STATE OF NEW MEXICO

ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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

CASE NO. 21567

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

THURSDAY, 2020

This matter came on for hearing before the New Mexico Oil Conservation Division, William Brancard, Hearing Examiner, Dylan Rose-Coss, Technical Examiner, Dean McClure, Technical Examiner, via Webex Virtual Meeting Platform

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C O N T E N T S

I N D E X OF E X H I B I T S

(Time Noted 11:10 a.m.)

HEARING EXAMINER Brancard: So I'm calling Case 21567, EOG Resources.

Holland & Hart, I believe.

Do we have anyone there? Ms. Luck, I think you're speaking, and you're muted.

MS. LUCK: Okay. There we go.

Good morning, Mr. Examiner. Kaitlyn Luck with the Santa Fe office of Holland & Hart on behalf of the Applicant in this case, EOG Resources, Inc.

HEARING EXAMINER BRANCARD: Okay. And do we have any other entries of appearance or interested persons for this event here, Case 21567?

MR. SAYER: Mr. Examiner, this is Matthias Sayer entering an appearance on behalf of NGL Energy.

HEARING EXAMINER BRANCARD: Are you entering it here today or have you entered it before?

MR. SAYER: Entering it just today. We just received Notice two days ago, and so we are a little bit behind the ball.

Just today.

HEARING EXAMINER BRANCARD: Okay. Do you have any witnesses or anything to put on today or are you --

MR. SAYER: No. Apology.

Mr. Examiner, no intention to present any testimony of any kind, just entering an appearance

HEARING EXAMINER BRANCARD: Okay. Excellent.

All right. We'll accept that entry of appearance, and you're excused for being late.

So where are we on this case?

Ms. Luck?

MS. LUCK: Thank you. And so EOG submitted exhibits on Tuesday and we are prepared to proceed with the testimony of our first witness.

(Note: Reporter inquiry re audio quality.)

HEARING EXAMINER BRANCARD: I would agree. Thank you, Ms. Macfarlane.

(Note: Discussion off the record.)

HEARING EXAMINER BRANCARD: All right.

Ms. Luck, tell us how you want to proceed today.

MS. LUCK: Thank you. We have five witnesses to present today, and so I would like to start by calling the first witness, Davis Lunsford, who would need to sworn at this point, although we can also have all of our witnesses sworn at once, if that's what the court reporter would prefer.

HEARING EXAMINER BRANCARD: Could you list your witnesses, please.

MS. LUCK: Yes. So we have Davis Lunsford, Carlos Sonka, Jenna Hessler (sic), Brice Letcher, and Matt Smith.

HEARING EXAMINER BRANCARD: Okay. We'll get the proper spellings when they first step up to the stand.

Are they all available for being sworn in right now?

MS. LUCK: Yes. And they can all stand.

(Note: Whereupon the above-mentioned witnesses were duly sworn.

HEARING EXAMINER BRANCARD: I don't know, Ms. Luck, if you want to summarize your case today before you start or how you want to do this.

MS. LUCK: I had not planned on giving an opening statement. I would defer to the witnesses providing their testimony about what EOG's requests are in this case, and then I'd like to summarize at the end EOG's requests in this case. And we would offer to provide a written summary if the Division would like it, but I would prefer to do a closing just wrapping everything up at the end.

HEARING EXAMINER BRANCARD: Is that okay?

EXAMINER ROSE-COSS: That's fine.

EXAMINER McCLURE: Good for me.

HEARING EXAMINER BRANCARD: Please proceed.

MS. LUCK: Thank you.

So with that I would call the first witness, Davis Lunsford.

DAVIS LUNSFORD,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. LUCK:

Q. Please state your name for the record.

A. Davis Lunsford.

Q. By whom are you employed and in what capacity?

A. I'm a senior facilities engineer for EOG Resources.

Q. Have you also previously testified before this Division?

A. I have.

Q. Can you previously state your education and experience.

A. Yes. I have a Bachelor's of Science in mechanical engineering from Baylor University, and since graduation I have worked for EOG Resources in a variety of technical engineering roles, primarily in the facility & Pipeline Department.

Q. Are you familiar with the Application filed in this case?

A. I am.

MS. LUCK: So that with that I would tender Mr.

Lunsford as an expert witness in facilities engineering.

HEARING EXAMINER BRANCARD: Are there any comments or objections?

(Note: No response.)

Okay. Mr. Lunsford is qualified as an expert.

Please proceed. And again, speak clearly and loudly. Thank you.

MS. LUCK: Thanks.

Just to start off with an introduction, EOG previously sought approval for a gas capture pilot project targeting the Avalon-Leonard Shale interval of the Bone Spring Formation in Case No. 20965, and that was back on December 12th of 2019.

And then the Division entered Order No. R-21061 on January 31st, 2020 approving that original case, and so we will talk about the Caballo pilot project in this case.

Q. Mr. Lunsford are you familiar with that case?

A. Yes, I am.

Q. Did you testify in that case, as well?

A. Yes.

Q. So could you start off by explaining to us how the Caballo project went.

A. Yes, ma'am. The Caballo project, the purpose of that was to pilot this closed loop gas capture before we expanded it fieldwide on more wells. And so that pilot project consisted of injecting various rates and volumes of gas to determine the injectivity of the well and at what pressures -- what pressures would be required to inject those rates and volumes, and also reproducing the well; and determining the recovery of the injected gas and the effect on that well and any neighboring wells.

So I think that the shortest conclusion of that test is it was a fantastic pilot. We achieved the volumes and rates that we hoped to during the injection. We saw minimal impact either to the parent well or to any offset, and fantastic gas recovery, uhm, when we reproduced the well.

And then in addition to the technical aspect of the project that we were piloting, it helped us to define the information flow and the production accounting, as well.

Q. Okay. And then in the Caballo case, that was the model applied to the Application in this case?

A. That's right. So as we discussed, I believe last hearing, the purpose of that was to define the project so that we could go in on a wider basis, and that's what we're here today discussing.

Q. Okay. And so in this case EOG is seeking

approval of injection into five wells; is that right?

A. That's right.

Q. So let's turn to EOG Exhibit 1 and let me know what this exhibit shows.

A. Yes. So this exhibit shows the location of the five wells, the sections that they are located in. Those five wells are in the southern part of --

EXAMINER ROSE-COSS: One second, Davis. I'm sorry. I believe I've made you a presenter, Ms. Luck. Do you have the ability to share your screen?

MS. LUCK: Yeah, I can share the exhibits.

EXAMINER ROSE-COSS: That might help everyone out.

Here we go. Thank you, Ms. Luck.

MS. LUCK: Yeah.

And I have... okay.

EXAMINER ROSE-COSS: Go ahead, Mr. Lunsford.

MS. LUCK: Sorry. This is Exhibit 1.

A. Okay. Exhibit 1 shows the location of the section for the wells in question in the southern part of Lea County. Those wells are the Black Bear 36 State 04, the Brown Bear 36 State No. 1, the Ophelia 27 No. 1 and the Hawk 25 Fed No. 1 and No. 2.

And I'll take this opportunity to point out that these wells were selected according to the same criteria that we used for the Caballo Pilot Project, and so these wells are all similar in terms of the reservoir and geologic criteria. They are all actually from the same producing interval as the original Caballo, and they all have similar production rates, production pressures, and they are all of approximately the same vintage.

Q. And so what is EOG's goal with this project?

A. The goal of the project is to temporarily inject into these wells during periods of market interruptions, and then when those market interruptions are over to reproduce the gas through the existing production facilities.

Q. And you mentioned that these wells have analogous geologic and reservoir properties to the Caballo project. Is that correct?

A. That's correct.

Q. And so what is EOG seeking differently in this application from the original application?

A. Well, I believe that the original application was really focused on defining the project from a pilot perspective, and our intent with these wells is to make the project operational so that in the event of a market interruption we would be ready to inject gas into these wells to prevent either flaring or the shutting in of wells in the area.

Q. And this project, like you said, is based on the results of the Caballo and how all that turned out?

A. That's right.

Q. So at this point EOG's plan is to only inject small volumes for short periods of time in these wells?

A. That's right. If these wells are ready to inject during periods of market interruption, those interruptions are usually brief, on the order of hours to a maximum of a few days, and they are a minimum amount of time in the life of the well.

Q. Now, turning to EOG Exhibit 2, can you explain what this exhibit shows?

A. I can. This exhibit shows EOG's infrastructure systems. And I'll walk through the exhibit beginning with what's really in the middle of the page, I guess the top left portion of the diagram, but that would be the production facilities that are shown and EOG's gas gathering system.

So their upfield production facilities supply gas to EOG, to an EOG-owned, gas-gathering system, and that gas-gathering system is shown in red.

Gas to issue (phonetic) in the gas-gathering system to a compressor station which is shown on the right side of the exhibit, and that compressor station exists to supply to third-party purchasers.

In terms -- any interruption on this system or further downstream blocks the flow of gas and requires EOG to either flare or shut in wells, and so the answer to those market interruptions, what we call closed loop gas capture, is shown beginning with the blue-grey pipeline leaving the compressor station.

So in the event of a third-party interruption, gas would be supplied through the blue-grey pipeline to a nearby well. It would be injected into that nearby well while the well is shut in, and then when the third-party interruption is over the gas would be reproduced through the existing production facility and introduced back into the gathering system and then on to market from there.

So I'll also point out that for all the wells in question in this hearing, they share a gas-gathering system. And so that's important. For instance, the gas composition that would be injected into any one of these wells will be fairly common across all of them.

Q. Okay. And so again I think you mentioned it, but why does EOG want to inject gas?

A. Right. Because an interruption on any part of this system requires us to flare or shut in wells, we've improved the reliability of the EOG-owned portions, the EOG gas-gathering system, the compressor station to the point that the largest source of interruptions is now third-party market. So the goal with this project is reduce our dependence on their run time and have another option so that we can increase our gas capture rate.

EOG's gas capture is currently above 99 percent, and that's a fact that we're proud of. And so as we look to how do we increase it still further, this project is in response to the third-party interruptions, and we think it will be a big part of how we continue to increase that gas capture rate.

Q. Okay. So now we will turn to Exhibit 3, and can you explain what this exhibit shows?

A. Yes. This exhibit is very similar to Exhibit 2, but it does highlight that EOG has two different types of compressor stations. The first which I mentioned earlier exists to supply gas to a third-party market. In addition, EOG has what we call localized gas lift stations or LGLs, and that localized gas lift station or LGL is shown here. And those compressor stations, they exist to supply gas to nearby wells for the purpose of gas lift.

So I wanted to highlight that distinction, because in the original Caballo pilot we used a localized gas lift station to supply gas to the well, and in the future that would also be a potential for us to supply gas for the purpose of closed loop gas capture from an LGL in addition to sales (phonetic) station.

Q. Okay. So initially before the original Caballo Pilot Project did EOG meet with and discuss the concept with the Division?

A. That's right. We discussed the concept really because this project didn't fall within existing regulations for existing types of injection.

Q. And as a result of that meeting did the Division Director provide EOG a letter outlining conditions that the Division wanted EOG to meet in order to consider approving a pilot project like in the original case?

A. That's correct.

Q. Is that exhibit marked as Exhibit 4 in the packet?

A. It is.

Q. So we will turn to that letter now.

So I believe you stated at the hearing on the original application if the pilot project was viable that EOG would seek similar projects at other wells in New Mexico. So based on the results of the initial pilot project, like we mentioned EOG is seeking approval of a second expanded project within the same interval?

A. That's correct.

Q. And so you mentioned previously that this project will be comprised of one injection well?

A. The five wells that I reviewed: The Black Bear 36, 04; the Brown Bear 36 No. 1; the Ophelia 27, No. 1; the Hawk 25 Fed No. 1 and 2.

Q. And there were two other wells originally included in this Application?

A. That's correct.

Q. And since this Application was filed EOG has decided to not seek approval of those two wells at this time?

A. That's correct.

Q. And later witnesses will discuss that.

A. Yes.

Q. Okay. So what is EOG's proposed timeline to implement this project?

A. Our timeline for implementation is that as soon as possible upon regulatory approval we are ready to install the necessary equipment and implement the project upon approval.

Q. And will EOG report the findings of the project as required by the Division.

A. We will. We will periodically report all relevant data.

Q. And did EOG also meet with other interested

agencies?

A. Yes. We met with the State Land Office, as well as the BLM, concerning the wells where there was federal interests, and the project has their endorsement.

Q. So now turn back to Exhibit 4.

Your area of expertise includes oversight and management of these facilities?

A. That's right.

Q. So you have already addressed what is under Bullet Point 1, Project Description, and so you're also going to provide information about monitoring and reporting, corrective action and reporting, right?

A. Yes.

Q. And then EOG has other witnesses here today to address the other conditions in Exhibit 4.

A. That's right.

Q. So let's discuss EOG's plans for monitoring injection. How does EOG's plan propose to monitor these wells?

A. Similar to the pilot project, all relevant data is already being brought into EOG's data system, which exists to transmit data from devices in the field for the purposes of storage and monitoring that information.

Q. And will there be equipment like an automatic shut-off or shut-down valve that prevents the surface

pressure from exceeding the maximum allowable?

A. There will. There will be multiple layers of protection.

Q. And I'd like to just briefly turn back to Exhibit 2 and see if you can point out on this map where the locations would be.

A. Okay. Yes. So as I mentioned, we will bring in relevant data, but just to explain what that data is and where that data is, from the compressor station we'll be collecting both pressures, temperatures and rates, as well as gas composition. And then of course from the injection meter we'll get injection rates and pressure.

We'll also collect casing and tubing pressures on the subject well during and after injection, as well as on the offset wells.

And from the production facility we will collect production rates, oil, gas and water, and we will also be, of course, collecting production rates on offset wells, as well.

Q. Thank you. And so in terms of this data that you're collecting, will EOG also submit a C-115 Form reporting the total production injection volume, pressures, and dates of operations?

A. Yes.

Q. And then turning to Corrective Action, what

plans did EOG have in place to respond to potential environmental problems that might arise?

A. So we don't expect engineering or environmental problems associated with this project, we have multiple levels of safeguards, but for all of EOG's operations, we have Standard Operating Procedures that direct how we respond to environmental or engineering emergencies, and those procedures are reinforced through safety training throughout the year, and they can be implemented either from the field level for folks in the field or from EOG's 24/7 control room.

Q. Okay. And then turning to the Project Reporting, uhm, the letter indicates a project report. So what is EOG requesting in this case?

A. After the Caballo pilot project we submitted all our findings for the pilot, and in the future, as we expose this wells across the field, it would be more appropriate to submit periodic reporting, as we discussed.

Q. And so I think that that looks like what I have for you.

Were Exhibits 1 through 3 prepared by you and compiled under your direction and supervision and do they consist of EOG's business records?

A. Yes.

MS. LUCK: So with that I would move the

admission of Exhibits 1 through 4, and then pass this witness for any questions from the examiners.

EXAMINER ROSE-COSS: You're muted, Bill, if you're trying to talk.

HEARING EXAMINER BRANCARD: Okay. Is there any objections to the exhibits?

Hearing none, those exhibits that were offered, 1 through 4, are admitted.

Questions from the examiners?

EXAMINER ROSE-COSS: Uhm, I can begin. I know Dean will have some questions for you, Mr. Lunsford, but nice to see you again.

THE WITNESS: You, as well.

EXAMINER ROSE-COSS: It's been the whole pandemic since I've last seen you all.

We have reviewed and made comments on the Caballo Pilot Project as it's been called. Unfortunately, you know, we haven't been able to speak with you much or at all about that, so that's a regrettable situation.

But good to see you again here for this.

CROSS EXAMINATION

BY EXAMINER ROSE-COSS:

Q. I suppose one of my questions is: So you-all are envisioning it's going to be similar parameters for the wells that you're proposing today that occurred in the

Caballo, but this is expected to be live.

What kind of time scale were you hoping that this pilot project would be issued for, this project would be authorized for?

A. As far as before implementation or what the duration of the Order would be?

Q. Duration of the Order.

A. We seek your guidance there, but we see this as a continuing project. So as long as there are third-party interruptions we'll want the option of responding to them using closed loop gas CAPTURE.

So whatever the duration is there, it might be something that we would review, you know, as needed.

Q. Sure. No, of course.

And, you know, the Division does appreciate EOG's efforts towards projects like this, that's for certain.

Could you describe for me again the difference in terms of how the gas will be captured and routed in this project versus the Caballo project?

A. Yes. If you will pull up Exhibit 3.

Okay. So for the purposes of the pilot project our goal is to approve it and define it from a technical standpoint, a regulatory standpoint, so we used what we call a localized gas lift station, because that localized the gas lift station already had a pipeline to the Caballo well for the purposes of gas lift, so we could use that existing pipeline, existing infrastructure to supply the gas from a compressor station to the subject well.

In the future we will primarily move gas from a sealed compressor station to the subject wells, which will require the installation of a new pipeline.

So that's really the key distinction between a pilot test and the wider implementation that we are discussing today is we will lay a pipeline from a sales compressor station to the subject well, and that would be new infrastructure costs that we wanted to avoid on the Caballo.

The reason that we will primarily use that sales station instead of an LGL station is, again, they exist for different purposes. So to throw numbers into an example, if both a sales station and an LGL station are moving a rate of 50 million and we have a market disruption to the tune of, say, 30 million so that the market can no longer take our gas, the 50 million that the LGL was moving is really still needed to support the production of the wells through gas lift, but the sales compressor station now has excess compression; it was capable of moving 50 million, the markets are only taking

30. So we'll use that delta to keep those compressors running at the sales station and inject in the nearby wells.

So that was a lengthy explanation but the key is we will be installing the pipeline from the sales compressor station to the subject wells, and that will be the primary way we inject for closed loop gas capture.

Does that make sense?

Q. Yes, I believe I'm following you.

So when -- I heard that you-all were ready to go, but by "ready" you mean you're ready to begin constructing a pipeline.

A. We're ready to begin construction, that's correct.

Q. Okay. And I guess I'm not following, in terms of the documents submitted as exhibits here, where the compression stations are in relationship to the wells, and whether or not all of the wells are on a similar pipeline. Like, how far are these wells from the compressor station?

A. So on a single gas-gathering pipeline we have multiple compressor stations. And each of the wells in question is as near as we could get them to a sales compressor station.

So for each of those wells the distance between the sales compressor station and the well in question is -- I -- it varies, but it's less than a mile on average, and the entire gas-gathering system stretches out over several miles.

So on a single gas-gathering station or gas-gathering system there's multiple compressor stations feeding these wells that we have.

Q. Okay. Would EOG be able to provide some plans and diagrams and explanations of --

A. That probably would be a simpler way to communicate it.

Q. Okay. Perfect. I think that would help us out.

I mean, how far would you say away these wells are from one another? It doesn't seem like they might be that proximal.

THE WITNESS: Maybe Exhibit 1 could give us a reference.

MS. LUCK: Yeah. Okay.

A. Yes. So you can see that the sections in question here -- I mean, you can see the section blocks on there -- to determine how far away from each other they are, approximately.

And the two Hawk wells and the two bear Wells, the Brown Bear and the Black Bear, are close to each other. And we've done that really just for operational simplicity and redundancy so that a single compressor station could deliver gas to either of the Hawk wells or either of the Bear wells, if needed, although I anticipate that we will inject primarily into one or the other.

Q. So am I mistaken in thinking that those are probably more or less seven miles apart? How much area would one compressor station cover?

A. One compressor station would cover an area of several square miles.

Q. So is it my understanding then from looking at this that -- or what you're telling me is the Hawk and the Bear, you know the two Hawk wells and the two Bear wells would serve one compressor station and be in between them?

A. The Hawk, the two Hawk wells would serve one compressor station, and the two Bear wells will serve one compressor station.

And we have some exhibits later on that other witnesses will cover that will show you where those wellbores are at a little bit more accurately.

EXAMINER ROSE-COSS: Okay. And then I feel like I'm stepping on Dean's toes here a lit bit.

EXAMINER McCLURE: That's okay. Keep going, man.

EXAMINER ROSE-COSS: He might have a similar line of questions for you.

Q. So are these all considered one field or these are different fields?

A. This would be considered one field, all in one gas-gathering system.

Q. Oh, okay. Well, I suppose I need to be refreshed on how to define a field that's based on a gas-gathering system, because I would think maybe that's not my conception of it.

A. We -- so all of these are in what we call our Red Hills area, our Red Hills fields.

Q. Okay. And all of the -- all of the wells across that expanse are kind of Avalon Bone Spring?

A. Uhm, they are -- we do have pretty consistent development across the Avalon Bone Spring in this field, and we also have lower development in the Wolfcamp.

Q. Okay. And is there going to be a witness coming up that's going to be speaking about kind of the anticipated volumes and durations and frequencies that we should expect?

A. I can speak to that a little bit.

So the way that we've identified the expected volumes and durations are we look at what kind of third-party interruptions we see commonly. And so those occur -- of course it's unpredictable, so I usually just say a minority of the time in the life of the well. We may go weeks without interruptions, we may go months without interruptions, or we may have a spell where maybe we may have two in a series of a couple of days. But we it on a wide-enough time scale and look at an average. It's a pretty small minority of the time that we are actually trying to respond to a market interruption.

When those market interruptions happen they usually last anywhere from a few hours to a maximum of a few days. So a maximum of two or three days would be the duration of injection, and more commonly it would be on the time scale of hours.

The rates that we typically would need to inject because we don't have another home for 'em, they were going to a third party and now that third party has gone down, those rates are usually anywhere from a few million standard cubic feet a day to a maximum of 10 to 15 million standard cubic feet per day.

So if you look at the total volume injected during an interruption, it's usually a few million to a maximum of 15 or 20 million would be the volume of injection during a typical market outage.

EXAMINER ROSE-COSS: Okay. Well, thanks for those answers, then.

And I feel like what I'm going to, uh -- what would help me -- I know that will be in the record now, but will help Dean and I writing the Order going forward, I think that I'll ask that you could submit a more detailed map of these well locations, and have displayed their relationship to the pipeline. Like, have, you know, "the fields" that -- you know, EOG's wells. You know, these wells kind of highlighted within those fields, the pipelines running through the fields, the compressor stations marked, the proposed pipelines that EOG would like to build from the compressor stations to these wells. Uh, some sort of description of the overall pipeline, so that -- and I guess I could ask, while I'm going through this: Has EOG received the updated guidance letter that the OCD made for projects like this?

A.   Yes.

Q.   Okay.

MS. LUCK: Excuse me. Sorry to interrupt, but it's our understanding at this point that that guidance document is still a draft. Is that correct, or is there a more final version that's been reviewed?

EXAMINER ROSE-COSS: Well, I believe it's a draft, and that's kind of the way we would like to move -- the information that we would like to move forward with but it's a draft in the sense that we would like maybe some feedback from EOG, and other operators potentially, and that we would like to be able to continue to amend it going forward. But as it stands now it's kind of still that guidance document OCD would like to be acting from.

So...

MS. LUCK: It's (inaudible).

EXAMINER ROSE-COSS: Sure. Sure. We hadn't spoken about it until we are live on the record now.

So one of the requests within that is to -- that all of the pipelines, all the wells are within like a similar gas-gathering line. So, uh -- hopefully I'm saying that right, Dean.

So this figure could include some description or verification that they are all kind of interrelated.

And I believe that's all I would like to see from that figure.

I'd like additional kind of graphs or charts or summary of the volumes that these wells might be expecting to see, sort of a definition of what low, medium, high might be, and the kind of volumes to be expected.

On a -- you know, I know it said it in the earlier document, your gas capture kind of summary, you know, this was low, medium. Maybe some analysis of what those volumes might be on a week or month or a year.

And, uhm, what else did I want to say?

Yeah. And, uh, that's it.

So --and I believe the Caballo exhibits touch on some of that, but if I could -- if we could have that again within these exhibits.

THE WITNESS: We can provide that.

EXAMINER ROSE-COSS: Thank you.

And that's all the questions I have, or requests, and I'll pass it to Dean at this point.

CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. Okay. I guess my first and foremost question is you did answer in the affirmative that you have seen this draft of the guidance document that I believe was emailed to EOG on the 17th of last month, I believe. Is that correct, and you have had a chance to review that?

A. That's correct.

Q. Okay. I guess is there anything on that in regards to reporting that you see problematic --

A. No.

Q. -- that EOG would not be able to provide, or what are your thoughts in regards to that.

MS. LUCK: Sorry to interrupt, but I would like to say that EOG has provided comments on that Draft Letter, and we would like for additional comments that were submitted on the letter to stand.

But I'll let Mr. Lunsford answer any questions that the Division might have about the letter or, anything about the (inaudible) in the letter.

A. No, I'd echo that statement, especially because EOG took the approach of having a real multidisciplinary team reading that letter, from reservoir to geology to production accounting to myself as facilities engineering. So I'm probably not equipped to speak, to, all of our comments, but we have reviewed it thoroughly.

Q. And unfortunately I haven't actually, I guess, seen your response email, myself personally, in regard to that, so this is probably discussion that's better had not in the middle of the hearing, I suppose, and not directly related to this particular case, then.

I guess the only thing that I may add is that the initial letter that you are referencing within this case, it actually expired 60 days after being originally sent to EOG, and as such the only real guidance, I guess, that we have out there is that Draft Letter, even if it is in a draft status at this particular juncture. It is the relatively novel approach of these projects, we don't have anything finalized as far as what we're looking at.

Uhm, I guess something that I was kind of, like, wondering -- and it almost seemed like, based of

your responses to Examiner Coss earlier, that your actual intention for this project isn't so much in regards to conducting tests on these wells but more along the lines of having these wells available to be used for their intended purposes, but yet you still intend to gather data on it as if it was having tests conducted on it? Is that a correct statement?

A. I think so, yes, sir. Of course, we want these operational to respond to third-party market interruptions. That doesn't mean that we'll stop collecting all relevant data to the project, you know as far as injection rates, pressures, production, after we inject.

And so I think the level of monitoring will continue to be extremely high, as it would be during the pilot project, and we want these to actually be operational.

Q. Okay. Now, as far as having data, then, prior to injection, you're consistently going to be maintaining your data so you will be able to present us with data prior to and after a test, under the understanding that these tests may occur not dependent upon your own schedule but just whenever your mainstream goes down.

A. Correct.

Q. Okay. Okay. Additionally to that, in regards

to something that we would like to see that we did not require as much in the prior pilot project, the Caballo, I believe -- I'm probably mispronouncing, so forgive me if I am -- is more data related to the neighboring wells.

Uhm, I guess -- and in particular I believe -- and if this is a better question for one of your other witnesses, please put it off on them and I'll ask it again. But I believe one of the wells, maybe it ws the Brown Bear 36 State, uhm, 50 over -- Black Bear 36 State 4H, I think might be the one. Let me actually bring it up.

Oh, excuse me. I apologize. It's Brown Bear 36 State 1H has a lease that is owned by an operator that's not EOG.

That is -- do you perceive being able to gather data off of that well to see how their production is affected when you're injecting into the 1H?

A. Another witness will be more appropriate to answer that question.

Q. Okay. Sounds good.

You know, I wasn't really sure. A lot of this stuff isn't really in the exhibits you already presented. Some of them's kind of overlapping between like production engineer, landman, and facilities engineer, so I wasn't sure.

A. Okay.

Q. A question that I did have: On your original pilot project then on this one you're asking for maximum allowable surface pressure of 3500 psi.

Can you explain more what your reasoning is for such a high value when you never even needed it in the initial pilot project.

A. Great question, and subsequent witnesses will really dive into that, and I think will explain our justification there. And we've actually lowered our requested maximum allowable surface pressure down from that 3500.

So I think we will allow for a review of that in depth in the production and reservoir section.

Q. Okay. Sounds good. I guess from the facilities standpoint, one of your new proposed maximum allowable surface pressure on is your proposed infrastructure that you're planning to build for approval. Is that going to handle whatever your MASP is as planned?

A. It is adequate --

Q. Okay.

A. -- for all the standard facilities --

(Note: Reporter interruption.)

A. (Continued) So in answer to the most recent question, yes, all of the surface equipment will be rated to the maximum allowable surface pressure.

Q. Okay. Sounds good.

Now, you've referenced conversation with the State Land Office and the BLM in regards to these wells. I guess was there any discussion in regards to the allocation of the gas as being reinjected back into these wells, or is that a question better for another witness?

A. I can speak to it briefly.

Q. Okay.

A. The allocation on the lease level doesn't change whether or not we're injecting for the purposes of closed loop gas capture or not. Across the field the gas on a given lease gets allocated as it leaves the lease, and this closed loop gas capture happens after that point.

Q. After it leaves the lease. Is that what you're saying?

A. Right. After it leaves the lease, yes.

Q. Okay. So then what you're reporting to the BLM, then, is essentially going to be what is going down the sales pipeline, and that is also how you're allocating it back to the individual well, then, as well. Is that kind of correct then?

A. Let me clarify.

So for wells that are not being injected into for the purposes of closed loop gas capture, the production allocation method won't change. So maybe would we could pull up Exhibit 2. I want to make sure I'm clear on this point.

The production facility is not involved with this process, so the two that are represented there in the middle of the stream. The production allocation methodology won't change on those leases.

For the wells involved in this closed loop gas capture process, we will allocate, uhm, native production that came from the native lease that the well would produce anyway, versus injective production.

And to give a brief overview of our method for determining that split, it's because when the gas comes out of the well we get a single number. We know how much gas came out of that well that day. And then the task is to divide it between, okay, what is native production that the well would have made and what's injection recovery.

And so we do that with a couple of methods that we use to confirm each other. The first is just decline curve analysis on the subject well. At this stage in these wells' life their production is fairly constant, so we can determine with a real high degree of accuracy what the gas production for a given day will be. And so when we reproduce this well, that's one indicator of what the native production is. The other is liquid production, because the gas/liquid ratio on these wells is also fairly constant.

So we use both those methods to confirm each other, and arrive at a production allocation for the native production, and then only anything in excess of that native production is recorded as recovered injection gas.

So I hope I made that clear and I hope that answers your question.

Q.   Yes, it does. But it does sound like a -- I mean, obviously it is as accurate as we could probably make it be. My question to you, though, is: As more and more of these wells are added on, is this something you plan on running these decline curve analysis and going from there for each and every month when we go to allocate?

I guess -- let me back up a second.

I guess what my concern is, is if -- making sure that 100 percent of the gas being injected is not being reported, I guess, as beneficial use or as just native gas lift operations is what my concern is, because we may not see full recovery of the gas.

A.   Right.

Q.   And if we disposition 100 percent of that gas

and only we recover 90 percent, you know then essentially this well, understanding that your actual sales line, your testing (phonetic) transfer point or field measurement point, depending what agency we're talking about here, is going to remain constant, what leaves the lease anyway. It may change the allocation to the individual wells, or potentially even leases, if you have a service commingling agreement in place -- or permit, excuse me.

A. Yeah.

Q. Yeah.

A. So we need to be fair to the leaseholders in the subject well, and so we prioritize that native production. So anything that the well makes that day, it's first counted as native production, and only anything on top of that, any excess production do we register as the recovered injection volume.

And it's -- as far as doing the calculation on multiple wells, the Caballo pilot allowed us, you know, not only to test, you know, technically and physically how this project works but also how the numbers flow through our production accounting system.

So that was a reliable method. We were able to automatically calculate and verify the native gas production, and we can -- we'll be happy to share further information. And sometimes the calculation can be helpful, you know, a sample calculation.

Q. I was thinking that probably won't be necessary. I'm pretty sure I have a pretty good idea of what you're looking at.

I guess my only other question is: If some of this injection gas is being recovered out of neighboring wells, are you accounting all the additional gas to the neighboring wells as native production from those wells, regardless of what you would presume it to be, I guess.

A. I'm going to defer that question to our reservoir engineer --

Q. Okay.

A. -- who will explain that we don't anticipate any gas migration to neighboring wells. And our pilot project confirmed that, as did our reservoir modeling.

Q. Okay. Okay. We -- I'll discuss that, I guess, with your later witness in regards to that topic.

I guess, how long ago did you talk to the State Land Office and the BLM? Was that recently and directly related to these specific wells?

A. Yes. Yes.

Q. Sounds good. They were both in the affirmative to this particular case, then?

A. That's correct.

Q. Okay. Sounds good.

Would EOG be opposed if the OCD requested a certain test to be conducted in this particular pilot project, uh, that we may perhaps have liked to have seen after reviewing the prior pilot project's data?

Let me rephrase that.

Would EOG be opposed to conducting tests at OCD's request for these wells once your infrastructure is in place.

A. Yes, we would be open to talking about tests on each of these wells.

Q. Okay.

A. And then I'll also note that as a facilities engineer I'm anxious, of course, to get a project on line, but we will be transparent with all data so that you guys have high confidence that these wells are performing as expected.

Q. Sounds real good.

I think the only other line of questioning I had was kind of touching back a little bit more on what Examiner Coss had referenced, and that is the all being linked to the same gas-gathering system.

I guess my question to you is: These are multiple leases, and it doesn't seem like you have a commingling permit in place for these wells, so is it

actually accurate to say that you have the same source gas for all these wells, or is that source gas isolated to these specific pressure stations, I guess, rather than being able to go to all three of these?

A. Yes. So my comment about the same source gas, I should have phrased it "similar source gas." The composition of gas across the field is fairly consistent.

Q. Uh-huh. Okay. I guess my question then would go to how many sets of same source of gas do we actually have within this application? Speculation is that you probably have one for each of those wells, so essentially three of them. Is that correct?

A. Uhm, the source gas that's drawn off of the EOG gas-gathering system that moves through the compressor station and into these injected wells will be a blended gas analysis from all the wells producing into that gas-gathering system.

So as far as the -- when I reference the source gas, I'm referencing really the blended gas from the EOG gas-gathering system.

Q. So then that's after it went through custody transfer, or is it still in EOG's custody at that point?

A. It's in EOG's custody at that point.

Q. So I guess what my question then extends, is: Do you know why there isn't a commingling permit for those

wells if your gas is being commingled prior to custody transfer?

A. I am not familiar with the production allocation on that level, so I'd probably defer that question. Uhm, but we can investigate that further and discuss it with you.

Q. I guess to better make sure I understand exactly what we are looking at, though, essentially would it be correct that the -- from the same delivery point you could then inject into all three of these wells? Or is that not correct, I guess.

A. From a single compressor station we will inject into one of these wells.

Q. Okay. I guess but as far as the gas that sources that compressor, does that come -- let's just say how many compressor stations there are, whether it's three, five, whatever, the same wells, are they producing into that same system and would it be fair then to say that gas from any of these wells could then be injected into any of the compressors, I guess.

A. Yes. The gas, just because of the pipeline hydraulics, will likely stay local to a given compressor station, but because the gathering system is connected, there is a possibility for blending across compressor stations.

Q. Okay. I think I'm having a better understanding, yeah.

So what we would be looking at -- I think what we will need to see is probably -- and this is in a later exhibit so it's probably to be discussed later, as well, but I believe we may only have one gas analysis that comes from like a compressor station. I think what we will also need -- well, I guess I'm not (inaudible).

What we'll also require is a gas analysis from each of your -- I don't want to call them injection facilities, but from each of the points that would be going into one of these wells.

Does that make sense to you?

A. Brice, our production engineer, has further gas analyses as part of this hearing that he'll review.

Q. Okay.

A. And we can get a gas analysis from each compresssor station.

EXAMINER McCLURE: Okay. Sounds real good. Sounds real good.

And if we don't have that as part of it, we'll probably -- we'll just need to see that prior to approval.

And I think that there was the main thing I was wanting to touch back on. I'm not sure if there's any more facility-related questions that comes to mind, off the top of my head, anyway.

So thanks a lot for your testimony.

THE witness: Thank you.

HEARING EXAMINER BRANCARD: Okay. Any further questions for this witness? Or Ms. Luck do you have any redirect?

MS. LUCK: Yeah, I just have a quick redirect question about Exhibit 4.

HEARING EXAMINER BRANCARD: Okay.

REDIRECT EXAMINATION

BY MS. LUCK:

Q. So Mr. Lunsford, do you know did the Division Director advise EOG to follow what has been marked as Exhibit 4 for this project, the October, 2019 letter?

A. For the purposes of the Caballo pilot project, yes.

Q. But then also for the --

A. Also to reference that guidance for this project, as well.

Q. As the Director of the Division addressed.

A. Yes.

Q. So that's why we went ahead and included this Exhibit 4, because the Director had advised us to follow this guidance.

A. Yes.

MS. LUCK: Thank you. So with that I think that's all of my questions for this witness.

Could we take like a brief break for just a moment to get the next witness in?

HEARING EXAMINER BRANCARD: Sure.

(Note: Timing discussion held off the record.)

EXAMINER ROSE-COSS: I would suggest a lunch break, too, and maybe some clarification or validation of the Director's approval of using the October 24, 2019, letter for these cases.

MR. McCLURE: We need that on our end, I would think, right?

HEARING EXAMINER BRANCARD: Mr. Coss, you're proposing...

EXAMINER ROSE-COSS: Well, if the Director -- that's news to us that the Director approved the use of the October 24, '19 letter to proceed as guidance for these cases.

HEARING EXAMINER BRANCARD: Okay. Well, I think you need to resolve that within the Division, then.

EXAMINER ROSE-COSS: Very well, then.

HEARING EXAMINER BRANCARD: Unless, Ms. Luck, you have some communication.

MS. LUCK: I don't know if we have anything in writing. I think it might be better for the Division to confirm internally.

HEARING EXAMINER BRANCARD: Okay. All right.

EXAMINER ROSE-COSS: We will go ahead and do that.

HEARING EXAMINER BRANCARD: Okay.

(Note: In recess from 12:15 p.m. to 1:00 p.m.)

HEARING EXAMINER BRANCARD: Okay. Ms. Luck, whenever you're ready to start resuming, we are on Case 21567. It is January 7, 2021.

MS. LUCK: Thank you. And just momentarily, if I may, I would like to recall our first witness David Lunsford to ask some questions that Examiner McClure had for him.

HEARING EXAMINER BRANCARD: Okay. How long do you think you're going to go with the rest of your witnesses today?

MS. LUCK: I'm not sure exactly how long it's going to go, but I would say the question that I have for Mr. Lunsford is brief, and he should be able to address that pretty quickly.

HEARING EXAMINER BRANCARD: Okay.

REDIRECT EXAMINATION

BY Ms. LUCK:

Q. Mr. Lunsford, I just want to return to Examiner

McClure's questions about commingling.

Can you explain EOG's process for measuring production from each of well on lease.

A. Yes. I think that some of the confusion may have been on my part in regard just to the language I was using in response to Examiner McClure's questions.

So to clarify: The point of valuation for royalties is on lease for all of the leases that are providing gas to the gas-gathering system.

So we have on-lease measurements before any gas enters the gas-gathering system. That means that any gas in the gas-gathering system is not actually commingled.

But I think I may have confused the point when I talked about our custody transfer meter at the compressor station. I was referencing that meter as custody transfer between EOG and the parties who are purchasing our gas, but it may have been confusing and it may have seemed like I was referencing that meter as the point of measurement for valuation on the lift level. But the valuation on lease level occurs on lease. It's on-lease measurement before it hits the gas-gathering system.

And a helpful analogy is gas lift. So for our gas lift operations the valuation occurs on lease and then, you know, gas lift, we take that off of the gas-gathering system after that point.

I hope that clarifies the point.

Q. And so just one more question. That means that surface commingling is not required between these five wells.

(Note: Reporter inquiry.)

Q. (Continued) Okay. I just want to confirm that this means that there's no surface commingling required for these five wells.

A. That's right, yes.

MS. LUCK: And so that was my last question for this witness.

HEARING EXAMINER BRANCARD: Okay. Mr. McClure, did you have any follow-up questions for that?

EXAMINER McCLURE: Not within the confines of this hearing, anyway. I have no more questions at this point on the topic.

HEARING EXAMINER BRANCARD: Okay. Mr. Coss?

EXAMINER ROSE-COSS: No more questions from me.

HEARING EXAMINER BRANCARD: Thank you.

Ms. Luck, you may proceed with your next witness.

MS. LUCK: Thank you. So I call Matt Smith, who is the land testimony -- the land witness. Sorry.

MATT SMITH,

having been previously sworn, testified as follows:

DIRECT EXAMINATION

BY MS. LUCK:

Q. Please state your name.

A. Matt Smith, M-a-t-t, S-m-i-t-h.

Q. By whom are you employed, and in what capacity?

A. I work for EOG Resources, and I'm the division land manager here in Midland.

Q. Have you previously testified before the Division?

A. I have not.

Q. Please state for the examiners your education and work experience.

A. I graduated in 1996 with a psychology degree from Texas Tech University. I've got 23 years of land experience, 16 of which were with EOG. I started with EOG in Fort Worth and spent seven years there, five years in San Antonio as Division Land manager, the last three years as Division Land Manager in Denver, and now I've been recently transferred to Midland as the Division Land Manager.

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

A. I am.

Q. I'm sorry. I cut you off. Do you have anything else to say about your education and experience?

A. No.

Q. So you're familiar with the status of the lands in this area?

A. Yes.

MS. LUCK: So with that I would tender Mr. Smith as an expert witness in petroleum land matters.

HEARING EXAMINER BRANCARD: Are there any other comments or objections?

Hearing none, Mr. Smith is accepted as an expert in petroleum land matters.

MS. LUCK: Thank you. And I will again share my screen so that everyone can see the exhibits again.

Q. Turning back to Exhibit 1. And again we reviewed this exhibit a little earlier, and this shows the project area. Uhm, can you again remind us about the land in this area and the three project areas.

A. You can see right there on the map the three areas that we're talking about today are called the Hawk, Bear and Ophelia areas. They are depicted on the map in Lea County, New Mexico.

Q. And EOG is no long seeking approval of the Diamond wells originally included in the application?

A. That is correct.

Q. Could you tell us a little bit more about why those wells were removed?

A. We have some work to do with our working interest partners and we didn't want to submit that application today or work on those wells today because we need to work with our working interest partners. We will be back with those wells very shortly.

Q. Okay. And so for the working interest partners and the remainder of the wells, has EOG any other concerns?

A. None whatsoever.

Q. Okay. And so now we'll turn to, uh, Exhibit 4 from the Division, and that requires notifications to the affected parties within a half-mile Area of Review surrounding the injection wells.

Did EOG provide Notice of the hearing to each of the parties in the half-mile Area of Review around each of the injection wells?

A. Yes.

Q. Did you prepare an exhibit identifying the affected persons entitled to Notice of the Application and hearings?

A. Yes.

Q. And so is that Exhibit marked as Exhibit 5?

A. Yes.

Q. I'm sorry. Let me see if I can minimize this.
If you could please explain to us what this exhibit shows.
A. This is a map showing the wells that we're applying for, a half-mile halo around them depicting the notified parties. They're all listed there. You can see there's quite a list: Endeavor, WBA Resources, et cetera.
So we've notified all these people around, and those people own in those purple-hatched tracts.
Q. And let's review this map in a little more detail. What does the yellow shading mean?
A. The yellow shading is the EOG leaseholds, and white is just unknown, or we didn't put the ownership there because it doesn't affect what we're doing here; and then the hatched purple and then I guess pink, is the affected parties' tracts that were notified here.
Q. Okay. And does this map show EOG's 100 percent working interest in these wells?
A. That's correct.
Q. Okay. We will turn to the next map. What does this map show?
A. This same thing here shows the half-mile halo around the Ophelia well. It depicts the offset owners that we needed to notify. The list is much shorter here, just Conoco Phillips and the Estate of Ralph D.

Williamson. And it shows our well in the middle there. We have 100 percent working interest in this well, as well.

Q. Okay. And then now turning to the last map, what does this map show?

A. It shows the wells with a half-mile halo around each of them. The yellow is EOG, the pink and purple hatched is offsetters that we notified. Again much smaller lifts than the first one, but again we have 100 percent working interest here. And -- there we go.

Q. Okay. Thank you.

And so you provided Notice of this Application and hearing to each of those affected parties for each of these wells?

A. That is correct.

Q. And did you also, or EOG also identified the owner of the surface on which each of the wells are located?

A. That's correct.

Q. Did EOG also provide notice to each of the surface owners?

A. Yes.

Q. And then can you just tell us generally what a surface ownership was that tends to (inaudible).

A. All three. BLM, Fee and State. And we notified everyone involved.

Q. And all parties that were entitled to Notice were identified based on the interests that were recorded at the time the Application was filed?

A. That's correct.

Q. In your opinion did EOG undertake a good faith effort to locate and identify the correct parties (inaudible) as required for notice in the half-mile Notice area?

A. Yes.

Q. So to the best of your knowledge are the addresses that you identified valid and correct?

A. Yes.

Q. Did you provide a list of those parties and their addresses to my office to issue Notice by Certified Mail?

A. Yes.

Q. Is Exhibit 6 -- let me turn back -- an affidavit from me with the attached letter providing Notice of this Application and hearing to the affected parties, including the affected agencies?

A. Yes.

Q. And then there's the letter and the parties.

And then finally is Exhibit 7 an Affidavit of Publication reflecting that Notice of the Application

was published in a newspaper of general circulation identifying all parties by name?

A. Yes.

Q. Just to clarify, this exhibit was received from the newspaper scanned like this, and it just was an error with the scanning. So I think if the examiners have some questions about it we've requested a new copy of this NOP that will show that all five wells were published to all of the affected parties by name.

A. Okay.

Q. So was Exhibit 5 prepared by you or compiled under your direction and supervision, or do they constitute EOG business records?

A. Yes.

MS. LUCK: With that I would move the admission of EOG Exhibits 5 through 7, which includes my affidavit and the Notice of Publication.

And then I would pass the witness for any other questions.

HEARING EXAMINER BRANCARD: Thank you. Are there any comments or questions about the exhibits?

Hearing none, Exhibits 5 through 7 are admitted.

Let's start with Mr. Coss. Do you have any questions?

EXAMINER ROSE-COSS: I'll go ahead and pass my opportunity for questions to Mr. McClure.

HEARING EXAMINER BRANCARD: Thank you.

Mr. McClure?

EXAMINER McCLURE: Yeah, I was going to say that I think that most of my questions weren't so much landman based, other than just the question on the Public Notice, which Ms. Luck had already addressed.

We will just need that, uhm, the -- we'll just need the new updated public notice submitted to us when you do receive that, demonstrating that all five wells was in fact noticed.

Beyond that the only other question I guess I have is:

CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. On the exhibits that was given to us on Monday afternoon, when was the -- uhm, when was that check as far as status with the United States Postal Service? Because I know it has a status here on all these lists. Do you know when that was actually updated? Was that on Monday or was it earlier than that?

MS. LUCK: So as of right now we're using a third-party mail service, and so I can't tell you the exact date it was updated. But we can request an updated tracking status from that company and I can submit that to the Division that shows all of the updated tracking information.

EXAMINER McCLURE: Yes, please. My only concern is, like for instance we had NGL decide to put an Entry of Appearance, and they just got Notice just prior, so my concern would be if somebody had not. But in theory the Public Notice should be good once we see that.

But I was just curious, I guess, as to what we were looking on that.

So yes, please do submit that one to get an updated version of that.

I believe that's all I had land-related, I believe, unless you think that you would be the correct one to ask, Mr. Smith, in regard to any of the other questions that I previously asked and was postponed to another witness.

MS. LUCK: I don't think so.

EXAMINER McCLURE: Yeah, I didn't think so either, but I was just checking.

Okay. Thank you for your testimony.

THE WITNESS: Thank you.

MS. LUCK: I'm sorry. Any other questions from the examiners?

HEARING EXAMINER BRANCARD: No. Any other questions from the other party?

Okay. Hearing none, Ms. Luck, you may present your next witness.

MS. LUCK: Thank you. So next I will call Brice Letcher.

BRICE LETCHER,

having been previously sworn, testified as follows:

DIRECT EXAMINATION

BY Ms. LUCK:

Q. Will you state your name for the record.

A. Brice Letcher. Brice is B-r-i-c-e, and Letcher, L-e-t-c-h-e-r.

Q. By whom are you employed and in what capacity?

A. EOG Resources as a Production Engineering Specialist in our Midland division.

Q. Have you previously testified before the Division?

A. I have.

Q. Could you briefly state your education and work experience for the examiners.

A. I graduated from Texas Tech University with a Bachelor's in Civil Engineering. I have 10 years experience as a production engineer in the Permian Basin. I'm a Certified Professional Engineer in the State of New

Mexico.

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

A. Yes.

Q. And have you evaluated the integrity and stability of the subject wells for this project, as well as the integrity of the surrounding wells?

A. Yes.

MS. Luck: So with that I would tender Mr. Letcher as an expert witness in production engineering.

HEARING EXAMINER BRANCARD: Okay. Any comments or objections?

Hearing none, Mr. Letcher is accepted as an expert witness.

MS. LUCK: Thank you.

Q. What aspect of this project falls within your supervision?

A. Primarily reviewing the well construction and overseeing operations of the well.

Q. And you'll be providing testimony that the wells proposed for this project meet the Division's criteria and conditions contained in Exhibit 4?

A. Yes.

Q. And so turning back to the technical letter, Exhibit 4, it says under Technical Information and

Standards for Installation/Operation, your testimony will cover those Roman Numerals IV through IX, which are parts of the technical testimony.

A. Yes.

Q. And let's go to Item IV.

Turning to Exhibit 8, can you explain with this exhibit shows.

A. Exhibit 8 is a wellbore diagram for each of the five proposed wells.

Looking at this first wellbore diagram for the Black Bear No. 4H, you can see that each wellbore diagram is, uh, a depiction of the well construction where the taking strings are set, and listing detail of how they were cemented.

Q. So walking through the exhibit, can you just go from left to right at the top and just explain like what each column shows and then we can walk through each of these wellbore diagrams.

A. Sure. We can kind of -- the wellbore diagram that show the Black Bear No. 4H. You know, starting with the surface casing is shown to be set at 994 feet. Uhm, it was cemented with 800 sacks and was cemented to surface.

Our intermediate casing for this well was set at 5050 feet. Uhm, that is 9 and 5/8, uh, and is also cemented to surface.

5 and 1/2 17-pound HCL production casing was set at 14,343 feet. The top was cemented at the production casing was calculated to be at 4600.

Going down, going to the next wellbore diagram for the Brown Bear 36 State NO. 1H, the surface casing here was set at 1102 feet, and was cemented to surface.

Our 9 and 5/8 intermediate casing was set at 5,075 feet and was cemented to surface.

The 5 and 1/2 inch 17-pound production casing was set at 14,282 feet with the top of cement being at 4300 feet, (inaudible) by a CBL run.

For the next wellbore diagram, Hawk 25 No. 1H, our 13 and 3/8 surface casing was set at 1350 feet, and that was cemented to surface.

The intermediate casing, uh, 9 and 5/8, was set at 5,154 feet and cemented to surface.

Our production casing 5 and 1/2 inch 17-pound set at 14,180 feet, and our top of cement is found to be at 30,900 feet by CBL.

And by CBl I mean cement bond mark.

For the Hawk 25 Fed Com No. 2H, our surface casing 13 and 3/8 is set at 1,350 feet and was cemented to surface.

Our 9 and 5/8 intermediate casing was set at 5,160 feet and cemented to surface;

And our 5 and 1/2 inch 17-pound production casing set at 14,457 feet, with the top of cement being found at 2,650 feet by CBL.

And last is the Ophelia 27 No. 1H. Surface casings 13 and 3/8 set at 904 feet and was cemented surface. The 9 and 5/8 intermediate casing was set at 5,014 feet and was cemented to surface.

The 5 and 1/2-inch 17-pound production casing is set at 14,470 feet with the top of cement being found at 3,950 feet by CBL.

Q. Thank you. And remind us again if these are all targeted within intervals?

A. So all five of these wells are drilled into the Avalon Formation.

Q. Okay. Do any of these wellbore diagrams show tubing?

A. No, none of these wellbore diagrams show our current end of tubing set depths. Uhm, what -- for how we will set those up for closed loop gas capture operations, our tubing string will either be 2 and 3/8 or 2 and 7/8, and we will set our inner tubing at 30 to 60 degrees in the curve. And that will be opening tubing, just meaning that we will not have a packer, which is, you know --

which is our typical set-up for gas well operations.

Since these wells will still primarily be producing wells, it would be ideal for us to set our tubing as deep as we can in the curve. We can work below, uh, reduce our volume of pressure as much as possible and produce the wells as efficiently as possible.

And also having opening in the tubing for purposes of the gas capture project, also enables us to be able to inject gas down the anulus as well as down the tubing. That way we can reduce the frictional back pressure that we observe while we are injecting into the well, which would help us, you know, achieve higher injection rates and volumes as we need.

Q. Okay. And this set-up is typical for all of the gas wells that EOG operates in the Basin?

A. Yes.

Q. And is it your opinion that each of these wells are effectively sealed off from the shallower fresh water reservoirs?

A. Yes.

Q. Turning to Exhibit 9 -- let me move in a little bit.

What is Exhibit 9?

A. Exhibit 9 is just a summary table summarizing the casing set depths, the basic, you know, well construction for each well.

So it is, you know, a depiction of looking down in the drilling bores, and also indicating, you know, the completion interval for each well.

Q. Okay. And does this explain when each well was originally drilled?

A. Yes. So all five of these wells were drilled within the last ten years, so these are fairly new wells. They're not circa 1980 or anything.

Q. So that's kind of the important takeaway from these reports, that these wells are fairly new vintage and in good shape?

A. Yes. Yes.

Q. So what is Exhibit 10?

A. Exhibit 10.

Q. Let me get there. See if you can turn that so it's right side up.

A. Okay.

Q. No. Oh, no.

A. You just went --

Q. Oh, yeah, that's the log.

A. Exhibit 10 is the cement bond logs for each of the wells that...

And so to show, for example, the first one we are looking at is for the Brown Bear State 1H, and then for each CBL has a couple of different logs shown here.

So on the far left is a Gamma Ray and it's a color locator log. So that just basically serves as a reference point in the wellbore.

That center of the log is your amplitude reading, which is reading the amplitude of the wave form as it returns to the encasement (inaudible), with higher amplitude, uh, higher reading indicating that there's more free pipe and a lower amplitude reading, uh, indicating that there's a continuation or resistance behind the pipe, which would indicate cement.

The far-right surface log is a density log which is actually just showing the entire acoustic wave form, and that is the reading. And that serves as an indicator of cement quality and cement bond to the pipe.

And so the way to interpret these logs: As you go down -- let's see. I think for the Brown Bear we may need to go down to about 4300 feet.

Q. There it is.

A. And so off of the amplitude reading you can see at 4300 the amplitude reading begins to shift more to the right, which would be higher value, indicating that there's more free pipe above that point in the wellbore.

And also the, uh, (inaudible) validity log would indicate a similar observation where you see, uhm, that there's more variation. You know, that the reading uh, is indicating that there is cement there. As you move further up the log there's lots of variation in the wave forms.

Q. Okay.

A. For each CBL that we've submitted here, you know the similar interpretation can be made, and that's just verifying the top of cement that we have shown on wellbore diagrams.

Q. Okay. And so do these CBL, the cement bond logs, reflect complete cement coverage for the entire vertical length of these wells, in your opinion?

A. Yes.

Q. And I think that covers everything under Item IV in the October, 2019 letter.

So turning to Item V, this deals with the MASP. So if you can explain what EOG is requesting as far as maximum allowable surface pressure, and what we will call the MASP here.

A. Okay. Maximum allowable surface pressure, MASP, for these five wells we are proposing a MASP of 2,250 pounds.

And we determined that by evaluating these wells and what we believe -- what pressure we need to inject into these wells, as well as evaluating the available pressure that we will be seeing from the compressor stations that would be sending gas to these wells.

Uhm, and also keeping in mind, you know, the potential on these for a further (phonetic) compressor to further increase our capability to inject into the wells, if necessary, to achieve the injection rates and volumes that we would need, but also to be in mind that the MASP that we are proposing, uh, is well beneath our rated casing burst pressures, and gives confidence that, you know, there would be no mechanical-integrity issues with injecting gas at those pressures.

Q. And so will the casing burst pressure be at least 120 percent of the maximum allowable surface pressure plus the hydrostatic pressure from a full column of reservoir fluid?

A. Yes. So just as an example, our 17-pound cement casing, which all five of these wells are 5 and 1/2 inch, 17-pound fuel (inaudible) casing, the casing burst pressure rating is 10,640 psi. Uhm, a full hydrostatic column of fluid for the proposed MASP would be 22 -- would be 2,250 psi plus. Just for an example, using 9,500 foot to the -- of the wells by your fluid gradient gives you around 6,500 psi.

Uhm, and so this is just a case of taking burst pressure rating is around 160 percent higher than the maximum allowable surface pressure for the full hydrostatic column of fluid.

Q. Okay. And just to clarify for the examiners, this injection rate that EOG is requesting is specific to the Avalon or the Leonard targeted interval for this project.

A. Correct. You have the pressure that we are proposing here is specific to these wells, the Formation that we will be injecting into, and the available equipment and facilities that we have in place for this project.

Uhm, and for other projects, this, you know, MASP has greater value than may be necessary for evaluating on other projects.

Q. Exactly. So EOG took what it learned from the Caballo project targeting this interval and suggested the pressure to be appropriate for this interval.

A. Sure.

Q. Okay. So just to skip over VI, we will turn to VII: Division lawyers ask EOG demonstrate --

Sorry. I'll start over.

Item VII states: The Division asks EOG demonstrate the mechanical integrity of the well complies comply with 19-15-26-11(A)(1) NMAC to a minimum pressure

of 110 percent of the maximum allowable surface pressure.
So has EOG conducted MITs on these wells?
A. We have not conducted MITs on these wells yet. Upon approval, you know, looking forward, I guess, we will go ahead and conduct those MITs and certify to NMOCD, you know, prior to conducting those tests and pressure test to 110 percent of our proposed MASP.
So to do that we will have to do a workover radial on each of the wells, pull the current production equipment, do the running of the of the RVP, set probably just above our takeoff point, flood the casing with water, and pressure up to 2500 pounds and hold that pressure for 30 minutes, and record that on a chart so that we could report that back to the NMOCD.
Q. Okay. And so EOG is willing to demonstrate that each of the proposed injection wells can meet the condition of -- that's listed as Item vii in the letter?
A. Yes.
Q. Okay. So turning to Item VI it says that EOG needs to perform an assessment of the surrounding wells to ensure they meet the requirements of Subsection 5.
Have you undertaken a review of the wells within the half-mile Area of Review?
A. Yes.
Q. And turning to Exhibit 11 if you can let us know

what this exhibit shows. It will take me a while to get there. Hold on just a minute.

A. This is 11, the map of the 12 Area of Review.

Q. Sorry. Hold on just a moment, please. (Note: Pause.)

A. Yes. Okay. So Exhibit 11 is a map of each of the proposed wells showing the half-mile radius around the wellbore, with all, you know, wells within the Area of Review being shown on that map.

It's -- with numbers that would, uhm, be referenced on, uh, the table that's Exhibit 12.

Q. Okay. So this first map just deals with the Black Bear Area of Review.

A. Correct.

Q. And then the next one, start to walk through that. Which one is that?

A. Looks this is Brown Bear No. 1H.

Q. And same thing with this map, it shows all of the wells producing in the Bone Spring Formation in the Area of Review?

A. We are showing all the wells within the Area of Review.

Q. I'm sorry, not just producing but also drilled.

A. Yes.

Q. And then this map?

A. This map is for the Hawk 25 Fed No. 1H, showing similar, uhm -- showing the same thing, half-mile radius, uh, half-mile Area of Review, with all the wells within -- I'm not sure what. Looks kind of -- okay, yeah. I see why.

Q. And again each of the wells are numbered and they correspond with the wells listed on Exhibit 12?

A. Yes.

Q. And then there is two more maps. So this one is for the next well?

A. This is for the Hawk 25 Fed No. 2H.

Q. And this map also shows each of those wells in the half-mile Area of Review?

A. Yes.

Q. Then finally this last map.

A. The last map is Ophelia 27 No. 1H, showing all the wells within the half-mile Area of Review.

Q. And is it correct that some of these wells in the half-mile area are operated by EOG but some of them are operated by other operators?

A. Yes.

Q. So turning to Exhibit 12, is that a list of all of the wells?

A. Yes.

Q. And explain what this shows.

A. So Exhibit 12 is a table where we have tabulated data for each of the wells that fall within the Area of Review for each proposed well, showing locations, operator, also showing the casing trim designs, and, uh -- you know. And, uh, reporting anything. Essentially the well construction for each of these wells.

Q. And how did EOG compile this data?

A. Uhm, we compiled this data by reviewing, you know, available public information, uh, off of the MSU website, and then for, you know, for all our wells of course we have internal data.

Q. Can you explain the distinction between what information you have on EOG wells versus wells operated by other operators or drilled by other operators?

A. Uh, how do you mean, I guess.

Q. Well, I guess -- le me rephrase. Sorry.

Does EOG have access to all information about these other wells?

A. We don't have access to all information, no. We were only able to review what is available publicly.

Q. Okay. And so that's typical that EOG doesn't have access as to all of the frac data for wells in a surrounding area?

A. Correct.

Q. So on this Exhibit 12, are any of these wells

plugged and abandoned?

A.   Yes, I believe there are -- there are several plugged and abandoned wells, which is in the table we included five wellbore diagrams for plugged and abandoned wells that penetrated our proposed injection zone.

Q.   Okay. So turning -- sorry. (Note: Pause.)

So turning to Exhibit 13, what is this?

A.   Exhibit 13 is the five wellbore diagrams for plugged and abandoned wells that fall within that Area of Review for the proposed wells.

Q.   So just to clarify, all five of these plugged and abandoned wells were operated by EOG?

A.   Yes.

Q.   And so there is a wellbore diagram for each of the five plugged and abandoned wells?

A.   Yes.

Q.   So we won't go through them one by one, but they have been provided here for the examiners to review.

Have you formed an opinion as to the integrity of the wells within the Area of Review and whether they meet the Division's requirements?

A.   Yes. Which I believe that all the wells within the Area of Review have adequate cementing of, uh, of casing strings; uh, that there should be no risk of communication between wells or communication to fresh water reservoir, or any sort of wellbore integrity that I could see.

Q. Okay. Okay. So turning back to that letter, it says that the in Item No. VII that EOG should demonstrate that the injected gas does contain corrosive gas such as H2s or Co2 that may damage the casing.

Have you conducted a gas composition analysis of the gas that EOG proposes to reinject in the project?

A. Yes.

Q. Is that included in Exhibit 14?

A. Yes. So Exhibit 14, we are providing gas analysis for the five proposed wells as well as, I believe, the last one or two pages of the gas analysis would be representative of our source gas.

This one here, if you can scroll through, is the gas analysis from our Red Hills Aladdin compressor station, the original compressor station that, uh, is drawing our gas-gathering system. This would be one of the sources, uh, for gas injected into -- uh, to -- you know, one of the proposed -- uh, one of those wells that we are proposing here.

And the gas -- you know, looking at the gas analysis here in the bottom left there, you see a breakdown of gas composition. You know, comparing that to the gas composition of gas produced from the wells, this gas is actually, uh, much -- of much better quality, really, so both in CO_2 content and in H_2S. So this gas would be much better quality than those wells were actually producing.

Q. Okay. So you were saying the well is better quality. Is it your opinion there's no --

A. Gas from the compressor station is better quality.

Q. Right. So there's risk of acidification or corrosivity as a result of injection based on those values?

A. No.

Q. Okay. I think that Mr. Lunsford testified that the well would be equipped with a device to prevent the surface injection pressure from exceeding the proposed maximum allowable, so explain how unlikely it is that high pressure would be of concern here, and how EOG's alarm systems work.

A. That's correct. So, you know, a couple of things here.

Since we are only injecting gas having a full column of gas in the wells we're injecting, our normal pressure that we will be seeing as we are injecting gas is quite a bit lower than what we were -- you know, hydrotest our casing tubes. So it will be far under pressures, uh, that will be required to burst our casing, and far under the pressure that would be required to initiate a fracture in the level.

But as this talks about earlier, each well will be equipped with emergency equipment. We have all these wells, uhm, on a casing system where we are constantly monitoring, uh, casing pressures, tubing pressures, uh, flow rates; and our control room would be, you know, notified instantly via alarms that we set up if anything -- if any of the operating parameters fall out of, uh, our -- uh, out of our set -- uh, out of our set parameters, really.

Q. Okay. So in your opinion will the granting of this application be in the best interests of prevention of waste and the protection of correlative rights?

A. Yes. Each of these wells will provide us an outlook, uh, to ability to prevent flaring and prevent waste.

Q. So can this project be operated safely and without preventing -- presenting a risk to human health or the environment, including from fresh and drinking water?

A. Yes.

Q. Were Exhibits 9 through 14 prepared by you or compiled under your direction and supervision or do they

constitute EOG's business records?

A. Yes.

Q. So with that I would move the admission of Exhibits 9 through 14 and pass this witness.

HEARING EXAMINER BRANCARD: Okay. Any comments on these exhibits?

Hearing none, Exhibits 9 through 14 are admitted.

And are there questions for this witness?

Mr. Coss.

CROSS EXAMINATION

BY EXAMINER ROSE-COSS:

Q. Hi. Good afternoon, Mr. Letcher.

(Note: Reporter request for mic adjustment.)

A. Hi.

Q. (Continued) So my one question: I understand that the maximum allowable surface pressure request has been modified from the Caballo project.

Where? What exhibit is that explained in?

A. Uhm, I'm not sure that we have an exhibit explaining the MASP, uh, specifically.

Again, that was more -- not so much of a calculation, more of an evaluation of what pressure would be necessary, uhm, to inject into the well, as well as looking at our facility and equipment constraints.

Q. And so what -- I guess aside from the calculation, where was that stated in the exhibits?

A. Uhm, I'm not sure that we have that stated specifically.

Q. Okay. How -- were we supposed to gather that information from the hearing, then, today?

MR. LUCK: Yes. Yes. We are offering the testimony of the maximal level surface pressure from Mr. Letcher, and his testimony as what would be appropriate in this case and the reasons why.

And also Mr. Sonka, who is our reservoir engineer, will later testify as to the appropriate pressures, given the reservoir characteristics.

MR. ROSE-COSS: Okay. Well, thank you, Ms. Luck.

Q. And the only other question I have -- thank you for your explanation of these mud logs, and this is mostly a point of clarification for me.

I'm scrolling to the correct spot in my notes, or in my exhibits. I'm getting there.

On page -- it's going to be roughly page 4. Sorry. I should have been there already.

It's the very last cement bond log. I'm trying to determine what well that is so we can all be on the same page.

MS. LUCK: Okay.

EXAMINER ROSE-COSS: I'm going to wear out my finger here. It's track ball.

THE WITNESS: Yeah.

Q. Okay. It's for well Ophelia 27 01H. It begins on page 120 of 229 in the exhibit packet.

A. Okay.

Q. Could you describe for me the furthest -- I see it's described in the key as a cement map with a scale beginning at 1 in black and ending at 8 in white.

How is one to interpret this?

A. Sure. No problem.

I think -- yeah, this may be, of the three CBLs that we have, this may be the only one with the cement map.

But the cement map essentially is, uh, is showing what the tool is reading radially, and so it's giving you a look at how the cement looks around the pipe.

And so the way to interpret that is the warmer or the darker colors will indicate, uh, you know, cement bond on the pipe, and the lighter, you know -- you know you can call it cooler or lighter colors would indicate free pipe.

So that's kind of a nice way to look at this and it's an easier way to quickly look at the log.

Q. So am I safe in assuming for our purposes here that black is good and the light is bad for our purposes?

A. Yes, sir.

Q. And in your expert opinion, scrolling through this, we shouldn't have anything to worry about here?

A. No, sir. I think this one, as you scroll down through the log, you'll find the top of cement around 3,950.

Q. Okay. Thank you. That explanation helped. I just hadn't seen this one before.

And with that I've exhausted all of the questions I have, and I pass the witness to Dean, Mr. McClure.

(Note: Pause.)

HEARING EXAMINER BRANCARD: Mr. McClure, do you have any questions?

EXAMINER McCLURE: Yes, I do.

I'm sorry. I had to change out my headset, the battery ran out.

Can you hear me?

THE WITNESS: Yes.

CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. I could have maybe missed a little bit of Mr. Coss's last question. It was still only related to the

three CBLs; is that correct?

A. Yes, sir.

Q. Okay. Sounds good. Okay. I was just making sure I'm not going to re-ask a question or anything.

I guess very first of all, I guess I have some questions in regard to the CBLs, as well.

It looks like on your Black Bear 36 State 4H, was that top of cement only calculated rather than a CBL ran?

A. Yes, sir. And I forgot to mention that. But when we go to run the MIT for that well we will go ahead and run a CBL to confirm that top of cement.

Q. That was actually -- you saw exactly where I was going with that.

Okay. Then the only other question I have on the CBLs, on your Brown Bear 36 State 1H, do you know if there was a DV tool ran on your production casing in that well?

Let me clarify the reason I ask.

I was wondering about the cement coverage from about 5,000 feet to 5500 feet.

A. About 5,000 feet to 5500 feet?

Q. Correct.

A. I would maybe need to review the detail, uh, casing, but to my memory I don't believe there was a DV.

Q. Okay. I guess on what we have here available on that, well it's slide 25, but that's the big long one that has the CBLs like halfway down. It looks like we lose a lot of amplitude and a lot of Formation noise.

You testified that you think we do have good cement coverage on that well. I just wanted to confirm, I guess, that you had reviewed that specific area. That was the only area on the CBLs, I guess, that made me pause as to the cement coverage, I guess.

A. I think we have adequate cement coverage here. It looks like we -- uh, you know, we did circulate cement (inaudible) in the casing.

Q. So yeah. And it clearly looks like it, because they, like, definitely did. That was the only reason I was wondering about the DV tool, because it seemed like there was a pocket there, I don't know if it fell back in the...

I'm not sure what went on. Anyway, I just wanted to make sure you had reviewed that in that area and were under the opinion that it is good. And I believe you have already answered that question.

So I guess, moving on, are you the appropriate witness to touch base on regarding communication on that well that's adjacent to the Brown Bear 36 State 502H that's not operated by EOG? I was

wondering in regards to how hard it would be to have the production data from that at times of injection tests.

A. For which well is that again?

Q. I believe it's the Brown Bear 36 State 502H. I believe -- I am not -- I apologize. I didn't have enough time to go into the very details, I guess, of the exhibits. I don't know for sure who the operator is of that well off the top of my head.

A. Okay.

Q. There was one to the west of it, though.

A. So, you know, what we do to maintain good communications with the operators that are around us, we don't share their production information off of each other's wells. But I guess also Carlos may be able to comment on this further.

But based on our testing of the Caballo, we believe -- you know, we believe it would be almost -- you know, highly unlikely that we would ever communicate directly to any offset wells. For a few reasons, really. I mean, just considering the amount of production from each of these wells, uhm, with our depleted well, I think most of these have produced over, you know, 400,000 barrels of water, or barrels of fluid, you know, along with -- you know, but the bcf I think for the Hawk well I think actually it produced over 2 bcf of gas. And, uh, so the depth that we are injecting, you know, certainly staying near wellbore, any variations in production, uh, you know offset wells, you know during injection operations, would more likely be related to, uhm, just pressure transient changes in the reservoir that come with the change in flow boundaries.

And I guess typically pressure waves move faster through the reservoir than the actual fluid that's conveying them, and so, you know, those effects can even be realized just by shutting the well in.

Does that help answer your question?

Q. Yep. Pretty much what we're looking at is we do have four other wells in which to continue to gather data on. Our concerns are, obviously, as to the magnitude of how -- where the balance, I guess -- what it is your balance of -- or where your midpoint is and which direction the flow is going in the reservoir is shifting towards the neighboring well, essentially.

So what you are saying is -- yes, I absolutely agree. Having said that, though, the upward shift in production for the neighboring wells during your extended tests in a previous pilot project most definitely was in a continuing slope upward. So the balance was definitely shifting more and more towards them.

So our concern is just making sure we have

additional data points to try to establish how much we are actually looking at, I guess, and that may actually occur, and at what point there could actually be breakthrough, I guess of fluid, between the two.

But regardless, I guess that's neither here nor there. My thought was if we were going to be able to get the data, then we would like to, but before the wells, it probably won't be necessary in this case, would be my initial take of the situation, I guess.

But I thought I would put it out there and ask what the possibility was of that.

I guess, moving along -- oh, well, go ahead. Unless you had another thought process on that.

A.   Just one other thought.

I do think that the nearest offset wells for each of these are operated by us, by EOG; and I think those, you know, they are wells that are near and operating that are nearest wellbores.

(Note: Reporter interruption.)

I was just commenting that the breach of these wells, the nearest offset wells are operated by EOG, and so those wells would be the best candidates for monitoring what (inaudible) would be able to provide.

Q.   Okay. Sounds good. I'm thinking that in nearly all the cases I think that is exactly right, from what I

saw, just that one may be close to the boundary release line.

But I'll -- I'll -- it's fine. I'm with you.

A. Okay.

Q. Let me move on.

In regards to the gas analysis -- oh, looks like your page is reasonably close to that now.

But it looks like there's only one data point or one source point that you've drawn from like a compressor station. It sounded like maybe there might be multiple points based off earlier testimony that may be slightly different.

If you -- are you going to be able to provide us with a gas analysis from each of the separate points so we have a full picture of what we're looking at?

A. Sure. That would be no problem. We just wanted to include this as an example. You know, this is pretty representative of gas composition that is on the system.

I think there is another last page there, also.

MS. LUCK: Yeah.

A. So this is a screenshot off our data system where we have an analyzer that, you know, we have readouts of our gas composition at this compressor station. This one's for Archer (inaudible) Compressor Station which is also on, you know, the gas (inaudible).

Q. Yes, sir. I -- oh, go ahead. I thought you were still going.

A. Sorry. We can certainly provide, you know, more gas analysis from each compressor station that would be relative to this project.

Q. Okay. Sounds good.

And we don't have any guidelines established in regards to at what point the concentration of Co2 is going to be I guess corrosive and damaging to the casing, and then how long it's going to take for corrosion to occur, and such.

I guess at what percent do you think that's going to occur, and when would you need to put a corrosion-preventive plan in place, I guess.

A. Yeah, we do have a corrosion plan in place on most if not all of these wells. These wells are producing, or gas looking wells that -- you know, they're typically injecting a corrosion inhibitor along with our gas flow injection stream.

So there would be some protection provided by that in the production phase.

With that, you know we don't anticipate needing any further kind of inhibitor treatment. In other words, we don't think we would need to be injecting corrosion inhibitor chemical with gas during the temporary closed loop gas capture injection.

Q. Now, as far as dehydrating your gas stream prior to injection, you're not having to do that, then, at this point and you don't predict that you would have to?

A. So with the gas coming from one of our compressor stations, you know, much of the liquid will have been -- gas is run through scrubbers at the compressor station, and so, you know, we don't anticipate having, having, uh, having (inaudible) being put back down the well near the gas streams.

Q. Okay. That's almost what I was wondering. I guess what my concern comes from is if we've got open-ended -- well, an open-ended anulus, whatever you want to say. Without a cubing packer are you concerned about liquids -- well, water specifically-- being introduced to the casing where you have some Co2 going past it and then the possibility of carbonic acid being formed from that? What is your thoughts in regards to that?

How much of a -- I'll let you answer the first question first. Go ahead, please.

A. Sir, I need you to -- can you say that again? I'm sorry.

Q. Oh, I apologize.

Since we do not have tubing packers planned to be put on these strings, are you concerned at all about water from the Formation causing carbonic acid to form on your casing and causing corrosion issues?

A. Uhm, no, sir. You know, based on normal operations and -- these are typical installations on how we normally gas up these wells -- we haven't seen any major issues with corrosion, uh, although, in these types of wells in the Avalon Formation, if it comes to a, uh -- well, depending on pressures with Co2 on the wellbore. And so that's one of the factors for corrosion rates in this type of well.

But a closed type of well, depleted as it is, you know, we don't foresee any issues with corrosion.

Q. Yeah. My only concern, of course, would just be once we start injecting a bunch of gas, if it -- contingent upon the duration of it would be if at that point maybe you start seeing an elevated, I guess, pressure.

I was going to say at this particular point I think this is something we need more data on, so I'm not going to -- obviously I'm not going to take a hard path, I guess at this point, of course.

But my next question for you would be:

Just how restrictive do you think it actually would be to your operations to have a tubing packer installed on these wells?

A. So the -- the main benefit -- a couple of reasons that we don't like to run packers. One of the main reasons is it will have a future fishing job, right? So the packer becomes stuck in the wellbore, it could destroy the future value of the well, just if we are unable to fish the packer out. And that's just, you know, part of life in the Permian Basin. You know, we do produce these Formation things, uh, and you can, uh -- you can get solids that they fall on top of your packer and, uh, could cause you to get stuck in the future.

That's probably, really the main reason we don't like to run packers on gas --

(Note: Reporter inquiry.)

The main reason we don't like to run packers in our wells that were producing, producing wells that are set up with gas lifts, the main reason is that we don't want that packer to become stuck in the future. And so in the Permian Basin -- you know, a lot of these wells will be producing, and, uh -- and those solids can fall out on top of your packer and cause you to get stuck.

And so that could, you know, destroy the future value of your well, really.

So that how's I was just saying that's one of the main reasons that we don't like to install packers.

You know, for the purpose of this project one of the main reasons that we do not want to pack at all is so we have the capability to inject gas, both down the anulus and down the tubing, which would reduce our frictional back pressure on our injection gas, which allows us to inject at higher rates and higher volumes, to achieve our goal of eliminating flaring off of our gas systems.

Q. Do we have like a projected value of just how much -- we don't have any estimated value of how much additional back pressure you're actually talking about from that, and how much that would reduce the rate, do we?

A. I don't have that off the top of my head, I'm afraid.

Q. Yeah, that there is fine. That's fine.

I'm just trying to follow that line of reasoning all the way down, but it's fine if we don't have any answer today for that.

Let's see. Sorry. I'm looking through my notes to see if there's anything else I should be asking of you before I turn you back, I guess.

I'm not seeing any other questions that I have -- at this time, anyway. Thanks a lot for

your testimony.

THE WITNESS: Yes, sir. Thank you.

EXAMINER ROSE-COSS: And I had -- another question came to mind, if I can interrupt again, Mr. Letcher.

FURTHER CROSS EXAMINATION

BY MR. ROSE COSS:

Q. I was curious again.

You said that you-all were not going to run MITs until a later date. Could I hear a little bit more about the logic of that?

Do you think that these MITs are going to be run before an Order might be issued; and should an Order be issued and then the MIT come back.

You know. In a core direction, how might EOG handle that?

A. Yes, sir. No, I think we just -- we wanted to get through the hearing today, but we are ready to begin running those MITs as early as next week, actually.

So we have plans to go ahead and begin with MITs. We -- I guess we didn't want to go run MITs and then have any other questions come up that would have had us have to go back to address, I guess.

MR. ROSE-COSS: I see. Those will be run, hypothetically, before an Order is issued.

Dean, you did have any questions or suggestions about the MITs before they run them?

EXAMINER McCLURE: Oh, I'm -- I'm sorry if I was being too expressive with my face.

The only other thing is I personally would be opposed to the Division issuing an Order contingent upon MITs being run prior to injection but post the Order being issued. Assuming that you're in agreement, Dylan.

EXAMINER ROSE-COSS: Yeah, that makes sense. That exhausts my questions, so I'll pass the witness.

HEARING EXAMINER BRANCARD: Thank you.

Ms. Luck, did you have any redirect questions?

MS. LUCK: No further questions for this witness. Thank you.

HEARING EXAMINER BRANCARD: Okay. How many more witnesses do you have, Ms. Luck?

MS. LUCK: I just have two more.

HEARING EXAMINER BRANCARD: Okay. Ms. Macfarlane, do you want to take a break about this point, or how are you doing?

(Note: Discussion off the record.)

HEARING EXAMINER BRANCARD: Okay. Please proceed. We will do one more witness and then take a break.

JENNA HESSERT,

having been previously sworn, testified as follows:

DIRECT EXAMINATION

BY MS. LUCK:

Q. If you will please state your name for the record. Sorry if I mispronounced it earlier.

A. Jenna Hessert. Jenna is J-e-n-n-a, Hessert is H-e-s-s-e-r-t.

Q. And by whom are you employed and in what capacity?

A. I am employed by EOG resources. I'm a geologist.

Q. Have you previously testified before the Division?

A. Yes.

Q. Can you briefly state your education and relevant work experience.

A. Yes. I received my Bachelor of Science in Geology and Geophysics from Yale University and my Master's in Geoscience from Texas Tech University. Those were in 2014 and 2016. And I've worked for EOG in Midland Division in the Permian Basin for the last four and a half years, and as a project geologist for them I oversee planning and development of wells in Lea County, as well as conducting exploration.

Q. Are you familiar with the application in this case?

A. Yes.

Q. Have you conducted a geologic study of the lands in the project areas?

A. Yes.

MS. LUCK: And with that I would tender Ms. Hessert as an expert witness in petroleum geology.

HEARING EXAMINER BRANCARD: Any comments or concerns?

Hearing none, she is accepted as an expert in petroleum geology.

MS. LUCK: Thank you.

Q. To turn back to Exhibit 4, it requires EOG to conduct geologic analysis, uhm, that address conditions 1 and 2, so have you prepared a series of slides outlining your analysis for each of the five wells?

A. Yes.

Q. So turning to what's been marked as your Exhibit 15, can you go ahead and explain what these exhibits show?

A. Yes. So all of these exhibits from the Bear leases to the Ophelia and Hawk are going to consist of cross sections and maps referencing the wells in question.

I'm first going to say all five of these wells were drilled in the Avalon Shale. That is the same target that the Caballo was drilled in and injected into for our pilot test well.

The Avalon Shale itself is a mud rock with very low porosity and permeability, and you're going to notice throughout all these cross sections and maps the similarity of this geologic unit across all five of these wells, and this helps us have a better and more robust reservoir model. As Mr. Sonka will show, he's used all of these geologic characteristics that I'm going to go over to construct his reservoir models for this project.

So this first map is of the Brown Bear/Black Bear lease. Our lease section, the Bear section, is shown in yellow with the two wells in red. There's surface holes and bottomholes identified and a cross section A to A prime, a three-well cross section roughly north to south across the area with all nearby wells shown.

The next two slides are the same cross section. This one is zoomed out. It goes from the Rustler all the way down to the Wolfcamp. The well tracts shown here are the gamma ray in the first tract, depth, then resistivity and porosity.

The Avalon target is at 9,450 feet. This is roughly 8,200 feet below the Rustler and any shallow-water hazard.

One more thing: This is a structural cross section, meaning it is not flattened on anything, so the fact that the depths are very consistent across all three wells, the lithology is consistent across all three wells, there's no structural or stratigraphic changes, and no structural hazards across this area.

On the next cross section, it's the same three wells. Now we are focused in to our target of interest.

Again the Avalon Shale target is a siliceous mud rock, so you can see at roughly 9,450 feet across all three wells it has a very high gamma signature, meaning it has a lot of clay in it, so it's going to be a very tight rock, has high resistivity, and then the neutron and density porosity response is to that high clay. So this results in a very low-porosity, low-permeability rock that will keep the gas injected very close to the wellbore.

Above this interval is the Bonespring Lime. That signature is a very low gamma ray, high resistivity and low porosity. This a very tight carbonate which will keep the gas confined to the Avalon and prevent it from migrating up into the Brushy above that.

Below the Upper Avalon is the Lower Avalon.

This is also a very tight carbonate, has low gamma ray, high resistivity, and very low porosity and will prevent the gas from migrating down into the First Bone Spring Sands.

And again, these target and characteristics are consistent across this entire area.

Q. And the cross section demonstrates that there is likely no communication or ability for the gas to migrate (inaudible).

A. Yes. It's -- for example, if we were looking for something with ultimate storage capacity, we would actually want the opposite, we'd want a very high porosity, high perm rock. So in this case we're targeting the exact opposite, we're targeting a formation that's low perm, low porosity, and will prevent the gas from migrating.

And also these geologic properties I've just discussed, Mr. Sonka has used them in his reservoir model to further showcase that the gas is staying near the wellbore and can easily be reproduced.

The next three are maps. This first one is a structure map of the Bone Spring Lime. That's the top marker of our interval. You can see it's generally dipping towards the southeast. These contours are at 100-foot intervals and there's is no drastic change in the contours across this section, showing that there are no faults in the area and the structure is continuous across this area.

The next map is an isopach from the top of the Bone Spring Lime to the top of the First Bone, so the entire Avalon Interval, but both the upper and the lower. And you can see it's very consistent across this area, 950 to 1000 feet all throughout this area.

So again not only is the geologic characteristic consistent stratigraphically but also the thickness and structure is consistent across this area, further adding to the robustness of our reservoir models.

And then finally this is a thickness map from the top of the Rustler to the top of the Bone Spring Lime. So as I mentioned, you have about 8200 feet or greater in between our injection interval and any shallow water zone. And again that's consistent thickness, or the thickness is consistent across this area, showing that there are no faults linking up our injection intervals to any shallow-water zone.

Q. So moving on to -- if you're ready, to Exhibit 16, what do these slides show and how do they differentiate from the slides we just reviewed?

A. Yes. So these next few slides in Exhibit 16 are of the Ophelia area map. They will go through the same process and order as the previous ones. They are going to confirm the Ophelia well and the surrounding geologic area for that well.

So it's going to have the same acreage, the well is in red, the surface hole and bottomhole noted, and then three-well cross section A to A-prime that is roughly north to south.

I won't walk through all of it exactly again, but it's the same log track as the previous one. Again, in this case our target interval was drilled at 9,400 feet in the Avalon. You have 8,300 feet or greater between our target interval and any shallow-water hazard.

And again you can see that the log signatures are very consistent across this entire area with no major changes in the depth, showing there are no structural concerns in this area.

Again this second cross section is the same cross section but zoomed in to our target interval. You can see that again we have very similar signatures with high gamma, high resistivity, and then that moderate porosity which is in response to the clay and water in the system, the clays and water in the system. But again this is a very tight, low-permeability and low-porosity mudrock with good barriers that are tight above and below with high-carbonate content that will prevent the injected gas from migrating away from the wellbore or into other wellbore zones nearby.

In this case, same thing with the structure map. It's the Top Bone Spring Lime structure. This is gently dipping to the east/southeast, and again in a very consistent manner, showing there are no faults and no drastic changes in structure, so no geologic concerns in this area.

The thickness of the Avalon again here is about 950 to about 1,000 feet thick and is consistent across this entire area.

Then the thickness maps or isopach maps from the top of the Rustler to the top of the Bone Spring Lime, again you're about 8,300 feet or greater separating our injection interval to any shallow-water hazards, and there are no drastic changes in this thickness across that area, again showing that this area is structurally benign.

Q. And finally Exhibit 17, what does this show?

A. This is the Hawk area lease map. So again our acreage that is specific to this lease is shown in yellow, our two Hawk wells are in red with surface hole and bottomhole locations denoted, and then three well cross sections A to A-prime, across the area.

This is the larger cross section that goes from the Rustler down to the Wolfcamp Interval. In this case our target again was at 9,400 fee in that Upper Avalon. We have 8,000 feet or greater between our injected interval and the Rustler and any shallow-water hazards. Again this, like the others, is a structural cross section, so it's not flattened on anything. Again there's no major changes in the depths across these wells, and integrity is consistent across the area.

Zooming in and looking at our target of interest, again we are very consistent in the gamma signature, the resistivity and the porosity, with those barriers above you and below you that are extremely tight, further showing that also in the Hawk well the gas will stay in your wellbore due to that low-porosity and -perm and will not migrate up or down to other sections due to the tight barriers in the rock above and below you.

The structure, the subsea lime structure is dipping gently to the southeast, again with no major changes in the structure contour across the area, showing that there are no faults to create any geologic hazard for these wells.

The isopach in this area is also very consistent. It changes very little across the area. It's almost exactly 1,000 feet within our injection interval, again showing that there are no drastic geologic changes that would give any concern throughout this area.

Then finally the top of Rustler to the Top of the Bone Spring Lime shows that consistent 8,000-feet-or-greater thickness across the wells that's going to separate our injection interval from any shallow-water hazard, and the fact that there are no offsets or major changes in these structure contours shows that there are no faults connecting us up a shallow-water hazard.

Q. So to summarize, and the reason that you are presenting these slides, could you explain to the examiners what these show in terms of the project area.

A. Yes. So in summary we have barriers above and below the Avalon to prevent gas migration (inaudible) both above and below us, and then the low porosity and permeability of the Avalon Shale will contain gas near the injective wellbore and allow it to be produced back over time.

From the maps and cross sections shown here the area is structurally benign with the no geologic fault conduits by which the injected gas may migrate out of the zone, so there's no geologic concerns throughout this area.

In addition to that, the fact that the area is structurally and stratigraphically consistent allows us to make very good, accurate reservoir models throughout this area that we can use for the project.

And for these reasons our temporary and infrequent injection of this gas will have no negative impacts on any nearby wells or any future well production.

Q. So in your opinion will the granting of this application be in the best interests of the prevention of waste and the protection of correlative rights?

A. Yes.

Q. And can this project be operated safely without presenting a risk to human health or the environment, including sources of fresh water and drinking water?

A. Yes.

Q. Were Exhibits 15 through 17 prepared by you or compiled under your direction and supervision?

A. Yes.

MS. LUCK: With that I move the admission of Exhibits 15 through 17 and I would pass this witness.

HEARING EXAMINER BRANCARD: Thank you.

Any comments or concerns about the exhibits?

Hearing none, Exhibits 15 through 17 are admitted.

Mr. Coss, do you have any questions?

(Note: No response.)

EXAMINER McCLURE: You're muted, Dylan.

EXAMINER ROSE-COSS: Thanks. Rambling to myself over here in my garage.

All I had said was, Thank you, Ms. Hessert, and nice to see you again, even if remotely here.

I would say I don't know how many questions I have as many as comments.

CROSS EXAMINATION

BY EXAMINER ROSE-COSS:

Q. So you attest to the low porosity and permeability of the Avalon Shale, the injection interval. What are the values that are low, and where --

A. Yes. So our petrophysics model that we run off of the log curves, that is a proprietary petrophysics model, but we are in the nanodarcy perm and very well percentaged in terms of porosity.

Q. Okay. I understand that the model is, uh, proprietary and you acquired that. I think something I would like to see in this is just the values that you extract from the logs and then subsequently are used in the models.

A. I can -- if it helps, I can give -- uh, I think it's on there but I'm not sure how clear it is. I can put a scale on those log tracks. And again I think it's on there but I think it's just very small. But I can further show -- yeah, we are in like the single-digit percent.

So...

Q. Sure. And I think maybe something that would help me out, or out of my curiosity as a geologist, I don't see on these cross sections where exactly the injection interval is. And I know it's the Avalon, and I'm just taking a guess that 452 EVNL is the top of that Avalon.

So I might request going forward that these log ticks be identified by more common names than maybe was used inhouse for EOG, just so, you know, on the more spread-out, zoomed-out cross sections that I can kind of -- I can take a guess and know more or less what you're talking about.

A. Yes, sir. We --

Q. The sub- -- what?

A. These are the generic tops that we've used for all of our submissions in previous, but we can give like more detailed ones. But these are generic GDS tops, so they are actually not our EOG inhouse ones. But if you would prefer more clarification on them, we can definitely tell them to fill out those shorthand versions. We can do that.

Q. Yeah. Yeah.

A. Yeah.

Q. Yeah. Just for, you know, in the future for the

public record if someone is going to be scanning through all of the exhibits, it would help me out, at least, I know, so speaking for the general public, too.

Captions. More captions than the little -- just a few more things spelled out about what is trying to be presented in each of the figures.

And I think in these cross sections what would help he out, too, is something that's even -- you know, identify what the injection interval is and have something -- like an especially zoomed-in log interval of just the injection interval, if you know what I'm talking about.

Because I can surmise from what you've presented how thick the injection interval is but it would be helpful if you provided just, you know, the 200 feet that you think is the injection interval, or however much it may be, for my own and the public's edification on these.

And then something that we could actually gather the information from, you know, so somewhere I could actually interpret values of resistivity and porosity and permeability. If that makes sense.

A. It does, and I'm sorry if I wasn't clear on mentioning the target TVD on each of those, but I can go back through them, if you would like.

I might have missed that, but I believe I did mention on each of those the target TVD for each well.

Q. Okay. Well, I believe it's in there and identifiable, and I know you provided, yeah, the well arc diagrams. So we should be fine.

It helps me to understand it if I can see little details like that and kind of figure captions. You know?

And beyond that I don't have any other questions. Thank you for your testimony.

THE WITNESS: Thank you.

EXAMINER McCLURE: I was gonna say I'm thinking you hit pretty much everything that would have been my hot-topic items. The only thing I might expand on Mr. Coss's discussion point, I'm almost wondering if maybe it would be advantageous, and maybe what he's getting at, may be indication not necessarily of where the Total Vertical Depth is going to be but kind of from the first take point to the last take point what is the vertical depth. Maybe even beyond that where you're actually at within the target formation. Because we might have dip on the target formation as the lateral goes, so that may not be quite as indicative as where the lateral is resting on.

But having said that, Mr. Coss, do you want them to submit anything in this application in addition, or what are you thinking there?

EXAMINER ROSE-COSS: Well, uhm --

EXAMINER McCLURE: Or am I incorrect in my thought processes of what you're looking for.

EXAMINER ROSE-COSS: I think I would like to see what you're describing, and I think a table describing the other values I've asked for.

THE WITNESS: So I believe our directional survey for wells are proprietary, but we could -- and I can double check, but we could give you like at least a range of depths, and we can mark that -- that could be easily marked on the cross section; and then, you know, give you average on what isn't proprietary with our log and petrophysical model.

So I would have to check that, but we can give you, you know, as much information as we're able to.

EXAMINER ROSE-COSS: That will suffice. Thank you.

EXAMINER McCLURE: I have no further questions. As long as Mr. Coss is happy, I'm happy.

EXAMINER ROSE-COSS: I'm happy. You've covered the salient points with regards to the geology project.

EXAMINER BRANCARD: Well, we're happy, so what I'm wondering -- first, Ms. Luck, do you have any redirect questions?

MS. LUCK: I have no redirect questions. Thank you.

HEARING EXAMINER BRANCARD: And somebody we really need to keep happy.

Ms. Macfarlane, are you ready for a break, or how are you doing?

(Note: Discussion off the record.)

(Note: In recess from 2:45 p.m. to 2:57 p.m.)

HEARING EXAMINER BRANCARD: Okay. Do we have everyone who's anything back on?

MR. McCLURE: I just changed headsets. Are you guys able to hear me on this one?

EXAMINER ROSE-COSS: Yeah.

EXAMINER McCLURE: Sounds good.

HEARING EXAMINER BRANCARD: Okay, where were we?

Ms. Luck?

MS. LUCK: I think we are ready to call our final witness, Mr. Carlos Sonka.

HEARING EXAMINER BRANCARD: Let's proceed.

CARLOS SONKA,

having been previously sworn, testified as follows:

DIRECT EXAMINATION

BY MS. LUCK:

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

A. Carlos C-a-r-l-o-s, Sonka, S-o-n-k-a.

Q. By whom are you employed, and in what capacity?
A. I'm employed by EOG Resources as a reservoir engineer.
Q. Have you previously testified before the Division?
A. I have.
Q. Were your credentials as an expert in reservoir engineering accepted by the Division and made a matter of record?
A. They were.
Q. Can you state your education and experience in engineering.
A. I graduated from Texas A&M with a Bachelor of Science in petroleum engineering in 2016, and since then I have been supporting petroleum engineering oil and gas projects in Lea County, New Mexico. So for about 4 1/2 years.
Q. Are you familiar with the application filed in this case?
A. I am.
Q. Have you conducted an engineering study of the lands within the project areas?
A. Yes.
MS. LUCK: With that I would tender Mr. Sonka as an expert witness in reservoir engineering.

HEARING EXAMINER BRANCARD: Okay. Are there any comments or concerns?

Hearing none, I will accept Mr. Sonka as an expert in reservoir engineering.

MS. LUCK: Thank you.

So we just heard EOG's geologist testify about why the targeted Avalon Interval will serve as an effective container to hold and temporarily store the injected gas. Have you built an engineering analysis off the geologic study that reflects the suitability of the Avalon for temporary reinjection?

A. Yes.

Q. And your testimony will address the requirements of Exhibit 4 which deal with the reservoir characterization and justification for the reservoir suitability, including the reservoir modeling?

A. Yes.

Q. And you have also considered the proposed maximum allowable surface pressure that's safe for this project?

A. Yes.

Q. So let's start with maximum allowable surface pressure. Could you go ahead and remind us what is the maximum allowable surface pressure that EOG is proposing.

A. For this application we are proposing 2250 pounds as the maximum allowable surface pressure.

Q. And again I will share my screen so we can look at Exhibit 18.

Please state for the examiners and explain what this exhibit shows.

A. Exhibit 18 is a report that's generated based on the frac simulation of this well. And so in the table is the average pressure when the pumps were turned on required to fracture the rock.

The next cell is the maximum pressure that was required.

The third cell is the initial shut-in pressure.

And the final cell is the frac gradient, which is based on the final shut-in pressure.

And below that there's a summary of the property (phonetic) used in the simulation.

So basically what this says is that in order to break the rock under virgin conditions, a frac gradient of .7 was required. And so that's the lowest pressure that will ever be required to fracture the rock because that's the core pressure deplete (phonetic), and the effect of stress increases, and the amount of pressure required to break rocks in a depleted scenario is higher.

So these wells have been on since 2012 and

2014, depending on which set of wells we're talking about, and so the frac gradient at .7 is the lowest it can be under current conditions.

So based on the true vertical depth of the laterals of these wells and the maximum well surface pressure, what we are applying for is a frac gradient as about, you know, .22 to .23, which is -- leaves a pretty sizeable buffer of pressure between the maximum we would experience in this project and the minimum that would be required to fracture any of the rocks that make up these reservoirs.

Q. And so far we have been discussing the frac related to the Black Bear 4H. Such information is similar to each of the wells; is that correct?

A. Right. So on the subsequent exhibit, the same data is compiled for each of the wells that are subject to this application, and so you can observe that the frac gradient ranges from the lowest value of .69 to the highest value of .76, but all of those leave a sizeable buffer between the maximum allowable surface pressure we are applying for and that minimum pressure it would take a break the rock.

In fact there won't be equipment, uh, of sufficient pressure rating to generate surface pressures that would cause the rock to break down as a part of our design, so we feel very comfortable with the maximum allowable surface pressures that we are proposing.

Q. And just to review the qualifications in the letter, the proposed maximum allowable surface pressure of 2250 exceeds the gradient of .14 psi per foot.

A. It does.

Q. And it's EOG's opinion, or your opinion that the 2250 psi is a safe maximum allowable surface pressure for the project and won't damage the reservoir?

A. Correct.

Q. And it's also your opinion there is a substantial gap between the formation's structure point and the MASP?

A. Yes.

Q. So based on this data, it's your opinion that the 2250 psi, which is greater than the gradient of .14 is justified?

A. Yes.

Q. So let's talk about the characteristics of this reservoir and how you came to that conclusion.

Have you prepared reservoir models to evaluate the potential for injected gas to migrate out of the formation and interfere with the producers or impact underground sources of drinking water?

A. Yes, I have.

Q. Let's turn to what has been marked as Exhibit 19, and explain what these models show.

A. Exhibit 19 starts with a photograph of a couple of slices of the model. And this is just to illustrate in a basic sense what the model looks like.

So these different shades of blue are different layers within the model that have different geologic properties assigned based on the log response that was testified to by Ms. Hessert.

And then you can see one of the wells traversing through the target layer, which is that lightest blue, all the way from heel to toe.

So the next slide, this is just, without any injection or closed loop gas capture operations, what the model looks, as well, uh, at current times. This is one of the Caballo wells that came on in 2012, and through the life of this well as it's produced, it has drawn down the pressure in the reservoir. So the red and orange colors are the initial virgin pressure, and then the blue region near the wellbore is a region where the pressure's been reduced below the virgin pressure associated with the production of this well.

And the extent of that blue region is limited by the low permeability of this reservoir.

So that's what that slide shows.

The next slide is a plot just illustrating -- it says that the well has actual production and pressure, and so what we've done is we've taken the log responses to build the initial model and then we fine-tuned certain reservoir (inaudible), to match the actual history of the well.

So once we match the history we feel better about the forecast associated with this model. And, uh, that maps all the times to the left of the red line, and then the at red line we begin simulated injection in the model.

And so we've matched the maximum volumes that will be associated with the project, and then alternatively injected and produced the well. And so what's really notable about this is that on a net basis the bottomhole pressure is continuing to deplete, which indicates that this well is a net producer, and that's confirmed by the oil and gas rates continuing to fall through time, as well.

The next slide is just a yearly oil and gas net production rate. And so what is of note here is that the trend is not significantly impacted by the intermittent injection, and actually to evaluate whether or not the intermittent injection would have any negative consequences on the wellbores and the recovery, it indicates where we never injected and ran up the casing until we could determine what the forecasted ultimate recovery would be, and then made an identical case where we changed the injection to be at the volumes and rates that will be associated with gas capture operation, and ran that case out. And what we found is that the recovery was the same in terms of oil and gas, leading us to conclude that they wouldn't have any detrimental effect on the ultimate production.

The next slide is a little bit more complicated in terms of the size of the model and how many wells are present.

So this we were trying to determine whether closed loop gas capture operations would impact any neighboring wells, and so we assigned three wells to this pink layer, which is our Leonard-A target.

The middle one has simulated closed loop gas capture operations, and the other two are just standard producing wells which we are monitoring for any impact. Uh, so...

The next slide shows -- this is without any injection or prior to any simulated injection. So this shows that same region of drawn-down matrix pressure that matches the actual production of the well, and just with multiple wells overlaid. And so what's notable here is that the draw-down is confined near the wellbores, and because of the simulation technology that was employed, the wells actually don't drain effectively in the matrix very far out, and so within the matrix there's regions of unaffected pressure due to the really low permeability. And so between the wells there's actually areas where the pressure is still close to 5,000 pounds, and so that's why we don't think that a surface pressure of 2250, even with a gas gradient on top of that, there's no way to flow the gas in the region that are at 5,000 pounds of pressure.

So we think the model and then the cross check of the model versus the Caballo test actual results indicate that the gas is staying very close to the actual wellbore and then being reproduced as soon as the well is turned back into production operations.

The next slide is a similar slide, but this is just showing on one day where we're injecting and then one day when we're producing.

So this is a Gas Per Unit area. In regions where the Gas Per Unit area is zero that's because the pressure's high enough it's at over-the-bubble point and so any gas is in trend in liquid form still. And then as you reduce the pressures some of the gas starts to evolve.

But what's notable here is that a massive quantity of gas has really been removed, such that when you cycle injection or production it doesn't really change what's going on in the reservoir because we're injecting a tiny percentage of the in situ reservoir quality that's been removed through the production life of these wells.

And so once we have this model built we would need to create additional models, which we just made to check if the geologic properties varied significantly or if the spacing varied significantly, how would that affect the behavior suitability of the closed loop gas capture well. And what was determined from all this modeling work is that all the wells in this application are suitable closed loop gas capture candidates.

The next slide is just an example of one of those, which is the Caballo.

You see four wells in the legend. Two of these wells are overlaid. It's an artifact of how the computer program treats injector wells. But there's really three entities. So the red line is the closed loop gas capture wells, and then on either side, east and west, you have the green line and the pink line which are the offset wells.

And so this is just the pressure, the average pressure of all the well blocks with the well perforations. So basically the bottomhole pressure of the well. And you can see that the offset wells, even though you're injecting with a closed loop capture well, there's no response in those well blocks and those continue to deplete on trend.

And then the actual injection well, as you inject it built a little bit of pressure, you know on the order of 200 pounds or so, and then as you produce it it depletes that back, and then through a longer time scale it continues to deplete the reservoir and produce the natural resources associated with that.

So that's all I have on that slide.

Q. Let me just be clear it's Exhibit 20 now, so...

A. Okay. Sorry.

Q. That's okay. And the next slide.

A. So the second slide on Exhibit 20 is the -- so before we looked at the pressure to see if there would be any impact. This is the cumulative production. And so the red well is the closed loop gas capture well, and then to each side you have the two offsets. And the trend of the production is unaffected by the start of the injection.

And in this case with the multiple wells we also ran a case where we didn't inject and a case where we injected, and compared the ultimate recovery, and that's what leads me to my determination that this intermittent closed loop gas capture injection won't have any negative impact on the ultimate recovery of these reservoirs.

Q. Okay. And so just to summarize, your analysis indicates that the injected gas will have a net positive impact on the ultimate recovery?

A. It should be neutral. There was no positive impact at this (inaudible).

Q. So the reservoir modeling indicates that the gas will be confined to the targeted interval and will not migrate from the Formations.

A. Correct.

Q. And it's your opinion that it's also not going to impact the offset wells.

A. Correct.

Q. And again could you -- I think you covered this, but just confirm that the models are built on a formation-wide basis because the area character and geologic properties with the Caballo wells?

A. All the wells that are subject to the application target the Leonard A, and so we built multiple models with different geologic parameters within the range that the logs indicate, and then varied them just to understand the low case, high case, kind of intermediate case within the Leonard A.

So we feel like these models encompass the areas where these candidate wells are located.

Q. Okay. And then, uhm, I think that might cover everything with my questions, except for these last few questions.

And so in your opinion will the granting of this application be in the best interests of the prevention of waste and the protection of correlative rights?

A. Yes.

Q. And can this project be operated safely without presenting a risk to human health or the environment, and will it be protective of fresh water and drinking water?

A. Yes.

Q. So were Exhibits 18 through 20 prepared by you or compiled under your direction and supervision?

A. Yes.

MS. LUCK: And with that I would move the admission of Exhibits 18 through 20 and pass the witness.

HEARING EXAMINER BRANCARD: Thank you. Are there any comment on Exhibits 18 through 20?

Hearing none, we will admit Exhibits 18 through 20 and pass the witness.

Mr. Coss.

MR. ROSE-COSS: Thank you. Good afternoon, Mr. Sanko. Nice to see you again. Thanks for your presentation.

I'm scrolling ing through the exhibits on my screen.

I do not have any questions and I pass the witness.

EXAMINER McCLURE: Yep, I do have a few questions. I guess the very first one is the proposed MASP of 2250.

CROSS EXAMINATION

BY EXAMINER McCLURE:

Q. Am I correct, then, in the assumption that we do not actually have that in writing anywhere, wherein we do have 3500 within the original application?

Is that correct?

A. Uh --

MS. LUCK: I'm not sure that the 3500 was included in the original application, but I can confirm. But I don't think that we have the 2250 in any of our exhibits now.

EXAMINER McCLURE: Okay. Mr. Brancard, do you think we need that in writing or can verbal testimony take the place of having the change in MASP in writing?

Within the original application it had 3500 psi stated, but do you think we actually need that supplemental documentation submitted or we go to verbal?

HEARING EXAMINER BRANCARD: So the applicant is okay with that number? Or...

MS. LUCK: I'm sorry. I'll let the witness speak.

THE WITNESS: Based on our test at Caballo we feel like this is enough pressure to do the project successfully, and so that's why we lowered it a little bit.

HEARING EXAMINER BRANCARD: Well, I think we have that on the record, Mr. McClure, so I think we are fine.

Mr. McClure: Sounds goods. That was all I was touching base on so far as the MASP goes, the 2250.

Q. The only question I guess I have somewhat related to that: When you could determine the hydrostatic pressure from the fluid column, did you take into account the MASP at surface, uh, where I'm assuming you did a nodule (phonetic) analysis or something to determine the actual density of the gas throughout the column. Or am I incorrect in that statement?

A. Yes, that was incorporated into our determination of this revised MASP. We don't have it quite in as much detail as we did on the Caballo pilot when we actually went through the density of the gas and, like you said, the nodular analysis in the pressure and density iteration. But that was incorporated into this determination, certainly.

Q. So that it's pretty safe to say that we have plenty of safety factored if we consider a fracture gradient of 0.65 instead of estimated fracturE gradients based off of the frac program.

Is that correct to say, then?

A. Yes.

Q. Okay. That there was kind of what I was, uhm, confirming, I guess. Based of earlier testimony it sounded like that was the case.

I guess the question I have on your models that you ran here: Did you change the model much from the prior model you had run for the Caballo or is it pretty much the same parameters, the same setup?

A. So for the Caballo we actually matched the production of the Caballo well, so we had really specific parameters. So this one we had that model as one of our models, but we had additional models with what we thought were reasonable numbers of what we thought the properties could be, just to determine, you know, if maybe our -- with the geologic uncertainty between models, just wanted to capture that and make sure that we'd be good in all those scenarios.

So it's different in the sense that there's more models for this hearing than there were for the previous one.

Q. It sounds good. Sounds good.

I guess the question I have for a follow-up is: Did your results from the previous pilot project relatively match what your prediction was from your models?

A. Yeah, that's a great question.

So the main difference -- so generally they did. The main difference was that we recovered the injected gas a little bit more quickly than the model suggested we would. And I think there's a couple of reasons for that.

The main reason is that within the model the simulated reservoir volume is static, and then in reality as the pressure depletes some of the fractures are closing or compressing, and so the fractures you don't close, their conductivity is reduced.

And so the gas is probably traveling less far in reality than it is in the model, which leads to a faster recovery of that injected gas.

But other than that the pressure responses, the ability of the reservoir to, you know, store the gas, everything like that was in line with what the models predicted.

Q. It sounds good.

I think I asked you this question like a year ago now, around about, but I do not remember what your response was at that time.

Do we have an estimate or any sort of projection as to what the vertical height is of the fractures, a typical fracture in this formation in this geographic area?

A. Yes. So there's a couple of indications of that. We don't have any exhibits to support that, but we collect a lot microseismic data. We monitor our frac pipe load. Definitely you can interpret it from the performance of packages where you have staggered vertical development, co-development.

And then we have, you know, some profit models.

The height in this model of the fracture for the simulated reservoir volume is 75 feet above and below the well. And so that's, like I said, probably the original simulated reservoir volume, and then through time that volume is decreasing as the pressure in the matrix of fractures increases and fractures begin to close and lose conductivity.

I don't know if -- did that make sense?

Q. Oh, yeah, yeah, yeah, yeah. I apologize. I was looking at the earlier exhibit, geographical exhibit, just

to try to see what the height was of our target formation, and it looks like it is well, well -- uh, well more than 75 foot each way.

So I guess my question would be: So then all speculation is that the fracture heights are well within the target formation and do not extend out of it, essentially. Is that correct?

A. That's the way I think about it. The geomechanical contrasts between vertical formations tend to arrest the fractite (phonetic) growth vertically more so than laterally, just because there's more contrast vertically.

Q. I guess in your model that you ran that you have the two neighboring wells, you don't have it depicted there, but how long of fracture half-length did you have in those models there?

And I guess I didn't see a scale as to how much distance there was between those wells. I apologize if you mentioned it and I didn't catch that.

I think you have a model there, there's like three of them. Yeah, that one.

A. Yeah. So the spacing on these was varied, uhm, just so we could understand if there was any sensitivity and suitability for closed loop gas capture as a function of spacing.

So this particular string shot, these wells are 800 feet apart, and so the fracture is, you know, about 150 to 200 feet total, so 100 feet or 75 feet each way from the wellbore.

I don't know if that's what you mean by fracture half-length.

Q. Uh, yeah, correct. The fracture half-length would be how far it extends in each direction from the wellbore, essentially, is what I'm trying to ask. Not vertically. Horizontally is what I'm wondering now.

A. Yes.

Q. And the answer to that is 75 feet, you're thinking?

A. It's 100 -- so in the middle it's 175 and 100 on the outer ones.

You know, we start with the completion design was, and we understand what our initial SRV assumption should be in these models, but then to match the history of the wells, in some cases you end up modifying the simulated reservoir volume -- if that makes sense.

Q. Now, in your actual results from the prior pilot project, you've seen, during your long injection test, increased production rates of, say, 200 mcf, if I remember correctly -- you can correct me if I'm incorrect on

that -- uhm, in the neighboring wells that were approximately a quarter mile away. Your explanat- -- well, what was your thoughts in regards to that?

A. Uhm, so that's a -- so we see similar responses when we shut in a well that's between two wells, and so some of that, you know, could be related to the different flow boundaries. So when you have two wells, mathematically with the pressure transient you have what we call a no-flow boundary between them where a molecule on one side of that will flow to one well and a molecule on the other will flow to the other. It's like the Continental Divide, or something, for rivers.

And then when you shut in a well you lose that image well that produces the no-flow boundary, and so the change in geometry of the drainage region can affect, you know, the instantaneous production. It's just a response that see we when we shut in wells, too.

So, uhm, I don't think -- you know, anyone on the technical team, I can't speak for them, but I'm not too concerned that that's an indication that gas is traveling through a fracture network in the nearby wellbore. I think it's just a function of the pressure waves in the reservoir.

Q. I guess what my question to you would be is where you had an upward slope of the flow rate continuing

to increase as time had went on, do you feel that that would eventually stabilized out or do you think it would have continued onward until you were producing all of your injected gas out of your neighboring wells instead of retaining any in the reservoir?

A. Are you referring to Exhibit 20 or are you referring to the results of the Caballo test?

Q. I'm referring to the results of the Caballo test, because I felt they were very much relevant, I guess, to continue the pilot projects.

A. Oh, yes, definitely.

So I think that if you were to continue to inject and produce out of your other wells, your injection pressure would continue to rise, as we saw, which indicates that you have defined volume into which you are injecting. And then the other wells definitely would turn a corner and start to produce less and less fluids.

So the pressure build that we observed on our injection pressure for the injection well, to me indicates that you have a defined volume that is filling up, and that's why the pressure's increasing.

So I don't think you were draining that volume with your offset wells.

So to answer your question: No, I don't think you would produce all your injected gas off the offsets.

Q. So then your thought process is: Moving this no-flow boundary closer -- I guess the no-flow boundary is moving closer to your injection well might be the thought process? I don't know how accurate the thought process would be there.

Uhm, your thought process is that it's eventually going to stabilize and that the neighboring well isn't drawing from a larger area than what it normally would be while you're injecting within the injection zone -- or the injection well, excuse me.

A. No, it's possible that your pressure support is coming from a larger region if you shut in your middle well, but the actual molecules of hydrocarbons aren't coming from that region, they're coming from nearer to the wellbore.

I don't know if I'm thinking about your question correctly.

Q. You're thinking -- you're thinking about my question correctly. I believe so. I'm only looking at the magnitude of the increase of flow that we saw, and that it's perhaps the drawing -- that draw-down area is further from the wellbore than what you're picturing, I guess, within your models, considering that we see, you know, the 200 mcf within a day of increase of production.

HEARING EXAMINER BRANCARD: Sorry, everyone. I need to simply interrupt for one moment. I know we are in the middle of a stream of thought, but one moment here. I see a new call-in user, and I wanted to verify -- I've unmuted you now, call-in user.

I have a Mr. Samaniego on the phone, on the call?

MR. SAMANIEGO: Yes, sir.

HEARING EXAMINER BRANCARD: Mr. Samaniego, I'm aware of the email exchanges that have gone on, and we would like to take up any issues you might have after we quit this case. I'll leave you on mute until then.

MR. SAMDIEGO: Yes, sir. Thank you.

HEARING EXAMINER BRANCARD: You're welcome.

MS. LUCK: I'm sorry, could you clarify who that person is and if it relate to this case?

HEARING EXAMINER BRANCARD: No. It's a member of the public who has called in respect to Cases -1605, -1606 and 21607.

MS. LUCK: Okay. Thank you.

HEARING EXAMINER BRANCARD: Yes. Pardon the interruption. You may proceed.

EXAMINER McCLURE: Do you want me to restate my last question, I guess.

THE WITNESS: Yes, if you don't mind, sir.

EXAMINER McCLURE: Yes, sir.

Q. I guess what my question is, is: Taking into account the magnitude of the 200 mcf increase in each of the neighboring wells, do you think that the draw-down that you're taking your hydrocarbons from within the reservoir extends further than your 100-foot fracture half-length?

Because I mean we've seen the immediate effect from the injection into your closed loop gas capture well.

A. Right. So the simulated volume is one thing, and then, you know, there are natural fractures present in all these reservoirs. So it's possible that you can communicate that quickly through a natural fracture, but it's the -- the aperture of that frac, you know, is not going to lead to significant communication, uh, more so than just the pressure, uh, type of pressure waves moving through there.

The response that we observed in the offset well was something that we observed whenever we just shut in a well, the offset wells will pick up a little production, as well.

So I always go back to the injection pressure build as indicating that there is a defined tank where the gas is going.

Q. I guess what my next question, then, is: With the understanding that we did see an increase of production from the offset wells in the prior pilot project that was of greater magnitude than when you shut in the wells, I guess is EOG opposed to the increased reporting of wells within a quarter mile of their requested closed loop gas capture wells for this pilot project?

MS. LUCK: I -- sorry.

EXAMINER McCLURE: Do you want me make it a little simpler, or maybe say the question in a better way, or what do you want?

MS. LUCK: Yeah. Can you (inaudible) the question a little more (inaudible).

EXAMINER McCLURE: Okay. Yes.

Q. I guess what I'm asking is: Is EOG opposed to presenting us with the data that we were requesting within that draft letter that we had sent on December 17th, I believe, for all wells within a quarter mile that EOG owns of the gas capture injection well.

Hopefully that was simpler.

MS. LUCK: Yes. I think that we might need a clarification. Are you speaking to only wells that EOG owns or wells operated by other operators?

EXAMINER McCLURE: I'm thinking with the

inclusion of the number of wells we're talking about. Then I think we can limit the scope to the wells that EOG owns.

MS. LUCK: I think that EOG is willing to accommodate the request of the Division in terms of providing the information, uhm, if we can have like some clarification about exactly what the Division wants to see. I'm not sure if we can have just like something that states exactly what needs to be provided in terms of these other wells or what the Division's requesting, and then we can see what we can provide based on that request.

EXAMINER McCLURE: Essentially it is the oil and gas production rates and the casing pressure -- production casing pressure, excuse me, for each of the wells within one quarter mile -- have a lateral, within one quarter mile of the lateral of the injection well.

MS. LUCK: I think that's something that we would be able to provide, and so that would have to be submitted after the hearing.

EXAMINER McCLURE: Okay. Sounds good.

Q. Moving on, I think I actually asked this question as well like a year ago.

So was consideration made for effect to the reservoir from injecting a lighter gas than what you're producing?

A. Uhm, yes. So EOG, the company has a lot of experience injecting lighter gas in this as part of the EOR, Enhanced Oil Recovery, kind of a secondary recovery program. And so in this case the pressure is so low that in terms of shifting the phase envelope or changing admissibility of any fluids, the pressure is too low for anything like that.

So, for example, we're talking about like 7- or 8,000 pounds surface pressures in some of our EOR projects, whereas here we're talking about 2200. And we just have a little bit different fluid mix, anyway.

So we don't think that there's going to be any type of EOR effect, and with how clean and dry the gas is, we don't think there will be any corrosive effect. The gas is, you know, all compatible with the reservoir fluid, so there shouldn't be any type of relative permeability or chemical effect to reduce the permeability of the well -- or the reservoir, I should say.

MR. McCLURE: Sounds good. I just wanted to confirm that you had taken that into account in your considerations. Sounds like your results come out in the affirmative.

Let me see if there's anything else, if I have any notes here, before I actually pass you back.

Yeah, I'm thinking that that kind of

covered everything I had in my notes. Thanks a lot for your testimony.

THE WITNESS: Absolutely. Thank you.

MS. LUCK: I don't have any other questions of this witness. I just want to confirm there isn't any questions of this witness before he's excused.

HEARING EXAMINER BRANCARD: Do you have any redirect, Ms. Luck?

MS. LUCK: I don't have any redirect, no.

HEARING EXAMINER BRANCARD: Okay. I don't hear any other desires to question the witness, so I think we're done.

MS. LUCK: Okay. And if I may, I'd like to just revisit the guidance from the Division Director. In terms of the (inaudible), I want to just be sure that everybody understands what EOG's direction was from the Director, and then I'll just make a brief closing statement.

HEARING EXAMINER BRANCARD: Sure. Go ahead.

MS. LUCK: Yeah. So as far as the October, 2019 letter, it's our understanding that EOG met with the Director in November of 2020, like through a series of phone calls with the Director and (inaudible) Powell, and they were the individuals at the Division who advised EOG to follow the October, 2019 letter, rather than, uh, new guidance that's still in the draft form and under comment.

And I'm not sure if you-all have had a chance to discuss internally. That's just our understanding at this point.

Uhm, and then just to summarize really briefly, I'll make a closing statement.

Uh, in this case EOG is requesting to start this project upon Division approval and not go through a pilot process. EOG is willing to provide the data that's been discussed during the hearing today for the Division's review, but we would request that an Order be issued as soon as possible so that EOG can commence the injection operations on these five wells.

And EOG is making this request based on the testimony that was presented today, as well as the exhibits and the results of the Caballo well that has been provided to the Division.

Uhm, and then also, as I mentioned, EOG would like to have an Order with an open-ended duration so that the Order would last as long as these wells are capable of injection and production, as contemplated by EOG, and if there's any kind of renewal that's required it would be through the administrative process rather than another hearing.

And I think with that, that sums up the primary request that EOG is making in this case, and if the Division would prefer, we could submit something in writing, if necessary.

Thank you all for your time today.

HEARING EXAMINER BRANCARD: Okay. There were a number of discussions about items the examiners may have wanted. Was there an agreement on any additional submittals that need to be made after the hearing?

MS. LUCK: I think we have a list of the items that were brought up during the hearing, and we intend to submit those to the Division as soon possible.

I'm sorry, I have discussed several with the staff with (inaudible) and still need to use the forms, so all of these things would be provided as they are available to EOG.

HEARING EXAMINER BRANCARD: Okay. I just wanted to confirm because I know, you know, items were brought up whether there was sort of an understanding about what needs to be provided -- and when would be helpful.

EXAMINER McCLURE: I was going to say the main -- go ahead. I'm sorry.

MS. LUCK: No, go ahead.

EXAMINER McCLURE: The only thing I was going to say: I don't know if, Mr. Brancard, you were directing it at us to say what we were looking for, or what do you want there.

HEARING EXAMINER BRANCARD: I was hoping somebody kept track.

EXAMINER McCLURE: I'm going to say the primary things that I was wanting to see, considering we are going with the verbal for the 2250 MASP, an infrastructure map showing how the infrastructure is interconnected, and then actually what may not have been mentioned is also a list of the wells which are supplying gas to that infrastructure and could be, in theory, injected into these wells.

In addition to that, a gas sample, analysis of a gas sample for each of the compressor sites.

HEARING EXAMINER BRANCARD: Mr. Coss, do you --

EXAMINER ROSE-COSS: That about summarizes it. The only thing I would add is a kind of a table of reservoir properties used in the model and a zoomed-in version of the logs specifically across the target interval.

Oh, it came to me. And then we had mentioned it also, a summary or analysis of the expected, uhm, kind of injectate volumes and a definition of what kind of duration, volume, frequency; and a definition of what low, medium and high volumes are kind of -- the ranges, a definition of the ranges, volumes expected.

EXAMINER McCLURE: And I apologize, I almost forgot the actual most important thing that we need, and that is a submittal of the complete Affidavit of Publication demonstrating that Public Notice was presented for all five wells.

I'm sorry, I missed that in my notes, but that's the most important thing we need to see.

MS. LUCK: And I actually received that from the newspaper during the hearing, so I will submit it after the hearing.

EXAMINER McCLURE: Good to hear.

HEARING EXAMINER BRANCARD: Okay. So you have a list of chores, Ms. Luck, to do here.

Anything else the examiners want to bring up at this point with this matter before we take it under advisement subject to further submittals?

EXAMINER ROSE-COSS: No. I thank everyone for their time and testimony.

EXAMINER McCLURE: And I'll say I'll just save it for the testimony. I don't there's anything else we need to discuss, at this particular point anyway. Thank you.

MS. LUCK: Thank you all for your time. We really appreciate your consideration of the case and the interest you have taken in all of our exhibits and asking thoughtful questions. And of course if there's is any other questions the Division has for EOG, please let us know.

HEARING EXAMINER BRANCARD: Okay. So Case 21567 is taken under advisement subject to the further submittals that were discussed briefly here.

Great. Thank you, Ms. Luck.

MS. LUCK: Thank you. And you all have a good weekend.

EXAMINER ROSE-COSS: Likewise.

HEARING EXAMINER BRANCARD: Thank you.

(Note: Time noted 3:47 p.m.)

REPORTER'S CERTIFICATE

I, MARY THERESE MACFARLANE, New Mexico Reporter CCR No. 122, DO HEREBY CERTIFY that on Thursday, January 7, 2021, the proceedings in the above-captioned matter were taken before me; that I did report in stenographic shorthand the proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability and control.

I FURTHER CERTIFY that I am neither employed by nor related to nor contracted with (unless excepted by the rules) any of the parties or attorneys in this case, and that I have no interest whatsoever in the final disposition of this case in any court.

/s/ Mary Macfarlane
____

Mary Therese Macfarlane, CCR
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