salts.

Q. And that would allow horizontal migration?

A. Correct. And that's something that comes out of that WIPP study as well on those anhydrites. Their big concern was they can actually watch fluid flow through those anhydrites, and that's documented in that same DOE study that was mentioned previously.

Q. Were Exhibits F and G prepared by you?
A. Yes, sir.
Q. And in your opinion, is the granting of Devon's application in the interest of conservation and the prevention of waste?
A. It is.
MR. BRUCE: Mr. Examiner, I move the admission of Exhibits F and G.
MR. EXAMINER: Mr. Feldewert?
MR. FELDEWERT: No objection.
MR. EXAMINER: Exhibits F and G are so entered.
MR. BRUCE: Pass the witness.
MR. EXAMINER: Mr. Feldewert?

CROSS-EXAMINATION

BY MR. FELDEWERT:
Q. Mr. Bitolar; is that right?
A. Biholar.
Q. What's that?
A. Biholar.
Q. Biholar. Okay, so no T. I want you to -- first off, if I look at your Exhibit F, when was this seismic shot, do you know?
A. The seismic was acquired in 2004.
Q. So long before Devon's incident?

A. Correct.
Q. Do you have any update of that seismic?
A. No. This is the most modern seismic that's available over this -- that's available over this location at this time, though it is being proposed to be shot in the near future.
Q. And the Pogo well at this point had been injecting -- well, it's been injecting since 1997, right?
A. Correct.
Q. And if I heard you correctly, your seismic here confirms that the approved disposal zone has an effective geologically sound seal?
A. What you heard is 3200 feet of anhydrite and salt is an effectively good geologic seal.
Q. Okay.
A. Now, it's not a geologically sound seal if there is salt deformation at that base. What you see at the seismic there on Exhibit F, there is some deformation within that salt deformation. You can see within the Castile package there's a bright orange reflector in the trough there. That's the base of one of these anhydrites.
Q. Okay. Well, I'll tell you what, let's do this: You show the injection interval down there,

correct?

A. Correct.

Q. And do you see effective geologic barriers existing between the injection interval and where you saw your water flow?

A. There could be, but seismic is not going to tell that.

Q. They're not?

A. No.

Q. Okay. What is the -- and as I move up this wellbore here, I see a blue line. That's the base of the salt?

A. Correct.

Q. What's the brown right below that?

A. That's when you're going to be getting into your Delaware faces, so you're going to be getting into your more clastic, which would be the injection interval.

Q. And above that would be the top of the Bell Canyon, correct?

A. Correct.

Q. And as I move up, I see some yellow streaks and that's, you said, some salt deformation?

A. Correct. Those are places where the salt has been allowed to flow, and we see that where we get reflections off of the anhydrites. We get a good reflection on that.

Q. So that would be horizontal, right? We don't see any upward flow?

A. You could be seeing upward flow in here. These structures map out in such a way that in places these anhydrite beds are vertical to near vertical. In places they're overturned within that package themselves. That would negate any -- any assumption that you have no vertical communication because now you're talking horizontal beds with permeability and you're turning them on their end. Now that water can migrate upwards.

Q. Do you see any evidence of fractures or faults here that would allow water to move out of the injection zone upward?

A. I don't see any evidence for fractures or faults, natural fractures or faults within the Bell Canyon or within the Salado, but I do see evidence for them within that Castile package.

Q. Do you see any evidence of karsting around the -- the base of the intermediate casing?

A. I don't see any evidence of karsting, this seismic was shot in 2004.

Q. Okay.

A. And these are structures that form in catastrophic collapse basically overnight.

Q. And if I -- if you had taken a seismic shot before the Whitten Ranch Sinkhole, what would you have seen?

A. So an example across the Whitten Ranch Sinkhole.

Q. Or what would a seismic show? Would you be able to see the -- would you be able to see the --

A. No, you wouldn't be able to see it before.

Q. You wouldn't see it?

A. You can see it afterwards.

Q. Okay. As I move up this -- the wellbore here, I get to the point up around the 1820 water flow; do you see that?

A. Uh-huh.

Q. Do you see little dark shadings there?

A. Yep.

Q. What -- are those geo hazards?

A. No, those are not geo hazards.

Q. What is it?

A. So those are -- within that interval you get strong reflections. Within the Salado, being dominantly a hilite -- or halite sequence, there are interbedded anhydrite associated with that. And what you're seeing there is probably an interface between one of those anhydrites and the halites. You're getting a strong peak reflection on there, being a black mark on here, my clarity is North American standard. So that's probably going to be an anhydrite bed above the -- where we got the water injection.

Q. That dark streak there?

A. Probably. Correct, yes. And it does continue, and you see that in the seismic. Those -- you're going to see changes in your amplitudes, which is the intensity of how much reflection you're getting back. That's going in very laterally.

Q. Is that seismic anomaly restricted to just your well?

A. No, that's continuous. You can map that reflector out.

Q. Okay.

A. You have a stronger response at the well, but that's -- it's got a relatively lateral continuous in it. That one actually intersects with the Diamond 34 just to the east.

Q. And you agree that saturated water is -- would not pose any damage to the salt, correct?

A. It would have to be 100 percent saturated to the point of not being able to dissolve any halite.

Q. You're aware, though, that the water that's injected by OXY is not undersaturated?

A. Perhaps with the other reservoir but I'm not sure if it is or not for being injected into a salt.

Q. You're not aware that halite contains a high count of chlorides?

A. I'm sure it does but I don't know what that count is that would cause dissolution within the Salado.

Q. And you seem to suggest that all of these anomalies that we've seen, that operators had observed in this region is limited to just the Castile zone; is that what you're suggesting?

A. Not all of them because it was presented with the Anderson case, and that's clearly within the Salado.

Q. That was my question. That's clearly the same basin?

A. Right. But from a geo risking standpoint, high rate flows within the near surface are expected to be within the Castile where we do get those deformations. Now, in the Salado, we don't really see too many of them. And out of those 22 examples there's really only one example, and that was the Anderson. And as was mentioned previously, that well may have been drilled. It was in the middle of four other wells that were offsetting up to 300 feet away.

But when you look at the actual mud weights of those wells, the mud weight on that Anderson that took the flood was at 9.7-pounds-per-gallon. All the adjacent wells, when they went through that same section previous to that were at a higher -- half a pound to a pound higher mud weight and so it may be that that was just an under balance for that section.

Q. We just don't know, do we?

A. And additionally, that flow, within that well and that Salado, wasn't near on the scale of the flow that we took with a 16-pounds-per-gallon mud that we encountered on our North Thistle Well.

Q. So would you agree with me that there are instances of isolated water pockets within the Salado zone?

A. Associated with the H2S, yes.

Q. Okay. And if there are some that are not associated with H2S?

A. If they're free flowing through anhydrites it's possible but not with the pressures that were encountered.

MR. FELDEWERT: Okay. I think that's all the questions I have.

MR. EXAMINER: Very good.

Do you wish to redirect?

MR. BRUCE: Just briefly.

REDIRECT EXAMINATION

BY MR. BRUCE:

Q. On your Exhibit F, the data is from 2004, correct?

A. Correct.

Q. And since then millions of barrels of additional water has been injected into the --

A. Correct. There's been another 12 years of injection.

MR. BRUCE: Thank you. That's it.

MR. EXAMINER: Mr. Brooks?

MR. BROOKS: No questions.

MR. EXAMINER: I have no questions for this witness.

Let's go ahead and take a break. We'll let you be the final witness for Mr. Bruce, and let's do about 15 minutes. Be back here at 20 of.

[Recess taken from 2:23 PM to 2:38 PM.]

MR. EXAMINER: All right, folks, we're back on the record.

You are on your final witness, I believe?

MR. BRUCE: Yes, sir.

MR. EXAMINER: Very good. Proceed, please.

CHRISTOPHER BROUGHTON

after having been first duly sworn under oath,

was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name and city of residence.

A. Chris Broughton. I live in Oklahoma City, Oklahoma.

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

A. I work for Devon Energy as a reservoir engineer.

Q. Have you previously testified before the Division?

A. No.

Q. Would you please summarize your educational and employment background?

A. I graduated with a bachelor's of science in mechanical engineering from Georgia Tech. I worked at Exxon Mobile for three years on various U.S. onshore and offshore Gulf of Mexico properties. Over the next two years I worked for Devon as a reservoir engineer in the Delaware Basin.

Q. Does your area of responsibility at Devon include this portion of Southeast New Mexico?

A. Yes.

Q. And are you familiar with reservoir engineering matters regarding this application?

A. Yes.

MR. BRUCE: Mr. Examiner, I'd tender Mr. Broughton as an expert petroleum reservoir engineer.

MR. EXAMINER: Mr. Feldewert?

MR. FELDEWERT: No objection.

MR. EXAMINER: Yes, he is so qualified, and proceed, please.

Q. (By Mr. Bruce) Well, Mr. Broughton, let's start off with -- and I think you reference their Exhibit 29?

A. Yes.

Q. Can you refer to the -- I mean OXY's Exhibit 29.

A. That's all right.

Q. Could you refer to that and discuss your opinions regarding the matters set forth in this.

A. Well, it looks like it's a typed log, and I see at the bottom of the log a reference to impermeable strata.

Q. Yes, sir.

A. And from what I'm inferring from this -- from this exhibit is the fact that, you know, flow couldn't exist beyond this impermeable strata. And I'd really just like to point out the fact that we see the same signature for our Second Bone Spring formation on our acreage. It's about 4 to 500 foot thick. And we see, you know, these same streaks occurring in that reservoir.

We typically target the lower Second Bone Spring, and we've actually started to try to infill this reservoir to understand, you know, the economics better. And we found that through DFIT analysis and also the infill well itself that there is communication above and below these -- these limestone streaks. So this suggests even though these streaks are present that communication can still exist.

I'd also like to point out the fact that the -- OXY's saltwater disposal well was fracked. And, you know, I'd like to preface with the fact that I don't have any visibility into internal evaluation by OXY, but I haven't seen, myself, any indication that that frac did not penetrate these impermeable strata that are mentioned.

Q. Okay. And then let's just move on, and I think you can be fairly summary. What is Exhibit H and what are you trying to show there?

A. So the first log just shows the future development potential for this section. As you see with that blue dot in the -- that little bottom left corner, we've already drilled the North Thistle 34 State 1H. In addition to that well, we have about 20 total wells planned for this section. These wells target anywhere from the Avalon to the first Bone Spring to the second Bone Spring intervals, which competitors and/or Devon have -- have proven up.

So over these 20 wells we're expecting about 8.7 million barrels of oil equivalent. After about a 19 percent NRIs taken by the state, we're left with about 81 percent NRI for Devon in addition to these 20 wells that are mentioned, and there's also upside potential in the upper Second Bone Spring as well as the Wolfcamp. Of particular notice, the Wolfcamp, as you can see from this diagram, it's typically over 1,000 foot thick so there's opportunity for multiple land influence in Wolfcamp which could significantly increase the well count and reserves estimates.

Q. Okay. Could you move to page 2 of this exhibit?

A. Sure. So I'll be brief with this page. I'd really just like to call your attention to the top left plot, which plots incremental EUR per well as well as incremental total EUR for the entire section, and that blue curve just illustrates the fact that as we increase the density for our wells that EUR per well goes down because of acceleration issues.

However, there's a capture component as well, so these additional wells actually recover in incremental reserves as well. And so on a total of section basis we actually increase the reserves as we increase the well density.

Q. And when you're looking at this, this is simply the Second Bone Spring?

A. That's correct. Yeah, so through some, you know, economic analysis basically what we've determined is six wells per section is optimal. However, if commodity prices improve then that six wells per section number could actually increase and we could be talking about, you know, even more wells and reserves that we could develop here.

Q. Page 3.

A. A similar story for the Avalon reservoir. On the top left plot we have incremental UR per well and total EUR. And basically, you know, EUR per well goes down as we drill more wells. But on a total section basis we recover, you know, more EUR as the number of wells increase.

For the Avalon, I have a five well per section density based on the economic evaluation. And, again, you know, if prices recover and increase the reserves then well count estimates could increase.

Q. And your economics for this exhibit are based on current economics; is that correct?

A. That's right. It's based off a flat, basically a flat pricing, which is pretty low.

Q. Okay. And, again, when you're talking about wells you're just looking at, for these exhibits, simply section 34?

A. That's right. That's right.

Q. Okay. And finally page 4.

A. Page 4 just illustrates the fact that there is potential in the First Bone Spring interval. This interval is relatively new in this area, but three or four miles away we actually drilled an appraisal well for this zone. And you could see the production indicating that, you know, we do have the presence of hydrocarbons in the First Bone Spring.

Q. And so, in short, you're not just looking at when it comes to safety issues, et cetera, you're not just looking at a couple of wells that might have problems. You're looking at a couple dozen wells?

A. That's right. You know, at least 20 wells, and with the upside potential and, you know, increased density due to pricing, you know, we could be looking at 30 to 40 wells.

Q. And was Exhibit H prepared by you?

A. Yes.

Q. And in your opinion, does the granting of Devon's application in the interest of conservation and the prevention of waste?

A. Yes.

MR. BRUCE: Mr. Examiner, I'd move the admission of Exhibit H.

MR. FELDEWERT: No objection.

MR. EXAMINER: Exhibit H is so entered.

Your cross.

CROSS-EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Broughton, are you there on Exhibit 29?

A. Yes.

Q. Do you see the blue bars with the impermeable strata?

A. Yes.

Q. That's put together by the geologist, right?

A. I -- I -- yeah.

Q. You're not a geologist?

A. No, I am not.

Q. Okay. And those are above the injection intervals; is that correct?

A. Yes.

Q. Now, you are a reservoir engineer. Are you familiar with radioactive tracer surveys?

A. Not as familiar as some of the other witnesses.

Q. Did you review Devon's results from their radioactive tracer surveys?

A. Briefly.

Q. And were you aware that they showed that the water was migrating -- not channeling upwards but would be migrating outward or downward?

A. Not specifically, no.

Q. You're not aware of that result?

A. No.

MR. FELDEWERT: Okay. That's all the questions I have.

MR. EXAMINER: Very good.

MR. BROOKS: No questions.

MR. EXAMINER: And I have no questions for you. Thank you.

MR. BRUCE: The only thing I have left, Mr. Examiner, is I have four witnesses, other than Mr. Schwegal and Mr. Hathcock, who could get on a plane to go home, and I'd ask that they be excused so they can flee the premises.

MR. EXAMINER: You don't want to use them anymore?

MR. BRUCE: I'm retaining two.

MR. EXAMINER: Okay. If it's such and you feel that you have no interest in these folks testifying further then by all means you may release and go home and enjoy.

MR. BROOKS: I'm assuming you have no objection, Mr. Feldewert, since you didn't say?

MR. FELDEWERT: I have no objection.

MR. EXAMINER: Well, he'd already asked them all the questions he's going to ask them.

MR. FELDEWERT: That's all I got.

MR. EXAMINER: But, yes, there's no objections from your part. Let's go ahead and get these folks on the road.

MR. BRUCE: Thank you, sir.

MR. EXAMINER: You're welcome.

So Mr. Bruce is done.

MR. BRUCE: Oh, but one final thing. It's minor. Exhibit I is my notice of affidavit regarding notice of the original hearing to OXY. I'd ask that that be admitted as part of the record.

MR. EXAMINER: Exhibit I is so accepted into the record.

[Recess taken from 2:49 PM to 2:50 PM.]

MR. EXAMINER: All right. We're back on the record.

Proceed, Mr. Feldewert.

THOMAS CLIFFORD

after having been first duly sworn under oath,

was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. FELDEWERT:

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

A. Yeah, my name is Thomas Clifford. I'm employed by OXY Petroleum Corporation, and I am currently the production authorization lead for New Mexico RMT.

Q. And do you have a degree within petroleum engineering?

A. Yes.

Q. And how long have you been working as a petroleum engineer?

A. Five and a half years.

Q. Do your responsibilities include a review of design and construction of injection wells?

A. Yes.

Q. And have you previously testified before this Division as an expert in the petroleum engineering?

A. I have, yes.

Q. Are you familiar with the history of OXY's disposal well at issue here?

A. Yes.

Q. And have you done an analysis of Devon's allegations and theorys concerning that disposal well?

A. Yes.

MR. FELDEWERT: I would tender Mr. Clifford as an expert in petroleum engineering.
MR. EXAMINER: Mr. Bruce?
MR. BRUCE: No objection.
MR. EXAMINER: The witness is so qualified.
Q. (By Mr. Feldewert) I think we can breeze through, Mr. Clifford, a number of these initial exhibits. OXY Exhibit 1 has an area map that shows the distance between the wells we've been talking about here; is that correct?
A. Yes.
Q. And is OXY Exhibit 2 a current diagram of the disposal well?
A. Yes.
Q. And it shows the current perforations?
A. Yes.
Q. And it shows that our current perforations are at least 170 feet below the top cement, correct?
A. Yes, that's correct.
Q. And when did OXY take over operations of this well?
A. In March of 2008.
Q. Okay. And if we turn to what's been marked as OXY Exhibit Number 3, does this reflect the more recent mechanical integrity test on the well?

A. Yes, all four of them.

Q. Two of these were operated or conducted when Pogo was operating the well?

A. Yes, that's correct.

Q. And two of these when OXY was the operator?

A. Yes.

Q. And then behind them is the results of each of these mechanical integrity tests; is that correct?

A. Yes, that's correct.

Q. And at least -- in each of these cases they were either witnessed by the Division or they were -- the Division was notified of these tests; is that correct?

A. Yes.

Q. As indicated by the records?

A. Yes.

Q. Okay. And have any of these reflected any kind of casing integrity issue?

A. No. After reviewing all four of these, there has never been an issue.

Q. And the most recent one was actually done in October of 2015 after Devon reported their incident, correct?

A. Yes.

Q. And that particular test was actually witnessed by the Division; isn't that true?
A. Yes, it was witnessed by Mr. Bill Sonnamaker.
Q. And there was no issues with respect to the integrity of the wellbore?
A. No.
Q. Then in addition to doing the mechanical integrity tests, did Mr. Bill Sonnamaker then also witness a Bradenhead test?
A. Yes.
Q. And is that reflected in OXY's Exhibit Number 4?
A. Yes, it is.
Q. And, again, did that reveal any issues?
A. No issues.
Q. And did that test the intermediate casing?
A. Yes, I believe so. I believe it tested the intermediate casing, and you can see some numbers on the -- or I have a table of production casing showing zero pressure, which would also be tied in with the mechanical integrity tests run the same day.
Q. Okay. And that would be the purpose of doing the test at that point after Devon had

reported their incident, right?

A. Yes.

Q. Okay. Then after these Bradenhead and MIT tests, did the company install pressure monitors on the intermediate casing?

A. Yes, we did.

Q. If I turn to what's been marked as OXY Exhibit 5, is that a current picture of the condition of the disposal well?

A. Yes.

Q. Would you just briefly run -- explain to us what is shown here?

A. Yeah, so the photo on the bottom left shows the current surface location for the Diamond 34 State SWD Number 1. The next picture over in the center is the surface pressure gauge at the surface. It's not a transducer but it's a clock gauge. This is where we monitor and report in our well tests the injection pressure at the wellhead.

The two photos on the right show the two Bradenhead pressure gauges that we've been, since October, monitoring to make sure we have zero PSI at all times on our intermediate brushing casing Bradenhead.

Q. And in your opinion, does the installation of these gauges on the intermediate casing on the annulus provide a thorough monitoring of that particular aspect of the wellbore?

A. Yes, because you've got a low top cement, you've got an open annulus all the way up that goes beyond the intermediate casing shoe. And if you have pressure coming up above the top of cement you would see similar pressures to what Devon experienced while they were drilling at 1820 feet on these Bradenhead pressure gauges. However, we had seen zero PSI on all instances on these two gauges.

Q. Zero?

A. Zero.

Q. Okay. And if I turn to what's been marked as Devon Exhibit Number 6, is this document, at least up through November, the readings on those two monitoring devices?

A. Yes.

Q. And is that -- are those readings reflected in the middle columns, Bradenhead Number 1 and Bradenhead Number 2?

A. Yes. Bradenhead Number 1 was the first pressure gauge we installed. On October 31st we installed a redundant pressure gauge to make sure the first one was working adequately, make sure we're in conformance, in compliance. And, yes, these are all measurements we took on a daily basis over the course of about a month or so.

Q. Okay. And referencing -- you've been here for the testimony here today, correct?

A. Yes.

Q. You've seen Mr. Hathcock's migration slide that he put together?

A. Yes.

Q. What he calls his potential migration slide?

A. Yes.

Q. If indeed the -- any water was moving up either outside or inside the intermediate casing, would these pressure readings be zero?

A. No. You would see it -- in some way, shape, or form you would see pressure on the Bradenhead because in order for the fluid to get from the injection perforations to the outside or inside of the intermediate casing, you'd have to get past the annulus which exists above the top of cement on the outside of the production casing. So in some way, shape, or form you would see pressure on these Bradenheads.

Q. And in your opinion as an expert, do these gauges and the readings that have been reflected on these gauges confirm that water is not migrating in or around the intermediate casing?

A. Yes.

Q. Did OXY also then take an additional step and test the intermediate casing while the well was injected?

A. Yes, we did.

Q. And is that reflected in what's been marked as OXY Exhibit Number 7?

A. Yes.

Q. Would you please explain what was done?

A. Yeah, so the photo here on the right shows the same photos on the previous exhibit. You've got your two pressure gauges, however, we removed the pressure gauge at item number D and put a Barton recorder on there to chart the Bradenhead because it's easier to show a chart of data versus just a bunch of photos showing zero PSI.

So we installed a Barton recorder on the -- on one of the intermediate casing head inlets and charted a 20-minute test while we were injecting down the tubing to show that we have zero PSI during a test.

Q. And in your opinion, does this further confirm that even when you are -- when the well is fully functional and injecting that there is no water movement in or around the intermediate casing?

A. Yes.

Q. OXY also did some temperature surveys on this well, did they not?

A. Yes, we did.

Q. Okay. And was that done at the request of Devon?

A. Yes. There was some talks in September about running some temperature surveys and so OXY ran a couple temperature surveys and then subsequently ran some more later on.

Q. Okay. And if I turn to what's been marked as OXY Exhibit Number 8, does that identify the temperature surveys in a period of time in which they were conducted in this particular disposal well?

A. Yes, these are the -- each of these show the different suites of temperature surveys we ran in 2015.

Q. And if I look at Mr. Hathcock's exhibit, let's go to -- so keep this out, and I want to go what was marked as Devon's Exhibit D-1. And Mr. Hathcock actually charted the results of that survey, do you recall that?

A. I'm sorry?

Q. Mr. Hathcock charted the results of this survey?

A. Yes.

Q. And that's reflected in D-1?

A. Yes, in D-1 this is the 25-day shut-in temperature survey which overlays their -- their temperature gradient from their baseline fiberoptic log. This is -- here references temperature survey number one on OXY Exhibit Number 8.

Q. And what generally do you observe about the temperature gradient above the zone of injection?

A. It's almost -- it overlays almost exactly the same temperature gradient as what you see in Devon's base -- or baseline log located six miles to the south of where we're at.

Q. And he notes three gradient changes on here, do you see that?

A. Yes.

Q. In your opinion, are those significant changes?

A. They're on the order of less than a tenth, a 20 -- or a tenth or a fifth of a degree Fahrenheit. They're very small, very insignificant, and they don't appear to be connected. You get instances where you get a little slight deviation to the left or cooler geothermal gradient for a couple hundred feet and then it goes back to the normal geothermal gradient on each instance. So, no, I don't think they're very significant here.

Q. If, as Devon suggested, water was traveling up the -- in or around the casing or up the wellbore somehow, would this chart show a consistent departure from their gradient line?

A. Yes, I would imagine so because if you look at the very bottom of Exhibit D-1, you see the blue temperature at the injection zone as very cool. So you'd see a cooling effect all the way up the wellbore to the highest point of water injection or water travel which would be somewhere higher than the injection zone. However, here it pretty closely mimics the exact same temperature gradient as what you see in a Devon-based land log from six miles south.

Q. In fact, there's absolutely no gradient change between, what, about 3,000 feet and 1800 feet where they had their water encounter?

A. Correct.

Q. If I then go to Mr. Hathcock's

Exhibit D-2 -- actually before we go to that I want to ask you a question about D-4.

A. D-4?

Q. Uh-huh.

A. Yeah.

Q. You were here for the testimony?

A. Yes, sir.

Q. And do you see how the water movement that goes to the right and to the left of what they call their normal gradient line?

A. Yes.

Q. Could that occur if you were actually having water moving out of the injection zone and up the wellbore as they suggest?

A. If it was consistently cooler than the geothermal gradient you could say possibly water -- you've got water seepage, maybe not at a high rate. Your temperature change is also -- you know, it's impacted by rates. If you've got a large amount of cool water coming up the wellbore, maybe you'd see a huge inflection to the left of the geothermal gradient.

But as we see from the purple log, the red log, and the orange log at the very bottom of this chart you've got a much cooler temperature in all three of these instances within the injection zone than you do up above the injection zone above the line where it says permitted time for the water to get hotter than the geothermal gradient above the geothermal -- or permitted top. It doesn't make sense that you've got cold water moving up the wellbore.

Q. Now, I want to focus then on his -- what he marked on Devon's Exhibit D-2 as the areas of the three gradient changes. Okay?

A. Uh-huh.

Q. At approximately what depths did each of these gradient changes occur?

A. The first change is approximately 3500 feet, the second change is at approximately 4300, and the third change is approximately 4800 feet.

Q. And as more clearly reflected here, do they always go back to the normal gradient line?

A. Yes, in every instance they -- in between all three of those they go back to the normal geothermal gradient so that tells us that they're probably most likely not connected at whatever they are.

Q. And did you examine the lithology of the

Devon wellbore where these slight gradient changes occurred?

A. Not the Devon wellbore, but in OXY's wellbore, yes.

Q. I'm sorry. Thank you. The OXY wellbore.

All right. And if I turn to what's been marked as OXY Exhibit Number 9, is this the start of your examination of those three gradient changes reflected in Exhibit D-2?

A. Yes. So the red starts at the top -- well, first off, all the squiggly lines on here are each independent temperature surveys we ran. The blue lines are all the shut-in or baseline temperature surveys shut in either at one day or one hour, 25-day shut-in period. The two lines on the far left represent the injection profiles we ran.

In the bottom X-axis you see the temperature increasing from 70 degrees to 98 degrees. What we want to key in on here is the colored stars. So the red stars at the top are indicating the first gradient change that Mr. Hathcock points out at 3500 feet. The green stars across each independent temperature survey represent the gradient change Mr. Hathcock points out at a depth of 4300 feet.

And then at 4800 feet, approximately, you see another group of yellow stars, and these are the third gradient changes that Mr. Hathcock points out in his exhibits.

Q. And you see slight changes at these locations, correct?

A. Yes, in every instance you either get a shift to the right or the left of the typical gradient curve showing some kind of anomaly happening at each of these things, and it's inconsistent. It's either hotter than the rock temperature or it's cooler than the rock temperature so it's something we looked into to try and determine if there was some correlation between this and lithology.

Q. Okay. So then if I turn to what's been marked as OXY Exhibit Number 10, does this explain the correlation that you found?

A. Yes.

Q. Would you walk us through this exhibit?

A. Yes. So I apologize, it's a pretty busy slide, but if you look at the plot on the -- or the chart on the left, you'll see -- on the far left side you see each of the three casing strings that OXY has in the Diamond 34 State SWD. The next curve over is the red curve which it indicates the drilling speed. It's an aggregate drill speed we obtained from the drilling records.

The next curve is the blue curve which indicates the 25-day shut-in curve or temperature survey. That has been shown on previous exhibits. And then it's kind of hard to see, but behind these red circles you see the dotted line which is the baseline log that Devon provided on their well Thistle Unit Number 6.

The colored boxes that go across the entire plot are the lithology reports from the drilling records back in '97 when Pogo drilled this well. What we're keying in on here is that I guess if you look first at the three red boxes or squares, these are three -- or circles, I mean. These are the circles that were pointed out by Mr. Hathcock as having a significant or, yeah, a gradient change, a temperature change.

If you correlate these, or if you try to correspond with these to the drilling speed, you'll notice the blue circles show the three slowest drill speeds while drilling this wellbore. If you look at the lithology, which are the colored boxes in the background you'll see in every instance there was change in lithology from salt to salt anhydrite, salt to anhydrite, or salt and anhydrite to anhydrite indicating that there's some kind of a lithological change going on here.

If you look to the right you've got three kind of photos of the -- these are case toll gamma ray logs and case toll neutron porosity logs. In each of these instances where you've got a gradient change within a couple of feet they match dead on to where you see a gradient change on the temperature surveys. So to us, we understand this is some kind of indication that there is a corresponding or correlation between the lithology, the lithology changing to the temperature survey changing or gradient changes.

Q. So with respect to the gradient changes that Mr. Hathcock shows on Exhibit D-2, in your opinion, do they relate to areas where the lithology has changed as you're moving down the wellbore?

A. Yes, absolutely.

Q. And when you take a look at the temperature surveys that the company did at the request of Devon, when you take a look at the Bradenhead tests that the company has conducted, and you look at the MIT tests that the company did, all after the Devon incident, do any of those tests indicate any migration of water out of the disposal zone up through the wellbore?

A. No, absolutely not. I mean, if you look at the Bradenhead tests that were approved by the NMOCD, if you look at the mechanical integrity tests, also approved by the NMOCD, all the temperature surveys that OXY ran, and at the other -- on top of that we monitored the Bradenhead ourselves internally, each of these points that there's no issue with confinement within the injection zone.

Q. Okay. Now, in addition to all these tests, did the company take an extra step and perform a radioactive tracer survey on the disposal zone?

A. Yes.

Q. And when did that take place?

A. December 17th and December 18th.

Q. These are after the temperature surveys?

A. Yes.

Q. And why was this done, why did you do it?

A. Radioactive temperature survey -- or tracer surveys are the -- probably the most definitive tool to figure out if you've got fluid migration behind the -- behind the pipe, behind the casing, or through the cement. There's been a lot of publications about it and we wanted to go confirm our temperature surveys and some of these deviations we saw, so that's why we went and ran some radioactive tracer surveys to go confirm that we have no channeling up behind the casing.

Q. And if I turn to what's been marked as OXY Exhibit Number 11, is this an e-mail from Mr. Hathcock to others within Devon?

A. Yes.

Q. And have you reviewed this e-mail previously?

A. Yes.

Q. And Mr. Hathcock says that another alternative is a radioactive tracer log. Do you see that?

A. Yes.

Q. Is that what you did?

A. Yes.

Q. And then he says: "This is what I have used in my past to prove to the Stage (LA & Texas) that we were injecting in our permitted zone."

Do you agree with Mr. Hathcock that this type of test is a definitive means of demonstrating to regulatory agencies that you're injecting within your permitted zone?

A. Yes, I have to agree there. OXY is in the business of water flooding, TOR or CO2 flooding. We perform about a thousand of these tests per year. In 2015, I think we logged a thousand tests with Renegade Waterline. And just part of our job every day is reviewing radioactive temperature -- or tracer surveys and temperature surveys. So, yes, I agree with this.

Q. Okay. With that said, then let's turn to what's been marked as OXY Exhibit Number 12. And would you please explain to the Examiner, using this exhibit, what was done over this two-day period.

A. Yeah, so this is the log, and with timestamps of when we pumped our radioactive tracer. The count here is megacuries. It's a measurement of radioactivity. What we did, we started with some slug flow, slug tests to figure out the flow rate calculations and figure out zonal -- or how much injection was going into each zone. These are the first portions of the test.

Then we ran some other velocity shots and channel checks to figure out in different distinct portions of the wellbore if you ever see radioactive material exiting the wellbore and coming back up past the tool itself. We ran six of these channel check or packer checks.

Q. And it looks like it was done over a two-day period of time?

A. Yes.

Q. Okay. Do you recall how much material was eventually utilized as part of your radioactive tracer survey?

A. Yeah, it was 39.25 megacuries of radioactive material.

Q. Is that a pretty good amount to get an accurate reading?

A. Yes, it's sufficient. A lot of the channel checks themselves or packer checks, we ran -- you run two to five or six megacuries of material. So at the point that we finished the test we had pumped 39.25, which would appear to be an adequate amount of radioactive material.

Q. And then if I turn to what's been marked as OXY Exhibit Number 13, does this give kind of an overview of the overall results of what you saw from your radioactive tracer survey?

A. Yes, it does.

Q. Okay. And what was the results? What's the highlights?

A. So the highlights here, basically what the -- as you can see on the wellbore diagram on the left, you've got a yellow square around the region that this H20 composite log is showing. The top of the log indicates the top of the Bell Canyon or top of the permitted injection interval.

The bottom shows, as far down as we went before tagging fill in our own wellbore while they were running these logs. If you look at the logs, at the very bottom you'll see blue bars and green bars. This indicates that the places where you've got all of your radioactive material exiting the wellbore, we determined this while doing our rate calculations and our slug flow tests initially.

This shows that virtually 99 percent or virtually all of our fluid that we inject was exiting the wellbore at 5520 feet to 5576, which is where we tagged fill. If you look on the right-hand side of the H20 composite log you'll see three points, point A, B, and C, which are different reference points for our temperature survey that we ran two days prior on December 16th.

The red curve and the blue curve on this right-hand side also indicate the injection profile or temperature surveys we ran a day or two prior to this radioactive tracer test.

Q. And what do you observe on the differences in temperature between, for example, C, B, and A?

A. So point C is where basically this is the largest portion of where we're taking our injection fluid. As indicated by the radioactive tracer, the blue bars, as you see just a little bit to the left of where it says number C or letter C, C is the lowest temperature. It was 83.8 degrees Fahrenheit.

As you move up the wellbore, which is the reverse of geothermal, you start warming, which indicates you're getting less and less fluid moving up the wellbore -- or less and less induced fluid that you introduce via water injection as you move up the wellbore. You see the inflection point where you stop increasing with depth and start going to cooling with depth, which is geothermal gradient at point A, which is at a depth of 5,254 feet. We believe somewhere below A, above B, is where the top of our actual injection is going into the Bell Canyon and permitted injection interval.

Q. What do you gain or what do you see, given the fact that point A is warmer than points B and C, what does that tell you?

A. That tells me that's your -- probably your geothermal gradient at that depth. If there's any cooling, maybe it's through conduction through the rock itself. But the fact that you see a pretty distinct inflection point there and it goes to the cooling upward versus warming upward, that tells me there's no fluid moving up past that point.

Q. And B and C are down where the active perfs are; is that right?

A. Yes, B and C are both -- if you can see an H20 composite log you can see in the very center there's a little diagram showing the tubing and the packer there. B and C are both within the improved injection zone and they're below the packer, below the top cement and below the intermediate casing shoe.

Q. Does this indicate to you that any of the injected fluid is migrating upward?

A. No.

Q. Now, I want to briefly go through each of the channel checks that was done. It was done over a two-day period of time, correct?

A. Yes.

Q. And we would start then with Exhibit Number 14. Is that the first check that was done?

A. Yes.

Q. And then there's a number -- series of exhibits after this, correct?

A. Yes.

Q. Okay. So let's get a handle on how these were put together. Can you please explain to us what you show on here, starting with the left and then moving to the right?

A. Yeah, so Exhibit 14 shows the first channel check that OXY ran at a depth of 5,510 feet. If you check the wellbore diagram on the left you'll see a yellow star. This indicates that we were -- this is the depth we had the two detectors set at during this channel check test. As you can see there, it was submerged within the perforations, however, we set it right above the top of those most active perforations that are taking 90 percent of the injected fluid.

What we wanted to see here is if we inject at this depth, we set the packer or set the tool right above those top perfs to take all the fluid. When we see that material again, which would mean that it's coming up behind the casing on the backside. We set the tool at 5,510 feet and held the tool on the spot for 950 seconds, which is about 15, 16 minutes. At second number 50, we ejected the slug and you see it pass on the bottom. This is the plot on the right now, the little log.

On the bottom you'll see it pass the shallowest detector, detector number 1. On the top log you see it pass detector number 2 at 50 to 100 seconds. Beyond here, moving right with time, you never see any sign of channeling up, meaning you never see the radioactive tracer show up again.

Q. So where is it going?

A. It's either going out or it's going down below the depth or investigation of the tool itself.

Q. So below, down or -- or out or below your active perfs?

A. Yes.

Q. Then if I turn to what's been marked as OXY Exhibit 15, is this another survey at a higher interval?

A. Yes.

Q. Are you still below the highest perfs?

A. Yes, this zone or this channel check we ran at a depth of 5,400 feet. This is also submerged within the perforations. This is now up higher than the previous test. What we did here is held the tool on this spot or at the same depth for 610 seconds. At second number 75, we ejected the slug. You see it pass the two detectors --

Q. Hold on now. When you say ejected the slug, it means put more material into the -- for testing?

A. Yes, we pump -- we pumped extra material here than we had done on the previous channel check as well as all the previous rate calculation checks where we had already pumped a pretty good amount of radioactive tracer at this point.

And then, so moving to the right on the scale, on the plot to the right or log to the right, you see the radioactive slug pass the detectors at second number 75 to second 100. And from there on out to the right you never see any sign of radioactive material again, meaning that there's no channeling up once again.

Q. Okay. Exhibit Number 16, where are we now with respect to the wellbore?

A. So Exhibit Number 16 shows a packer check, which is the same as the channel check but it's set in the packer or right above the packer. We set the -- if you look at the wellbore diagram on the left, the yellow star indicates that we are setting right above the packer itself. If you look at the log to the right, we held the -- or we held the tool on depth for 535 seconds, which is about 7-and-a-half minutes, ejected a slug of fluid or RA material. And over the course of 450 seconds or 7.5 minutes, never saw any sign of this RA material or any of the previously pumped RA material during the course of this test, which also indicates there was no sign of channelling up at this point.

Q. And then if I go to OXY Exhibit 17, where are we now? Where is the tool now, exactly?

A. So Exhibit Number 17, this was a channel check run at the intermediate casing shoe, which, based on previous witnesses, seems to be a big point of interest in this hearing.

Q. So let's stop right there. So let's go to Devon Exhibit D-5. That would be Mr. Hathcock's Potential Fluid Migration Paths. Do you have that in front of you?

A. Yes, sir.

Q. Do you see his little dashed blue arrows around the casing shoe?

A. Yes, to the left of the Diamond State Wellbore.

Q. Okay. With respect to OXY Exhibit 17, now this is a test right at that general location where the casing shoe is, correct?

A. Yes.

Q. Okay. Now, how long had this survey been going on when you got to this depth? How long have they been putting material into the zone?

A. Approximately three hours.

Q. And if there was anything moving out of the zone and up the wellbore and into the intermediate casing area, would it show up on this type of test?

A. Yes, it would, because at this point that we ran this channel check at 4830 feet we had already pumped approximately 16.25 megacuries of this material over the course of the previous three-and-a-half hours or three hours. And I believe that would be adequate time for this to migrate up the wellbore if they were acting such a conduit as referenced earlier.

Q. Okay. Now, what about the pathway was somehow away from the wellbore and then moving up and then somehow went back to the casing shoe as they seem to be suggesting would be possible. Even if that was the path, the wellbore path away from the wellbore, would this test also read any kind of activity like that?

A. Yes, it would indicate any sign of radioactive material pumped over the previous three hours, whether it was traveling up the wellbore or out into the formation and coming back to our wellbore, this would show a sign of -- you would see the RA material appear again on this test. And this was a 34-minute test where we held the tool there for a very long period of time because this was the biggest zone in question for OXY as well as Devon.

Q. And you didn't see anything?

A. No.

Q. No detection whatsoever?

A. No detection.

Q. Okay. Then I believe if I move on to OXY Exhibit 18, and we can move a little more quickly here. This was a repeat test done the next day, correct?

A. Yes, I believe this was done on December 18th, the day after.

Q. Okay. So this was after the material had set in the zone for at least, what, 17 hours or whatever time they came back?

A. Yeah, approximately about 17 hours or so.

Q. Approximately how much material was in the zone at that point in time?

A. At this point we have 33.25 megacuries of radioactive material in the zone at this point.

Q. Okay. And when they came back the next day and tested at this particular level of 5.500 feet, this is, again, right around the perfs?

A. Yes.

Q. Okay. Any indication of the radioactive material?

A. No. So we injected the slug at 130 seconds, and over the course of the next 810 seconds or 13.5 minutes we never saw any sign of this RA material or any previously pumped RA material over the course of the previous 17 hours.

Q. And Exhibit 19, is that another recheck just below the packer the next day?

A. Yes.

Q. And how long did you sit there and wait to see any results from the radioactive material injected on the previous day and then again on that day?

A. So we sat on this at this depth right below the packers, you can see in the wellbore diagram to the left, for 38 minutes after we had ejected the slug of RA material. So at this point we had pumped 39.25 megacuries of RA material over the course of the previous 18 hours and never saw this RA material appear again, as you can see from the log on the right.

Q. Okay. Now, Mr. Clifford, looking at this Exhibit D-5, this migration pathway up and around the intermediate casing, okay, OXY ran an MIT test, a Bradenhead test, monitored the pressures at the intermediate casing; is that correct?

A. Yes.

Q. Did temperature surveys?

A. Yes.

Q. Did radioactive tracer surveys?

A. Yes.

Q. In all of those tests, is there any evidence to support that the fluid is migrating from the injection zone up the pathways as depicted on these dashed lines in Mr. Hathcock's D-5 slot?

A. No. And neither of the dashed lines have been demonstrated by the evidence we've presented here so far here today.

Q. Is there any doubt on that point?

A. No, absolutely not.

Q. Did you also take a look at the condition of the formation in which you are objecting?

A. Yes.

Q. And does the water injection history for OXY's well support a confined environment?

A. Yes, it does, based on permeability calculations and inject activity index, it appears that we were injecting into a confined reservoir system or matrix reservoir system.

Q. And has that confined reservoir system pressured up over time?

A. Yes.

Q. If I turn to what's been marked as OXY Exhibit Number 20, does that reflect the increasing pressurization of the reservoir?

A. Yes, it does.

Q. Would you please explain to us where that's shown on here?

A. So Exhibit Number 20 shows -- at the top it shows our initial estimates of reservoir pressure, which was taken from a Sandia report in the WIPP area. It's called Sandia 86, from 1986. They demonstrated some of the permeability in reservoir pressure measurements within their well DOE Number 2. It was conducted in the Hays, Hays sandstone, which is a portion of the upper Bell Canyon.

They demonstrated reservoir pressure, which we adjusted for hydrostatic depth. So our initial reservoir pressure estimate was 2392 PSI for this area. This was also confirmed by the drilling mud weight as they drilled the Diamond State 34 Well. Our current shut-in reservoir pressure is demonstrated by Devon's intersection with it at 5640 feet. In September it was about 2894 PSI. This means that over the course of the last 19 years of injection, within the Diamond 34 State SWD Number 1, we have increased our reservoir pressure approximately 500 PSI, which would mean that we're injecting into a confined zone. We've increased the reservoir pressure at a distance from our wellbore, which means that there's probably no leaks, no seepage out of zone.

Q. Okay. And if there was any kind of leak or seepage, you wouldn't see the increase in pressure, would you?

A. No, because if you have a leak it's going to leak to what would be a lower pressure system. That would be something more on the hydrostatic pressure. This 2894 is above hydrostatic pressure, and so if you have a seepage or a leak or some kind of area or place where you've got your high pressure fluid can exit that area or that reservoir it would migrate to something of lower pressure which would be something more along the lines of normal hydrostatic pressure. So, yes, it would seep up or down into a different zone.

Q. Did you also take a look at the injection permeability of the disposal zone?

A. Yes, we did.

Q. And is that reflected in OXY's Exhibit 21?

A. Yes.

Q. And just briefly explain to us what you did and the result.

A. So what we did here is used the Darcy's law equation for injectivity index, which is basically the same thing as productivity index, if you guys are familiar with that. It's basically a ratio of the injection pressure and barrels of water injected per day divided by the delta pressure and net pressure, which would be your injection pressure minus your reservoir pressure.

In this calculation, for injectivity index you'll see in the third line down we use the injection rate, injection pressures indicated on one of the previous slides where it shows us monitoring our Bradenhead pressures. These are our inputs here. And the 2894 you see there on the right-hand side, it's the reservoir pressure that Devon encountered within their wellbore.

This calculates to an injectivity index of about 1.43 barrels of water injected per day per PSI. This a common -- a common thing. You -- you monitor for injector wells to figure out if you've got injection leaving zone or if you've induced some fracture or if you've got damage in your wellbore, you -- you monitor the injectivity index over time to see if you can detect these things so you can take the corrective actions early on.

The next calculation below is just the Darcy's Law equation. You plug in the injectivity index calculated above and use some of our assumptions, which we have demonstrated, and the permeability calculates to 2.44 millidarcies, which indicates matrix permeability within the sand face. There's no issue or no question here that this does not appear to be a fractured reservoir system with 2.44 millidarcies.

Q. Okay. And does that result that you came up with correspond with the literature in the area about the normal conditions of the Bell Canyon?

A. Yes, it does.

Q. If I turn to what's been marked as OXY Exhibit Number 22, does that support your statement?

A. Yes, this is the same -- same document or same -- same piece of evidence or documentation that we used to calculate the reservoir pressure initially within our wellbore. That's the Sandia report, Sandia 86, from 1986. It was done at the WIPP site, which is located about 14-and-a-half miles west for the Department of Energy. The title of the article is Hydraulic-Test Interpretations for the Well DOE Number 2 at the Waste Isolation Pilot Plant Site.

In this article we found some measurements of permeability within the Hays sandstone member, which is a member of the Bell Canyon formation of 2.3 to 2.4 millidarcies. So this would be representative of what we calculated in our wellbore, the Diamond 34 State Number 1, as basically the same thing that the WIPP site or the Sandia report estimates for the -- and the WIPP area to the west.

Q. Now, do you still have this, Mr. Hathcock's well migratory path fluids?
A. D-5?
Q. D-5.
A. Yes, sir.
Q. Now, we dealt with this first proposed migratory path. I want to address now the one he's

got going to the right, the Humble State and then out the 1800 feet. Do you see that?

A. Yes, I do.

Q. Okay. You were here for the testimony that this was -- this particular wellbore was examined by the Division in '97 when the well was first permitted?

A. Yes.

Q. And as reflected in OXY Exhibit 24, it was reexamined again in 2010 when you requested to move the packers; is that correct?

A. Yes.

Q. And according to the Division, this particular wellbore, based on all evidence presented appears to be adequately plugged and cemented?

A. Yes, that's correct.

Q. And if we take a look at OXY Exhibit 23, is that a diagram of that Humble State Well?

A. Yes, it is. It's a wellbore diagram.

Q. And it shows three plugs above the zone of injection for OXY; is that correct?

A. Yes, that's correct.

Q. Okay. In your opinion, is Devon's water shell at 1800 feet enough to suggest that the Division was wrong about the Humble State Well in

1997 and again in 2010?

A. No.

Q. If we go through Mr. Hathcock's theory here, you would have to assume that the water somehow migrated through both of those plugs; isn't that correct?

A. Yes, based on Exhibit D-5, it appears that way, yes.

Q. And if I'm looking at OXY Exhibit 23, not only do we have two plugs that it would have to migrate through but then there's a third plug; do you see that?

A. Yes.

Q. Okay. Now that would be above the 1800 foot zone that we say encountered water?

A. Yes, that's correct.

Q. And wouldn't you have to assume that that plug somehow held to force the water to go out into the formation?

A. Yes, you would have to assume that the bottom plug at 5,000 to 5,100 feet, and the second plug from the bottom, 3310 to 3410 feet, both failed, but the upper plug at 940 to 1,040 feet maintained its integrity and therefore kept the fluid, injection fluid below that point of 940 feet to 1,040 feet.

Q. And there's roughly 2,000 vertical feet between the boot and the top, the bottom and the top between that second plug and the third plug; isn't that correct?

A. That's correct.

Q. And according to Mr. Hathcock, that water would have to just somehow magically go out right at 1800 feet within that zone, correct?

A. Right. It would be hard to understand why it would preferentially want to take a left turn, I guess, as you would say from this slide D-5, at a depth of 1820 feet when it's got over 2,000 vertical feet where it could exit the Humble State Wellbore.

Q. And wouldn't you have to agree that -- wouldn't you have to also assume that the water is not only going out within that zone at 1800 feet but it's not moving out elsewhere?

A. Right. You would assume that if there was a laterally extensive formation or a formation that you could map out across at a lateral orientation, it would flood -- it would flood the zone, basically. It would travel in 360 degrees from the wellbore. It wouldn't move preferentially in one direction. So therefore, based on Darcy's law you have pressure disbursement with distance because one barrel of water gets divided 360 different directions and so your pressure depletes the further away you get from your wellbore.

But, yes, it wouldn't go in one direction to the left or to the west to the North Thistle 34 State Well.

Q. And in your opinion, does this suggest a pathway of migration also inconsistent with the increasing pressure over time that you see within the disposal zone?

A. Yes, it's inconsistent because we have increased the reservoir pressure or the pore pressure within the Bell Canyon or permitted injection zone over time for the last 19 years and if we had water seeping out we would see that. We wouldn't see such a drastic pressure increase over the last 19, 20 years of 500 PSI.

Q. And in addition to all that, wouldn't you also have to assume that there is enough pressure from the disposal zone to push the water up the wellbore of the Humble State and then push the water out of the Humble State Well and go all the way back over to Devon Energy's well at 1800 feet?

A. Yes, you would have to have a pretty

remarkable amount of pressure to have it travel from OXY's wellbore of 1730 feet east to the Humble State, travel up 3,300 feet of the Humble State Wellbore, traveling through two cement plugs, which are both 100 feet thick, and then take a left turn, go back west 2700 feet to the North Thistle State Well.

Q. And did you look at the types of pressures or how the actual documented pressures would correspond to this theory of migration?

A. Yes.

Q. If I turned to what's been marked as OXY Exhibit 26 -- or let me step back. Does OXY Exhibit 25 identify the distances vertically that would have to be involved under these migration theorys that Devon has put forward?

A. Yes, these are the two -- or the two different directions of -- with horizontal distances between the wellbores. The red and dotted line marked as 1350 feet indicates one of the flow paths or potential flow paths. The other potential flow path, as indicated by Exhibit D-5, is indicated by the blue dotted line, which shows from OXY's wellbore the yellow star, 1730 feet east and then it takes a left turn and goes back 2900 feet to the west through the North Thistle Well.

Q. All right. Keeping that in mind, could you then turn to what's been marked as OXY's 26. This is comprised of two pages, correct?

A. Yes.

Q. Okay. And would you explain to us what you're showing on the first page and the information that you utilized?

A. Yeah, so the first page here is just general hydrostatics. What we did, if you follow the arrow down the Diamond 34 State Wellbore down to the perforations you'll see a blue arrow and then you'll see a blue star at 5,526 feet, which is the depth that the radioactive tracer log indicates a majority of our injection is leaving the wellbore. We calculated a shut-in bottom hole reservoir pressure of about 3274. This is --

Q. That's documented pressure?

A. Yes, this is based on the surface pressures OXY has witnessed and recorded multiple times while the well was shut in.

Q. Okay.

A. And then we corrected for hydrostatic based on the actual hydrostatic fluid weight of OXY's injection water. And then moving to the west or to the left, if you look at the bottom of the North Thistle State Com 1H Wellbore, you see another blue star, which is another documented pressure. This is at 5,640 feet. This is the second kick that Devon experienced once they drilled out their intermediate casing shoe. This has a pressure of 2894 PSI, a bottom hole pressure. This one, I believe, I saw in some of Devon's exhibits earlier so I think they agree to this number.

Q. So this is the pressure they saw when they reached the injection zone?

A. Yes.

Q. And you show a difference there of 380 PSI. Why is that? Why would that occur?

A. This is basically the same thing I indicated about the Charles P. Miller Humble State Wellbore, if you have injection at a point it's going to flood in every direction, and based on Darcy's law you have disbursion radially with pressure. So all the water or pressure we induce at our wellbore, at our near wellbore at our perforations, since it travels radially and not in direction like a pipeline, you lose pressure radially.

And so basically over the course of

1350 feet horizontally we lose 380 feet or PSI of reservoir pressure within our own permitted injection zone.

Q. So that's documented. We know that's the difference?

A. Yes.

Q. Okay. And with that in mind, what did you do in the upper part of this exhibit?

A. So in the upper part I took, on the left-hand side, the blue star, another documented pressure, the 1514 PSI, 1820 feet, this is the first kick that Devon experienced on September 3rd. And to the right-hand side, if you see the blue arrows coming up the Diamond State Wellbore, these are indicated or these basically mimic what is seen on Exhibit D-5 by Mr. Hathcock as the potential flow paths.

So what we did is corrected the 5,526 foot shut-in bottom-hole pressure in the OXY Diamond State Wellbore for just hydrostatic pressure, assuming zero friction whatsoever as you travel up the wellbore and through the reservoirs. This pressure that we calculated at 1820 feet in the Diamond State Wellbore, which is also not supported by evidence, calculated to be 1497 PSI. However, keep in mind that this does not include vertical friction pressure.

We're talking about a distance here of 3700 feet vertically. If you look in the horizontal scope of things, 1350 feet indicates a 380 PSI pressure drop based on friction or radial flow. If you look at traveling up the wellbore, we're talking 3700 feet, so you assume that would be a greater pressure drop. However, we indicated worse-case scenario for OXY. We neglected that pressure drop and only corrected for hydrostatic pressure.

Q. Okay. Let me stop you right there. So you, in doing this calculation here of 1497 PSI, you first off assumed that water was migrating up the casing?

A. Yes.

Q. And secondly, did you assume that it was just an open straw, that there was absolutely no friction whatsoever?

A. Yes, we did. Basically what we assume, it's like a four-inch piece of pipe with no friction whatsoever. It's just whatever pressure here, you just correct it for hydrostatic pressure up here.

Q. Taking the water weight, so you just took the water weight?

A. Just the water weight.
Q. And taking all that into account, you come up with a pressure of 1,497 PSI at 1820 feet?
A. Yes.
Q. And that's already lower than what Devon experienced at 1820 feet in their Thistle Well?
A. Yes, it's already lower even before you apply, again, the horizontal frictional pressure drop as you see at the depth of 5,640 feet, the 380 PSI pressure drop because of radial flow. If water was going up the OXY wellbore it wouldn't just go up the OXY wellbore and to the left, it would again flood in 360 degrees, in every direction, based on pressure disbursion due to radial flow, you would lose probably about the same, 380 PSI pressure drop.
But, yes, without even applying that, the pressure at OXY's depth of 1820 feet is already lower than what Devon experienced.
Q. So given that, given the fact that you have these recorded pressures, known pressures when you did your calculation here conservatively, is it even physically possible for the water to be traveling up as depicted and then going over to the Devon well and resulting in 1514 PSI at their Thistle Well?

A. So to answer the first question, we don't believe it's possible that water is migrating up the wellbore based on the mechanical integrity test results, Bradenhead pressure, Bradenhead test results, temperature surveys, radioactive tracer surveys, and the other Bradenhead pressure monitoring that OXY did, so we don't believe there's any vertical migration.

Horizontal migration, I don't see how that could be physically possible because the water at OXY's wellbore is already lower than that of the Devon wellbore at 1820 feet. It's not going to -- water is not going to migrate towards higher pressure. It's always physically going to migrate to areas of lower pressure. So it doesn't seem to make sense that water would migrate from OXY's wellbore, the theoretical pressure of 1490 PSI at 1820 feet to the west to Devon's wellbore at 1820 feet.

Q. Okay. And then having done this analysis here, using these documented pressures, did you carry that over to analyze your second theory of migration that is of the Humble State Well?

A. Yes.

Q. And let's turn to the second page of this exhibit. Would you please explain to us then what you started with and how you did your calculations. Start with what are the known notes.

A. Okay. So the two blue stars are the same stars indicated on the previous slide. On the North Thistle State Well, on the far left you see the 1820-foot kick zone or kick pressure of 1514 PSI. Now, if you look at the Diamond State and follow the blue arrow down again, this is the same 5526 foot shut-in bottom hole pressure of 3274 PSI, as previously indicated on the slide before.

Now, what we did is show the other theoretical potential migration path going east to the Humble State Wellbore within the permitted zone, traveling up the Humble State Wellbore, past two cement plugs, and then taking that west left hand or west turn over back towards the North Thistle State Well. Since we don't know the pressure drop over 1730 feet within the Bell Canyon, we only know what we saw between OXY and Devon at 1350 feet, we assumed, again worse-case scenario for OXY's case, the same pressure drop of 380 PSI going a further distance to the Humble State Well. So we assume 380 PSI is the pressure drop to the east.

Q. And that's based on the prior page of this exhibit?

A. Yes, based on a shorter distance, which was shown on a prior page, yeah. This equates, also ignoring hydrostatic pressure corrections, 5300 feet within the Humble State Well, a theoretical pressure TD at 5300 feet would be about 2894 PSI. Now, if you assume zero vertical friction losses traveling up the Humble State Well, traveling through two cement plugs at about 100 feet thick apiece to a depth of 1820 feet, basically we only corrected for hydrostatic, again, assume zero PSI friction drop, this equates to a pressure of 1,135 PSI at a depth of 1820 feet in the Humble State Well, which is significantly lower than what Devon has already experienced at a depth of 1820 feet in their North Thistle Well.

Q. So I'm going to ask you the same question: Given that you've got 1,135 calculated PSI at the Humble State at 1820, with all the assumptions that you made, is it physically possible that that type of pressure at that location would result in 1,514 PSI in Devon's well at the same level, 1820 feet?

A. No, it's physically impossible. I mean, we're already talking about a 400 PSI difference between the Humble State, it's already 400 PSI less from what Devon experienced, and then it would have to travel 2700 feet or 2900 feet. So, no, it's not going to move towards an area of higher pressure. It's going to -- the pressure is always going to move -- or hydrology dictates that fluid always moves to an area of lower pressure. So it's not going to move towards the Humble -- or North Thistle Well. It's going to move away from the North Thistle Well to the Humble State, if anything.

Q. In your opinion, is there any -- does the reported pressures support either of these proposed migratory paths that Devon has brought forth here to the Division?

A. No, absolutely not.

Q. Is there any evidence to suggest that the OXY Diamond State Well and Devon's North Thistle Well is hydrostatically balanced?

A. No, it does not.

Q. Or to suggest that the Humble State Well is somehow hydrostatically balanced with the -- with the injection well or the Thistle Well?

A. No, there's no evidence to support that.

Q. Okay. There is some talk, Mr. Clifford, here -- I'm going to jump ahead slightly to

Exhibit 31. And there was a discussion -- you're an engineer, right?

A. Yes, sir.

Q. You're familiar with mud weights?

A. Yes.

Q. You're familiar with calculations to determine mud weights?

A. Yes, I am.

Q. And there was -- there was some discussion earlier about the fact that the examples here, at least from the records, you couldn't actually determine what the actual mud weights were that were involved in each of these instances. Do you remember that?

A. Yes.

Q. As a result of that discussion, were you able to locate a WIPP study?

A. Yes, we were.

Q. And, in fact, if I look at Devon's Exhibit E-10. That particular exhibit in the inlet box references a WIPP study, does it not?

A. Yes, it does. Waste Isolation Pilot Plant, yes.

Q. And there is -- and only a certain portion of that report was referenced there. Are you familiar with the other aspects of that report?

A. I believe so, yes.

Q. Okay. And are you familiar with the aspects of that report that discuss the Salado hydrology?

A. Yes, I am.

Q. And the other aspects of that report that discuss the high pressured water that was sometimes encountered in the Salado zone?

A. Yes, I'm familiar with that.

Q. And then was there a subsequent WIPP report that likewise reflected those conclusions?

A. Yes.

MR. FELDEWERT: May I approach the witness?

MR. EXAMINER: You may.

Q. (By Mr. Feldewert) I've handed you what's been marked as OXY Exhibit 37. Is that a subsequent WIPP report that relates to the report that is cited in Exhibit E-10?

A. Yes, I believe so. It's a 2004 WIPP compliance recertification application conducted by the DOE in 2004.

Q. Okay. And I've only -- it's an extensive report, right?

A. Yeah, it has a few hundred pages.

Q. Okay. And so on the second page of this exhibit, page 2-98, does it discuss the hydrologic characteristics of the Salado?

A. Yes, it does.

Q. And where within this report does it identify the types of pressures that they observed in these isolated pockets of water?

A. In the middle of that first paragraph at the top it describes the -- once again, this is referring to the Salado hydrology saying: "The highest pore pressures observed in anhydrite are approximately 12 megapascals, which is about 1,740 PSI.

Q. So you took that number and was able to convert that to PSI?

A. Yes.

Q. And how does that reported PSI relate to pressures that Devon saw in their particular well?

A. It's much higher. Devon experienced 1514 PSI. I believe this report for the WIPP site by the DOE indicates the highest pore pressure they've observed in the Salado formation are approximately 12 megapascals or 1740 PSI.

If you look at the bottom of this first paragraph, it also indicates that the -- "For comparison, the hydrostatic pressure for a column of brine at the depth of the repository is about 7 megapascals," which is much lower than the 12 megapascals of the weight of the water or the brine, and then with the static pressure, calculate some density measurements at ERDA, which is a well, number 9, it's about 15 megapascals. So this indicates that the pore pressure they witnessed in the Salado formation was somewhere in between the hydrostatic pressure and the lithostatic pressure, which would indicate overpressure.

Q. That's in the Salado, right?

A. Yes.

Q. Not just the Castile, but in the Salado?

A. There were a lot of reports in this about the Castile as well, but this report is specifically citing the Salado formation.

Q. And in your opinion, this indicates that you can't have pressurized water pockets as high as 1740 PSI in the Salado?

A. Yes, I would assume they would be pressurized pockets because there's SWDs within the WIPP site.

Q. Okay. All right. I want to now talk about the final topic here, and that is Mr. Johnson's timeline of events. Were you here for his testimony?

A. Yes, I was.

Q. You were. If I turn to his Exhibit A-4, and he notes in here that within their wellbore that they had a pressure reduction of 200 PSI at 13:00, which would be, what, about 1:00 o'clock?

A. Yeah, 1:00 PM.

Q. And that's on September 7th, 2015?

A. Labor Day, yes, sir.

Q. It was Labor Day, right? Okay. All right. And their contention is that this pressure reduction took place after OXY shut in the Diamond SWD test on Labor Day?

A. Yes.

Q. That's what they suggested in this exhibit?

A. Yes.

Q. Although he says the exact time is unknown?

A. Yes, that's correct.

Q. And has Devon previously cited this? When they first started talking to you, did they cite this timeline as a primary basis for their concern with OXY's well after you did the MIT test and after you did the Bradenhead test?

A. Yeah, I believe every meeting, every

verified statement that I've read has indicated that there was a 200 PSI pressure reduction in the North Thistle 34 State Well right after OXY shut in the Diamond State Wellbore.

Q. So if I go, for example, to OXY Exhibit 28, about halfway down, do you see an e-mail from Kerrie Allen to Donna Havens? Do you see that?

A. Yes.

Q. Kerrie Allen is with Devon?

A. Yes, that's correct.

Q. And Donna Havens is with OXY?

A. Used to be with OXY. She retired.

Q. Yeah, she's retired. That's right.

And about -- in the second paragraph Ms. Kerrie Allen, in the very last sentence, cites this purported timeline of events, does she not?

A. Yes, in the last -- last sentence of the highlighted portion: "For example, when OXY stopped injecting, Devon saw the pressure decrease at these shallower depths."

This e-mail is dated September 28, 2015.

Q. Okay. And you were here for Mr. Johnson's testimony where he said that it was important to his conclusion that this shut in took place before they observed the PSI reduction?

A. Yes.
Q. And were you here for his testimony where he said that if it -- the shut in actually occurred after this reported PSI reduction that it would indicate no communication between the two wells?
A. Yes.
Q. And do you agree with that observation?
A. Yes, I do, because we actually shut the well in on September 8th.
Q. So did you personally investigate this timeline of events?
A. Yes, I did.
Q. Okay. And what did you examine to determine when you had actually shut in your well?
A. So we talked to the surface operations team, the pumper, the production coordinator, a guy Brent Bengolan, who fielded the call for Mr. Kyle Johnson, and each of the pumpers, each of OXY's operators in New Mexico have a GPS tracker in their vehicles when they drive out every day on their routines. We checked the GPS data and also followed up with every other person we've talked to out there in Carlsbad, New Mexico and verified that we didn't shut the well in until about 1:00 o'clock -- 12:00 o'clock or 1:00 o'clock in the afternoon on

September -- Tuesday, September 8th.
Q. 24 hours later?
A. Yes.
Q. 24 hours after they received their -- they show their 200 PSI reduction?
A. Yes.
Q. Okay. And is that reflected in the documents that OXY provided to Devon?
A. Yes, it is.
Q. If I turn, for example, to OXY Exhibit 27.
A. Yes, it's on here.
Q. Is this a timeline of the shut in and when the well was online based on OXY's records?
A. Yeah, this was provided to Devon in the first subpoena. It was the list of times that OXY had either begun injection or shut in injection on the Diamond State well. We worked with the field surface operations team to come up with dates and times that we actually sent a pumper out to location to either turn on the well or shut in the well.
You'll see some comments here on the right-hand side indicating a reason for the shut in. The shut ins are all indicated by the red boxes. The blue column is when we put the well back online in each instance.

Q. And if I go to September 5th, it says the well is online. Do you see that?

A. Yes.

Q. And then the change takes place on September 8th?

A. Yes, on September 8th. We indicate here it's 11:00 AM when we shut in the well for a workover rig pulling unit tubing or to pull the tubing and packer. It was actually about 1:00 o'clock in the afternoon on that day on September 8th, the day after Labor Day when we shut the well in.

Q. Okay. All right. So there's no doubt then when you shut the well in that it was after they observed their 200-pound pressure decrease?

A. Yeah, exactly. There's no doubt in my mind. This well is in a pretty remote location. Using the GPS tracker, we have no person going out to location on September 7th because it was Labor Day. It was a day off. We didn't feel the need to send someone out to location that afternoon to shut in the wellbore. So we checked the GPS, three or four days prior to this event, three or four days after this event. We could not place anybody, any OXY personnel on location on Monday, September 7th when this event is claimed to have occurred.

Q. So what does this actual timeline tell you about Devon's theory that these two wells are actually connected and that OXY's disposal operations is the cause of the pressure water that they saw at 1800 feet?

A. This tells me that they weren't connected. This probably leads me to believe that this was an isolated pocket because if Devon started witnessing pressure dropping before OXY had even shut our well in, the pocket of high pressure was probably starting to deplete at this point. It would lead me to believe that there is no indication of these wells hydraulically communicating at this point since we shut in our well after Devon saw the pressure drop 24 hours after.

Q. And were OXY Exhibits 1 through 29 -- or 28 prepared by you or compiled under your direction and supervision?

A. Yes.

MR. FELDEWERT: Mr. Examiner, I would move the admission into evidence OXY Exhibits 1 through 28.

MR. EXAMINER: Mr. Bruce?

MR. BRUCE: No objection.

MR. EXAMINER: Exhibits 1 through 28 are so entered.

MR. FELDEWERT: And that concludes my examination of this witness.

MR. EXAMINER: One point of moment. Wait, Exhibits 31 and 36 were referenced. Do you want to use those again?

MR. FELDEWERT: I'm sorry, Mr. Examiner. Thank you. I would -- Exhibit 36 is actually the Division records, so I would move the admission into evidence of that exhibit. And then I would also move the admission into evidence of OXY Exhibit 37.

MR. EXAMINER: 37, okay. And 31?

MR. FELDEWERT: 31, we will have another witness that will talk about that.

MR. EXAMINER: So Exhibits 36 and 37?

MR. BRUCE: No objection.

MR. EXAMINER: Very good. Exhibits 36 and 37 are also in the record.

Your witness, Mr. Bruce.

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Clifford, I'll try to go through your exhibits in the order you presented them.

A. Yes, sir.

Q. I may not succeed. Your Exhibit 3, OXY -- sir, these are all the MIT tests. I'm not getting into that. But why is the March 2002 MIT test, why is the PSI of the casing so much lower than the other tests?

A. I think the rules under the Division indicate that an MIT has to be conducted at a pressure over 300 PSI and it must hold that for a duration of 30 minutes and be charted. So in this instance, I can't -- I can't speak to what Pogo did back in the day, but Mr. Gonzales with the NMOCD was on location and approved the test. So that's all I can attest to there, but anything over 300 PSI, as long as it holds pressure over that 30-minute examination or charted test stands to be an approved MIT.

Q. Okay. And then your Exhibit 5, so there was none of this on the well until October 2005 -- 2015, excuse me.

A. Just the surface gauge.

Q. Just the surface gauge.

A. The two -- and there was a casing valve or casing gauge as well. The two intermediate or Bradenhead gauges were both installed in October. The second Bradenhead gauge was installed

October 31st.

Q. So, again, how did you monitor intermediate casing pressure prior to October 2015?

A. Just on annulus or Bradenhead tests, annual Bradenhead tests, and we have, I believe, a report, Mike, that -- that he introduced to us earlier this morning with our -- all of our approved MITs and Bradenhead tests in the Division records.

MR. FELDEWERT: Is that not up there?

MR. CLIFFORD: I don't think it is.

MR. FELDEWERT: May I approach?

MR. EXAMINER: Yes, sure.

A. So -- I'm sorry, so let me continue with my answer. So in this past what we did was just open up the intermediate -- or intermediate to production Bradenhead casing inlets, and when the NMOCD is on location or a representative is on location, you open it up and if you see any pressure or surge or any bleed off then it would stand to be a failed Bradenhead pressure test. This report here shows all of the passed -- the reports that have passed over the history of this well since 2002, at least.

MR. FELDEWERT: Actually, I think -- I'm sorry, I think I may have given you the wrong one. I did. I meant to give him the well inspection history. I gave him the wrong one. I'm sorry.

A. Yeah, so both these -- both these forms show the same thing, really. In the middle of the form it says: "Reason for MIT," it says ANMTFT, that's an annulus test, which is a Bradenhead test. It reports here every year that we ran one, the dates and that they were all approved. And then the other form that Mike just handed out shows the same thing, that -- it shows the lists of all the dates and comments from the NMOCD themselves saying that everything was in very good shape and that we passed the MITs or Bradenhead tests conducted on those dates.

Q. (By Mr. Bruce) And as to the MIT tests, why were these test pressures significantly lower than the injection pressure?

A. It's a standard rule that anything over 300 PSI on the backside of the tubing, between the tubing packer and casing, production casing, anything over 300 PSI is adequate.

Q. Now, in September, starting September 15th, I believe, you pulled the tubing on the well?

A. On September 9th through 16th, yes. Or the rig was on location September 9th through 16th.

Q. I'm looking at a document here that says --

regardless, it was after Devon contacted you?

A. Yes, sir.

Q. Why was that done?

A. So there's a line of events that occurred up to this point. At some point in August, OXY determined that we had probably breached the injection pressure, even though our carte data didn't actually show that. Our pumper had reported, at some point, that OXY had gotten over the permitted injection pressure. So what we did was, on October 19th, went and checked our pressure -- pressure limiting device research valve. Basically that limits the pressure downstream of that pump to be below the permitted pressure. That was on August 19th.

Following that we realized that it was probably some kind of damage that we had introduced to the wellbore so we rigged a coil tubing the first three days of September, tried to clean out the well. This is when Devon experienced the issue with coil tubing on location. We ran it with coil tubing. The tag fell in the packer, so we tagged some kind of obstruction. We were led to believe it was obstruction, that's probably what was causing the high amount of back pressure at the pumps and at the surface pressure gauge.

So we got a rig out there and pulled the tubing, pulled the packer, pulled the on/off tool and found that there was wirelines stuck in the packer that was probably causing an obstruction which is why our pressure had breached the maximum allowable permitted pressure at some point in August. And we reran the packer and tubing, pressure tested it, and it passed the MIT following that on October 1st.

Q. Have you ever injected into the intermediate casing to verify a connection to the annulus below the intermediate casing?

A. No, we have not. We would if there were indications of pressure to see, but standard Bradenhead test rules that you just open up the Bradenhead or casing inlet and if it bleeds off pressure then you pass the test. So we've never had any reason to pump pressure down the backside.

Q. Just out of order, your OXY Exhibit 37, the WIPP report.

A. Yes, sir.

Q. When you're talking about the highest observed pore pressure, highest, you calculate it out from the -- from the terminology they used to say the highest pressure is about 1740 PSI; is that correct?

A. Yes, sir.

Q. Is there an average?

A. They don't provide it. All they provide is that there have been documented high instances of pore pressure within the Salado only 14 miles west of where we're talking about, our area of interest.

Q. Okay, 14 miles west. What is the depth, do you know?

A. It would be shallower than what we're talking about here. I'm sure one of the geologists could discuss that further. But it would be a shallower depth than here, so if you're talking about correcting for hydrostatic pressure at a deeper depth and moving east to where our area of interest is, then, yes, the 1740 PSI or 12 megapascals would be probably even higher than this.

Q. And, you know, you ran tests on October 2nd, October 20th, and December 15th, or 15th through 17th. Why did you run so many logs on three separate waterline mobilizations?

A. We ran the first one baseline. It was a 25-day shut in. Basically this would serve as our future reference or this is probably the warmest the reservoir was going to get. Since injection had been shut in for so long, it probably wouldn't be quite so hindered by introducing cold fluid via injection.

The next suite, we ran an injection profile and shut-in profile to see -- since we hadn't done an injection profile on October 2nd, we wanted to see what the injection temperatures would look like, and then following that, a one-hour shut-in pressure run, temperature run, to see how quickly the reservoir would reheat.

Following this, we decided, well, the data is inconclusive. Let's do a series of runs where we do -- this is the December 15th through 18th or 17th. Let's do a series of warming runs, so that's why we ran an injection profile. And then we did a zero-hour, four-hour, eight-hour, 12-hour, 24-hour, and a 48-hour shut-in run to see the warming profile of the geothermal gradient and how quickly certain zones heated or were not being heated, basically.

This is what led us to start investigating the lithology because we thought maybe it was something to do with maybe water entrained in the three anhydrite layers within the Castile. Maybe the -- we know the specific heat of water is pretty low so it doesn't heat as fast. So maybe that was instances why the temperature gradient was below that of a geothermal gradient at these depths.

This is kind of what led us into this investigation. It's just kind of as we stepped into this whole hearing in this case and kind of had some more -- better understandings, after meeting with Devon, we kind of came up with our own ideas about how to investigate this further.

Q. Moving to your Exhibit 20, you don't really need to look at it that much, but this is your injection volumes?

A. Yes, sir.

Q. This kind of ends toward the end of last year, looking like maybe October?

A. Yeah, October, November probably, somewhere in there.

Q. What have been the injection volumes per month since then?

A. They're relatively low again. We have had our well shut in a lot of the fourth quarter of last year. We shut in due to the issues, or when Devon asked, so in September. We also shut in again, I believe, sometime in October through -- so we shut in quite a bit of last year while this case was going on when we had questions ourselves. We were questioning whether this well was in -- had integrity.

So proactively OXY went ahead and shut in the well at certain times and we had another hearing with the Division. They said OXY is okay to start resuming injection again. So there are other instances why we did not inject into this wellbore. It wasn't due to overpressure or anything in the past. We just didn't have the water capacity that we needed to dispose or we were shut in trying to be proactive.

Q. Well, from what I understand, the tests kind of ended in mid December. Since then, what have been the injection volumes?

A. I couldn't tell you. I haven't looked at it a whole lot in the past month, but it's typically a few hundred barrels a day when we have the capacity. A lot of these wells, and you'll see in, I'll say mid September 2015 to right before September 2015, the highest portion in the last year or two, you'll see a couple spikes there of about 40,000 barrels of fluid per month.

This is right after OXY had drilled about

13 horizontal wells within lost tank/red tank, which are tied into this same well. There's about 14 SWDs in this area, all in one big integration system, and we had a lot of water we had to dispose, but at this point these wells have declined. As you know, any horizontal well and unconventional resource declines very rapidly. We don't have the disposal needs as much anymore, although it's nice to have. This is the well we need for our future operations, right. So, yeah, we've had a reduction in our need for disposal but it has nothing to do with the injection pressures.

Q. Now OXY is claiming -- you are claiming that this is -- whatever Devon hit is a localized zone where there was a high pressure water?

A. I mean, we believe so. We didn't try to investigate what the source was. We just tried -- we're focusing on it's our well, does it have integrity, and are we doing the right thing as a prudent operator.

Q. If Devon drilled another well, say, 1400 feet to the east of OXY's SWD well, would that indicate anything to you about the SWD well?

A. I can't answer that. I'm not sure what exists 1400 east -- or 1400 feet east of the SWD well. All I know from our study is that our well is in compliance and has integrity that we got approved by the NMOCD.

Q. Yeah, but aren't you saying that a well 1400 feet to the west of OXY's SWD well is totally unrelated?

A. Well, if it's 1400 feet to the east I would expect that you would probably get flows again at 5640 feet or somewhere around there, between 5335 and 5748 is the bottom perf. I don't think there would be any reason to believe that you would have shallow flows again.

Q. If they did have shallow flows, what would that indicate to you?

A. I would have to look at how the pressures were reacting to OXY's SWD. If OXY's well was shut in and you guys had a lot of pressure at a Devon well that was drilled 1400 feet east, then I would believe they're probably not communicating. There's other instances that I would have to look at, but that would be a pretty big study, once again, like we've conducted on this well over the last six months to try and figure out if it's communicating or not, yes.

Q. Looking at your exhibits, at 23 and 24, you're saying that the OCD looked at the Humble State Well in 1997 and then again, I guess last year, late last year. If water was escaping at the 1800-foot, plus or minus level, there's nothing on the surface that an inspection would show about that, would it?

A. On the Humble State Well, no, because there's a cement plug at surface from 0 to 35 feet, and plus another two cement plugs between that 1800-foot zone and surface.

MR. BRUCE: Okay. If I may approach the witness, Mr. Examiner.

MR. EXAMINER: Please.

Q. (By Mr. Bruce) I've handed you Devon's Exhibits J and K, which are -- I think you're aware are internal OXY e-mails.

A. Yes, sir.

Q. Exhibit J, tell us a little bit about the casing issue.

A. So this is an e-mail from Lomar Smith, Exhibit J. Lomar Smith is a production engineer. He actually works for me and my team. He says here in the third paragraph of this e-mail: The Diamond 34 Number 1 follow-up test was planned for 11/16/2015, however, it was suspended after the --

or however it was suspend after the well was shut-in as a result of the tracer test or from a tracer test. A follow-up test will be subsequent to actions to repair well's casing issue.

Lomar Smith was, at one point early in October, involved in this case for OXY as soon as Devon had let OXY know that they gone ahead and filed a request to shut in the SWD or revoke the injection authority.

Lomar was no longer included after the first couple of hearings. He was not aware that OXY had passed the MIT and Bradenhead tests on October 1st or 2nd. He was not aware of the temperature surveys that OXY had run between these dates of whenever this hearing started or all these communications started on September 3rd and this e-mail date of November 19th. So he was not aware of any of the issues.

He was a brand new engineer to the team. He just switched from facilities engineering. He's a first-time production engineer. He's going mid summer, and so he was unaware of all the issues involved. It was just an e-mail that he sent to my supervisor Omar and myself to try to let us know the status of a follow-up test that we were looking at running.

Q. But what was the casing issue he was talking about?

A. There was no casing issue. We were investigating any possible integrity issue we could think of in October when all of this started. Subsequent to the meeting with Devon in October in Oklahoma City, we were looking at any possible issue that could arise and any possible source of what water or pressure you guys encountered in your well at 1820 feet.

He was led to believe there may be a well casing issue, likely one of our discussions that we looked at. But that's also why we ran our radioactive tracer tests, our temperature surveys, our Bradenhead monitoring, our NMOCD-approved Bradenhead tests, and our mechanical integrity tests. However, Lomar was not included in all those conversations so he probably did not get the memo beyond some of our preliminary talks.

Q. And then Exhibit K, and I don't want to put words in your mouth, but it is -- is the e-mail correct about the maximum injection pressure in the SWD well of 1020 PSI?

A. Yes, that's correct.

Q. Okay. And that's the originally permitted injection pressure; is that correct?
A. Yes, it is.
Q. And there were no separate tests to further inject --
A. No, sir.
Q. -- or to increase the injection pressure?
A. No, sir, we never requested to increase the pressure on SWD.
Q. And they're talking about there is no kill switches. I infer from that that OXY really didn't have good control over pressures that it was injecting at. Would that be a fair statement?
A. Yeah, I guess you could say that. The battery here is located at the red tank 35, 1 or 3 SWD is located five-and-a-half miles west, and we have a five-and-a-half mile pipeline where this water is pumped from the facility, which is shared with another SWD, over to the Diamond SWD to our surface location.
Yes, there is a big discrepancy here with discharge pressure, which is why you see 1500, 1490, and 1520 PSI discharge pressure and the pressure at the wellbore or at the wellhead, which is 970 or 1,000 PSI. We've made sure that we have pressure

relief devices installed to make sure we do not exceed these pressures, and so no matter what these pumps discharge, if it exceeds 1,020 PSI, it goes in the recirc valve and that pressure is recirculated back to the lower pressure until it finally gets pumped down into the wellbore.

Q. And when were those pressure limitation devices installed?

A. As far as I know, it's part of the approved permit from 1997, so Pogo installed them. We checked them in August, and on August 19th, 2015 we made sure they were working. That was the last work order we had approved where we sent the surface opps facilities team out to location and they made sure the pressure relief devices were working and adequate.

Q. And then how come you were exceeding injection pressures?

MR. FELDEWERT: Object to the form of the question, lack or foundation.

MR. BROOKS: Overruled.

Q. (By Mr. Bruce) You're saying there is pressure or limitation devices so you shouldn't be injecting at excessive pressures, yet you admit you were?

A. We weren't. We were injecting 970 PSI, 970, and 1,000 in this e-mail, if you read it correctly, at the well. We're permitted 1020 at the well, not at the facility. The facility is five-and-a-half miles west.

Q. But there are periods where you were over injecting?

A. At some point earlier in August, yes, which is why on August 19th we went out and made sure those pressure relief devices were working correctly.

Q. And they apparently weren't?

A. I'm not saying they weren't. We haven't investigated that far enough. We've looked at everything we have, all the documentation we have, which is primarily in our carte system, our lowest, which is lack of a well information system which is a Weatherford product. And everything we can tell from there, our pressures are within the limit of what the NMOCD approves of 1,020 PSI.

It was brought to light from a pumper that at some point in early August he saw pressure higher than what we had approved. That's why we went and checked on August 19th the pressure limiting device.

MR. BRUCE: That's all I have,

Mr. Examiner.

MR. EXAMINER: Redirect?

MR. FELDEWERT: No questions.

MR. BROOKS: Nothing.

MR. EXAMINER: Just a few questions. As was brought up by Mr. Bruce, there has never been a separate test conducted on this well; is that correct?

MR. CLIFFORD: As far as I know there has not. I think there may have been in 2014, but that was via word of mouth but we never identified or found it and I don't think it was ever filed with the state.

MR. EXAMINER: Sad. Let's see, as far as injection chemistry, what kind of fluids are we putting in this well? We've talked about doing calculations and permeability and whatnot. What -- what well does this service?

MR. CLIFFORD: So this services a large group of wells. It's everything in our lost tank/red tank field. It's probably 3 or 400 wells, vertical and horizontal wells in this area, a lot of which were the old Pogo wells, which this SWD used to service as well a lot of new ones that OXY has drilled in the area in the last 10 years, 5 years.

We're talking Delaware, so Brushy Canyon wells. I think -- I believe a couple in the Cherry Canyon. We have vertical and horizontal in the Brushy Canyon. Avalon, First Bone Spring, Second Bone Spring, and Third Bone Spring. We have some vertical Wolfcamps and vertical Morrow wells, so it's a pretty good concoction of different waters coming in and mixing into this disposal system.

MR. EXAMINER: Have we ever done chemistry of them?

MR. CLIFFORD: Yes, we have water samples. We take a water sample every month, so we used our actual hydrostatic pressure or fluid weight in all of our hydrostatic pressure calculations. And we can provide those. We probably have two dozen or so from last year, but we looked at the water quality chlorides, TDS, TSS, H_2S, CO_2, all the components.

MR. EXAMINER: Okay. Has OXY made any type of effort to look at the impacts of having this well fracked at the time when Pogo was operator?

MR. CLIFFORD: No, we didn't -- we didn't dig into it too much. I mean, it was 250,000 pounds at the uppermost set of perfs, which was at the time 5435 to 5748, I believe. There was a zone, a smaller zone in between, and then Pogo went back and reperforated all that. And then at some point in 2010, OXY went trying to perforate the tubing, shot the casing, which was a Dave Stewart e-mail that got brought up this afternoon at some point.

But the fracked perforations were a little bit deeper, probably 250, 300 feet below the top of the approved injection zone. And we don't think a 250,000 pound frac or pound of sand frac would cause much of an issue. We've looked at a lot of other SWDs in the area, all OXY's, Devons, and many other operators, and it's pretty standard to put a hydraulic fracture on these wells on the order of 2, 3, 400,000 pounds of sand.

MR. EXAMINER: And let's see, was there any other type of well work or rehab done, other than tubing and packer replacement? Did you acidize or treat the well in any way?

MR. CLIFFORD: No, sir. With the coil tubing rig on location September 1st through 3rd, they displaced some acid when they started tagging fill on the way in the well. It turns out it was most likely that wireline we retrieved when we had the pulling unit there September 9th through the 16th.

But when the coil was going in they kept tagging something and they were pushing it down the hole so they pumped some acid down there to see if they could open it up. I think it was a thousand or 2,000 gallons. I believe Devon has the report for the coil tubing job. It wasn't a whole lot of acid, maybe like a thousand gallons, and ultimately they couldn't get through the obstruction. So that's why the coil tubing or the workover rig followed about a week prior to that.

MR. EXAMINER: But no perf -- I mean no cleaning off the perfs with an acid, no acid?

MR. CLIFFORD: No, sir.

MR. EXAMINER: Okay. And last question: As far as confining zone, I mean, we're assuming the Bell Canyon is a permeability barrier or are we taking a combination of lithology as keeping things in intervals? Your opinion as to what's keeping injection at least below Castile?

MR. CLIFFORD: Like ultimately it's, you know, better described by a geologist but I can, I guess, put my two cents in. There's multiple barriers, and Russ, our next witness, will show he's got multiple, distinct what he's identified as barriers and him and the geologic team at OXY who have looked over this.

There's plenty of publications and literature from the WIPP, from the Department of Energy listing the Castile and the Salado as impermeable barriers, and I think we heard it today from Devon themselves. I think there's plenty of adequate barriers. People have been disposing water in the Bell Canyon, Cherry Canyon for plenty of years, and I think there's good reason that's been done in the past. We haven't seen issues on any of our SWDs in the past. And after a pretty conclusive study here, we feel pretty comfortable that we're still in -- have integrity of our injection zone and we don't have any -- a lot of seepage out of the permitted injection zone.

MR. EXAMINER: On that note, we're done with this witness. Thank you very much.

Let's take a break, another 10 minutes. But first let's have a discussion. You have one more witness?

[Witness excused.]

MR. FELDEWERT: One more witness, and I anticipate 15 minutes.

MR. EXAMINER: Really? Oh, wow.

MR. FELDEWERT: It's not unheard of.

MR. EXAMINER: We'll stay for you then.

I'm not going to break this up. We've done it this far and if you have such that we're not going to be like the geothermal hearings and go into three or four days then we will go ahead and proceed.

All right. Take a 10-minute break.

[Recess taken from 4:29 PM to 4:39 PM.]

MR. EXAMINER: Okay, folks. Let's go back on the record.

Mr. Feldewert, continue with your presentation.

RUSS COOPER

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

DIRECT EXAMINATION

BY MR. FELDEWERT:

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

A. I'm Russ Cooper, employed by OXY Permian Resources. I'm chief geoscientist.

Q. And how long have you been with OXY?

A. About 35 years.

Q. And how many years have you spent for OXY in the Permian Basin?

A. 16 years.

Q. Are you familiar with their various

projects?

A. Yes.

Q. Including their enhanced oil recovery projects?

A. Absolutely.

Q. And their disposal operations?

A. Yes.

Q. Have you previously testified before the Oil Conservation Division as an expert in petroleum geology?

A. No.

Q. Would you outline your educational background?

A. I have a BS degree in geology from Virginia Tech.

Q. And then you have your 35 years with OXY. Has that been as a geologist?

A. Yes.

Q. Are you member of any professional affiliations or associations?

A. The U.S. Geological Society, the Society of Exploration Geophysicists, the American Association of Petroleum Geologists, and I'm a certified petroleum geologist with the state of Texas.

Q. How long have you been a member of the

AAPG?

A. Most all of my entire 35 years.

Q. What about your certification as a petroleum geologist in Texas, when did you receive that?

A. As soon as they were available. I forget how long that's been.

Q. Have you conducted a geologic review of the area at issue and the formation in which OXY's Diamond State was approved for disposal?

A. Yes, I have.

MR. FELDEWERT: I tender Mr. Cooper as an expert witness in petroleum geology.

MR. BRUCE: No objection.

MR. EXAMINER: Mr. Cooper is so qualified. Thank you.

Q. (By Mr. Feldewert) Mr. Cooper, would you turn to what's been marked as OXY Exhibit 29. Is this a type log for the Diamond State Well that you or your team prepared?

A. It is.

Q. And is there a larger version of that type log behind this particular exhibit if the Examiners were interested in examining?

A. Yes, there is.

Q. Now, you show the injection interval here, correct?

A. Correct.

Q. And then way at the top you show the stratographic equivalent where Devon encountered their water pocket; is that right?

A. Yes.

Q. You've also identified on here the location of the intermediate casing shoe?

A. Yes, at the 7-and-five-eighths and at Salado 4830, measured depth.

Q. Now, there was a question from the Examiner about the confining barriers above this particular approved injection interval. Can you walk us through those, please?

A. Yes. If you notice above the top of the shallowest injection perforation at 5335, between that depth and the top of cement at 5165, they are approximately three tight streaks shown in the blue bars to the right side of the type log. These are believed to be impermeable strata. And then as you move upward in the section above the top of cement toward the base of the anhydrate there are another three permeability barriers, 10 tight streaks.

Q. And then once you get to the top of the

Bell Canyon, is that a fairly confining -- how would you describe the top of the Bell Canyon?

A. The top of the Bell Canyon would be equivalent to, in this case, the base of the anhydrite as well as that interface there. That's a pretty -- that's a pretty definitive vertical permeability barrier.

Q. Okay. And then once you get above the top of the Bell Canyon, what do you have above that?

A. Over 3,000 feet of evaporites consistent with the Castile and Salado formations.

Q. And are these fairly impermeable?

A. Very impermeable.

Q. Are there -- speaking -- keeping in mind the migratory pathways that they have suggested could occur here, does the lithology, in your opinion, support the theory that the injected water could migrate from the injection zone to the casing shoe or beyond?

A. No, it does not.

Q. And then if you focus on where the casing shoe is located, where they raised some concerns about water migration theory because of karsting or some other reason, what's the nature of the methodology where the casing shoe is located?

A. It's set in anhydrite.

Q. And is that a good place to set the casing shoe?

A. It is. It has a high mechanical integrity.

Q. Is it also an impermeable area?

A. It is.

Q. If water somehow migrated out of the injection zone and up to the 4830 feet where the casing shoe is located, is there going to be any kind of washing or karsting or anything like that in that anhydrite?

A. No.

Q. Why is that?

A. It doesn't react with that formation.

Q. What would occur? Would you have --

A. Nothing.

Q. Nothing, okay. Do you have an opinion as to the potential source of the pressurized water that Devon encountered at 1800 feet?

A. Yes.

Q. And what is that?

A. Shallow brine filled pocket.

Q. Okay. Have OXY and other operators observed these isolated events in this general region?

A. They have.

Q. Does OXY Exhibit Number 30 assist in explaining these types of isolated events?

A. It doesn't explain the isolated events so much as it explains overpressure and the nature of development of overpressure.

This is a pretty simple diagram, but the top part of this diagram has a couple of boxes on the left and right side for the explanation of the formation of normal pressure. So in the upper left side you'll see the uncompacted settlements with the black arrows on top pushing down indicating or illustrating overlying strata pushing weight on this -- on this uncompacted sediment.

And in this normal pressured situation you have a permeable layer around the uncompacted sediment, such that when increasing aerial depth occurs the water is expelled from the formation and eventually you get to a grain-to-grain contact compaction setting at which point the overburden weight is supported by the rock grains. And this leads to a condition on its hydrostatic gradient.

The two boxes below are fairly similar but there are some differences. In the overpressure situation you start with the same basic situation except now you are surrounded by impermeable formation such as shale and salt. So now as the compaction tries to occur and the weight increases there's no expelling of the water. And so the -- so the overlying strata is supported by the fluids not the rock grains. And as such we approach and achieve a lithostatic gradient also known as overpressuring.

Q. And in order to have these overpressured events you have to have a confined sealed zone; isn't that correct?

A. That's correct.

Q. And in your opinion, are the types of pressures that Devon encountered at 1800 feet; is that the type of pressure that could be encountered if you have a confined sealed zone?

A. Yes.

Q. And could you have that type of pressure if the zone wasn't confined and it was just laterally contiguous across the area --

A. No.

Q. -- because of bone sandstone?

A. No. You would have more of a hydrostatic condition.

Q. You wouldn't have the overpressure?

A. You would not.

Q. And if we then -- in preparation for this hearing, did you -- did OXY's team document instances where these -- these isolated pressurized water pockets have been found in this region?

A. Yes.

Q. Now, turn to what's been marked as OXY Exhibit 31. Is that the system identifying these instances?

A. It does.

Q. And there's a larger version of this map behind the second page of this exhibit, correct?

A. Yes.

Q. But roughly, what do the -- or not roughly. What do the red dots represent?

A. The red dots indicate wellbores that have been identified as having shallow water flows.

Q. And then if I look in the middle of this exhibit, have you identified the location of the area in question?

A. Yes. It's in township 22, south range 33 east, section 24 to the south. It's hard to read here.

Q. It looks like section 34, okay. You have little stars there?

A. It is section 34, yes.
Q. And you have stars --
A. Now when you say it, it is 34. Yes, stars indicate the Diamond 34 and the Thistle.
Q. Okay. And then on the second page of this exhibit, have you documented the Division records with respect to each of these 22 instances?
A. Yes.
Q. And there's been some talk here about -- today that these instances involved primarily H2S flows. Were you here for that?
A. Yes.
Q. And did you review this chart to determine whether there's -- these records actually indicate in all of these instances that there was accompanying H2S?
A. Yes.
Q. And what have you found?
A. Well, some of them and do some of them don't. About -- I think about nine out of this collection of 22 don't have any reference to H2S.
Q. Okay. So, for example, if I start at the top there's some reference there to the Cloyd Number 1 and Number Two wells. Do you see that?
A. Yes, the Cloyd 1 and 2.

Q. Yes. And those are actually in the same township and range as the wells in question; isn't that right?

A. Yes.

Q. And they do reflect sulphur water, right?

A. They do.

Q. And the next one reflects black water. Does that tell you exactly whether it involved H2S or not?

A. Not necessarily.

Q. Okay. And then the very next entry doesn't have any reference to H2S; isn't that correct?

A. Correct.

Q. And then we go down to the state A-1, and again we see a reference to black saltwater.

A. Yes.

Q. But there's no reference to H2S?

A. No.

Q. And then there's a whole series starting with the Humble State Number 1 in the Federal K-1 and the Covington Federal Number 1, and the Federal Number 1 reflect no instance of H2S in their records, do they?

A. They do not.

Q. And you see, as you go down the line, there's other kind of -- sometimes they reference H2S and sometimes they don't?

A. Correct.

Q. Okay. So is it fair for them to suggest that all of these instances or most of these instances involve H2S?

A. It's not accurate, I don't think.

Q. Okay. Now, these, you would concede or you would agree, Mr. Cooper, that these are sporadic, isolated instances?

A. Yes.

Q. Are they predictable?

A. Absolutely not.

Q. Are they totally random?

A. Yes.

Q. Okay. In examining these instances, did you prepare some slides to show how sporadic and random they could be?

A. I did.

Q. And if I turn to what's been marked as OXY Exhibit 32, does that correspond with the Anderson well --

A. Yes.

Q. -- 5H well, which is the last well listed on Exhibit 31?

A. Yes.
Q. Okay. This indicates, it says 7.9 miles to the northeast of our location, correct?
A. Right.
Q. All right. What was significant about that?
A. Well, you have a number of wells drilled here, starting with the Anderson Number 1, which is a vertical wellbore that did not encounter any shallow water flows followed by the 2H -- 3H, which also did not experience any shallow water flows. And then the last well, the 5H, did at a depth of 1,668 feet.
Q. Now, let me ask you about that. Is that in the Castile?
A. That would be in the Salado, I believe.
Q. Not in the Castile?
A. I don't believe so.
Q. This would be an example of one of those water pockets in the Salado itself?
A. Yes.
Q. And does the second page of this exhibit reference the fact that this is roughly at the same geologic depth as the Devon well?
A. Yes, it does.

Q. And what -- and how would you describe that?

A. Well, in the lower left corner, lower left part of this exhibit you'll see a table that shows the depth down from the top of the Salado to the depth of overpressure is about the same. And then the cross section, the two well cross section on the right is a little confusing. But the Anderson 1, as shown, it's being used as a representation of the Anderson 35 5H. And then the North Thistle -- that should read 34 Number 1, not 24 Number 1H is represented by the Diamond 34 Number 1 saltwater disposal well.

Q. And I think you made a point of identifying, at least on the first page of the previous exhibit, how close these wells actually are to the Anderson.

A. Yes, the Anderson 35 2H is only about 300 feet south of the 35 5H, which is all the shallow water flows. And then to the north, about 730 feet north of the 5H well the 3H did not encounter any shallow water flow.

Q. In your opinion, is this a good example of how isolated and random these isolated -- these water pockets could be?

A. Yes.
Q. Okay. Then if I go to the next exhibit, OXY 33, is that another example that you brought to the attention of the Examiner?
A. Yes.
Q. How far away is this particular example?
A. 5.35 miles northwest of Ridge Runner Number 7.
Q. And what are you showing here? How close are these -- is this grouping of wells?
A. We have seven wells within like a half-mile radius. And the second to the last of those seven wells encounter the shallow water flow at 39 and 44.
Q. Just the second to the last well?
A. The second to the last, yes.
Q. And is there -- is this another example of how random and isolated these water pockets could be?
A. Yes.
Q. Then turn to what's been marked as OXY Exhibit 34. Now, this is an area that's only 3.5 miles away; is that correct?
A. Yes.
Q. And what's -- what are you showing here?
A. Well, back in 1962, the Richardson & Bass

State AQ Number 1 was drilled in the middle of a field that did not have any shallow water flows yet. The Richardson & Bass State AQ Number 1 did have some shallow water flow at 3730, and it was killed with a 12-pounds-per-gallon mud.

Q. And none of the offsetting wells reflected any instances of a similar pressurized water?

A. Correct.

Q. And was this indeed an overpressurized zone?

A. Yes.

Q. And then finally, OXY Exhibit 35, where is this located and why did you include this as an exhibit?

A. I included this as an exhibit, this is a representative of the Devon Energy operated wellbore located 7.85 miles northwest of the Diamond saltwater disposal. This is the White Swan 9 Federal Number 3, and you'll see in the drilling program, section number 9 in the box at the left of the little map, abnormal conditions, pressures, temperatures and potential hazards. Highlighted in yellow, it's been reported that some offset wells encountered brine water flows and associated H2S from the salt section at around 3,300 feet. Brine rates have been 200 to 300 barrels per hour and H2S was measured at around 60 parts per million.

Q. And this is -- this would be within records accessible to Devon, correct?

A. It should be.

Q. Now, isn't it true, Mr. Cooper, that the -- not only is the nature of these water pockets extremely isolated and random but that the pressures that are encountered can vary from area to area?

A. Yes, they can.

Q. And you're likewise familiar with the WIPP study that's been marked as OXY Exhibit 37?

A. Yes. I'm trying to find a copy of it here.

Q. On your right.

A. Here we go. Got it. Yes, I am.

Q. And you've observed this and they too -- they also, at least this particular section, actually focuses on the Salado; is that right?

A. It does.

Q. And that is the same zone that's at issue here?

A. Yes.

Q. And it reflects very high pressures?

A. Yes, it's -- it was discussed a little bit earlier, I believe. They observed pressures in the range of 12 megapascals.

Q. And have you also examined other reports?

A. Yes. There's another WIPP study that was referenced by Mr. Schwegal earlier.

Q. That's in one of his exhibits we went through earlier?

A. Yes, but it's a different part of that -- of that same article.

Q. And what does the different part address?

A. It talks about how the brine flows are unpredictable, you know, difficult to -- difficult to predict in terms of their location, and that the pressures range anywhere -- they're very much like this report here, anywhere from the hydrostatic or 7 megapascals to upwards of 15 megapascals.

MR. FELDEWERT: And just for the record, that report or that reference to the report can be found at Devon's Exhibit E, slide 10.

Q. (By Mr. Feldewert) Mr. Cooper, in your opinion, what is the most likely source of the water that Devon encountered at 1800 feet?

A. Shallow overpressured water pocket.

MR. FELDEWERT: That's all the questions I have.

MR. EXAMINER: Very good.

Mr. Bruce?

CROSS-EXAMINATION

BY MR. BRUCE:

Q. Mr. Cooper, looking at your Exhibit 31 -- is that right? Yeah. There are 22 instances of water pressure encountered. It looks like, as far as I could tell, other than the Anderson -- the bottom well of the Anderson 35 5H, all of these are at depths of, say, 3,000 to 4500 feet, basically?

A. Yes.

Q. And as you show the, Anderson 35 5H well is at roughly 1670 feet?

A. Yes.

Q. Now -- and then you -- over in the right-hand column there's some comments about H2S, black water, et cetera, what causes black water besides hydrogen sulfate?

A. I'm not sure.

Q. And then moving on to your Exhibit 32.

A. Okay.

Q. Again, talking about the Anderson 35 5H, was the mud weight used to control that well around 12 PBG?

A. This is the Anderson 35 5H we're talking about now?

Q. Yes, sir.
A. It says it weighted up to 10-4.
Q. Okay, 10-4. And that's substantially lower by a factor of a third of what Devon had in its section 34 well, which was 15 to 16?
A. Yes.
Q. So you could say the Devon well was anomalous at 15 to 16 PBG?
A. Yes.
Q. And then just going through, again, you have, once again, the Ridge -- your Exhibit 33, the Ridge Runner, that's at 30 -- that's at almost 4,000 feet; is that correct? Much deeper than the Devon zone?
A. Yes.
Q. And then you move to Exhibit 34. And, again, that's 3700 feet, much deeper?
A. Yes.
Q. And that one had 12 PBG to control the well as opposed to Devon's 16; is that correct, in the North Thistle 34?
A. I can't answer your question.
Q. Okay. And, again, this shows a sulphur water flow?
A. Yes.

Q. And Devon encountered no sulphur; is that correct?

A. Correct.

Q. And then you move to Exhibit 35. Again, this is a deeper -- the flow was deeper, 3300 feet, and, again, there was H2S present, correct?

A. Example -- example 35?

Q. Exhibit 35.

A. 35, there's -- there's no -- there's no shallow water flow in Exhibit 35.

Q. What did you highlight then?

A. We just highlighted the fact that Santa Fe and, hence, afterwards Devon should have been aware of the fact that there's shallow brine flows in the area.

Q. Okay.

A. That's all.

Q. Okay. Brine water flows and associated hydrogen sulfite, correct?

A. Correct.

Q. Now, just a couple of final things. How far -- you referenced the WIPP study. I forget the exhibit, Number 37 or something. How far is that away from the wells we're talking about today?

A. I forget the exact distance. It's more than 10 miles away, I believe.

Q. Okay. Is the WIPP site near the edge of the Capitan Reef?

A. I'm not sure.

Q. Capitan Reef is a known aquifer, correct?

A. I'm not sure.

Q. Do you know if the Capitan is known to charge water into shallower formations?

A. No.

Q. Go back to your Exhibit 32.

A. Okay.

Q. Go to the top of the Salado, and you got the marker number 2. If the marker bed is correlative in the zone, how do isolated pockets form?

A. I wish we knew.

MR. BRUCE: I think I'll end it with that, Mr. Examiner.

MR. EXAMINER: At this point we do have exhibits that need to be addressed.

MR. FELDEWERT: And I do have one.

MR. EXAMINER: Well, let's do the real stuff that makes money.

REDIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Cooper, were OXY Exhibits 29 through 35 prepared by you or compiled under your direct supervision?

A. Yes.

MR. FELDEWERT: I move the admission into evidence of OXY Exhibits 29 through 35.

MR. BRUCE: No objection.

MR. EXAMINER: Then Exhibits 29 through 35 are so entered.

Your questions.

Q. (By Mr. Feldewert) And, Mr. Cooper, you didn't get a chance to, I don't think, fully review the chart. If I go to Exhibit 31, and I go to the second page. I think they tried to suggest that only one of these inferences was in the Salado; do you remember that?

A. Yes.

Q. And they just focused on the Anderson 35 5H well?

A. Okay, I see it now. Go ahead.

Q. If I look at the Humble State Number 1 well --

A. Yes. Yeah.

Q. That's water at 1518.
A. Yes.
Q. Where would that be?
A. That's in Salado.
Q. And there's no evidence of H2S there, correct?
A. Correct.
Q. Then if I go to the Federal K-1 --
A. Yes.
Q. -- flowed saltwater while drilling from --
A. Right.
Q. What's that say?
A. 1310.
Q. 1310. Where is that located?
A. That -- that's the Salado as well.
Q. No H2S reported there either, right?
A. Correct.
Q. If I go down to the Lost Tank 35 State Number 11.
A. Okay.
Q. Where would that be located?
A. 2626, it could be lower Salado.
Q. Okay. And no evidence there of H2S, correct?
A. No.

Q. No H_2S reported there?

A. Correct.

Q. And it said that -- and then there was something else I saw. Oh, I know what it was. Up there at the Humble State Number 1 it indicates they didn't pump mud. They pumped cement to stop the flow?

A. Correct.

Q. Cement is pretty heavy, isn't it?

A. Yes.

MR. FELDEWERT: That's all the questions I have.

MR. EXAMINER: Very good.

Mr. Brooks?

MR. BROOKS: No questions.

MR. EXAMINER: Your testimony has answered most of my questions. I don't have any additional questions for you.

At this point we would offer to each attorney the ability for rebuttal. Has there been any thought on your part?

MR. BRUCE: Let me check with my clients but I don't think so.

MR. EXAMINER: Very good.

MR. FELDEWERT: Nothing from us.

MR. EXAMINER: And thank you for your testimony.
THE WITNESS: You're welcome.
[Witness excused.]
MR. FELDEWERT: So, Mr. Examiner, that concludes our presentation.
MR. EXAMINER: I can't believe you don't have a closing statement.
MR. FELDEWERT: We don't need a closing statement.
MR. EXAMINER: You don't need a closing statement.
MR. FELDEWERT: Unless you want one.
MR. EXAMINER: No.
MR. BRUCE: And I wasn't planning on one either, Mr. Examiner.
MR. EXAMINER: We wore both of you gentlemen out as a result of saltwater disposal wells and its many stories.
On that point, I thank you all for bearing through all this motion. We will take case 15397 under advisement, and thank you all for your time and your effort.
MR. FELDEWERT: Thank you.
[The hearing was recessed at 5:12 PM.]

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 15397 heard by me on March 29, 2016
Examiner
Oil Conservation Division

REPORTER'S CERTIFICATE

I, Lisa Reinicke, court reporter, do hereby state that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings and was reduced to printed form under my direct supervision.

I FURTHER STATE that I am neither employed by nor related to any of the parties or attorneys in this case and that I have no interest whatsoever in the final disposition of this case in any court.

Lisa R. Reinicke,
Court Reporter