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

APPLICATION OF DCP MIDSTREAM, LP FOR AUTHORITY TO INJECT TREATED ACID GAS INTO THE LOWER CHERRY CANYON AND UPPER BRUSHY CANYON FORMATIONS THROUGH ITS ZIA AGI #1 AND ZIA AGI #2, LEA COUNTY, NEW MEXICO.

CASE NO. 15073

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

February 13, 2014

Santa Fe, New Mexico

BEFORE: JAMI BAILEY, CHAIRPERSON
TERRY WARNELL, COMMISSIONER
ROBERT S. BALCH, COMMISSIONER
BILL BRANCARD, ESQ.
CHERYL BADA, ESQ.

This matter came on for hearing before the New Mexico Oil Conservation Commission on Thursday, February 13, 2014, 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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EXHIBITS OFFERED AND ADMITTED

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(9:05 a.m.)

CHAIRPERSON BAILEY: I'll now call Case Number 15073, which is application of DCP Midstream, LP, for authority to inject treated gas -- acid gas into the Lower Cherry Canyon and Upper Brushy Canyon Formation through Zia AGI #1 and Zia AGI #2, in Lea County, New Mexico.

Appearances?

MR. RANKIN: Morning, Madam Chair, Commissioners.

Adam Rankin, Holland & Hart in Santa Fe, representing DCP Midstream, LP. I have two witnesses this morning, one technical, one fact witness. And I would like an opportunity to make some brief opening remarks.

MR. WADE: Morning. Gabriel Wade representing the OCD, and I have one witness.

CHAIRPERSON BAILEY: We will swear witnesses at the time of their testimony.

Would you like to make your brief opening remarks?

OPENING STATEMENT

MR. RANKIN: Thank you very much, Madam Chair, Commissioners. Good morning.

Madam Chair, we're here today on DCP's

application to approve authorization to inject for two new acid-gas injection wells associated with a brand-new gas processing facility in southeastern New Mexico. The AGI wells associated with this plant are necessary and with the operation plant itself, and the plant is needed to meet growing demand for gas processing in southeastern New Mexico.

Today you'll hear testimony from DCP's witnesses that it's planning to commit nearly half a billion dollars constructing these wells, the plant itself, and related infrastructure associated with the plant and facility. And they intend to commence operations of the plant and the injection wells in about a year and a half.

From DCP's perspective this vast commitment of resources and money and planning and time is entirely dependent on the, first of all, these two AGI wells. The facility as it was planned is unworkable without the exact wells. The design just won't accommodate any other approach, and DCP would have to step back and re-evaluate the project entirely.

And more importantly, the economics and the business rationale supporting the proposed project and the plant would be seriously undermined without the approval of these wells.

With respect to the economics and the business rationale, DCP has proceeded with the intention of committing the money and resources for this project on the premise that the project will be a 30-year-plus project. So they have intended to go forward and commit the resources with that foundational understanding.

Today you'll hear testimony that DCP has also reached agreement with the Division with respect to the Division's concerns, that they raised in their pre-hearing statement, regarding four wells within the half-mile area of review, in addition to some additional requests or conditions to approval.

And you'll also hear testimony today that DCP's C-108 will adequately protect fresh groundwater resources, that it's otherwise approvable, and that it will protect human health and the environment by reducing net air emissions and that the application will prevent waste and protect correlative rights.

Thank you, Madam Chair. With that, I'd like to call my first witness.

CHAIRPERSON BAILEY: Let me see if Mr. Wade has any opening statements.

MR. WADE: We will withhold statements for now.

CHAIRPERSON BAILEY: Please call your first witness.

MR. RANKIN: Thank you, Madam Chair. I would like to call my first witness, Mr. David Stone.

CHAIRPERSON BAILEY: Will you please stand and be sworn by our court reporter?

DAVID LEE STONE,

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

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Good morning, Mr. Stone. How are you?

A. Good. Thank you.

Q. Good.

Will you please state your name for the record?

A. David Lee Stone.

Q. And for whom do you work?

A. I work for DCP Midstream.

Q. And how long have you been employed by DCP?

A. Approximately 16 years.

Q. And what is your current position with DCP?

A. I'm currently the vice president of commercial and operations for our southeast New Mexico assets.

Q. And in that role or position, what are your duties?

A. I'm responsible for commercial activities, business development, and day-to-day operations of our assets within southeast New Mexico.
Q. That would include oversight and planning for this proposed new building facility and the new wells?
A. Yes. That falls under business development. I am currently the responsible officer at DCP for what we call our CF program project.
Q. Stepping back, what is DCP's business in southeast New Mexico?
A. DCP is a midstream service provider. At our core, we gather gas production from the wellhead; deliver it to processing plants, such as we're discussing today with the Zia 2 Plant; process that gas between methane and natural gas liquids; and then deliver that to markets out at the tailgate of the plant.
Q. And today you're appearing as a nontechnical fact witness; is that correct?
A. That is correct.
Q. And Mr. Alberto Gutierrez will be testifying on behalf of DCP as the technical witness; is that correct?
A. Yes, that is correct.
Q. And, Mr. Stone, have you prepared demonstrative slides to assist you with your testimony today?

A. Yes. We have a number of slides today to go along with the testimony.

Q. All right. So, Mr. Stone, just -- as I mentioned in my opening remarks, these two new wells are associated with the entirely new gas processing plant and facility; is that correct?

A. That's correct. The Zia II processing facility will be a new grassroots facility, inclusive of both a cryogenic processing process, as well as -- we're premising the acid-gas injection wells.

Q. How did DCP come to decide that there was a need in southeastern New Mexico for an entirely new gas processing plant?

A. Essentially through volume demands and from the producing community. I think it's very apparent of the increased activity that we've seen in southeast New Mexico in recent years. It continues to escalate. Our systems are essentially full to this point, creating some constraints with the producing community, not only ours, but others within the area.

Q. And when DCP was evaluating this new proposed plant, it had intended -- tell me a little bit about the decision to do acid-gas injection wells.

A. Our intent or the basis for going on with the acid-gas injection wells, first off, we are applying for a PSD permit which is the most onerous of air permits that we can seek for the facility. It requires a very low set of permitted emissions. The AGI provides the United States the best available technology, one that we're also familiar with a number of our other facilities, to be able to meet the requirements of the air permit, and provide the service that the producers request, and that the State demands from an emission footprint.

Q. Mr. Stone, you mentioned PSD. That's the acronym for prevention on the significant deterioration; is that correct?

A. Yes, that's correct.

Q. That's the acronym jargon for the type of air permit you're talking about, right?

A. Yes, sir, that is correct.

Q. Now, when you evaluated the project and the processing -- gas processing plant, what is the anticipated capacity of the new plant?

A. The nameplate design for the Zia II facility will be 200 million cubic feet a day.

Q. That value, that number, 200 million cubic feet per day, is that based on the projections of demand?

A. Actually, it's a combination of a couple of things. DCP operates a number of legacy facilities that have gone past their time relative to technology. There are issues around efficiency, and they have a larger emissions footprint. So in part, we're looking to roll in legacy plants, two small ones, plus, also, bring into the plant a fold vintage [sic] compressor station on the low pressure side on the plant. That will make up approximately 30 percent of the initial volume within the facility. And then in addition to that, we have premising a growth rate of roughly 70 percent with new volumes and drilling by producers.

Q. So the benefits of the proposed plant facilities are that you would roll in outdated facilities in addition to meeting your demand?

A. That's correct.

Q. By rolling in the outdated facilities, you're improving the overall functionality of the operations in southeast New Mexico?

A. We are improving the reliability within our system. We're also improving our pipeline integrity. Zia II will perform a lower pressure base, which provides hydraulic benefit on our system. And then additionally to that, we will reduce our permitted emissions footprint in southeast New Mexico with the addition of Zia II by approximately 700 tons per year.

Q. And that emissions reduction, is that with respect for the DCP's emissions or overall field emissions?

A. Only associated with DCP emissions. From total field emissions standpoint, if you include the producing community's flare volumes, we've seen that escalate here in recent time and due mainly to capacity constraints. So with the Zia II project, the added capacity, our view is that we will be able to accommodate more flow, which should reduce producer flaring at the wellhead.

Therefore, it's not only an emissions benefit from a DCP-permitted base footprint, but also the potential to reduce flaring from the producers' standpoint, and better management of state resources.

Q. Mr. Stone, tell me a little bit about the prospects for the proposed plant in the absence of the two AGI wells?

A. There really would be no prospects for a Zia II facility without AGI, especially on the timeline that we talked about relative to demand. Our system has seen increasing acid gas rates with the composition increasing in both CO2 and H2S over time, to a point for us to meet our air emission standards, we have to have some levels of sequestration in treating associated with those increasing acid gas rates and our inlet stream.

In addition, growth volumes that are being premised by producers are showing like-kind increases over what we have seen historically associated with acid gas concentration in both CO2 and H2S levels.

We are at a crossroads relative to the plant itself. To be able to benefit the widest amount of volume, both existing on our system today and premise growth, we need to have a sour facility. Otherwise, with just a sweet facility, I do not believe that we would be able to provide the surface level that the producing community needs, nor be able to reduce the resulting flaring and emissions that would go along with the continued capacity constraint in the area.

Q. Thank you, Mr. Stone.

So in summary, without the ability to inject the acid gas, you would be at increased emissions over time. Would DCP, or any provider, be able to meet the gas processing demands without relying on a -- without an acid-gas injection well facility?

A. How I would answer that question is this, is that if you do not have the sour gas capability within the Zia II facility or any other facility that does natural gas processing within the state of New Mexico, today or going forward, it's going to limit the ability of producers to drill in all zones. You would only be looking at those wells that had what I call merchantable quality that would not require treating and would not need to have an acid-gas injection to take care of the treated overhead component from that treating.

Q. And Mr. Stone, I'd like to talk now just a little bit about the economics and the economic premise underlying the proposed plant and the AGI wells. Can you explain to the Commissioners a little bit more about how the AGI wells are integral for the development and planning of the gas processing plant?

A. I'm going to ask you -- would you restate that question.

Q. I just wanted you to just talk a little bit more specifically about the economics and how the underlying economics affected the decision by DCP to proceed with this project. In other words, what are the underlying economic premises for the development on the project?

A. The underlying economic premise of the project -- first off, the Zia II program is roughly half a billion-dollar investment for DCP. We are a large company, but that is a very significant level for us. It'll be the largest investment that we have made in our southeast New Mexico footprint ever.

The economic premise is based on volume throughput and our ability to service that volume from the wellhead.

We look at the Zia II program as a long-term asset within our footprint. When I mention long-term, we look at it as a 30-plus-year investment. Our economics are based upon many variables, all which deal with risk, most of which are either going to be time based, which is the tenure of that facility and operations, and also trying to take into account market volatility associated with commodity price, as well as what we premise activity to be. I think we can all appreciate that we do live in somewhat of a cyclical environment relative to production.

Therefore, it is a requirement for our economic premise that we look at derisking portions of the project associated with that volatility, and the way we compensate for that is with added time duration on the expectation of that economic premise.

Q. Mr. Stone, if I might ask you: Without the AGI wells and if DCP had to go forward with a sulfur reduction unit, for example, and could not rely on the injection of the acid gas as a disposal methodology -- what would be the economic impact on the proposed facility now, if DCP had to rely on a sulfur reduction unit, for example?

A. A sulfur recovery unit and tail gas incinerator design for any plant is, first off, burdensome relative to a cost standpoint. It's not the best available technology for capturing and sequestration of acid gas at this point. It is not the best design relative to reducing air emissions.

From our standpoint, if we had to look and move away from an AGI and look at an SRU and tail gas incinerator, it would add substantial time to our permitting process. Given the current permitting requirements, both state and federally, I have no visibility as to what that added time would be. We are trying to pursue what we believe and others, our experts, subject-matter experts, have all concluded as the best available control technology to benefit the producing community, the state of New Mexico, management of their resources, and the general public.

Q. Mr. Stone, I want to go back to something you mentioned earlier in your testimony. You said that DCP views this project as a long-term investment, 30-year-plus investment.

Can you explain to me a little bit about what the impact on DCP's ability to commit to this project would be if there was a substantial change in the regulatory environment, if DCP could not -- cannot be assured that it would have a 30-year-plus life span with this plan?

A. If we didn't have certainty that we could have a continual operation for 30 years or longer -- and I'll reference back that our facilities in southeast New Mexico have been in operation in excess of 60 years, a number of them. But if we did not have that certainty that we could operate continually for an unlimited period of time, beyond, say, ten years, we would have to re-evaluate the economic view that we have and, most likely, look at other alternatives to try to accomplish the same as what we can do with Zia II as premised before you today.

Q. What would some of those other alternatives be if you couldn't -- if you couldn't be assured of the ability to inject acid gas for a period of the 30-plus years?

A. We would look at alternative investment in other areas that we might be able to provide the same level of service. Of course, it would be at an added cost to us. I think it would ultimately be at an added cost to the benefit of the state resources and managements of those and to the producing community and the economic development in southeast New Mexico, because what we would be talking about is extended time. I have no certainty as to what those alternatives would be, but that would be the path we would have to take.

Q. Now, I mentioned in my opening remarks, Mr. Stone, that there was -- and you mentioned this as well -- that DCP projecting about a half a billion dollar cost of the infrastructure for this. Could you just briefly review for the Commission what some of the infrastructure and cost would be associated with this?

A. I think you've heard me reference the Zia II not only as just the Zia II plant, but as the Zia II program. The Zia program is, of course, the Zia II processing plant with the acid-gas injection facility. It's also 50 miles of 20-inch trunk line that runs north and south and bifurcates our system today, which essentially on a hydraulic basis will double our processing capacity within our pipe system.

Additionally, we have premised growth through compressor stations and low pressure gathering to service producers at the wellhead. We'd be able to convey that volume, as I described earlier, from the wellhead to the Zia processing facility.

Additionally, we had talked about the consolidation of legacy vintage facilities. Those facilities, with the added pipe and the lower pressure base, can be rolled into our Zia II facility.

Ultimately, the overall program, inclusive of all of those components, actually creates a super system for DCP within southeast New Mexico, which creates optimization across our system. What that means to us is that -- and to the producing community -- is that our reliability improvements, as I had mentioned earlier, will come through being able to leverage all of the facilities that we have on our system. We would then be able to mitigate downtime and fold gas in for short periods of time into other systems because of the added infrastructure that is added to the system, primarily through 50 miles of 20-inch pipe bifurcating our system.

Q. And all that development that you've been referencing and the super system that you're referencing, is that all dependent on approval of these two acid-gas injection wells?

A. Yes. The two acid-gas injection wells, as we have the layout for the plant today, are a critical path algorithm. Without the acid-gas injection wells at Zia II, as I stated earlier, there will be an increase in acid gas rates. Of course, given the composition from both CO_2 and H_2S, we would be unable to service the producing community's growth perspective, and therefore, the added development between the pipes, the added compression, the optimization benefit for the system we would not be able to support because we would not have the capacity to be able to justify that project.

Q. Thank you, Mr. Stone.

Mr. Stone, I'd like you to just talk a little bit about the proposal to operate two acid-gas injection wells concurrently. Can you explain a little bit for the Commission what the benefits are that DCP sees with operating two or a redundant AGI system?

A. I believe DCP will be a prudent operator. I think we look back at lessons learned. We have, as you are aware, acid-gas injection wells at a number of our facilities. We clearly understand the burden to the producing community, the burden to emissions, should we have a failure in one of those wells. So as a prudent operator, we believe that the investment is supportable to go ahead and -- easily supported to go ahead and make that initial investment to drill both wells or two wells and have redundancy on site to mitigate downtime, to reduce the potential of flaring, both at the wellhead and at the facility, and basically to provide the best service available to the customers, as well as to maintaining our permitted emissions levels.

Q. Now, talking a little bit about the plans going forward, what is DCP's anticipated timeline for the approval of all these outlying permits and the construction of the plant and subsequent commencement of the operations?

A. As we're talking today, the permit for the AGI is a critical path for us. Should that permit be granted, our expectation is -- and, of course, the PSD permit from the NMED. Our expectation is we would look at commencing construction in April, of course, subject to the granting of those permits, with completion -- current expected completion in the midsummer 2015.

With that said, this is a very complex project. There are a number of variables to which I just mentioned in the permitting process and then, additionally, the potential of delays associated with long-lead items. There are many things that go into a processing facility, processing skids, compression, a multitude of materials, any of which, with long delays, could extend our construction period by a number of months, anywhere from 3 to 12, potentially, just as an example. And with the current activity and demand for materials in the oil and gas sector, we are seeing that more and more that we are experiencing delays. I think that we have done prudent and appropriate planning thus far. I think we've secured the majority of our long-lead items at this point, at least on paper, but there are still those items that can fall out, but the base premise is to be completed by midsummer of '15.

Q. And, Mr. Stone, you were referencing some of the challenges and complexities of constructing and preparing an operations facility and project of this size. Are some of those complexities and, would you say, challenges the reason why you're seeking a three-year authorization prior to commencement of the injection in this case?

A. Yes, that's correct. As I described earlier, the AGI permit is, of course, the critical path. I think we've established that at this point. We still have the variable of time with the NMED air permit. We believe that we're on course for an April start at this point, but that's still subject as an unknown. Additionally, with the long-lead items, we do not have good visibility. So having that latitude of time on the back side allows us to compensate for those unknown potential delays that could arise over the course of a project as complex as this.

Q. And, of course, before you reach those trigger points, those decision points to provide with some of those construction activities, it's necessary first to have the approval for the injection through these two wells; is that correct?

A. That's correct.

Q. Yeah. And, therefore, you need to have the approval and that additional lead time before injections commences to accommodate all the construction complexities and all the permitting that DCP anticipates it might face?

A. Yes, that is correct.

Q. It's a fair statement?

A. Yes.

Q. Now, Mr. Stone, you have had a chance to review the Division's pre-hearing statement; is that correct?

A. Yes, I have.

Q. And you've had a chance to look, particularly, at the Division's proposed conditions that they have anticipated asking the Commission to impose on any permit approval?

A. Yes.

Q. And would you mind -- I guess, let me just take the four wells that the Division has identified as having some concerns about. With regard to those four wells that the Division identified in its pre-hearing statement, is DCP willing to engage in good faith to cooperate with the Division and the operators of those wells to work with the Division to ensure that the Division's concerns are addressed with respect to the protections across the injection interval?

A. It is DCP's intent to work in good faith with the Division to address any issues or concerns and corrective measures that are necessary associated with the Zia II AGI request.

Q. Is it your understanding that DCP has reached agreement with the Division on those terms and conditions that they have proposed for those wells?

A. That is my understanding.

Q. And will your DCP technical witness address the specifics of those wells in his testimony?

A. Yes, he will.

Q. Now, Mr. Stone, with respect to the other conditions that the Division has proposed for the approval of this order, does DCP agree to conduct a yearly MIT on both of these wells?

A. Yes, we do. We believe that to be prudent.

Q. And does DCP also agree to monitor the treated acid-gas injection pressures and temperatures?

A. Yes, we do. And I believe our technical witness will describe that and go into detail if the process is there.

Q. Thank you.

And with respect to the Division's proposal to submit monthly summary data reports on a Form C-103, is it your understanding that the Division has agreed with DCP's proposal to submit quarterly summary data reports?

A. Would you repeat the question again? I want to make sure that I clearly understand.

Q. Sure. I probably convoluted that, made it into a very complicated question.

Do you understand the Division originally proposed monthly summary data reports?

A. Yes.

Q. Is it your understanding that DCP and the Division have reached an agreement to provide, instead, quarterly summary data reports?

A. Well, I'm going to tell you I am not positive about the response that we've agreed to the quarterly. My view, and the conversations I've had at this point relative to the monthly reporting, we find it to be administratively burdensome. We would request semiannual or quarterly, and at your request, anytime that you wanted information, we would be more than happy to provide it.

We believe that the summary operating information is very important both for DCP, as well as the Division. But the monthly, I think, is, from our viewpoint, an option that is needed if there have been experienced issues around a well and we're trying to track parameters more closely.

We do monitor our well on a daily basis, and I think that our view is that from a quarterly or semiannual time frame, that we can give good visibility and still have confidence, from an operator's standpoint, that we are performing, and the well is performing as prescribed to the satisfaction of the Commission.

Q. Thank you, Mr. Stone.

I think that was it.

Mr. Stone, would you mind, just in summary, summarize for the Commission what it is that DCP is requesting here?

A. Sure. Thank you.

As I've covered in the conversation today, the Zia II program and associated AGI system is extremely important, not only to DCP and the expansion of our system, but I believe it to be important to the state of New Mexico from a development and management of their natural resources through the producing community.

The project itself will provide added capacity, and, in our view and through our design and analysis, it will reduce our excess emissions -- or our permitted emissions footprint within southeast New Mexico. It should reduce flaring at the wellhead by the producing community, and it will provide capacity for future growth of production within southeast New Mexico.

It is our request that the Commission approve our C-108 as submitted.

Q. Thank you, Mr. Stone.

MR. RANKIN: Madam Chair, I pass the witness. I have no further questions.

CHAIRPERSON BAILEY: Mr. Wade, do you have any cross-examination?

CROSS-EXAMINATION

BY MR. WADE:

Q. And did you request that the Commission approve the application you submitted or with the conditions of approval as agreed upon with the OCD?

A. As agreed prior with the OCD.

MR. WADE: No further questions.

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

COMMISSIONER WARNELL: I do.

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. Good morning, Mr. Stone.

A. Good morning.

Q. You talked about reduced flaring on the operators.

A. Yes, sir.

Q. Will there be any flaring at your plant if two wells are improved?

A. Within the operating environment, rotating equipment, any process, there is always going to be some level of mechanical failure, no different than when you drive your car. And there is always going to be the potential for flaring. We look at it to be a very short duration.

We can experience flaring if we have third-party outages such as a power surge [sic]. You know, we can have flaring if our residue or if the NGL take-away pipes were to abruptly shut down. We do have some amount of NGL storage at the facility, so we're less susceptible to the NGL component, which then allows our operations time to coordinate with producers to shut their wells in and mitigate that relative to those events. The whole premise of the AGI, though, associated with the new facility is to mitigate that and reduce our exposure to flared emissions.

COMMISSIONER WARNELL: I have no more questions.

CHAIRPERSON BAILEY: Commissioner Balch?

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I have a couple of questions.

A. Yes, sir.

Q. Good morning, Mr. Stone.

A. Good morning.

Q. So in the foreseeable growth in gas production that DCP is trying to capture with this development, about what percentage of that future development in five, ten years is going to be sour gas?

A. I think from the very beginning, Commissioner, that we're going to see rates of acid gas in our composition that are going to require the sour facilities. Avalon Shale, in particular, we're starting to hear a lot of conversation around the Avalon Shale. We're seeing rates on Avalon gas gathering today in the 12 to 14 percent CO_2 range. H_2S is in pockets. We are seeing that periodically, but it's enough in the blend relative to being able to meet the marketing specifications on deliveries that we're required to treat. And at that point, we would then be classified as a sour gas stream. So as I had mentioned earlier, we've already seen CO_2 and H_2S rates on the legacy volumes within our system increasing.

I don't have a crystal ball that can tell me, you know, within a range of where I'm expecting to see growth go, and so this, to a point, is trying to be preemptive and trying to get ahead of where we think those rates may go.

We do know that we'll see producers over the years switch back and forth from developments. Some will be sweet. Some will be sour. Some will be more sour than ours. This gives us the flexibility to be able to service all of those zones and be able to meet the marketing specifications and constraints on the tailgates of our facilities.

Q. Thank you.

The two wells that we're talking about today, you mentioned they're critical path for your development?

A. Yes, sir.

Q. And they would be drilled beginning in April. Would there be, to your knowledge, any injectivity testing or other methods of determining whether they'll meet the capacity you're requiring before further development goes on? Do you have a no-go decision point based on the performance of these wells?

A. We will have an evaluation period. And I would prefer to pass that to our subject-matter expert on the technical side, if that's okay.

Q. That's fine. Thank you.

CHAIRPERSON BAILEY: I have a couple of questions.

CROSS-EXAMINATION

BY CHAIRPERSON BAILEY:

Q. You mentioned rolling in vintage -- two vintage plants and folding in two vintage plants. Are those euphemisms for closing down two vintage plants?

A. Yes, ma'am. Yes, ma'am.

Q. In response to your attorney's question, things got a little muddled. So is DCP expecting the quarterly reports?

A. Yes, ma'am. We would accept the quarterly reporting period.

Q. Okay. You're objecting to monthly reports?

A. Yes, ma'am.

Q. Just so we have that very clear on the record.

Those were my only questions. You may be excused.

A. Thank you, ma'am.

CHAIRPERSON BAILEY: Do you have any redirect, gentleman?

MR. RANKIN: Madam Chair, I have one question.

But I just wanted to advise you that Mr. Stone has a flight this afternoon, and we would ask, if there are no further questions of Mr. Stone, that he be excused to leave prior to the Commission's recess.

CHAIRPERSON BAILEY: I think any other questions that we have could be handled through your next witness.

MR. RANKIN: Thank you, Madam Chair.

REDIRECT EXAMINATION

BY MR. RANKIN:

Q. With respect to DCP's plan to develop this plant with two AGIs, was part of the purpose of proposing two AGIs to reduce plant flaring?

A. Yes.

Q. Can you explain a little bit for the Commission how a two-AGI system will help reduce plant flares?

A. The two-AGI system as designed, each well can handle the total overhead off of our treater of acid gas, and having both of them in continual operation allows us to move total volume to one side or the other. Therefore, if we have any issues associated with the wellbore, then that would mitigate flaring, as we've seen with a single-well setup.

Additionally, we are adding aboveground facilities that will give us redundancy on the compression standpoint, that we would have a full standby component to horsepower for the downhole injection, which then allows us to do preventative maintenance where we take our units down and do our appropriate operating maintenance program and not incur flaring during that period of time.

Q. Thank you, Mr. Stone.

MR. RANKIN: I have no further questions, Madam Chair.

CHAIRPERSON BAILEY: You may be excused.

THE WITNESS: Thank you, Madam Chair, Commissioners.

MR. RANKIN: Madam Chair, with that, I'll call our second witness, our technical expert on the injection and the C-108 application, Mr. Alberto Gutierrez.

MR. WADE: Madam Chair, can I request that we take maybe a five-minute recess? My witness had to leave, and I want to make sure he's here for this testimony.

CHAIRPERSON BAILEY: Sure. Let's come back at 10:00.

(Break taken, 9:50 a.m. to 10:04 a.m.)

CHAIRPERSON BAILEY: Would you stand to be sworn, Mr. Gutierrez?

ALBERTO A. GUTIERREZ,

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

DIRECT EXAMINATION

BY MR. RANKIN:

Q. Good morning, Mr. Gutierrez. How are you today?

A. I'm just fine. Thank you.

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

A. Yes. My name is Alberto A. Gutierrez.

Q. Can you please tell the Commission where it is you reside?

A. I live in Albuquerque.

Q. And where do you work?

A. I work for Geolex, Incorporated in Albuquerque.

Q. And what is your position with Geolex?

A. I'm the president of the company.

Q. What does Geolex do?

A. Geolex is a geologic and engineering consulting firm, and we work in the area of environmental -- geology and environmental work associated with different types of industrial projects. And then we have specialized expertise in the area of acid-gas injection as it relates to oil and gas operations.

Q. You've worked on acid-gas injection permits, correct?

A. I have.

Q. How many have you worked on?

A. I've worked on probably 15 or 20 at this point.

Q. And of those 15 or 20, you've worked as a primary consultant working on the approval of those applications?

A. Yes.

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

A. I have.

Q. And have you -- at the time of your previous testimony before the Commission, were your qualifications as an expert in petroleum geology, acid-gas injection, well operation and design and hydrology and groundwater contamination been accepted and made a matter of record?

A. They have been, yes.

Q. Mr. Gutierrez, did you prepare the application -- the C-108 application that was submitted to the Commission?

A. Yes. My office and I prepared it, yes; a number of staff worked on it.

Q. But you oversaw the application and the preparation of the application?

A. Directly, yes.

Q. And that's been marked as Exhibit 1; is that correct?

A. I don't know if it's actually Exhibit 1, but it --

Q. I will ask you: The C-108 before you, is this a copy of the C-108 application that you prepared?

A. Yes, it is.

MR. RANKIN: I'll mark that as Exhibit Number 1 for the record.

Q. (BY MR. RANKIN) Mr. Gutierrez, did you prepare a PowerPoint presentation reviewing the C-108 application and its salient points?

A. Yes, sir, I did.

Q. Did you prepare the C-108 application and the presentation you prepared today for the Commission?

A. I did indeed.

MR. RANKIN: Madam Chair, I would tender Mr. Gutierrez as an expert in petroleum geology, acid-gas injection, well operation and design, hydrology and groundwater contamination.

CHAIRPERSON BAILEY: He is accepted.

MR. RANKIN: Thank you, Madam Chair.

Q. (BY MR. RANKIN) Mr. Gutierrez, I'd ask you just to proceed with your slide presentation, and if I have any questions, I may interject, if that's okay.

A. Sure.

Q. Thank you, Mr. Gutierrez.

A. Okay. Basically, the Commission is familiar with how we've presented these things before. What I'm going to do is go through and try to summarize for you as succinctly as I can and as completely as I can, first, the initial C-108 application, how we determine the area of review and the notice procedures that we followed in providing notice to the potentially affected parties, and then to summarize the detailed technical evaluation that we made to support the application, present that to you and then end with a brief overview of the Division's pre-hearing statement and the discussions and agreements that we reached with the Division earlier this week after reviewing their recommended modifications to any kind of an order that the Commission would issue.

So let's get started. Basically, as Mr. Stone mentioned, DCP's requesting authority to inject acid gas from two identical -- and in this case, they're deviated wells. It's a difference that this Commission has not seen from our AGIs previously, but I will explain the rationale for why we are deviating these two wells, as you will see in the presentation.

As you can see from the C-108, we're proposing a maximum injection rate of approximately 15-million cubic feet a day at a maximum operating surface pressure of 2,233, which was calculated based on the normal procedure that the Division uses for calculating maximum allowable pressure for injection wells.

In addition, we modeled the ultimate size of the plume for the two wells, both at their proposed maximum injection rate, as well as two times their proposed maximum injection rate. The result of that modeling is that based on the reservoir characteristics that we have been able to define, the radius for each well after 30 years, in terms of the injection of 15 million a day, is about a quarter of a mile. The injection radius is about .37 miles if you double that injection rate. And so in either case, the 100 percent safety factor brought us under half a mile.

There is no current or anticipated production in the Brushy Canyon and Cherry Canyon Formations. That's something we've discussed at length, also, with the BLM in this area. As you will note from our application and from my discussion later today, this facility is being built on BLM property, and the minerals in that area are BLM minerals. And there are some specific requirements that we have discussed and agreed upon with the BLM, through this process, as far as the well design because of where the wells are located.

There are about 29 wells that penetrate the injection zone within a mile radius of the area of review. Seventeen of those are active wells. Twelve of them are plugged wells. Most of them are Strawn-Morrow-Cisco wells. Within a half a mile, there are nine wells that penetrate the injection zone. Seven are active. Two are plugged and abandoned.

While we feel that all of those wells -- you know, the concept of protecting and keeping the injection in zone is a function of, basically, three primary factors. One is how far is there a feature, such as an old well, either active or abandoned, from the injection point in terms of the likelihood of acid gas actually reaching that well. That's one factor. The second factor is the actual construction of the well itself and the reliability with which we understand that construction. And then the third is really the geologic environment and what protection the geology itself provides.

In our case here, these wells are generally outside of the area that we anticipate will be affected after 30 years. However, we have discussed some specific wells with the Division that we have agreed have less than optimal protection across the injection zone, and even though we feel they're far enough away, we don't have a problem with addressing them in the way that we will discuss going forward.

Also, the proposed injection zone is capable of permanently containing the injected fluid. We have done a careful analysis, looking for any kind of features that would indicate that we've got structural problems or fractures or faults in the area, and we have found none at this point.

So what are the key elements of the C-108? Obviously, the AGI project has some substantial environmental benefits. I think some of those were touched on by Mr. Stone's testimony in terms of the sequestration of CO2 and the reduction of flaring that is associated with the ability to take this sour gas that is currently, in some cases, being flared by the individual producers.

Also, nearby oil and gas wells and water wells and surface water are protected by the well design and geologic factors that we will discuss. And a detailed, long interpretation has permitted the accurate delineation of the reservoir and assuring that both the nearby saltwater disposal wells and producing wells are protected.

The application, we believe, provides the Commission with all of the details necessary to approve the installation of the AGI wells. An H2S contingency plan obviously has not been drafted for the plant yet, which isn't fully designed, but certainly the DCP is committed to and has retained us to prepare such a plan that would be submitted for approval prior to commencing injection.

The adjacent operators, including the operators of even the wells that we have discussed with the Division, are supportive of the project. The BLM is generally supportive of the project, and there have been a number of permitting steps that are ongoing with the BLM to obtain the lease for the facility.

Operators and surface owners have received proper notice, and there have been no objections to this AGI project from surrounding operators or surface owners.

Q. Mr. Gutierrez, just to interject, you mentioned that the H2S contingency plan has not yet been submitted to the Division for approval, correct?

A. Yeah. It hasn't even been drafted yet.

Q. When you do submit it to the Division for approval, will it include both the plant operations -- the processing plant operations, as well as the two AGI injection wells?

A. Yes. As a matter of fact, that's really how we do the H2S contingency plans, just like we have done at Linam and Red Hills and a number of other facilities. The plan includes not only the AGI wells and the AGI facility itself, but it's integrated as one overall H2S contingency plan that takes care of the overall plan of the facility.

Q. Thank you.

A. The proposed AGI wells are designed to support the operation of the Zia Gas Plant. As Mr. Stone mentioned, there is some real dependency on these wells for this project, and the reason, as he mentioned, is because we are seeing a fair amount of CO2 -- increased CO2 concentrations in inlet gas out there. And not only from the pure -- even under the best of circumstances, sulfur-reduction units are very difficult to permit and to operate within air-quality constraints, but they're especially difficult to operate in a situation where you have either increasing or unpredictable variations in CO2 concentrations because it requires -- SRU requires a kind of stable and relatively low CO2 concentration to operate efficiently.

Furthermore, the production that will be -- as Mr. Stone represented, there's going to be -- about 30 percent of the facility is basically production that's consolidated from some small treatment facilities like the existing Zia facility, but 70 percent of it is new production that is anticipated to be generated in the area. So that will provide some new revenue to the state.

Here's where the plant is. It's kind of out there in the middle of nowhere, in the Coracho [phonetic] Plains area. It is, essentially -- Section 19, which is where the plant is being built, curiously enough, is right on the west boundary of Section 19, which is the county line between Eddy and Lea Counties. So it's really at the extreme western edge of Lea County.

Let me give you a little bit about what the site is going to look like. The overall site can encompasses about 188 acres, and the actual plant operations area, including the AGI facility, will encompass about 50 acres. The lands are all owned by the U.S. Government, and they will be leased on a long-term lease from the BLM.

The field gas is going to be sweetened by two amine units. As Mr. Stone mentioned, they're also going to have a cryo unit for removing the NGLs prior to the sweetening process train.

In addition, the proposed wells and all the surface equipment will be contained within the fenced plant area, and therein lies the reason why we're using deviated wells.

We would like to have the bottom-hole locations of these wells separated by about 12- to 1,400 feet to minimize interference between the two wells, since they're going to be injected and operated simultaneously. But at the same time, we have a competing interest, if you will, and that is minimize aboveground, high-pressure acid-gas piping, which is a safety factor. And so what we want to do is keep the surface locations of the two wells relatively close together, but then we want the bottom holes apart. So you'll see how we have proposed to accomplish that.

The Zia AGI Well #1 is going to be drilled 2,100 feet from the south line, 950 feet from the west line of Section 19. The #2 well is intended to be drilled, essentially, 200 feet south of that same location, but the bottom-hole location of the two wells, they're going to be deviated such that the bottom-hole location is going to be approximately 1,300 feet or so apart. And they will be shown here on the next map.

Here you can see that the AGI #1 we intend to drill right here is the surface location (indicating). Here is the bottom-hole location (indicating). We will deviate the well to the north, and then the #2, we are deviating here to the southeast (indicating). And the rationale for those specific bottom-hole locations will become clear when you look at the geology. So it's not just separation. We're also trying to get to the sweetest spot in the reservoir and the thickest available porosity section so that we can minimize the extent of the acid-gas plume.

Here is a preliminary drawing that represents what the plant is going to look like. The process trains for the facility are located here (indicating), the amine contactors here (indicating) and the amine regeneration here (indicating). So basically in yellow you see what is going to be low-pressure acid-gas piping and then, in orange, the high-pressure acid-gas piping. So basically the gas is going to be collected from the amine unit and taken out to the acid-gas compression at the northwest portion of the facility, and they're going with one single high-pressure line that Ts off to both of the wells. And so that's a general layout based on the proposed plant layout.

The anticipated fluid, as we mentioned, is about 15-million cubic feet a day total for the facility based on the best estimates currently of the CO2 and H2S in the inlet concentrations. Injected fluid is essentially anticipated to be about 11 percent H2S, 89 percent CO2, with some traces of light hydrocarbons.

We have looked at the compatibility with our own injection experience into similar formations and what we understand about the water in the Brushy Canyon and the Lower Cherry Canyon, and we don't anticipate a problem. As I mentioned before, the MAOP that we've calculated is 2,233.

Okay. So let's talk a little bit about what the reservoir looks like. And I'm going to go into the detailed geology a little bit later but just a summary here. We anticipate -- we've got some pretty good data from drill stem tests and a variety of other wells in the area that give us an understanding that we are anticipating somewhere in the neighborhood of 120- to 125-degree temperatures at the reservoir and about 2,400 psi. And given that -- those reservoir conditions, we've calculated that the anticipated capacity and the anticipated volume that that TAG is going to occupy in the reservoir is somewhere in the neighborhood of about 7,000 barrels a day; 7,050 is actually what we've calculated.

After 30 years of operations, given what we understand about the reservoir in that area, we're looking at about a .36, actually, radius from a single well, if you were injecting from a single well. The partition between the two wells, we're looking at radii of approximately a quarter mile. This is what it looks like (indicating). I call it my Venn diagram because it's -- the two -- the red shape that you see here (indicating) is the two wells at the 15-million-a-day rate, and the blue is the two wells at a 30-million-a-day rate. The purple line, just for reference, is an outline of Section 19.

So you can see, this western boundary (indicating) that I was saying, that's the western boundary of Lea and Eddy County.

As we develop the application, you know, we tried to essentially follow what has been our understanding over the last year and a half of developing the new rules that are ultimately going to be presented to the Commission in terms of AGI wells, which is going to be a welcome thing to have. But we tried to follow as much as we could the procedures that we anticipate those rules are going to show.

So consequently, we evaluated everything within a mile, but given that we simulated that the 30-year injection plume was going to take up less than .37 miles, we notified everybody within a half-mile radius of each of the two proposed wells. And as it turns out, having given notice to everybody in that area is the same as giving notice to everybody in a mile, because they're all the same operators. So we did do that, and there weren't unleased minerals in the area.

We provided the notice, along with a complete application to all of those surface owners. There are no businesses or residences within a mile of the facility, but we provided it to all of the surface owners.

We also -- the Commission published -- or the Division published the newspaper notice. We have had no objections to the application, and the adjacent operators, as we mentioned, do support the projects, which is going to be a benefit to not only the area but to the state in general.

Q. Mr. Gutierrez, might I interrupt you for a moment, and I'm going to ask you just to identify? Is this -- what has been marked as Exhibit Number 3 and included with the pre-hearing statement today, is that a copy of the letter that was sent out to all the affected parties that you've identified requiring notice?

A. Yes, it is. And in addition, I'll just mention that this same information is included in our appendix that contains the land information.

Q. You mention an appendix. Are you talking about at the end of the C-108 application?

A. That's correct.

Q. And the difference between Exhibit 3 and the appendix is that Exhibit 3 just contains a copy of the letter that was sent out to the affected parties?

A. Right.

Q. And then it also contains the green card receipts indicating that the notice was mailed to those individuals by certified return receipt requested?

A. That's correct.

Q. And then, Mr. Gutierrez, just to walk through a little bit more about the notice issue, you said that BLM is the landowner; is that correct?

A. Yes, sir.

Q. And did the BLM also conduct an Environmental Assessment for this project?

A. There is an Environmental Assessment that has been prepared and submitted to the BLM, and, yeah, it's been back and forth. I don't know exactly -- I think it's under its final review stages at the present time.

Q. Now, regarding the identification of these parties, just explain a little bit -- in a little more detail for the Commission how you identified the affected parties requiring notice.

A. Yes. I mean, we obviously went through the process of retaining a land firm, NBS [phonetic; sic], that did a detailed review of the OCD records, the state land records, the federal abstracts, and then actually went to each of the courthouses involved to evaluate and identify all of the operators, lessees or mineral interests in that area. And that's where we obtained the information.

Q. So the addresses that were included for the notice purposes, were those addresses in the record at the time the application was submitted?

A. Absolutely. Yes, sir.

Q. In your opinion, Mr. Gutierrez, did you make a good-faith effort to locate and identify all the affected parties?

A. Yes, we did. And, frankly, we got a couple of applications returned because they weren't -- where there was really no forwarding address for that particular party. And in one case, we actually had an individual contact us because another leaseholder had received an application and they hadn't, but it was because their address of record -- they had moved since their address of record. So we immediately sent them a copy as well.

The only other one that I recall that we had kind of a funny deal with is the one that we sent to the BLM. Of course, the BLM was well aware of the project and everything else. But in the courthouse, the address of record for the BLM in Santa Fe is a certain P.O. Box, and apparently they had changed that P.O. Box. So after three -- after about two weeks, we got that application back. We got a correct address, street address, for the BLM, FedEx'd them that application. And then several -- about a week after that, we got that application back in the mail from the BLM, and they said, Oh, send this to the Carlsbad District instead, you know, which is kind of funny, because the Carlsbad District, while they take care of the technical issues, supposedly the state office is the one that's supposed to be notice as a mineral owner and land owner. But we did that as well.

Q. Thank you, Mr. Gutierrez.

Just as a recordkeeping matter, since I identified your notice as Exhibit 3, I just want to make clear that the hard copy of the presentation that you're reviewing and submitted along with the pre-hearing statement is identified as Exhibit Number 2; is that correct?

A. Yes. This is the slides we're reviewing right now.

Q. Thank you, Mr. Gutierrez.

So just in case we reference your slides, I want to be able to reference -- to indicate that is Exhibit Number 2, for the record.

A. Okay.

Q. Thank you, Mr. Gutierrez. Continue.

A. Okay. So I think -- at the risk of boring the Commission, because I know that they've heard this before, but it's always a little different every time, I want to go over kind of what are -- just review very quickly what are the important features that we look for when we're looking for a reservoir for acid-gas injection.

We want a geologic seal that will permanently contain the injected fluid. We want to make sure that the zone is isolated from fresh groundwater. We want to have no effect on existing or potential production in the area. We want to make sure that the reservoir is laterally extensive, it's permeable, and it's got good porosity. And we want to have excess capacity for the anticipated injection volume and, lastly, of course, a compatible fluid chemistry, which is generally not a problem in terms of these saline zones that we're looking at. So we believe that DCP's application and these two wells as designed meet these criteria.

So the process that we go through, of course, we identify and characterize the wells and the stratigraphy in the area. As I mentioned, we had a number of wells, 29 wells, that penetrate the injection zone within a mile. There are no completions or current production or injection in the area that we are -- within the area of review into our injection zone. There are wells that penetrate the injection zone, as I mentioned, largely deep Strawn-Morrow wells.

Within a half mile, we've got nine wells, seven active and two plugged, that penetrate the injection zone, and we'll review those in more detail as we proceed.

And as I mentioned, I think that either the wells are far enough away or they're properly completed, with the exception of the four wells that we have discussed with the Division, which, while being relatively far away from the perspective of injection, they are within the half-mile area, and we have agreed that there are prudent actions we should take relative to those wells.

This is a map (indicating). It's included in the application as well. It shows the one mile from both of the bottom-hole locations, and you can see the wells in the area that penetrate the injection zone. There are actually a lot more wells than this, as you'll see in the application, in the area, but the bulk of the wells in the area are completed in the Delaware Sand above our injection zone.

And as a matter of fact, during the break, I was visiting with the Division and wanted to point out that there is a waterflood unit in this area, but it is in the Delaware, above our injection zone, not in our injection zone.

The wells within the half mile that penetrate the injection zone, you see this is the general layout of those wells (indicating). This shows, as I mentioned, those wells relative to the anticipated footprint and the half-mile area of review and the 100 percent safety factor area, which is the area that is included in red. And we'll discuss the wells in more detail as we go along.

Let's talk a little bit about the stratigraphy of the proposed area. The proposed wells are on the southern slope of the northwest shelf of the Permian Basin. The Cherry Canyon and Brushy Canyon

Formations are sandstones and shales that are deposited at the toe of the Capitan fore reef and are basically contained above and below by low permeability stacks of siltstones and shales. And we'll show you those in our presentation.

The wells will penetrate the Capitan Aquifer. Now, that's important, because as I'm certain the Commission is aware, there is an area that is immediately adjacent to the area that we're in, actually, that is the BLM's four-string casing area, that requires four strings of casing.

Now, our particular zone is outside of that, and so we've dealt -- we've discussed this in detail with the BLM and worked with them on the design of the wells to make sure that the Captain Aquifer is adequately isolated. And we've extended our intermediate -- I mean our surface casing to below the bottom of that so that we can isolate it with not only the surface but also the intermediate string and our production string and cementing.

And I want to emphasize that the Capitan Aquifer has the capacity to yield a lot of water, but it's not drinking water. But the BLM still protects that water because they consider it usable water, and, in fact, it is used for a number of waterflood projects in the area. It is brine, basically, in many areas, but it is still considered protectable, usable water by the BLM.

Okay. So this is the general kind of Permian overview of the main structural features (indicating), and as you can see, we're located off the south end of the northwest shelf as it goes into the Delaware Basin there. This is kind of a cartoon that shows you the stratigraphy -- general stratigraphy in the area, and the zone that we are looking at injecting in is the very lower portion of the Cherry Canyon and the upper portion of the Brushy Canyon here.

As I mentioned here, you can see, this Capitan Aquifer protection area is this area (indicating) that is shaded in blue. It actually extends quite a bit further than that to the north and west, but in terms of the immediate vicinity of our plant, this is the area where it's located.

And so you can see our two wells are in the -- within the eastern portion of that area, and consequently that's why we had discussed in detail our well design with the BLM and agreed on a design that would be protective of that aquifer.

This is kind of a type log. It's one of COG's wells in the area. It gives you a pretty good indication of where the production is relative to our injection zone in this area. Of course, as you know, the groundwater in this area, usable groundwater, is -- I mean potable water is restricted to the alluvium and the Rustler, and then there is some water in the red beds there. But this is up in this area (indicating) of the section, within about 300 feet of the surface.

There also is production in the Seven Rivers-Yates area. There is some production in the Delaware and in the very, very top of the Cherry Canyon, except the reason why these stars are in green is because in this area, that production is more than a mile and a half away. It is not in the immediate vicinity. Whereas, the stars that are in red, there is production in those zones within the area of review, as we mentioned earlier.

Also, there is some production in the Wolfcamp, away from the area of review, but this is, in fact, where a lot of the new gas is anticipated to come from for this plant.

So let's take a look at a couple of cross sections, if we can, kind of from the north to the south and then east to west, and we can see what the geology looks like. This is a northwest-to-southeast cross section. You can see the top of the Cherry Canyon has got some fairly good low permeability. Those are shown in brown zones, which are interbedded with some other sandstones that have higher permeability and porosity.

Our proposed injection interval is located here (indicating), between the bottom of the Cherry Canyon and the top of the Brushy Canyon. The Lusk West Field has some pay zones that are about a mile and a half away, but they're here below us in the very lower portion of the -- well, the bottom of the Brushy Canyon and really in the very basal or top -- basal portion of the Brushy Canyon, top of the Bone Spring.

Looking east to west, we again see the same kind of pattern. This is just a very regional kind of cross section, but you can get an idea of what -- we're looking at injecting into a package of these zones that are interbedded with caprock and injection-quality reservoir within this Brushy Canyon-Cherry Canyon area. And, again, the pay zones in the Lusk Field, which are about a mile and a half or two away, are in this portion of the Lower Brushy Canyon.

So if you look at kind of a composite log that shows a proposed injection zone, here is our proposed injection zone. We have -- again, that Lusk production, which is not too far away, is downdip. And then lower or below us -- the production that we have above in the waterflood is more in the basal portion of the Delaware, up above these impermeable portions of the lower -- I mean the Upper Cherry Canyon.

Q. Mr. Gutierrez, based on your analysis of the geology -- the overlying geology and underlying geology, is it your opinion that the injection zone would contain the injected acid gas?

A. Yes. That's a fundamental -- that's kind of a red flag that we start with when we are evaluating the reservoir.

Q. So based on your analysis of all the cross-section wells in the composite log, your opinion is that that injection [sic] treated acid gas will stay in the zone?

A. That's correct.

Q. Thank you.

A. Now, the next two maps that you're going to look at provide, at least, our initial basis for understanding what kind of reservoir we have in terms of what is the total porosity that is available for us to inject into in the two primary zones that we're looking at.

So this is the lower 200 feet of the Cherry Canyon. You can see that we have essentially an alignment north-south of some -- of the troughs and the thick and thin spots of good sandstone, with greater than 10 percent porosity. In the area, we're looking at -- we're looking at approximately 110 to 115 feet for AGI #1, bottom-hole location, and about 105 feet or so of sandstone that has greater than 10 percent net porosity for the AGI #2.

This map here -- and I want to emphasize, these maps, you know, were not just drawn using the half-mile area of review, but really incorporating the data from all of the wells within about a couple of miles so that we could get a better idea of what the trends look like in terms of thicknesses in the reservoir.

Here you can see -- this is kind of our sweeter spot (indicating). The upper 400 feet of the Brushy Canyon gives us about 300 feet, roughly, of good -- 10 percent or greater porosity in this zone. For the bottom-hole location for AGI #1 and the bottom-hole location for AGI #2, what we're trying to do is get into these two sweet spots with our well location.

Just to point one out, this well here to our west (indicating) provides a kind of factor that we wanted to stay away from, simply because this is a horizontal well. Here is the surface location (indicating), and it's in the basal portion of the Bone Spring there, but it extends horizontally to the north. And this is well below our injection zone, but we just were wanting to stay mainly in the sweeter spots of the reservoir, which are located to the east here.

And, Commissioner, you asked a question about the testing of the wells to Mr. Stone. And, of course, when we drill these wells, we're not only going to use our normal logging program of some fairly detailed geophysical logging of the wells, including FMI of the injection zone and caprock, and also coring of those zones and then do core analysis to verify our permeability and porosity and get a good understanding of our -- to ground truth [sic] our irreducible-water determinations for the area. But in addition to that, we will do testing of the wells -- injection testing of the wells with warm-back profiles, because as you accurately pointed out, I mean -- and as Mr. Stone mentioned -- these wells are critical to the -- and the long-term viability of these wells is critical to the viability of the plant. So we will certainly be testing those wells to confirm what has been our best determination to date that they will be adequate to handle this kind of volume.

So what about the structure? The figure on the next slide shows the structure of the top of the Brushy Canyon. You'll see it dips about one-and-a-half degrees to the south. This is really no evidence of faulting at this level in the area. And, you know, you can see we're in a little bit of a canyon there in the -- or a little depression in the top of the Brushy Canyon, but it's generally pretty flat. And then this little canyon (indicating) was probably going down from the shelf towards the Delaware Basin.

Calculations that we did of the reservoir area affected -- I think by now the Commission is used to how we do these things, but basically we use the available information on the reservoir conditions and then our determination using some software -- the best software we have available to us, either CSM GEMs or AQUAlibrium, to determine what the conditions of the acid gas and what kind of area it's going to occupy in the reservoir.

Q. Mr. Gutierrez, you mentioned that you used the available reservoir data. Could you just briefly explain for the Commission what kind of data that is, and, I mean, how much data we're looking at here to come up --

A. Well, we're looking at the data from all of the wells that penetrate the injection zone, plus drill stem tests of those zones. And I'll show them. These two slides are a good example. We took wells in the area and did bottom-hole pressure trends for wells -- shallower wells and deeper wells and wells within or close to our injection zone, and this is where we got this kind of bracket of about 2,250 to 2,500 psi, if you will, in our injection zone, what we anticipate expecting.

And then we did the same thing with temperature. We got a little wider band in terms of the temperature. And you'll notice that we've assumed about 120 degrees in our calculations. The data would indicate approximately 122 to 127, but what we have actually seen in other wells in the Cherry Canyon there indicates that it's a little cooler than that. And, in fact -- so that's why we've assumed 120. If we used 122, it might be slightly larger, the amount of area that would be encompassed by the plume but not significantly.

Q. So, Mr. Gutierrez, with respect to both of these charts you've been showing us, the bottom-hole pressure trends and the bottom-hole temperatures, is each point on these charts, is that the individual well data point?

A. Yes, sir. Yes, sir.

Okay. So, again, based on our reservoir volume calculations, we got a radius of about .36. Actually, it was less than .37 miles after 30 years and about a quarter of a mile of -- per well. For each well, you would add seven and a half. So in other words, if we were putting it all in one well, it would have about a .37 radius after 30 years, but if we put it in the two wells, each one will have about a quarter mile of radius.

Again, this is one of the things that we are proposing to do and that we have discussed with the Division, that after the well is drilled, cored, logged and tested, that we will come back -- we will rerun our plume simulation, so to speak, and then we will have the best possible idea of what that is likely to be using the actual data from the wells themselves. And hopefully -- we try to be conservative. So I will hope that what we actually find will allow us to have actually more porosity than we currently are assuming.

This chart is impossible to read (indicating). It would be easier to read in your application, but I want to point out that we noticed that we had put a wrong version of this chart in the application originally. And in our pre-hearing statement, we gave you a page to substitute. All the calculations were correct. It's just that we were doing various simulations, and when we had the final one, we just inserted incorrectly into the application. So this was -- and the difference was a slight difference in the MAOP. I think the one that you have shows a slightly higher MAOP. But this is the correct one (indicating). And the correct calculation was in the text. It was just an error in what we put into the application.

These two circles (indicating), again, show what we anticipate to be the 30-year footprint. And, you know, again, I think one of the things that is important to note is that, you know, we use this 30-year number because it's typically, as Mr. Stone alluded to, a minimum kind of life span for these kinds of facilities, and it's been what we have traditionally used in our evaluations of these wells, so we continue to do that.

So let's talk a little bit about the general design of the AGI system. As you know, we have been doing these wells now for almost 10 years, 11 years. We like to learn from our -- as the science involves. And so we started -- you know, as this Commission is well familiar, we modified the design at the time of requesting permission to drill Linam AGI #2 because of the experiences that we had with tubing leaks in Linam AGI #1. And what we had come up with, based on all of the work we had done, was that the area of the tubing that was most at risk and of the casing was the area immediately in the vicinity and immediately above the packer.

So what we had come up with is a design that encompassed, obviously, a CRA section, or corrosion-resistant casing section, in which we set the packer, but then also a corrosion-resistant section at the basal portion of the tubing string above the packer.

Now, what we have found is -- and that was a design that we've used. We used it in the -- we used it in what was approved for Linam #2, which hasn't been drilled yet, but we also did it in Red Hills, which has been drilled and will be completed soon.

But what we found is -- as we started really doing this work, we started thinking, okay, this tubing -- for example, the 2550, which is this Sumitomo material that is corrosion-resistant material, in three-and-a-half-inch tubing, this 2550 material costs about -- the quotes that we get bring it between about 1,100 and $1,300 a foot. Okay? So it's pretty expensive pipe. And we've been looking at putting, you know, somewhere in the neighborhood of 300 to 500 feet of that corrosion-resistant tubing at the basal portion of the string.

And, you know, one day I started -- I was talking with one of our drilling engineers and reservoir engineers and then our metallurgist, and we were just talking. And all of a sudden, I said, Wait a second, guys. You know, when we've designed, we've designed a number of wet AGI wells, right?

And we use normal L-80 tubing, but we line it with fiberglass, the whole tubing, because we know we have a wet stream going down all the time. And we've designed and constructed a number of wells that way, including the Jal 3 well for Southern Union, and we've never had problems. We've operated them for a long period of time. As long as you put the tubing together correctly and you do it carefully and you have a good quality control on your lining material, it's actually, you know, perfectly fine to put -- to use -- even in a situation where you're mixing the acid gas with water at the surface.

And I said, Why don't we just line the tubing even if it's a dry-injection well? Forget about it. Don't even bother putting in corrosion-resistant tubing only in the bottom. For the same price, we can -- essentially, for the same price we have this blended tubing string, we can have a tubing string put in that is lined with fiberglass all the way to the surface, and you protect the entire tubing string, not just the bottom 500 feet or so.

So that is a modification that we have made in the design, I think, which will essentially upgrade the design of the dry AGIs to meet the same conditions that we have in a wet AGI, which, theoretically, you should never encounter in a dry AGI. But we all know, based on Linam, that sometimes you can have a problem.

So I think it's a far better approach. And so that's the only real difference in this design that there is. It's more like a design for a wet AGI well.

Again, the annulus will be filled with corrosion-inhibited diesel fuel, like we have discussed before, and we will also do downhole pressure and temperature monitoring realtime on at least one of the wells or possibly both of the wells. And that will give us a better idea what of the reservoir conditions are during and for the life of our injection project.

Q. Mr. Gutierrez, on that point, what are some of the factors that would lead you to believe that only one of the wells would require this downhole pressure monitoring?

A. It's going to depend on how similar the reservoir looks in the two areas where we actually wind up at the bottom hole. You know, the likelihood is we're probably going to include it in both wells. But if the reservoir looks essentially the same in the two, it may not be necessary, but it may be that -- you know, we haven't made a final determination on that, but we definitely will have it in one. And in all likelihood, we will probably have it in both.

Q. And the determination on the similarity of the reservoir would be based on running science logs and the evaluation of the reservoir that you do at the time you drill the wells; is that correct?

A. That's correct. That's correct.

Q. Thank you.

A. So we'd like to have that flexibility.

Here's the general schematic of the AGI design (indicating). It's a general schematic. As I explained to you, the wells are in Cline [sic], but the -- and so actually -- the actual length of the wells, because they are in Cline [sic], is going to be -- or deviated, is going to be longer than the total depth. But at least here you have just a picture -- just cartoon of what the wells will look like. A more detailed design is provided here (indicating), which gives us a kick-off point of 4,650 feet. That's where we're going to kick off with the deviated well. So we're going to go and run our surface -- our conductive casing about 50 feet or so, and then we're going to run our surface casing to the depth below all of the fresh water in the area and the Capitan protection zone.

And then our intermediate casing is going to be taken to just above that kick-off point, and at that kick-off point, we'll take off at about a 27-degree slant in the two directions that we outlined on the map.

And then the well will be perforated. The injection zone is roughly from 5,500 feet to 6,000 feet, or 6,500, depending on what we actually encounter. So let's just say 5,500 to 6,100 feet for the injection zone, and the wells will actually have a measured depth of closer to 6,200 feet, total depth based on the slant.

One of the things that's also very important that we discussed in detail with the BLM is that in the wells, we're going to use -- in the portion of the well that is deviated, we are going to use some special centralizers on every joint of pipe so that we can assure that we get a good cement job. Because basically what happens, unfortunately, when you do a deviated well is that as you run your casing, it lays up against the side of the borehole, and if you don't separate that casing from the bottom of the borehole, when you sequence and you pump your cement, you don't get cement against that side of the casing.

So the way we deal with that issue -- and this has become an issue not just, by any means, on injection wells but on production wells as well, that because there are so many more deviated and horizontal wells now than there used to be, people have developed some specific centralizers that are -- extra-strength centralizers that actually hold the pipe centered in that deviated hole and enhance your chances of getting a good cement job.

Of course, the zone that's shown in red here on this diagram is the corrosion-resistant portion of the casing. There we will use some 2535 or 2550 equivalent or -- you know, that's a trade name, but I'm just saying we will use a corrosion-resistant casing that has those properties in that zone where we set the packer.

Obviously, also, we will run corrosion-resistant cement all the way from the base of the well to at least 200 feet within the intermediate casing, and then we will run standard cement above that. That's been our traditional kind of design to assure that we have both the injection zone, then the caprock, and then into the intermediate section protected with not only corrosion-resistant casing but also corrosion-resistant cement.

And this is an area that we've discussed in extensive detail with the BLM because of the issues associated with Capitan Aquifer.

So all the casing strings are going to cemented to the surface, pressure tested and verified using 360-degree cement bond logs. The deviated string will be cemented in the critical caprock area and all the way, as I mentioned, 200 feet -- approximately 200 feet into the intermediate casing with CorrosaCem or Evercrete or an equivalent. I mean, those, again, are trade names. It depends on whether you use Halliburton, or Schlumberger or Baker. They each have their own products, which are essentially similar, but they're named differently.

In the deviated interval that I mentioned are the centralizers. We're going to use additional and specific types of centralizers to aid in the cement job. And the casing and cement program is consistent with the BLM's guidelines in the area, as well as, obviously, the Division's requirements.

The groundwater conditions in the area, let's talk about that a little bit. There are only four freshwater wells within a mile of the DCP AGI. None of those wells are currently used. They were wells that were drilled in 1982 by Phillips Petroleum for exploratory purposes to understand where the -- and I don't really know what the purpose of their project was. I think it may have been to look at potential water for some project that they had going on there. But those wells were never really completed as water wells that are used, and they don't produce any water for consumption. But they range from 1,190 feet to about a total depth -- the deepest one, 350 feet. Three of them are more like 250 feet deep, and they're within the red beds. Of course, those will be well isolated by three strings of casing. Here's where they're located, where those three wells are located (indicating).

There are no farms or ranches out in that area. There is no domestic production. Now, there may very well be and I anticipate -- though I have not heard the specific plans for one, but I anticipate that the plant will probably drill a water supply well for their own domestic purposes at the plant, to have their flush toilets and cafeteria or whatever they have that they require fresh water for at the plant.

But in any case, if such a well is drilled, it would be drilled probably to a depth of only about 190 to 250 feet, depending on the water needs at the area and, again, will be properly completed and cemented and will be in the zone isolated by three strings of casing.

So let's summarize what these geologic factors are that assure the integrity and safety of the proposed wells. There are no structural pathways like faults or fractures that were identified in the area of review. There are wells that are penetrating the injection zone, isolated in that zone, and with the enhancements we've discussed with the Division, those wells will be even better isolated, the ones that are somewhat tenuous.

The caprock is a low-porosity interbedded impermeable zone that is an effective barrier above the injection zone. The injection zone is vertically and horizontally isolated from adjacent production zones, as we have seen. The freshwater zones are isolated by both the conductor and the surface casing, and the proposed injection pressure is well below the fracture pressure of the reservoir and caprock. And the log analyses demonstrate that we have a closed system.

Furthermore, the reservoir pressure is sufficient that at that reservoir pressure and temperature, we will be able to keep the acid gas in a super-critical phase, which is a good thing.

So what DCP is requesting for the

Commission to provide us in an order is permission to drill, test and complete the AGI wells as specified in the application and as modified by the discussions that we have in this hearing.

We want to injection 15 million a day into both of the wells, so a combined injection rate of 15 million a day. Now, Mr. Stone laid out the fact that there is a possibility that there is a real benefit to the redundancy that is supplied by these two wells. Our goal is to use both of the wells simultaneously and split the flow between them, because our feeling is that using a single well for the entire flow may result in a little higher than what we would like surface pressure, still under the MAOP but a higher surface pressure than we want to be compressing to all of the -- all of the time, simply because of the resistance to flow within the tubing itself.

But what is good about the system is that while we intend to operate both wells at the same time, we can -- for, you know, relatively short periods of time, in the matter of, you know, certainly hours or days or perhaps even weeks, we can operate with a single well. So if we have a problem with one of the wells, we can shift over to the other with minimum disruption and minimum chance of having to flare.

We'd like to have three years. I know typically the Commission has granted two years from the date of the order to complete the wells. As Mr. Stone has stated and has been made very clear to me, DCP's desire is to get this plant up and running by the second quarter of 2015. So, clearly, that's well within this three-year period.

But as he mentioned, you know, we have a number of issues, balls that are being juggled right now in terms of long-lead items for the plant, the final approval from BLM for the plant lease itself, those kinds of things. And so we would just like to have a little longer time period even though it is an intent to start sooner. So that's basically what we have.

I've got some additional -- about eight slides that I would like to go over. Maybe we could take a short break. I'd like to go over those, because those are the slides that go over the Division's pre-hearing statement and what their conditions are and evaluate those four wells closely and what we have arrived at with the Division as an agreement going forward.

CHAIRPERSON BAILEY: Then why don't we a ten-minute break, come back at 11:20, and you can go into those other slides?

(Break taken, 11:14 a.m. to 11:23 a.m.)

Q. (BY MR. RANKIN) Mr. Gutierrez, you indicated before the break that you had prepared some additional slides referencing the Division's issues and concerns of the proposed conditions on an order. Would you mind reviewing those for us now?

A. No problem.

Q. Mr. Gutierrez, is this a hard copy of your slides? This has been marked Exhibit Number 4; is that correct?

A. Yes, sir.

Okay. On Thursday evening last week, we received a copy of the Division's pre-hearing statement, which included an analysis conducted by the Division's technical staff that pointed out some desired conditions that the Division would like to see in the order, as well as raising some concerns about four wells that are located within the half-mile area of review.

Subsequent to that time, we had a couple of conversations, and then on Monday afternoon, I met -- myself and Mr. Jim Hunter from our office met with Mr. McMillan and Mr. Goetze and Mr. Wade regarding these conditions. We talked about the technical details involved. And subsequent to that time, after I had consultations with DCP's project folks, we transmitted, through Adam, communications to the Division that, generally, we were in agreement with some small modifications of what these requests were. I'd like to go through, first of all, what the requests were from the Division and what we have agreed upon.

The first one is, of course, something that's going to be included, hopefully, in the new AGI rules, which is an annual MIT. We have no problem with that, and that would be what we proposed to do anyway. So that was the first point that was raised by the Division.

Second is daily monitoring of pressure data, diesel replacement, atmospheric H2S and safety measures in place. In fact, the monitoring of all of those parameters -- with the exception of diesel replacement, because diesel replacement is something that only happens occasionally, that you may have to put some additional diesel into the annular space. But the rest of those activities, the pressure -- the temperature of injection, the pressure and temperature of the annular space and the sensing of H2S or potential H2S releases are not monitored daily. They're monitored continuously. Okay? So they're monitored 24/7, continuously. So those are -- we don't have any problem with that request. And, in fact, like I said, it's part of the normal operating procedures of the plant.

Q. Mr. Gutierrez, with respect to the diesel replacement activities, just to be clear, has DCP agreed to keep or maintain the maintenance log of the replacement activities conducted of the diesel for the annular space?

A. Yes, they have.

And I would propose and just note that, for example, the one other well where we've done this monthly reporting, which is Linam #1, because of the issues we had with Linam #1, in that reporting, we not only analyzed the annular pressure and temperature and injection pressure and temperature and the injection rate and provide that data to the Division on a C-103, but on those very graphs -- or in these C-103s, if we have had any kind of diesel-replacement activity or some other modification of the well, that's also included in that report.

So I would propose that here, in the quarterly reporting that we provide to the -- that we have agreed on with the -- with the Division, that in addition to maintaining that log on the site, that if there had been any kind of diesel-replacement activities or anything like that, that would be noted on that quarterly report when that occurred as well. So the

Division would have that information not only if they wanted to look at a log, but, you know, since it's key to analyzing that data, we would include that in the quarterly report. Okay?

Q. And so the maintenance log for the diesel would be maintained and retrievable upon request by the Division?

A. That is correct.

Q. Thank you, Mr. Gutierrez.

A. And furthermore, I think I would emphasize that we felt that monthly reporting was onerous for a well that hasn't had any kind of a problem. I mean, given the fact that we are, you know, collecting that data daily and -- not daily but continuously and we're immediately aware, we have alarms set -- later on, we'll talk about these immediate-notification parameters that we're working out with the Division. So those all will provide the ongoing monitoring of that. But then we felt that quarterly was a more reasonable way of just submitting that information to the Division.

Now, of course, if we noted that there was any kind of an issue, we would be reporting that based on whatever we agreed with the Division of the immediate-notification parameters. But just a routine reporting, since this is going to go on for

30-years-plus, we would like to do that on a quarterly basis.

One of the things that we talked about, was laid out by the Division, and has been the subject of other orders we have discussed is that 30 days prior to the start of injection -- and usually we'll do it even before that, but sometime prior to the start of injection, no less than 30 days -- we'll sit down with the Division, both the district office and, if so desired, with Mr. Goetze or a representative from the Santa Fe Office and work out the immediate-notification parameters and alarms for the annular pressure, injection pressure, those kinds of issues.

The Division has requested, basically, that happened twice, not only once prior to injection, but then also, that 90 days after injection has begun and we've got a better sense of how the well is operating, to go and review those again and see if they need to be adjusted and modified. And that's a normal thing we would do anyway, and we'd be happy to do that with the Division.

Furthermore, the Division has requested that those immediate-notification parameters be reviewed periodically with OCD but not less than once a year. And what I would suggest there and what we would agree is, yes, we will review those with the Division as needed, and then once a year, if there is -- and I would propose that we could just do it as part of one of the quarterly reports, that we would just say, Okay, we believe the parameters are fine going forward, because after about some period of operation, those parameters really shouldn't change very much.

So unless there is a reason to change those, what I envision is that once a year, at least, we will lay out in that quarterly report: Here are the notification parameters; we don't believe they really need to be revised or changed. But we would consult with the Division at that point and determine if they felt it needed to be changed.

The approval to commence injection, the Division requested that a condition be put on there that we have to have an approved Rule 11 plan, and, of course, we don't have any problem with that. That's required even for the facility to start up. So we have no problem with that.

Q. And, again, Mr. Gutierrez, just for clarification, that contingency plan would relate to the facility and the injection wells?

A. It is a contingency plan for the overall plant, including the AGI system. It wouldn't include the gathering system, of course, but the plant itself and the AGI.

Okay. To get to the meat of the issue that the Division had, Mr. Goetze, in his analysis, which he will present, identified four wells, three active wells and one plugged well, within the half-mile radius that either have no cement, apparently, across the injection zone or less-than-adequate -- in the Division's view, less-than-adequate records indicating where the top of cement actually is in these wells.

So I'd like to go through each one of the wells individually, because they're a little bit different. Again, three of these are active wells. I should say two of them are active wells.

One is still classified as an active well, but it's not an active well. I mean, it still has a tree on it, but it hasn't had any production for about five years, and it is not TA'd or PA'd. So that well, while it's an active well in the context that it still has its tubing and everything in it, it's not producing.

And then the fourth well is a plugged well, which was P&A'd in the mid-1990s and was last operated by Phillips.

So let's take a look at where these wells are. Here's our little plume map, if you will. These wells are located here (indicating). There is the Lusk Deep Unit #8 here. This, by the way, is the plugged well. We have the Delhi Federal #1 down here, which is located towards the south and outside -- by the way, again, just as a point of reference, the blue line is the 30-year plume, with 100 percent safety factor. The red line is the actual 30-year plume. You can see, these three wells are even outside the 100 -- or right on the 100 percent safety factor line. This Gulf Federal #3 is at the edge of our 30-year injection plume.

So even though the Division had some concern about the construction of these wells, they recognize clearly that these wells are not really an immediate issue but that they may become an issue as injection proceeds down the road.

Q. Mr. Gutierrez, just to be clear, the blue line which you said is a 100 percent line for injection volumes, when you say 100 percent --

A. 100 percent safety factor, I said. So that's twice the injection volume.

Q. Thank you.

A. Right.

Okay. So let's take a look at each of the wells. Here's the Delhi Federal #1. This well has --

is a producer from the Strawn -- basically from the Strawn. This well has produced both gas and oil since the well was originally drilled. This was a heck of a well, frankly. This well produced -- flowed 500 barrels a day when it was originally drilled. And as you can see, the well is still producing a dozen barrels a day of oil as of last year. It hasn't produced any gas since 2008. And it is producing a little more water now. But this well is still a viable well and probably will continue to produce for some period of time.

This well has a production string which is cemented from about the bottom of the well to about 8,300 feet, and then it has a zone that was squeezed as a result of a casing leak at the depth of about 6,087, which is near the base of our injection zone. But it appears not to have cement in the rest of this zone, which would encompass a portion of the injection zone. So this was the first well that was of concern to the Division.

Oh, I hit the wrong button. I'm sorry.

The next well is the Lusk Unit #5. This is, essentially, a well that is not really an economic well anymore. As you can see, it hasn't produced any oil since 2005. It is still producing gas, but it sure as heck is not paying for itself. It's only producing about 2 million -- it produced a little over 2 million Mcf of gas in the entire year of 2013. So it's not much of a well at this point, and so we think that this well is likely a candidate to be plugged within the next few years anyway. And we'll talk a little bit about what we think should be done about that well. It doesn't appear to have any cement across the injection zone, with a top of cement at about 9,800 feet in this well.

This well, the Gulf Federal #3, which is the well I said had no production since 2009, produced only 219 barrels of oil in 2009, and it's just been sitting there. So that well is not doing anything. It is a well that should be TA'd and PA'd. And I don't know. Maybe the Division has some further information on this well. It may be -- we don't know if even the operator is a currently viable operator or not. So this well is definitely en route to be plugged at some point.

The last well, which was one that we had some -- a little bit more discussion with the Division about, because, based on our calculations and based on the calculations that were done and the records we have of plugging, this well does have cement apparently across our injection zone, but it's calculated. And it's not -- there is no cement bond log. So we don't really know how -- what the cement conditions are in the well. And so the Division was still concerned about this well. And this, unfortunately, as luck would have it, happens to be the plugged well. So if remediation is necessary in this well, we will have to re-enter it and squeeze off that zone, which is what we have discussed with the Division.

Fortunately, unlike the previous nightmare wells that we dealt with on the Red Hills, this well does not have the casing pulled. So fortunately, we still have casing apparently in the hole, so hopefully we would not have the kind of issues in re-entering this well that we had on those.

So what would we do with these wells? We just gave an example of one of the two -- one of the four. This is the Gulf Federal #3, and this is what we talked about with the Division. We said, Look, what do we need to do to isolate our injection zone? This is the main concern that we have. Even though it's not an immediate concern, it could be a concern down the road.

So what we have suggested and what we have agreed upon with the Division is that we would agree to work with the operators of these active wells and/or the Division, if it turns out that one of these is an orphan active well, in assuring that the injection zone is isolated when the well is plugged or worked over, whichever comes first, or 15 years, whichever comes first. So we've got a long time before we get anywhere near these wells to have a concern, but the Division wanted to put a time limit on it.

We would like to minimize the disruption to the operators, and we want to minimize the cost of doing this. So what we want to do is to be able to do this when the well is worked over, plugged, or 15 years, whichever is sooner.

And in this case, this is an active operating well. It does have a plug because -- this well, for example, was plugged back, so it's now producing from -- from the Yates. It was plugged back in 1981. So it has one plug down at a depth of -- the bottom of the intermediate casing, and then it's been plugged from -- we don't really know where the top of cement is, but it's been plugged from roughly 7,500 feet down to the bottom of the well. And there is a plug in the well at that depth. This is when it was plugged back to the Yates.

So here what we would do is go in, pull the tubing and drill out those two plugs and then perforate and squeeze the casing and squeeze 100 feet or so of corrosion-resistant cement above and below the actual injection zone. And, of course, by that time, we will know exactly where our injection zone is. You know, we provide our best estimate, but, of course, when we actually complete the well, we know exactly where that injection zone is. So anyway, this would be a sample of what we would propose would be done with these wells. And this we have discussed with the Division, and they would agree that this is an approach that achieves the objective.

So what are the recommended actions after drilling Zia #1 and 2 but prior to injection? That we will implement the conditions that we talked about earlier, items 1 through 7 in the OCD's pre-hearing statement. We also said we will recalculate the plume and safety zone extent with an updated model plume when we complete the wells. We'll re-evaluate what is appropriate for these wells, but we already have agreed with the Division that we've come up with an approach that I think everybody can agree with.

So let's just summarize what we propose specifically for each of these wells. There are three active wells: Delhi Federal #1, Lusk Deep A5 and Gulf Federal #3. So for those, we've agreed -- and the Division has agreed with the language that we proposed -- that we'll make a good-faith effort to work with the operator of the well, or the Division in the case of an orphan well, to enhance the isolation of the injection zone when the operator either works over the well, plugs and abandons the well or after 15 years, whichever is sooner.

For the three active wells, we would also request that when any of these wells are plugged or when the operator would propose to plug and abandon these wells to the Division, that the Division should make it clear that as part of that plugging effort, that this zone should be squeezed and isolated. And, of course, we'll work with those operators. If we receive our approval in this application, we will actually make contact with those operators sooner rather than later just to advise them of what the requirements are and try and see when things are going to happen.

With respect to the one orphaned or potentially orphaned well, I think we will work with the Division to figure out what the status of that well is and see if that's a well on that we'll need sooner action on just because of its current status and in maintaining compliance with the Division's rules.

The plugged well, we would like to do a couple of things. One is that we may -- we're going to search to see if we can find any additional records which would determine whether or not that cement is actually up to the 5,400-foot level or not, but if -- if we can't get any further information, what we would propose to do is, within the next 15 years, we will re-enter that well and drill out those plugs and attempt -- the Division has recommended or suggested that we might drill out the plugs and then just run a CBL. If indeed the CBL shows that there is cement across the zone, we don't need to bother perforating and squeezing.

But, frankly, once you drill out the plugs, I'd rather just go in and perforate and try and squeeze. And if I can get the cement in there, then it wasn't properly cemented. If I can't get the cement in there, then it is properly cemented. And I think we talked about that with the Division, and they were fine with that approach. They were just trying to save us a little money.

Q. Mr. Gutierrez, you mentioned CBL. Is that a cement bond log?

A. Yes, sir. Yes, sir. And, unfortunately, this well did not have a cement bond log when it was originally drilled.

Q. And I'd like for you, briefly, Mr. Gutierrez, to explain to the Commission why it is that a 15-year period is acceptable and protective in this case. Would you mind going back to your map and explaining to the Commission -- or remind them of the location of these wells and the distance from the point of injection?

A. Yes. I mean, the wells are here (indicating), here (indicating), and here (indicating). This is the 100 percent safety margin after 30 years of injection. The one well which is closer is right at the edge of our 30 years of injection. If we look at a 15-year of injection period -- I mean, we haven't done the exact calculation, but you can basically see that we would be nowhere near these wells after 15 years. Now, actually, the closest well, this Gulf Federal #1 -- let's see -- is this well, which actually is likely to be dealt with much sooner than 15 years anyway, because it's the well that should be in current T&A status and probably should be plugged sooner rather than later, not because of this project, just because that's what's required by the Division's rules.

Q. And with respect to -- at the time when remedial action is taken with respect to these wells, whether it's during a work-over event or some other trigger event, or within the 15 years, is DCP agreeing to conduct reasonable and prudent remediation as directed by the Division at that time?

A. Yeah, as part of the plugging program, in the event that the well's being plugged, or as a separate squeeze job if the well is just being worked over.

Q. Now, one other thing I wanted to just mention or discuss with you, Mr. Gutierrez, is during the break, I had the opportunity to speak with the Division's counsel, and they indicated -- he indicated that the Division would -- their preference would be to have bottom-hole temperature and pressure monitoring for both the Zia wells, AGI wells. Is that something that DCP would agree to do in this case?

A. Yeah. I've discussed that with DCP, and they would agree to put it in both. I mean, we don't really -- I don't know that it's absolutely necessary from just the reservoir-data perspective, but we don't have a problem with that. And it will help to monitor the operation of the wells, so we would agree to put the bottom-hole pressure and temperature measurements -- or monitoring in both of the wells.

Q. Mr. Gutierrez, just to summarize your testimony today, is it your opinion that the design -- the proposed design of the two acid-gas injection wells that are part of this application will enhance the reliability of the injection and the overall functioning of the proposed gas-processing facility?

A. Yes.

Q. And in your opinion, will the proposed injection pose any threat to underground drinking water or other freshwater sources in the area?

A. Absolutely not.

Q. And is it your opinion that the granting of DCP's application will further the protection of human health and the environment?

A. Yes, because it will reduce emissions and chances of flaring and permanently sequester those GHGs.

Q. And GHG being greenhouse gases; is that right?

A. Yes.

Q. Mr. Gutierrez, is it your opinion that the granting of DCP's application will prevent waste and otherwise protect correlative rights?

A. Absolutely, because you won't be flaring gas, and we're not going to be affecting negatively any production in the area.

Q. And will it also be meeting additional accepted demand in production?

A. Yes.

Q. Mr. Gutierrez, were Exhibits 1 through 3 either prepared by you or under your direct supervision?

A. Yes, they were.

MR. RANKIN: Madam Chair, I'd move to admit Exhibits 1 through 3.

Q. (BY MR. RANKIN) And Exhibit 4, is that correct, Mr. Gutierrez?

A. Yes. Exhibit Exhibit 4 is this presentation (indicating).

MR. RANKIN: Move to admit Exhibits 1 through 4.

CHAIRPERSON BAILEY: Exhibit 1 as modified and amended?

MR. RANKIN: Correct, Madam Chair, as modified and amended based on today's testimony.

CHAIRPERSON BAILEY: And the supplemental corrected page that was sent to the Commissioners?

MR. RANKIN: That's correct. The page 7 which is replacing Table Number 1, which was provided with DCP's pre-hearing statement.

CHAIRPERSON BAILEY: Any objection?

MR. WADE: No objection.

CHAIRPERSON BAILEY: Then they are admitted.

(DCP Midstream, LP Exhibit Numbers 1 through 4 were offered and admitted into evidence.)

MR. RANKIN: With that, I pass the witness.

CHAIRPERSON BAILEY: Let's break for lunch. Come back at 1:15 sharp, and then we will begin cross-examination and questions.

(Break taken, 11:53 a.m. to 1:10 p.m.; Mr. Brancard not present; Ms. Bada present.)

CHAIRPERSON BAILEY: Mr. Wade, I think it was your turn for cross-examination.

MR. WADE: And the OCD does not have any questions for Mr. Gutierrez.

CHAIRPERSON BAILEY: Okay. Mr. Warnell?

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. Bear with me here for a second, please. We went through that presentation so quickly. I think I've got some questions in here. I've got a lot of little asterisks or marks, meaning maybe I had a good thought, so let me share a few of them with you.

A. Yes, sir.

Q. Mr. Gutierrez, please, how do you define your injection area, I mean, as far as permeability and porosity, or do you have a handle on that?

A. Yes. Basically, we do it in a pretty traditional geologic-analysis point of view. What we do is we identify the potential injection zone based on logs and any core data that may be available. It's usually not. It's usually just geophysical logs or maybe -- and then -- so we gather all the logs that penetrate the potential injection zones that we're looking at, and based on those logs, we do analysis to determine the porosity. You can't really get very good permeability data from the logs, but you at least get pretty good information on porosity.

And so then, based on that analysis, we typically will take a certain relatively arbitrary cutoff, depending on what porosity range we see for that zone. And in this case, we used greater than 10 percent porosity.

And then we identify and basically tabulate -- for all of the wells that we have in the area, for all the control wells that go to the injection zone, we tabulate the thickness of those zones that are greater than 10 percent porosity, and then we do an isopach map on that. Then based on that, we figure out -- also on the logs, we calculate our best estimate of irreducible water content. And then what we do is just use a radial model from these wells to basically fill up that pore [sic] space in the area.

Q. So you have no core data to back up permeability or --

A. (Indicating.)

Q. What is your target permeability? What kind of permeability?

A. Well, it depends. Usually, you know, if we get anything north of 10 or 15 millidarcies, we're usually in pretty good shape. But we do look for -- the permeability data we have found is quite variable anyway in these zones, because you don't really know diagenetically if some portion would be affected and another portion not affected.

So what we do to really try to get a handle on it -- we do what we can with the data that we have when we prepare an application, but then prior to operating the wells, when we drill the wells, that's why we do -- what we do first is we typically log the hole, and then based on the results of the log, we pick points for cores. And then we go back in and do sidewall cores throughout the injection zone and the caprock, and then we send those off for analysis from Weatherford or someone like that, and then we get those actual data back. And then we do the same process that we did before, but we do it with better data.

Q. I guess what's bothering me is you do the calculations for your plume, but without any handle on permeability. And it seems to me like that would be very dependent upon the permeability of your injection formation.

A. Well, what's more dependent on the permeability is how rapidly one of those zones may be able to take the gas -- the TAG or not take it. What is a larger controlling factor of the ultimate extent of the plume is how much available space there is that can be used in the reservoir to fill it up. But, yes, clearly, if you have some -- the thicker and the greater amount of porosity that you have, the less expansive the plume is going to be, basically.

But, yes, permeability is an issue, but there is just no good way to get a handle on it very effectively usually with the data that are available until you actually drill it and test it. So it's a risk every time that you drill the well. You can run into a situation where the permeability is not as good as you anticipate. And where it tends to be more of a problem is not so much in the volume that you're going to be able to inject but whether you're going to be able to inject it at a pressure that is under the maximum allowable operating pressure.

Q. Okay. Bear with me.

BLM. I've got "100 percent BLM." Any state or land minerals associated at all with this project?

A. No. No.

Q. It's all BLM --
A. Yes, sir.
Q. 100 percent BLM?
A. 100 percent BLM.
Q. Another question about permeability. Will you core as you drill, or do you do sidewall cores?
A. We're going to do sidewall cores.
Q. You testified at one time, "one of our drilling engineers and reservoir engineers." When you said that, are those engineers that are your employees?
A. No. They're contractors.
Q. They're contractors?
A. Yes, sir.
Q. How many people in your company?
A. In my company? We've got about 14 people.
Q. My mind is wandering a little bit. Excuse me.
So we talked a bit about cement bond log, cement evaluation logs. You're talking about the newer technology, the spherically focused, the 360-degree ability to look at the bond log?
A. Yes, sir. The BLM, by the way, requires that.
Q. 17-and-a-half-inch surface string, I believe. Is that what I saw in your well sketches?
A. Yes.
Q. And something that caught my eye here is, I

believe you've got your surface pipe set at 250 feet?

A. Yes.

Q. And there was one of those four offset wells where -- no. One of the water wells that you mentioned, where they were 300 -- maybe two of the water wells, 350 foot deep.

A. Yes, sir.

Q. So why would you set your surface string at 250? Wouldn't you want to set it at 350 or greater?

A. Because from the records that we saw of those wells, they encountered water, but they didn't encounter water that deep. I mean, by the time they got into that portion of the Rustler, it wasn't producing very much water. But, I mean -- and they're not wells that are even being actively used in that area. But, I mean, we would -- we typically -- you know, we say that it's 250 feet. Ultimately, we may -- what we try to do is get through all of the Rustler and set the surface casing below any freshwater zones in the Rustler, even though much of the water in the basal portion of the Rustler is getting pretty salty anyway.

Q. You testified or mentioned something about diesel replacement. There was a problem with diesel replacement. Could you expound on that?

A. Sure. Not a problem with diesel replacement, but we said that we would report if there were any diesel-replacement activities. And let me tell you what would cause you to have to replace some diesel.

Every time you do an MIT, right, you need to bring that annular pressure down to zero, and then bring it up to 500 pounds. The only way we can manipulate that annular pressure is by pumping in or drawing out diesel. So, ultimately, every time you do an MIT, you take a little bit of diesel out; you put some diesel back in.

And, of course, I didn't raise this issue, but if you were ever to work-over the well, you have to remove all of that diesel, of course, and then put it all back in. But it's more to deal with topping up the diesel after you do an MIT.

Q. And you mentioned several times about "active wells." What is your definition of an active well?

A. My definition of an active well is a well that is actively producing or is in a condition where it could produce.

Q. So reporting production?

A. Yes, sir.

Q. Thank you. That's all the questions I have.

CHAIRPERSON BAILEY: Commissioner Balch?

COMMISSIONER BALCH: I've got a few

questions as follow-up on Commissioner Warnell's questions about the coring.

CROSS-EXAMINATION

BY COMMISSONER BALCH:

Q. These wells are probably a couple million dollars each, I guess?

A. Yeah. They're more than that. They're probably closer to about $4 million each.

Q. Each?

A. Yes, sir.

Q. And you're still looking at a relatively small percentage of the overall project running [sic] into these wells?

A. Yes, sir.

Q. Compared to a facility of half million dollars?

A. Yes, sir.

Q. How many sidewall cores do you plan on taking do you think?

A. We usually try and take -- in an injection zone like this one that's 500 feet, we'll probably wind up taking 60 to 70 sidewall cores, something like that.

Q. Do you think you'll get enough information from that? Would there be maybe -- well, it's rig time to do full core?

A. It's not just rig time. It's also picking the point where you're going to start to make sure that you catch what you want to catch, you know.

Q. Right. And you're not sure -- you're not particularly sure enough where the lithology is going to start to --

A. Exactly. And so that's why we do it that way.

Q. You're going to have the first well drilled --

A. Yes, sir.

Q. -- before you drill the second well?

A. Yes, sir.

Q. So you would know, potentially, where you would start for a full core. Think -- to me, it seems like you'd want to understand that formation as best you can. I don't know if that's something you would consider or not.

Similarly, for logging, what are the logging plans?

A. We do a full triple combo, and then we do an FMI across the caprock and the injection zone. And then we also do a log that we can -- sonic log.

Q. Shear sonic?

A. Yes.

Q. Okay. That was my question. I wanted to make sure you were going to get that detailed lithologic --

A. Absolutely.

Q. -- understanding that you get less shear sonic --

A. Yeah.

Q. So you're going to operate these wells, and you're going to try and put half -- half the TAG into each well?

A. That's the plan, yes, sir.

Q. So a typical day of operation is this -- 50/50?

A. Yes, sir.

Q. And the only time you'll be 100 percent is if you were working-over or doing something with one of the wells?

A. Yes, sir.

Q. That'll be for the whole duration of the project?

A. That's correct.

Q. And that reservoir pressure and temperature, your CO2 is going to be super critical?

A. Yes.

Q. I was pretty sure of that because you were describing the liquid barrels, but I wanted to make sure that was the case.

A. Yes.

Q. What's the -- what is your estimate or understanding of the current reservoir pressure? Is it under pressure?

A. We don't believe it's really under pressure. It seems to be normally pressured.

Q. And you think that -- what sort of pressure do you expect to see at the end of 30 years?

A. Based on our knowledge of that zone and what's happened in other places, we anticipate that -- to be honest, I don't have a good sense of exactly what the pressure's going to be after 30 years. We have seen some injection wells, waters wells, in those zones that have injected water for 20-plus years, and the injection -- and the reservoir pressure is elevated about 15 percent or 20 percent. And it is -- and it tends to drop off pretty quickly when you stop injecting.

Q. Are they pushing water into those wells, or is it dropping down?

A. Pushing, yeah.

Q. Pushing?

A. Yeah.

Q. Do you know what kind of range of values for those injection pressures?

A. I think they're running roughly around 5- to 700 psi at the surface.

Q. And you're going to go around to 1,200?

A. Probably. We're going to go with whatever is the minimum pressure it takes to put the stuff away.

Q. So we've talked about your simulation before. You're using a GEM module, or CMG?

A. We use that, and we also use can AQUAlibrium. We use them both. And we usually compare the two. And AQUAlibrium tends to be a little more conservative than GEMs, so that's what we end up using most of the time.

Q. Okay. So on your GEM model, it looks like there's kind of one-dimensional modeling. That's why you have the radius --

A. Yes, sir.

Q. -- instead of an amorphous plume shape?

A. Right.

Q. Are you using any of the radioactive components that CMG has available, the reactive transport?

A. Well, we have used some of those really for more kind of almost research type of projects, but, you know, typically we just don't have the reservoir data in these, like, declined curves or in these zones, because, obviously, they're zones that haven't been -- we look for zones that are not producing and haven't produced.

Q. So you're going to sample the reservoir fluid, the waters that --

A. We are, indeed. Yes, sir.

Q. So you would have -- you would have enough information to be able to do reactive transport modeling?

A. Right, although most of -- a lot of the work that I've been looking at in the whole AGI arena shows that, you know, in terms of that interface where those reactions take place, that it really affects a relatively small portion of that overall plume. Most of it stays as a phase-separated fluid.

Q. I'm not sure I agree with that. I think a lot of it goes into residual. I mean, there is a lot of -- a lot of it gets stuck in the cores and residual water, for example.

A. Oh, yes. Yes. Yeah, but as opposed to actually dissolving in the water.

Q. Right.

A. That's what I'm saying.

Q. Okay.

You mentioned that the nearby Brushy Canyon production was up higher than your reservoir, about a mile and a half away. Which direction?

A. It's towards the southeast, and it's actually below our -- it's not above.

Q. It's also downdip stratographically?

A. Yes, sir. Yes, sir.

Q. On the type log in your presentation, I was wondering if you'd be able to identify with some of the secondary seals. Do you have that handy?
A. Yes.
Q. I'm looking at this one.
A. Oh, okay.
Q. It might help the other Commissioners if it was on the screen.
A. I can put it up on the screen.
MR. RANKIN: Mr. Gutierrez, Commissioner Balch is referring to Exhibit 2; is that correct?
COMMISSIONER BALCH: Exhibit 2, yes, somewhere around the middle.
THE WITNESS: I know which one he's looking for.
MR. RANKIN: It's entitled "Stratigraphy and Lithology of Producing Zones Above and Below Proposed Injection Zone"; is that correct?
THE WITNESS: Right. That's right.
I believe it's this slide. Now, when you say that you're asking about the secondary --
Q. (BY COMMISSIONER BALCH) What would be the first -- if it were to get out of the primary seal, where would it go? Where would it be able to stop?
A. Well, if it was to get out of the Upper -- that

low-permeability zone in the Upper Cherry Canyon, it would go into the Delaware.

Q. And there is some Delaware production -- I think that Gulf Federal Fee is producing from the Delaware?

A. It's producing from the Yates and Seven Rivers.

Q. Oh, it's higher up?

A. Yeah. It's even higher up.

Q. Anything in between? Looks like dolomites, limestones.

A. Yeah. I mean, I don't think it would -- I mean, there are some relatively low-permeability zones, but not continuous zones in that section of the Delaware. So it could make it -- if it got out of the Cherry Canyon, which we don't think it will, I mean, my sense is it would go to the Delaware.

Q. And is there any potential production within a mile or two in the Delaware?

A. Not that -- no. It's more -- it's actually more than two-and-a-half miles away. And it has been tested in this area, and it's tested wet all the time.

Q. Tested wet?

A. Yeah.

Q. And then the Yates-Seven Rivers is the Yeso and stuff [sic]?

A. Yes, sir.

Q. That is -- there is some production there?

A. Yes, there is.

Q. And there could be, potentially -- higher up in that area?

A. It's pretty old production. I think it's -- the Yates-Seven Rivers has been pretty well produced in that area. I don't think there would be anything new in that zone.

Q. So going back a little bit to your modeling, in the absence of a three-dimensional plume model -- I was looking at this last night and trying to visualize the three-dimensional shape. I imagine the plume would go into -- based off your cross sections and your isopachs -- I think it would be useful for me, at least, to have your net porosity isopach hung on the base of the -- of the primary seal --

A. Yes.

Q. -- for overlaying on the contour map on the primary seal, just for trying to visualize where that plume is. Because I imagine, at least from my understanding, is that there's going to be a little bit of a barrier somewhere less than quarter of mile to the west of those two wells where the CO2 is probably not going to go much further --

A. That's right.

Q. -- in that direction.

A. That's right.

Q. It will instead probably go up towards some of those thicker, more porous zones.

A. I would agree.

Q. So instead of your -- your Venn diagram, I imagine more of an oval, perhaps trending a little bit more north.

A. It could be, yes. And, obviously, if you look at the -- and that's the reason why, when we drill the wells and do the core analysis, we go back and try to remodel that, although it's not a true three-dimensional model. But we try and take in consideration, you know, the thicker zones. It's kind of a balancing thing. You know, when you get a thicker porous zone, you tend to have a little bit better permeability in that zone, too.

But, you know, the zone, if it's thicker and has more porosity, it tends to limit the areal extent of the plume. In reality, the real -- it's much more complicated than it would seem initially. And I know we simplify it because of the data constraints that we have. But, I mean, in reality, what we do is when we actually do the logging and the coring, then we pick -- we don't just shoot the whole injection zone. We actually try and pick the zones that are better within there. And that's an advantage in that there really are primary seals throughout even our injection zone. And so we end up kind of stacking the stuff up in between the less permeable layers.

Q. How much of that net pay do you think you're going to perf?

A. We'll perf everything that looks good in our well, yes.

Q. And you don't anticipate you have to do any fracture stimulation perf --

A. Yes, sir. Well, we'll probably acidize it to clean up the perfs.

Q. Switching gears, let's talk a little bit about your tubulars.

A. Yeah.

Q. Is that a very expensive -- I guess that's some kind of a very expensive stainless?

A. Sumitomo 2550 is a chromium-nickel blend alloy.

Q. It's solid? It's not a coating?

A. Not a coating.

Q. It's solid?

A. It's solid.

Q. Coatings get scratched.

A. Yeah.

Q. And everything inside might as well be exposed?

A. That's right.

Q. And you're going to stab the packer with that? That's what's going through the packer?

A. No. It was -- our intent was to have what we -- yes. I mean, we're going to have a section of that right in the packer. But then as I was trying to explain, we decided that rather than having 500 feet of that go up, what we were going to do is line the entire tubing.

Q. Which is my next question, that fiberglass liner. Is that something that's produced with a pipe, or something that's used after the fact?

A. No. It's -- well, is it -- I'm not certain. I believe it's added after the fact, I mean, in terms of the manufacturing process. When you buy it, it's already sold as a lime product, but I don't know if, in the manufacturing -- I'm assuming in the manufacturing process, they have to add it later.

Q. So is it like a sleeve or a coating?

A. It's a sleeve, really. It's a sleeve that is essentially adhered.

Q. Do you know how thick that sleeve is?

A. If I remember -- it's been awhile since we used it at Jal, but it's about a millimeter thick, about a millimeter thick.

Q. And how does that handle with the joints?

A. Very carefully. We have to -- you have to be very careful at the joint, because you use a flush joint, you know. And what you want is -- the real problem with that -- where anyone has had problems with that -- fiberglass, right -- is because the joints have been overtorqued. And then you get a little bit of separation on that fiberglass, and then you actually -- less than a corrosion issue, what happens -- what I've seen happen even with a -- I haven't seen it happen in my well, but I have heard of where actually this fiberglass delaminates inside the pipe and then collapses, and actually you wind up with a blocked tubing. You've got to go out and rework the tubing.

But, you know, it is pretty standard, and they've gotten a lot better with their lining material and the technology. But it is absolutely crucial at the joints.

And here's what we do to deal with that. We typically hire a company that is called Gator Hawk, and they have a device that, on every single joint, it pressure tests -- first of all, you have to use a very specific torque wrench. You don't just, you know, grind them up. You have a very specific torque wrench. And the casing guys and the liner guys are out on site, and they are overseeing the torquing of each individual joint.

But then beyond when we torque the joint, we put this Gator Hawk device on it, and it tests it to 3,500 pounds. It tests that joint before it goes in the hole. It's a water test, basically. And then, you know, we're certain that we've got a good joint and that we've got a good joint at the torque specs that the liner manufacturer has.

And like I say, we have the -- the well in which -- that has had the longest operation where I have used that material is this Jal #3 well, which has now been injecting for about eight or nine years, and we haven't seen any problem with that.

As a matter of fact, it's kind of interesting. E. L. Gonzales, from the district, who is now gone, he was pushing us all along. We had always designed our wet wells with this kind of lining, and he was saying, Well, why don't you do that for dry wells? And we used to say, Well, you know, we really don't think it's necessary, you know, as long as the stuff is properly dehydrated. But then after we had this issue with Linam, I started thinking, well, it might not be a bad idea to go that route. So, you know, we kind of migrated from -- you know, you would have a certain amount of probably better protection in the ideal world if you ran 2550 for the whole string, but then --

Q. Half million dollars?

A. No. Then it's -- in this case, it would be about $6 million just for the tubing.

Q. So DCP will hire out, and they'll have specially trained people that have experiences with this?

A. Absolutely. Absolutely.

Q. I just wanted to make sure.

So downhole pressure and temperature, are you doing just a flood [sic], or are you doing a distributed system all the way up?

A. We'll do a distributed system to monitor it when we do -- throughout the entire injection zone when we do the injection testing. But in terms of the permanent downhole monitoring, we will do it only at the -- at the -- basically, at the base of the well. So what we're going to have is -- we'll have annular pressure, and we will have injection pressure and temperature at the surface. Okay? And then downhole, we will annular pressure and temperature at the location immediately above the packer.

Q. A little poke-through [sic]?

A. That's exactly right. Baker makes the piece, and, basically, it's about this long (indicating). It costs about a hundred grand for a piece of pipe this long (indicating). And then it's got a special port on it that goes -- and, you know, I was kind of leery about this, because in my mind, it's, all right, you made a connection now between the annular space and the inside of the tubing, but there is no other way to monitor what is going on in the reservoir down there without that.

So, basically, there will be one sensor placed immediately above the packer in the annular space, which will give us annular temperature and pressure in the diesel, basically, and then there'll be this little port that goes -- and the sensor is just inside the zone, and it's monitoring the pressure and temperature -- essentially, bottom-hole pressure and temperature right at the packer.

Q. So you may be curious or you know this already, but you can get a continuous fiber-optic cable?

A. That's what we're using.

Q. And you can measure DTS at any point in the annular space all the way between the bottom and the top, any interval you want.

A. For the pressure. Yeah. And Baker has mentioned that to us, and, you know, that might be a consideration. You know, we felt that with having it at the top and bottom, that would be adequate.

Q. And then just rely on keeping track of the pressure in the annular space to make sure you're not losing fluid somewhere?

A. Well, that's what we're doing all the -- we do it all the time anyway. Even when we didn't have bottom hole -- the first well that we have completed or in the process of completing that has that is the Red Hills AGI #1. And so we don't have a lot of experience with that.

What we have done is we've measured and monitored annular pressure and temperature at the surface. And really that's kind of the state-of-the-art. And most people, that's all they do in these injection wells, and monitor it. And we find if you keep good track of it -- and that's why it's important to collect this data continuously. And as we have seen with Linam AGI #1, once you establish those parameters and you are looking at that, you can spot pretty quickly if you've got a problem.

Q. So the main advantage of a distributed pressure and temperature system is that the fiber optic goes all the way?

A. Yes.

Q. Fiber-optic tube --

A. Right.
Q. -- actually comes on a spool.
A. Right.
Q. If you do have an issue, you know within a foot --
A. Right.
Q. -- where your problem is.
A. Exactly.
Q. I'm not sure it's terribly expensive, but they use -- the primary application right now, besides some of the experimental work being done on CO2 injection --
A. Right.
Q. -- is, in California, they're using them for measuring temperature in steam injection --
A. In geothermal wells, right?
Q. Well, steam injection --
A. Oh, steam injection.
Q. -- for heavy oil.
A. Oh.
Q. It's out there.
A. And just a question. Maybe I'm not supposed to ask questions, but I'm curious. Do you know the manufacturer? Is that a Schlumberger product?
Q. It's a Schlumberger.
A. Okay.

Q. I didn't want to say because I'm not trying to sell their stuff.

A. I understand. I understand.

Q. Is there a reason why you don't want to run the corrosion-resistant cement to surface?

A. Yeah, because it's just not necessary. It's expensive, and it's difficult to handle. Okay? Because the cement -- it's not like normal cement that you kind of can mix it on site. It comes -- you've got to know your volume and exactly what you want. And then it comes out, and it has to be run within X amount of time. It's a difficult cement to deal with. And we felt that once you're inside the intermediate string, there is no real need for it.

Q. That's all my questions. Thank you very much.

A. Thank you.

CHAIRPERSON BAILEY: I have a couple questions, some to do with keeping the record clear.

CROSS-EXAMINATION

BY CHAIRPERSON BAILEY:

Q. You do realize -- you've mentioned potable water as part of your explanation several times. You do realize that we do have to protect all waters less than 10,000 milligrams per liter?

A. Yes. Yes.

Q. We are not only concerned with potable water but protectable water.

A. Yes, although, Commissioner, my -- and maybe this is different than my -- than the regulatory definition, but when I say potable water, I mean water that is less than TDS, because the State Engineer considers that protectable water. But in the case of the Capitan, there are places where that water is greater than 10,000 TDS, but the BLM still considers that usable. They call it usable water, and they still want that water protected.

Q. Also, there was a comment on quarterly reporting. I just want to be very clear that the C-115 monthly reporting for injection volumes is still in effect.

A. Absolutely. Absolutely. That's a given. But, you know, the C-115 provides, basically, just the volume injected for the month and the average pressure for that month. It's a lot less definitive than what data we're talking about collecting continuously and reporting on a quarterly basis.

Q. Right. I just didn't want it confused that we were giving you permission to only file that report on a quarterly basis.

A. No. We're very clear that the C-115s need to be done every month.

Q. Learning from past issues, during the Linam investigation, there was discussion about including a biocide along with the corrosion inhibitor on that diesel, on the back side.

A. When I refer to corrosion inhibited diesel, it includes both biocide and corrosion inhibition.

Q. And then, of course, the cement bond log will be sent in before injection?

A. Oh, absolutely. As a matter of fact, we have to run the cement bond log -- the BLM is very, very picky about the cement bond logs, and we run it -- and they won't even let us move to the next stage of completion without signing off on the cement bond logs.

Q. And then you have several examples of the area for the plume projection. If you would like to refer to the slide. It's well location and plumb projection.

A. Uh-huh.

Q. The examples show that the area's influence are circular, and it appears the circular areas are just added together to make this lumpy kind of design. How do you compensate in calculating the area of influence for injection from another well, which is reducing the available porosity within the area of overlap between the two wells?

A. Well, what we have tried to do is to set up the bottom-hole locations far enough apart that after 30 years, basically, they're just getting to touch each other. I mean, they're not -- we put them -- we calculate that each well will have a radius of about a quarter mile after 30 years in terms of the plume size, and we've put the bottom hole of the two wells 1,200 feet apart. So we're trying to minimize the interaction between the two wells, but there is likely going to be some interaction in any case between the two.

Q. Because we're talking a radius of 600 feet from each individual bottom-hole location.

A. That's correct. That's correct.

Q. Which is undefined as to how much of the area of overlap is going to change the outer circumference of this plume.

A. Well, the overall volume that's going to be injected would only fill up a radius of .37 miles, if you were using a single well. So what's happened is that we've got something that's much closer to about -- a total length of about .4 or .42 miles when you put those two quarter-mile sections together at the distances that the current bottom-hole locations are apart from one another.

So I think that what we've calculated is the amount of volume and the surface expression of that volume in acres, and that 15 million cubic feet, or in the case of 100 percent safety factor, the 30 million cubic feet, those areas encompass that full amount of acreage. That's how they were drawn on the map.

(Mr. Brancard enters the room; Ms. Bada exits the room.)

Q. As additive rather than compensating for the porosity that's already filled?

A. That's right, because -- I mean, the porosity that -- the overall area has only X amount of porosity. And then the question is: Given the amount of volume of gas that you've put it, what is going to be the surface expression of that three-dimensional plume? And that's what we have represented on those two maps.

Q. Because you are asking for a 30-year permit, in effect, because all of your calculations are based on 30 years, what is your objection to having a review at some point before those 30 years are up in case there is some sort of change or miscalculation or impact that was not anticipated at this time, say 15 years or 10 years? Because it's not necessarily a termination of a permit. It would be a review of: Let's see how things are going?

A. I guess our position is that the data that are required to conduct that analysis, in effect, are being submitted already quarterly to the Division. So, I mean, certainly the Division not only has the data at some point, but, I mean, they could do that analysis anytime that they wanted to with all of the data that's being provided to them on a quarterly basis.

So I guess the biggest concern, very frankly -- and that's what I think Mr. Stone laid out -- is that if you're going to spend half a billion dollars building a plant, you don't want to have something built in that -- other than the normal risks that you assume. I mean, clearly, the Division has the ability -- if they think that there is a problem associated with that injection at any time, the director has the ability to order the operator to stop injecting or to modify their injection. But to have a defined window in a relatively short period of time when you haven't even amortorized the cost of the building or facility over that time period, it provides a certain degree of just lack of comfort that I think affects the decision-making of the economics of the project.

I don't think that there is any problem with, you know, working with the Division to analyze the data or to -- but in terms of trying to understand what has occurred, I mean, that's what the purpose, in our mind, of that quarterly reporting of the pressure and volume submitted to the agency is.

Q. Those are all the questions I have.

CHAIRPERSON BAILEY: Do you have any redirect?

MR. RANKIN: Madam Chair, just a few questions -- just a couple questions. It won't take but a moment.

REDIRECT EXAMINATION

BY MR. RANKIN:

Q. Mr. Gutierrez, I wanted to just talk to you a little bit about your testimony about the fiberglass liner system.

A. Yes.

Q. That system you described, I believe you testified that it's a -- you buy it from the manufacturer, and it comes with the liner already inserted into the tubing; is that correct?

A. Yes, as -- yes.

Q. And the manufacturer constructs that product for the purpose of injecting acid gas for disposal; is that correct?

A. Or acid gas for EUR projects, yes.

Q. So it's being -- you'd be using this for the purpose for which it is manufactured?

A. Oh, absolutely. Yeah. That's specifically what it's made for.

Q. And you'd be using it by the specs provided for by the manufacturer?

A. Yes.

Q. And when you install the tubing with the fiberglass piping, the installation would be done according to the specs provided by the manufacturer, correct?

A. And with the manufacturer's representative sitting on the rig floor while it's being done.

Q. Thanks, Mr. Gutierrez.

And then I just wanted to ask you a question to follow on Madam Chair's questions about the periodic review. If the Division at any time had a question about the modeling based on actual data, could they call DCP or call Geolex and have you or a DCP representative run through the data that's already been provided?

A. Well, certainly they can call DCP, and they can call me if I happen to be working for DCP on that or if they choose to use me for that particular project, yes.

Q. And when they called you to ask you about what the data presented shows, what would you do at that point?

A. Basically, we would take the volume that had been injected to date -- the actual volume, which in some cases is usually less than the maximum, and then redo the same kind of calculations and analyses that we do. And we'd also look at the pressures. But those are also information that are being provided on these quarterly reports.

Q. And the step you would be taking would be just to plug it into the model equation that you've been using; is that correct?

A. That's correct.

MR. RANKIN: No further questions.

CHAIRPERSON BAILEY: Anything else?

MR. WADE: (Indicating.)

CHAIRPERSON BAILEY: Then you may be excused.

THE WITNESS: Thank you.

CHAIRPERSON BAILEY: Do you have any other witnesses?

MR. RANKIN: No further witnesses. I'd like to make a few closing remarks, if I might, before you take this under consideration.

CHAIRPERSON BAILEY: Well, let's give the OCD an opportunity to make a statement if they care to.

MR. WADE: We'll pass on making a

statement, but we will call our one witness, Phil Goetze.

CHAIRPERSON BAILEY: Stand and be sworn.

PHILLIP RODNEY GOETZE,

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

DIRECT EXAMINATION

BY MR. WADE:

Q. Mr. Goetze, can you give us your name and your occupation?

A. My name is Phillip Rodney Goetze, and I'm an employee of the OCD as a member of the Engineering and Geologic Services Bureau.

Q. What's your past work and education?

A. I graduated in 1977 from the New Mexico Institute of Mining and Technology. I am currently a registered professional geologist in the states of Texas, Arizona, licensed in Alaska. The current history with OCD is that I have been reviewing injection well permits associated with saltwater disposal, enhanced oil recovery, as well as reviewing submittals by DCP on their other acid-gas wells.

Prior to that, my experience in oil and gas is with the United States Geological Survey and the United States Bureau of Land Management as a fluid minerals geologist, is what they call it, as well as a geologist -- joint geologist for review of leases, as well as development of agreement -- unit agreements and review of seismic.

Q. Thank you.

So part of your duties at the OCD is reviewing applications made under Rule 26?

A. Correct.

Q. And did you review the DCP C-108 application before the Commission today?

A. I reviewed it with input from the district geologist in Hobbs. That would be Mr. Paul Kautz, as well as the director -- not the director -- the chief of the bureau, which is Richard Ezeanyim.

Q. And after review, did the OCD propose conditions to the application as proposed?

A. We submitted in our statement some terms that have been used on previous wells. And to carry on a consistency, since this is a process done through the Commission, we tried to incorporate as many of the terms that were identified previously.

Q. And were those conditions discussed here today?

A. Yes, they were.

Q. Did DCP propose modifications to those conditions?

A. They have brought forth several items, which we looked at and found no problems with.
Q. And you were present for Mr. Gutierrez' testimony regarding the application, the OCD conditions and the modification to those conditions, correct?
A. Correct.
Q. And was Mr. Gutierrez' testimony an accurate reflection as to what was discussed between OCD and DCP?
A. Yes, it was.
Q. Are DCP's proposed modifications to the OCD's recommended conditions of approval acceptable to the OCD?
A. They are at this point.
Q. And just to get into some of those conditions -- or some of the reasoning behind the conditions for the Commission's benefit, why did you use a half-mile area of review?
A. Well, the half-mile area of review is stipulated in our agreement with the EPA, so it is a minimum distance that we are required to look at. Additionally, we have had -- in the past, looking at wells at the one-mile radius, my experience of reviewing previous C-108s, a concern was raised for the one-half mile. And at that consideration, when identifying the wells that we did, the four wells that we felt had

corrective actions required, we primarily stayed within that area.

Q. Going to one of those wells in particular -- this would be -- I hope I've got the correct one identified. This would be the plugged well, the Lusk Deep Well #8. You heard Mr. Gutierrez testify that there would be a search for additional records regarding that well, and those would be given to the OCD. What additional records would the OCD need to see to make any further determination?

A. There would have to be substantial documentation as to the placement of cement. Basic calculations are provided only in summary on the sundry notices. So there would have to be something viable, such as a temperature survey or a CBL or trip tickets with daily logs, things that could be verified. But a simple one sheet with the word "top of cement calculated" is not sufficient information.

Q. Regarding Madam Chair's question to Mr. Gutierrez as to a 10- or 15-year review period for DCP to provide a review document to the OCD, what do you see as the benefit to such a document?

A. The benefit would be a system of continuity. We're looking at a project that is going to be almost a third of a century in life that we're going to have change in personnel, that the consistency of having at least some documentation by the operator to us -- in essence, making sure we do our portion of the homework also -- that we come with the same conclusions as the operator does. We do not have as much expertise, and certainly we do not have the modeling capability which has been presented here.

Q. Just a couple more questions. Based on your review of DCP's C-108 application as modified with the conditions, does the OCD find the application protective of fresh water, human health and safety and correlative rights?

A. As presented and modified, yes, we do.

Q. And would you recommend the application be approved with the conditions and modifications?

A. The application can be approved. We still have one item left to do and that's verify the -- we have received the return receipts, and then we'll just go ahead and confirm the mailing list.

Q. And that would also be contingent on the -- I'm spacing on the name -- on the plans -- contingency plans?

A. Well, again, with the approval of the well, will be incorporated into the surface facility, so those goes hand in hand.

MR. WADE: I don't have any further questions.

CHAIRPERSON BAILEY: Any cross-examination?

CROSS-EXAMINATION

BY MR. RANKIN:

Q. Just so I'm clear, Mr. Goetze, you are satisfied with the agreement that DCP -- that there is an agreement between DCP and the OCD of how to address these four wells that were identified by the Division as having concerns?

A. We have a working agreement. There are always situations in the field. We will have to deal with those as we go along. I do have concerns with the 100-foot above and below, as presented in this document, your Exhibit Number 4, for, I believe -- if I may -- for your Gulf Federal #3. Again, that will depend what is found in the hole, and so we may look at having just the entire interval cemented as opposed to just caps on either end.

Q. Do you recall Mr. Gutierrez' testimony that DCP would agree to reasonable and prudent --

A. Oh, yes.

Q. -- recommendations by the Division in terms of how it would facilitate sealing off the zone?

And if DCP follows through with that, is that acceptable to the Division?

A. This is going to be a working relationship as far as these, and, again, there are downhole situations we're going to find as we go along. So good faith has been shown by DCP on this, and they have responded to these four wells we have identified. So we're satisfied with that.

Q. With regard to your comments -- your testimony about the seeing the return receipts for the notification purposes, what is your recollection or understanding of the rule for providing notice for an injection well application? In other words --

A. Oh, I just want to verify the names coming in with what you've submitted in your C-108. I have not had time to look at.

Q. I guess what I want to be clear about is that under the rule -- correct me if I'm wrong. My understanding of the rule is that notice is required to be issued to the affected parties identified within the area of review, but they don't actually necessarily -- in other words, are you saying you want to see that they actually received notice?

A. Well, I just want to verify what you gave me, that the 108 and the package, the supplemental, that that's correct.

Q. Okay. I understand. Thank you very much.

MR. RANKIN: No further questions.

CHAIRPERSON BAILEY: Commissioner Warnell?

COMMISSIONER WARNELL: No questions.

CHAIRPERSON BAILEY: Mr. Balch?

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. So you're the lucky guy that gets to look at these every quarter?

A. Well, this is -- again, this has been a learning process.

Q. So I think there has been maybe a little bit of a disconnect on the idea of a review. A formal review, I think, to the company makes them think that the plug could get pulled on the basis of that. But for someone that's looking at just kind of monitoring the status of the project and then you're going to have quarterly reports --

A. Correct.

Q. I'll be done in a second here.

-- quarterly reports, but would a periodic summary report, with updated model, give you the data you needed to make that continuing acceptance of the operation?

A. Okay. In the past, DCP has submitted

information on a shorter period, I think. What has been evident by that experience is that this is a slow-moving process. And so the dynamics of it, having reports come in over a shorter period of time with a summary in it of the overall project, doesn't seem to be very beneficial.

Q. Not on a three-month basis, quarterly. I'm talking about every four years, five years; just give you a summary of what's happened to that point, probably based on their quarterly reports, for the most part, and updated models thrown in. I think there's probably going to be a lot more of these, and manpower's limited, perhaps, at the OCD at times. So I don't know if that would be sufficient to allow you to make a -- for you to periodically have it refreshed in your mind what the state of the project is.

A. It's something to consider. I don't know the frequency that would be best. It has been thrown around their idea of long periods, short periods. Again, we would have to rely on what industry generates as far as how wide of an area did you get gas expanding into. So it might be worth considering something on a shorter period than 10 years or 15 years.

Q. I'm envisioning something more like a summary report than --

A. Oh, yeah.

Q. -- bring them into the Commission or the Division and have them give a presentation, unless you want them to.

A. No. I will let you choose that, though. But I think we're working with a very limited skill set, and I don't see where it would be too apprehensive to bring forth that your model has been successful, or there are issues that have been identified. Our intention is not to shut it down. Our intention is to make sure that if we have issues coming over the horizon, that we can address them and make it successful.

Q. Thank you, Mr. Goetze.

CHAIRPERSON BAILEY: Followup?

MR. WADE: That would conclude the OCD's presentation of witnesses.

CHAIRPERSON BAILEY: Any closing statements?

CLOSING STATEMENT

MR. RANKIN: Madam Chair, if I might, I have a few statements to make for the benefit -- I appreciate your patience this morning, if I might.

First, I want to make a couple of summary highlights about today's presentation. I think today we've heard from more than one witness that the AGI is the current and best available technology for handling the disposal and the long-term disposal of acid gas from these gas processing plants.

DCP, as you've heard, is committed with approval of these two acid-gas injection wells to commit up to nearly half a billion dollars to construct what's been described as a super system in the southeast part of the state, which will provide multiple benefits both in terms of the producers in the field, reducing the emissions, increasing the reliability of production and gas process, meeting increasing demand. We see it as a win-win for the state and the general public and for the producers in the field.

As you've heard, the application is protective of groundwater sources. It will protect human health and the environment by reducing emissions, and the application will prevent waste and protect correlative rights.

Now, with respect to DCP's commitment to go forward with this project, you heard testimony from Mr. Stone that it's based in premise on a 30-year projection. And he didn't have occasion to testify to this fact, but what he did say was that any significant impairment to that projection -- or to that basis, that premise could cause an issue with respect to their ability to commit to the investment of these resources.

I think it's important to consider that and what that means going forward. That, in turn, would risk impairing southeast New Mexico's gas processing capacity in the immediate future.

As I think was testified to, the Division is getting these quarterly -- will be getting these quarterly reports, data that's taken on a continuing basis. And it's the data that is necessary essentially to check it that DCP is actually injecting and operating its facility in a way that it proposed that it would. And if the Division wants to follow up on any of the data and the meaning of that data, DCP is available to answer those questions.

Secondly, I think it's important to consider that if the Commission is considering an evaluation period or any kind of a reporting requirement, we're sitting here today without having had any real notice of that or a formal proposition for what that would look like or language for how that would be imposed or what exactly the Division would like to say. So we haven't had time to really evaluate that.

So I think our recommendation, Madam Chair, is that if the Commission is interested in that, that they might think about it in terms of a rulemaking or think about it in terms of a working group that's currently meeting on a semi-regular basis to discuss these issues. At this point in time, I think, with respect to this project, we haven't had the time to evaluate any concrete formal proposal for what kind of data evaluation would be imposed. And I think I will leave it at that.

But if the Commission is serious about considering that kind of a imposition or provision in the order, rather than close this hearing, we might ask that you keep it open, so we can bring back Mr. Stone to address that specific issue, if that's something the Commission is seriously considering today.

With that, I have no further comments.

CHAIRPERSON BAILEY: That concludes this case.

We would like to go into -- or do I hear a motion to go into closed session in accordance with New Mexico Statute 10-15-1 and the OCC resolution on open meetings?

COMMISSIONER BALCH: I'll make that motion.

COMMISSIONER WARNELL: Second that motion.

CHAIRPERSON BAILEY: All those in favor?

(Ayes are unanimous.)

(Closed Session, 2:18 p.m. to 2:42 p.m.)

CHAIRPERSON BAILEY: Do I hear a motion to go back on to the record?

COMMISSIONER BALCH: I'll make that motion.

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 Case Number 15073.

Counsel Bill Brancard, would you please relay the results of our decision?

MR. BRANCARD: Okay. The Commission proposes to approve the application of the DCP Midstream, LP for this facility as provided in its C-108 as amended, along with the conditions agreed to by DCP and OCD, which includes but is not limited to an annual mechanical integrity test, daily monitoring, quarterly reporting, notification parameters and a process to identify and review them, a hydrogen sulfite plan prior to the commencement of the operation, and further that DCP and OCD will enter into an agreement on the four wells within the zone and the actions that need to be taken at these wells that meet with the requirements of OCD.

In addition, the Commission requires that every ten years, DCP shall submit a report to the OCD which characterizes -- with all the information available at that time and using the best available modeling technology under current industry standards, a characterization of the plume at that point and any information about plume migration, along with a summary of all the injection results to date.

Did I catch everything?

CHAIRPERSON BAILEY: I believe so.

And if you would please submit a draft order. And if you can do that in time, then we would be able to sign it at our next meeting, which is March 13th.

COMMISSIONER BALCH: Four weeks from today.

MR. RANKIN: Madam Chair, I'll work with the Division to get a draft that's acceptable to submit, if I can, before the next Commission hearing.

CHAIRPERSON BAILEY: Well, we have to have it before then, so we can --

MR. RANKIN: Review it.

CHAIRPERSON BAILEY: -- review it.

MR. BRANCARD: So at least a week before that meeting.

COMMISSIONER WARNELL: Three weeks.

CHAIRPERSON BAILEY: Is there any other business before the Commission today?

Then do I hear a motion to adjourn?

COMMISSIONER WARNELL: Motion to adjourn.

COMMISSIONER BALCH: I will second.

CHAIRPERSON BAILEY: All those in favor.

(Ayes are unanimous.)

(Case Number 15073 concludes, 2:45 p.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

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