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

APPLICATION OF FRONTIER FIELD SERVICES, LLC FOR A MOTION TO AMEND ORDER NUMBER R-13443, REQUESTING THE COMMISSION TO AMEND THE ORDER WHICH AUTHORIZES FRONTIER TO DISPOSE OF TREATED ACID GAS, TAG, FROM FRONTIER'S MALJAMAR GAS PLANT BY INJECTING THE TREATED ACID GAS STREAM INTO ITS MALJAMAR AGI #1.

CASE NO. 14664

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

BEFORE: CHAIRPERSON JAMI BAILEY
COMMISSIONER TERRY WARNELL
COMMISSIONER ROBERT S. BALCH

February 14, 2013

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Commission on Thursday, February 14, 2013, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico.

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ALSO PRESENT: Mr. Jesse Allen, Law Student and OCD Legal Intern

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EXHIBITS OFFERED AND ADMITTED

(9:03 a.m.)

CHAIRPERSON BAILEY: Today I call Case Number 14664, Frontier Field Services, LLC's motion to amend Order Number R-13443, requesting the Commission to amend the order which authorizes Frontier to dispose of treated acid gas, TAG, from Frontier's Maljamar Gas Plant by injecting the treated acid gas stream into its Maljamar AGI #1.

We will call for appearances.

MR. LARSON: Good morning, Madam Chair, Commissioners.

Gary Larson for Frontier Field Services.

MS. GERHOLT: Good morning, Madam Chair.

Gabrielle Gerholt, Oil Conservation Division.

This is Jesse Allen. He's a law student at UNM and an OCD legal intern this semester.

CHAIRPERSON BAILEY: Thank you.

Would you like to have an opening statement?

MR. LARSON: I would. I'd ask for your indulgence for a moment. My witness has a PowerPoint presentation and needs to get that set up, if that's acceptable.

CHAIRPERSON BAILEY: Okay.

(Pause in proceedings.)

OPENING STATEMENT

MR. LARSON: Thank you for your indulgence, Madam Chair.

I'm not sure that the Commission's familiar with Frontier Field Services, LLC. It's a midstream company owned by the Southern Ute Tribe that gathers and processes natural gas. Frontier owns and operates gas processing plants in New Mexico, including the Maljamar Gas Plant.

Division Order Number R-13443, which I believe was the last acid gas injection order that the Division issued, authorizes Frontier to inject acid into the Maljamar AGI #1 well, which is located a very short distance from the Maljamar Gas Plant. And as the plant manager, John Prentiss, testified at the June 2011 Division hearing in this case, the vast majority of the gas that Frontier processes is sour gas. Mr. Prentiss also testified that acid gas that was derived from the processing plant will be injected into the Maljamar AGI #1 well with 88 percent CO_2 and 12 percent H_2S.

As Mr. Prentiss further testified, there are two major reasons why Frontier requested the authorization to dispose of acid gas in the proposed AGI well. First, as part of its overall environmental program, the Southern Ute Tribe wanted to eliminate, to the greatest extent possible, CO_2 and SO_2 emissions from the gas plant.

And, secondly, Frontier saw the need for expansion of the plant based on increasing demand in the field for sour gas processing. And because the plant is a Clean Air Act Title V facility and it's bumping up on the maximum emission rates for SO_2 in its air quality permit, Frontier needs to inject the acid gas from the plant to facilitate a needed expansion to the plant's capacity.

And in its application, Frontier requested primary and secondary injection intervals for disposal of acid gas, and that request is very pertinent to our motion today. And Mr. Gutierrez will address that in his testimony.

There was no opposition to Frontier's application at the hearing, and the Division issued its order on August 11, 2011.

And the order identifies eight offset wells, which are completed in the upper and lower Wolfcamp Formations within 1.5 miles of Frontier's Maljamar AGI well and requires Frontier to put H_2S warning flags or other safety indicators on the wells and plug any of the offset wells whose H_2S level exceeds

100 ppm H_2S.

As the time came for Frontier to begin drilling the well and complying with the requirements of Order Number R-13443, Frontier realized that the plugging requirement was unnecessary and unworkable. And accordingly, Frontier determined that it should file a motion with the Commission requesting that plugging requirements be eliminated.

Frontier's motion has two specific requests for review. The first involves lowering the uppermost elevation on the injection interval, which basically involved eliminating the secondary injection interval addressed in the order. And Mr. Gutierrez will also testify that the proposed change will merely reflect the proration of the wells actually completed.

The second request involves the elimination of the plugging requirement for the offset wells. Mr. Gutierrez will also provide testimony demonstrating that the wells are all currently operated by other companies and that five of the wells have H_2S levels that significantly exceed 100 parts per million H_2S without any injection by Frontier. And in any event, the outer edge of the injection plume, after 30 years, will be a considerable and safe distance from the wells.

As I'm sure Ms. Gerholt will discuss in

more detail. William Jones of the Division has submitted pre-filed testimony in which he supports Frontier's motion to modify the order in paragraphs six and seven in Order Number R-13443.

In conclusion, Frontier will demonstrate that its proposed modifications to the order are reasonable and are necessary to reflect actual conditions on the ground and that the Commission should grant Frontier's motion in its entirety.

CHAIRPERSON BAILEY: Shall we swear in your witness?

MR. LARSON: Certainly.

ALBERTO A. GUTIERREZ,

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

DIRECT EXAMINATION

BY MR. LARSON:

Q. Morning, Mr. Gutierrez.
A. Good morning.
Q. Please state your full name for the record.
A. Alberto A. Gutierrez.
Q. What is the name of your company?
A. Geolex, Inc.
Q. What is your title?
A. I'm the president of Geolex.

Q. Can you please describe Geolex's and your personal involvement with Frontier Field Services Maljamar AGI #1 Well?

A. Certainly. Back in early spring of 2011, Frontier and their parent company, Aka Energy, which is, as you mentioned, a subsidiary of the Ute Tribe, approached us and said, you know, We have this gas plant out here that currently -- this is a plant that is a relatively small plant and never had a sulfur reduction unit. They were permitted to just burn all of their acid gas. So they were permitted and are permitted, until the most recent change of their air permit, to burn up to five tons a day sulfur equivalent of SO2 in their flare. And that, for the last 20-plus years of the operation of that plant, has been an adequate way of handling the acid gas.

But what the plant found is that over the last, say, five to six years, they were getting increasing concentrations of H2S in their inlet stream that they were processing. So, in fact, the gas they were processing was getting more and more sour. And that's a reflection of what's -- the natural evolution of that field that is feeding most of the gas that goes to that plant. And as a consequence, they were having to scale back even the capacity of their current plant,

which is about 55-million cubic feet a day. So it's a
relatively small plant. But it has a capacity of about
60-million cubic feet a day, but they weren't even able
to run the capacity because of this five ton-a-day
limitation. They were really running about 53-, 54
million a day, and that was -- that was basically
bringing them up to like 4.8 or 4.9 tons of sulfur a day
emitted from the flare.
So they approached us and said, What kind
of solution do we have? We not only would like to run
our plant at its current capacity, but we have a plan to
expand the plant, and we clearly need some way to deal
with the acid gas. Can you do a study and determine
whether there is a possibility for us to do injection
with that? And, at the same time, the Ute Tribe, in
particular, is very -- is really leading the edge in
terms of their whole approach to minimizing greenhouse
gases associated with their oil and gas and their other
operations. I mean, they have a lot of oil and gas
operations not only in New Mexico but in Colorado as
well, both processing, as well as exploration
production.
And so they approached us and said, Can you
help us? So we said, Okay. We did our normal approach
of doing a feasibility study. We identified two

reservoirs in the area of the plant, what we call the lower Leonard Formation. Other people call it the upper Wolfcamp. And that's neither here nor there. But we saw that the upper Wolfcamp, or lower Leonard, and the lower Wolfcamp appeared to be good reservoirs out there, although there was a concern that we had that there was not really enough very good deep well control in the area for us to be able to characterize that reservoir.

So we went the added step of obtaining a 3D seismic over the area and were able to very carefully and very well delineate the extent of this body in the lower Wolfcamp that we intended to inject into. And just -- I won't go into all the details because it's not really necessary for what we're here for today, but just in general, the lower Wolfcamp there is a, kind of, four-reef facies into the basin, and it has a series of, kind of, reef-like units that are being developed on the continental shelf there in this part of the basin.

And so even though you may have a Wolfcamp well over here (indicating) and you have a Wolfcamp well over here (indicating) and they're both either producing or injecting into the Wolfcamp, those two are not necessarily connected, because there is really porosity barriers that are very visible. And we'll see that on a map that I have here. And so we identified two zones, the upper Wolfcamp and the lower Wolfcamp that could be injected into.

We presented that in a hearing, as Mr. Larson indicated. It was not opposed by anyone. And we had presented to the Divison this proposal to inject into that zone.

Now, Mr. Jones was the hearing officer for that hearing, and, ultimately, the order that was issued -- they did approve -- he did approve our order following the hearing, but he added a condition that a specific eight wells that are offsetting the plant, that -- at the time, Mr. Jones was under the impression, I think, based on OCD records and in general that (A) those wells were either shut-in or plugged or going to be in the near future, that they were barely economical and that they were sweet. And even though he was very pleased, I think, with the depiction and the work that was done in the seismic to supplement the log analysis, he added into the order a provision -- while approving both of our units, because, primarily, the lower Leonard was in potential communication with the zones where these other wells were completed.

By the way, it's six wells that are producing -- seven wells that were producing wells or are producing wells and two wells that are saltwater wells. One of the producing wells was converted to a saltwater disposal well.

Anyhow, you know, the request -- or the condition in the order was that we place warning signs at each of these wells, poison gas warning signs or some other, you know, appropriate warning at each of those wells and that if those wells were to exceed 100 ppm H2S, that we would be required to go in and plug those wells, or re-plug them. And, you know, it seemed like a reasonable thing when the order was issued. And, frankly, in hindsight, we should have addressed it much earlier, but, you know, we were more concerned about, okay, we got our approval, and we're going to proceed and drill the well.

So this was two-and-a-half years ago. We started doing the work to drill the well, get ready to drill the well. And then actually before we even completed the well or when we were getting ready to complete the well, two things we noted. And we did extensive testing.

By the way, this is a copy of the final well report which was provided to the OCD, which we do as a matter of course, that really details everything that was done when the well was drilled, logged, tested. And so it has provided an excellent follow-up and confirmation of the work that was done out there.

And fortunately we were able to confirm our seismic very well. We did a sonic log, and we did a synthetic on our particular well, as well as the other wells in the area. And, in fact, our seismic analysis was pretty accurate.

So when we drilled the well, we noticed that in the lower Wolfcamp, which was our primary proposed injection zone, it probably is not as good as we thought it would be originally, but it certainly was going to be sufficient for the volumes of gas that this plant is going to produce and is producing now.

To give you, kind of, a frame of reference, the total amount of acid gas that this plant will be producing currently is about 600,000 cubic feet of gas a day. So it's about .6 million cubic feet a day, which, you know, if you compare it, say, to the Linam Plant, which produces up to 6- or 7 million cubic feet, you get a sense of the scale. So the actual 30-year footprint is less than two-tenths of a mile. It's about .18 something, and it, obviously, will stay in this Wolfcamp reservoir.

So we said, Why bother with the lower Leonard or the upper Wolfcamp? That zone, we don't really need it. There's caprock between the lower

Wolfcamp and that zone. Why don't we just eliminate that zone altogether and not use it for injection, because we don't really need it, and that provides an additional buffer or safety with these other wells.

But then, ironically enough, when I was discussing with my client the fact that this -- you know, once we started with completing the well and everything, we said, Oh, you know, we better go out there and get a baseline sample from these wells because we are going to have to monitor to see if they're -- or we're going to somehow be aware of whether they go over this 100 ppm level that is specified in the order.

Well, it didn't take very long for me to say that to my client and I got a call back from, actually, one of their gas-purchasing people who said to me, Wait. You sent me the API numbers for these wells. These wells are all connected to our system. They're producing wells, and they're incredibly sour already. So I said, Oh, okay.

So what we did is, we went out and sampled the wells, and what we found is indeed correct, that they are producing very sour gas and oil. But they are producing wells. They're not plugged, and they're quite economical. They're producing significant quantities, and the operators, basically Conoco and VF Petroleum, who operate those wells, said, Oh, we have no plans to shut those wells in or shut them down at all. We're continuing to operate them, and we're selling you the gas. In fact, they weren't slightly over 100 ppm. They were ranging between 450 ppm H2S and one percent H2S. So, I mean, they're very, very sour wells.

Now, the two saltwater disposal wells, they're obviously not producing wells. They're injection wells. But one of the two wells which was converted from a production well in the zone that we're actually going to be injecting into -- but it's quite a ways away; it's about a mile away -- before it was disconnected, was 1.1 percent H2S, produced in the gas coming out of that well. And both of those saltwater wells currently take very, very sour water. They're basically sour water, saltwater disposal wells.

So the zone is already -- that we're going to be injecting into already has some fairly significant concentrations of H2S.

So we came back and said, Wait a minute. This makes no sense. First of all, we don't really have the authority to go in and plug these wells because they don't belong to us, and they're not abandoned. They belong to another operator. And, you know, more importantly, we still haven't begun -- we're in the process right now, actually, of just starting to inject acid gas. We haven't even begun yet. We're just starting to do the run-up now this week, as a matter of fact. So we've never injected a drop of acid gas out here, but the wells are not -- are already very sour. So we needed to find some solution to that. So we met with the agency, and that's what brought us here today.

So I think that's just a quick rundown of where we went.

Q. (BY MR. LARSON) Did Examiner Jones qualify you as an expert in petroleum geology --

A. Yes.

Q. -- and hydrogeology at that hearing?

A. Yes, sir.

Q. And in other acid gas injection well cases before the Commission, have you been qualified as an expert in those areas?

A. I have.

MR. LARSON: Madam Chair, I'd request that Mr. Gutierrez be qualified as an expert petroleum geologist and hydrogeologist for purposes of this hearing.

CHAIRPERSON BAILEY: Any objection?

MS. GERHOLT: No objection.

CHAIRPERSON BAILEY: He's so qualified.

Q. (BY MR. LARSON) And you mentioned a moment ago that during the Division hearing, you provided testimony about the model's radius to the acid gas plume after 30 years. And what is the extent of the plume after 30 years, based on your modeling?

A. Our estimate is that it will extend approximately .19 miles from the well.

Q. And did Frontier provide --

A. After 30 years. Sorry.

Q. Sorry to interrupt.

Did Frontier provide individual notice of today's hearing to the operators of the offset wells and provide Order --

A. Oh, absolutely.

Q. -- R-13443?

A. Absolutely. We noticed them in the initial hearing, and we noticed them again. And we have daily contact with these operators because they sell their gas to us.

Q. And did you consult with the Division regarding what individual notice would be appropriate for today's hearing?

A. Yes. When we started talking about filing this motion to amend, we talked to the Division, and the Division recommended or requested that we provide separate, individual notice to these operators, and to the BLM, by the way.

Let me just add one thing I forgot to mention.

Q. Sure.

A. This well is located on BLM land. It's on a lease from the BLM. And so not only in addition to getting an order from the OCD or from this Commission to allow to us to inject, we had to go through the whole process, essentially, again, with the BLM to obtain permission from them for the APD process. So there are basically two agencies involved.

Q. And could you identify for the Commission the document that's been marked as Exhibit Number 1?

A. Yes. This is a copy of the individual notices of this hearing that were provided to the BLM; to Conoco, which is an offset operator; to COG Operating, which is an offset operator; and to VF Petroleum, which is an offset operator. And these are the return receipt cards from those certified mailings.

Q. And are the documents that comprise Exhibit Number 1 true and correct copies of the notice letters that Geolex sent to the offset operators and the BLM?

A. Yes, sir.

Q. And could you also identify what's been marked as Exhibit Number 2?

A. Yes. That's the PowerPoint that is on the screen. It's the hard copy of the PowerPoint.

Q. And did you prepare the PowerPoint selects?

A. I did.

MR. LARSON: Madam Chair, at this time, I move the admission of Exhibits 1 and 2.

CHAIRPERSON BAILEY: Any objection?

MS. GERHOLT: No objection.

CHAIRPERSON BAILEY: Exhibits 1 and 2 are admitted into the record.

(Frontier Exhibit Numbers 1 and 2 were offered and admitted into evidence.)

A. I'd like to make one -- I noticed one correction. I mean, it's kind of a silly typo, but it eluded all of us, I think. On page 5 of this PowerPoint, at bullet one, it says: "We request a change to reduce the interval from 9,500 to 20,230 feet." That is incorrect. It should be 10,130 feet. And it's correct in the next line. I don't know where the 20,230 feet came from, but I don't think we want to inject into the basement at this location.

Q. (BY MR. LARSON) Thank you for clarifying that.

Could you move on to the next slide, please?

A. Yes, sir.
Q. What were Frontier's goals in seeking authorization to inject acid gas in the Maljamar AGI #1?
A. As I mentioned, they wanted to be able to inject the current flow rate, which is about 600- or 700,000 cubic feet a day into the well, and then, ultimately, when they expand their plant, they would like to inject up to 1.8 million cubic feet into the zone. And when we did our calculations on displacement, we used 1.8 million for the whole 30 years, to be conservative.
And also they wanted, as you mentioned, Mr. Larson, to replace their existing flaring limitation to provide a capture of the C2 and H2S as opposed to allowing those emissions to continue.
Q. Could you move to the next slide?
A. (Witness complies.)
Q. You've touched on this. Could you go into some more detail about the current status of the well?
A. Sure. The well's been drilled and completed. We logged the entire well with triple-combo sonic and formation microimaging logs, and we identified both our primary and secondary injection intervals. The lower Leonard was our secondary injection interval. And as I mentioned, we just don't think it's necessary, and for

that reason, we basically left it behind pipe, but we don't intend to ever use it.

So we confirmed, in our analysis, that there was a very good quality caprock above the Wolfcamp injection zone and between it and the lower Leonard. We also confirmed the presence of sour water and lack of hydrocarbons in the injection zone, and we tested the formation waters in the injection zone. We confirmed that there was adequate porosity and permeability to accept the TAG even at the maximum rate over 30 years.

We actually completed the well and perforated it between 9,550 and 10,130 feet, which is strictly in the lower -- in the lower Wolfcamp. And there have being some other additional wells completed in the area since the order was issued that further confirmed our interpretation of the seismic, and we discuss all that in detail in this final well report that was submitted to the Division.

Q. And does the new data you generated from drilling and completion of the well have any impact on your original modeling of the radius of the injection plume after 30 years?

A. Not really. I mean, what we confirmed is that the -- that the plume shouldn't be more than about two-tenths of a mile.

Q. And had you testified it was 0.19 at the Division hearing?

A. Yes, that's what I recall.

Q. Could you briefly describe the design of the acid gas injection system as depicted in slide number four?

A. Yes. By now, I think the Commissioners are quite familiar with this design, but, in general, the well is a -- has got three strings of casing, and the production string is taken down to a total depth 10.130 feet, and that is in the lower Wolfcamp.

We did, as I mentioned, a triple-combo log, a formation microimaging log, and based on those logs, we selected four locations and poured both the caprock and the -- and the injection zone. And we wound up selecting perforations between 9,579 and 10,130. And I mentioned 9550 because the packer is set at about 9,452, but the zone -- even though we didn't perforate up as high as 9,550, that 9,579 zone is connected up to about 9,550. So our injection zone, in effect, would be from 9,550, approximately, to 10,130.

You can see we've got our subsurface safety valve set at 295 feet, and we have a significant amount of both H2S monitoring at the compressor facility, which is located immediately east of the plant, literally.

It's just outside the fence of the plant, again as I mentioned, on BLM land.

Q. And is the plant itself on fee land?

A. The plant itself is.

Q. Could you move to the next slide, please?

A. However, I will mention that the plant is on fee land, but the compressor station -- the compressor facility and the well are on a BLM lease, and the flare is also on a BLM lease, and has been for the last 25 years.

Q. And I believe you mentioned that the well was actually completed in the lower Wolfcamp?

A. Yes, it was.

Q. And is that what you've identified, at the first hearing, as the primary injection interval?

A. Yes, sir.

Q. And is limiting injection to that lower Wolfcamp interval and the actual completion of the well the basis for Frontier's request that the Commission reduce the uppermost elevation of the injection interval?

A. Yes. In conjunction with the fact that eliminating the lower Leonard, while we think it is still a reasonable and good injection zone, since we don't need it, why not have that extra safety factor from the surrounding production? So that's why we're requesting that.

Q. And with regard to the offset wells identified in Order R-13443, what exactly is Frontier required to do?

A. What we're required to do is to place warning flags at those wells that say "poison gas." We've done that. That's already done. In addition to that, we are required -- it doesn't say we're required to monitor it, but it does say that if the concentrations of H2S exceed 100 ppm in those wells, that we're required to go in and plug them.

Now, you know, I don't know how we would know that, other than an operator may be complaining if their well had -- if they started seeing H2S in their well. But that's not specified in the order. That's basically what the requirement of the order is.

Q. As you mentioned, Frontier has already placed warning signs on the eight identified wells in the order?

A. That is correct.

Q. When was that accomplished?

A. In November, after we completed the well, we went around, and we obviously got permission from the operators to put those signs on their wells. Two of the wells, the two saltwater disposal wells, already were signed for sour gas or -- because those wells are accepting H2S contaminated water on a continual basis.

Q. So the operators of the SWD wells have taken it upon themselves to put up signs?

A. Yes, they have. We put our signs next to theirs just for double precaution.

Q. Can you move to the next slide, and explain to the Commission this slide?

A. Yes. And I apologize for how small it is, but this slide is a diagram of the well as completed. And you can see it's got the very specific injection zones that we perforated in the well. We labeled those zones from W0, at the base, to W6. All of those are within what we call the Wolfcamp Formation. And there are some differences in terminology up there. So those are the perforated intervals.

Basically, the lower-most one is from 10,000 feet to 10,130 -- I mean, from 10,090 to 10,130 feet, and then the next one up, 10,009 to 10,025. And these were individual porous units going up to 9,579 that we perforated in the well.

Q. Would you move to the next slide, please?

A. As I mentioned, the well was completed with a permanent packer set in a corrosion-resistant joint that is set at 9,452. And that interval is -- the interval above that depth has been permanently sealed and cemented off, which includes the lower Leonard Formation. And we won't ever use that for TAG injection.

The actual perforations in the well occurred, like I mentioned, actually at 9,579, but since that unit goes up to 9,550, we say 9,550 to 10,130. And the actual injection interval is effectively sealed both above and below by a competent caprock.

Obviously, as you will hear from the Division and as we understand from our meetings with them, they concur with the reduction of the injection zone and our request to eliminate the need for potentially plugging these already sour wells.

Q. And the next line, I believe, is a map -- I'm getting ahead of myself.

A. This is the actual language that is in the order. I just wanted to have it for the Commission to see. You can see that basically it calls out these eight wells. The two farthest wells are the only two sweet wells. And those wells are over one mile away. One is 1.1 mile, and the other is one-and-a-half miles away. And they're completed in a different interval, and those are VF Petroleum's wells. And we'll see those on a map in just a moment. The rest of the wells are very sour, and they're closer to our facility.

As you can see in here, it requires that we put warning flags or other safety indicators, as BLM or the Division's Hobbs District requires -- and as I've mentioned, we've done that -- until such time as a flagged well is permanently plugged back above the equivalent disposal interval.

And as it turns out, the reason why I think Mr. Jones, based on our discussions, put this in the order is because that lower Leonard or upper Wolfcamp interval is the one that he is talking about as an equivalent to our disposal interval.

It also then says that we will take all the steps necessary to ensure that we stay only in the permitted formation. And that, by the way, is the only part of these two paragraphs that we are requesting not be eliminated, and the Division requests not be eliminated. And we don't have a problem with that. I mean, that is a normal paragraph in all of our orders.

It's the next sentence, where it says: "If H2S levels reaches [sic] 100 ppm, they should be shut-in -- that our well should be shut-in until we have plugged those wells that exhibit newly discovered H2S. Well, that isn't workable for the reasons we've discussed.

Go ahead.

Q. These wells identified on slide eight, does Frontier have a legal interest in any of those wells?

A. We do not.

Q. So you alluded a moment ago to the map. That's your next slide?

A. Yes.

Q. That identifies the operator of each of the eight offset wells?

A. It does. I want to show a couple of things that we talked about. If you see my little green amoeba shape here (indicating), that is what we define as the porous interval based on the seismic that we were able to find in the Wolfcamp Formation that we were actually completed in. So that is the boundary of the porosity that has been identified in the Wolfcamp Formation.

The little blue diagram is what we believe would be the maximum extent of H_2S and CO_2 invasion of that zone after 30 years. You can see it's a little -- it's not perfectly radial because the porosity isn't. So what we've done is, based on the dip and the porosity, we've mapped out where we think, essentially, that plume will be restricted to, but in no case would it be able to go out of this green area. We have confirmed that both with seismic and with our completions that that is really the limit of that body that we're injecting into.

Now, with respect to the eight wells, here are the eight wells. Here are the two saltwater wells. This first well -- we'll go through each one of these.

By the way, the data from the -- I did bring the actual analyses. I don't think we've got those as an actual exhibit, but I brought them in case the Commissioners would like to see them. They were taken from these wells just about a month ago.

Q. Mr. Gutierrez, before you address each well, that larger circle --

A. Yes.

Q. I'm slightly color-blind.

MS. GERHOLT: Yellow.

MR. LARSON: Yellow. Thank you.

Q. (BY MR. LARSON) What does that circle depict?

A. That's just the one-mile radius from the well.

Q. What's called the area of review?

A. That was the area of review. Yes, sir.

Q. That's all I have. You can address the slide.

A. Let's start at the -- I want to start with these two wells down here (indicating) because they're the saltwater injection well.

This well, the Federal B1, was a producer in the Wolfcamp. It was actually a pretty poor producer and watered out pretty quickly. But before that production was terminated, you can see that it was producing H2S at a rate of 11,000 parts per million.

The Maljamar SWD 29 is a relatively new injection well, saltwater injection well. It's located here just west. And COG operates both of these wells, and they use both of them for disposing of very sour water associated with their protection in the area.

This well (indicating) was not sampled, obviously, because it's an injection well. There is really nothing to sample, but you can see that it is, essentially, completed in the same zone that this one -- this one's (indicating) a little bit higher, but it's just updip a little from that well, and they're completed in, essentially, the same zone. So the water that's in this zone probably -- we could expect this kind of H2S concentration in that well. But obviously it couldn't be sampled because it's an injection well, and we'd just be sampling whatever was being injected at that time.

COMMISSIONER WARNELL: So is that what's there on the other 11,000 parts per million H2S?

THE WITNESS: Yes, that's an injection

well, but it was -- it was a production well. So that 11,000 --

COMMISSIONER WARNELL: Oh, that was?

THE WITNESS: -- is from just before it was converted to a saltwater.

A. These two wells, the Elvis #2 and the Elvis #4 (indicating), are also wells that are really located in a zone that is really above and outside of our injection zone. You see this one is 8,900 to 9,500 feet, but really, as I said, they're really completed in a different part of the Wolfcamp that is outside of the area we identified under seismic. But even so, these wells, which are current producers, are producing pretty sour gas; 450 parts per million right now is the average from those wells.

These two wells (indicating) -- and I apologize because the printout only shows one of the Baish wells. They're both here, and they both are tied together. So this sample of 6,000 was from both of these wells. This is also perforated in what really is the lower Leonard. This is the zone that we're not going to be using as an injection, but you can see it's already also pretty sour, about 6,000 parts per million.

Then these two wells (indicating) that are located, as I mentioned, 1.1 and one-and-a-half miles away, are the only two sweet wells in the area. They're completed, really, in a completely different part of the Wolfcamp, well isolated from ours. And you can see even isolated from these other Wolfcamp wells that are much more sour.

These two (indicating) are sweet wells. And, you know, we've talked with both Conoco and VF, and they don't have any concerns about their wells there.

And I want to emphasize, we haven't injected a drop of acid gas yet. So obviously this H2S (indicating) didn't come from us.

Q. (BY MR. LARSON) As we sit here today, is the well completed?

A. It's completed, but it's not injecting yet.

Q. Can you give the Commission an expected start date for injection?

A. Yes. We're actually working with it now. We've got a little bit of scale built up on our perfs, because the well sat there for -- it was completed in October, and we've been waiting for the completion of the surface facilities, the compression facilities and all that. We're in the process of doing the testing of those, and then we're going to be injecting acid gas, hopefully, this week or next week starting.

Q. And your next slide addresses the sampling that you did of these offset wells. Is there anything you want to add to the information on slide number ten?

A. Not really. I think it summarizes what I just stated. As I said, five of the wells are very sour and have those H2S concentrations that range from 450 to 11,000.

And by the way, I'll emphasize that one of the other things that our gas purchaser told me was that they're somewhat variable in concentrations. You know, sometimes they may be 1,000 ppm, and other times, they'll be 500 ppm. But, you know, they're generally well above -- they've always been above 100, ever since they've connected to our system. And, in fact, these are the very wells -- not just these, but this is an example of the very wells that have been increasing in H2S concentration, and it's the whole reason that the plant is now being able to run at full capacity, because they're getting more H2S in the area.

Two of the wells are sweet, as I pointed out, but they're located outside of our reservoir, and, in fact, even outside the area of review.

And the last well was a new saltwater disposal well that also varies -- H2S content varies based on whatever the injection fluid is.

Q. And would it be fair to say that your next slide basically compiles the data on your map and what you've just testified to?

A. This slide, yes.

Q. And the last column there, "Miles Outside of ROI," that would be the distance from the edge of the injection plume to the --

A. That would be the distance -- not from the well, but from the closest edge of the 30-year plume, yes.

Q. Could you move on to slide 11?

A. Oh, I'm sorry.

Q. That's okay.

A. Yes. This tabulates the results that we've been discussing for each of the wells. It identifies the type of well. Most of these -- by the way, all the wells that we're talking about are really -- they're primarily oil wells, but the casing had gases, what Frontier is taking from those wells. So they're producing very sour oil and sour casing head gas, with the exception of the Hudson wells, which are the two sweet wells that are 1.17 and 1.5 miles away.

As you can see, the column there says "Miles from AGI." That's from the actual well itself. And the other is distance from the edge, the closest edge, of the 30-year plume. And as I noted, Frontier has not injected any acid gas yet.

Q. And based on your initial modeling and your testing and the process of completing the well, is there any likelihood that acid gas injected by Frontier could migrate to any of these offset wells?

A. In my opinion, there is no reasonable probability that that would occur.

Q. And during the Examiner Hearing, did you provide any testimony regarding plugged and abandoned wells within the one-mile of the area of review?

A. Yes, we did. And all of those wells were well plugged, and very few wells actually penetrated the injection zone, plugged wells in that area.

Q. And the ones that did, were they cemented through the injection interval?

A. Yes. They were fully cemented through the injection interval. In fact, they were fully cemented through both the Wolfcamp and the lower Leonard.

Q. Could you move on to the next slide? Is there anything you want to add to what appears on this slide? It's number 12.

A. No. I just wanted to point out that, as we mentioned before, because these six wells are currently producing -- and two of them are saltwater wells, which we don't own or have any interest in -- we couldn't legally go in and plug those wells anyway, unless the operator itself was ordered by the Division to plug them. And most importantly, since the subject wells are producing wells or active injectors that are being used for disposal, plugging them would result in waste and would impair the correlative rights of those operators.

Q. And moving to the last two slides, would you summarize the grounds upon which Frontier seeks relief in its motion?

A. Sure. This slide deals with the issue of the well plugging. And as I mentioned, these wells are not owned and operated by Frontier, a significant and safe distance from the limits of 30-year injection plume. Five of the eight wells have already been demonstrated to have H2S concentrations that are significantly over 100 ppm. In fact, it's those very wells and other wells like those that are the reason why the plant is getting an increasing sour gas inlet stream.

The one well that we did not sample is a saltwater injection well. It's into the same sour interval where the Federal B1 is, which had 1.1 percent of H2S in it before it was converted to salt water. Two of those injection wells obviously receive sour water, which is often saturated with H2S. And if NMOCD, in the future, decided that any of these wells had to be plugged, we don't have the ability to do so, because we don't own the well or operate them.

Frontier requests that we remove the requirement that's cited in the order for these wells to be plugged and abandoned.

We don't have any problem with the signage requirement. We did that. And probably those wells should have had those signs on them anyway, at least the sour one.

So I guess our summary is, we request that we reduce the approved injection interval by eliminating the secondary injection interval in the lower Leonard. And we've already placed the warning signs. However, we would request that we eliminate the offset well requirements and remove paragraphs six and seven on page 5 of the order. The only modification to that that I would make is that I concur with the Division's request that the one sentence in paragraph seven that requires us to assure that the injection stays in the injection zone, that we leave that sentence in the order.

Q. So I take it you've reviewed Mr. Jones' written pre-filed testimony?

A. I have.

Q. And you agree with his proposal that the Commission entirely delete the order in paragraph six and delete the last sentence of the order in paragraph seven?

A. Yes, I do.

Q. And do you also agree with his proposed issue ordering paragraph number one in the order?

A. Yes. I have to go back and look at what that was. I have Mr. Jones' pre-filed testimony.

Q. Here, I have a hard copy.

MR. LARSON: Madam Chair, I'm handing him a copy of Mr. Jones' testimony.

A. Oh. What Mr. Jones is proposing is that -- he says the approximate well language is no longer applicable. That was what we put in, because when the order was written, the well wasn't yet drilled. But obviously we know exactly where it's going to be -- where it is completed now. So we have no objection to that.

Q. (BY MR. LARSON) And in your opinion, would the requirement that Frontier plug the offset wells identified in Order R-13443 impair the correlative rights of those well operators?

A. Absolutely. And I'll tell you, those well operators would not be happy. We've spoken to them. They would not want their wells plugged.

Q. And in your opinion, would the plugging of those wells result in waste?

A. They would, because those wells are still economically viable producing wells.

MR. LARSON: Pass the witness.

CHAIRPERSON BAILEY: Do you have any cross-examination, Ms. Gerholt?

MS. GERHOLT: Yes, Madam Chair. Thank you.

CROSS-EXAMINATION

BY MS. GERHOLT:

Q. Good morning, Mr. Gutierrez.

A. Good morning.

Q. You and Mr. Larson met with Will Jones and myself prior to this hearing; is that correct?

A. Yes, we did.

Q. At that meeting, did you provide Mr. Jones a copy of your slide presentation?

A. I did. And in addition, I think a couple of days after, I provided him -- we were just finishing the final well report, and I provided that to him a couple days after that.

Q. Do you remember the approximate dates of the meeting and of providing the well report?

A. My memory's not that good, but I can get the exact date, because I can look at my calendar. I believe it was late last month.

Q. Does January 31st sound about right?

A. That sounds correct, because -- yes, I think that is correct.

Q. You provided Mr. Jones with the end-of-well report a couple of days after that?

A. That's right. I think we met on a Thursday, and I provided him the report on Monday.

Q. So a couple of weeks before prehearing statements were due?

A. Yes. And, in fact, in Mr. Jones' testimony, he indicated that he had reviewed the final well report and went through his review in detail.

Q. Very good.

If I could now draw your attention to slide nine. Am I correct that the amoeba shape in green is the calculated 30 years of injection, or is it the blue shape?

A. It's the blue.

Q. It's the blue amoeba shape.

A. The amoeba shape, green, is the actual limits based on the seismic of the porosity zone within the Wolfcamp that we're injecting into.

Q. And this calculated area is for 30 years of injection, correct?

A. That is correct.

Q. What are Frontier's plans after that 30-year period?

A. Well, we have routine -- I mean, I don't think that there is any particular plan to shut the plant down or anything, but we've just usually used 30 years as a lifetime -- you know, an engineering, kind of, based lifetime for the well. I mean, it could actually operate for longer than that.

Q. Would it be feasible to then, after this 30 years, revisit the injection authority either with the Division or the Commission? Since we've tied this to the 30 years, to have some sort of requirement that after 30 years, come back, and if they need to inject -- additional injection authority, to just provide some sort of time frame for the Division and for Frontier?

A. I don't think we would have an objection to that. I don't think it's necessary because I think that the fact that this reservoir is a limited reservoir, it probably -- once we get, you know, much further beyond that 30 years, I think we may run into a reservoir beginning to pressure up and really not being able to be used for further injection. But I wouldn't have an objection to a 30-year revisiting.

Q. In regards to the R Order, the current R Order in ordering paragraph nine -- and I don't believe you have it in front of you, Mr. Gutierrez. But it does require an MIT test every two years?

A. Yes.

Q. Would there be an objection to having it MIT tested every year?

A. No. And I have already informed my client that I think that's what they should be doing, and it's their intent to do an MIT every year regardless of whether that gets changed in the order or not.

Q. Very good.

MS. GERHOLT: If I may have one moment, Madam Chair?

CHAIRPERSON BAILEY: Yes.

(Pause in proceedings.)

MS. GERHOLT: I have no further questions for this witness.

CHAIRPERSON BAILEY: Commissioner Warnell, do you have any questions?

COMMISSIONER WARNELL: I do.

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. I'll cut it down to one question. I'm curious as to the -- if my calculations were right, looking at Exhibit 2, page 6, the top perforation is 9,579; is that correct?

A. That's correct.

Q. And then the packer it shows being set at 9,452, which is, doing the math, 127 feet above the top perf?

A. That's correct.

Q. The original order -- well, in most orders that come out of OCD call for that packer to be within 100 feet of the top perf.

A. That's correct.

Q. Why is this 127 feet?

A. Sure. That's a good question. When we drilled the well and logged it, what we found is that the zone that was the most competent caprock was in that interval rather than any lower than that. So we set our corrosion-resistant joint in that interval, and that's where we set our packer, because of the geology.

Now, as I mentioned, our injection zone really goes up to 9,550, because where we're injecting at 9,579, it's essentially the bottom portion of a porous interval, the most porous portion of that interval.

At the time, we were being very well aware of that normal practice and requirement that we be 100 feet or within 100 feet of the packer. So when we were getting ready to perforate the well, we contacted

Mr. E. L. Gonzales at the Division district, and we asked him whether he thought that we should go ahead and perforate up to 9,550, because this zone -- but it would have been basically just to fulfill the 100-foot requirement, because we didn't feel like even if we perforated that upper portion of that zone, that there would be much fluid going into it there. And he specifically said, No, don't bother; I don't have a problem with it being 127 feet below the top perfs. So that's why we did it that way.

Q. So then on the schematic wellbore, the red, is that your H2S? Do you see that where the packer is?

A. The red is the extent of the corrosion-resistant joint that is in the production string where the packer is set.

Q. Do you know the depth on that?

A. Yes. 9,437 to 9,467.

Q. Is that on here?

A. Yes, it is. It's in red, right where it says "corrosion-resistant alloy joint, 9,437."

Q. Is that what it says?

A. Yes, sir. I'm sorry.

Q. Give me those depths again, will you please? 94 --

A. 9,437 to 9,467.

I will mention, also, the other reason that that was not a concern is that the packer -- the way these packers are designed, they have a seal assembly. Below the packer that extends -- the tubing extends like 30 feet below the bottom of the packer in that shoe. So the bottom of the tubing, in effect, really is at about 9,482 or so. You can see it on the diagram. It extends down below, and it's got a check valve down there.

COMMISSIONER WARNELL: Those are all the questions I have. Thank you.

CHAIRPERSON BAILEY: Mr. Balch?

COMMISSIONER BALCH: I have a couple of questions.

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Of course, I'm a geophysicist, so I'm going to ask about the seismic. Did you perform that analysis, or who performed that analysis?

A. We had a geophysicist, Lou Mazzola [phonetic] in Denver, perform that analysis for us. I mean, we worked together with him and did that, yes.

Q. These are carbonate reef complexes?

A. Yes. They're kind of detrital carbonates that are -- they're kind of reefs, and then they've got -- in between them, they've got very fine grain, essentially almost like turbidite-type flows.

Q. What's the caprock? What are your boundaries on those?

A. It's a very, very tight dolomitic -- analytic [sic] dolomite and shale.

Q. So you're -- the difference is going to be due to porosity?

A. Yes. Absolutely. That's, in fact, what we found, and how we were able to define that body.

Q. You said that you did do a sonic log?

A. Yes, we did.

Q. And grain [sic] synthetic seismogram?

A. Yes, we did.

Q. 550 feet or so of interval. I'm presuming there are multiple wavelets within there. How precise were you able to pick out your porous zones within the overall reef complex?

A. I can't say that with the sonic log and the seismic we were able to have the kind of definition that we were able to have with our, basically, triple-combo log and the formulation microimaging log. So with those. And then with those logs, we selected core locations, and then we actually did quite a few, about 30 cores, in both the caprock and the injection zone. And the detail core analysis and all of that was all put together in this final well report.

Q. The lateral extent of the -- of the reef complex that you drew in here --

A. Yes.

Q. -- your green line --

A. Yes.

Q. -- that's based on, essentially, the acoustic difference between the caprock and the porous zones?

A. Yes, it is.

Q. And you feel confident that that pick is a good pick?

A. Yes. And I think it was confirmed by our synthetic -- sonic log that we did. And we used another log from a well nearby that had a sonic log before we drilled ours, and then we just did a sonic log on ours to try to put the two together. And it worked out quite well, and, frankly, the seismic looks pretty well. In the initial hearing record, we presented the results of that seismic within the time slice, basically, a series of time slices. So through that zone of the caprock and the injection zone, so we could see those porosity differences. It was pretty clear on the 3D seismic.

Q. Okay. I counted 186 feet of perfs -- I was reading tiny numbers, so I may have gotten that wrong -- in your 550-foot interval?

A. Yes, that's about right.

Q. And you seemed to indicate, in response to Commissioner Warnell, that that wasn't all of the porosity. It was just perfing [sic] at the bottom of the porous zones?

A. No. That was more -- it's not all of the porosity, but it's the best porosity in that zone. But we do have some zones -- some interlayered zones in between -- in between our perfs that are pretty darn tight.

But where I was answering Commissioner Warnell's question was relative to that top perforation zone. We could have perforated -- and really when we had -- literally were getting ready to go in with the perf guns, before that, we spoke with both E. L., primarily, at the District, but we spoke with Will as well and said, Look, I mean, we can perf -- if we need to be within 100 feet of the thing -- of the -- of the packer, the uppermost perf needs to be within 100 feet, we can go ahead and perf there, but we just don't think it's going to take much work, because it's pretty tight there.

And the reason, really, why we didn't set our corrosion-resistant joint any lower is because we wanted it against a very, very -- you know, we wanted the whole corrosion-resistant joint against a very good, very low-porosity zone, and we didn't want to get into the very top of -- even though it's not great porosity, it still had some.

Q. So that injection zone is fairly close to the perf number?

A. Yes. Yes, I would say it is.

Q. And your CO_2 models are proven models based on volumetric calculation?

A. Yes, sir, they are.

Q. And what net interval do you use in that calculation?

A. We used the -- we basically used everything that we actually perfed. So we just used the actual perforations.

Q. Do you know what the pressure in the reservoir is right now?

A. I think it's about -- I'm trying to remember right off the top of my head the bottom hole pressure, but I think it's 3,900, 4,000, somewhere in there.

Q. That's a little underpressure?

A. Slightly underpressure, yes.

Q. Did you model the pressure again at the 30-year injection?

A. We did not. We did not. It's our intent --

you know, we're starting to work with -- as I think we've discussed on other occasions, we've been starting to work with this GEM's model, and we've been thinking about starting to get some injection history from these wells over time and try and build some models there, but we have not done any prospective modeling of that pressure increase.

Q. Does the existing order have a pressure-injection limit?

A. Oh, yes, absolutely. I think it is 2,960, or somewhere in there.

Q. I see it. 2,973.

A. Yeah.

Q. Okay. If you work through a volumetric analysis based on the outline of the reef -- porous part of the reef, what is the maximum TAG that you could put in there? Did you do that calculation?

A. At this rate, we could probably do it for about 60 years, I think.

Q. Before you filled it up?

A. Before we filled it up.

Q. Irregardless [sic] of pressure? The pressure would probably change?

A. Yes, sir.

Q. Those are my questions. Thank you.

CROSS-EXAMINATION

BY CHAIRPERSON BAILEY:

Q. Would you care to comment on the BLM objection that was sent to us?

A. Yes. Sure. I think that there was -- and I've spoken to Mr. Peterson subsequent to that and have communicated with them. I think there was a misunderstanding when they -- when they received Mr. Larson's motion. They had two issues.

One is that because we're requesting that those two paragraphs be eliminated, including the signage requirement, they said, How -- one objection they had is, they thought that the signage requirement for those wells should not be eliminated, and they were wondering why we thought not putting signs up there -- or putting signs there would damage correlative rights. And I think that was just a misunderstanding that was one.

The second item was that on the last page of Mr. Larson's motion, there was a typo that said "Rule R-1344," and it left off the three. And Mr. Ingram, who's the head petroleum engineer down at the Carlsbad District, is very precise, and he looked that up. And said, Wait; this order has nothing to do with this well. Why are you wanting that changed?

When we received that objection from the BLM, I contacted Mr. Peterson. I explained to him what we were really asking for, and he said, Oh; if that's the case, why don't you go ahead and amend your motion to correct the typo, and to say that you don't want to eliminate the signage requirement. And we said, Well, we really don't want to do that because then we have to re-advertise and put the hearing off again, and we wanted to get this behind us. And then he said, Well, maybe you could just write me a letter to explain what that is. And I did send -- and I also told him that we do monitor the H2S content in those gas wells anyway, because they're connected to our system, and, in fact, we're buying their gas. So we know how much H2S is in that gas all the time. And he was satisfied with that.

I wrote him an e-mail that confirmed that, and Mr. Larson wrote him a letter clarifying what we were requesting in the motion, and they elected not to pursue it any further.

Q. I looked through the order to verify certain conditions that were placed in this order, and I just would like to confirm that there will not be any water injected with the H2S and the CO2?

A. Absolutely. That's our intent.

Q. One of the requirements was that a log of the primary rock stress direction and oriented fracture finder on the wellbore stress be run. Was that run and filed with the OCD?

A. Yes, and analyzed in detail and included in the final end-of-well report. Plus, we filed the logs earlier.

Q. What is the status of the H2S contingency plan that needs to be approved by the OCD?

A. The H2S contingency plan was approved by the OCD on November 28th, and there were two conditions added to that plan that required Frontier to do an assessment of their gathering system. The two conditions didn't have anything to do with the AGI itself, but that they assess whether the gathering system has appropriate signage, within 200 feet of public roadways, and that we do an assessment to assure that that was the case.

And the second condition was that we do an assessment to determine if there were any additional monitors that would be required, specifically SO2 monitors required around the flare stack itself, and we did that assessment as well. We never -- we only documented that we did those with a memo to the file, because in the conditions of approval, there was no requirement that we specifically get back to the

Division with respect to what the results of those assessments were. It was just to assess whether we were in compliance with existing regs, and we did that.

Two days ago, I received a call from Mr. Chavez requesting information on what we did about those two conditions, and subsequent to that, I provided him a copy of the -- of the confirmation of those conditions having been met by us doing those assessments. I also provided him with a copy of the new air permit, because, in effect, Mr. Chavez' concern about SO2, we felt, was really not well placed, because, in effect, what we're doing -- right now, we're burning five tons a day of SO2 out of that flare, and that is a permitted discharge that is based on the height of the flare and that amount would not endanger public health.

So, in fact, when we go to using the well, we'll eliminate that entirely, except for the use of that flare under upset conditions. And that's already regulated by the new air permit. So I also provided him a copy of the new air permit, which shows that every single time there is a flare event, it has to be documented exactly how much SO2 and NOx is released. And they have specific -- much lower limitations now under only upset conditions for that.

So we did an assessment of the placement of the monitors, both H2S and SO2 monitors, and determined that the 15 H2S monitors we have around that flare area would be sufficient.

Q. I notice that this order did not include some of the requirements that have been placed in other instances, such as corrosion-resistant packers and tubing and downhole monitoring equipment. Are those equipment safety measures part of Frontier's practice?

A. Oh, yes, absolutely. All of the -- the tubing is corrosion-resistant tubing. The packer is an Inconel corrosion-resistant packer; so is the subsurface safety valve and the tree itself, but there is no downhole pressure-monitoring equipment in this well.

Q. What about temperature controls within the alarm system? There have been other instances where temperature control was an important factor in the AGI --

A. Yes. The temperature, annular pressure, injection pressure, all of those, are controlled and are part of the SCADA System that the plant monitors, and they're continuously monitored.

And because of, specifically, the temperature problems that we experienced on the Linam well, we have gone into significant detail with Frontier about the importance of controlling and maintaining a narrow temperature band in their operation of the well, and they're well aware of that; and certainly they've got the monitoring capability to do that.

Q. Is there an alarm system that is part of that procedure there?

A. Oh, absolutely. All of this information is sent to the -- sent to the plant's -- what I call SCADA System. And I'm not sure what that means. It's essentially all the panels that the operator views, and each one of the parameters has a high and low alarm. So they know immediately if any of those parameters exceed their normal operating range.

Q. This order does not specifically require that the diesel on the back side -- has corrosion inhibitors included.

A. Yes.

Q. Is there an objection to including that in the order-to-be?

A. No. And we did that when we completed the well. I mean, we do try to learn lessons from the past, so we did that anyway, regardless of whether it was in the order or not.

Q. Those are all the questions I have. Thank you.

CHAIRPERSON BAILEY: Do you have any redirect?

MR. LARSON: I have no redirect, Madam Chair.

CHAIRPERSON BAILEY: Then you may be excused.

THE WITNESS: Thank you.

COMMISSIONER BAILEY: Ms. Gerholt, do you have a presentation?

MS. GERHOLT: No, Madam Chair. The Division filed testimony by Mr. Jones that has been discussed and presented with our prehearing statement.

CHAIRPERSON BAILEY: Do you have a closing?

CLOSING ARGUMENT

MR. LARSON: Just briefly.

Madam Chair, as I said in my opening, it was my belief that we would demonstrate that the relief requested by Frontier's motion is both realistic and reasonable, and I confirm that we have met our burden, understanding our entitlement to relief, and, therefore, ask the Commission to grant the motion.

CHAIRPERSON BAILEY: Do I hear a motion from the Commission to go into closed session to deliberate this case in accordance with New Mexico Statute 10-15-1 and the OCC resolution on open meetings?

COMMISSIONER BALCH: I'll make a motion to discuss this case.

COMMISSIONER WARNELL: Second the motion.

CHAIRPERSON BAILEY: All in favor?

(Ayes are unanimous.)

(Closed Session, 10:34 a.m. to 10:57 a.m.)

CHAIRPERSON BAILEY: Do I hear a vote for us to go back into open session in accordance with New Mexico Statute 10-15-1 and the OCC resolution on open meetings?

COMMISSIONER BALCH: I'll make a motion to go back in session.

COMMISSIONER WARNELL: I'll second that motion.

CHAIRPERSON BAILEY: All those in favor?

(Ayes are unanimous.)

CHAIRPERSON BAILEY: The only thing that was discussed was this case, during our closed session.

Mr. Brancard, as the counsel for the Commission, would you please explain the decisions reached after our deliberations?

MR. BRANCARD: The Commission considered Frontier's motions, considered the evidence presented today, and along with the Commission's need to protect public health and the environment, fresh water and correlative rights, the Commission proposes as follows:

Number one, the Commission proposes to

reject the motion to delete condition six of the order due to lack of evidence to support and the fact that these warning signs are already in place;

The Commission accepts the motion to amend paragraph seven, to remove the second sentence requirement based on the need to protect correlative rights;

The Commission also accepts the amendment to order paragraph number one, in accordance with the wording provided in the Division prehearing statement, which lowers the area perforation both at the top and bottom, as it was actually in violation of the Commission order, the perforation that was done. But this will put the order in accordance with how the actual drilling was accomplished and the perforation was done by Frontier.

In order to protect -- further protect public health and in response to removing the protections of paragraph seven, the Commission has decided to clarify the order by putting in the following protections: That the order pertains to a 30-year injection limitation, that the injection is based on the 1.8 MMFCD injection limits, as provided, that should now be put into the order.

Also placed into the order is, the

mechanical integrity test requirement is moved from two years to annual requirement. Also added into the order is the requirement for corrosion-resistant tubing, corrosion-resistant packer and biocides and corrosion inhibitors placed in the diesel annular fluid and that there be temperature monitoring done with this facility.

These conditions have been placed in other orders, and we can provide the language that you can provide in your proposal, Mr. Larson.

MR. LARSON: (Indicating.)

MR. BRANCARD: Have I covered everything?

CHAIRPERSON BAILEY: I believe so.

Mr. Larson, if you would present a draft order to Mr. Brancard for his review on this case that would incorporate all of those items that Mr. Brancard discussed.

What date would you like to have those?

MR. BRANCARD: Can you get it back in 20 days? Is that possible, Mr. Larson?

MR. LARSON: Certainly.

CHAIRPERSON BAILEY: Any other business before the Commission today?

Then do I hear a motion for adjournment?

COMMISSIONER BALCH: I'll make a motion to adjourn.

COMMISSIONER WARNELL: I'll second that motion.

CHAIRPERSON BAILEY: All in favor?

(Ayes are unanimous.)

(Case Number 14664 concludes, 11:01 a.m.)

STATE OF NEW MEXICO
COUNTY OF BERNALILLO

CERTIFICATE OF COURT REPORTER

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

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

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

Mary C. Hankins

MARY C. HANKINS, CCR, RPR
Paul Baca Court Reporters
New Mexico CCR No. 20
Date of CCR Expiration: 12/31/2013