STATE OF NEW MEXICO

ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

CASE NO: 20965

APPLICATION OF EOG RESOURCES, INC.
FOR A GAS CAPTURE PILOT PROJECT INVOLVING
THE OCCASIONAL INJECTION OF PRODUCED GAS INTO
THE BONE SPRING FORMATION,
LEA COUNTY, NEW MEXICO.

REPORTER'S TRANSCRIPT OF PROCEEDINGS
EXAMINER HEARING
December 12, 2019
SANTA FE, NEW MEXICO

This matter came on for hearing before the New Mexico Oil Conservation Division, EXAMINERS LEONARD LOWE, DEAN McCLURE, DYLAN COSS and LEGAL EXAMINER ERIC AMES, on Thursday, December 12, 2019, at the New Mexico Energy, Minerals, and Natural Resources Department, Wendell Chino Building, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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HEARING EXAMINER COSS: I'm going to call us to order again. The Division would now like to hear Case Number 20965. Call for appearances.

MR. RANKIN: Good afternoon, Mr. Examiner. Adam Rankin appearing in this case on behalf of the applicant, EOG Resources Incorporated. We have five witnesses today.

HEARING EXAMINER COSS: Any other appearances?

MS. BENNETT: Good afternoon. Deana Bennett on behalf of Marathon Oil Permian LLC.

MR. BRUCE: Mr. Examiner, Jim Bruce representing BTA Oil Producers LLC. I have no witnesses, and I would ask that I be excused so that I can save myself time and my client money.

HEARING EXAMINER COSS: You're excused as long as Mr. Rankin agrees.

MR. BRUCE: My client has spoken with EOG.

MR. AMES: I don't think Mr. Rankin has the right to require Mr. Bruce to be present, so it's all good.

MS. BENNETT: Just for the record, I don't have any witnesses, either, on behalf of Marathon, and I don't intend to ask any questions.

MR. AMES: Very well. Thank you.

HEARING EXAMINER COSS: At this point then I would ask that the witnesses in Case Number 20965 to stand and be sworn in.

(Oath administered.)

MR. RANKIN: Thank you, Mr. Examiner. May it please the Division, I would like to call our first witness in this case, Mr. Davis Lunsford. Watch the wire.

DAVIS LUNSFORD

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Will you state your full name for the record.

A. Davis Lunsford.

Q. By whom are you employed?

A. EOG Resources

Q. And in what capacity do you work for EOG?

A. I'm a senior facilities engineer in the Midland Division.

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

A. No, sir.

Q. Would you please review for the Examiners your education and work experience as a facilities engineer?

A. Yes. So starting with education, I graduated from Baylor University with a degree in mechanical engineering. While I was at Baylor University, I had an internship with BP working as a mechanical reliability engineer for an offshore platform.

Immediately after graduation I went to work for EOG in our Ft. Worth division, where I worked on various facilities and pipeline design and construction projects.

And then in March of 15 I moved to the Midland Division where I have had some experience in the field as a production completion and drilling engineer, and then my current role as a facilities engineer where I design and construction for a geographic area for transportation and process equipment.

Q. Mr. Lunsford, are you familiar with the application that was filed in this case?

A. Yes, sir.

Q. Have you conducted a review on how to design and plan the project that EOG is seeking approval for today?

A. Yes, sir.

MR. RANKIN: Mr. Examiner, at this time I would ask Mr. Lunsford be -- I tender Mr. Lunsford as an expert in facilities engineering and ask that he be recognized as such.

MS. BENNETT: No objection. If I may, I will just make a standing no objection to any of his witnesses. Thank you.

HEARING EXAMINER COSS: The witness is so recognized.

MR. RANKIN: Thank you so much, Mr. Examiner.

BY MR. RANKIN:

Q. Mr. Lunsford, as an initial matter, would you briefly state what it is that EOG is seeking today from the Division with this application?

A. Yes, sir. EOG is seeking permission to temporarily inject gas into a producing well during periods of gas market interruptions, and then to produce that gas through existing production facility equipment when the market interruptions are over.

Q. Now, just to be clear, what you are asking for here is injections of only small volumes for a very temporary period of time and only during those market interruption periods?

A. That's right. This would be during market interruptions, which would be intermittent and minority of the time.

Q. If you would, referencing what I'm going to put up here on the screen, and what is before in your exhibit packet, what's been marked Exhibit Number 1, will you just explain for the Examiners what a market interruption is, what you mean by that term. And then just reference this exhibit and the diagram and explain how -- what happens to EOG when there is such a market interruption.

A. Yes, sir. So this exhibit shows EOG's gathering system as it exists today, EOG's infrastructure. And so starting at the production facilities shown. Gas is gathered from surrounding wells to production facilities where the oil, gas and water are separated.

The oil and water are stored and then transported away from production facility. And the gas is metered through meters shown with those blue boxes, and then it leaves the lease and enters EOG's gas gathering system shown with the red lines. And the gas flows through the gas gathering system to an EOG-owned compressor station where the boost -- where the gas is boosted in a compressor that's shown with the triangular shape, boosted to the pressure needed to deliver to a third-party purchaser. The gas is metered through a custom meter shown with the blue rectangle and then on to a third party.

So when I talk about an interruption, I'm talking anything in this system or further downstream on a third-party system that would prevent the flow of gas.

And so EOG has worked to improve the reliability of its systems, the production facilities, the gas gathering system and the compressor station to the point where now the largest source of interruptions is not on EOG systems, but on third-party systems. And so when those interruptions occur, we lose the ability to sell the gas, and, as a result, wells are either flared or shut in.

Q. Tell me a little bit about EOG's current status,

current ability to -- current rate of gas capture at its production facilities, and explain, if you would, to the examiners how this project will aid in the ability to further improve the gas capturing abilities.

A. Yes, sir. By improving the reliability of EOG's systems, we have increased our gas capture rate to year to date to around 99 percent, and I think that's competitive with just about anyone in the industry. And so as we think about how to improve it further, we are really targeting -- we want an options to respond to what we have previously been unable to respond to, which is the third-party interruptions. And the idea that we have come up with that we are calling closed loop gas capture is what we are here to talk about today.

Q. Explain a little bit more about why it is that EOG, in addition to increasing its gas capture percentage and ability, why is it EOG is looking to temporarily inject gas in this type of project?

A. Sure. So you know the gas capture percentage is just a metric used to reflect flaring, and so the goal here is to reduce flaring and to avoid waste that occurs either by flaring or by not being able to operate the wells as we desire and having to shut in at times we don't want to shut in.

Q. The only alternative here to shut in is flaring,

so you are trying to avoid either one of those detrimental outcomes, and that's the ultimate goal?

A. Correct.

Q. Now, let's talk about, this is a generalized view of what the current system is. Let's talk about what is EOG is proposing here in a general case.

Looking at Exhibit 2, what's been marked as Exhibit 2 in your packet, just review for the Examiners what this next exhibit shows and what each of the pictures represent.

A. Yes, sir. Exhibit 2 is a diagram that includes what we have previously seen in Exhibit 1, but it's zoomed out further and it includes the system that we are proposing.

So again, gas flows from the production facilities, and they are in the middle of the page, through the EOG gas gathering system, to the compressor station, and when that third party interruption occurs, what's new that we are proposing is shown here with the blue lines.

So that would be a valve, when that third party interruption occurs, we would open a valve, flow gas through a pipeline, through an injection meter, and to a nearby well. We would inject gas into that well during the time period of the interruption so that we can continue to produce the wells throughout the field.

And then when the interruption is over and the third party is back up and running, we will open the well, reproduce the gas from the well to the production facility, through the production facility and back into the EOG gas gathering system, closing the loop, and allowing that gas to ultimately move to the third-party purchaser.

Q. So just to be clear, where you are proposing to put the control valve to divert gas during a third-party interruption, it would be upstream from the custody transfer meter in your system?

A. Yes, sir.

Q. Now, this is a -- the generalized idea, and now for this specific pilot project, you have something that's slightly different that you are proposing and seeking authority for; is that right?

A. That's right. So to implement this project we have to lay the blue pipeline from a compressor station to a nearby well, but if you will reference Exhibit 3, we -- this looks a lot like something we currently do which is gas lift.

So in the Midland Division, we have two types of compressor stations. The first is a sales compressor station like we discussed before that exists to take gas from the EOG gathering system, boost it to the pressure unit to deliver to a third party.

We also have compressor stations that we call localized gas lift stations or LGLs. Those exist to gather gas from the EOG gas gathering system and deliver it to nearby wells for gas lift, a form of artificial lift, to increase the well's production.

So what we would like to do for a pilot project is to mimic the -- mimic the process of closed loop gas capture with an LGL station. So we currently have a compressor station, and from the compressor station a pipeline to a nearby well, and that pipeline currently exists for the purpose of gas lift, and again will mimic the closed loop gas capture with that pipeline and that's shown here in purple.

So this line that exists from an LGL compressor station to a nearby well for the purpose of gas lift will be used for our test pilot project. And really the only, the only difference you will see from surface between gas lift and this project is it will close the production valve during the injection period.

Q. That valve will be on that -- the wellhead. Will you indicate where the injection well is on this diagram so the Examiners are clear?

A. Yes. The well is here in the middle of the page shown in this section labeled wellpad, and the production valve is the valve that allows the flow from the wellhead to the production facility on the left side of the page.

Q. The only difference between what EOG is proposing for approval in this case and what the generalized concept would be for future cases is that rather than having a control valve off the gas transfer meter where it's indicated on the compressor station, you are going to have an existing line off the LGL compressor station?

A. That's right. In full development where we will need a new outlet is at the sale station where the disruptions are occurring.

Q. The only reason you are not doing that now is because you have to extend that pipeline and pay, you know, have to implement that additional pipeline where you already have this pipeline existing?

A. Correct.

Q. Okay. Now, you mentioned the term gas lift. And I would -- if you would just briefly take a moment to explain and make clear what gas lift is and how EOG is currently using gas lift as part of its production strategy?

A. Yes, sir. So gas lift is an artificial lift method where you inject gas into the wellbore to lighten the -- the gradient from the tubing, and, and decrease the bottom hole pressure. So it's very common for EOG. It's our most dominant form of artificial lift in the Midland Division. It's something we do on hundreds of wells.

Q. Okay. So the only difference between a gas lift type of operation which you are currently using in hundreds of wells across the basin and what you are proposing here is what exactly?

A. So we will inject into the well with the production valve closed. So the difference -- that will result in the difference of gas lift usually travels down the well and then back up and circulates within the wellbore. This gas will exit the wellbore and stay near the wellbore in the fracture network, and then the recovery will just happen later when the disruption is over and we open the well.

Q. Let's talk about this more with witnesses later, but the principal difference then is really not in the construction of the wellbore itself, but in its operation.

A. That's right. Yes, sir.

Q. And you are going to be -- we will talk about that with another witness, but just to be clear, this is a process that EOG is familiar with and implementing it across many of its wells, but the only difference being operationally how, how the well is being operated?

A. Yes, sir.

Q. Okay. Now, just to be clear, this -- this proposal here is targeting one pilot project well; is that correct?

A. That's right.

Q. Where is the well you are targeting here that you are seeking approval for?

A. The Caballo 23 Fed Number 2.

Q. Where is that well located, approximately?

A. Section 23 of Lea County.

Q. And we will talk about that in more detail when we talk with another witness and identify the specific location. Now, has EOG, prior to this hearing, did EOG meet with the Division to review this proposed project?

A. We met with the Division a couple of times.

Q. What was the purpose of that meeting?

A. The purpose of that meeting was really to seek the Division's guidance on how to move forward, number one, operationally; but, number two, from a regulatory perspective since this project currently falls outside of kind of established regulatory frameworks.

Q. With the idea being that the regulations address certain types of injection, but this type of injection is not directly addressed in any of the regulations for injection; is that correct?

A. Yes, sir.

Q. So therefore you were seeking a pathway forward for approval from the Division where there wasn't a clear regulatory path in the Division's regulations?

A. That's right.

Q. So in addition to the Division, who else -- did you meet with any other regulatory agency?

A. We have. We met with the BLM a couple of times, and with the Land Office. They are both aware of the project, supportive of the project and aware of this hearing.

Q. Now, as a result of the meeting with the Division, did the Division director send EOG a letter outlining conditions and information that the Division wanted to see in order to approve a project such as you are proposing?

A. Yes, sir.

Q. Has that been marked in your exhibit packet as Exhibit Number 4?

A. Yes, sir.

Q. Now, looking at Exhibit Number 4, you have already addressed some of the issues that the Division requested that EOG prepare and present. You have already discussed the project description generally. Is that correct?

A. Yes, sir.

Q. Look here on Page 1 of the exhibit and just below where the heading project description, there is an item that says duration. What is EOG's proposal for how long it

intends to take to implement this pilot project and when it believes it will have sufficient data to determine its viability?

A. Yes, sir. Our current time line is one to four months to install the process and production equipment needed, and another one to four months to test various injection scenarios. So that would put us reporting back to the Division in approximately eight months, which is within the one-year guidance that we received.

Q. Okay. Now, there is other topics in here that we will describe about what line of reporting is to be done, and we will address that later in just a moment, but as to the viability, if EOG determines that this project is viable, does EOG then intend to seek to implement this type of project in other wells across the basin in New Mexico?

A. Yes, sir. We would consider implementing this anywhere we have sales compressor stations where we might experience market disruptions.

Q. You know other witnesses are here today to address other aspects of the Division's requests and conditions. Looking at Exhibit Number 4, Mr. Lunsford, if you go to the second page, you will see an outline here of some additional items that the Division has requested EOG address.

Will you be addressing items Roman Numeral IV

through IX on that list -- not that group, sorry. You will be addressing the headings titled Monitoring, Reporting, Corrective Action, and Post-Project Report?

A. That's correct.

Q. Didn't mean to throw you a curve ball there. So let's go ahead and jump down to the monitoring portion of your testimony.

The Division has asked that EOG install certain monitoring equipment and so forth. Will you please just review what EOG's plans are for meeting those conditions and requirements?

A. Yes, sir. We want to collect any data that will really influence the safe operation of this project. So, if you will, turn back maybe to Exhibit 3, the diagram. To highlight a few areas where we will monitor, not all of the areas we'll monitor, but some of those relevant ones, we'll -- we'll be monitoring our volumes and pressures and rates through our injection gas meter shown there in the middle of the page near the wellpad.

We'll monitor casing and tubing pressure on the well, and also casing and tubing pressure on adjacent wells. We'll monitor the production rates, oil, gas and water rates through the facility. We'll monitor pressures in the facility. We'll also have automatic shutdowns on the well itself so that we can shut the well in remotely either automatically or from a manned EOG control room, 24-7 control room that we will be watching this operation.

We will also have automatic shutdowns on our compressors, for instance, in case our injection pressure starts to rise, we will have an automatic shut down on our compressor, and we will talk more about where we set those shutdowns and why.

Q. Now, Mr. Lunsford, you mentioned that this is going to be monitored remotely. What type of systems will you have in place to actually do the monitoring? What type of equipment is it that will be testing, keeping track of all the information?

A. Yes, sir. So this will be coming in through our SCADA system, which is a system to collect, store and display information from instruments in the field, and that's essentially live.

Q. So it's real time monitoring and it will be visible at the -- through your Midland data center, and then also be -- the alarm should be set so your personnel will realize there is issues and can go to the field?

A. Yes, sir.

Q. What's the typical response time when an issue arises through a monitoring system for personnel to actually arrive in the field?

A. So these are, any alarms that we get in the control room, the control room operators are trained to direct the response, and we usually measure that response in minutes rather than hours.

Q. Okay. Now, let's talk about the next topic here -- and is everything that's been -- that was requested of EOG under the heading -- under the Monitor heading in Exhibit 4?

A. Yes, sir.

Q. Moving down to the heading under Reporting, the Division is asking EOG to submit a C-115 each month. Will you just review the reporting information and data that EOG intends to submit to the Division every month?

A. Yes, sir. We will submit the standard C-115 which will show production and injection and any other data that we think is helpful to understand the project.

Q. Okay. So EOG will keep track of when it's injecting, when it's producing and report the volumes injected and produced every month?

A. Yes, sir.

Q. And any other volumes or data and pressure data that the Division requests?

A. Yes, sir.

Q. Okay. Looking at the next heading under Corrective Action, what plans does EOG have in place to respond to the potential engineering and/or environmental

issues that may arise during operation of this pilot project?

A. Yes, sir. So multiple -- multiple ways to respond to environmental and engineering emergencies. The first is to prevent them, and we will do that through a pre-startup safety review, design review, where it's common for us as facility engineers to take every piece of this process and look at it from a safety and reliability standpoint, and first ensure ourselves of its safety and reliability; and then, second, make sure the operators who will be working on it understand it and know how to respond to different scenarios.

We will also in our EOG 24-7 control room will be watching this project and can direct any, any response needed. And that will be based really on our EOG safe practices manual, which is kind of the foundation of our, of our safety culture, and then on monthly safety trainings that all of our operators are required to go to.

And, again, I will just point out that, that this is, this looks a lot like gas lift which is something that we do very routinely, so the operators will be familiar with really the dynamics of the project.

Q. So operate -- operationally and as a matter of personnel standpoint, this project is going to look like the LGL gas lift projects that you guys are doing at hundreds of

wells across the Basin already?

A. Yes, sir.

Q. How long, just so we know, how long has EOG been using gas lift as a form of artificial lift?

A. Gas lift has been used as a form of artificial lift for decades in the Midland Division. It's been the predominant form of artificial lift since I have been with EOG for the past five years.

Q. Thank you very much. Now, last topic to discuss is the under the heading Post-Project Report on Page 2 of Exhibit Number 4. And just, if you would, the Division has identified numerous data and information that they would like EOG to report on at the end of the project. Is EOG prepared to submit a post-project report that addresses each of those elements?

A. Yes, sir.

Q. Mr. Lunsford, were Exhibits 1 through 4 either prepared by you under your direction and supervision or do they consist of EOG business records?

A. Yes.

MR. RANKIN: At this time, Mr. Examiner, I would move the admission of Exhibits 1 through 4 and pass the witness.

HEARING EXAMINER COSS: Exhibits 1 through 4 are so admitted.

(Exhibits 1 through 4 admitted.)

MR. RANKIN: Thank very much. No further questions.

HEARING EXAMINER COSS: Examiner Lowe?

EXAMINER LOWE: Good afternoon --

THE WITNESS: Good afternoon.

EXAMINER LOWE: -- Mr. Lunsford, I have a few questions for you.

In your -- in the latter part of your presentation here you indicated environmental and engineering concerns. What are your environmental and engineering concerns?

THE WITNESS: Yes, sir. We have very few environmental or engineering concerns, again, because this is something similar to what we currently do. And some of the key differences we have analyzed under the direction of the Division, and I think that our reservoir engineer and geologist and production engineer will go through this.

My point on environmental and engineering emergencies is really that we are equipped to respond to anything unforeseen.

EXAMINER LOWE: Okay. And you mentioned that your installment would take one to four months?

THE WITNESS: Yes, sir.

EXAMINER LOWE: And then you mentioned, I think, after that another, what was -- you indicated another one to four months. What was that?

THE WITNESS: That's to test various injection scenarios. So under full development, you know, the injection rates and volumes will be determined by the magnitude and duration of the market interruptions, so however much, you know, market capacity we lose will kind of dictate how much injection that we will be trying -- how much we will be trying to inject in this well.

Again, that will be intermittently and a minority of the time, but during that one- to four-month period, what we will want to do is play with some combination of rates and volumes in terms how long we inject and how quickly we inject to really understand the response both during injection and during recovery of that gas.

EXAMINER LOWE: Okay. You also mentioned that you met with the OCD to discuss this prior to coming to, to coming -- to starting it. Who did you meet with here in the OCD, environmental or engineering?

THE WITNESS: The engineering bureau.

EXAMINER LOWE: Engineering bureau. Will Jones, or who did you meet with?

THE WITNESS: I believe Will was there. I don't remember.

EXAMINER LOWE: Okay.

THE WITNESS: I don't remember for sure.

MR. AMES: Leonard, I was there. Adrienne was there as well.

EXAMINER LOWE: Okay. And your C-115 you mentioned, but I guess that will be on our side. That is all the questions I have for you. Thank you.

THE WITNESS: Thank you.

EXAMINER McCLURE: Yes. You mentioned that your duration you are looking at is anywhere from two to eight months. How long is EOG actually asking for the permit to be extended to for this pilot project?

THE WITNESS: One year.

EXAMINER McCLURE: One year?

THE WITNESS: Yes, sir.

EXAMINER McCLURE: The other question I had, and I'm not sure if you've talked about it yet and that is your surface pressure I guess.

THE WITNESS: Yes.

EXAMINER McCLURE: Is that for another witness?

THE WITNESS: Another witness will -- both Brice, our production engineer, and Carlos our reservoir engineer will go and calculated that. The surface pressure we have recommended is 3500 pounds, and that's -- to briefly kind of frame how we selected that, it's to be low enough to ensure the integrity of the wellbore, of the reservoir, and of the surface equipment, but high enough to allow us to inject the volumes and rates we anticipate we will need. But I figure they will answer your questions more fully.

EXAMINER McCLURE: My only question in regards to that, that maybe should be directed to you, as far as your pipelines, your facilities, your compressor for your gas lift, all of that is perfectly fine with the pressure you have selected, obviously?

THE WITNESS: That's right. Our current sales compressor station --

EXAMINER McCLURE: Well, you are going to use your artificial gas lift compressor; is that correct?

THE WITNESS: That's correct.

EXAMINER McCLURE: Is that what you are referring to? I'm sorry, go ahead.

THE WITNESS: Yes. So when we are in full development with the sales compressor station or during the pilot project with the localized gas lift compressor, the equipment currently on the ground won't even allow us to get to 3500 pounds. That equipment is good to discharge pressure of roughly 1440.

And so if we do see the need to increase above our current capacity, to something under 3500 pounds, we can do that with a booster compressor on site, and the slot for that booster compressor is shown on Exhibits 3 and -- 2 and

3.

EXAMINER McCLURE: Okay, I'm with you. So initially you will try to run up to 1400 PSI, and if needed to get the results you are looking you are looking for you may put another booster compressor on site itself. Is that correct?

THE WITNESS: Yes, sir.

EXAMINER McCLURE: Okay. I don't think I have any more questions for this witness. Thank you.

HEARING EXAMINER COSS: I don't have any questions. Do you have any redirect?

MR. RANKIN: I have absolutely none. Thank you very much, Mr. Examiner. I ask that Mr. Lunsford be excused so I can call our second witness.

HEARING EXAMINER COSS: Mr. Lunsford may be excused.

MR. RANKIN: Mr. Examiner, at this time I would ask that Mr. Charles Bassett take the stand.

CHARLES BASSETT

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Good afternoon, Mr. Bassett. Will you please state your full name for the record.

A. Charles Bassett.

Q. By whom are you employed?

A. I'm employed by EOG Resources, Midland Division, as a landman, Permian Basin.

Q. Have you previously testified before the Division?

A. Yes, I have. I've testified several times before the Division.

Q. For the Examiners, briefly recount your education and relevant work experience as a landman.

A. Sure. Bachelor's in business in 1998, followed by a master's in business in 2008, Texas A & M University Commerce. And EOG, let's see, I have worked there the last three years. Prior to that, ten years with Williams companies, which was Barnett Shale, followed by San Juan Basin, followed by Permian Basin. I can keep going, but that's kind of all I remember.

Q. That's a good high level of accounting your experience as a landman. You are familiar with the application filed in this case?

A. I am.

Q. Did you conduct a study of the lands that are the subject of the pilot project and any of the offsetting proposed injection area?

A. Yes.

MR. RANKIN: At this time, Mr. Examiner, I would retender Mr. Bassett as an expert in petroleum land matters.

HEARING EXAMINER COSS: He is so recognized.

MR. RANKIN: Thank you very much.

BY MR. RANKIN:

Q. Mr. Bassett, will you please review for the examiners what has been marked as number, Exhibit Number 5 and orient the Examiners to the general location of this proposed pilot project?

A. Sure. So Exhibit Number 5 is an overview map identifying the Caballo, the area where the Caballo 23 Fed Number 2H Well is. It's located in Section 23 of Township 25 South, Range 33 East, Lea County, New Mexico.

Q. And, Mr. Bassett, you are familiar with the letter that the Division sent to EOG outlining it's requirements for approval of this pilot project?

A. I am.

Q. You're aware the Division asked EOG to identify parties entitled to notice in accordance with this injection rule?

A. I am, yes.

Q. Have you undertaken a study to identify all parties within the half mile area of review surrounding those injection wells?

A. I have.

Q. Will you review for the Examiners what Exhibit 6

shows?

A. So Exhibit 6 here is the -- it depicts the half-mile radius of notice around the Caballo 23 Fed 2H Well, and it also identifies the operators within each tract within that half-mile radius of notice by color.

Q. So following the Division's regulations to identify in the hierarchy of affected parties, you have identified the operators of each tract as being parties entitled to notice for purposes of this hearing?

A. That's correct.

Q. And are those parties identified in the minute type in the top left corner of the exhibit?

A. That's correct.

Q. And those parties, for the Examiners who can't see, who are those parties?

A. Those parties are EOG and BTA and XTO. XTO is considered orange. I can't really tell.

Q. It changed colors.

A. Excuse me. I forgot I had this line. So XTO is in Section 15. BTA is 22 and 27, and then -- yeah, that's right. EOG, of course, is 14, 23 and 25. EOG is also in 15 as well.

Q. Okay. So let's talk about the land in tracts that EOG operates. Is EOG 100 percent working interest owner in those tracts identified in this map?

A. That is correct.
Q. Okay. And now, as to Section 15 where it references XTO, does EOG in fact own -- is it the operator for the shallower depths down in top of the base of the Wolfcamp?
A. Yes, EOG is the operator for those depths.
Q. And XTO is operator for the depths below the Wolfcamp?
A. That's correct.
Q. Now, the portion that EOG is the operator, those are below the stratigraphic equivalent of this pilot project; is that correct?
A. Repeat that.
Q. EOG -- I'm sorry -- EOG -- I'm sorry. XTO is the operator in depths in Section 15 below the stratigraphic equivalent of this pilot project?
A. That's correct.
Q. But EOG had noticed them out of abundance of caution as well?
A. That's correct.
Q. Now, as to the other sections, those are operated by BTA?
A. That's correct.
Q. Okay. Now, did you identify each of the owners that were entitled to notice based on records at the time

the application was filed?

A. Yes.

Q. And in your opinion, did EOG undertake a good-faith effort to locate and identify the correct parties and valid addresses for all of those parties entitled to notice?

A. Yes.

Q. In addition to those offsetting operators, did you also identify the owner of the surface owner where the well is located?

A. Yes, we did.

Q. Who is that?

A. That would be BLM.

Q. So in addition to those parties, you also gave notice to the BLM?

A. Correct.

Q. Did you provide a list of those parties and their addresses to me and my law firm so we could send out certified letters giving them notice of the application and of the hearing?

A. Yes.

Q. And is Exhibit 7 in your notice packet a copy of the affidavit prepared by me and my law firm reflecting that we have provided notice to those parties under the addresses you gave us?

A. Yes.

Q. The second page of that exhibit is a copy of a letter we sent out providing notice of today's hearing date as well as the application?

A. Yes, it is.

Q. And the follow page is the certified mailing receipt status showing that each party actually did receive notice?

A. That's correct.

Q. And the following pages are just the reports from the US Postal Service showing we did send out by certified mail?

A. That's correct.

Q. And is Exhibit 7 a copy of an affidavit of publication from the newspaper in the county where the wellbore is, reflecting that we went ahead and published notice of this application and the hearing in the newspaper of circulation in that county?

A. Yes.

Q. And we identify each of the parties by name in that notice of publication?

A. We did.

Q. Okay.

A. Yes.

Q. Mr. Bassett, were Exhibits 5 and 6 prepared by

you or compiled under your direction and supervision?

A. Yes, they were.

MR. RANKIN: At this time, Mr. Examiner, I would move the admission of Exhibits 5, 6, 7 and 8, which include the affidavits prepared by myself and newspaper here into the record.

HEARING EXAMINER COSS: Exhibits 5, 6, 7 and 8 are so admitted.

(Exhibits 5, 6, 7 and 8 admitted.)

MR. RANKIN: Thank you, Mr. Examiner. At this time I have no further questions and pass the witness for questions by the Examiners.

HEARING EXAMINER COSS: Examiner Lowe?

EXAMINER LOWE: I know you mentioned it, but who is the surface owner again?

THE WITNESS: BLM.

EXAMINER LOWE: BLM. Okay, that's all the questions I have. Thank you.

EXAMINER McCLURE: I have no questions for this witness.

HEARING EXAMINER COSS: And I have no questions for this witness.

MR. RANKIN: If there are no further questions, I ask Mr. Bassett be excused and ask that we can call our third witness.

HEARING EXAMINER COSS: You are excused and you can call your third witness.

MR. RANKIN: At this time I call Mr. Brice Letcher to the stand.

BRICE LETCHER

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. RANKIN:

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

A. Brice Letcher.

Q. By whom are you employed?

A. EOG Resources.

Q. In what capacity?

A. As a senior production engineer in our Midland Division.

Q. Have you previously had the opportunity to testify before the Division?

A. No, sir, I haven't.

Q. Would you review briefly your education and relevant work experience as a production engineer.

A. Yes, sir. I graduated from Texas Tech University in 2014 with a bachelor's in civil engineering. I then went to work for Yates Petroleum in Artesia as a production engineer.

And for the six years leading up to the EOG acquisition of Yates, I worked for Yates as a production engineer and completions engineer.

Since the EOG acquisition of Yates, I have since transferred to EOG's Midland Division where I continue to work as a production engineer. And also obtained my master's in business in 2018 also from Texas Tech. Also certified as a professional engineer in the State of New Mexico.

Q. And you are familiar with the application filed in this case?

A. Yes.

Q. And you have been involved with and helped with the design of the proposed pilot project well as well as its operation?

A. Yes.

Q. And you have also conducted a study of the wells within the area of review, half mile surrounding the proposed pilot project?

A. Yes, sir.

MR. RANKIN: At this time, Mr. Examiner, I would tender Mr. Letcher as an expert in production engineering.

HEARING EXAMINER COSS: He is so recognized.

MR. RANKIN: Thank you very much.

BY MR. RANKIN:

Q. Mr. Letcher, for purposes of orienting the Examiners to your testimony, what aspects of the pilot project did you work on and what will you be testifying to today?

A. I've been responsible for investigating, verifying our wellbore integrity, and designing the downhole equipment setup for this project, and also for the production operations for the well. And since the well falls in my production area, I'm also responsible for overseeing the general production operations of the well.

Q. And so referring to what's been marked as Exhibit 4 in your packet, which is now up on the screen, will you be providing testimony on topics identified by the Division as a condition of approval labeled item numbers Roman Numeral IV through IX?

A. Yes.

Q. So let's go ahead and start with Item Number IV first on that list. Division has requested that EOG provide a well diagram, casing information, drilling reports, and a CBL or cement bond log for the well.

Let's take the first of those items in sequence here, and if you would, please review for the Examiners what has been marked as Exhibit Number 9 and review for the Examiners what it shows.

A. Yes. So this is a well diagram for our proposed pilot test well, the Caballo 23 Federal Number 2H. You see in the top right-hand corner of the diagram we have the location noted as being 50 feet from the north line, 2200 feet from the west line, located in Section 23, Township 25 South and Range 33 East.

In the center you see the well diagram which is really just a simple depiction of the well design where we have casing set at a casing size and grade and also a description of the cement that was placed behind each casing string.

And so we can probably just run through those real quick for the record. Surface casing was set at 1190 feet. That's 11 and 3/4 inch, 42 pounds. It was cemented to surface.

And our intermediate casing is set at 5005 feet. That's eight and 5/8 inch, 32 pound casing, and that casing sleeve is also cemented to surface.

Our production casing string is 5.5 inch, 20 pound, casing that was set at 14,097 feet in the lateral, that sets a total vertical depth of 9456 feet. The cement bond log that we ran recently in November verified that our top cement for our production casing string is at 4806 feet.

Q. So just to touch on a couple of things you identified. Based on the casing and cement you just reviewed, is it your opinion that this well effectively

seals off the shallow, fresh water zones around this well?

A. Yes.

Q. And you identified that the well was drilled to a total vertical depth of 9456 feet. That will effectively be your injection interval there, the depth of that lateral?

A. Yes.

Q. What is the zone, the formation at that depth?

A. That's in the Leonard A Formation. I think you all use quite a bit more specifics on the details of the geologic location.

Q. Some people also call it the Avalon; is that correct?

A. Yes.

Q. Now, the other aspect of this wellbore diagram, which is a little bit different is the tubing. If you would, Mr. Letcher, just review for the Examiners how this well is constructed and why it is constructed in that way.

A. Sure. So this also shows that we have our tubing set at 9451 feet. That's about 55 degrees on the curve. This is a pretty typical opening, the tubing insulation that we do on many wells that we are gas lifting. And so for production operations, we are injecting gas down the casing to the end of tubing and lifting up the tubing, producing up the tubing.

Q. So what's the -- is there a reason -- you call it

open-ended. That simply means there is not a packer, no packers that are isolating the anulus from the production casing; is that right?

A. That's correct. And for the purpose of this project, by leaving the tubing set open-ended, we would be able to take advantage of being able to inject down both the casing and the tubing, which would give us a larger cross sectional area to inject gas down and reduce the frictional back pressure that we would see during gas injection, so allow us to inject at lower surface injection pressures, and it will also help us inject at the rates and volumes that we are looking for.

Q. Okay. And that setup is typical for all your gas lift wells that you have been operating for a number of years across the Basin?

A. Yes.

Q. This is how the well is currently constructed, you are not changing any aspect of the construction of this well?

A. That's correct.

Q. And the only change is going to be operationally, as Mr. Lunsford testified, to close off the production well while you are injecting?

A. Yes.

Q. Very good. So that's the wellbore diagram. You

also have prepared an exhibit reflecting the casing, the drilling reports. Is that right?

A. Yes.

Q. It's the next exhibit. Will you review for the Examiners the highlights to take away from this very small-print exhibit so they know what purpose it serves.

A. Yes, sir. So Exhibit 10 is a summary of the operations when the well was originally drilled in 2011, and really the take-away from this is just verifying what we were showing in the wellbore diagram, verifying that we successfully installed and cemented the casing in place.

Q. Okay. Now, in addition, under that same item, Roman Numeral IV here in Exhibit 4, the Division asked for a cement bond log as well. Is that your next exhibit?

A. Yes.

Q. Exhibit Number 11. And what's the take-away on this exhibit? Review for the Examiners what this shows and the significance of the different log tracts on this exhibit.

A. Okay. Yeah. So this is a CBL that we obtained in November of this year to verify the top of cement. And for anybody that may not be familiar with radial cement bond logs, what we are looking at here, starting on the left-hand side, I know it's going to be hard to read, and we will be sure to get you the PDF version of this or an actual log for you to look at, but on the left-hand side here you have your gamma ray and your casing collar located, and that serves as a reference point in the wellbore.

And so the next portion over on the log is measuring amplitude. And so measuring amplitude of the waves as they return to the acoustic tool. And so the way that that is interpreted is this is measuring amplitude from the, I think, the scale is negative 100 to 100.

And so higher amplitude indicates that there is more free pipe, so lower amplitude indicates that there is some attenuation or, you know, resistance behind the pipe indicating there is cement behind the pipe.

The next portion over is the variable density which is the actual acoustic wave form shown by the tool. And then the far right is just a cement map which is nice to look at because it gives you a view of what the log is radioing, so completely around the pipe, so --

And so, you know, this top portion where it's showing that this is a, you know, free pipe, you can see that amplitude is showing a higher value, so we see completely free pipe. But as you go down the log, I think it is probably Page 3, and again, it's hard to view the depths, of course, but at 4806 feet, you can see that the amplitude jumps sharply to the right to higher values indicating that that is where we start to see free pipe below that point. The log is indicating that you can see cement behind the pipe.

Q. So and that's reflected on the far right as well where, if you would just review what the warm colors mean versus the cooler colors in terms identifying cement.

A. Sure. So the far right, the cement map warmer colors are indicating, you know, better bond with the pipe.

Q. So 40 to 100 feet down to the bottom of this log run you've got cement coverage?

A. What was that, sir?

Q. From the -- from that 48 -- approximately 4800 feet down to the bottom of this well, you've got sufficient cement coverage in this well?

A. Yes. Yes. And the log runs from 9000 feet up until the top of the cement.

Q. And so when was this cement bond log run?

A. In November of this year.

Q. And you stated that EOG will provide the Division an electronic version of this log so we can read the depths and review the quality of the tract adjacent --

A. Yes.

Q. -- in a reasonable manner?

A. Yes.

Q. Thank you. Is that everything that was requested by the Division under Roman Numeral IV on Exhibit 4?

A. I believe so, yes.

Q. Let's move to Item Number Roman Numeral V. And in that item the Division asked that EOG confirm that the well will meet the following minimum requirements:

"A, the casing burst pressure shall be at least 120 percent of the maximum allowable surface pressure, plus the hydrostatic pressure from a full column of reservoir fluid."

And before you answer that question, I just wanted -- we need to address the first part of that issue, and that is the maximum allowable surface injection pressure.

A. Sure.

Q. Has EOG identified a pressure that it believes is appropriate for the maximum surface injection pressure for this project?

A. Yes. And as Davis alluded to also, the pressure that we are proposing for our maximum allowable surface pressure is 3500 psi. And the way that we came up with that really was, as Davis described, you know, to be sure that we would be able to inject into the formation, but also stay below pressures that -- below our maximum pressure ratings for casing and well equipment and to protect the reservoir, of course, too.

Q. And in addition, you need to be able to inject

the volumes that are being obtained from a third party shutdown with no interruption.

A. Correct, sir.

Q. Okay. So with that you've got your proposed maximum allowable surface pressure of 3500 psi. With that pressure will your -- will you be able to meet this condition that the Division has requested you to demonstrate?

A. Yes.

Q. Will you just review for the Examiners your calculations to demonstrate that you can meet that condition?

A. Yes. So the burst pressure rating of our 5.5 inch casing is around 12,600 pounds. The, you know, worst-case scenario that we would never envision really seeing in, in operation during our temporary gas injection is, as the Division had asked us to look at, our maximum allowable surface pressure plus a full hydrostatic column of fluid.

And so that max pressure comes out to 7600 psi, and that's just taking 3500 psi plus your total vertical depth, 9456, times your fluid gradient, .433.

And so based on that, you can say that our, our max casing burst rating is 166 percent greater than that scenario.

Q. And all that time that EOG has been operating for

nearly a decade its gas lift wells, have you ever encountered a situation where you have a full hydrostatic head in that gas lift injection situation?

A. No. Certainly not on wells that have been producing for as many years as this well.

Q. And this, so therefore this calculation is a very conservative approach to determine this condition?

A. Yes, sir.

Q. Now, I believe that addresses Item Number V(a). We've already discussed Item Number V(b), which are the drilling reports and CBL. And you have, "Casing and CBL is adequate position for purposes of this project."

A. Yes, sir.

Q. Move on to Item Number Roman Numeral VI, the Division here is asking that EOG perform an assessment of the surrounding wells to ensure that they meet the requirements of the Division in terms of their casing and cement.

Have you done that evaluation of the wells within the half mile area of review surrounding the proposed injection pilot project?

A. Yes, sir.

Q. Let's go ahead and look at your area of review map. This is Exhibit Number 12. Will you review for the Examiners what this shows?

A. This is just showing the Cabello Federal Number 2H in the center there, and the half mile area of review circling the well, and then each of the 48 wells that fall within that area, and each well is numbered to -- that goes along with Exhibit --

Q. Exhibit 14.

A. -- 14, where we have -- we have data tabulated for each of those wells.

Q. Yours doesn't have it?

A. It does. I just didn't find it.

Q. 14, it's in there?

A. Uh-huh.

Q. In that table of data on Exhibit 14, you have identified all the facility data relative to the casing and cement for each of those wells?

A. Yes, sir.

Q. How many of those wells in the area of review have you drilled and are operated by EOG?

A. The majority of those wells are operated by EOG. Six of the wells are operated by other operators. And there are three wells that have been plugged and abandoned.

Q. So did you take a closer look at those wells that were not drilled or operated by EOG?

A. Yes, sir.

Q. And the P and A wells as well?

A. Yes, sir. Took a closer look at those all put together well diagrams.

Q. Those are marked as Exhibit 13 in your exhibit packet?

A. Yes, sir.

Q. So those six wells you included, each of them you took a more careful look at them because they weren't drilled or operated by EOG, essentially; is that right?

A. Right, yeah. We just wanted to ensure that that -- those wells also had appropriate communication strings and adequately isolate the proposed zone that we are -- we will be injecting gas into.

Q. Based on your review of each of the six wells that are in your area of review, including the P and A, have you cited any concerns with casing or cementing that's insufficient to adequately protect against migration through these wells to other zones?

A. No. From reviewing the wells, found nothing that would make us be concerned about communication to other wells. All wells appeared to have appropriate cementing of casing strings and adequate isolation of the zone we are proposing our temporary gas injection.

Q. As to the EOG wells within the area of review, are you satisfied that those wells are constructed with casing and cement specs that are sufficient to meet the

Division's requirements as well?

A. Yes, sir. Yes. All the EOG wells within the area of review have pretty similar designs as the Caballo 2H, and so all those appear to have appropriate cementing and adequate isolation.

Q. This is a topic for another witness to some extent, but I do want to just ask you, Mr. Letcher, the fact that these wells are within the area of review, is it -- is it your opinion that the gas is not going to even approach these wells within the area of review based on the nature of the reservoir and rock?

A. Correct. And I think Carlos, our reservoir engineer, he will go into great detail on the modeling that we have done that appears to show that there is, you know, the gas won't go very far, essentially.

Q. And EOG doesn't want the gas to go very far; correct?

A. Right. Correct.

Q. It wants to stay right by the wellbore?

A. Yes, sir.

Q. So in light of that, let's look at Item Number VI. Is it your opinion that that's all the information required by the Division in Item Number VI in terms of the assessment of the surrounding wellbores?

A. Yes, sir.

Q. Look at the next item, Roman Numeral VII in Exhibit 4, the Division here asks that EOG demonstrate that the mechanical integrity of the well comprised with the Division regulation for mechanical integrity testing to a minimum pressure of 110 percent of the maximal allowable surface pressure. Is EOG able to demonstrate that this well can meet that condition?

A. Yes, sir. So what we -- what we did hear was back in November when we ran the CBL is when we conducted our MIT and RBP at 9000 feet.

Q. Stop you right there. What is RBP?

A. A retrievable bridge plug.

Q. Okay. Thank you.

A. So RBP at 9000 feet, loaded the casing with fresh water and pressured up to 1650 psi and held that for 30 minutes. So the equivalent pressure at 9000 feet during the MIT test would have been 5550 psi, and that's, you know, 1650 psi, plus 9000 feet by your fluid gradient .433.

At the same depth during our temporary gas injection operations, the max pressure that we would expect would only be for 4760 psi. That would be your 3500 psi max allowable surface pressure, plus a column of gas.

And so for our gas gradient, we used .14 psi per foot to calculate that. And so having said all of that, our tests indicate that, that we have, you know, good integrity up to over 110 percent of -- of our max expected pressure during the temporary gas injection operations.

Q. So your next exhibit here, let me just go through real quick, is the recording data from your MIT test; is that correct?

A. Yes. This is our pressure charts.

Q. Will you just review the, show, explain what that shows and --

A. Sure. So at the top you can kind of see where it, the chart is recording in minutes as it rotates. When we pressure up here, you can see this blue line jumps up to 1650 psi, and we hold that pressure all the way around for 30 minutes.

Q. So based on that, and based on the calculations, would you consider it a fairly conservative approach to identify the maximum pressure?

A. Yes, sir.

Q. And you determined based on the MIT that this well can meet the Division's condition in this item?

A. Yes, sir. I believe so.

Q. Okay. Now, moving on to the next item number, Item Roman Numerable -- Numeral VIII, the Division here in Exhibit 4 asks EOG to demonstrate the injected gas does not contain corrosive gas such as H2S, hydrogen sulphide, or CO2, that may damage the casing. Have you prepared an

analysis of the gas that you intend to inject into the well?

A. Correct.

Q. And that has been marked as Exhibit Number 16, I believe.

A. 16, is it?

Q. Is that correct?

A. Yes.

Q. Please review for the Examiners what that exhibit is.

A. So Exhibit 16 is a gas analysis from our Caballo LGL that is the proposed source of gas for this pilot test. And what we are looking at here is in the kind of bottom, left portion, we are seeing a breakdown of the gas percent for each component. And we are showing zero percentage H_2S and .8 percent CO_2. And at such a low concentration of CO_2, there would really be no expected corrosion tendencies in the well.

Q. And tell me a little bit more about this gas compared to the gas that's native in this formation. What's the quality relative to the gas that you are seeing in the formation?

A. Yes. So two things to note. This is the gas we are currently using to gas lift the well and have not seen any corrosion tendencies caused by injecting this gas for gas lift operations. And also that the native gas in this well has a higher CO_2 concentration than this injection gas, so --

Q. So in the course of using the same gas for gas lift and the same gas being produced from this formation, you haven't seen any issues with corrosion within the tubing or production casing in this well?

A. Right. We haven't seen any corrosion tendencies.

Q. And you don't expect that to be an issue?

A. Don't expect it.

Q. Okay. Now, Mr. Lunsford testified that the well and the facilities that you will operate for this pilot project will be equipped with some alarm systems and automatic shutdowns should the pressure reach the proposed maximum injection surface pressure of 3500 pounds. Would you just review a little bit how unlikely it is that that pressure would be attained?

And we have another witness who will get into more depth on that topic, but briefly explain how much of that pressure will be attained here, and how EOG's alarm system and shutdown mechanisms would actually work.

A. Sure. So again, since we are only injecting gas, and we have a lateral that has, you know, hundreds of perforations, there's lots of places for the gas to go, right.

And kind of additionally to that, this well has produced close to 1.8 BCF of gas over the life of the well, you know, over 300,000 barrels total fluid, and so it would be unlikely that we would be able to inject enough gas to, you know, build pressure in the reservoir to a point where we could, you know, do any damage to the reservoir.

Q. So in the unlikely event that were to occur, as we understood from Mr. Lunsford, you don't even have the horsepower to achieve those pressures with your gas on injection.

A. Right.

Q. But in the unlikely event that were to occur, what systems are in place that EOG has to monitor, set alarms and shut down the system should have it ever approach that maximum surface injection pressure?

A. So like Davis talked about, we will have valves on the wellhead that will be automated so that if we approach and if we hit that max operating pressure, we would shut in the well. We would shut off injection to the well. We would also, like Davis talked about, we are constantly collecting all the data from this well through our control room or our SCADA system of the pressures, rates, volumes. And so we would also have the ability to set up alarms and set up -- set up parameters, you know, with our alarms to signal us to any irregularities in the normal operations of the well.

Q. So that gives you the ability to do that once you have established what the parameters are for injection and how the reservoir responds to the injection and production; is that correct?

A. Yes.

Q. Okay. And then the automatic shutdown, it can be set so that if the pressures ever do reach that 3500 maximum allowable surface injection pressure at the well, injection could be shut in automatically without any action required by any personnel?

A. Absolutely.

Q. Okay. Now, I think that's all the questions I have for you, other than the last couple here. In your opinion, will granting the application be in the best interest of conservation and resources, prevention of waste and protection of correlative rights?

A. Yes.

Q. In your opinion, can this pilot project be operated safely and without presenting a risk to human health, environment, or fresh water sources?

A. Yes.

Q. Mr. Letcher, were Exhibits 9 through 16 prepared by you, under your direction or supervision?

A. Yes.

MR. RANKIN: At this time, Mr. Examiner, I would move the admission of 9 through 16 into the record.

HEARING EXAMINER COSS: Exhibits 9 through 16 are so admitted.

(Exhibits 9 through 16 admitted.)

MR. RANKIN: At this time I have no further questions and pass the witness.

HEARING EXAMINER COSS: Examiner Lowe?

EXAMINER LOWE: Good afternoon. I have a few questions for you. You indicated your max pressure of 3500 psi. That's your -- that's your 120 percent? Is that what that indicates?

THE WITNESS: What's that?

EXAMINER LOWE: Is that a 120 -- is that the 120 percent number --

THE WITNESS: 120 percent.

EXAMINER LOWE: -- this is in reference to asking questions in reference to V, was that V(a)?

THE WITNESS: So the 3500 psi is the maximum allowable surface pressure that we are proposing for the well.

EXAMINER LOWE: And that's your max pressure. What do you anticipate to be your nominal pressure?

THE WITNESS: Nominal pressure?

EXAMINER LOWE: Yeah, if that's your max.

THE WITNESS: Downhole?

EXAMINER LOWE: Yes, downhole, yes.

THE WITNESS: So during temporary gas injection operations, we would have a full column of gas plus that 3500 psi, and so that's 3500 psi, plus the total virtual depth 9456 feet by .14 psi per foot, and so I believe that came out to around 4800 psi.

EXAMINER LOWE: On your Exhibit Map Number 12, you referenced, when you were discussing that map, you referenced Exhibit 14. Is the green lines on that map on Exhibit 12 the items listed on Table 14 or Exhibit 14? Is that what you are representing?

THE WITNESS: Yes, they are. Each well on the map is numbered.

EXAMINER LOWE: Okay.

THE WITNESS: And that number corresponds with the -- the column here that says map legend number.

EXAMINER LOWE: That's all I have for now. Thank you.

EXAMINER McCLURE: During your MIT, you actually started with about 1600 pounds, 1650, and then you gained 200 pounds over your 30 minutes. I guess, what's your thought towards that?

THE WITNESS: We envisioned we probably had a little gas bubble there that migrated on us.

EXAMINER McCLURE: I got you. So this was --

this took place -- you were just came out of the hole after setting your bridge plug, so you supposedly had a gas bubble at the bottom that slowly migrated?

THE WITNESS: Right. So we filled the casing --

EXAMINER McCLURE: I'm with you.

THE WITNESS: -- shut in the pressure valve. You are correct, we did see a little bit of gain there.

EXAMINER McCLURE: Okay. I guess the question I had, another question I had, at the time that you ran your cement bond log, were you holding pressure on your casing at that particular point, or were you just had a column through in the hole?

THE WITNESS: Yes, sir. We held a thousand pounds on the casing in that log.

EXAMINER McCLURE: I'm with you. Another question I had, as far as that, this -- maybe this is a better question for the facility engineer, to your awareness, do you guys run into paraffin issues?

THE WITNESS: In this particular well, not really. The Leonard A, we see some scaling tendencies on occasion, but not -- not really bad paraffin problems.

EXAMINER McCLURE: What do you think is the difference, I guess, for just why you are getting scaling in the other well, the Leonard, I think you said?

THE WITNESS: The Leonard A formation.

EXAMINER McCLURE: Oh, I apologize. I'm with you. Okay.

THE WITNESS: We can -- we can see paraffin. We have seen paraffin, but not a large tendency for it, I don't think.

EXAMINER McCLURE: My other questions might be more for the reservoir engineer. And in regards to that, I was just asking because that sort of related to the thoughts in regards to injecting that gas back into a reservoir down there.

As far as the completion side questions and in regards to the frac, would that be a better for the reservoir engineer, or are you prepared to talk about that?

THE WITNESS: Yeah, I think Carlos may have more detail on that through his modeling.

EXAMINER McCLURE: I wasn't sure. You are a production and completions engineer, I wasn't sure who to ask.

THE WITNESS: I would be happy to attempt to answer your question if you want to ask it.

EXAMINER McCLURE: I was going to say, the main question I have is, do you guys have access -- do you have any level of confidence as to the height, the top and bottom of your fractures in these wells?

THE WITNESS: Yeah, I'm probably not the best to answer that question.

EXAMINER McCLURE: I'm sorry. I will withdraw that question. Yeah, I just wasn't sure -- this may be another question, I apologize, that may be better for the engineer.

As far as installing a transducer, something along those lines at the bottom of your tubing, what is EOG's thoughts in regards to that if that's something the Division would like to see?

THE WITNESS: For the purpose of just --

EXAMINER McCLURE: Monitoring downhole pressure.

THE WITNESS: And just to collect the data?

EXAMINER McCLURE: Correct. And just in regards to that, perhaps, also allow it to fill and shut your well in, I guess. I'm not sure what you think the liability is and what -- something along those lines.

THE WITNESS: Yeah. I think we feel that by monitoring the surface injection pressures, that we would be able to, to have a good picture of how the well is performing during injection operations and during production operations. And in that it really, you know, wouldn't be necessary to take that step, I guess, that by finding any irregularities we see in the surface injection pressure, we would be able to tell that, "Hey, something may be going on downhole that would be concerning," and we would shut in the well based on that.

EXAMINER McCLURE: So your concern would obviously be like back to looking at a gas column, which was in a fluid column, our concern would obviously be that somehow we end up with a fluid column in the hole, and as such, like your MIT, then it reached the level as to what your pressures could reach if you had a fluid column just for starting instance. And at that point we start increasing our pressures beyond what we would typically like for our fracture gradient, I guess, if you are at 3500 pounds plus a full fluid column of the reservoir fluid.

And that, I guess that there is where we were approaching from one to potentially monitor the downhole pressures. I don't know, I guess, if you had any thoughts in regards to that. Do you think that by surface monitoring you could identify when if --

THE WITNESS: Yeah, I think so.

EXAMINER McCLURE: -- a fluid column were to rise?

THE WITNESS: I really think too that since we are only injecting gas, we would actually have a better, you know, we could probably argue that you maybe have a better picture of what's going on downhole because you have a consistent injection, you know, you have a consistent column of gas that you could predict pressures at depth. And then also just kind of want to hit back on the point that, you know, not expecting -- not expecting to have much of a fluid level or, I think, you know the static fluid level in this well is probably not far from our end of tubing even early as depleted as the well is still. I don't know if that helps answer your --

EXAMINER McCLURE: Oh, well, I'm in complete agreement with you in regards to when you are injecting. My concern would be after the injection period, if the reservoir pressure would increase and allow a fluid column to build and at that point you start reinjecting again, at that point, at the initial period you could have a fluid column within the anulus.

I guess that is the sort of time frame I guess I was looking at. Obviously during production you are going to shove your fluid out with your gas, so --

THE WITNESS: Right.

EXAMINER McCLURE: So in regards to that --

THE WITNESS: It's something we can certainly visit.

EXAMINER McCLURE: We may end up having later discussions about it, perhaps. We'll just see, I guess, how it goes from there.

THE WITNESS: Okay.

EXAMINER McCLURE: I believe that's all the questions I have for you, for this witness. Thank you.

EXAMINER LOWE: I have two more questions. Being that this is a pilot project, and I have always seen MIT charts has an OCD witness there. I don't know if this falls under that as far as OCD. Did you contact the OCD district office to be present for this, or is it just a pilot, you don't need OCD presence there?

THE WITNESS: No, we did not. I guess, just for the letter from the Division I guess didn't really specify that someone needed to witness.

EXAMINER LOWE: I was just curious to know. Another question, I just want to reemphasize, you are going to resubmit Exhibits 2 or 11 with the chart; right?

MR. RANKIN: We will submit electronically so the Division has an electronic version so they can zoom in and identify some of the depths and the numbers and log cases.

EXAMINER LOWE: That's all I have. Thank you.

HEARING EXAMINER COSS: Thank you. Is that it, Mr. Lowe?

EXAMINER LOWE: Yes.

HEARING EXAMINER COSS: Okay. Well, thank you, Mr. Letcher for your presentation here today. It looks as if you all have done a good job of answering all the questions we put forth. So thank you for that.

I just have a few very simple questions for you.

On Exhibit 13, your area map of the wells in review -- oh, no, it's 12, the area map. 13 is the wells that aren't -- maybe I just haven't seen it yet -- the wells that aren't under EOG, which of those wells, are those in Exhibit 12? Are they labeled?

THE WITNESS: Yes. Those are also labeled. Yeah, I guess the tricky part there is you have to look at the well diagram, get the name of the well, go to the table on Exhibit 14 --

HEARING EXAMINER COSS: Okay.

THE WITNESS: -- and find the well name and then, you know, that far left column is the map legend number where it would show on the map.

HEARING EXAMINER COSS: I see. Okay. So I can go back and forth if I want to?

THE WITNESS: Sorry about that. If I would have thought, I would have added numbers to those, too.

HEARING EXAMINER COSS: But you have testified that they are fairly far away, so I won't put too much effort into those. And I would only ask, my only other additional question, in your testimony for request Number V, you ran through a handful of calculations to justify the max surface pressure of 3500 psi, and are any of those calculations laid out for my geological mind to follow on a piece of paper?

THE WITNESS: So the 3500 psi wasn't necessarily calculated. We were basing that off of the, you know, our presumed site bottom hole pressure in this well is probably 800 to 1000, 1100 psi, so we wanted to make sure that we were, you know, of course able to overcome that in order to inject into the formation. And then also stayed below the max pressure ratings of our casing and wellhead equipment. So all the well equipment is rated to 5,000 pounds, and then, you know, also to ensure that -- that the reservoir is protected, too.

And so in terms of that calculation I guess, you know, looking at the frac gradient for the well, when this well was originally completed, the frac gradient was .75 psi per foot. And so in order to frac the well, you really would have to be pumping viscous fluid at a high enough rate to overcome fluid loss into the formation and achieve a pressure of over 7000 psi to initiate a fracture.

And so the max expected pressure, like we were talking about that we would see downhole, would be the 3500 psi, plus a column of gas. And so 3500 psi plus the vertical depth, 9456 feet, times your gas gradient, .14 psi per foot is what we used to calculate.

HEARING EXAMINER COSS: I can appreciate that, but if you would submit me something that would explain it.

THE WITNESS: Sure.

MR. RANKIN: Sure. I think just to help facilitate, I think Item V is really asking to confirm that the casing pressure would be at least 120 percent of the maximum allowable surface pressure.

THE WITNESS: You're right.

MR. RANKIN: So that calculation, I think, Mr. Letcher can just give -- we can submit the numbers. Maybe even Mr. McClure can --

THE WITNESS: We can submit that. Sorry about that.

HEARING EXAMINER COSS: That was my only other question, so thank you.

MR. RANKIN: If I might just have a quick redirect to help clarify.

REDIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Letcher, as to Examiner McClure's questions about downhole monitoring, were there ever to be fluid in the wellbore casing, wouldn't that appear instantaneously in your surface pressure monitoring that you have through your SCADA system?

A. Sure. Yeah. If we had a sudden influx of fluid, it would certainly change the injection pressure.

Q. So that pressure is being monitored on a real time basis and being monitored at EOG's facility

headquarters; is that correct?

A. Yes.

Q. So if you wanted to set an alarm to notify EOG personnel once it reached a certain level, would that give EOG adequate time to reach the well to address any issues in terms of operating downhole pressure?

A. Yes. Yes. We would have the ability to shut in operations remotely, and as Davis alluded to earlier, that our response times in the field is pretty remarkable, really. We measure in minutes rather than hours, so there is somebody close by usually.

Q. Okay. So as far as your concern about being able to address the issues should there be a reflection of a sudden increase in pressure at the surface, it's your opinion that there is no problem with EOG being able to, A, monitor the well, B, shut it in either remotely or get the personnel on site to correct and nominalize in a short period of time?

A. Right.

Q. So that's the basis for your statement that you feel like downhole monitoring is unnecessary in this case?

A. Yes.

Q. So there is no, there is no H2S or poisonous gas that would cause any impact or concerns to human health or environment that would require, you know, downhole

monitoring of that type, in your opinion?

A. No, sir, I don't think so.

Q. Okay. I just wanted to make sure I understood the basis for your statement.

MR. RANKIN: I have no further questions.

HEARING EXAMINER COSS: Well, this witness may be excused and you can move on to your next.

MR. RANKIN: Thank you very much. I believe we can get through fairly quickly, and I'm happy to continue to press on, however, in the event that the court reporter, if we want to take a short five-minute break, I'm happy to do that as well.

(Recess taken.)

HEARING EXAMINER COSS: Okay. We will go back on the record here and continue.

MR. RANKIN: Thank you very much, Mr. Examiner. I would like to call our fourth witness to the stand, Ms. Jenna Hessert.

JENNA HESSERT

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Good afternoon, Ms. Hessert. Will you please state your full name for the record?

A. Jenna Hessert.

Q. By whom are you employed?

A. EOG Resources.

Q. And have you previously testified before the Division?

A. No, I have not.

Q. Will you please briefly review your education and relevant work experience as a petroleum geologist?

A. Yes. I graduated from Yale University in 2014 with my bachelor of science in geology and geophysics. I then attended Texas Tech University for my master's in geoscience, graduated in 2016. My thesis was Structural Geology Base in the Arbuckle Incline in Oklahoma.

And I had two internships with Occidental Petroleum 2013 and 2014. I worked for the Williams Formation in the -- and the Clear formation in the Midland Basin, and am currently working in the Delaware Basin in -- out of the Midland office as a project geologist. So I oversee planning and development of wells across Lea County, as well as doing exploration.

Q. And your current responsibilities with EOG are as a petroleum geologist are over the southeast part of New Mexico?

A. Yes.

Q. You are familiar with the application filed in this case?

A. Yes.

Q. Have you conducted a study of the geology and land that is the subject of this pilot project?

A. Yes.

MR. RANKIN: And at this time, Mr. Examiner, I tender Ms. Hessert as an expert in petroleum geology.

HEARING EXAMINER COSS: Ms. Hessert is so recognized.

MR. RANKIN: Thank you very much.

BY MR. RANKIN:

Q. Now, Ms. Hessert, reviewing Exhibit 4, which is the letter that the Division sent to EOG, will you be testifying today about the items under Page Number 1 addressed Technical Information Standards for Installation and Operation, in particular, the items that relate to the geology of the reservoir in the target the injection zone?

A. Yes.

Q. Let's go ahead and jump in. And have you prepared a series of slides reviewing your assessment of the geology here?

A. Yes.

Q. Let's go ahead and look at them. They start on Exhibit Number 17; is that correct?

A. Yes.

Q. And could you just review for the Examiners what

the first page of Exhibit 17 shows and review for the Examiners.

A. Yes.

Q. Feel free to try this, too, because we have a clicker.

A. This is the Caballo area lease map. Shown in the center is Section 23 outlined in yellow as Mr. Bassett went through our acreage position. The red line is the Caballo 23 Federal Number 2H. The surface hole is marked by a star, and the bottom hole is marked by a hexagon, and then surrounding oil wells that have been drilled, all nearby wells that are beyond that half mile radius.

Q. Okay.

A. This next map is the same map, but with now a cross-section. It's going to be roughly north to south across the Section 23. So it will be from A to A prime with three wells shown on the next few slides. So this cross-section and the next cross-section are going to be exactly the same, but in the second cross-section I'm going to zoom in to the interval.

So again A to A prime, it's shown north to south, and this cross-section, and we can also submit a clearer version, this is a little blurry. It goes from all the way from the Rustler, so pretty much to surface, and then I've taken each of them down to the Wolfcamp where it shows well logs were run.

So the first well tract is gamma ray, the depth, and then resistivity, and then two porosity tracts. The blue is neutron porosity and the black is density porosity.

Our injection interval is going to be in the Avalon section, so I will get into that. But I wanted to point out where the Rustler is located, just about 1000 feet, and our injection interval is 9456, so we are about 8100 below, and consistently below.

The other thing I would like to point out, this is actually a structural cross-section, so it's not signed on anything. But you will notice the consistent lithology, the consistent thicknesses, and no offsets even though it's not signed on anything.

A. This is that same cross-section. This is the Bone Spring 1 formation. Our interval would be right here. This is the 9500 depth. We are at 9450 is the Upper Leonard or Upper Avalon section. This is a siliceous mudrock, so what I mean by this is it's very quartz rich mudrock, but it's very tight, very low porosity and low permeability. This is ideal for this project.

So most of the time when we want to inject something, if we are looking for ultimate storage capacity or for production or actual reservoir, you want something with high porosity and high perm so it will travel, we look for the opposite. We want something with low porosity, low perm that will contain the gas in the wellbore. This mudrock has natural porosity already in the rock.

This section here, the Avalon, it has a very high gamma ray signature that shows that, again, keeping that -- it remains very small, tight pores with all the clay present. High resistivity, and then the porosity tracts are actually shown in response in the high percentage. And you will notice that signature is very consistent across that entire interval.

Above the injection interval is the Bone Spring line. This is a very tight carbonate. That's where you see the gamma ray drop really low, and then porosities are tight with high resistivity. This will be a frac barrier to the Brushy Canyon above the Avalon.

And in the lower Avalon section is an interval with very high carbonate, so again, similar response, very low gamma ray, high resistivity and low porosity. So this will be a frac area to the First Bone Spring Sand that's below it.

So we feel that injecting this interval, we will have containment both above and below, and then also keep the gas in the wellbore due to geologic properties. And Carlos, our reservoir engineer, will describe a little bit more, but we use these geologic properties in his reservoir model to model how far away we think the gas will migrate and it will stay near the wellbore.

This is a structure map of the top of the Bone Spring Lime interval. So again, the interval that's right above the Avalon is very consistent marker across the area. And this is to address the Division's concern of any geological faulting or structural complexity.

And as you can see, it's dipping very gently to the southeast. These contours are 50 foot intervals, marked every 100 feet. So you can see it's a very consistent gradual dip, no drastic changes across the area, showing there is no faulting or anything structural that would be of concern in this interval.

To further showcase that point, this is the isopach for the thickness interval from the top of the Bone Spring Sand to the top of the First Bone, in other words, our entire Avalon interval. You can see it's very consistent across the whole section, so about 1000 feet, maybe 90 -- 90 -- 950, maybe 1050, but again, there is no stratigraphic pinchout.

So again, we understand this interval is correlative across the whole unit, the geologic property carrying across the whole unit, so we feel comfortable using this property as a reservoir model.

And then the final map is to address the shallow water hazard concern. So as I mentioned previously as shown in our cross-section, we are about 8100 feet below the top of the Rustler -- our wellbore and casing integrity, but again it's very consistent, 8100, 8200. And I also forgot to point out the fact that there is no drastic thickness changes, also shows there is no fault, even though one interval might be thick, there is no fault connecting up to the shallow water zones.

So again, this area is very structurally benign, which is one of the reasons we chose it. And then the interval itself has very low porosity and low perm which will keep the gas injected right near the wellbore and allow it to be produced over time.

Q. So in summary, based on the identification in the cross-section, that question about sealed above and below, in your opinion there is no chance of migration of this gas out of the zone to impact either zones above or below your target interval?

A. Correct.

Q. Again, based on the formations in your review, there is no geologic conduits or pathways by which the gas might migrate out of zone based on a fault or pinchout or any other kind of concern in the geology here?

A. Correct.

Q. Now, in your opinion, will the granting of this

application be in the best interest of conservation of resources, the prevention of waste and protection of correlative rights?

A. Yes.

Q. And in your opinion, will this project be able to be operated safely and without presenting a risk to human health, environment or to underground sources of drinking water or fresh water in the area?

A. Yes.

Q. And have you prepared or did you -- did you prepare or under your direction and supervision have someone prepare Exhibit Number 17?

A. Yes.

MR. RANKIN: At this time, Mr. Examiner, I would move the admission of Exhibit 17 into the record.

HEARING EXAMINER COSS: Exhibit 17 is so admitted.

(Exhibit 17 admitted.)

MR. RANKIN: No further questions, and we pass the witness for questioning by Examiners.

HEARING EXAMINER COSS: Examiner McClure?

EXAMINER McCLURE: I don't have very many questions.

The only question I have in regards to your defining layers above and below being a frac barrier, do you have stress fail, something along those lines, to clarify maybe more to the reason you believe they would qualify as such?

THE WITNESS: Yes. We have done multiple microseismic studies, so we are confident in those being frac barriers above and below, and I believe Carlos will address it a little bit more. But, yes, we are confident that those are frac barriers through multiple tests, as well as offset well tests monitoring production or even internal frac studies.

EXAMINER McCLURE: Do you have microseismic to confirm that?

THE WITNESS: Not in this specific area, but we have done studies across the Basin.

EXAMINER McCLURE: That's very good. Okay. The only other question I might have on the better cross-section you are going to provide, could you include headers on it as well?

THE WITNESS: Yes. They are very small on there, and I will make sure they expand. They didn't present well.

EXAMINER McCLURE: I think headers might be cut off on them, but I could be mistaken, it just didn't look like they are. But anyway, thank you. That's all the questions I have for this witness.

HEARING EXAMINER COSS: Just looking at it now, how thick is this interval that is that formation?

THE WITNESS: So the Avalon itself is about 1000 feet thick, but our injection interval -- and Mr. Sanko will show the wellbore diagram -- but it stayed fairly flat along that 9450 interval itself.

HEARING EXAMINER COSS: Okay.

THE WITNESS: Yes.

HEARING EXAMINER COSS: Do I have any other questions?

EXAMINER McCLURE: I can't answer that one.

HEARING EXAMINER COSS: Thanks, Mr. McClure. I guess you called it siliceous and it doesn't have any bearing, but I'm going to use a term Ms. Bennett taught me earlier. For my own edification, how siliceous is it?

THE WITNESS: So siliceous just means that it has a quartz content.

HEARING EXAMINER COSS: But then you called it clay rich?

THE WITNESS: So it has a high percentage of quartz and clay. So it's not completely clay rich. It's not 100 percent clay. It's not 100 percent sandstone. It's like a -- mostly clay rock with some percent of quartz, and it can also have some percent of carbonate in it, so it's just like a mixed clay system. So the highest percent would be clay content, but, yeah, it's going to have some -- some silt-size grains, so some quartz in there as well, as well as some carbonate, yeah.

HEARING EXAMINER COSS: Wonderful. Okay. So I don't have any other questions for you. Thank you.

THE WITNESS: Okay.

MR. RANKIN: With that, Mr. Examiner, we would ask that the witness be excused and be permitted to call our final witness of the day.

HEARING EXAMINER COSS: Ms. Hessert is excused. You may call your next witness.

DAVID CARLOS MACOSSAY SONKA

(Sworn, testified as follows:)

DIRECT EXAMINATION

BY MR. RANKIN:

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

A. My full name is David Carlos Macossay Sonka.

Q. By whom are you employed?

A. I'm employed by EOG Resources as a reservoir engineer.

Q. Have you previously testified before the Division?

A. I have not.

Q. Will you briefly review for the Examiners your relevant education and experience as a reservoir engineer?

A. Sure. In 2014 I began my career in oil and gas interning on the King Ranch, working wells targeting the sands. In 2015 I worked as a reservoir engineer interning on the Eagleford studying well interference. In 2016 I graduated from Texas A & M with a bachelor's of science in petroleum engineering, with a senior design focus on reservoir modeling.

Since that time I have been working full time for EOG Resources in the Delaware Basin, focus primarily on New Mexico.

Q. And your current obligation, current job duties and job description include oversight of the southeast part of New Mexico including the subject area for this proposed well project?

A. Yes.

Q. You are familiar with the application on this case?

A. Yes.

Q. Have you conducted a reservoir study of the proposed project area?

A. Yes.

MR. RANKIN: At this time I would tender Mr. Sonka as an expert in petroleum reservoir engineering.

HEARING EXAMINER COSS: So recognized.

MR. RANKIN: Thank you very much.

BY MR. RANKIN:

Q. Mr. Sonka, Ms. Hessert just reviewed her geologic assessment explaining why the Avalon or Leonard A shale and mudrock will serve as an effective containment for your proposed reinjection project.

Have you built off a geologic study, prepared a reservoir model to assess the feasibility of the reservoir for you project?

A. Yes.

Q. Are you prepared to review for the Examiners what you have done and how you constructed your model?

A. Yes.

Q. Let's do it. So let's first, before we do, I want to, for clarification, looking at Exhibit 4 in this packet, this was again the conditions that were requested by the Division.

You are going to be filling out the rest of the information requested by the Division under the heading on Page 1, Technical Information and Standards for Installation and Operation?

A. Yes.

Q. That would be Item Numbers II and III in terms of the reservoir modeling showing the net effect of your injection on the ultimate recovery of the reservoir?

A. Yes.

Q. Okay. And in addition, you will be also addressing on Page 2 the request by the Division to justify the maximum allowable surface pressure with a gradient greater than .14 psi per foot. Is that correct?

A. Yes.

Q. So those three things we'll be addressing today. Let's go ahead and start with the first, in reverse order, we'll take the issue under Item Number IX, which is justification of the maximum allowable surface injection pressure that you proposed, and the fact that it exceeds the gradient point .14 psi per foot.

So you prepared an exhibit that outlines your analysis on that topic. Is that marked as Exhibit Number 18?

A. It is.

Q. Will you review it for the Examiners?

A. Sure. So on the Exhibit 18 what we have are average parameters during the original stimulation treatment. Notably the ISIP and frac gradient. So to explain what an ISIP is, before we fracture the rock, we inject a small volume until we observe a pressure response that indicates the rock has just begun to crack. And then we shut down and observe the reclosure pressure of the fracture, and from that we can infer what pressure it took to initiate fracture.

And so a frac rating of .75 is very in line of what we have seen on a large number wells targeting this, and that's what we will be using as the frac propagation pressure for the zone.

Another thing to point out is, while we were fracking this well, of course we had a full column of water, and we subjected the casing surface pressure of 7786 pounds. Average sustained pressure is almost 6500 pounds.

Q. And so just to reiterate that what you are seeking or requesting is a maximum surface injection pressure of 3500 psi; is that correct?

A. Yes.

Q. And based on your what you just reviewed for the Examiners, how do you know that that maximum surface injection pressure is a safe surface injection pressure for this project and will not damage the reservoir?

A. So the way we tried to determine what is an absolute term was the propagation pressure was we multiplied the .75 frac gradient that was observed, times the true vertical depth of 9450, and the result of that multiplication is just over 7,000 pounds. Applying the 90 percent safety factor that the Division requested we are down to about 6300 pounds, and the 3500 pounds that we are asking for, plus column of gas .14 psi per foot puts you at approximately 4800 pounds, in other words, 2500 pounds below what we anticipate to be 90 percent of the frac propagation stress.

Q. So that's below even what the Division has identified as a limit for what they want to see the pressures in this zone?

A. Correct.

Q. Now, 2500 pounds, that's a gap between what you expect the downhole pressure to be and what your propagation fracture pressures are measured to be in the zone. Is that correct?

A. Correct.

Q. Now, tell me a little bit about how unlikely or how difficult it would be for EOG to, to reach that additional pressure that would result in propagation fractures in the zone under this proposed operation?

A. So to understand how much gas we would have to inject to propagate a fracture, we studied the amount of volume that had been removed at in situ conditions in the reservoir to result in the surface volume that we produced out of this well.

And we determined that if we were injecting gas at 3500 pounds of surface pressure, we would only be refilling just over 1 percent of the volume that had already been removed at the largest interruption of volumes that we've observed.

Of course to build pressure greater than that, that 1 percent would start to compress, and so the amount of gas we would have to produce would be several, several BCF to pack in all that gas and continue to build pressure. And the surface pressure we would require to break the rock would be such that we don't have a compressor in our Division that's capable of outputting that surface pressure. So there's -- it would be really, really difficult for us, even on purpose, to try and break any rock with gas.

Q. So just as an example, an estimate, how much gas or how much time would EOG need to inject in order to even approach that propagation fracture pressure limit?

A. At the peak rate we've observed, for our disruptions, if we injected at that for just over two months, we would have the -- continuously, we would have the amount of volume, but again we would lack the horsepower to pressure that up significantly enough to fracture the rock.

Q. So in light of that, is it your opinion that the 3500 pounds as the maximum allowable surface injection pressure is justified here in the circumstance?

A. That is my opinion, yes.

Q. Now, before we move into your modeling, I want to ask you an additional question that came up during prior testimony. And that was the question about whether you would be willing or able to implement or install a downhole

monitoring system in this well.

And I wanted to just ask if you would -- what is your opinion about the -- how well that kind of system would function in this environment at the downhole location here?

A. So as a reservoir engineer, we are always very interested in the bottom hole pressure, so we like to run real time gauges, but we've had very bad luck with the reliability. So typically what we run are memory gauges and use those to verify our correlation.

So of course putting any electrical component in a situation where it's going to be washed over by very high salinity water explains why there is such reliability issues. But we will show a little bit in the model what we think the resultant energy of the reservoir is after maximum volume of injection and how much fluid that can support. And EOG would be willing to confirm that model after injection by shooting a fluid level and verifying where the new fluid level was established once equilibrium is reached with additional pressure that is injected.

However, to support a full column of fluid, the well would need to be about 80 percent of its initial pressure. And like we said, injecting 1 percent of the volume that you've removed is not enough nor near enough to re-energize the reservoir such that it could support that much.

Q. So there's essentially numerous reasons, at least two reasons why it would be easier to prove it's unnecessary to include that equipment; number one, it's an environment that doesn't do well with electrical components, and they tend to not -- they tend to fail. And as a result, would EOG then have to shut in the well, pull the tubing in order to replace that equipment?

A. Depending on the method of conveyance, the most reliable one you would have to retrieve the tubing string and completely reinstall new tubing string, and you wouldn't be able to use the well for injection during that time.

Q. And the other reason you stated is as a physical matter, matter of physical fact that there is just not the ability for this reservoir to support a full column of fluid across the wellbore, is that right, based on the production history of the well?

A. The reservoir does not have sufficient energy to support a column of fluid and the additional energy caused by injecting gas does not add enough energy to make it to where it can support a column of fluid.

Q. Very good. So moving on from that issue, let's go on and talk about how you constructed a model to evaluate the reservoir in this case.

I'm going to turn to what's been marked in your exhibit packet as Exhibit 19, the first page of that

exhibit.

Would just review for the Examiners the components of this exhibit and what you did in the construction of this model?

A. Sure. So based on the geologic responses we see in the logs, the stratigraphy and all of those maps, we assign a 3-D grid space that we want to understand the properties of, and that's what these little griddings are.

So in the model this grid space is fully populated. I sliced away to where you could see the wellbore. So what these little grids are, are individual cells that assigned certain properties, assigned a pressure, a saturation, fluid components and everything like that. And permeability porosity, of course.

And then based on you know, Jenna's work, we were able to assign those, you know, what we assumed to be the initial proper properties to each of these layers, and then we have seven years of wellbore history. So the model will give us outputs, and we will make fine-tuning modifications to the completion parameters and to the geologic parameters until the model is matching very accurately what the well has done over it's lifetime in terms of production rate and pressures.

Q. So once you have established the model and it's components, what's the next step?

A. So the next step -- so this is a snippet through time at modern day -- approximately modern day of the pressure around the wellbore. So this is before any injection has been simulated, and you can see the area where the matrix has been drawn down, it's really well-confined near wellbore, and that's a function of the low permeability of the rock. It's really confined, and the boundary between the undrained and drained area has really high delta pressure, and that speaks to the really low permeability.

So what we are able to do from here is, one, continue to the run the model and come up with a baseline understanding for what we think the well will do indefinitely into the future with no injection. Two, we are able to make a new model with the exact same parameters and simulate alternating cycles of injection and production and then injection and production again and compare the results of the two.

And so that's how we were able to determine whether the -- what effect the injection process would have on the well, on the offset wells, and of course on the ultimate recovery of the well in terms of gas and oil. Another thing we were able to determine is the bottomhole pressure that we see after a cycle of injection and the pressure trend that we see through cycles of injection.

Q. For purposes of clarification for the record,

would you mind just highlighting what the colors mean on this second page of the exhibit so we understand what you are talking about?

A. Sure. So the orange cells that kind of go into red are the initial pressure of the reservoir, and it's increasing because it's getting deeper. The blue colors are regions where the pressure has decreased in the function of pushing fluids into the wellbore, so those are defined here. The little bit lighter blue towards the edges are just a little bit less efficient drawdown.

Q. What's the difference between the image on the left versus the image on the right?

A. The images are the exact same model at the exact same time. The difference is that certain layers have been excluded from this to allow a picture of the wellbore, and in that case that layer at the wellbore has been included to show the extent of the blue region which is the drawn down area.

Q. The point I think you are making is there is a strong almost immediate gradience between where the formation has been drawn down and where you encounter the original formation pressure; is that correct?

A. Yes. So we would expect that any injected gas would stop right at that boundary.

Q. That's because it's encountering essentially

negative formation pressure at that permeability barrier; is that right?

A. Correct.

Q. That's why you believe this rock in particular is a great zone for conducting this pilot project because it will stay within that area that is lower pressure as a result of production?

A. Correct.

Q. Okay. Very good. Now, what does this next page of your exhibit show?

A. These are outputs from the model in terms of the oil and gas rate in the lowest bottomhole pressure for the case where we started injecting. So on the X axis we have time. On the left axis in log rhythm scale, we have gas rate in solid red. The right axis in log rhythm scale we have oil rate in dashed blue, and then in linear we have the bottomhole pressure of the well.

And so the observation we want to make, at this red line we began simulating the cycles of injection and production. And so immediately after injection, the wellbore pressure is up from what it is today, but not up in any manner that would be able to support a significant column of fluid. This amount can support about 2500 feet of reservoir fluids, which would leave you 7000 feet of TVD approximately of low pressure gas.

And really notably on this chart is that the gas rate, oil rate in the well bottomhole pressure over a long period of time are continuing to decline which supports the idea that this well should be classified as a producer. We are still getting net production out of the well. We are still drawing down the well and approaching the ultimate life of the well.

Q. The point you are making about the repressurization during the production phase is that you would never be able to achieve a full column of fluid within the well at any point going forward?

A. Correct. So the -- at none of these points in the cycle would be able to achieve a full column. That would have been right back here when the well was initially turned on would be the pressure required.

Q. Very good. Anything more on this particular exhibit?

A. No.

Q. Let's look at your last page of this exhibit and will you just review what the purpose of this exhibit is and what it shows?

A. So this again is an output from the model showing the injection case. We are showing the month -- or the yearly trends of gas and oil, and so the most rigorous way to compare the impact was comparing against the baseline, which we did, and that's what gave us the confidence to say we are not expecting any impact on the ultimate recovery.

But this kind of helps illustrate that the trends are very much in line with and without injection from what we would expect from a well this age.

Q. Now, I think that all covers the issues identified by the Division to demonstrate that it will not migrate from the formation, interfere with other wells, or affect underground sources of drinking water under Item Number 2. Is that fair to state?

A. Yes.

Q. Is it your opinion that in light of the nature of the rock in your modeling, the reservoir, that it's not going to leave the near bore zone -- the near wellbore zone, so it won't interfere with other wells, nor will it affect underground sources of drinking water?

A. Yes. The multi-well model was actually done as well to confirm that the offset wells would not experience any effects positive or negative.

Q. So in addition to any single-well modeling, you did a multi-well model to expand your analysis, assessment about the reservoir using the same data, and it shows there is no interaction between the neighboring wells?

A. That's correct.

Q. Okay. Now, the last part of your testimony here,

Item Number III, under the topic to provide a technical analysis to evaluate whether the injected gas net will have a net positive, neutral, or negative effect on the pool's ultimate recovery. Have you conducted that analysis as well?

A. Yes.

Q. Could you describe what your assessment was?

A. The determination was that it would have a negligibly positive effect on the pool's ultimate recovery in terms of oil and gas.

Q. Now, Mr. Sonka, in your opinion, will the granting of this application be in the interest of conservation of resources, prevention of waste and protection of correlative rights?

A. Yes.

Q. In your opinion, will this pilot project, can it be operated safely to prevent impacts or harm or risk to human health and the environment and to fresh water sources?

A. Yes, it can be done safely.

MR. RANKIN: At this time, Mr. Examiner, I would move the admission of Exhibits 18 and 19 into the record.

HEARING EXAMINER COSS: Exhibits 18 and 19 are so admitted.

(Exhibits 18 and 19 admitted.)

MR. RANKIN: No further questions. Pass the witness.

HEARING EXAMINER COSS: Examiner McClure?

EXAMINER McCLURE: I have a few questions. Can we go to your identification of the fractured gradient, your initial tests that were conducted, and I'm assuming they were the standard step rate test; is that correct?

THE WITNESS: No. So we, in the modern era we do DFIT analysis.

EXAMINER McCLURE: Sorry, I'm with you. Okay, so you have a DFIT analysis?

THE WITNESS: Right. However, in 2011 we were not collecting high enough resolution data to do an accurate DFIT. But studying the relationship of DFITs to initial frac gradience, we feel pretty comfortable that it's representing it well enough.

EXAMINER McCLURE: Now, as far as providing us then with what you used to come up with that number, does EOG have a problem with that?

THE WITNESS: What we used to do come up with the number was hydrostatic gradient plus the initial shut-in pressure divided by the TVD. So I think that the data is here, but we can provide additional data if you guys request it, certainly.

EXAMINER McCLURE: Would you say that once more?

THE WITNESS: The way we determined the frac gradient is by adding initial shut-in pressure you see in Column 3 of Exhibit 18.

EXAMINER McCLURE: Okay. Go ahead.

THE WITNESS: To a column of hydrostatic fluid.

EXAMINER McCLURE: And you were just -- and you are assuming that the fracture closure pressure then? Is that what we are getting from that? Is that your thought process then?

THE WITNESS: Right. When you take an ISIP, you pump a little volume and shut your pumps. So of course when you change the flow rate of a viscous fluid, you observe a water hammer, so we let the water hammer resolve, and then is proprietary interpretation shortly thereafter that backs out what we think the initial fracture gradient is.

EXAMINER McCLURE: Okay. So depending on how the math works for your -- your requested surface pressure, we may end up requiring something, they're not regulations -- require step rate test to -- or equivalent -- to allow a fracture gradient higher than the .65. Having said that, that may not be the case here depending on I don't think your max surface pressure reaches that.

THE WITNESS: No, sir.

EXAMINER McCLURE: I don't have a calculator or anything to look at that.

The other question I have for you, you have an average pressure and max pressure here for when the frac was occurring. As far as your barrels per minute, anything along those lines, in order to actually compute a downhole pressure, I don't see anything that would be required to actually make these numbers themselves usable, I guess. What's your thoughts towards that?

THE WITNESS: Right. Obviously EOG has the pump rate pressures, but we felt that, you know, that was a little bit proprietary, so we can can submit them under sort of seal process if needed.

EXAMINER McCLURE: It may not be necessary. I was just asking because you had supplied these numbers, but you know, without considering our dynamic pressure it's hard to really use them for anything for this purpose. But they are probably -- I doubt we need the support, that was just a question I had.

Now, this well has been in production for seven years; is that correct?

THE WITNESS: Yes.

EXAMINER McCLURE: Okay. Now, the number that you have been stating, I don't know how many billions cubic feet you said that's come out of this well. I see it here and there, but are you saying we are looking at one percent of that? I guess, is there any consideration to the fact that you want to put the 1 percent back in in a far shorter time than at seven years?

I mean, that stated, this is a low permeability, low porosity formation, so is that like one month of injection you are going to be able to get it shoved out to that point? Was there any consideration in regards to your modeling -- I would presume that it takes into account with regards to the pressure and stuff?

THE WITNESS: So the model injects 15 million in one month, so that's kind of the typical interruption frequency and rate and volume that we would expect, but in terms of frictional components, that will all be spent before you really see the formation in terms going down the casing and tubing and then the -- especially through the perforations. So we think that that just adds to the conservativeness of all the stuff we've presented today.

EXAMINER McCLURE: Oh, I apologize, I wasn't -- I wasn't referring to that. I was referring to the fact that it takes time to get to -- to get the volume back into the formation. It's not going to take it that fast. I don't think you are going to have any restriction in regards to the pressure loss within your tubing or within your perf, which I would presume without running the numbers.

THE WITNESS: Sure. So the model suggested it's possible. Certainly we would want to confirm that with field data that we can even inject that, and that's really one of the reasons we selected the max surface pressure we did because we feel that will enable us to, but definitely after the results of the pilot, we will have to have more conversation, about you know, what rate and what volume we are able to get and how that looks going forward.

EXAMINER McCLURE: I'm looking forward to that process if we get there.

Now, you mentioned -- now, I'm complete -- I'll just put a comment out there. I understand where you are coming from as far as tranfusion reliability. Obviously there are issues with it. You mentioned potentially shooting fluid levels. Your thought process would be after an injection period, shoot a fluid level with like an echo gun, something along those lines, and then submit that in a sundry at that time, or what is your thoughts in regards to that?

THE WITNESS: Yes, sir. If granted approval, we would obviously try quite a few different combinations of volumes and rates, and then maybe the top five combinations that would tend to re-energize the reservoir and the very last one we do as well, we would shoot a fluid level, and we use echo meters, and I think we would be willing to submit those to the Division. I can't authorize the submission, but I would anticipate EOG would be willing to share all that with the Division on a sealed basis.

EXAMINER McCLURE: I would anticipate it as well, but obviously we are talking -- now, you mentioned that you believe this will have a net positive effect on the recovery. I guess, what was your thoughts in regards to why you thought net positive?

THE WITNESS: Really it was a neutral effect. The change was extremely small to the point where I would consider it, you know, within the error on the model, but it was a slight positive effect. And that's probably mostly due to re-adding energy, driving.

So in a depletion drive when you are re-adding energy, you are helping to drive in new molecules that were previously passed over perhaps.

EXAMINER McCLURE: Okay, I'm with you. I guess what my question would be, and it's related to an earlier question I had with regards to paraffin, was there any thoughts in regards to when you are taking your processed gas, like come out of similar reservoirs to this -- it's leaner than the gas that's coming out of this reservoir, has any thought been put towards whether that will cause your heavier oil to drop out or paraffin to form within your reservoir and cause permeability issues or your permeability to decline? What your thoughts for that?

THE WITNESS: So we haven't observed anything like that. The addition of leaner things should, I think, tend to make your heavier components come in gas more so than a heavier stream, but typically what we observe is when you cool the reservoirs is when you have paraffin issues, and this gas would not be pooling the reservoir, so we don't anticipate any issues with paraffin dropping out in the reservoir or wellbore.

EXAMINER McCLURE: But you have considered it would be my question?

THE WITNESS: We have considered it, and we don't think it's a significant risk.

EXAMINER McCLURE: Okay. That's kind of what I was looking for. I believe that's all the questions I had for you. Thank you.

THE WITNESS: Sure.

HEARING EXAMINER COSS: Carlos, nice to see you again. Thank you for your presentation and the modeling you performed here. Good to see.

I don't really have many substantive questions here, but one of the them would be, what's the grid size? What's the -- how big are your grids?

THE WITNESS: We would be willing to share that with the Division on a sealed basis. So the gridding, especially as it relates to the draw down, how far we think the draw down is extending, we consider that to be confidential business information, so --

HEARING EXAMINER COSS: I see. But you feel it's an adequate size to capture the fracs and the gas injection of this well?

THE WITNESS: In terms of the resolution of the model, yes. Yes, certainly the grids are a size to where the model ran very slowly.

HEARING EXAMINER COSS: Very well. And so having -- you're not -- how far down this horizontal wellbore are you envisioning the gas, the injected gas traveling?

THE WITNESS: In terms of laterally extended?

HEARING EXAMINER COSS: Uh-huh.

THE WITNESS: That's really a dynamic deal that will be a function of the rate and how many perforations are open in the heel and how many garbage is in the perforations, and then, ultimately, you know, how well the formation is taking it.

So it's -- it's really difficult to say other than, you know, probably every portion of the lateral will take some gas, and the heel will take the most, and beyond that it's -- it's really difficult to speculate.

HEARING EXAMINER COSS: I see. I lost my questions. That's all my questions.

MR. AMES: That was your last question then?

HEARING EXAMINER COSS: Right.

MR. RANKIN: With that, Mr. Examiner, I have no further questions at this time, and I ask that Case Number 20965 be taken under advisement by the Division, and we will, subject to our provision of the confidential information, the cement bond log, electronic version of the cross-sections and the calculations that were requested, other than that, I think we have provided everything that the Division has requested in its October 24, 2019 letter, and upon submission of that additional information, we ask that the Division take this case under advisement.

HEARING EXAMINER COSS: Case Number 20965 will be taken under advisement.

MR. RANKIN: Thank you very much.

HEARING EXAMINER COSS: With that, we will adjourn.

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

REPORTER'S CERTIFICATE

I, IRENE DELGADO, New Mexico Certified Court Reporter, CCR 253, do hereby certify that I reported the foregoing proceedings in stenographic shorthand and that the foregoing pages are a true and correct transcript of those proceedings that were reduced to printed form by me to the best of my ability.

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

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

Dated this 12th day of December 2019.

____
Irene Delgado, NMCCR 253
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