STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION COMMISSION

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

APPLICATION OF DUKE ENERGY FIELD SERVICES, LP, FOR APPROVAL OF AN ACID GAS INJECTION WELL, LEA COUNTY, NEW MEXICO

CASE NO. 13,589

ORIGINAL

2006 MAR 23 PM 12 05

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

BEFORE: MARK E. FESMIRE, CHAIRMAN
JAMI BAILEY, COMMISSIONER
WILLIAM C. OLSON, COMMISSIONER

March 13th, 2006

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Commission, MARK E. FESMIRE, Chairman, on March 13th, 2006, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

March 13th, 2006
Commission Hearing
CASE NO. 13,589

(Continued...)

SMITH, SNYDER & AC WITNESSES:

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E X H I B I T S

Applicant's	Identified	Admitted
Exhibit 1	100	173
Exhibit 2	161	173
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Exhibit 5	168	173
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* * *

Smith, Snyder & AC	Identified	Admitted
Exhibit A	15	-
Exhibit B	18	-
Exhibit C	19	-
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Exhibit E	88	-
Exhibit 1	214	224
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(Continued...)

E X H I B I T S (Continued)

Smith, Snyder & AC	Identified	Admitted
Exhibit 7	239	252
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Exhibit 9	240	252
Exhibit 10	-	-
Exhibit 11	201	-
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Exhibit 13	200	-
Exhibit 14	77	-
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Exhibit 16	241	252
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Exhibit 22	248	-
Exhibit 23	26	-

* * *

Division	Identified	Admitted
Exhibit C	281	310

* * *

Additional submissions by Smith, Snyder & AC, not offered or admitted:

* * *

Additional submission by Xcel, not offered or admitted:

* * *

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* * *

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* * *

WHEREUPON, the following proceedings were had at 9:00 a.m.:

CHAIRMAN FESMIRE: Okay, at this time the March 13th specially set meeting of the New Mexico Oil Conservation Commission will be called to order. Let the record reflect that it's 9:00 a.m. in Porter Hall, 1220 South St. Francis, Santa Fe, New Mexico.

To repeat, this is a special setting date at the request of the parties on Case Number 13,589, the Application of Duke Energy Field Services, LP, for approval of an acid gas injection well, in Lea County, New Mexico.

At this time we'll call for appearances.

MR. CARR: May it please the Commission, my name is William F. Carr with the Santa Fe office of Holland and Hart, L.L.P. I'm appearing today in association with Joshua B. Epel, assistant general counsel to Duke Energy Field Services. And also here is my associate Ocean Munds-Dry, who I think already advised you she's our audio-video girl or something.

I have two witnesses that I will present this morning.

CHAIRMAN FESMIRE: Okay. Mr. Hall?

MR. HALL: Mr. Chairman, Commissioners, good morning, Scott Hall, Miller Stratvert, PA, Santa Fe, appearing on behalf of Mr. S.G. Cobb, Mr. Beach Snyder, who together comprise the AC Ranches Partnership, and also on behalf of Randy Smith. And I will have two witnesses this morning.

CHAIRMAN FESMIRE: Okay.

Mr. Carr, would you have an opening statement -- Oh, I'm sorry. Just zipping right along.

MS. O'CONNOR: Cheryl O'Connor on behalf of the Oil Conservation Division, and we have -- potentially have two witnesses.

CHAIRMAN FESMIRE: Okay. Sir?

MR. HENSLEE: Gale Henslee, I'm with Xcel Energy, based out of Amarillo, and we've got Bobby Gonzales, a safety consultant for Maddox Station and Jeffrey Parham, who's the plant engineer at Maddox Station.

CHAIRMAN FESMIRE: Will they be testifying today?

MR. HENSLEE: We have a written statement, and I'd like to give you a statement.

CHAIRMAN FESMIRE: Okay. At this time will the witnesses please stand and be sworn?

(Thereupon, the witnesses were sworn.)

CHAIRMAN FESMIRE: After that, I feel like everybody should go off to basic training.

Mr. Carr, since you're the Applicant, do you have an opening statement?

MR. CARR: Yes, sir, I do, a brief opening statement.

May it please the Commission, Duke Energy Field Services is here today seeking authorization for acid gas injection in its Linam AGI Well Number 1 located in Section 30, Township 18 South, Range 37 East, in Lea County, New Mexico.

The purpose of this hearing is for the Commission to consider our Application to inject under the current Rules and Regulations of the Oil Conservation Division and Commission. This is not a rulemaking proceeding. We have an Application that we have filed in accordance with existing Rules. We have received additional requests from the Oil Conservation Division concerning notice and other matters. We have fully complied with those, and the purpose of the hearing today is to consider our Application.

This is not the first acid gas injection well in New Mexico. It is, however, the first Application to be treated in this fashion. Duke filed the Application September 14th, and unlike prior applications that were approved by the Division administratively, a couple of days later we received a written response, 12 questions from the Division that we were asked to respond to, and also advised that the case would be set for hearing before the Commission.

Thereafter, we responded to each and every one of these questions, and we even have held a public meeting at the facility to enable Duke to review its plans, and in particular its safety plans, and explain to the community how the facility would be operated and, in particular, what measures were taken to assure that it was operated in a safe fashion.

The evidence today is going to show that we have done more than what has been required. We have more than complied with every rule and requirement of the Oil Conservation Division.

And we're going to call two witnesses.

First, we're going to call Chris Root. Mr. Root is the principal engineer and senior project manager for the Linam Ranch acid gas injection facility, and he's going to review for you the proposed well and the facility. And we're going to emphasize at the outset the safety features. And we're going to show you that when we designed this facility, special concern was paid to the safety issues to assure that this facility could be operated safely for Duke employees and would be safe for other people who resided in the area.

We're also going to call Alberto Gutiérrez, a geologist. He's going to review for you the geological background and the considerations that went into picking this particular site for an acid gas injection well, and then Mr. Gutiérrez will review the permit Application and related issues.

At the conclusion of the hearing we will have shown you that this well and the related facilities can and will be safely drilled, completed and operated, and operated in a fashion that's consistent with other land uses in the area. And when you review the evidence you will see that this Application should be approved.

CHAIRMAN FESMIRE: Mr. Hall, would you like to give an opening statement, or reserve it, or...

MR. HALL: I have only the briefest of comments, Mr. Fesmire.

Duke Energy Field Services made application to the Division for a Class II saltwater disposal well under the Division's administrative processes and without notice to my clients. They sought administrative approval for their project.

The problem is, Mr. Chairman, Commissioners, this is not a Class II saltwater disposal well. It's a facility for the transmission, compression and injection of ultra-hazardous substances as defined by law.

And the question we pose to you by way of our intervention in the case is to see whether Duke's Application is really in conformance with the Division's

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statutory charge under the Water Quality Act and under its rules, specifically Rule 811 for the handling of hydrogen sulfide. We would submit to you that it is not.

We submit to you that the Division's process for handling this Application is perhaps flawed and ought to be reviewed. We are not asking for a rulemaking in the context of this hearing, but in the context of this Application, the Commission must examine whether under this process Duke's Application meets the Division's statutory charges under 70-2-12.A.(21) and (22) to protect the environment and to safeguard human health. Those statutory duties which you have, I think have been neglected by the way Duke Energy has posited its Application to you.

Now, if I might, Mr. Chairman, we also have pending before you a motion to dismiss I filed on behalf of our clients. We touched on it briefly a month ago when we last met. And if I might, I'd like to go straight to that if that's appropriate at this time.

CHAIRMAN FESMIRE: Mr. Carr, would you have an objection?

MR. CARR: No object.

CHAIRMAN FESMIRE: Ms. O'Connor?

MS. O'CONNOR: No objection.

CHAIRMAN FESMIRE: Mr. Henslee?

MR. HENSLEE: (Shakes head)

MR. HALL: Some materials to provide to you in conjunction with the motion.

Mr. Chairman, in our motion to dismiss we asserted two primary issues. One is whether Duke Energy has property right to utilize the lands for its proposed injection facility. We also raised the issue of adequacy of notice, given the true purpose of the Application, being far beyond what's typically involved with a saltwater disposal well.

Let me take up the first issue with you first, the property-right issue.

We have provided to you in our motion and what we have marked as Exhibit A as a State of New Mexico oil and gas lease for the southwest quarter equivalent to Section 30, 18 South, 37 East, the subject lands here, issued to Geolex, Inc., who was Duke Energy's agent, who in turn assigned the oil and gas lease to Duke Energy Field Services.

The point we had made at our motion to dismiss is that an oil and gas lease does not give one the right to utilize the lands for anything other than the drilling for, exploration and production of oil and gas, period. If you look at the terms of the lease, it says on its face it is "exclusively, for the sole and only purpose of exploration, development and production of oil or gas (including carbon dioxide and helium), or both thereon and therefrom..." So it's for oil and gas only, CO_2 and helium.

And their further provision of the oil and gas lease that I think apply and then ask you to consider, what activity is it that Duke Energy proposes to undertake that would perpetuate their oil and gas lease -- which I understand they believe is the basis of their right to use state lands -- what would perpetuate the oil and gas lease beyond the initial primary term? It's going to take more than the payment of delay rentals. It's going to take drilling, exploration, production activities.

The injection of hydrogen sulfide and carbon dioxide for storage and disposal services does not do that.

So at the very most, at the end of the five-year term, Duke's assumed property right to use the southwest quarter of Section 30 goes away, presuming they had one to begin with under the oil and gas lease. I submit to you that they didn't.

I would also point out to you that I believe the case law has well established that the oil and gas lease does not give one the right to use the subsurface structure, any lands, under any lease, unless there's some specific provision for it.

CHAIRMAN FESMIRE: Mr. Hall, can I ask a quick question? Your clients don't own the location where this well is drilled, do they?

MR. HALL: AC Ranches owns the grazing lease where the well is to be located.

CHAIRMAN FESMIRE: Okay.

MR. HALL: And Mr. Smith owns the lands immediately to the north, 660 feet to the north of the proposed well.

CHAIRMAN FESMIRE: So what gives your client standing to raise those issues?

MR. HALL: Well, we'll get into that in the context of this hearing, but we will prove to you that by virtue of Duke's operation their acid gas fluid will, in fact, extend beyond their presumed oil and gas boundary and well into my client's property. We don't think they have the right to do that. We think that they're asking the Oil Commission to authorize a trespass, a subsurface trespass, on their lands. And as I believe you know, that's strictly prohibited by virtue of the *Snyder Ranches vs. Oil Conservation Commission* case. So that's a center point of our objection here today.

In that regard, Mr. Chairman, I would assert in the context of this proceeding, it is well established in the case law that an oil and gas lease does not give one the right to use the subsurface structure. That remains with the land owner.

And I think the leading case is a case called *Emeny vs. United States*, and the citation for that is 412 Federal 2nd 319, Court of Claims case from 1969. And that involved a lawsuit brought by a landowner, a surface owner, against the United States because the United States authorized one of its oil and gas lessees to inject and store helium under its lands. The Court of Claims determined the United States did not have that right. And so that was therefore a taking, and that surface owner was compensated. That was the first in a succession of cases that established that point, and I think that point is applicable here.

Earlier, in the context of our motion to dismiss, I had made the point that Duke Energy Field Services had not obtained any sort of right-of-way permit, easement, business lease or anything from the State Land Office to utilize state trust lands here. And it was my assumption that just as soon as the Land Office issued such a lease, that issue would have gone away.

I was astonished when I finally saw the document that was issued by the Land Office, and I have marked that as Exhibit B. And when I say I was astonished, I don't mean to say that I'm second-guessing the work of another lawyer here. Why I was astonished is because I had gone through this very debate with the Land Office three or four years ago.

If you'll look at the face of Exhibit B, the terms of the grant to Duke Energy Field Service on this form are for three buried pipelines -- one 10-inch gas, one 4-inch fuel gas, and one 4-inch utility line -- plus a surface facility, a surface facility on the entire southwest quarter of Section 30, T 18 South, R 37 East, with a 1500-by-1500 fenced facility consisting of a compressor station, injection well and well pad.

When I saw this, what struck me about this was, by this I don't believe Duke Energy acquired the rights it believes it has to use state lands for injection purposes. There is no reference to any sort of right to utilize the subsurface.

And the reason I was so astonished when I saw this, some of you may recall a dispute that had cropped up three or four years ago involving the Grama Ridge gas storage facility. The second amendment to the Grama Ridge unit agreement is marked as Exhibit C in the materials I have given you.

In that particular case, the Grama Ridge unit started its life as a traditional production unit comprised primarily of state lands, also some federal and fee lands. And over time, as the gas reserves were depleted from the unitized formation, the Morrow formation, the facility was converted to a gas storage facility. Over time, two of the state oil and gas leases that were dedicated to the Grama Ridge unit expired for failure to pay delay rentals.

And I represented the facility operator. I argued to the State Land Office, wait a minute, those leases are perpetuated. They are necessary for the operation and continuation of the unit. The State Land Office disagreed.

I researched this with State Land Office counsel at length, for well over two years, to really try to ascertain what's the nature of this facility and what are the legal rights necessary to utilize it? And we concluded as follows.

If you will look at page 2 -- actually the third page, marked page 2 -- of the Grama Ridge document, paragraph 9 explains what this is.

Paragraph 9 says, "The Commissioner and Raptor" -- Raptor is the unit operator --

> The Commissioner and Raptor agree that the Unit Agreement is unique and that it, among other things, conveys to the unit operator a right to inject, withdraw and store extraneous gas and that this right is in the nature of an easement that exists independently of the oil and gas leases that were

initially unitized under the Unit Agreement.

Turn again to pages 4 and 5. At the bottom of page 4 there's a further explanation addressing the termination of oil and gas leases. Paragraph 25 says:

> ...the rights of the unit operator to inject, withdraw and store extraneous gas under this Unit Agreement shall survive the cancellation, forfeiture or any other termination of any or all of the state oil and gas leases that are now or may become unitized hereunder. The existence, duration and nature of such injection, withdrawal and storage rights shall be determined strictly in accordance with the Unit Agreement, as amended hereby, and shall not depend on or arise under any state oil and gas lease.

Now, that's important for your consideration here because in the case of the Grama Ridge unit, the parties to the agreement specifically identified a storage interval. The specifically identified a particular stringer in the Morrow, defined by picks off of a well log, to define what property right the unit operator would acquire and could utilize. It's well defined in the unit agreement itself.

This is not the entirety of the unit agreement, and I'll be glad to provide you with the entire document if you need that.

But that was not done for Duke Energy's proposed facility, and I was frankly surprised by that, given the history at the Land Office.

If you will look at the next handout I've given you, it's a couple of the rules from the State Land Office, and it provides some guidance how you ought to go about to secure to utilize the subsurface, the geologic structure, for injection disposal purposes.

Rule 100.61, it says in essence -- I've highlighted some language there -- if you're seeking the right to utilize state lands for underground disposal, you go to the "oil and gas division"; if you're seeking the right to utilize state lands for surface disposal, you go to the "land surface division".

For some reason, they departed from that protocol here. They went to, I understand, the right-of-way divisions, part of Commercial Resources, I believe, and gave Duke Energy basically the pipeline right-of-way. The tail end, it does describe an injection well, but it does nothing more than that. There's no identification of the target formation and the vertical or horizontal extent of the zone the seek to utilize of the state lands for disposal purposes.

There's plenty of other guidance available to counsel crafting documents of this nature. I think reference could also be had to the Underground Gas Storage Act. It's part of the same chapter as the Oil and Gas Act, and it defines that you must acquire the specific interval to utilize underground gas storage facilities. There's lots of direction available to the parties here.

And I would submit to the Commission that the rights Duke believe it has secured here are inadequate. And I would also submit to you that until it has secured the property right necessary to operate its facility, application before the Commission is premature, you shouldn't consider it.

Now in our motion to dismiss we had also raised the notice issue. And I would agree with Mr. Carr, I believe Duke has complied with the notice requirements under the Division's Rule 107, and for its -- I'm sorry, Rule 701 and the notice requirements under the Division's C-108 form for saltwater injection wells, except for the fact that they failed to notify the surface lessee as Mr. Jones had directed them to do. They didn't accomplish that much.

But still, I challenge the adequacy of notice in this case, particularly when we're dealing with ultra-hazardous substances like hydrogen sulfide and carbon dioxide. I think we all have to bear in mind the discharge of this agency's statutory duties in the Oil and Gas Act.

And I think one starting point for us to examine the adequacy of notice is to look at the Division's Rules, starting at Rule 1207, and it sets forth the obligations of the Division to publish notice.

And under 1207.A.(6) that Rule provision directs that a reasonable identification of the adjudication subject matter that alerts persons who may be affected if the Division grants the application shall be published.

Now, was that done here?

Then you look to the applicant's notice, and for that you go to Rule 1210. 1210.A says, applicants for the following adjudicatory hearings before the Division or Commission shall give notice in addition to that required by Rule 1204 as set forth below.

And then in this case I think what was followed was Subrule 1210.(9). It says adjudications not listed above, notice shall be given as required by the Division. And the documents you'll see in this case, Mr. Jones directed Duke Energy Field Services to provide additional notice to the state grazing lessee. They did not do that.

Then, additional notice requirement for the applicant at 1210.C. It says at the hearing the applicant shall make a record either by testimony or affidavit signed by the applicant or its authorized representative. At A, the notice provisions of Rule 1207 have been complied with.

In other words, has Duke Energy's notice reasonably identified the subject matter to alert the persons who may be affected? And who are those persons?

Well, if they have an interest that may be affected, I believe they're entitled to notice. And I believe that's what the *Johnson vs. Oil Conservation Commission* case instructed us. I think it's much more instructive to the agency than the *Uhden* case ever was, but the *Johnson* case says if you have an interest affected by an agency action, you're entitled to notice, and the applicant ought to provide for that notice.

If you look at what was published in the Hobbs paper and then what was published for the Commission's docket, you see references to proposed injection of acid gas. I recall seeing this advertisement on the dockets for months now, and I remember it catching my eye simply because I didn't know what acid gas was. But there was nothing in there to alert me that we were talking about the injection and disposal of carbon dioxide and hydrogen sulfide. I think at the very least, the notice should have provided to that, and I think there should have been a broader scope of notice than what's typically provided for, for a Class II saltwater disposal well.

And the reason I think that's necessary, I believe it's necessary for you to notice -- direct that notice like that may be given so that you may discharge your statutory duties. I've provided you with a copy of 70-2-12, and if you'll look at subparagraphs 70-2-12.B.(21) and (22), I believe those are the operative statutory charges to you.

When you're dealing with the disposition of nondomestic wastes from production or nondomestic wastes resulting from the oil service industry, then you must act to assure that you protect public health and the environment.

So the question I think you need to do -- you need to address, is whether this level of notice satisfies those statutory criteria.

Further -- Do you need to confer? Go ahead.

CHAIRMAN FESMIRE: Yeah.

(Off the record)

CHAIRMAN FESMIRE: I'm sorry, Mr. Hall, you were starting to say -- ?

MR. HALL: Further, Commissioners, if you would take before you our exhibit notebook and turn to Exhibit 23, that is a copy of the Governor's Executive Order 2005-56, the Environmental Justice Executive Order.

Do you not have a complete notebook, Mr. Fesmire?

CHAIRMAN FESMIRE: I do, but it's in pieces.

MR. BROOKS: I only have 15 exhibits here.

CHAIRMAN FESMIRE: It's in the supplement --

MR. BROOKS: Oh.

CHAIRMAN FESMIRE: -- that was my problem.

Exhibit 23?

MR. HALL: Yes, it's the last one

MR. BROOKS: Now, wait, this is just another copy of the one I already have, I think. Let's see. This is 1 through 15. Now, is this the one you just handed me? Yeah, I just have two copies of --

MR. HALL: I didn't get enough, so I apologize.

MR. BROOKS: Well, it's important for the Chairman to have one, it's not important for me to --

MR. HALL: I'm sorry.

MR. BROOKS: -- have one, so...

MR. HALL: If you will turn to Exhibit 23, that again is Executive Order 2005-56, and it says a number of things, but what I believe it directs all state agencies to do is that where there is an agency action with the potential of affecting the environment, then you're directed to disseminate information related to the Application as broadly as possible to bring in the community, to bring in all interests, to see if they have concerns that can be expressed and potentially addressed by an order that -- issued by the agency.

And it's simply my view that that's not done under this process and under this case. Duke cites to you earlier precedents for applications and approvals of hazardous waste disposal wells.

I've looked at those, and I've given you an example of one. It's the Order Number R-11,769, issued to Agave Energy Company in Case Number 12,812. I've marked that as Exhibit D. And if you take the time after the hearing and go through this order, you will be stricken by the fact that the order makes no findings with respect to the protection of human health, safety and the environment, which I believe the statutes direct you to do.

Again, you can go through the witness testimony from the Examiner in that case. In my view, it's devoid of any evidence or testimony probative of those two issues that would allow the agency to base findings or conclusions that public health, safety and the environment are protected.

So that's the precedent. The question for you is, is that a precedent we should be following? I would submit that it's not. I would submit that we need to break from precedent and make sure the agency fulfills its statutory duties, provides adequate notice, so that everyone with an affected interest is notified and has the opportunity to protect themselves.

Thank you, Mr. Chairman.

CHAIRMAN FESMIRE: Thank you, Mr. Hall.

Mr. Hall, at this time we're going to take your motion under advisement, but we're not going to rule on it. We will probably rule on it in the context of the rulings on the case itself.

MR. CARR: Mr. Chairman, could I respond briefly, though, to the motion?

(Off the record)

CHAIRMAN FESMIRE: Commissioner Bailey, do you -- is that a satisfactory way to handle this for you, to take the motion under advisement?

COMMISSIONER BAILEY: Sure.

CHAIRMAN FESMIRE: Okay.

COMMISSIONER OLSON: I'd like to hear on any first -- what Mr. Carr has got to say.

CHAIRMAN FESMIRE: Okay, Mr. Carr can respond. Go ahead.

MR. CARR: Mr. Chairman, Mr. Hall's argument, I believe, underscores the poverty of the position he's bringing before you here today. It's clear from his argument that he wants to convert this proceeding into a rulemaking. He wants to change the Rules, the Rules under which we have filed our Application, the Rules under which you have approved prior acid gas injection wells.

If that's his intent, I would suggest this is the wrong case, and we should have a rulemaking proceeding.

He then wants to come and challenge actions and documents and agreements reached with the Commissioner of Public Lands. If that's what he wants to do, I would suggest he is in the wrong forum.

His motion to dismiss presented two arguments: One, whether or not Duke had the right to use the property. And we heard a lot about the importance of an oil and gas lease.

I'll tell you why the oil and gas lease is important. Duke is going to drill a well. If they encounter an oil- and gas-productive zone, they want to hold the oil and gas lease on those minerals. That is why they got an oil and gas lease.

They then went to the Commissioner of Public Lands and with the Commissioner negotiated a right-of-way easement for the facility. They have done exactly what Agave and others have done when putting a facility in of this kind. And we stand before you with the right to be there, to drill the well, to use these lands. The only person who thinks we don't is Mr. Hall.

CHAIRMAN FESMIRE: Commissioner Olson --

MR. CARR: We've had a lot of -- We've had a lot of straw men raised. Underground trespass. What happens if -- you know, at the end of a primary term of an oil and gas lease? What about the Governor's Environmental Justice Order?

Well, we've raised these, we haven't -- We've had no technical testimony that would support an underground trespass. Mr. Scott Hall is not an expert on those matters, and he has indicated in his prehearing statement he doesn't have an expert. So that's not an issue that we're properly bringing here, if it was an issue proper for the Commission to determine in the first instance.

As to the Governor's Environmental Justice Order, I didn't hear that anybody who needed notice didn't get it. Mr. Hall's clients got notice, they're here, they're fully participating in this procedure.

And so I would suggest to you that we've raised an awful lot of straw men to try and divert this hearing from what it's all about, and that is approval of an acid gas injection Application filed under the Rules of the Division.

It would seem to me that we had a -- Mr. Hall is desperate when he starts talking about the Grama Ridge and citing that unit to you. If you look at the agreement -- He talked about attorneys crafting documents. This document was crafted by Mr. Hall, after certain leases had expired and there were questions about the viability of the unit.

And they say that this unit agreement is, quote, on page 2, in the nature of an easement. An interesting view of a unit agreement that will survive under the provisions he cited later, after the leases terminate. And it is executed by Mr. Hall's client and the Commissioner of Public Lands, and not signed by all the other people who are shown on Exhibit B who own interest in the unit agreement.

I would suggest the one word in this exhibit that is appropriate is in paragraph 9 when it says the Commissioner and Raptor agree that the unit agreement is unique, and it has no bearing on what we're doing here before the Oil Conservation Commission.

Mr. Hall then wants to talk about notice. This is not a rulemaking. We complied with the C-108 requirements. And when you're looking at a Class II injection well, you have a right to craft site-specific procedures and impose additional conditions on an applicant, and you did. And we notified other people pursuant to your directive.

The notice issue is again a straw man. It is trying to divert this hearing from the very reason we're here, and that is to show you that we have a proposal that has been well engineered, that is safer than what is going on out there right now, and one that we are entitled to bring to hearing under the Rules of the Division as they stand today.

CHAIRMAN FESMIRE: Thank you, Mr. Carr.

Commissioner Olson, how would you like to handle the motion for continuance?

COMMISSIONER OLSON: Well, I think we can handle it as you suggested.

CHAIRMAN FESMIRE: So let the record reflect that the Commission has decided to defer a decision on the motion for dismissal -- I'm sorry, not continuance -- and that the Commissioners concur.

MR. HALL: Mr. Chairman, I would ask that Exhibits A, B, C, D and 23 I utilized in conjunction with the motion be made part of the record.

CHAIRMAN FESMIRE: The --

MR. HALL: Exhibits A, B, C, D and 23 be made part of the record, please.

CHAIRMAN FESMIRE: Is there any objection?

MR. CARR: I object to Exhibit D. It's the Agave Application. I would submit it has no relevance to the proceeding before us here today.

MR. HALL: Well, I would point out, Mr. Chairman, that I believe Duke is using the Agave order as one of its own exhibits.

MR. CARR: And we haven't admitted that or moved its admission.

MR. HALL: It's Exhibit 9 in their exhibit notebook.

CHAIRMAN FESMIRE: Mr. Carr, I'll overrule the objection and go ahead and admit it.

Ms. O'Connor, would you have an opening statement, or would you like to defer that?

MS. O'CONNOR: I would like to defer that.

CHAIRMAN FESMIRE: Mr. Hennessy? Henley? I'm sorry.

MR. HENSLEE: I think I'd like to defer, not being that familiar with your proceedings.

CHAIRMAN FESMIRE: We're kind of making them up as we go.

(Laughter)

CHAIRMAN FESMIRE: So if at the end of the Applicant's and the Protestant's cases you'd like to give a statement, we'll go ahead and do it that way, then.

MR. HENSLEE: Okay, thank you.

CHAIRMAN FESMIRE: Mr. Carr, I guess you can proceed with your case in chief.

MR. CARR: May it please the Commission, at this time we'd call Chris R. Root.

CHAIRMAN FESMIRE: How do you spell his last name?

MR. CARR: R-o-o-t.

CHAIRMAN FESMIRE: Mr. Root, you've been previously sworn?

MR. ROOT: Yes, I have. Yes, sir.

CHAIRMAN FESMIRE: Mr. Carr, proceed.

CHRIS R. ROOT,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CARR:

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

A. My name is Chris R. Root.

Q. Mr. Root, where do you reside?

A. I reside in Conifer, Colorado.

Q. By whom are you employed?

A. I'm employed by Duke Energy Field Services, LP.

Q. And what is your position with Duke Energy Field Services?

A. My position is twofold. As a principal engineer, I'm one of the senior engineers in the company. We have a series of different engineering ranks, and this is the most senior rank. And as a senior project manager, I manage large construction projects for the company throughout the United States, of which the Linam Ranch acid gas injection well could be one.

Q. And you are the senior project manager for the Linam Ranch acid gas injection well?

A. Yes, I am.

Q. Have you previously testified before the New Mexico Oil Conservation Commission?

A. No, I have not.

Q. Would you briefly review for the Commission your educational background?

A. My educational background consists of a bachelor's of science degree in chemical engineering from the University of Oklahoma and a master's of science in chemical engineering from the University of Oklahoma.

Q. Could you review your work experience for the Commission?

A. My work experience is approximately 25 years of industry experience in the oil and gas industry, including 17 years with Amoco Production Company and later British Petroleum for a few months, followed by a year and a half with Pearl Development Company, a small engineering construction company where I was engineering manager for the company and also a senior project manager on a large amine treating plant, followed by six years' experience with Duke Energy Field Services where I'm a principal engineer and senior project manager, managing several large projects, including a previous project of acid gas injection at the Artesia gas plant in New Mexico.

Q. And you've worked in an engineering capacity in all of these jobs?

A. Yes, sir.

Q. Are you a registered professional engineer?

A. I'm a registered professional engineer in the State of Colorado.

Q. Is a summary of your education and experience what is marked as Duke Exhibit 11?

A. Yes, that is correct.

Q. Are you familiar with the Application filed in this case on behalf of Duke Energy Field Services?

A. Yes, I am.

Q. And are you familiar with the proposed acid gas injection well and related facility?

A. Yes, I am.

MR. CARR: We tender Mr. Root as an expert witness in chemical engineering.

CHAIRMAN FESMIRE: Is there any --

MR. HALL: No objection.

CHAIRMAN FESMIRE: Commissioners?

COMMISSIONER BAILEY: No objection.

COMMISSIONER OLSON: (Shakes head)

CHAIRMAN FESMIRE: Mr. Root is accepted as an expert chemical engineer.

Q. (By Mr. Carr) Mr. Root, would you briefly summarize what Duke Energy Field Services seeks in this case?

A. Duke Energy Field Services seeks the right to inject acid gas into the lower Bone Springs formation at about 8700 foot of depth.

Q. When we talk about the lower Bone Springs formation, do many operators refer to this as the Wolfcamp?

A. Yes, that is correct.

Q. Are we also going to test the Brushy Canyon member of the Delaware group?

A. We do have plans to conduct drill stem tests of the Brushy Canyon as an alternate injection zone if the lower Bone Springs injection zone doesn't prove to be sufficient for our needs.

Q. Are you seeking authorization to inject into the Brushy Canyon member of the Delaware with this Application?

A. No, we are not seeking permission at this time.

Q. You simply will evaluate it at this time?

A. Yes.

Q. Will Duke be calling an additional witness to review the geological aspects of this Application?

A. Yes, that is correct, so I'll defer most of the questions on geological aspects to our second witness.

Q. Basically, you're going to be testifying about what happens above the ground, and our other witness will be looking at what goes on below the ground; is that right?

A. That's exactly right, Mr. Carr, and I think -- I'd like to say that we really put safety first on this project, and throughout the company. And so that -- we want to emphasize that by talking about the safety provisions of this project first, before we move on to the technical portion with regard to the well itself.

Q. And the way we're structuring our presentation, really, is to address this issue which so many people are concerned about right up front, and it's consistent with your jurisdiction to be sure that what we and others do, you know, is in the human health, safety, and the environment. And so that's what we're going to focus on first.

And then as we move through our presentation, we will look at the geological reasons for this site, and then we'll go through the more routine portions of the C-108 Application.

Mr. Root, what is acid gas?

A. Acid gas consists primarily of carbon dioxide and hydrogen sulfide. In the case of the Linam Ranch gas plant, it's approximately 75 percent carbon dioxide, 24 percent hydrogen sulfide on a dry basis. It also is water-saturated, contains water, and it contains about 1 percent hydrocarbons and other impurities which might include mercaptans and other sulfur compounds.

Q. Why is acid gas injection a good idea?

A. Acid gas injection is a good idea because it can help improve the environment and -- by reducing the amount of sulfur dioxide emissions that we have at the Linam Ranch sulfur recovery unit.

Q. And at the Linam Ranch, why are we proposing this? Is it more reliable?

A. I believe so. We have three main reasons that we're proposing this. We're proposing this to improve safety at the Linam Ranch gas plant, versus our existing sulfur recovery unit, and also to increase reliability for both ourselves and our customers, and finally to reduce emissions at the gas plant.

Q. At the present time you operate a sulfur recovery unit?

A. Yes, that's correct.

Q. Can you tell us the volume of emissions that are being put into the air by virtue of the use of the sulfur recovery unit?

A. Yes, the current permitted emissions are 1302 tons per year of sulfur dioxide at the Linam Ranch gas plant.

Q. And so that's currently being released to the atmosphere?

A. Emissions at or below that level are being released, yes.

Q. If you inject these, what is the benefit?

A. The benefit is that the current sulfur recovery unit has about 95-percent recovery of sulfur, as liquid sulfur, with the remaining 5 percent being admitted as sulfur dioxide. A typical acid gas injection project has approximately 99.2-percent recovery on average, and as such it will reduce the sulfur dioxide emissions at the facilities by 80 percent, approximately.

Q. Instead of releasing this sulfur to the atmosphere, in fact, what we're going to do is sequester the greenhouse gases in the ground; isn't that true?

A. We'll first of all sequester the sulfur in the form of H_2S, but in addition to that we'll sequester an additional amount of carbon dioxide in the ground, along with the hydrogen sulfide.

Q. In your opinion, can what you propose be safely done?

A. I believe it can, and I would like to review some --

Q. Can this be done consistent with other land uses?
A. This can be done consistent with other land uses.
Q. Is it safer than what we're currently doing?
A. It is safer than the current sulfur recovery unit.
Q. Could you, before get to your PowerPoint, just briefly summarize Duke Energy Field Services' prior efforts in New Mexico to obtain approval for acid gas injection?
A. Duke Energy Field Services operates an additional acid gas injection well at the Artesia gas plant. That well was started up in November of 2003 with surface injection facilities for that well. That well was approved administratively, and we were able to go ahead, then, and drill the well -- obtain a drilling permit, drill the well, complete the well, and begin injection into the formation.
Q. And have you been able to safely operate this facility since November of 2003?
A. Yes, we have.
Q. Are you ready to go to your PowerPoint presentation?
A. Yes.
Q. Why don't we go to that? It is -- We have a PowerPoint presentation. This is an abbreviated version of the presentation made at the public meeting that we held at the facility in February. It also is contained in our

exhibit book, copies of all of these slides, as Duke Energy Field Services Exhibit 13.

So Mr. Root, why don't you take over here and tell us what this exhibit is?

A. Okay, this exhibit describes the design and safety features associated with our proposed acid gas injection system and well for the Linam Ranch gas plant.

To summarize right up front, the Linam Ranch acid gas injection well will include design features, primary safety features around the design of the compressor, piping equipment, pipeline and well, to make sure that it's safe.

It will include secondary features which are pressure and leak testing. We'll fully pressure-test all components of the system, and we'll fully leak-test all components of the system to provide a guarantee that we'll be safe in the vicinity of the project.

Thirdly, we'll have instrumentation and purges, which I'll talk about a little more later, alarms and shutdown systems which will allow us to safely operate the acid gas injection unit and safely shut down the unit. In addition, we have plant operators around the clock at the Linam Ranch gas plant. They'll be monitoring the well, they'll be trained on operating procedures and trained on acid gas injection in general and provide another measure of safety.

Our fourth level feature will include hydrogen sulfide monitors, an alarm and shutdown system which will shut down the injection well if we are releasing hydrogen sulfide in the vicinity of the well or compressor. In addition, under Rule 118 of the OCD we will supply an H_2S contingency plan prior to starting up the facility, although we have drafted a rough draft at this time, even though it's a very preliminary plan, since we haven't fully designed the facility.

And finally, we believe we have a safe design, we know we have a safe design, as safely as we possibly can, so that we can all sleep at night and feel like we've done our best job that we can on this project.

Q. All right, let's go to the project overview --

A. Okay.

Q. -- of acid gas injection.

A. Okay, the next slides relate to that.

What we plan to do here if we can get approval is to drill and complete an injection well in the lower Bone Springs formation. We'll install a two-stage 800-horsepower electric-drive compressor at the Linam Ranch gas plant and an 8-inch diameter acid gas pipeline. This acid gas pipeline will be equipped with a high-density polyethylene liner and it will travel or traverse approximately 9000 feet to the well site.

At the well site we'll install an additional four-stage injection unit and spare compressor to further compress the acid gas. This will allow us to inject the acid gas, the hydrogen sulfide/carbon dioxide stream, into the well and allow us to idle the existing sulfur recovery plant at Linam Ranch.

The main incentive to do this project is to improve overall safety for Duke Energy Field Service employees and for the public. We believe that this project will improve safety relative to the existing 30-year-old sulfur recovery unit, which is in operation. This will increase plant reliability for our customers and provide some environmental benefits by reducing sulfur dioxide emissions and sequestering some CO_2 at the facility, and also address the age and capability of the existing SRU plant.

Q. Okay, let's go to the diagram.

A. In diagram form, the acid gas injection system will take gas from the existing amine system at the Linam Ranch gas plant. The remaining -- This amine system treats the sour gas, which is currently entering the gas plant through three main pipelines, and then sweet gas goes on to the rest of the plant for NGL recovery and other processing.

The acid gas at a very low pressure will be boosted in two stages of compression to about 90 p.s.i.g. and sent through an acid gas pipeline, the 8-inch pipeline, to the well site where it will be further compressed to approximately 2000 p.s.i.g. and then injected into the well.

And one of the main points is, we selected this configuration based on a quantitative risk analysis that was performed for us by an expert contractor in qualitative risk analysis, and they determined that the risk to both DEFS and the public was minimized by transporting the gas in a gaseous state at a low pressure, versus transporting it in a high-pressure liquid state.

So based on that study, we determined that this was the optimum design from a safety standpoint, even though it potentially could cost a little more, although it does allow us to fit all the equipment into one train of compression.

Q. So what we have here is, we have a low-pressure line?

A. Yes, that's right.

Q. And that's the result of the quantitative risk analysis that you had performed?

A. That is correct.

Q. The purpose of this was to evaluate this project from a safety point of view, was it not?

A. That's exactly right.

Q. And copies of this quantitative risk analysis are included in our exhibit book as Exhibits 4 and then a summary as Exhibit -- I mean Exhibit 6, and a summary as Exhibit 14; is that correct?

A. I believe that's correct, yes.

Q. All right, let's go --

A. Yes.

Q. -- to the conceptual layout of the plant, the next exhibit.

A. Physically what we'll be doing is, the existing plant has the amine system and the sulfur recovery unit, which is only about 300 feet away from a major highway to the north of the plant. It will allow us to shut down this sulfur recovery unit and move any acid gas farther away from the main road. We'll send this acid gas through piping to an acid gas injection compressor, and then through piping offsite, through an emergency shutdown valve which will allow us to isolate the pipeline if there is an emergency, and then transport the gas through the pipeline to the well site.

I think the next diagram shows the well site. The acid gas will enter the well site, go through another emergency shutdown valve which will provide us with a means to isolate safely the acid gas within the piping, and then go on to further compression and then through another emergency shutdown valve and into the injection well, which is equipped with additional safety devices.

In addition, we'll provide a flare at the well site at least 100 feet tall, or possibly taller, depending on SO_2 dispersion calculations, and -- which will allow us to collect any of the relief valves or other vents of hydrogen sulfide or acid gas from the well site and safely burn it on site. However, most of the flaring -- if the unit is down, most of the flaring will be done at the existing Linam Ranch gas plant and the existing flare system, rather than at the well site. This is truly only for emergency use at the site.

I'd also like to go through some additional details on the equipment design and safety features associated with this project. This slide again shows the overall diagram of the system and summarizes all of the safety features. Basically, we plan to have a compressor design in accordance with the National Association of Corrosion Engineers in terms of metallurgical selections for the compressor. We plan to have double distance pieces with a purge system, which is a best-design practice for high-H_2S-concentration gas streams.

We plan a pipeline, which is a low-pressure design, to meet the results of the QRA study that was completed. We plan to bury the line at least three feet deep, minimize pigging on the line due to the fact that abnormal or infrequent operations can lead to the greatest safety concerns. And we'll provide a liner, a high-density polyethylene liner, inside the steel pipe. This liner will have test connections every couple thousand feet to allow us to determine if there's any leakage through the liner and determine if there's integrity problems with the liner. And so we basically have a double-pipe system. We have an interior liner which will provide containment of the acid gas, followed by a steel outer pipe which provides additional containment.

The well has three main safety features. It will have a subsurface safety valve approximately 300 or 400 feet below the surface to allow the acid gas to be safely shut in if there's an emergency or a problem with the well. It will have a bottomhole check valve at the bottom of the tubing string. In case there's a problem with the tubing, it will allow the acid gas to remain in place in the zone where it's been injected. And we'll have an inert annular fluid in between the tubing and the casing, a diesel fluid which is noncorrosive, so that we can prevent contamination from the acid gas injection well.

Overall safety features include the emergency shutdown valves that I've talked about, hydrogen sulfide gas detection, our SCADA, distributed control system, DCS system and emergency shutdown system, ESD system, which will provide control of the process. We'll design it all to sour service requirements, which are presented by the National Association of Corrosion Engineers for all equipment. We'll provide 100-percent X ray of all piping, a hundred -- a full pressure test and a full leak test, some of which are not necessarily code requirements but additional requirements which Duke Energy Field Services feels is warranted in all hydrocarbon and acid gas injection systems, and we'll provide 100-percent spare unit to provide increased reliability, and finally a closed flare system to direct any possible sour vents to the flare, and a closed water system to contain any sour water within the well site and the plant site.

And I do have additional slides where I can go through more details on all of these features, and I'd like to do that if the Commission so desires.

COMMISSIONER BAILEY: Yeah, I think that would be very helpful.

CHAIRMAN FESMIRE: I think the consensus is, go ahead.

THE WITNESS: Okay. In more detail, the flare system will collect all of the vents, the pressure safety valves, and take them to the flare. It will have a continuous pilot to make sure that it's lit all the time, so that if any sour gas goes to the flare it will be able to be combusted. We'll also have a fuel gas pipeline to the well site so we can supply additional fuel to the flare as needed to combust acid gas, which is difficult to burn.

Q. (By Mr. Carr) Now is this flare at the plant site?

A. This will be an additional flare system at the well site, but the plant has an existing flare system. The existing flare system will flare the volumes if the acid gas injection compressors are shut down at the well site or at the plant site for whatever reason, we use the existing flare system to keep the flare at its current location during a period of down time.

Q. So flaring at the well is only a secondary safety?

A. That's exactly right.

The compressor, I have a few more slides to describe the safety features of the compressor, a few separate slides to describe the piping, vessels and coolers, and I would like to point out that we use an electric motor drive on the compression. It will have a variable frequency drive to allow us to operate at gas volumes between 2 million standard cubic feet a day and 5 million standard cubic feet a day, and it will be approximately an 800-horsepower unit at the plant and 1200-horsepower unit at the well site. So this is not trivial equipment, it's certainly some fairly large equipment.

The plant equipment will all be designed for 150 p.s.i.g. MAWP, maximum allowable working pressure. This is well in excess of the 90 p.s.i.g. which we anticipate in the discharge line from the plant.

The well compressor will be designed for up to 3225 p.s.i.g., in anticipation of a maximum permit limit that might be in -- for injection, that might be on the order of 2700 p.s.i.g. for acid gas, again well in excess of the injection limit.

The scrubber liquids on the compression system will separate out liquids in between each stage of compression, and these liquids will be maintained in a closed system by either routing them to the previous stage or, in the case of the first stage, pumping them into a closed system so that we can make sure that no hydrogen sulfide which is dissolved in the water could possibly escape. So these liquids will be maintained in a closed system.

All of the piping, all of the bottles or pressure vessels associated with the compressor, all the cooler tubes and headers on the compressor skid, will be manufactured out of carbon steel. They'll be designed in accordance with the National Association of Corrosion Engineers requirements for sour service, and they'll be 100-percent X-rayed to make sure that all of the wells are 100-percent satisfactory throughout the system. The unit will be hydrotested by the manufacturer and then leak-tested on site.

The compressor purge consists of double distance pieces, to provide maximum safety to the operators of the facility and to the public, and packing rings which consist of three sets of packing in between the different sets of distance pieces. And the primary and intermediate packing are both purged with fuel gas to provide additional security to make sure that hydrogen sulfide is contained within the compressor system.

I have a couple slides that show the overall arrangement of this compressor purge. This shows a double distance piece cylinder arrangement. The compressor cylinder is at the outer end here, which contains the acid gas. And there's a primary packing section, and then a secondary, and a third wiper packing. All of these packings are fed with oil to make sure that the compressor rod, which is moving back and forth, is properly lubricated, and also provided with this purge gas to make sure that we contain the acid gas within the closed system.

This shows the primary packing and shows that the sour gas, which -- unfortunately, this diagram is reversed from the other one. The cylinder side with the acid gas or sour gas is on this end. It shows sour gas can leak along a piston rod by virtue of the design. However, we'll be injecting sweet gas at the other end of the purged packing. And there's multiple sets of packing here, and each set of packing is capable of containing 95 percent of the pressure difference between atmospheric pressure and the operating pressure of the compressor.

In the center of the purge packing is a vent section which allows sour gas and purge gas -- the sour gas migrating from the compressor end and the purge gas migrating from the purge connection -- to both be directed to our closed flare system where it will be safely combusted. This contains the hydrogen sulfide within the compressor, to allow safe operation.

Slide.

In addition, we'll have two separate lubrication oil systems: one for the crankcase system, which is a primarily sweet system, exposed to the atmosphere, and a separate oil system to supply oil to the cylinders, to the packing, and also as flushing oil to the inlet gas to the compressor cylinder itself. So we'll have two separate oil systems to keep any sour gas within the cylinders.

The next slide.

This describes the piping. The piping will be in compliance with the National Association of Corrosion Engineers recommended practice MR-0175, which relates to sulfide stress cracking in sour service. This specification basically suggests that carbon steel piping be used at certain pressures in this type of service, which is what we're doing.

And in addition, we'll design it in accordance with our own specifications and requirements, which include providing all welded connections on small lines, which is not always done in all construction, providing 100-percent X ray of all the welds to make sure all of the welds are secure and contain -- provide full pressure containment for the gas. And our specifications provide greater wall thickness than the industry specifications may require in most line sizes. In addition, we'll use ring joint flanges on the higher pressure system to provide additional security, versus just using gaskets in between the flanges.

From more of a plant safety and awareness standpoint, we'll paint the sour acid gas pipeline -- or not pipeline so much as the lines within the facilities -- yellow in order to denote which ones they are. We'll hydrotest all of the piping to make sure that it's safe and then leak-test it again afterwards, again to make sure that it's providing full containment for the acid gas.

The pipeline design I think I've talked about pretty much already, but it's an 8-inch-diameter line, which was set forth based on the QRA study. It will be designed for at least 150 p.s.i.g. and provide extra wall thickness for corrosion. It will be designed again in accordance with the NACE requirements. It will have a high-density polyethylene plastic liner which is corrosion-resistant, because we'll have wet acid gas inside the line which could be corrosive, and so this will provide corrosion resistance.

We'll still have the carbon steel pipeline for a second level of safety and leak-monitoring connections along the pipeline, and finally we'll hydrotest and leak-test the line to make sure that it's safe.

On the external side of the pipeline, we'll coat and wrap the line to prevent external corrosion and provide cathodic protection. We'll bury the line at a depth below three feet to try to keep it safe from people that would inadvertently dig. In addition we participate, obviously, in the one-call program and other safety features.

We'll patrol the line at approximately two-week intervals and provide pipeline markers as required in the regulations.

We'll have two other lines in this same ditch, in effect, with the production -- or acid gas injection line.

This will include a fuel gas supply line, which will be a steel pipeline, and a water disposal line, which will be steel with a plastic lining again.

Q. Now, Mr. Root --

A. Yes.

Q. -- we are going to patrol the line at two-week intervals. In fact, that is a requirement that the Land Office proposed and we have agreed to do in our negotiations with the Commissioner of Public Lands; is that --

A. That certainly is -- This will be also a DOT-regulated line. It will be designed, operated and maintained in accordance with DOT requirements for gas pipelines. And the two-week interval is actually a requirement in liquid pipelines, rather than gas pipelines, but we agreed to that due to the nature of this line, we agreed to that additional measure of safety, to patrol the line more frequently than would be typically required for a gas pipeline.

Q. Okay, let's go to the instruments and the controls.

A. Okay. Finally, some of our third and fourth levels of safety are the instrument and controls, and these include full hydrogen sulfide detection at both the plant and the well site; acid gas measurement -- we'll measure the acid gas flow to the compressor, to the sulfur recovery unit, as long as it's still operating, and to the flare at the plant so we can account for all of the acid gas, all the hydrogen sulfide, so that we're sure that we know where it is going at all times.

We'll also measure the acid gas flow to and from the pipeline and to the well, so that we're sure that we can account for all of the acid gas, again, as it's being injected into the well.

We'll provide a compressor control and ESD system, emergency shutdown system. This will consist of alarms and shutdowns that if any of the parameters for operation of the compressor get outside of their normal ranges, there will be an alarm to allow operators to try to correct the situation. And if they can't correct the situation, there will be a shutdown at some additional level which will shut down the unit and shut down emergency shutdown valves around the unit. We'll also -- start-and-stop pumps from the compressor control system and also have some key controls in the plant, distributed control system, in order to control the unit.

And finally, we'll have a wellhead control panel, which is described, I think, in more detail on the following slide. This wellhead control panel includes a subsurface safety valve, fail-safe panel design, and then also automatic control of a master and wing valve. So we have multiple valves that we can shut to make sure that acid gas stays in the well if there's an emergency situation.

In addition to these emergency shutdown valves, we also have the valves I described previously at the inlet to the well site, the compressed gas to the well. And these are all automatic fail-closed valves, so in the event the control system is not functioning properly these valves will still close, if they need to close, in order to provide safety.

This diagram shows some of the information that would be included in a contingency plan. It shows preliminary locations for hydrogen sulfide detectors at the wellsite facility. We plan on providing 21 hydrogen sulfide detectors around the perimeter of the equipment, around the perimeter of the shutdown valves and pipeline and around the perimeter of the well, and also at the northern perimeter of the facility, to provide an alarm at about 10 p.p.m., which is the eight-hour exposure limit for workers, according to OSHA, and then a shutdown signal at about 90 p.p.m., which is below, again, the hazardous level for H_2S.

So if there's a detection of H_2S at 10 p.p.m., we'll set an alarm off and allow the operators to try to take corrective action. Or if they can't take corrective action, they can also manually initiate a shutdown. If the level in any of the ambient monitors reaches 90 p.p.m., we'll shut the system down automatically.

The next slide shows some of our safety equipment, which will comply with your Rule 118 and be developed fully in our contingency plan. Our contingency plan will also include notification of any interested parties that are nearby within the radius of exposure of the acid gas injection well and will comply with Recommended Practice 55 of the American Petroleum Institute, which relates to hydrogen-sulfide safety, and also OSHA regulations. We'll have windsocks, breathing air packs and a breathing air system for maintenance on the well site, in addition to typical safety equipment such as fire extinguishers, first aid kids and eyewash stations.

The next diagram shows an overview showing that we'll have multiple breathing air packs for emergency escape for operators or emergency use if they're on site. We'll also have a breathing air setup in the vicinity of the compressor so that people can work safely on the compressor, and windsocks so that people know which way the wind is blowing so if they need to escape, they can escape perpendicular to the wind direction to get off the site.

In addition, there will be fire extinguishers scattered throughout the site at key locations and of appropriate types for the equipment. Some of the ones inside the buildings will be smaller extinguishers and designed for use around control equipment and electrical equipment.

And then in summary, to repeat an earlier slide, we've provided design features to meet all of the requirements of Rule 118 and API RP-55. We'll do that in our final design. We'll provide secondary features, pressure and leak testing. A third level of features, instrumentation systems and operator training and plant operators to provide safety. And finally a fourth level of features, which consists of the hydrogen sulfide monitors, alarm and shutdown systems, and an H_2S contingency plan to notify nearby persons if there is an emergency which is deemed by the plant operators or incident controller to be significant enough to require notification.

And finally, we believe that this provides a safe design in accordance with all the Rules and Regulations and as safe a design as I think can be provided for an acid gas injection system.

I thank you for your attention to this detailed technical information.

Q. Mr. Root, what Duke is going to use at the Linam Ranch is, in essence, the same type of system that it has

employed at Artesia; is that right?
A. That is correct.
Q. And you've been operating that with no safety problems?
A. That is correct.
Q. And it is your testimony that what you -- Duke has used is the optimum AGI configuration in terms of safety, design and operation?
A. Based on the QRA study that was performed, we selected the optimum design to minimize the pipeline inventory in the system.
Q. And as you go forward with your efforts to develop the facility, you will be submitting the H_2S contingency plan prior to the commencement of operations?
A. That's exactly correct, we're --
Q. And you are drafting that to comply with all provisions of Rule 118?
A. We will do so, yes.
Q. In fact, you have already reviewed your contingency plans for H_2S and the other safety features at a public meeting at the facility, have you not?
A. That meeting was conducted in early February by the plant personnel. In concurrence -- or also attending were the first responders and interested public parties. So the plant reviewed the existing contingency plan for the

Linam Ranch gas plant, and we plan on doing the same thing with the new plan for the well site once we get into construction.

Q. Were representatives of the Maddox plant also in attendance at that meeting?

A. I believe they were, yes.

Q. Attached to the Oil Conservation Division's prehearing statement was a list of Division Engineering Bureau recommendations for the DEFS Linam AGI Well Number 1. Have you seen those?

A. Yes, I have.

Q. Are those conditions acceptable to Duke Energy Field Services?

A. Yes, those conditions are acceptable to

Q. And you will --

A. -- Duke Energy.

Q. -- implement and follow all of those conditions at this facility?

A. Yes, we will.

Q. Now in our exhibit book, your Exhibits 6 and 14 are part of the quantitative risk analysis. Exhibit Number 11 is a list of your qualifications and experience, and Exhibit Number 13 is a copy of your PowerPoint presentation. Were Exhibits 6, 11, 13 and 14 either prepared by you or have you reviewed them and can you testify as to their accuracy?

A. Yes, I can.

MR. CARR: At this time, may it please the Commission, we would move the admission into evidence of Duke Energy Field Services Exhibits 6, 11, 13 and 14.

CHAIRMAN FESMIRE: Any objection, Mr. Hall?

MR. HALL: I have something of a dilemma, Mr. Chairman. I -- With respect to Exhibit 6 and 14, the QRA is the quantitative risk analysis prepared by Quest Consultants in Oklahoma. I believe it's the sort of information you ought to have before you to make your decision. Duke hasn't brought forward a sponsor for the exhibits, and I'd like to cross-examine, perhaps, Mr. Root, if he can, about some of the underlying assumptions in the QRA.

CHAIRMAN FESMIRE: Okay, with respect to just 6 and 13?

MR. HALL: It would be 6 and 14.

CHAIRMAN FESMIRE: Fourteen, 6 and 14. So you have no objection to item 13?

MR. HALL: Well, I do object to 6 and 14 on hearsay grounds, but I would like to examine Mr. Root. I think that's the way we probably ought to proceed, if he's -- has knowledge of the underlying assumptions of those studies.

CHAIRMAN FESMIRE: Okay, why don't we let you take the witness on voir dire with respect to those two exhibits, and then go into your cross-examination, okay?

MR. HALL: Okay.

CHAIRMAN FESMIRE: Before we admit or deny admission of those two exhibits.

But 11 and 13 are satisfactory to you?

MR. HALL: Yes, sir.

CHAIRMAN FESMIRE: Okay. Ms. O'Connor, do you have any objection to 11 and 13?

MS. O'CONNOR: No objection.

CHAIRMAN FESMIRE: Mr. Helmsley?

MR. HENSLEE: No, sir, we haven't seen them, sir.

CHAIRMAN FESMIRE: Would you like to take a minute to look at them?

MR. HENSLEE: No, I think they're probably...

CHAIRMAN FESMIRE: Okay. So with that, we'll admit 11 and 13.

And Mr. Hall, you can voir dire the witness on 6 and 14.

VOIR DIRE EXAMINATION

BY MR. HALL:

Q. First let me ask you, Mr. Root, were you involved in the preparation of Exhibit 15? It's not been offered yet.

A. No, I was not, although I have reviewed it and I am well acquainted with Exhibit 15 and agree with it 100 percent.

Q. Okay. Let's talk about Exhibit 6 briefly.

A. Okay.

Q. Tell us briefly, who is Quest Consultants?

A. Quest Consultants is a consulting firm which has special key computer programs and expertise in quantitative risk analysis or risk assessment. I think it's an engineering consulting firm with perhaps about a dozen people located in Norman, Oklahoma.

Q. And in conjunction with their analysis, what were they specifically tasked with doing?

A. They were tasked to evaluate the three pipeline options which we developed for consideration and use at the Linam Ranch plant for acid gas injection, and to compare those to equivalent in a sulfur recovery unit from a safety standpoint.

Q. Let me refer you to -- In Exhibit 6, it's marked page 2-5 --

A. Okay.

Q. -- at the bottom, and if you'll refer to paragraph 2.7, it says, "None of the facilities associated with the current gas plant and the proposed reinjection pipeline have any residential or business structures within

2000 feet."

Let me ask you, is that accurate? How close is the surface facility to the Maddox plant?

A. It's 1600 feet from the road, so I guess it's close -- it's approximately 2000 feet from the Maddox facility.

Q. All right. Further on in that page, paragraph 2.8, the study seems to take into consideration meteorological data, wind data, for purposes of conducting the risk assessment. Is it your understanding that -- What's the purpose of considering wind data in the risk analysis?

A. The purpose of considering wind data is, the risk assessment is conducted in a very detailed, probabilistic analysis that includes meteorological conditions of different wind velocities at 15-minute intervals, I believe, throughout the day. And so wind data was only available from Midland, Texas, was the nearest site that had sufficient data to analyze at the frequency required for the consultant's computer program.

Q. All right. And if you will turn to Section 5 in Exhibit 6, it's titled "Risk Analysis Methodology".

A. Okay.

Q. It's page 5-1.

A. Okay.

Q. Could you summarize for us how wind speed, wind direction, was taken into consideration for this particular --

MR. CARR: With your permission, I thought Mr. Hall was going to voir dire this witness as to the admissibility of the exhibit. He's going far beyond that and basically cross-examining as if the exhibit was admitted, and I think we should deal with the admissibility of it at this time and cross-examine later.

CHAIRMAN FESMIRE: Right. Mr. Hall, I think I -- Do you want to respond?

MR. HALL: Well, how do we go about this then, Mr. Chairman? I need to understand the underlying assumptions about the study and Mr. Root's ability to articulate that. If we don't do it in voir dire prior to the admission of the exhibit -- because it is -- on its face right now it's hearsay, so it's a problem for us.

MR. CARR: May it please the Commission, I think I can admit this as a business record, if I ask -- am allowed to ask Mr. Root several questions.

CHAIRMAN FESMIRE: If you think you can go ahead and make this admissible with a couple of questions of Mr. Root, why don't we go that route, and then you --

MR. CARR: That's fine.

CHAIRMAN FESMIRE: -- can cross-examine him.

DIRECT EXAMINATION (Resumed)

BY MR. CARR:

Q. Are these reports kept in the records of Duke Energy Field Service?

A. Yes, they are.

Q. And is this the type of record that is ordinarily kept in the regular course of your business?

A. Yes, it is.

Q. Are you a custodian of these records?

A. I am.

Q. Was it prepared by an expert working for you?

A. Yes, it was.

Q. And is it what you relied upon to make your determinations as to the safety of the facility you're proposing here today?

A. Yes, it is.

MR. CARR: I move its admission as a business record of Duke Energy Field Service.

MR. HALL: Two questions, follow-up.

VOIR DIRE EXAMINATION (Resumed)

BY MR. HALL:

Q. Mr. Root, do you -- have you reviewed the underlying data utilized in the risk assessment?

A. A certain amount of the underlying data. If you mean have I reviewed the computer program used by Quest

Consultants, no, that's a proprietary program, and so I haven't reviewed the program itself. However, I reviewed the program's use with the consultants, and they acquainted me with the methodology used by the program.

Q. And did they also acquaint you with the data they would be utilizing with its computer program?

A. Yes, in -- Yes, they did.

Q. And do you believe that to be reliable?

A. I believe it is, yes.

CHAIRMAN FESMIRE: Mr. Hall, we'll go ahead and admit Exhibit 6.

We still have the issue of Exhibit 14.

DIRECT EXAMINATION (Resumed)

BY MR. CARR:

Q. Is Exhibit 14 simply a summary of Exhibit 6 prepared by you?

A. Yes, Exhibit 14 is a summary --

MR. CARR: I would move --

THE WITNESS: -- prepared by myself.

MR. CARR: -- its admission.

CHAIRMAN FESMIRE: Mr. Hall?

MR. HALL: I have no objection then.

CHAIRMAN FESMIRE: Exhibit 14 will also be admitted then.

Mr. Hall, did you want to proceed with your cross-examination, or like to start where we were on Section 5 of the report?

MR. HALL: Well, let me back up. We'll do traditional, orthodox cross-examination and try to follow the sequence of events with direct.

CROSS-EXAMINATION

BY MR. HALL:

Q. Mr. Root, you mentioned that you had originally intended to evaluate the Brushy Canyon, and then that was subsequently dropped from the proposal. You don't seek permission to inject into the Brushy Canyon formation now; is that correct?

A. That is correct.

Q. And why is that being dropped?

A. Because we're confident that the lower Bone Springs will provide sufficient injectivity, as I think our geological consultant will detail later, and what we plan to do is just test that zone as a possible future injection zone, but it would require a separate permit process in order to inject in that zone.

Q. All right. Did your company receive an objection from ConocoPhillips Company to using the Brushy Canyon?

A. Yes, we did.

Q. And did you discuss their objection with them?

A. I personally did not, but our geological consultant --

Q. And what do you understand the nature of the objection to be?

A. The nature of the objection --

Q. From ConocoPhillips?

A. -- was with regard to possible oil and gas production out of that zone.

Q. Have you actually been on the site, Mr. Root?

A. I've driven by the site; I haven't trespassed on the site, if that's the question.

Q. Let me ask you, why can't this injection facility be built at the Linam gas plant?

A. Basically, we had a full geological evaluation completed on injection at the Linam Ranch site, and the direction we provided was to try to inject at the Linam Ranch gas plant if we possibly could. Unfortunately, as the geological evaluation will show later, it's not feasible to inject underneath the Linam Ranch gas plant due to the nature of the zones underneath the plant, or lack of zones underneath the plant.

Q. Was safety at the plant an issue?

A. Safety at the plant is always an issue. I'm not really sure what the question is.

Q. Well, was safety a consideration in your decision not to locate the injection facility --

A. Safety was not a consideration, other than the fact that we had the QRA study run because we were able to inject at the plant site. So once it became obvious that we needed to inject off site, we did everything we could from an engineering standpoint to make sure we could design the system as safe as possible.

Q. Let me refer you to our Exhibit 6 --

A. Okay.

Q. -- and let me give you a complete copy.

Mr. Root, in your direct testimony you discussed current methods for disposing of hydrogen sulfide in use at the plant. Is Exhibit 6 a copy of the Duke Energy Field Services air quality permit for the Linam gas plant?

A. Yes, it is.

Q. And is it under the authority of this permit that Duke Energy is authorized to dispose of hydrogen sulfide emissions into the atmosphere?

A. Yes.

Q. If you'll turn to, actually, page 8 of Exhibit 6, at paragraph 3.2.4, is that the limit placed on hydrogen sulfide emissions by the air quality permit?

A. Section 3.2.3?

Q. Four.

A. 3.2.4, I'm sorry. Yes, I guess -- It is from that specific process unit, from the flare.

Q. So as it stands now, Duke Energy Field Services currently has sufficient authority to dispose of hydrogen sulfide production from the gas plant, under the current plant configuration?

A. Yes, it does, although 3.2.4 is actually an emergency provision. I mean, the main -- the main provision relating to SO_2 emissions at the plant is a different provision of the permit.

Q. All right. Is economics a consideration in the utilization of injection as opposed to flaring, to dispose of hydrogen sulfide at the Linam plant?

A. Well, currently this hydrogen sulfide acid gas is processed in a Claus sulfur recovery plant, the sulfur recovery unit, or SRU, at the plant, and it's only flared in an emergency situation.

But to a certain extent, I don't believe economics is the consideration. The best available control technology that I'm aware of for sulfur recovery right now is acid gas injection. It certainly is a best practice in terms of high control efficiency versus a traditional sulfur recovery unit.

Q. After the sulfur is recovered from the hydrogen sulfide in the gas stream --

A. Yes.

Q. -- through your sulfur recovery unit --

A. Uh-huh.

Q. -- in the past, how had Duke Energy disposed of the sulfur?

A. In the past, and presently, Duke Energy trucks the sulfur off site from the unit.

Q. Is it a saleable commodity?

A. From time to time it is a saleable commodity. Currently sulfur prices are relatively low, and it's not a -- It's not a very profitable venture, making sulfur.

Q. So is it more economic for Duke Energy to dispose of the hydrogen sulfide through underground injection, as opposed to recovering it -- removing it through the SRU?

A. On a continuing operating cost basis, we don't feel that there's any reduction in operating cost from one system versus the other. However, we feel that acid gas injection -- we know that acid gas injection will provide us with better control efficiency of sulfur dioxide emissions, and it's a better technical solution than the old sulfur recovery unit technology.

Q. I'm not sure I understand your answer. Does it result in cost savings to Duke Energy?

A. Relative to operating costs, no, not versus the continuing operation of the current SRU.

Q. Any other cost savings?

A. Versus purchase of an entirely brand-new sulfur recovery unit, acid gas injection is a preferred technology, and it is a more efficient technology and less expensive technology, and really state-of-the-art technology relative to sulfur recovery.

Q. Well, are any of those cost savings passed on to your gas processing customers?

A. I don't work in the commercial aspects at Duke Energy Field Services, so I don't really feel qualified to answer that question, if that's all right.

Q. Just briefly about the Duke plant at Artesia. Is that plant working all right?

A. The plant is processing its full inlet capacity and injecting a portion of the acid gas into the acid gas injection well and processing a portion of the acid gas in the sulfur recovery unit in accordance with its air emissions permit.

Q. Are you realizing the injection volumes that you had planned on?

A. We are not. We had hoped to completely shut down the sulfur recovery unit as a condition of doing the project, and unfortunately the injection zone we selected was not sufficient to inject the full gas volumes.

We do have plans to install an additional compressor at the plant site, which could potentially allow us to inject all volumes.

Q. Mr. Root, if you would turn to our Exhibit 14 in the exhibit notebook before you there.
A. Yes.
Q. Do you recognize that as Division Rule 118 for --
A. -- Yes. Yes, I do.
Q. -- hydrogen sulfide gas?
A. Yes.
Q. When Duke originally made its Application to the Division for approval of this facility, did you understand that you would be required to comply with Rule 118?
A. Yes, Mr. Hall, I understand that we'll be required. However, the provisions only require an H_2S contingency plan prior to operating the facility.
Q. So my question was, when you made application, did you understand at that time Rule 118 applied?
A. By nature of the project involving hydrogen sulfide, Rule 118 obviously applies for facilities which have H_2S concentrations above 100 parts per million.
Q. So is the answer to my question yes?
A. Yes, I understand that it applies.
Q. At the time you made application, did you understand that it applied?
A. I understood that it applied even before we made application. I understood it applied because we have an H_2S contingency plan for our Artesia acid gas injection

well in place, and we complied with Rule 118 there.

Q. And after the Division received your Application for administrative approval of the injection well, wasn't Duke Energy requested to provide an H_2S contingency plan?

A. Yes, and -- I believe we were, and we do have a proposed draft plan prepared. But under the nature of the Rules, it's only required to have a plan in place before starting up the facility, which clearly we're not anywhere near that right now.

Q. Was it not your understanding that the Division was requesting it immediately?

A. I have already prepared -- I have prepared a draft H_2S contingency plan, to comply with whatever requirements the Division may have.

Q. I understand. My question specifically was, when you received the request from the Division, didn't you understand that the Division was requesting the contingency plan then?

MR. CARR: May it please the Commission, I think Mr. Hall is starting to testify about what the Commission was requiring at that time. I think the witness has testified that he was aware of Rule 118 at the time he filed the Application.

I think if we want to get into what is required for an H_2S contingency plan and why you continue to refine that until you get ready to commence operations and what the rule requires about filing an H_2S contingency plan before operations commence, we can get into all of that. But we believe we are in full compliance with the Rules in preparing the H_2S contingency plan that you asked us to prepare.

CHAIRMAN FESMIRE: Mr. Hall, I'd ask that you go ahead and comply with some of the ideas that Mr. Carr stated, but also I'd ask the witness to go ahead and answer the questions that are asked of him.

THE WITNESS: Okay, so the question was -- ?

MR. CARR: And if you don't understand, ask.

THE WITNESS: Okay.

MR. CARR: We'll restate the question.

THE WITNESS: All right.

Q. (By Mr. Hall) My specific question was, when Duke Energy made application for administrative approval of its facility, what rules did you understand applied?

A. I understood that the rules pertaining to a C-108 form applied at the time that we made administrative application.

Q. And is that all?

A. That is what I understood applied at that time, yes.

Q. Mr. Root, have you been involved in providing H_2S

contingency plans to the Bureau of Land Management for hydrogen sulfide facilities, production or processing facilities, on federal lands?

A. No, I have not.

Q. Are you familiar with the requirements of the federal regulations?

A. Only to the extent that it's one of your exhibits.

Q. Mr. Root, can you explain to the Commission why the design for the facility has changed over time?

A. The design for the facility has changed -- once we received additional engineering information. I mean, as you engineer a project, you'll continually improve the design until you finalize the design, at which point you'll construct the design. So the design has been continuously improved as we look at our previous experience on other projects, and also as we try to refine this design, we try to continuously improve the design.

Q. All right, we're in agreement that the design has changed since the time Duke submitted its C-108 Application; do you agree?

A. Yes, because the C-108 Application, I believe, may reference completing all the compression at the plant.

Q. All right. And tell us about the various design changes made over time.

A. The main design change was that we evaluated different pipeline configurations. There are seven possible configurations of combinations of compressing the gas. Since there are six stages of compression, you can either compress the gas and have stages 1 through 6 at the plant or stages 1 through 6 at the well site.

I evaluated those from a process engineering standpoint and determined that the three feasible designs from a process engineering standpoint, from good operability standpoint, were to either compress all of the gas at the plant, to send a liquid to the well site; or to compress all of the gas at the well site and send a large pipeline volume -- a large-diameter pipeline between the plant and the well site; or to compress to an intermediate pressure with two stages at the plant.

And then having developed those different options and looked at the other options, the other possibility, the other seven -- the other five combinations out of seven total, determined that only those were the applicable combinations for study in the QRA study.

And then based on the QRA study, it clearly demonstrated that the pipeline option to compress to an intermediate pressure provided the minimum radius of exposure to the plant personnel and to the affected public. So we selected that option as the preferred option for design.

Q. So it was the results of the Quest QRA study that determined the final configuration for the facility?

A. That is correct.

Q. I see. Can you explain the change over time with respect to the utilization of the plastic liner in the pipeline?

A. We originally considered a steel pipeline if we were at high pressure. By nature of the acid gas compression project, or process, the acid gas compression process dehydrates the gas so that it places it in a noncorrosive state because it's undersaturated with water at the final stage of compression, at the final discharge. And so a steel pipe is a good selection and a typical selection in an acid gas injection project for a high-pressure discharge pipeline to the well.

However, once we completed the risk assessment and it indicated that compression to an intermediate pressure provided a greater measure of safety, we decided we needed additional corrosion resistance for the pipeline, and so we searched for different options that could provide that measure of protection.

Q. Explain to me how this works in the physical construction of the pipeline. You have a plastic liner and welded pipe; is that correct?

A. That is correct, we will weld the steel pipeline as if it were going to be a stand-alone steel pipeline. The steel pipeline will be rated for the full pressure. And then by an extrusion rolling process the plastic liner is placed into about 2000 foot of pipeline length at a time, and then the ends are stretched and formed up to the full diameter of the pipeline, providing a microannular space between the two pipes for monitoring purposes, and the ends are then flanged together and sealed at each 2000-foot section.

Q. And then what is monitored in the annular space between the lines?

A. The annular spaces need to be vented because they -- because you don't want to collapse the pipe if there a were a pressure buildup on the outside of the plastic pipe and you rapidly depressured the inner pipe. So they are vented, and so you can check for H_2S at these vent connections --

Q. And are the vent --

A. -- or for vent flow.

Q. I'm sorry?

A. Or you could check for flow rate through the vent connection.

Q. All right. there is no inner fluid between the pipelines?

A. There -- Not deliberately, no.

Q. I see. And how frequently are these vents located up and down the pipeline?

A. They'll be approximately every 2000 foot.

Q. I see.

A. By virtue of the construction process, the plastic pipe can only be inserted in lengths of up to 3000 feet.

Q. And is there any way to test the integrity of the outer pipe and the inner plastic liner, aside from monitoring H_2S in the annular space?

A. No, there's not, not that I'm aware of.

Q. To your knowledge, does Duke Energy Field Service have any leaks in the pipelines to the Linam plant?

A. Yes, there are leaks in the pipelines, and they are promptly repaired as soon as they are found.

Q. And can you say what causes those leaks?

A. Generally either internal corrosion or external corrosion or possibly a -- third-party hits, if you will, even though there's a one-call system in place. Perhaps some lines are damaged from external -- from a backhoe or other equipment externally.

Q. Do you know if corrosion from H_2S is a factor in any of those leaks? Is that typical?

A. I suspect it's a factor in many of the leaks. I should make it clear that I'm not -- I haven't reviewed all of the pipeline data for the lines to the Linam Ranch gas plant. We have other engineers that are more well versed in that aspect of the facility.

Q. Let me have you refer back to our Exhibit 15.

A. Okay.

Q. And that's a copy of BLM's Onshore Order Number 6 with respect to hydrogen sulfide operations. And if you will turn to page 4 of that, paragraph S., it discusses how you are to calculate a radius of exposure from H_2S. And it refers to the Pasquill-Gifford derived equation. Do you see that there?

A. Yes, I do, Mr. Hall.

Q. Is that the same methodology used in the Quest QRA?

A. No, that is not the same methodology used in the Quest QRA.

Q. Can you --

A. The Quest QRA is a more detailed, rigorous methodology that takes into account different types of leaks that could occur from the pipeline or compression system and calculates the affected radius of exposure based on meteorological conditions throughout the day and calculates a probability -- if someone were standing at a particular point 365 days a year, 24 hours a day, a probability that they could be affected by the event.

Q. And so are the meteorological data important in the quest QRA?

A. Yes, they are, obviously.

Q. Let's turn to the QRA, your Exhibit 6.

A. Okay.

Q. And if you will page to -- turn -- I'm sorry, if you will turn to page 2-6, it's a Figure 2-2 --

A. Okay.

Q. -- and do you know what that is?

A. Yes, it's the wind-direction diagram for the study.

Q. And it's wind data from Midland Texas Airport?

A. Yes, it is.

Q. Why was wind data from Midland selected?

A. Midland, Texas, was the nearest meteorological site that provided sufficient data on the 16 different directions and different categories of wind speed that the consultant could find. I specifically asked the consultant in a review meeting a couple weeks into the project why they weren't using Hobbs data, and they specifically answered that the Hobbs airport data was insufficient for the type of study they were trying to complete, so they used data from the nearest available site.

Q. Are you familiar with the meteorological phenomenon called the Marfa dry line, the adiabatic dewpoint pressure line, that lays between Midland and Hobbs? Do you know anything about that?

CHAIRMAN FESMIRE: At the risk of embarrassing you, you're going to have to define "adiabatic".

MR. HALL: It's a pressure front, is what it is. It's a dewpoint front that separates weather boundaries.

THE WITNESS: No, I am not.

Q. (By Mr. Hall) Well, if the wind data utilized by Quest is incorrect, would it affect the conclusions about the safety aspects of their study?

A. I questioned the Quest engineers that were preparing the study about that specific topic, and their opinion was that based on the available data that they had from Hobbs, which was insufficient to enter into their computer program, there were not sufficient differences between the two sites.

So I specifically instructed them to check that, and they did check that, and they did not believe that there was any difference between the two sites.

Q. Do you know what sources they checked to confirm that?

A. No, I certainly didn't get into the study in that level of detail.

Q. Mr. Root, do you have any reason to believe that when a community builds an airport it will configure the primary runway into the prevailing winds?

A. I'll take your word for that. I'm not an airport design engineer.

Q. Well, isn't runway configuration something that Quest or you could have taken into consideration to determine prevailing winds in the area?

MR. CARR: Do you know? The question is, first, do you know?

THE WITNESS: I'm not really sure what the question relates to. I mean, we -- I don't know we could have taken that into consideration, no. No, sir.

Q. Well, let's look at something here.

A. Okay.

Q. Mr. Chairman, I'll note this is Exhibit E. I haven't marked the copies there, but we'll do that at some point.

Mr. Root, let's look at your Figure 2-2 --

A. Okay.

Q. -- page 2-6 in the Quest QRA study, the wind rose there, and does that figure tell you that the prevailing winds are from the south?

A. From the south to perhaps the south southeast.

Q. Okay. And if we look at the first page of our Exhibit E, that is an airport diagram, federal publication for the runway configuration at Midland Airport where your wind data comes from.

A. Okay.

Q. And if you'll look at the primary runway there, it's 9500 feet long, and it runs south southeast. That's consistent with the QRA Figure 2-2; isn't it?

A. It appears to be, yes.

Q. Now, how far away is --

MR. CARR: With your permission, I'm going to object to the foundation that's being laid for these questions. Mr. Hall is testifying about what these exhibits mean and what the orientation of them is. If he has an expert who can come in and tell us about the prevalent wind direction in the area and why you lay a runway in that particular area, then perhaps that person can testify. But what he's doing is, he's asking Mr. Root to simply assume things that he is actually testifying about and then applying them to exhibits where Mr. Root says he doesn't know.

And I object to the questions. There's no way a foundation -- be laid for this line of testimony.

CHAIRMAN FESMIRE: Mr. Carr, I think we've been kind of lenient in letting exhibits in. I understand the point he's trying to make. I also understand that Mr. Carr is correct and that his witness keeps saying, I don't know.

And I'm going to allow you to ask the questions, but you have to understand, if he says I don't know, he doesn't know.

MR. HALL: Well, I believe you testified that it's consistent -- my exhibit is consistent with his, and I believe I'm entitled to probe the credibility of their QRA, their quality risk assessment -- it's a hearsay exhibit, by the way, which we're allowing in -- and this is an appropriate way to do that, so...

CHAIRMAN FESMIRE: Okay. Like I said, we've been real lenient in letting exhibits in. I understand your point, but I think we're getting to the limit here.

Q. (By Mr. Hall) Okay. What's the closest airport to the proposed injection facility?

A. It's the Hobbs airport that's on US Highway 62/180.

Q. All right, and it's -- what would you say, three or four miles to the east?

A. About four miles away, yeah.

Q. All right. Let's turn to page 2 of our Exhibit E, and if you'll look at that --

MR. CARR: Was this exhibit pre-filed --

MR. HALL: No --

MR. CARR: -- or is a new exhibit?

MR. HALL: It's rebuttal.

Q. (By Mr. Hall) If you will look at Exhibit -- page 2 of Exhibit E, you understand that to be an airport diagram for the Hobbs/Lea County Regional Airport?

A. Yes, it is.

MR. CARR: I think the question should be whether or not he does. We're leading him, we're trying to get him to accept testimony being offered, really, by Mr. Hall. Object to the form of the question.

CHAIRMAN FESMIRE: And again, Mr. Root, "I don't know" is an acceptable answer if you don't know.

THE WITNESS: Okay, I guess I don't know.

Q. (By Mr. Hall) Do you have any reason to dispute that it is?

A. I don't know that I do either.

(Laughter)

Q. If you look up there, right-hand -- upper right-hand corner, it says Hobbs/Lea County Regional Airport. Do you have any reason to dispute that this is the airport diagram for Hobbs airport?

A. No, I don't have any reason to dispute that.

Q. And if you look on there, is the longest runway 7398 feet long?

CHAIRMAN FESMIRE: Mr. Hall, we just crossed the border there. If the witness is not familiar with it -- I see the point you're trying to make, but I don't believe that this is the witness to bring this up.

Q. (By Mr. Hall) Well, isn't it true, Mr. Root, that the prevailing winds in the Hobbs area are from the southwest and not the south?

A. I believe that is true, Mr. Hall, and you'll find that marked on some of the diagrams that I've presented for H_2S detectors for the facility.

Q. But that's not the assumption that underlies the Quest QRA, is it?

A. No, it is not, but I guess I would like -- I don't know if I'm allowed to present additional testimony at this point --

CHAIRMAN FESMIRE: Answer the question.

MR. CARR: Answer the question.

THE WITNESS: And the question again? Could you repeat the question, please, Mr. Hall?

Q. (By Mr. Hall) Well, isn't it true that the underlying assumption for the Quest QRA is that the winds are from the southeast and southeast?

A. That is the underlying assumption in the Quest QRA.

Q. Okay.

A. And that assumption was based on the fact that they needed meteorological data at specific time increments and specific wind directions, which was unavailable from a source nearer than the Midland-Odessa airport, and that's why they chose that -- selected that airport.

But I would point out that some of the figures -- for example, page 6-8 in the Quest study, you can see that the radius of exposure calculated from their computer program is relatively symmetric, regardless of the prevailing wind direction assumed. And I would contend that there would be very little difference in the diagram, if you used a different prevailing wind direction.

And I specifically asked the consultant at a review meeting, while they were preparing the work, whether there would be an impact from the prevailing wind direction, and they answered that there would not, that in their opinion, that the prevailing wind -- that the meteorological data that they were using for their study was more than sufficient for the purpose.

Q. Well, let's talk about this Figure 6-2 a little bit more. Earlier, I believe you testified that the Maddox plant, the Xcel Maddox plant, is approximately 2000 feet or so to the west of the proposed injection facility; isn't that right?

A. That's correct, yes.

Q. Okay. And then if we look at the Figure 6-2, it shows a vulnerability area of 4185 feet.

A. You're on a different page than I am. Which --

Your Figure 6-2 on page 6-4 --

Q. I'm sorry.

A. -- I guess.

Q. I'm sorry, I'm confused. You're going to have to straighten me out now. You were referring to --

A. Well --

Q. -- Figure 6-4?

A. -- I referred to Figure 6-4, just to pick a figure, but Figure 6-2 would be sufficient as well, to show that the study really considered a symmetric zone for any of the releases.

Q. And going back to Figure 6-2, does it portray a maximum possible toxic impact zone also reaching out 4185 feet?

A. Yes, it does.

Q. Explain the difference between the two, the vulnerability zone and then the maximum toxic impact zone.

A. The maximum toxic impact zone relates to a multiple failure of different safety devices that are in place in the proposed Linam acid gas injection will. This figure would assume that the bottomhole check valve failed, that the subsurface safety valve failed, and that the pipe had ruptured on the surface, plus additional safety measures which are not really taken into account specifically also failed to protect the system.

However, there's a probability of each one of those things occurring, and the study in a previous section referenced the probabilities of a failure of a check valve of a subsurface safety valve, based on reported data.

And based on those probabilities, the study then calculates a figure such as Figure 6-4, which I referred to, on page 6-8. And based on the meteorological data, the different wind speeds, it then calculates a probability of a fatality, if a person were standing at a particular point 365 days a year, 24 hours a day, unaware of what was going on around them, and calculates a probability or a risk to a person standing on the road near the Maddox electric station, for example, of 10^{-8}, or 1 in 100 million chance of a fatality if a person were to remain at that point 365 days a year, 24 hours a day.

The report is for a unique individual, it's not for a collective population as well, as the report states. So it's for one individual.

Q. And for the record, isn't it correct that the majority of the population in the Hobbs-Lovington area is located to the south and east -- I'm sorry, the north and east of the proposed injection facility?

A. I don't know precisely, but I assume that's correct.

Q. Let's look back to your Figure 6-2 again.

A. Okay.

Q. You're showing a vulnerability zone, radius 4185 feet, and the well is located 1980 feet from the west line of the section.

A. All right.

Q. Does this mean that it's possible -- possible -- that the vulnerability zone and the toxic impact zone would intrude across the west line of Section 30 by some 2200 feet?

A. That is correct, if there were multiple failures of the protective system at the plant.

In addition, the study is extremely conservative, because there are no data to take into account on many of the other safety features which we have designed in the plant. There is no publicly available data, for example, on plastic-lined pipelines, and it's an additional level of safety feature, over and above a steel line. So we've provided additional safety features over and above what was assumed in the study.

Q. All right. At the very bottom of that same page --

A. Okay.

Q. -- it says the "risk contours do not describe the risk to populations that are inherently mobile, such as traffic on roadways or employees within a facility." Why is that?

A. Because as it says in the sentence before, the risk analysis is based on one's presence 24 hours a day, 365 days a year at a given site. So if a person is mobile and not at that site for -- full time, then it doesn't specifically address that person.

Q. Are there not employees on location at the Xcel Maddox plant full time?

A. Yes, there are. Well, I believe there are, I don't know that for a fact, I'm sorry.

MR. CARR: If Mr. Hall is going to go on a little, would there be any chance of taking a break for -- a brief break?

CHAIRMAN FESMIRE: Mr. Hall, how much longer do you think you're going to have?

MR. HALL: I'm guessing another 30 minutes. If you want to --

CHAIRMAN FESMIRE: Then let's take a break.

MR. HALL: -- take a break, that's fine.

CHAIRMAN FESMIRE: We'll take a 10-minute break and reconvene at 11:15.

(Thereupon, a recess was taken at 11:05 a.m.)

(The following proceedings had at 11:18 a.m.)

CHAIRMAN FESMIRE: Let's go back on the record. I believe, Mr. Hall, you were in the middle of cross-examining Mr. Root.

MR. HALL: Thank you, Mr. Chairman.

Q. (By Mr. Hall) Mr. Root, if you would turn to Duke's Exhibit 13, you have a map in there, radius of exposure, quantitative risk assessment calculation.

A. Page 13 or --

Q. Exhibit 13.

A. Exhibit 13 --

MR. CARR: No, Scott, those we did not admit. I gave -- you and I discussed those, and those were not part of our prefiled exhibits. We pulled those.

MR. HALL: So this is not part of 13 now?

MR. CARR: No, it isn't. I told you this morning we weren't going to...

Q. (By Mr. Hall) Mr. Root, in the QRA calculation of the radii for exposure under the different scenarios in the study, what are the applicable parts per million limits that are used in those calculations?

A. There's a detailed table presented earlier in the report that describes the different toxicological symptoms of H_2S, and that's --

Q. Can you point that out to us, please?

A. It'll take me a minute. That's on page 3-3.

Q. And this is under Exhibit 6?

A. Under Exhibit 6, page 3-3, Table 3-1 presents the toxic responses to hydrogen sulfide and then continues on in Figure 3-1 in a graphical format, and then continues on in Figure 3-2 and ultimately develops into Figure 3-2, which shows exposure times and mortality rates in percent versus H_2S concentrations based on a probit value. And the values in Table 3-2 ultimately get used in the computer program in the calculations.

Q. And so if we can go back to Figure 6-2, the radii of the vulnerability zone and the maximum possible toxic impact zone, and you compare that with Table 3-1, could you tell us which of the concentration levels shown in the left-hand column of Table 3-1 would have been applicable to compiling Figure 6-2?

A. I believe it would be 100 parts per million. So that figure effectively corresponds to 100 p.p.m. radius of exposure, based on the detailed QRA study.

Q. And then the way Table 3-1 works is, you go from left to right. That shows you the symptoms that will develop with the duration of exposure at that 100 p.p.m. limit; is that -- am I understanding that correctly?

A. That's correct. And -- Yes.

Q. Do you have Duke Energy's C-108 exhibit before you, the Duke Energy Exhibit Number 1?

A. I didn't bring it up with me, but I can grab it. Thank you.

Exhibit -- I'm sorry, which exhibit?

Q. It's this exhibit --

A. Okay, yes.

Q. -- Exhibit 1. If you would turn to Tab Section VII --

A. Okay.

Q. -- in the --

MR. CARR: May it please the Commission, this exhibit book was prepared by Mr. Gutiérrez, our second witness, not by Mr. Root. You may want to pursue the questions with him.

MR. HALL: I think this is within the realm of his expertise, if I might ask him about the fifth page --

THE WITNESS: I actually did supply this exhibit to Mr. Gutiérrez.

CHAIRMAN FESMIRE: Okay, continue, Mr. Hall.

Q. (By Mr. Hall) If you would turn to the fifth page under the Section VII tab --

A. Okay.

Q. -- what is that?

A. This is the page that -- at the top of the exhibit it's Mobile Analytical Labs.

Q. Does this exhibit show the hydrogen sulfide content of the acid gas that we're dealing with at this project, and is that level 235,738 [*sic*] parts per million?

A. Yes, that's correct.

Q. All right. Could you tell me briefly, if you -- Excuse me, turn back one page under that same exhibit. It says Linam AGI Compressor.

A. Oh, okay. All right.

Q. Linam AGI Compressor, Wet Gas Composition - Discharge --

A. Okay.

Q. -- and then it has all the chemical components. And in the columns there's a column for Design, and then Low Case and then High Case, and carbon dioxide and hydrogen sulfide have line-item entries for each. What does this exhibit show you?

A. This exhibit -- I prepared this exhibit based on 17 individual compositional analyses similar to page 4- -- page 4 out of 5. So from 17 individual spot samples, this is the average of those samples, and covers the range of the maximum and the minimum of the individual samples.

Q. So this is the range of the hydrogen sulfide content for the acid gas we're going to be handling; is that right?

A. That is correct.

Q. Okay. Tell me how the injection facility will work. The C-108 Application and Duke's other material speaks of fluid injection, and it also speaks of gas injection. Could you explain to the Commission, once the gas reaches the compression at the wellhead, what happens at that point?

A. The acid gas is in a gaseous phase, similar to water vapors in a gaseous phase, throughout the compression process.

Once it exits the final stage of compression and is cooled in an air cooler, it enters a so-called dense phase. It's above the critical pressure for acid gas, and above this critical pressure there's no distinction between gas or liquid phase. So there's a so-called phase envelope below that pressure where you could have gas or liquid. Above that pressure you have only a single phase possible, and it would be a dense acid gas phase.

Its properties are very similar to a liquid, it's similar to a three-quarter -- it's three-quarters of the weight of water, in terms of liquid density, so it's more similar to a liquid than it is to a gas. But it's in the so-called dense or supercritical phase.

Q. And this is downstream of compression?

A. This is downstream of compression, going to the well.

And then as the fluid proceeds downhole, if that was part of the question, it stays in this supercritical liquid phase as it increases in pressure farther and farther above the critical pressure.

And as it goes farther and farther up in pressure, it becomes less and less saturated with water. It has the capability to hold more water in saturated conditions, and so it becomes less saturated with water as it proceeds through the process, which provides an extra measure of safety in terms of preventing condensation of water and preventing possible corrosion from water.

Q. I see. And so is maintaining that fluid pressure at the injection point critical to maintaining it in its fluid state?

A. Yes, it is.

Q. Okay. And if there are variations in the pressure, what happens?

A. If there were variations in the pressure, you could potentially drop into the gaseous state. However, we'll provide a back-pressure control valve on the compressor to make sure that the compressor is not affected.

And in addition, if you do the hydrostatic calculations for the well, you'll find in order to inject at this depth it would be virtually -- I believe it would be impossible to envision a situation where you could drop below the critical pressure in this pipeline while you were injecting gas into the well.

Q. At any point during the compression operation, do fluids -- strike that -- do liquids drop out of the acid gas?

A. I think I presented that in one of my exhibits. Yes, they do.

Q. And what happened -- I'm sorry, did I interrupt you?

A. No, go ahead.

Q. What happens to those liquids?

A. Those liquids are collected in interstage scrubbers. The nature of a gas compressor is that it can only compress a single gas phase. If you get liquids into the compressor, it could damage the compressor. So we provide a gas scrubber upstream of each stage of compression to separate any liquid out. That liquid will be predominantly water, and it will be dumped to a closed water handling system.

Q. Is that a surface disposal system?

A. Actually, our design concept is to send that water back to the Linam ranch plant in closed piping and to keep it fully contained throughout its transit between the scrubbers and the plant.

Q. And then what happens to the water back at the Linam gas plant?

A. It's proposed to take it to the B tanks at the

Linam Ranch gas plant, which are closed tanks, and have a water system which then goes on to our existing water disposal system at the Linam Ranch gas plant.

Q. Will the addition of the handling and processing of the liquid that drop out of the acid gas require you to seek amendments to your discharge plan at the Linam plant at all; do you know?

A. We do not believe so.

Q. Have you checked with the Environment Department or OCD to confirm that?

A. We have supplied some preliminary information to the Environment Department. I wasn't directly involved in that, although I supplied the information to the environmental permit engineers that did so.

Q. Mr. Root, as I understand when you were qualified this morning, were you involved in the feasibility evaluation for -- using the Brushy Canyon and Bone Springs formation for the injection facility?

A. Not directly. I'll defer that question to our geological expert.

Q. Okay. Were you involved at all in the preparation of Exhibit 15?

A. No, I was not, although I have reviewed the exhibit.

Q. Mr. Root, you discussed the public meeting that

Duke Energy had in February at the plant, and you said, quote, interested public parties, close quotes, were invited. How did you determine who those interested parties were?

A. I wasn't involved in the initial meeting in February that you're referring to, so I can't say how that was determined.

Q. Was there more than one meeting?

A. There was a meeting to discuss the existing Linam Ranch gas plant, which presented -- was presented by the plant operations staff, by the plant manager and his workers. And that was on the existing facility with the first responders and I believe with anyone within the radius of exposure of the existing plant.

We then held a second meeting specifically related to this project where we reviewed the safety features in a little more detail than I did today and answered questions for actually several hours from interested parties.

Q. Let me make sure I understand your answer. You weren't involved in determining who to invite to the second meeting?

A. I didn't directly issue invitations, no.

Q. Okay, so you don't know who --

A. I don't know what the rational was for who to invite.

MR. HALL: Nothing further, Mr. Chairman.

CHAIRMAN FESMIRE: Ms. O'Connor, do you have any cross-examination?

MS. O'CONNOR: Yes, Mr. Chairman, thank you.

Mr. Root -- I'm sorry, I'll stand. I know I'm kind of tucked away back here.

CHAIRMAN FESMIRE: She can hide behind Will.

MR. HALL: Do you want to sit here?

MR. EPEL: Do you want me to move so you can have the microphone?

MS. O'CONNOR: No, that's all right. If you can't hear me, tell me and I'll speak up.

EXAMINATION

BY MS. O'CONNOR:

Q. Mr. Root, does DEFS have the capability to detect gas in the tubing casing annulus?

A. Yes, we will.

Q. And tell me what that's actually going to be.

A. That will consist of a pressure gauge and a pressure transmitter which will allow us to monitor the pressure in the tubing casing annulus.

Q. Okay. And how often is that -- or exactly how often would those detectors -- the location of those detectors and the frequency of them?

A. Those detectors should be monitored in our computer control systems so they'll be available on a continuous basis --

Q. Okay.

A. -- however, they'll be reported on, I guess, whatever basis is specified in the injection permit.

Q. Okay. Now we know that part of the concern here is obviously the notification issues to the surrounding people in case of a failure.

A. Uh-huh.

Q. Do you have any plans to hard-wire systems to the people who live within the radius of exposure?

A. Not right now, but that's something we could consider, especially for sites that are attended 24 hours a day.

Q. Have you ever done that before in any of your plants?

A. We have not in any of our plants. I have read in the literature where other highly sour gas developments have hard-wired signals to other nearby industrial plants.

Q. Okay. When we're talking about your piping system, have you ever used the double-wall piping system before? And this is described for -- excuse me, have you ever used the double-wall piping system before that you've been describing that you'll use for this particular plant?

Have you ever used that system before?

A. Yes, we have, as a company.

Q. And where has that been?

A. We've used it on some replacement lines in the Linam Ranch area, on the sour inlet lines to the plant.

Q. Okay, have you used it in any place besides that?

A. We've also used it in the Texas panhandle, in high-pressure gas lines there and replacement lines.

Q. And how have they functioned?

A. They have performed very well.

Q. Have you had any failures at all?

A. Not that I'm aware of.

Q. Okay. Will cathodic protection be used on the well or on the pipeline?

A. It will be used on the pipeline. From different experts I've heard that cathodic protection may have varying degrees of success on a deep wellbore, so we don't plan to use it on the wellbore at this time.

Q. Okay, and why is it that you don't plan to use it on the wellbore?

A. Because it -- in many circumstances, it's ineffective below the water table, certainly, and to the full depth of the well. So we don't plan it on the well itself.

Q. Let's talk about your safety model for the H_2S

air dispersion.

A. Okay.

Q. And there is a system that -- a protective model that's described in Rule 118. Are you familiar with that?

A. Yes, I am.

Q. Okay. What is more protective, the H_2S air dispersion model that you have been using and relying upon, or the model in Rule 118?

A. I believe the model that we used in the QRA study is certainly a more rigorous model and a more exact model, because it takes into account differing pressures and inventory in different pipeline sections, in addition to different leak sizes, where the calculation in Rule 118 only takes into account the volumetric flow rate of the gas and not the pressure -- the operating pressure of the gas.

Q. Okay. Let's turn a little bit to if you do have a failure. If you have an escape out of the formation, a gas escape out of the formation, will that gas burn?

A. It will be within the flammable limits for a hydrogen sulfide mixture. However our experience has been, in most of our flare systems, we need to add additional fuel to get good, complete combustion.

Q. And so if you have to add additional fluid -- or excuse me, if you have to add the additional material, how difficult is that and what's your time frame in being able to do that?

A. Well, we'll provide a fuel gas pipeline between the plant and the wellsite in order to add that fuel, and we can automate that process. You have to recognize, we haven't done all of the detailed design yet, so we'll plan on automating that process.

Q. And when do you plan on completing your contingency plan?

A. Prior to operation of the facility, as required in the Rule. And we can -- you know, we can supply it as early as the State would like to have the contingency plan. It's just until we've finalized all the design details, it won't be an exact plan, it will only be a draft plan.

Q. And when would you be able to provide that draft plan to the OCD?

A. I can supply a draft version of the plan today if you wish to have one.

Q. And provided -- with the turnaround with the OCD looking at it, when do you believe -- and obviously making their suggestions -- when -- how long would it take you to prepare a final plan, do you believe?

Q. I don't think we can prepare the final plan until we do the final design on the facility. And you have to understand, in order to minimize our financial risk on the project, we've proposed internally drilling the well and testing the well and deciding if we have a satisfactory injection well before we spend additional money on doing the detailed engineering and starting to actually buy equipment and complete construction on the facility. So...

We plan to do this in a sequential process, and so from our standpoint it really hasn't made any sense to do the detailed design until we actually confirm that we have a good well.

Q. So is it your testimony, then, that you cannot provide a final contingency plan until after the permit has actually been granted?

A. Until the injection permit has been granted, that's true, yes.

MS. O'CONNOR: Could you give me just one moment? That's all, thank you.

CHAIRMAN FESMIRE: Mr. Henslee?

MR. CARR: May it please the Commission, under your new procedural rules, if someone doesn't appear and prefile exhibits they're permitted to make statements, but they're not allowed to cross-examine.

CHAIRMAN FESMIRE: Okay. Mr. Henslee, I think he's right.

MR. HENSLEE: Okay.

CHAIRMAN FESMIRE: Commissioner Bailey?

MR. CARR: Would you like me to do redirect before the Commission?

CHAIRMAN FESMIRE: I was figuring that would come after.

MR. CARR: Thank you.

EXAMINATION

BY COMMISSIONER BAILEY:

Q. You testified that the 8-inch pipe between the plant and the injection well would be lined with high-density polyethylene plastic, right?

A. Yes, ma'am.

Q. I'm confused, then, when I look at your Exhibit Number 3 -- no, Exhibit Number 2, which is the letter from the OCD. Do you have it?

A. Yes.

Q. On the second page, paragraph 8) --

A. Okay.

Q. -- the last line says, "Duke maintained that plastic coated tubing will be permeated and destroyed by acid gas."

How can we correlate those two statements?

A. There are two different types of plastic that are being considered here and two different situations for the acid gas fluid.

The situation addressed in item number 8) is for the gas at the discharge of the compressor, which is undersaturated in water and therefore will be less corrosive than the lower-pressure gas.

And then there are the two different types of plastic. The high-density polyethylene is a different material than the epoxy material, and while it is permeable it's also a stronger structural material. It's not just a coating that's applied to the surface of the steel, to the interior surface; it's an actual physical piece of pipe that's inserted into the other pipe. So it's structurally a stronger piece of pipe, which allows it to withstand the acid gas.

Q. So there's no reaction between the acid gas that would be going through the pipeline and the HDPE?

A. There's no reaction that would sacrifice the structural integrity of the high-density polyethylene.

Q. Can you ever test that, given that you have the liner vents?

A. Yes, you can. You can monitor the liner vents for flow rate of escaping gas to see if the high density -- if the inner liner has been ruptured in some instance, or you can check for H_2S with an H_2S monitor or detector and check to see if there is any leakage during normal patrols.

Q. Exhibit Number 3 --

A. Okay.

Q. -- the page that has the number 3 in the bottom right-hand corner --

A. Okay.

Q. -- paragraph number 6, the last couple of lines there, We intend to only inject dried gas (less than 1% residual water). For this reason, we would propose a similar system without plastic tubing -- without plastic coating in the tubing.

That is consistent with what you were just telling me about the different types of plastic --

A. The different types --

Q. -- that would be --

A. Different types of plastic and different types of fluid. This relates to the -- between the discharge of the final stage of compression and the tubing in the well, which will be undersaturated with water, and therefore in a less corrosive environment, and so we propose not to line that tubing because there is not free water present.

However, in the pipeline, between the plant and the well site, we know that there will be free water present due to condensation in the line, and that is why we propose to use the plastic lining in that particular line.

Q. The slide show, Exhibit 13 --

A. Okay.

Q. -- slide 5, where will you have these liquid knockouts?

A. There will be liquid knockouts before each stage of compression. So there will be a liquid knockout -- there will be two liquid knockouts on the acid gas booster compressor at the Linam Ranch plant site, and then at the well site there will be an inlet scrubber or slug catcher, and there are four stages of compression there. There will be an inlet knockout before each of the four stages of compression to prevent free liquids from making it into the compressor itself.

Q. The pipeline will be 9000 feet or so. Where will the pigging stations be?

A. They'll be at each end of the pipeline, ma'am, at the plant and at the wellsite.

Q. Okay. Exhibit 6, page 4-5 --

A. Okay.

Q. -- the second paragraph before the listings of all the different pipeline sizes, the paragraph that begins, "Data compiled from DOT data..."

A. Okay.

Q. -- which brings up the question, is this project required -- are the DOT requirements required for this project, or is this a voluntary compliance with DOT requirements?

A. We've had some discussion internally as to whether they're required or not. But in our discussions with the State Land Office, it was a requirement of the State Land Office to make this a DOT pipeline. And I believe we would have made it a DOT regulated pipeline on our own, even without that requirement.

Q. Okay, back to my question now. "...compiled from DOT data on gas pipelines...show a trend toward higher failure rates as pipe diameter decreases..."

A. Yes.

Q. "(Smaller diameter pipes have thinner walls..." Which means that the 8-inch-diameter pipe that you're proposing has a higher rate of failure than the larger pipes?

A. Right.

Q. So the overriding consideration was what?

A. That was taken into account in the QRA study when we compared the option to send -- to use an 18-inch pipeline to send low-pressure gas to the plant versus an 8-inch pipeline to send intermediate-pressure gas. And so the risk ratios or failure rates that are listed in the report were taking into account those probabilities in determining the risk to the public of the different options. So -- I don't know if I answered your question or not.

Q. No.

(Laughter)

A. Sorry. Could you repeat the question for me again, please?

A. What was the overriding factor, given the fact that the 8-inch pipeline has a higher failure rate than a large-diameter pipeline?

A. The overriding factor was the detailed calculations and the probabilities of the different failures, and also the inventory in the different lines. The 8-inch pipeline has a limited inventory of acid gas in it, and so it offers less of a release if there is a -- if there is damage to the pipeline.

I'm still not sure if I answered your question, but I'm trying to answer it as best as I can.

Q. Slide 6, I guess -- Okay, several of your maps indicate that the pipeline will cross a major highway and two smaller public roads. Is that the extent of the crossing of public transportation corridors?

A. Yeah, I think it will mostly just cross the main highway, and then there may be some non-public roads that it would cross within the state land.

Q. Because your maps do show two smaller roads.

A. Two smaller road crossings, okay.

Q. Yes, particularly page 4-5.

A. Okay.

Q. Well, not there. Slide 6 from your slide show.

A. Oh, okay.

Q. What special precautions will you be taking to ensure safety crossing public roads or public highways?

A. When we've finalized our design, we'll apply for a permit with the highway authorities in order to do the road crossings. We will either case the line with an external casing or we'll apply additional concrete. Either method has been used for road crossings to help protect the pipeline itself against damage from the road itself.

Q. But you said for highway. Does that include the two minor roads? Because the Highway Department is not going to have jurisdiction over those smaller public roads.

A. Right. Then we'll also case those lines or apply the concrete, even at the smaller roads.

Q. So that's a firm commitment to do that?

A. I will see that it's done, yes, ma'am.

Q. There's been several comments that Duke Energy is being treated differently from other applicants and companies who have also been approved for acid gas. What is your impression as to why this is suddenly a Commission Hearing and if you are being treated differently?

A. I think our comment was that previous acid gas injection permits had been approved administratively, and this one was being subjected to a public hearing, and I can't answer as to what the rationale was that you all had to do that.

Q. I'm asking for your impression.

A. My impression, my opinion. I suspect it's because of the crossing of the public highway and going offsite from the plant, although I think at least one of the other injection facilities is outside the plant fence as well.

Q. Are there major differences in the design and construction of the well itself or the piping to get to the well? I'm sure you've looked at others in the area.

A. Yeah. I mean, versus Artesia site, there's very little difference. However, due to the length of the pipeline between the plant and the well site, we're going with this low-pressure split compression design as described in the QRA study.

Versus the Agave and Indian Basin, the Agave proposed site, I guess, and the Indian Basin site, my understanding is that those are water-based injection processes, and so there is a fundamental difference in that those sites have concurrent injection of water along with the gas to reduce compression requirements in the process.

Q. Do you expect to encounter any water or any fluids within the injection zone?

A. Yes, we do. We -- based on the drill stem tests of some of the previous wells in this zone, which will be talked about later, water was encountered in this zone.

Q. With the mixing of the acid gas and the formation water, formation fluids, an extremely strong acid will be formed within the neighborhood of the wellbore?

A. It's been speculated in a lot of literature that at the interface between the injected acid gas and the water that's being displaced in the formation, that you can form a carbonic or sulfuric acid at that interface, due to dissolving the gas in the water.

Q. Can that migrate upwards and dissolve the cement that's part of the construction of the wellbore?

A. We'll use cement that's acid-resistant as part of our design for the well. So I do not believe it will damage the cement.

Q. Do you expect that that acid would create pathways out of zone?

A. No, I do not expect that.

COMMISSIONER BAILEY: That's all I have.

CHAIRMAN FESMIRE: Okay, Commissioner Olson?

EXAMINATION

BY COMMISSIONER OLSON:

Q. I just had a couple questions. I guess you were saying that you were going to, in the pipeline trench, also lay in the water disposal line. This may be just for my understanding of this. Is that water disposal line for the water you're getting from the scrubbers, then, to go back to the plant? Is that --

A. That's exactly correct.

Q. Okay. And then on the acid gas pipeline that's coming through, you're saying you can monitor the annular space between the high density plastic liner and the steel pipeline. Is there a plan in here somewhere for how you will monitor that frequency and how this will be conducted?

A. That will certainly be part of our pipeline patrol at two-week minimum intervals -- or maximum intervals, actually, I'm sorry. And we'll investigate if there's any other instrumentation that we could install to allow us to do that continuously, but I don't know of any systems right now.

Q. So how would you propose that be monitored at this time?

A. At this time, when the pipeline is patrolled the line will be walked and each one of those stations can be checked to see if there's high flow rates coming from those connections, and also checked for hydrogen sulfide in those vent connections.

Q. So they're just directly -- measure gas that might be venting from the --

A. Right.

Q. -- the vents?

A. There are also techniques to capture gas leaks in like a balloon or whatever, so that you can quantify how much gas is leaking and compare it to the known permeation rates that are designed into the system.

Q. And I guess -- I was just thinking, it would help people more if you guys had had some type of a proposal for how you're going to monitor that. I didn't see that as part of the information that you have now, since that seems to be a key point, is how you're going to monitor the leaks from the pipeline.

A. And our proposal for now is that we'll monitor it during the pipeline patrols, and if we can develop a better system, we'll certainly try to do that.

Q. So if you have -- Let me see if I understand this correctly. You're saying that you have a flange every 2000 feet, and that's where you have the venting from the -- each annular space?

A. Right.

Q. Is that how that works?

A. On each side of the flange there's a -- each side of the flange connection, which is completely sealed with the plastic liner and steel, there's a coupling on the outside of the pipe, which has an extension pipe and a valve at the surface which has to be left open, and that's where you would monitor the section of pipe.

Q. Okay, so there's about four or five --
A. Yes --
Q. -- of those points along the way?
A. -- there will be.
Q. And when I go back to your slide you had, slide number 21 --
A. Okay.
Q. -- that's where you located H_2S detectors --
A. Right.
Q. -- it seems like a lot of the areas are pretty well ringed with monitoring, but I don't see anything to the east of the injection well. Why is that?
A. Well, we provided three monitors at 120-degree intervals surrounding the injection well, so we felt like that was sufficient, based on possible dispersion of H_2S. But we can investigate adding additional detectors, if -- and we'll go through additional safety reviews, we'll go through a normal process hazards analysis as part of the design, and we'll sit down as a team with plant operators, maintenance personnel and engineering, to make sure that we've fully protected ourselves, but...

This is effectively what we did at the Artesia plant, is, we had three detectors at 120-degree intervals around the well.
Q. And which three are those in this diagram?

A. Those would be this detector, this detector and this detector. And we try to put them where they'll be out of the way if we have to bring in a workover rig or something to do some kind of work on the well, so the detectors won't be damaged by bringing the rig in and out, so that sort of sets some of the spacing.

Q. Would you object to placing another detector somewhere directly east of that, to kind of fill that hole in the --

A. No, I have --

Q. -- monitoring area?

A. -- I have no objection to that at all.

Q. Okay.

A. I can draw that in.

Q. And then you mentioned at the -- Were you at the public meeting that was conducted?

A. The second public meeting that applied to the acid gas injection project, I provided the same slide show, only a little bit longer, to the public.

Q. Okay. But how many people -- You might have said this, but I might have missed that. How many people showed up for the meeting?

A. I believe approximately 25 people were there.

Q. And where were these -- where was representation from?

A. There were a number of ranchers, primarily ranchers. There were folks from the Xcel power plant. There were representatives from the State Land Office and the OCD. And that, I think, complies -- I don't know of any others.

COMMISSIONER OLSON: All right, thank you very much. That's all the questions I had.

CHAIRMAN FESMIRE: Mr. Root, just --

MS. O'CONNOR: Mr. Chairman, could we follow up with just one follow-up question from the Commissioner? We just did that with a cross-examination question.

CHAIRMAN FESMIRE: Any objection --

MR. HALL: No.

CHAIRMAN FESMIRE: -- Mr. Hall?

Mr. Carr?

MR. CARR: (Shakes head)

EXAMINATION

BY MS. O'CONNOR:

Q. Could you explain what you're going to do when you find a leak in the pipeline? You've talked about how you're going to monitor, but we're wanting to know exactly what is your actual plan for what you're going to do when you find a leak.

A. If we find excessive amounts of leakage from any of the connections above what's a normal permeation rate, then we would shut -- we would attempt to determine the location of the leak first and then repair the leak as soon as is practical to do so, and analyze the significance of the leak, and that would determine how quickly we would need to repair the leak. We haven't obviously written the plan yet or procedure for that, because that's a little ways down the road for us.

MS. O'CONNOR: Thank you.

EXAMINATION

BY CHAIRMAN FESMIRE:

Q. Mr. Root, the acid gas mixture, is that heavier than air?

A. Yes, it is.

Q. And all the components are heavier than air?

A. Not all the components. Some of them include methane, which is lighter than air.

Q. Yeah, but I mean the two that we're worried about.

A. The two that we're worried about are heavier-than-air components, that's correct, sir.

Q. Okay. Now your testimony to the Commission is that the proposal will improve the environment by reducing sulfur-dioxide emissions; is that correct?

A. That is correct.

Q. And it will improve safety?

A. We believe -- I believe it will improve safety, yes.

Q. Why do you say that?

A. Versus operating or 30-year-old sulfur recovery unit, which is about 300 feet away from the major highway, we believe that having an acid gas injection well, which is state-of-the-art technology and will be all new equipment, will significantly improve our safety.

Q. Okay. So you think it will be safer than the current procedures?

A. Yes, I do.

Q. Now, I understood from your testimony that the Artesia plant had initially a blemishless record out there, but then a little later in your testimony you mentioned some problems with the Artesia plant, probably due to compression or --

A. The main problems with the Artesia plant have been injectivity into the well. Unfortunately, the zone we injected into, the water zone, didn't turn out to take as much gas as we had hoped.

Q. Is that the zone you're still completed in?

A. It is still the zone we're completed in.

Q. And adding another stage of compression is going to alleviate that problem, you think?

A. We've had a detailed reservoir study run by a consultant who's an expert in that field, and they've calculated that if we go to the maximum allowed injection pressure in our permit, that we'll be able to inject the volume of gas we currently have for a number of years. I don't remember the exact number, I think it's about 10 years. So we believe there is a plan forward to try to inject all of the gas into that well.

Q. Okay. I know you don't have a procedure written for this yet, but have you done any thinking about what if you have to pull the tubing in the well? What's your procedure for that going to be?

A. Yeah, and we do have a procedure in place at Artesia that's part of our contingency plans there. I assume that it would be a similar procedure, that we would make sure that we kill the well, and -- and I'm not a petroleum engineer, so perhaps I shouldn't really testify as to petroleum engineering, but we do -- we will have a procedure in place.

Q. Okay. You know, if you don't know the answer, tell me, but it seems to me that with the safety valves, the back pressure valves that you've got there, it's going to be awfully difficult to get in and unseat that packer and kill the well. Has anybody done any design work on that, or --

A. We've been able to do that at Artesia, at least once, to unseat the packer.

Q. Okay, did they have to snub out of the well, or did they --

A. I don't know the answer to that.

Q. Now, you said the reason for not putting the well closer to the plant was not safety but was for a geologic consideration?

A. That's exactly correct.

Q. And the next witness will tell us all about that?

A. That's correct.

Q. You indicated that the plant operators were going to need some additional training. I assume it's the same kind of training they have in Artesia?

A. Yes, it is.

Q. Can you tell us a little bit about what you're going to cover in that training?

A. In that training -- They already know the hazards of hydrogen sulfide, that's already been covered with them because they've got H_2S in the plant. We'll certainly review that again. We'll review the design details of the project, we'll review some of the thermodynamic principles at an elementary level, showing phase behavior and what happens as the gas is compressed through successive stages and how the density changes and what important parameters there are for operation of the facility.

We had a complete manual that we used at the training session at Artesia for the operators, and I put on a day-long training session for them on the mechanics, and with the assistance of the process safety coordinator at the plant we covered all of the alarm and shutdown systems, the contingency plans, the reporting requirements for the well and other aspects of the well. So we had a detailed training session to cover all aspects of the compression and well design, and we would do the same here as part of our normal process safety management process.

Q. I may have missed it. What's your designed wellhead injection pressure?

A. We hope the operating pressure is about 2000 p.s.i.g., but we're going to design for up to -- 2700 pounds, I guess, is in the OCD testimony that's proposed for the well. And we'll provide a pressure-limiting device to make sure that we don't go above that pressure.

CHAIRMAN FESMIRE: Mr. Carr, I have no further -- Do you have redirect?

MR. CARR: I have just a few.

CHAIRMAN FESMIRE: Mr. Olson?

COMMISSIONER OLSON: Just one point, I guess. Maybe I can ask this of Division counsel. Is the Division going to provide any evidence on what the contingency plans maybe should be for the pipeline?

MS. O'CONNOR: Mr. Commissioner, what our plan is at this time is to address the concerns which will also be the concerns of what we see now with what they've submitted as to what the OCD might like to see in a contingency plan and the concerns. At this point in time the OCD has not seen a contingency plan, so it can't really address what the fallacies of the contingency plan is when it hasn't yet seen one.

COMMISSIONER OLSON: But you'll be looking at making some recommendations?

MS. O'CONNOR: Certainly we will be raising some recommendations and some questions.

COMMISSIONER OLSON: Okay, thank you.

CHAIRMAN FESMIRE: Mr. Carr, I'm sorry to interrupt you there.

REDIRECT EXAMINATION

BY MR. CARR:

Q. Mr. Root, there have been testified about the decisions to use steel pipe versus plastic-coated tubing.

A. Uh-huh.

Q. Isn't it true that one of the real determining factors in making that decision is the pressure in the line?

A. That is correct.

Q. And with a lower pressure you have liquids drop out?

A. That is correct.

Q. With liquids that they drop out, is it more corrosive?

A. Yes, it is.

Q. And in those circumstances you would have to go to a lined tubing; isn't that right?

A. That is correct, or a lined pipeline, yes, sir.

Q. When you talk about monitoring the pipeline to assure its integrity --

A. Uh-huh.

Q. -- you talked about various tests that are run. Before you install the pipeline, though, there is rigorous monitoring and testing of the line before it is installed; isn't that true?

A. That's correct.

Q. And then with the regular monitoring, will you be able to know if, in fact, you're having a problem develop that requires some sort of a remedial action by Duke?

A. Yes, we will.

Q. Duke prepared a quantitative risk analysis. Was that required by the Oil Conservation Division?

A. No, it was not, it was something we did on our own behalf.

Q. And when you take those results and you look at the risks of exposure --

A. Uh-huh.

Q. -- the testimony was that these numbers that were presented were if one person stayed in place 365 days a year, 24 hours a day, correct?

A. That is correct.

Q. When you have a more mobile person, doesn't that significantly reduce the risk to that individual?

A. If an individual is there less than full time, the risk is lower.

Q. In response to questions by Commissioner Olson, you talked about how you're going to take the water from the scrubber back to the plant. Isn't that basically the system that's employed right now out at Linam?

A. That is correct, whatever water is collected in the SRU is also taken back to the plant disposal system.

Q. In response to Commissioner Bailey, you were talking about certain questions about plastic-coated tubing and various paragraphs in the response that we submitted to the OCD. Isn't that letter really addressing questions within the wellbore?

A. That's exactly correct.

Q. And isn't your testimony really focusing on issues concerning what is on the surface?

A. Primarily on the surface, yes.

Q. So there may be some confusion there that maybe Mr. Gutiérrez can respond to?

A. I believe so, if I haven't already answered the question.

Q. Now, in terms of the questions concerning the diameter of the line and the smaller the line, the higher the risk of failure, is diameter the controlling consideration, or are there a number of issues when you make a determination as to the diameter of the line?

A. I think the controlling issue in the risk here was the inventory in the line, and a smaller diameter actually reduced the inventory in the gas-phase pipelines.

Q. ConocoPhillips objected to our Application, did they not?

A. Yes, they did.

Q. Did they withdraw that objection?

A. Yes, they did.

MR. CARR: That's all I have.

CHAIRMAN FESMIRE: Mr. Hall?

MR. HALL: Very briefly, in response to a couple of matters raised by Mr. Carr just now, if I might.

CHAIRMAN FESMIRE: Okay, I don't want to get into that much --

MR. HALL: I won't --

CHAIRMAN FESMIRE: -- but go ahead.

MR. HALL: -- I understand.

RECROSS-EXAMINATION

BY MR. HALL:

Q. Mr. Root, I understood from your earlier testimony that it was the quantitative risk assessment that determined the final design configuration for the pipeline and injection facilities. Is that still the case?

A. That is correct, yes.

Q. And can you show us where in Exhibit 6 Quest took into consideration pipeline operating pressures?

A. Yes, I can. Specifically in one of the first sections on page 2-3 -- well actually, I'm sorry, on page 2-4 -- well shoot, I'm going to have to correct myself again, it's actually Table 2-5. On page 2-5 it shows the pressure at the Linam Ranch inlet end of the pipeline for the three different options: 2250 p.s.i.g for option one, which was the high-pressure pipeline; 90 p.s.i.g. for the split compression pipeline; and 4 p.s.i.g. for the compression at the well site case.

MR. HALL: Thank you, Mr. Root, that concludes my recross.

And Mr. Chairman, I'd move the admission of Exhibits 6, 14, 15 and E into the record.

CHAIRMAN FESMIRE: Mr. Carr?

MR. CARR: I'm going to object to the admission of Exhibit E. There was no foundation laid for the admission of Exhibit E, which was a composite of various schematics of airport runways, and we would object to that as having -- one, being irrelevant, and two, no proper foundation has been laid for that.

CHAIRMAN FESMIRE: I think 6 and 14 have already been admitted, have they not? If they haven't, we'll admit them now.

I tend to agree with Mr. Carr on Exhibit E. Do you have a witness later who can lay the foundation for these?

MR. HALL: That's fine. I would simply say it's a self-authenticating document. The last page of that shows the source of the publication. It's a governmental publication, I think it's something the Commission can take notice of.

Exhibit 15 is a copy of Onshore Order Number 6, and again I believe it's a self-authenticating governmental publication. I think the Commission can take notice of that. The witness testified to that with respect to the risk assessment models that were used in the Quest study, that comported with the Onshore Order 6.

CHAIRMAN FESMIRE: Mr. Carr, Ms. O'Connor, do you have any --

MR. CARR: No.

CHAIRMAN FESMIRE: -- problem with that?

MR. CARR: No.

MS. O'CONNOR: No.

CHAIRMAN FESMIRE: Okay, 15 will be admitted.

(Off the record)

CHAIRMAN FESMIRE: Mr. Hall, I think you're correct about the self-authenticating document, but we still haven't gotten over the relevance hurdle.

MR. HALL: That's fine. But Mr. Chairman, I'd simply point to some of Duke's slides, for instance their Slide 7. Look in the lower left-hand corner, that tells you which way the wind blows. So I think you're going to have that information before you by virtue of their --

CHAIRMAN FESMIRE: Okay. Point taken, Mr. Hall. But Exhibit E won't be admitted at this time.

Mr. Carr, how much time will you need with your second witness?

MR. CARR: Well, I thought I would need 30 minutes with my first witness.

(Laughter)

MR. CARR: And I think I need 30 with my second.

CHAIRMAN FESMIRE: Okay. Why don't we break for lunch, because Commissioner Bailey informs me that she's needing a lunch break --

COMMISSIONER BAILEY: I get really grouch if I don't.

CHAIRMAN FESMIRE: -- and reconvene at 1:15, and we'll start with Mr. Carr's second witness.

(Thereupon, noon recess was taken at 12:17 p.m.)

(The following proceedings had at 1:17 p.m.)

CHAIRMAN FESMIRE: Okay, let's go back on the record. This is the continuation of Cause Number 13,589, the Application of Duke Energy Field Services, LP, for approval of an acid gas injection well, in Lea County, New Mexico.

I believe, Mr. Carr, you were getting ready to start your second witness?

MR. CARR: Yes, sir, I am.

At this time we call Alberto Gutiérrez.

CHAIRMAN FESMIRE: Mr. Gutiérrez, you've been sworn?

MR. GUTIÉRREZ: Yes, I have.

CHAIRMAN FESMIRE: Okay. Begin, sir.

ALBERTO A. GUTIÉRREZ,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CARR:

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

A. Alberto Alejandro Gutiérrez.
Q. Mr. Gutiérrez, where do you reside?
A. Albuquerque.
Q. By whom are you employed?
A. Geolex, Incorporated.
Q. And what is your position with Geolex?
A. I'm a geologist, and I'm the president of the company.
Q. And what is the nature of the business of Geolex?
A. We're a geological and engineering consulting firm.
Q. What is your relationship with Duke Energy Field Services in this case?
A. I was retained by Duke to evaluate potential targets for acid gas injection in the vicinity of the Linam plant.
Q. Were you also asked to prepare the Form C-108 Application for authorization to inject?
A. Yes.
Q. Have you previously testified before the New Mexico Oil Conservation Commission?
A. Yes.
Q. At the time of that testimony, were your credentials as an expert witness, geological witness, accepted and made a matter of record?

A. Yes.
Q. Are you a registered petroleum geologist?
A. I'm a registered professional geologist in about 20 states.
Q. In New Mexico?
A. Not in New Mexico, because New Mexico doesn't have registration for geologists.
Q. Are you familiar with the Application filed in this case on behalf of Duke Energy Field Services?
A. Yes.
Q. Have you made a geological study of the area that is the subject of the Application?
A. I have.
Q. And are you prepared to share the results of your work with the Oil Conservation Commission?
A. I am.
Q. Is a summary of your education and experience marked as Exhibit 10 in the Duke Energy Field Services exhibit book?
A. Yes.
MR. CARR: May it please the Commission, we tender Mr. Gutiérrez as an expert witness in geology.
MR. HALL: No objection.
CHAIRMAN FESMIRE: Any objection from the Commission?

COMMISSIONER BAILEY: No.

COMMISSIONER OLSON: No.

CHAIRMAN FESMIRE: Mr. Gutiérrez' credentials are so accepted.

MR. CARR: Thank you.

Q. (By Mr. Carr) Mr. Gutiérrez, let's go to the PowerPoint presentation. I might note that the PowerPoint presentation is marked as Duke Energy Field Services Exhibit 15, and many of the exhibits that are included in this PowerPoint presentation were also filed with the Form C-108 and can be found in our Exhibit 1,t he Form C-108 at pages 57 through 67.

So why don't you begin?

A. All right. Chairman Fesmire, Commissioners, I want to just describe very briefly, if I can, the process that we went through in evaluating the potential for acid gas injection in the vicinity of the Linam plant, and what I'd like to do is kind of take you through the logic of how we did it and review the geological information that led us to recommend the specific target for acid gas injection and the location.

To start, we were retained last May by Duke to evaluate and to locate a geologic reservoir that's capable of accepting about 5 million cubic feet a day of acid gas, for an expected life cycle of somewhere in the neighborhood of 20 to 30 years.

We were given really very little guidance as to how -- what to do to get there, we just were asked basically that the reservoir be a reservoir that is capable of accepting the injected fluid and can do it safely without affecting either existing or potential oil and gas production, and that the well would have to be in a location and would be constructed such that it would minimize any potential leakage into groundwater and that the reservoir would have the geological properties and integrity to assure that the acid gas remains in the reservoir. Furthermore, we were instructed to try to find such a target under the Linam Ranch plant. So that was basically what we were charged with doing.

Q. What is this next slide?

A. This next slide is just to add a little levity to the process, but really finding an appropriate reservoir is a question of balance. It is balancing a variety of different factors, geological factors and other factors that we'll be discussing in the presentation as we go forward.

So very briefly, the process is as follows.

We identified regional background geologic data, which is summarized in what I've called Exhibit 8. I think it's in a different number in our booklet here, but you'll see it as we go through.

We defined what would be the characteristics of an ideal acid gas reservoir, if you will, and that we used those characteristics to compare the geologic information against -- to try and locate the best potential reservoir.

We then identified, located and evaluated all of the wells that were in the local area, in the vicinity of the plant, and that would penetrate or near-penetrate the zone that -- or potential zones, if you will, that could take acid gas.

We then evaluated that stratigraphic information, we identified reservoirs that would meet the basic ideal geologic criteria for an acid gas reservoir.

We constructed a variety of cross-sections, stratigraphic and structural cross-sections.

We then also went and looked for seismic availability of seismic data to further be able to put a better understanding on our geological model of this site. And we were fortunate enough, as you'll see, that we were able to locate seismic data, in fact, that goes in two directions, both east-west and north-south, right through our proposed location.

We also evaluated nearby well test data, drill stem test data, and plugging status of surrounding wells, as well as a couple of wells that are used for -- have been used for saltwater injection in the vicinity.

We then conducted a preliminary reservoir analysis just based on the available data to give us a good sense that the formation was capable of taking the ultimate amount of gas that we would give to it. Of course, that's going to have to be refined when we actually drill the well and do a more detailed reservoir analysis.

And then we identified some potential secondary targets, and we finalized the recommendation to DEFS.

This gives you a pretty schematic picture of the geology in the area. If I can work this thing -- There we go.

Q. We're now on what is marked Exhibit 8 at the bottom?

A. That's correct. This area -- The plant site is located right here. In terms of the geology of the area, it's located at the very north end of the Central Basin Platform, which is a raised basement platform --

(Off the record)

A. In any case, the Central Basin Platform divides the Midland and Delaware Basins, and really the plant site is located at the extreme kind of northwest end of that Central Basin Platform. So geologically it's in an interesting location, and I think this will give you some sense of why we were not able to find an adequate reservoir beneath the plant site itself.

This area right here schematically shows where the plant site is located, and you can see that we've got the San Andres, Queen, and the Capitan Reef up here, and then we grade into the Clearfork shelf deposits, which then are underlain in some places by a thin sliver of Pennsylvanian-Wolfcamp before you get to the Ellenburger and then basement rock.

As you proceed into this basin, the Delaware Basin or into the channel between the Midland and Delaware Basins, the section gets considerably thicker, and you pick up a whole series of units, both in the Abo reef and the Bone Spring, and then this Pennsylvanian-Wolfcamp thickening that takes place down here where you get a better development of the units that ultimately were the units that we felt were the best potential candidates for injection.

Let's talk a little bit about what constitutes an ideal acid gas reservoir.

One, it's got to be laterally extensive, permeable, and it's got to have good porosity.

Ideally, you want it to be below existing or potential production. It doesn't have to be necessarily below that production, but that is the easiest way to make sure that the production will not be affected.

Also, it should have a decent geologic seal that will be able to contain the gas or the fluid.

It should have a fluid in the reservoir itself that is compatible with the injected fluid.

And of course it should be isolated from any fresh groundwater.

So those were the main characteristics that we looked for when we were evaluating the individual geologic units.

Let's talk a little bit about what we did first. We looked at, first, what were the wells in the area. There are many shallow wells in the area. Many are old wells that were drilled in the 1920s, '30s, '40s, through the '60s, many of which have been played out and have been plugged and abandoned. There's actually very few deep wells -- and we'll see it on a figure coming down the road -- most of which were drilled to -- for production or to test the Abo reef units.

Based on the stratigraphic analysis, we found the lower Bone Spring was the best target. And really, it's only found west and north of the plant site. Also, we identified the Brushy Canyon as another zone that has -- while up on the platform equivalent of the Brushy Canyon there is some production, there is no production in this area from the Brushy Canyon, and we felt that that also had a potential for injection.

Then we did a detailed stratigraphic analysis and a seismic analysis, and we recommended the closest location to the plant that we could find that maximized the potential for encountering an adequate thickness and porosity of the lower Bone Spring, and then also combined with where would be some potential for the Brushy Canyon.

We also had some well logs and tests in this Conoco State Number 1 well -- and I'll show you those logs in a little bit -- that demonstrated that the target was really nonproductive for oil and gas, but it was permeable, porous, and it had some pretty decent flowing pressures of sulfur-cut saltwater.

So if we go to the next slide, I can show you this. And if you look in your -- in the C-108 Application, which is marked as Exhibit 1 -- unfortunately, my copy doesn't have the page numbers at the bottom here, but behind Section VII there is the various information about the injection fluid and formation fluids. And then we have this part that says Supplemental Information for Section VII - Geology. You'll see the first map is this map.

Q. That is on page 59.

A. Okay. This map -- the first map is basically -- on the left side, shows all of the well control in the area. Just to orient you again, here is the plant site, and all of these are a combination of all wells, including oil or gas wells, saltwater injection wells and plugged wells in the area.

We then kind of started taking slices of the data, if you will, by looking at wells that were deeper than 4000 feet, which is the Queen, the main productive units that have been productive in this area, and then deeper than 7500 feet. And you can see the well numbers drop off pretty dramatically.

And in this last map you can see that a trend develops for the wells that are deeper than 7500 feet, which runs in this area, and those are basically Abo wells that were drilled in the Abo reef trend. Now most of those wells, even here, did not penetrate the lower Bone Spring. Most of them terminate in the Abo reef. But there were a few, as you'll see in some of the cross-sections, where we were able to get some sense of the lower Bone Spring.

This next map is a little bit complicated, because it's got a lot of information on it. But for right now what I'd like to focus on is the location of two cross-sections which I'm going to show you. One, it starts at this well here, at LBS1, and goes north to this well and then goes to this well and this well right here. Those four wells are shown in the cross-section that we'll be looking at in just a moment.

And then also we have another cross-section, a structural cross-section, drawn across here from this well just north of the plant site to -- across here. And those --

Q. And how is that cross-section or that trace marked? What are the initials on it?

A. UP1 and UP1'.

Q. Okay.

A. Okay, so if we go to the next slide, we can show you the first, which is a stratigraphic cross-section. And this would be on page 60, I believe, of your Exhibit 1. This is cross-section --

MR. EPEL: Sixty-two.

THE WITNESS: Sixty-two? Oh, yeah, thanks. Give me one that's...

This cross-section is a stratigraphic cross-section that we did to try and look basically at what kind of control we had in this lower Bone Spring. And in general we were looking at the whole section, but we really wanted -- what we keyed in on was the porosity and permeability shown on these logs, highlighted in the areas that were blue.

And in some of these wells -- this one, this one in particular, and this one, which would be the Conoco State Number 1, the Lea ACF State Number 1, and the

Moonrise State Unit Number 1 well -- there were also drill stem tests in the upper section of the lower Bone Spring, which gave us some pretty good indications of, one, whether or not there was a potential for production in those zones and, two, whether or not we had the kind of porosity and permeability that would be reasonable to inject gas into those zones.

You can see in this well, which is located about three miles west of the plant, much further into the Basin, you get some very good porosity developed in that well, even better than what we have in this area. But given the flowing pressures and shut-in pressures that we saw for the saltwater here and how much was produced from those zones, we feel very confident that the Bone Spring in that area has the right characteristics to be an adequate reservoir.

Next slide.

This cross-section now, which is shown on page 64 -- I'm sorry, not 64, page 66 of your Exhibit Number 1, is a structural cross-section that shows the porosity and resistivity logs through various middle and upper Permian stratigraphic units, including, up here, the Brushy Canyon. Most of the production in the San Andres is updip of this location. These sections in the Brushy Canyon --

Q. (By Mr. Carr) And they're shaded yellow on this exhibit?

A. Yes, they are shaded yellow here. -- were zones that had pretty good porosity and permeability but did not have shows of oil but rather water and some gas-cut water.

So this was identified as a potential secondary target. What we're trying to do is take a look at a zone -- again, going back to my question-of-balance slide -- a zone or an area where we could maximize in a single wellbore the potential for making sure that we would get a unit that would be capable of producing the acid gas. So...

The next slide, go back to this map.

What basically the end result of the stratigraphic analysis was is that this green zone here was shown -- we developed what we call the fairway for the lower Bone Spring. Based on the stratigraphic information on this isopach map, you can see the thicknesses of the lower Bone Spring shown and some inferred structures that we see there that are basically platform bounding normal or in some cases possibly reverse faults, and they're basically high-angle faults that bound the Central Basin Platform.

And then this purple zone was really the -- right here, the updip limit of the porosity that we could identify in the Brushy Canyon. And so this was kind of the fairway for the Abo and Brushy Canyon porosity.

And so what we ended up doing was recommending a zone right in this area, included the southwest quarter of Section 30 and actually the southeast quarter also of Section 25. So...

Q. This is actually a composite map, isn't it?

A. It is indeed, yeah.

Q. And using this map, you've actually combined the geological features of each of the zones indicated on that map?

A. That's correct.

Q. And what you have is a location that is basically where all of the geology comes together and when you look at in total, this is the best location for the well; is that what you're saying?

A. That's right. In fact, if you look at the plant site itself, you can see that based on our interpretation of the stratigraphy and based on the availability of the wells and our knowledge of the rest of the -- because most of these structures are propagated up to about the San Andres, so we got a good idea of what the structure was by doing these stratigraphic and structural cross-sections across there, and right under the plant there just is no Bone Spring to speak of. And so despite my client's significant desire to complete the well under the plant itself, geologically I just couldn't make that recommendation.

So the next thing that we did is, okay, what do we have that gives us -- what other data could we find or locate that would allow us to have a better control, one, on the structures that we were talking about? Because originally there was some thought of, well, perhaps we could do directional drilling from the plant site itself to the location where the Wolfcamp, the lower Bone Spring, would be ideal for injecting. So we wanted to get a better sense of what those structures were. And also, if we could confirm our geologic model from the cross-sections that showed the increase in thickness from the lower Bone Spring in that portion of the section.

So fortunately, we were able to purchase some seismic data that had two lines, a north-south line and an east-west line that crossed in Section 30 of Township 18 South, Range 37 East. We evaluated that seismic data, and based on that evaluation we were able to confirm that the lower Bone Spring thickness increases to about somewhere in the neighborhood of 140 to 160 feet thick in the area where we recommended it. And the structures that were inferred from our stratigraphic and log analysis confirmed that the Bone Spring is an ideal reservoir there.

So...

Q. Now, Mr. Gutiérrez, also in the exhibit book as

Exhibit Number 4 is a summary of the seismic analysis that goes into more detail than what you've just gone through; is that correct?

A. Yes, and I would be happy, if the Commissioners or anyone wants to go into that seismic analysis in more detail, if you -- I'd be happy to do that. But you can read it certainly in there, and we've got the interpreted seismic sections.

One thing I'll also add is that not only did we just look at the seismic sections themselves, we had a synthetic seismic section generated from two of the wells that penetrated the lower Bone Spring there so that we could aid in correlating those units on the seismic lines. And again, that is described in detail in Exhibit 4.

So fundamentally, to summarize, the lower Bone Spring is a formation that in this area, in our opinion, is an excellent, safe, acid gas reservoir that's capable of containing 5 million cubic feet of acid gas without detrimental effects on oil and gas resources or groundwater in the area.

And I will mention that we evaluated the groundwater resources in the area, we looked at -- there are four wells within the one-mile radius, there were water well, stock wells, that are completed either in shallow alluvium or in the Ogallala there, the deepest of those wells being about 142 feet.

And as best we can tell from the geologic information, even though it's unclear because as many of the logs that are produced for oil and gas wells don't worry too much about the upper 200 or 300 feet of the section from the surface, that the Ogallala is probably not any thicker than about 200 feet in this area, to the depth of 200 feet. And the design of our well, as is shown in the C-108 Application, contains surface casing that will be set down to 530 feet and cemented all the way up. So we will be well out of the groundwater in the area.

Also the lower Bone Spring, unfortunately, doesn't underlie the Linam plant as much as we wish that it would. It just isn't there. And directional drilling was not recommended because, frankly, I've never known of any acid gas well yet that has been drilled directionally. And my client I don't think wants to be the pioneer in that arena.

And secondly, the adequacy of the target reservoir will be tested by drill stem tests and core analysis when the well is drilled. The C-108 gives all of the details necessary to approve the installation of this AGI well, I think especially in the context of our responses to the questions that were provided by the Division in Mr. Jones' letter to us of September 16th and our response of the 7th of October.

One other thing I just want to emphasize, just so that the Commission really understands why we have staged this in kind of sections is that the -- despite my level of confidence in my own geologic analysis and my client's confidence in that analysis, everybody that has ever worked in the oilfield or in any geologic arena knows that the proof is in the pudding, when you actually drill the well.

So really, we want to make sure when we drill the well and we test the zone, core the zone and do a reservoir analysis, that indeed that zone will be capable of taking the acid gas like we think that it will be, before my client spends a lot more money doing detailed pipeline design and compressor station design and all of that, surface facilities which Mr. Root described in his testimony, because if we can't make a decent injection well there, then that other stuff is really moot.

So I think that summarizes the -- my testimony about the C-108, and I'm happy to answer any questions that you may have.

Q. Now, Mr. Gutiérrez, the Exhibit Number 1, the C-108, also contains a summary of your geological testimony, does it not?

A. In fact, it contains both a summary and more details than what I've described here.

Q. As we've been presenting this case, there has been, it seems to me -- sometimes we talk about gas, sometimes we talk about fluids, and there seems to be some mixing of these terms. Is that an appropriate observation?

A. Well, I've heard the same thing, and I think it may just be somewhat of a confusion. I mean, really, as a scientist I think of gas as a fluid. I mean, a fluid is a more general term, but I think what we're talking about here, as Mr. Root described, is that we will have a fluid that is, in effect, in a gaseous phase, that will be compressed and dried so that it then becomes a lighter-than water fluid that is in a liquid stage when it's actually injected into the reservoir.

Q. I'd like to ask you several background questions and then review the Form C-108 Application with you.

I think first it would helpful to have you just testify as to the status of the lands on which the well will be drilled.

A. Well, if you can recall the map that was on page -- let's see, sixty- -- let's just say 61, would be fine, or the one that we used that was on page 66, I believe -- I mean, on 68 -- -7, sorry, I just didn't have these labeled in mine.

But if you look at any of those maps, what we did -- once we -- we did the geologic analysis independent of the land status. We had no idea what -- We knew that Duke owned the Linam plant itself, but once we figured out that we weren't going to be able to find a unit capable of taking that gas beneath the plant itself, we just did the geologic evaluation to find the best possible zone.

When we looked at this land status, we then determined that the area that we were recommending, the eastern half of that area which falls in the southwest quarter of Section 30, was state land with state minerals. The rest of that section, for the most part, except for one small section, had all state minerals, and a couple of pieces of it were held by production, but that that quarter section in the southwest quarter of Section 30 was open state land.

Q. And what did you do to acquire the rights to utilize that property?

A. Well, two things. Duke asked me, do we need to get a mineral lease in order to be able to have our injection well there?

My answer in short was no. I do not believe that based on the Rules we needed to have a mineral lease to do that. But given the fact that we were going to drill what is essentially a test well, I felt very uncomfortable recommending to my client that we drill that without having a mineral lease, because what happens if, you know, we're wrong and there's some oil and gas in any one of those units? Not -- I mean, we're drilling through some zones that are productive of oil and gas in the area above our unit, and what if we make an oil or a gas well? I didn't want to be in that situation or have my client be in that situation without having the rights to produce that oil and gas.

And then we had to go through the process that was described earlier with the State Land Office to get an easement and a right-of-way, to be able to have the pipeline and the surface facilities.

Q. Now, we're here today because Duke is seeking authorization to inject into the lower Bone Springs formation in this AGI well, correct?

A. Yes.

Q. And you are the person who prepared Exhibit 1, which is Duke's Application for authorization to inject?

A. Yes.

Q. When did Duke file this Application?

A. September -- if I remember correctly, I think it was September 12th of 2005.

Q. And what response did Duke receive to the Application that it had filed?

A. On September 16th, I received a letter from Will Jones from the Oil Conservation Division that basically asked a couple of clarifying questions -- or not a couple, about 12 points regarding the Application and the process and the notice and other issues, as well as informing us that this would be set for hearing and would not be an Application that would be approved administratively.

And I think I may have spoken to Mr. Jones even before he sent me the letter, where he kind of clued me in on that.

Q. And the letter from Mr. Jones is marked Exhibit Number 2 in the Duke Field Services exhibit book?

A. Yes, sir.

Q. And then how did Duke respond to Mr. Jones' inquiry and questions?

A. That response is marked as Exhibit Number 3 in that Duke book, and that is a response that we prepared and submitted to Mr. Jones.

Q. Have you had discussions with Mr. Jones since filing these responses?

A. I think I may have spoken to him once, but I don't think we've had any extensive or substantive discussions.

Q. I'd like to look now at the C-108 Application and just simply work through this with you to be sure that we have in the record all of the requirements for this permit.

Is this an expansion of an existing project?

A. No.

Q. In Exhibit Number 1, the C-108, is there a plat as required by the Rules that show the location of the injection well, all wells within a half mile, the ownership in the area, and the area of review?

A. Yes.

Q. And are those plats contained on pages 6 and 7 of Exhibit Number 1?

A. I would say that they're contained in 5, 6 and 7.

Q. Okay. Does the exhibit contain all information required by the Oil Conservation Division for each of the wells in the area of review that penetrates the injection interval?

A. We believe that it did. However, there were some questions in Mr. Jones' letter of September 16th that indicated he wanted some diagrams for plugging and -- for some of the plugged wells, and we just had not produced all of those records because we felt they were already in OCD's database, but then we did do that in response to Mr. Jones' letter.

Q. But the data you have filed as to each well in the area of review shows the well type, the construction, the date drilled, location, depth, and method of completion?

A. It does.

Q. You've included on page 4, I believe, a wellbore diagrammatic sketch for the injection well?

A. Yes, and we also submitted a modified one that addressed some specific questions Mr. Jones had, in response to his letter.

Q. Will Duke Energy Field Services circulate cement on all casing strings in the well, to cover the Ogallala with surface casing and cement?

A. Yes.

Q. Are you going to be using -- What type of tubing are you going to use in the well?

A. Well, the actual tubing itself will be similar to what has been used at the Artesia injection well, which Mr. Root described, which will have -- it's a tubing that then has an inert fluid in the annular space, which is diesel fluid.

Q. Now you've reviewed the construction, in fact you prepared the diagrammatic sketch; is that not correct?

A. I did.

Q. And is it your opinion that this construction assures that injected gases and fluids will stay in the injection zone?

A. Yes, and especially in conjunction with my understanding of the geology there.

Q. What is the source of the fluids that are to be injected?

A. The come from the processing of gas as described by Mr. Root at the Linam Ranch plant.

Q. And what is the composition of this fluid or gas?

A. It's basically about -- on the average, 73 percent or so CO_2, and about 25, 26 percent hydrogen sulfide, and then a few other compounds as described by Mr. Root.

Q. To ensure the integrity of the wellbore, will the annular space be filled with an inert fluid?

A. Yes.

Q. Will there be a pressure gauge at the surface as required by the Federal Underground Injection Control program?

A. There will be, and in addition there will be the additional safety features, which Mr. Root described, downhole in the well.

Q. Will Duke conduct all mechanical integrity tests required by the OCD?

A. Yes.

Q. And you're going to continuously record tubing pressures and annulus pressures and injection rates; isn't that correct?

A. Yes.

Q. And that data will be made available to the Oil

Conservation Division, reported to them?

A. Yes.

Q. Now you testified that you'd provided some diagrammatic sketches for plugged and abandoned wells within the area of review; is that right?

A. Yes, they're not sketches that we did, but they're sketches that were part of the plugging records of those wells.

Q. Have you reviewed that data, and have you been able to assure yourself that there is no old plugged and abandoned well in the area of review that can become a vehicle for the migration of injected fluids into any other zone?

A. I have.

Q. Have you reviewed the available data on the wells, and have you satisfied yourself that no remedial work is required on any of these wells?

A. I have.

Q. What is the injection volume, the daily volume, that Duke proposes to inject in this acid gas well?

A. Five million cubic feet of gas a day, which converts to a liquid of 2200 to a maximum of 2500 barrels a day of acid gas liquid.

Q. And this will be a closed system?

A. It will.

Q. And what will be the pressure that you will be using?

A. The pressure that we will be using will be a maximum pressure of about 2700 p.s.i., probably range somewhere between 2600 to 2700 p.s.i. In fact, we had proposed a slightly higher pressure and -- just based on our understanding of the formation pressures in the area and so forth. But we received some recommendations that the Oil Conservation Division recommended in general, not only for the pressure but for the completion and drilling and logging of the well. And in fact, we're completely comfortable with those recommendations and we planned to do them anyway. And in fact, there's a number of areas where we're going to do some additional steps beyond what is recommended by the Division there.

Q. If the pressure that you are recommending should exceed a surface injection pressure of .2 pound per foot to the top of the injection interval, would this .2 pound per foot at the surface be satisfactory for Duke?

A. I'm sorry, Mr. Carr, I didn't follow that.

Q. Okay. Initial pressure -- The OCD generally uses a .2-pound-per-foot-of-depth pressure limitation at the surface, .2 pound per foot of depth to the top of the injection interval, as a base limit on injection pressure. Would initially that work for Duke?

A. Yes, and in fact that is consistent with the pressures I just gave you that would be calculated using the same formula that the Division recommended.

Q. And at that pressure you are hopeful and anticipate that the well will accept the fluid volumes that you hope to inject?

A. Yes.

Q. If you have to go to a higher pressure, would Duke justify a higher pressure by an OCD-witnessed step rate test?

A. Yes. As a matter of fact, we intended to do a step rate test anyway, as part of our confirmation of the injectibility into that zone, and we would be doing that anyway, even whether or not we felt we needed a higher pressure.

Q. Are the wells in the area of review properly completed and cased so as to prevent migration of any fluid into a freshwater zone?

A. Yes.

Q. Have you examined the available geologic data on this reservoir, and as a result of that examination have you found any evidence of open faults or other hydrologic connections between the injection interval and any underground source of drinking water?

A. Absolutely not.

Q. What are the freshwater zones in this area?

A. It's really very simple. It's shallow alluvial aquifers in the bases of draws and the Ogallala underlying it.

Q. And what would you anticipate to be the maximum depth of any of these freshwater zones?

A. Roughly 200 feet.

Q. Is page 69 in Exhibit 1 a review of the water analyses on the closest water wells to this injection well? And I believe they're located in Section 11.

A. They're not the closest water wells, they're the closest water wells for which we could get analytical data for, yes.

Q. Have you also included as your Exhibit Number 5 the Lea County Regional Water Plan?

A. I have --

Q. And -- Go ahead. Is that just for reference?

A. It's really just to provide additional background information for the Commission on the general status of groundwater in Lea County and of the extent and depth and thickness characteristic of the Ogallala.

Q. I'd like to ask you now a couple of questions about notice. If you'll, in Exhibit 1, turn to pages 70 through 77 --

MR. HALL: I'm sorry, Mr. Carr, my pages are not numbered. Could you refer to the section --

THE WITNESS: Right behind the last tab.

MR. CARR: The very last tab in the book, Scott, I'm sorry.

Q. (By Mr. Carr) Mr. Gutiérrez, is this an affidavit with attached receipts and return mailing receipts and copies of letters confirming that notice of this Application was provided to affected interest owners in accordance with the provisions of Rule -- of Form C-108?

A. Yes.

Q. Now, Mr. Jones in his September letter requested that we provide notice to all affected parties within one mile -- within a one-mile radius of the wellbore. Was that done?

A. Yes.

Q. He also requested that we provide notice to the City of Hobbs. Has that been done?

A. Right. In fact, yes, he recommended that, and he specifically stated in his letter, you know, what his understanding of the ownership of those lands were and who should be provided notice.

Q. And you did that?

A. We did.

Q. Is a copy of the notice to the City of Hobbs marked Exhibit 7 in the exhibit book?

A. Yes, it is. And in fact, further to that notice, I think that notice was sent to the city manager but then further referred to the fire chief in Hobbs, and he called me personally to ask some questions about it, and I provided further information to him verbally about the proposed project.

Q. Would you identify the documents behind Exhibit Tabs 8 and 9?

A. The administrative order that grants approval for injection of acid gas at the Artesia facility is behind Tab Number 8, for Duke Energy's Artesia -- or the AGI Number 1 well there.

And then the Tab Number 9 is the administrative order granting permission to inject for Agave's facility in the Metropolis AZL State Com Number 1.

Q. And why are these included?

A. They're basically just to show that this is not a unique situation, this is -- these applications were prepared consistent with the C-108 process the same way we did ours, and they were granted administratively.

Q. And you testified earlier that you have reviewed the conditions recommended by the Oil Conservation Division that were attached to their prehearing statement?

A. I have. There's two pages of recommendations regarding the drilling and the completion and evaluation of the zones for acid gas injection.

Q. And you indicated these are acceptable to do?

A. Not only are they acceptable to do, but I think we intended to do them anyway, and frankly we're probably going to probably do -- not probably, we will be doing things that are not even in here, like for example coring in the reservoir unit itself so we can do a detailed reservoir analysis based on cores, not only a step rate test or a drill stem test.

Q. In your opinion, will approval of this Application be in the best interest of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. If we look at the exhibits in the exhibit book, Exhibit 1 is the Application for authorization to inject, 2 is the Oil Conservation Division letter to Duke dated September the 16th, 3 is Duke's response dated October the 7th, 4 is your seismic analysis, and 5 is the site-specific regional groundwater plan that you have prepared. Were all of those either prepared by you, or have you reviewed them and can you testify as to their accuracy?

A. Obviously the letter from the OCD was not prepared by me, but it certainly is the letter I received. And the Lea County Regional Water Plan, we didn't prepare that, that was just available information and in large measure provided as background information about the Ogallala itself and its characteristics in the area.

Q. You prepared the notice letters and affidavit marked Exhibit Number 7, did you not?

A. Yes, sir, I did.

Q. Is it your request that the Artesia well application and the Agave applications were enclosed as Exhibits 8 and 9?

A. Yes, sir.

Q. Exhibit 10 is the summary of your qualifications and experience?

A. It is.

Q. And Exhibit 15 is your PowerPoint presentation; is that correct?

A. That is correct.

MR. CARR: May it please the Commission, at this time we would move the admission into evidence of Duke Energy Field Services Exhibits 1 through 5, 7 through 10 and 15.

MR. HALL: Mr. Chairman, no objection. However, I do have a query with respect to Exhibit 15. There's one slide in there that wasn't discussed. I want to make sure it's included in the exhibits presented to the Commission.

Mr. Gutiérrez, I'd simply ask you about this.

Among Exhibit 15 there is a grid, it's labeled "Position of Injected Acid Gas Front with Time". Do you have that in your set?

THE WITNESS: Yes. Yes, I do have that.

MR. HALL: Was that prepared by you?

THE WITNESS: It was.

MR. HALL: And Mr. Chairman, may I inquire, is that also included within your -- the Commission's sets?

CHAIRMAN FESMIRE: Yes.

THE WITNESS: It should be the next to last one.

MR. HALL: No objection.

CHAIRMAN FESMIRE: With that, we'll accept Exhibits Number -- or Ms. O'Connor, I assume you have no objection?

MS. O'CONNOR: No objection.

CHAIRMAN FESMIRE: We'll accept Exhibits 1, 2, 3, 4, 5, 7, 8, 9, 10 and 15, including the graph marked "Distance in Feet from the Edge" [*sic*] versus time in years.

MR. CARR: Correct.

CHAIRMAN FESMIRE: Okay, those exhibits are accepted into evidence for the cause.

MR. CARR: And that concludes my direct examination of Mr. Gutiérrez.

CHAIRMAN FESMIRE: Mr. Hall, would you have a cross-examination of Mr. Gutiérrez?

MR. HALL: Yes, sir. Thank you, Mr. Chairman.

CROSS-EXAMINATION

BY MR. HALL:

Q. Mr. Gutiérrez, good afternoon. Let me ask you a couple of questions. And while I do that, why don't we find a good plat to orient ourselves? And if you would turn to your Exhibit 1, the C-108, behind the tab marked Section V, there is a good -- it looks like an ownership plat. I'm sorry, my pages aren't numbered, but it looks like this.

A. Looks like it's page 7 on -- I believe. Mine weren't numbered, but we switched. So now I've got a numbered one.

Q. Do we have the same one?

A. Yes, we do.

Q. Mr. Gutiérrez, I understand from your direct testimony that it was your view that an oil and gas lease was not required in order to conduct injection operations; is that correct?

A. That's correct.

Q. Okay. And you did acquire an oil and gas lease for the equivalent of the southwest quarter of Section 30, correct?

A. That's correct.

Q. And I understand why -- from your explanation, in the event you encounter a productive zone, you need an oil and gas lease. Makes perfect sense.

Absent that, is there any activity that would perpetuate the state oil and gas lease beyond the primary term by, say, injection operations?

MR. CARR: I think this is calling for a legal conclusion, and I don't know if Mr. Gutiérrez is competent to make that determination.

MR. HALL: I think it's directly within the scope of the question asked to him on direct.

CHAIRMAN FESMIRE: Mr. Gutiérrez, remember, if you are not qualified to answer it or don't know, you can answer --

THE WITNESS: Yeah, I'm not a lawyer. I know that oil and gas leases can typically be held by production, but I don't know the intricacies of what can and can't hold the lease.

Q. (By Mr. Hall) And is it your view and the view of Duke Energy that the right-of-way permit acquired from the State Land Office for the surface of the southwest quarter equivalent is sufficient to allow Duke to conduct its injection operations?

A. Again, I'm not an attorney, but that is my understanding. We went to the State Land Office to get an understanding of what would be required to do that, and that's what we were told and that's what we negotiated.

Q. In the course of your negotiations with the State Land Office, did you discuss at all identifying the vertical extent of the injection interval that you were seeking?

A. Well, we told them what was the zone we were seeking to inject into, and that's the lower Bone Spring formation, which is a defined stratigraphic unit as described in my testimony.

Q. And that's not described anywhere in the State Land Office permit, is it?

A. I don't know.

Q. All right. Let me ask you, why was the Brushy Canyon dropped from the proposal?

A. Well, I wouldn't say the Brushy Canyon is dropped from the proposal. It's just that we are confident the lower Bone Spring will be sufficient to take 2200 to 2500 barrels a day of acid gas for 20 to 30 years.

And yet, while trying to reduce drilling risk, we wanted to locate our location where we would intercept multiple zones that would be capable of producing a reservoir that would be adequate for injection. I still feel that the Brushy Canyon may well be an adequate zone for injection, and it's our intent to test that zone as we drill.

But really the Commission, when they wrote us back the letter that is marked as Exhibit -- 3, I believe, or Exhibit 2 -- it said that only the lower Bone Spring would likely be considered in this Application and that if we needed other intervals an amendment could be requested. And we didn't really have any problem with that approach, so that's why we have focused this on the lower Bone Spring.

Q. Would you explain to the Commission, if you know, what was the basis for the ConocoPhillips objection to the inclusion of the Brushy Canyon?

A. Absolutely. As a matter of fact, I'm the one who talked with ConocoPhillips about that, so I'm probably the best person to testify about that.

The first -- Their objection was going to be to the acid gas injection Application as a whole, and the reason was because their offices had been completely evacuated for Hurricane Rita, and in between the time when they received our request or our notice and -- they said their geologists were gone from there, and there was no way within the 15-day time period that they were going to be able to evaluate its merits. And so they basically were intending to do that on a -- just to kind of protect their rights within the specified time frame until they could evaluate that.

Then when I talked to them about -- and talked to their people and they evaluated the lower Bone Spring, they felt pretty comfortable that they wouldn't have an objection to injection into the lower Bone Spring.

The Brushy Canyon, however, because it's further up in the section and conceivably needs a greater degree of analysis to determine whether or not it might have an effect on production, they didn't feel they had sufficient time to do that analysis.

And then -- and we asked them, Well, how long is it going to take you to do that?

And they said, Well, we don't know, it's not our top priority.

And then at that same time frame as that was going on, if you'll recognize from the dates of the letter from OCD, which was in the beginning of September, right after that Hurricane Katrina, Hurricane Rita, the OCD says, Well, we really only want to consider the lower Bone Spring at this time.

We feel comfortable that's -- "we" being Geolex and Duke -- feel comfortable that that zone is capable of taking the gas, and so we're not concerned with the use of the Brushy Canyon right now.

So we communicated with that to Conoco, and they dropped their objection.

Q. They dropped their objection with respect to both formations?

A. They dropped their objection that they had with respect to the Application for acid gas injection, with the proviso that it was one for the lower Bone Spring. If they were to -- if we were to insist or want to use the Brushy Canyon, they would want to do further geologic analysis.

Q. All right. And let's refer back to the ownership plat in the C-108, Exhibit 1, if you have that in front of you there?

A. I do.

Q. Does ConocoPhillips offset the Duke Energy lease to the east?

A. It does.

Q. Do they have any penetrations into the Brushy Canyon in their lease?

A. I'd have to go back and look to be sure. I'm not positive whether they do or not. I believe that they do, but I'm not -- I don't believe that this lease is held by production on this physical section that's shown. It's part of a larger, older lease that's held by production elsewhere.

Q. I see. Looking again at the ownership plat, to the north of Duke's proposed location it's shown with ownership in blue, and if I understand correctly that is fee surface and minerals, correct?

A. To the best of our understanding. We did not go and do a detailed takeoff on that, but it is our understanding that it is clearly fee surface and there are fee minerals there.

Q. And Duke did not acquire to utilize any portion of those fee minerals or surface, did it?

A. We're not going to be drilling on that property.

Q. Okay, my question is, did you acquire the right to utilize any portion of that fee acreage in any way?

A. No, because we're not going to utilize it.

Q. Okay. Mr. Gutiérrez, what do you understand to be the projected end of life of the project?

A. I think it's a little ill-defined at the present time. But you know, the scope of the project that we were told was probably 20 to 30 years.

Q. Okay. And if we look at your C-108, the very first page of that, you've referred to the injection volumes at paragraph VII, Roman numeral VII, second subparagraph 1, and you refer to an injection rate of 2200 barrels per day, and -- check my math -- over the course of 35 years that's about 28 millon barrels?

A. I haven't done the math.

Q. Sound about right?

A. I don't know, I'd have to do the math.

Q. Okay. And then variously in your executive summary, the very last page, very last exhibit, in Exhibit 15, it looks like you were looking for a reservoir that would contain -- that would accept 5 million MCF a day -- I'm sorry, 5 million cubic feet a day?

A. Right, or -- of gas, or when you convert that to barrels it's in that range there.

Q. It's the approximation of the 2200 barrels a day?

A. That's right, that's right.

Q. Okay. Let me ask you, does -- still unclear on this. The injection, as I understand it, will occur while the acid gas is in a fluid phase, correct?

A. A fluid -- a gas and liquid are both fluids. I mean, that's -- it will be in a liquid stage or phase, liquid phase.

Q. And the fact that it's in a liquid phase when it's injected, does that affect the compressibility at all?

A. Well, it's already been compressed to get it into that liquid phase.

Q. All right. Does injecting it in its liquid state, as opposed to a gaseous state, affect the injectibility of the material?

A. Well, it's the most practical way to inject that kind of a gas stream. I mean, you could try and dissolve the gas in water and inject it in that way, but that -- to take these volumes of gas, it would take a tremendous amount of water to do that, so this is the preferred method for doing that.

Q. All right. And as the injection stream radiates throughout the reservoir, it will be in a fluid or liquid state then; is that correct?

A. It should remain in that, although there may be some of the gas that would go into solution in the existing formation water.

Q. Have you calculated the pore volume for the southwest quarter of Section 30?

A. The pore volume in what?

Q. In the Bone Springs, your injection interval.

A. I don't think I've actually done the full pore volume calculation. We did do a calculation that indicated -- based on our understanding, roughly, of the thickness and the effective porosity of the Bone Spring from what we have as log information, we calculated enough to satisfy ourselves that we had sufficient pore volume to be able to take the gas that we're intending to inject into that zone.

Q. Have you calculated the lateral extent of the reservoir you need to inject the projected volumes?

A. What we did was based on the assumptions, if you will, of the thickness of the Bone Spring and its porosity in that area. We did some rough calculations that indicated that the ultimate lateral extent would be on the order of about 260 acres.

Q. And how much -- and that's not inclusive of the Brushy Canyon, correct? It's simply Bone Springs?

A. We're not injecting into the Brushy Canyon as far as this Application is concerned.

Q. Right. Now, how can you be sure that the injection volumes won't escape the Bone Springs vertically?

A. Well, because the -- I've done an analysis of the geologic information and the formation characteristics information, waters in the Bone Spring and the overlying units, and I feel confident that based on those geologic units it will stay within the Bone Spring.

Q. Now by that same token, how can you be sure that the injection volumes won't escape the southwest quarter horizontally?

A. I didn't attempt to make that evaluation.

Q. Let's turn to your seismic analysis, Mr. Gutiérrez, your Exhibit 4, and if you will look at the second paragraph there, I want to clarify something. It says, In summary, the final location which Geolex recommends for the AGI well test is in the northeast southeast quarter of Section 30. Is that a mistake?

A. No, it's in the northeast quarter of the southeast quarter of Section 30.

Q. And the final location of this well is where?

A. It's actually -- I mean, to us, the reason why we put it up in that northeast quarter is because we felt that maximized the thickness of the Bone Spring, but we're comfortable with the location anywhere in that section. And since -- and so what we tried to do was do a standard location, which was the location that was proposed in the C-108.

Q. All right. Then in the fourth paragraph you indicate that the lower Bone Spring is often called the Wolfcamp by local operators.

A. That's right.

Q. Is so-called Wolfcamp Bone-Wolfcamp distinct from the Abo in the area?

A. Yes.

Q. How so?

A. It's a Basin equivalent.

Q. And is that shown on your cross-section?

A. It is indeed.

Q. And continuing on to page 2 of your Exhibit 4, I'll summarize. Tell me if I misstate, but the lower Bone Spring tends to thicken along down to Basin faults, so it's thickening to the north and west; is that correct?

A. Yes.

Q. And with respect to the faulting in the vicinity of Section 30, you concluded that the faulting is not extensive enough to result in any sort of compartmentalization within the Bone Springs in that area. Accurate?

A. I'm not sure I understand your question.

Q. Well, let me just read what you said. The next to last paragraph says, "The faults terminate a little above the...Bone Spring formation; so the throws within the Lower Bone Spring are probably insufficient to provide much fault-induced compartmentalization within the detrital unit. For these reasons, we believe that the lateral permeability within the Lower Bone Spring is carried across the faults..."

A. That's right.

Q. And that continues to be your opinion?

A. That's right.

Q. Mr. Gutiérrez, in your view as a geologist, are there any other potential drilling targets for hydrocarbon recovery in Section 30?

A. Well, not that haven't really been evaluated at this point. I guess theoretically the Ellenburger could be a possibility, but it hasn't been productive anywhere in that area. And so the answer in short is no, I don't believe there are other targets that haven't been evaluated.

Q. All right. Let's look at your Exhibit 15, and I believe it's slide Exhibit 8. I don't know what page that is. That's your geologic overview.

A. Yeah.

Q. You're showing that the Bone Springs in the area interfingers with the Abo and overlays the Wolfcamp, as you've portrayed it there. And isn't it true that all the penetrations in the area to date have all been vertical drills?

A. Well, they're intended to be vertical. Whether a well is ultimately vertical or not is a different question.

Q. All right, you don't see any purposeful horizontal drills in the area, do you?

A. That is correct.

Q. Okay. Isn't it possible that the Wolfcamp here offers economic targets for some horizontal drills?

A. No, not in my opinion.

Q. Okay. That's simply a function of economics, isn't it?

A. No, it's a function of the fact that it's below the oil-water interface. It produces a tremendous amount of saltwater.

Q. But really, there's nothing preventing someone from penetrating the storage zone in the future, is there?

A. Well, I mean certainly -- unless they were to do it illegally, they'd have to get a permit to drill.

Q. Presuming they have a permit and a lease and a right to drill, isn't it possible that the gas storage zone could be penetrated by a new drill?

MR. CARR: You know, I think we're just getting pretty far into the realm of hypothetical. I mean, there's no foundation for this.

CHAIRMAN FESMIRE: Well from what I understand, you're trying to ask, is there a potential for the disposal zone to be penetrated by deeper exploratory type --

MR. HALL: For any reason.

CHAIRMAN FESMIRE: Okay, I think that's a legitimate question.

Q. (By Mr. Hall) Can you answer that?

A. I think it's far-fetched. I don't believe that -- There's been no indication, and the existing penetrations that go below the lower Bone Spring-Wolfcamp in that area, which there are, including the Conoco State Number 1 well, have offered absolutely no encouragement to drill below there.

Q. And when were those wells drilled?

A. Well, the Conoco State Number 1 -- I'd have to go back and take -- if you'll give me a moment, I'll tell you exactly when that one was drilled, but I believe it was in the late 1990s, early 2000.

Q. It was a different economic environment, would you agree?

A. Not for saltwater.

(Laughter)

Q. For oil and gas, how about?

A. Yeah. Unfortunately, there's no shows of oil and gas in that zone.

Q. If in the possibility that there are new wells to be drilled in the area -- You cannot preclude that can you, absolutely?

A. No.

Q. -- are we creating an additional risk of corrosion to casing strings that was not present before, for those new drills?

A. Only if they were to penetrate the injection zone within the area where that gas had migrated.

Q. Is there any way that the operator of a future well would be placed on notice that he might be penetrating an acid gas storage zone?

A. I would imagine that that might happen through the permitting process of a proposed test to a deeper zone in that area. After all, it does have to go through the Oil Conservation Division, who would be aware that that zone is being used for injection.

Q. How would the permitting process trigger that notification?

A. I don't know. I would imagine that in the evaluation of the drilling permit for that -- for a test that would go below that zone, that the Division would be able to be aware of that fact, and I would think it might be a relevant fact.

Q. Do you believe that special drilling casing and cementing programs should be required for any new drills in the area that might penetrate the storage zone?

A. I don't know, I think that would be up to the Division.

Q. What do you think?

A. Well, I can't see why anyone would penetrate that zone in the area that we anticipate would be influenced by the gas, because it's already been tested and it's shown to be productive of only sulfur saltwater.

Q. I understand that. Presume for me, if you will, that there were to be a new penetration. Do you think there ought to be a drilling, casing and cementing program where the wells penetrated the storage zone?

A. I think it would be appropriate to have an H_2S contingency plan when they were drilling such a well.

Q. But otherwise, they could utilize an orthodox casing and cementing program without any special precautions? Is that your view?

A. Well, when they -- It's a different thing, if they were actually going to complete a well through that zone.

Q. Let me ask you something, Mr. Gutiérrez. If you would turn to our exhibit notebook right there in front of you --

A. Let's see --

Q. It's right there. It's by your left hand, under your left --

A. This one?

Q. Right there, on the bottom.

A. This one?

Q. Yes.

A. No, this is the --

Q. Oh, I'm sorry.

A. I don't think I've got it here.

Great, thank you.

Q. Now, the location for the injection well is proposed at 1980 from the south and west lines of Section 30. If you'll look at our Exhibit 5, it shows a pre-existing wellbore there. Do you see that?

A. I may be -- Yes, I do see it, uh-huh.

Q. In your C-108 Application, under your Section VII [*sic*] tab, could you help me locate the well file for that particular well, that old well. Under which tab is that one?

A. Okay, and are we talking about API Number 3002505519?

Q. Yes, sir.

A. Okay. It's going to probably take me a minute to go through these and find it.

Q. Let me shortcut it a little bit. Look under your Tab D. That's for the Gordon Cone Superior State Well Number 1. The miscellaneous report doesn't show a surface location, but if you refer back to the first page of your exhibit under Tab VII, you look at the Gordon Cone Superior State, it's the fourth well down there. Do you see that? It's at a location 1980 from the south and west line.

A. Could you tell me what page you're looking at?

Q. The very first page under that tab.

A. Under Tab VII?

Q. VI, I'm sorry. It looks like this.

A. Oh, the tabular information.

Q. Yes.

A. Okay, yeah. I was already there.

Q. Leave that there. And then once you have that, that locates the well --

A. Yeah.

Q. -- and that's the well at your proposed location, correct?

A. That's right.

Q. And then you turn to Tab D. Is this all the well file information we have on that well?

A. Yeah, it was only a depth of 709 feet. That's the total depth for that well.

Q. And have you taken an independent investigation to see if, in fact, that well is plugged?

A. Well, based on the records that were available from the Oil Conservation Division, that well is plugged and abandoned. And furthermore, I would say it's irrelevant. It's only 709 feet deep.

Q. But that's what you're relying on, the old OCD records, correct?

A. I am.

Q. Let's turn to your Exhibit 5 --

A. By the way, behind -- just to shed a little more light on that, if you want to look behind Tab D there, you've got the plugging report on the well and it shows, Filled hole from 810 feet, which is what it shows here as the TD, with mud to 250 feet. Bridged and set cement plug, 25 sacks at 250 feet to protect surface water. Filled remaining hole with mud to surface. Cemented regulation marker with 12 sacks of cement in the top of the hole.

Q. All right, I see that. So you're satisfied that all the wells within your area of review have been properly plugged and abandoned?

A. I am, based on the records I've reviewed.

Q. Again, let's turn to your Exhibit 5 -- it's the Lea County Regional Water Plan -- and if you would turn in that exhibit to page 6-18, let me ask you if you agree with the statement in the plan, that first paragraph. It says, The mechanisms responsible for areas still experiencing decreasing water quality (since the mid-1980's) are not -- are unknown. It may be possible that water migrating from former unlined brine disposal pits is still occurring.

A. I'm sorry, I don't know where you're reading that. I'm --

Q. The first paragraph there, midway.

CHAIRMAN FESMIRE: Mr. Hall, of what?

MR. HALL: It's Exhibit 5, it's the Lea County Water Plan, and it's page 6-18.

THE WITNESS: You mean the one that starts with, Improved water quality from the mid-1980s to the present is probably attributed to changes in oilfield practices related to brine water? That's the paragraph you're talking about?

Q. (By Mr. Hall) Correct, if you'll refer down, the sentence begins, The mechanisms responsible for areas still experiencing decreasing water quality (since the mid-

1980's) are unknown. It may be possible that water migrating from former unlined brine disposal pits is still occurring. Another possibility is that saline water from deeper aquifers is able to migrate into the ground-water through poorly completed or failing oil field wells.

Do you agree?

A. That's a general statement that you could make about any oilfield there, anywhere in the United States, or in the world for that matter.

Q. So you agree?

A. So I'd say yeah, it's certainly a possibility.

Q. On your C-108, Mr. Gutiérrez, you're asked to provide water samples from water wells within two miles, and I understand you utilize samples from wells located in Section -- I'm sorry, Section 21, more than two miles away; is that right?

A. That's right.

Q. Why didn't you use any water samples within the two-mile area of review?

A. We couldn't find any samples of those wells in any of the State Engineer's files which we searched for that information. Furthermore, we felt that the information from the wells where we did have sample data from -- in combination with the information provided in the exhibit that you were just referencing gave a good sense of the water quality in the Ogallala. So -- and I remind you that we're going to be completing this well with surface casing cemented down to 530 feet, a good 300 feet below the Ogallala.

Q. Did anyone from Geolex actually go out on site to see if there were any closer water wells in Section 21?

A. We searched the State Engineer records -- we've been on the site, we didn't go out there looking for wells specifically -- we searched the State Engineer records, and we did find four wells that are detailed there in the Application.

Q. Let's look at Duke Exhibit Number 2, if you could take that in front of you, please. And that's the September 16, 2005, letter from Mr. Jones of the Division, addressed to you. And if you'll turn to the second page of that, first paragraph, it says, The surface lessee should also be notified.

Why wasn't that done?

A. Very simply, I spoke to Mr. Jones, after I got this letter, about the notice procedures specifically. And I asked him, you know, about these notices. And he said, Well, I want to make clear that these are recommendations, that you don't have to do these notices.

And furthermore, when we talked to the -- and it shows the surface owner to be the New Mexico State Land

Office, and when we talked to the Land Office they said that, you know, they were clearly on notice. We were negotiating with them to try and get an easement, and so we did notify the surface owner, and the Land Office said that if they had a grazing lease that would be impacted, that they would take care of that, you know, dealing with the grazing lessee when they were going through their process of evaluating our right-of-way application.

Q. So do you know what form of notice the State Land Office may have provided to the surface lessee?

A. I don't, I don't know at all. I will note that we did indeed also provide notice in the City of Hobbs newspaper of general circulation in this area.

Q. And is that contained within your exhibits?

A. It is, as a matter of fact, I think that it was in part of the original submission of the Application, the C-108 Application. The legal notice is actually the --

Q. It's the very last page, isn't it?

A. Well, it's actually -- yeah, it was on the last page there. And then subsequent to the submission of the C-108, when we received the actual -- you know, it takes a few weeks to get the proof of notice back from the newspaper. We submitted that to the Oil Conservation Division.

Q. Well, let's look at the very last page of your

C-108 legal notice. Is there any indication in there, the newspaper advertisement, that indicates the project will be handling hydrogen sulfide and carbon dioxide?

A. Yes.

Q. Where?

A. "Acid gas". That's the definition of acid gas. And we're in an area that has probably been familiar with oil and gas production and operations for 80 years, and so I think acid gas is a common term that is understood to be sour gas and contains hydrogen sulfide and CO_2.

Q. So you presume that by using the phrase "acid gas", that lay persons in the Hobbs area would understand we were talking about hydrogen sulfide?

A. Yes.

Q. Mr. Gutiérrez, you were on the Water Quality Control Commission for a number of years, weren't you?

A. I was.

Q. And in fact, you were chairman of the Environmental Improvement Bureau for a period, weren't you?

A. No, not of the Bureau. I was the chairman of the Environmental Improvement Board, yes, for quite a number of years.

Q. Yeah. And so by virtue of that background you're familiar with the Environment Department's handling of hazardous waste disposal?

A. Yes. As a matter of fact, under -- I was the hearing officer for a couple of the updates of those hazardous waste regulations.

Q. And do you understand that the authority for the disposition of hazardous wastes underground was delegated to this agency?

A. For -- The delegation as I understood it at the time -- and it's been quite a few years since I was the chair of the Environmental Improvement Board -- was for -- wastes related to oil and gas production and processing activities were delegated to the Oil Conservation Division.

Q. And so you understand that Class IV wells are simply not permitted; is that correct?

A. Yeah.

Q. And why is that?

A. Well, I don't recall what the specific reasons were, but Class -- I'd have to go back and look at the classifications. I do know Class IV wells are not permitted.

Q. And for the record, let's define what Class IV wells were. Do you know?

A. I can't recall.

Q. Weren't they for the disposal of hazardous wastes and drinking water supplies with 10,000 TDS or less?

A. That sounds right. I don't really specifically recall what all the classes were. But yes, clearly you cannot use a drinking water reservoir to dispose of hazardous waste.

Q. And so under the OCD's regulatory scheme, what provision has filled that gap? Under what provision can an operator make application for the underground disposal of hazardous waste?

A. Well, the underground disposal of hazardous waste is regulated by the State's equivalent of the RCRA regulations. However, what we're talking about in this case is not a RCRA-regulated waste.

Q. Let's turn to our Exhibit 12, if you would, Opponent's Exhibit 12. Since we spoke of the delegation of authority to the Oil Conservation Division, do you recognize this as a publication from the OCD's Environmental Handbook that describes Oilfield E&P Waste Regulations?

A. I mean, I see that. I haven't seen this before, that I can recall.

Q. And is the only applicable provision that you're aware under item number 6, Saltwater disposal, Class II wells?

A. My understanding is that it has been the Division's practice, and continues to be the Division's practice, to use the C-108 application process for disposal of fluids associated with production or treatment of oil- and gas-related wastes, including saltwater and acid gas using Class II regs like the C-108 process.

Q. Let's look at our Exhibit 13, if you would please. Do you recognize that as a brochure from the OCD's Underground Injection Control Program, Class II Well Facts?

A. That's what it says.

Q. If you turn to the third page, the very top has "Injection Well Classification"?

A. Yes.

Q. Again, it makes reference to Class II. This is the category you utilized in filing the C-108 with the Division for this Application, correct?

A. Uh-huh, yes.

Q. And then referring to your Exhibit 3, page 3 -- just tell you what it says; you can tell me if I'm wrong -- but you indicated to the Division, to Mr. Jones, that "None of the injected fluids are subject to regulation under Subtitle C of RCRA", correct?

A. That's correct, No wastes subject to Subtitle C will be disposed of in the proposed well.

Q. And tell us what Subtitle C is.

A. Subtitle C is the portion of RCRA that characterizes what is a hazardous waste.

Q. But you recognize that hydrogen sulfide is a hazardous waste, nevertheless, correct?

A. I recognize that wastes associated with production of oil and gas are exempt by statute under RCRA, so that there are substances, hazardous substances, which are included in saltwater, for example, that are RCRA hazardous substances, if they were, in and of themselves, handled separately from the production of oil or gas. Benzene is probably the best example. And those -- when they are in the context of oil and gas operations or, in fact, even underground storage tank operations, they're exempt from RCRA regulation as a hazardous waste.

Q. All right. If you'll turn to our Exhibit 11, please, sir, and this is the EPA List of Lists, Consolidated List of Chemicals subject to the Emergency Planning and Community Right-to-Know Act. Are you familiar with that?

A. I am.

MR. CARR: I'm going to object. It seems to me that we're now talking about a different statute. It has no bearing on the issue before this body. We're talking about RCRA-exempt wastes which are, by statute, not hazardous and therefore are delegated appropriately to you for injection in a Class II well which, by your own definition, are wells used to dispose of fluids associated with the production of oil and natural gas. And while we've been working around this issue, it still seems to me we have now gotten into an unrelated statute that is not relevant, and it has no bearing on this hearing.

CHAIRMAN FESMIRE: Mr. Hall, I have a tendency to agree. Are you arguing that hydrogen sulfide and CO_2 cannot be injected into Class II wells? Is that where you're attempting to go with this?

MR. HALL: Mr. Chairman, what I'm trying to prove, if I may follow up with the witness, is that in my view the Division's procedures for handling the underground disposition of hazardous wastes like hydrogen sulfide, carbon dioxide as well, ought to be subject to a little bit more comprehensive scrutiny than they are presently.

I believe I heard Mr. Carr just indicate that hydrogen sulfide is not on the RCRA list of hazardous wastes. That's not true.

CHAIRMAN FESMIRE: Well, I don't think that is true, but I think what is true is that if it's generated during oil and gas operations, during oil and gas production or treating operations, that it's not a -- while it may be characteristically hazardous, it is not a hazardous substance under the law, under that portion of the law, the law that we're here to examine today.

If you're arguing that we need to change the law, this is not the place to do that.

If you're arguing that this is a hazardous waste and shouldn't be injected in a Class II well, this is not the place to do that.

MR. HALL: What I'm arguing, Mr. Chairman, is that it is a hazardous waste, it is on the RCRA list, it's on the RCRA "U" list, and I think consequently it triggers the broader notification requirements under the community right to know -- That's my point.

CHAIRMAN FESMIRE: If you're going to make that point, you'd better make it in a hurry, because we've gone a long way without getting very far here.

MR. HALL: I'm going to move on, Mr. Chairman.

CHAIRMAN FESMIRE: Okay, thank you.

Q. (By Mr. Hall) Mr. Gutiérrez, let's turn back to your Exhibit 15, and I'd like to discuss with you this plot you've created. It's titled "Position of Injected Acid Gas Front with Time".

A. Yes.

Q. If you would identify that, please, and explain what it's intended to show.

A. Yeah, it's a -- basically a crude calculation of the potential maximum distance of the front edge from the injection well of the gas front in the reservoir, based on the characteristics of the reservoir as we could determine them from the available data.

Q. And the reservoir you're speaking of, again, is the lower Bone Springs --

A. Correct.

Q. Now, let's see if I understand what you're showing correctly. Your well is located 660 feet from the northern boundary of your lease, correct?

A. That's correct.

Q. And as I understand it, what this shows is how fast and how far the acid gas front will extend over time, correct?

A. Like I said, it is a crude calculation of that based on the available data at the present time.

Q. And did you assume that the acid gas would be injected at the average rate of 2200 barrels per day?

A. That's correct.

Q. And again, what were your assumptions regarding the permeability of the Bone Springs here?

A. The permeability and porosity algorithm that we used was essentially an average of what we saw in the wells that were closest to the proposed location, primarily the Conoco State Number 1 well.

Q. All right. And is the flow from the wellbore radial or directional?

A. It is radial to a certain extent, but the geologic characteristics of the reservoir laterally, as you get farther away from the well, will ultimately determine what the shape of that would be.

Q. It's going to follow the thickness, isn't it?

A. It's going to follow the what?

Q. The thickness?

A. No, it's going to be spreading laterally in every direction unless there are variations in porosity and permeability that would then tend to distort that radial pattern.

The typical pattern that is assumed by most reservoir models is that it will go in a radial direction.

Q. All right, let's talk about this a little bit more. If you look at the distance axis, again your well is approximately 660 feet from your northern lease line, correct?

A. Yes -- yes.

Q. And so if I understand this correctly, your plot shows approximately when the acid gas front will cross your lease line, and would you agree that that occurs in approximately 2007?

A. Based on this plot, roughly, yes.

Q. And then at the end of the plot, out to 2025, if I'm reading this correctly, the acid gas front will extend approximately 1900 feet from the wellbore?

A. It might.

Q. And that's approximately 1240 feet across your lease line, correct?

A. Yes.

Q. And again, you don't know --

A. If it were to extend in that direction.

Q. All right. You've previously testified there's no real compartmentalization resulting from the faulting in this area, and you expect penetration of the flow to be extensive, don't you?

A. I expect it to be sufficient to take the volume of gas that we said.

But the faults are not the only things which would control the migration of that within the lower Bone Spring. The lower Bone Spring itself has got variations in porosity and permeability, and those are really what are going to govern what that pattern of dispersal of the gas in that reservoir would look like.

Q. Doesn't this exhibit show that the acid gas volumes will not be contained within the southwest quarter of Section 30?

A. They may not be.

MR. HALL: I have nothing further, Mr. Chairman.

CHAIRMAN FESMIRE: Ms. O'Connor?

MS. O'CONNOR: Yes, thank you.

CHAIRMAN FESMIRE: You surprised her.

EXAMINATION

BY MS. O'CONNOR:

Q. Mr. Gutiérrez, concerning the Bone Spring coring, do you know if -- or could you explain whether this will be sidewall coring?

A. Probably sidewall coring, yeah.

Q. Okay. If it's -- Will sidewall coring take it into the Brushy Canyon as well?

A. I don't think so. I think we're going to just do a drill stem test in there first. I think -- I don't know, it will depend on what it costs and how much my client wants to really evaluate that zone, ultimately. We may do it, we may not.

Q. Let's talk a little bit about your logging program. Could you elaborate on what the logging program will consist of?

A. Yeah, I think that the logs that were recommended by the Division in here were roughly the same kinds of logs that we were looking at. I don't know whether -- I haven't looked at the specific log suite. We certainly would do resistivity, neutron density, porosity logs. We probably would do some additional -- there's a -- depending on what logging contractor you use, they have different logging suites. But I mean, clearly we want to log that with as many relevant logs as we can, because we want to be certain that we have as much information as possible to develop a reservoir model.

Now one of the considerations here was a dipole sonic log or formation microscanner log or their equivalents. I envision that we probably will do that kind of logging as well. We may also use a dipmeter type of tool to look at the attitude of the formation. But we're going to run a pretty thorough log suite there, in addition to the coring.

Q. Are you referring to one of your exhibits when you were answering this?

A. No, I was referring to your -- I was referring to your recommended logging suite.

MS. O'CONNOR: Thank you very much.

CHAIRMAN FESMIRE: Mr. Carr, redirect?

MR. CARR: No redirect.

CHAIRMAN FESMIRE: Okay. Mr. Gutiérrez, thank you very much. I guess --

MR. CARR: That concludes our direct presentation in this case.

CHAIRMAN FESMIRE: Okay. Would you all like to take a 10-minute break and come back here at 3:10?

MR. HALL: Let's do that.

CHAIRMAN FESMIRE: Okay, and -- Oh, whoa, whoa, Mr. Gutiérrez, I am sorry. I have run over the Commission again. Commissioner Bailey apparently has --

THE WITNESS: I'm sorry, Commissioner.

CHAIRMAN FESMIRE: -- questions. I apologize.

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Would you agree that it's normal industry practice to frac a well and acidize it in order to enhance production or to enhance permeability for disposal?

A. In certain formations, that would be considered appropriate. It's usually only done if it is necessary.

Q. And because the Bone Springs is a carbonate, would you expect that -- Well, let me put it this way: What impact would you see with the injection of acid gas mixing with formation water? What impact would that have on the reservoir rock itself?

A. I think that, you know, as you brought up in your question to Mr. Root earlier, we could have some acid formation, especially near the wellbore. And then typically what that could do is to basically etch or dissolve portions of the carbonate. Although it's a fairly dolomitized carbonate, so it shouldn't be -- you know, it's not like just a limestone. So I think there could be some etching and some effect on the formation.

Q. How about the upper and lower formations, above and below the injection zone? My concern here is, how do you keep the injected materials from migrating above or below the injection interval?

A. Well, I mean, the geologic information that we've evaluated and the stratigraphy and looking at the formation fluids indicates to us that the connection between the zones below and above the Bone Spring are relatively unaffected.

I mean, they have distinct characteristics of formation fluids themselves, and so there doesn't appear to be a tremendous amount of natural mixing in those zones. And given also the flowing pressures and the shut-in pressures that we observed in the wells that did penetrate that zone, it seems to us that on a macro scale, you know, while there may be some small invasion into the zones above and below it, we anticipate it wouldn't be more than on the order of a few inches or feet at most, because the porosity and permeability of those units is significantly lower than the Bone Spring. That's why we selected the Bone Spring in the first place.

Q. You said that you would conduct additional steps above the OCD recommendations. What specifically are you talking about?

A. The coring, for example, sidewall coring of the zone, and also we may do some additional logs to the logs that the OCD has recommended here, to evaluate that zone.

And when we do the step test, it's our intent to do a much more detailed reservoir model based on the results of the coring analysis and of the logs.

COMMISSIONER BAILEY: That's good.

CHAIRMAN FESMIRE: Commissioner Olson, I won't forget you.

COMMISSIONER OLSON: No questions.

CHAIRMAN FESMIRE: I apologize, ma'am.

I have no questions of this witness.

This time I really mean it. Thank you --

THE WITNESS: Good.

CHAIRMAN FESMIRE: -- for your testimony.

And we'll come back here at 20 after 3:00 and reconvene. Thank you.

(Thereupon, a recess was taken at 3:11 p.m.)

(The following proceedings had at 3:23 p.m.)

CHAIRMAN FESMIRE: Let's go back on the record. Let the record reflect that it's 3:20 on March 13th, and we're going back on the record, and I believe Mr. Hall is going to call his first witness.

MR. HALL: At this time, Mr. Chairman, we would call Mr. S.G. Cobb to the stand.

CHAIRMAN FESMIRE: Mr. Cobb, you've been previously sworn?

MR. COBB: Yes.

S.G. COBB,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. HALL:

Q. For the record, please state your name.

A. I'm S.G. Cobb.

Q. Mr. Cobb, where do you live?

A. I live in Hobbs, New Mexico.

Q. And what do you do for a living?

A. Beg your pardon?

Q. What do you do for a living?

A. That's a good question.

(Laughter)

A. I'm a realtor, a rancher and manufacturer.

Q. Could you explain to the Commissioners who the partners are in AC Ranch Partnership?

A. Unless someone's changed it, my partner was Ben Alexander, and he gave that to his grandchildren some years ago. And his son-in-law, Beach Snyder, represents the grandchildren.

Q. I see. And does AC Ranch Partnership own the ranch unit upon which Duke is proposing to locate its injection well?

A. Yes, it is, leased land, yes, sir.

Q. You're familiar with your own ranch, I take it?
A. Yes, sir.
Q. How long have you had that ranch?
A. 1976, if I recall. I'll have to look -- I believe it's 1976.
Q. All right. Let me ask you a little bit more about your background. In addition to being a rancher, what else have you done in your lifetime?
A. Well, gentlemen and ladies, I'm old as the hills. I'm 83 years old. I was a -- I was raised a rancher in Haskell County, Texas, and still have a ranch there. And part of it I bought before I moved out here. Now you're going to have to understand. And I came out here and went into the food business, had a USDA plant from 1940 -- about 45 years ago, RMS Foods. We now manufacture for Boca Foods under Kraft Foods.
And prior to that I was -- I've been an appraiser for the Federal Land Bank of Houston, ran a -- National Farm Loan Association in Seymour, Texas, rancher there prior to, had a little experience in the oil business. And in moving to Hobbs, I sold food under USD throughout west Texas and New Mexico, furnished a lot of -- this is a little bit -- you need to know who I am and what I do -- and we served Dairy Queens and so forth in Texas, shipped meat to Japan.

And I've been a land developer in Hobbs. Nearly all the land around Hobbs, I've owned a portion of it, both north and south. And that's what I like to do, and I'm still doing it, own land in Lubbock, Texas, developer over there. I'm very busy and enjoying my life, and that's about it.

Q. Mr. Cobb, are you familiar with land values in the Hobbs area and in the vicinity of your ranch?

A. Well, yes, we priced our ranch in the meantime, and it's worth a lot of money because of the east side of it, part of the deeded land and close to our -- part of the state lease land and next to our deeded land, we join the city limits of Hobbs. And if you'll watch closely, you'll find that they burned it up January the 1st. And so I'm very familiar with ranch land, land north of Hobbs, subdivision developments, et cetera.

Q. Mr. Cobb, if you would please open the exhibit notebook --

A. Okay.

Q. -- and turn under Tab 1 --

A. All right.

Q. -- do you have that map in front of you there?

A. Yes, sir.

Q. If you will refer to the land indicated in green where the well is proposed to be located --

A. Okay.

Q. -- let me ask you, does AC Ranch own that state grazing lease?

A. AC Ranch leases that grazing land.

Q. All right. Now, immediately to the north of your grazing lease, that land owned in blue, who owns that?

A. I don't believe this is -- I can't quite identify that. I've got a better map -- Is this supposed to be a map of our ranch?

Q. Well, let's turn to Exhibit 2.

A. All right, okay. I mean -- Yeah, okay, now you're --

Q. What is Exhibit 2?

A. (No response)

Q. Mr. Cobb, does Exhibit 2 show the boundaries of your ranch?

A. Yes, it does. The marks around, that's the exhibits [*sic*] of the AC ranch -- exhibits the AC Ranch.

Q. And if you look in the lower left-hand corner there, you have that backward-L-shaped parcel.

A. Yes.

Q. That's part of your ranch, correct?

A. Yes.

Q. Do you know who owns the land to the north there?

A. Yes, sir, a gentleman in the office.

Q. What's his name?

A. Randy, Randy Smith.

Q. Thank you. If you would, please, would you briefly summarize for the Commissioners your ranch unit and describe the improvements you have located on the ranch?

A. When we bought the ranch it was -- nearly all the fences were down, or they were three-wire, four-wire, the posts were not in good shape. And Mr. Alexander and I -- I being a rancher all my life, and he wanted to be a rancher, and we decided we'd just make that a nice ranch adjoining, and if you'll look, that road comes -- Bender Boulevard, which is a major boulevard of Hobbs, and we decided to rebuild all the fences and divide the pastures to make it a better ranch, because we could take care of the grass better. And we did that, we drilled some new windmills, built new fences, built corrals, put in all new tanks, and we -- with the Land Commission, they had areas that we could spend money to make the grassland better and so forth, and we never overgrazed the land. And every time it got dry -- and you know it happens in this country -- we shift our cattle where it was wet. And we did that twice so we would damage the ranch.

And when this fire came through, if you'll look at it closely, they couldn't stop it because the grass was so good. That was our understanding. So we burned it out and we planned to rebuild it as soon as we -- This was in January, and they were -- I believe we had -- it seemed like it was 269 head of -- on there. I believe they were heifers, if I remember right. And now it's not usable as a ranch because of that, and -- The reason I'm saying that, I'm a rancher at heart, and that's what I do, and my ranch -- I'm building all new fences in Texas, and that's what I want to do, is make a ranch look good and raise good cattle.

Q. So up until the time of the fire the first part of this year, was the ranch continually used for grazing purposes?

A. It was used for grazing purposes unless it was too dry to leave them there.

Q. All right. Tell us about the water improvements you have on the ranch.

A. Every windmill -- seems like there's seven or eight, and we've got one or two -- one, I guess, with a pump, electric pump, and the rest of them are still windmills. And we built all new -- I think it's 20 or 30 feet big, circular tanks on concrete everywhere there's a windmill. And we improved every fence, and we still do it, and we will just as -- and you can't get any labor, by the way, today to build a fence. That's not your problem.

Q. If you would turn to Exhibit 3, Mr. Cobb, what is

Exhibit 3?

A. On, this is the path of the fire that went through there.

Q. Now is this an aerial photograph of your ranch?

A. Yes, we obtained that from the City, if I recall.

Q. And is your ranch indicated in orange?

A. In orange, yes, sir.

Q. And the hached area again, is that the area of the fire earlier?

A. Yes. There's a little bit on the south side that's not in the area of the fire. Now, wait a minute, is that -- yeah, that's on the south side.

Q. Does Exhibit 3 show the location of the Xcel Maddox plant?

A. Yes, it does. It's right -- nearly due north of the well location. I mean due -- excuse me, due east of the well location. West, I'll get it right in a minute. I have an allergy, and I hope it's not you gentlemen and ladies that's created what I've been sneezing.

Q. Let me ask you, Mr. Cobb --

A. Okay.

Q. -- are you opposed to Duke's facility on your ranch?

A. Opposed to what?

Q. The location of Duke's injection well facility on your ranch?

A. Yes, I am.

Q. Why?

A. There's two reasons. It's in a position, if they put it in there and there's any leakage, it can leak in the wind direction that I've always thought pushes -- if it's a gas -- poisonous gas, it pushes it where the main location of Hobbs, New Mexico. It just goes through the main location of Hobbs, New Mexico.

The other reason that I -- just -- and this is the other reason. I had plans -- I'm a land developer, remember that, and I've had plans since some things have happened in Hobbs to break up some of the deeded land, and because of the need in the -- generally speaking, the land in Hobbs, the higher price goes to the north. But the land out there in one-acre or 10-acre tracts or up to 20- or 30-acre tracts brings up to $10,000 an acre, and if you're going to put --

And there's another problem, there's -- if you go toward Lovington there's a lot of dairies out there. And a lot of people -- and may I say this, if you're dairy people, they don't like the smell of dairy around where they are. And we're in an area out there that you don't have to do that. And we have inquiries about selling some of our land. And as I said, I put in subdivisions, and

I've used five-acre tracts and so forth, and we've looked at that. But since this has come up, we've abandoned that until this is settled.

Q. Let's look at Exhibit 4 in the notebook. Can you identify that for the Commission, please?

A. Yes, that was made -- I believe Beach Snyder, my partner in this, to identify where they were going to put this well.

Q. Were you present when these pictures were taken?

A. No, I've got a different set. He lives in Austin a lot of the time, and he came at a different time and I've got a different set of pictures. I didn't take this specifically, I know where it was, yes.

Q. Where is it?

A. Well, it's about -- to identify it, Randy Smith, it's about 300 yards or so from Randy Smith's land to the north of it.

Q. All right. If you look at the lower right-hand corner, do you understand -- what is that -- what does that stake there?

A. You mean the lower left-hand corner?

Q. Lower right-hand corner. What's that stake?

A. Huh?

Q. The lower right-hand corner.

A. Hm, well -- oh, well, yeah, it's -- northwest tract, it says on it, and I don't -- That's all I know about it. And I was told that's where -- that Duke Energy was preparing to drill this well.

Q. All right. In the lower left-hand corner now --

A. Yeah, okay.

Q. -- what is that?

A. Well, that's an abandoned well, is what I was told. And I've seen that out there, but I never did test it out or anything. And it looks like a plugged, abandoned well to me.

Q. All right. Let me ask you, Mr. Cobb, did AC Ranch or you ever receive notice of the project from Duke Energy?

A. No.

Q. How did you find out that the disposal of hazardous materials was being proposed?

MR. CARR: I object. I mean, we're talking about, as we know, a RCRA-exempt exploration and production waste. That isn't, by definition under statute, hazardous.

CHAIRMAN FESMIRE: Yeah, Mr. Carr, I think everybody's aware of that. I think Mr. Hall is making the point that he's made, but that's his prerogative.

Q. (By Mr. Hall) Mr. Cobb, how did you find out that the disposal of hazardous materials was being proposed?

A. From a neighbor, Randy Smith. He told me, and the first I knew about it, and that was -- I don't know, two or three weeks ago. He came by and said, Did you know they're drilling a well on your land?

And I said no, and he said -- I said, Where is it?

And he said it's right south of me.

And I said how close? And so forth. And of course we've been neighbors a long time, and he called me on the phone and then he came by. That's how I learned about it.

Q. Were you ever aware that the project was advertised in the Hobbs newspaper?

A. No, sir.

Q. Did Duke ever ask you for permission to use your ranch?

A. Not to my knowledge.

Q. Did Duke ever try to negotiate with AC Ranch Partnership in any way?

A. Not to my knowledge.

Q. In your opinion, Mr. Cobb, will the project adversely affect the value of your property?

A. May I expound on that just a little? He mentioned poisonous gas in Hobbs. And since this has happened, I talked to a fellow yesterday -- he worked for a major oil company, and he said, You know, when I learned about -- he lived down in Texas, and when he learned about this poisonous gas he said, you know, I refused to move out there for a while. I know how poisonous it is, and I don't want to be anywhere around it.

And that's my understanding, and if anybody -- if they put a riser out there and somebody says it's poisonous gas, I don't believe anybody will want it. I'm talking about near around it.

Now that's my opinion. You asked for my opinion.

Q. Do you believe that your property values will be adversely affected?

A. Very muchly.

Q. In your view, does the project pose a safety risk?

MR. CARR: I'm going to object. I don't think -- We haven't qualified this man to render an opinion on what constitutes a safety risk. He can say that he lives there and that he's concerned, but unless he's qualified as an expert and can discuss safety issues, I don't think he should be allowed to render that opinion.

CHAIRMAN FESMIRE: All right, I'll sustain that objection.

THE WITNESS: Can I answer that?

MR. HALL: That's all right, Mr. Cobb.

That concludes my direct of Mr. Cobb. I'd move the admission of Exhibits 1 through 4.

CHAIRMAN FESMIRE: Any objection?

MR. CARR: No objection.

CHAIRMAN FESMIRE: Ms. O'Connor?

MS. O'CONNOR: No objection.

CHAIRMAN FESMIRE: Exhibits 1 through 4 are admitted.

Mr. Carr, did you have a cross-examination?

MR. CARR: I have just a few.

CROSS-EXAMINATION

BY MR. CARR:

Q. Mr. Cobb, if we go to Exhibit 2 in the book, tract on which the well is proposed.

A. There it is, okay.

Q. And this is a map of your ranch?

A. Yes, sir.

Q. If we look down at the tract on which the well is proposed --

A. Uh-huh.

Q. -- if I understand it, that is a State of New Mexico grazing lease that you hold on that property --

A. Yes, it is.

Q. -- is that right?

A. Yes, sir.

Q. Do you own any of the minerals --
A. No, sir.
Q. -- under that property?
Now, that's the only tract on the first page of the exhibit that it tells me what's state minerals, what's fee. If we look at the rest of your ranch, do you own that property in fee, or do you own grazing leases on that property?
A. Well, I own part of it in fee and part of it in grazing leases.
Q. Some of the tracts are shaded dark.
A. That's right.
Q. What are those?
A. They're owned in fee.
Q. And so the rest of the acreage inside that boundary, is that State of New Mexico land?
A. Yes, it is.
Q. And do you own the minerals under your fee tracts?
A. No, sir.
Q. You have just surface out here; is that right?
A. Yes, sir.
Q. As I look at this map, in Section 16 it looks like there is a Gulf well, an oil and gas well. Is that a current well?

A. I don't know, I just don't know. Where is it located?

Q. It's located in the northwest of the southeast of Section 17, right above the section that's all shaded dark. Right north of there it says Gulf, and there's kind of a little mark like there was a gas or an oil well on that property.

A. Section -- there's 21, 23 -- some of these -- Let me see.

Q. Let me just ask you, maybe that -- on the map. Are there oil and gas wells on your property?

A. Most of it is -- you'll notice the -- this is Bender Boulevard --

Q. Uh-huh.

A. -- on this map --

Q. Right.

A. -- coming out, and right -- as you come out of Bender, the curve, and --

Q. Uh-huh.

A. -- all the wells that are productive, to my knowledge, are right there in -- there's about 900 acres. And I own part of the deed -- I mean part of the deed to that, yes.

Q. And so there's some wells on your ranch?

A. On the -- OXY, used to be Shell --

Q. Uh-huh.
A. -- I mean, if I remember right, OXY.
Q. Do you graze that part of your ranch?
A. Yes, sir.
Q. Did you attend the public meeting that was held at Duke's offices --
A. Yes, sir.
Q. -- to review this? So you have had an opportunity to have the project reviewed before?
A. Yes, sir, they did a very good job. He's the one that reviewed it.
Q. You've heard him twice?
A. Yes, sir. It's tiresome the second time.
(Laughter)
A. I'm just honest, I --
(Laughter)
A. I've got more important things to do.
Q. It may get tiresome the first time.
(Laughter)
A. No, I enjoyed it, I learned something.
Q. Let's go to Exhibit 3.
A. Okay, all right.
Q. All right. The orange is the acreage where you hold the grazing right?
A. Yes, sir.

Q. The well is actually located over on the far west end; isn't that right?

A. That's exactly right.

Q. That L-shaped piece?

A. Uh-huh.

Q. Most of your ranch is to the east and north of the well; isn't that true?

A. Uh-huh, northeast, yes.

Q. In fact, your ranch extends four miles or more off to the northwest, does it not?

A. Uh-huh, northeast.

Q. Northeast, right.

A. I have to correct you every once in a while, you're -- go ahead.

(Laughter)

MR. CARR: That's all I have.

THE WITNESS: All right.

MR. CARR: That's all I have.

CHAIRMAN FESMIRE: Ms. O'Connor, do you have any questions of this witness?

MS. O'CONNOR: No, Mr. Chairman.

CHAIRMAN FESMIRE: Commissioner --

THE WITNESS: I didn't hear that.

(Laughter)

CHAIRMAN FESMIRE: Commissioner Bailey?

EXAMINATION

BY COMMISSIONER BAILEY:

Q. The state Section 30 --

A. Beg your pardon?

Q. -- the backwards-L portion of your ranch --

A. That is --

Q. -- Section 30 --

A. That's owned by the State, yes.

Q. Yes.

A. That L-shape.

Q. Since it's not contiguous to the rest of your ranch, is it more difficult to manage?

A. No, it's contiguous. It reaches all the way over here. This is not quite right, this map isn't. Well, basically, but there's a little bit, see -- Let me see if that's right, now. No, let me see.

See, this other line over here, if you want to correct this, this other line, we've got another -- Let me see, let me see. No, that's right, it is right. Yeah, it is right, it's exactly right.

Q. So it only --

A. It is -- it does join.

Q. It touches right at that corner line?

A. Yes, uh-huh.

Q. Is it more difficult to manage because it's --

A. No, ma'am.

Q. -- not a part of the block?

A. No, ma'am. We've got a windmill over there that they didn't find when they were looking out there, but we've got a windmill over in this pasture.

Q. And the land values are about $10,000 an acre?

A. No, I didn't -- I said under certain conditions. North, they're $10,000 and up, of Hobbs. And an old cowboy with a horse or two doesn't want to pay that much for a piece of land. And since the racetrack has gone in, it made the values -- and the LES -- You know what LES is? That atomic energy thing. The land values in Hobbs exploded, and they've done it on farm and ranch and the City of Hobbs. Real estate is hard to find, it's hard to find.

Q. Have your rental rates gone up for that grazing lease?

A. With what?

Q. Did you rental rates go up for that grazing lease?

A. Did --

Q. Did you rental rates --

A. From the --

Q. -- go up?

A. From the State?

Q. Uh-huh.

A. No, because I don't have any grass now. It's burned out.

Q. Well before January?

A. Yes, they did, a little bit, I think. I can't recall that. Let me tell you what -- I'm very busy, and some of those things I don't look at closely, I've got somebody that does it for me.

Q. Did you ask any damages from Duke Energy for the use of the surface on your grazing lease?

A. They never have told me they were out there yet.

Q. Did you --

A. In fact, let me tell you what. I went out there -- the fence was down -- about 10 days ago. Somebody went with me. And there was a man from Lubbock out there with two Hispanic people that couldn't speak English. I said, What are you doing out here? They're not yours.

And they said, Well, we're putting an entrance in here.

And I said, Well, what are you doing?

Well, we're putting a -- we're running a pipeline across here.

And I said, Well, who gave you permission?

Me no sabe English.

And I called his boss and he came over and they had torn down the corners -- I mean the stretch lines and so forth. We have those problems.

But Duke Energy never did contact me at all. Neither has the -- Finally I got a letter somewhere that they were going to have -- and I've got a girl that brings it and puts it on my desk when I'm gone and I don't see it for two weeks. And nobody's contacted anybody. I've got a son there, if they had come in there and they can't reach me I've got answering machines and I've got four phones. Duke didn't even -- they didn't call me.

Q. Did you talk to the Land Office about any of your --

A. No, ma'am, I didn't.

Q. -- objections?

A. I don't talk to the Land Office. And the only -- Generally, I don't have any problems with it. They do a good job. The last time I talked to them, we -- They have an improvement program going on, and Mr. Alexander and I and Beach Snyder and I have always had someone to evaluate what we need to do and how we need to do it and do the fences to be -- improve the land. And that's what we're doing with that ranch.

COMMISSIONER BAILEY: I have no other questions.

CHAIRMAN FESMIRE: Commissioner Olson?

COMMISSIONER BAILEY: I have no questions.

CHAIRMAN FESMIRE: And I have no questions.

Mr. Hall, do you have a redirect?

MR. HALL: No, sir.

THE WITNESS: Did I get through? Okay.

MR. CARR: Can I just ask one question?

CHAIRMAN FESMIRE: Surely.

FURTHER EXAMINATION

BY MR. CARR:

Q. Do you happen to know if those wells on your property are sour gas wells?

A. I have no idea. And somebody doesn't warn me, I think everything's all right.

MR. CARR: That's all.

CHAIRMAN FESMIRE: Mr. Cobb, thank you very much.

THE WITNESS: All right, thank you for listening.

CHAIRMAN FESMIRE: Mr. Hall, your next witness?

MR. HALL: At this time, Mr. Chairman, we would call Randy Smith to the stand.

<u>RANDY SMITH</u>,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. HALL:

Q. For the record, sir, please state your name.

A. I'm Randy Smith.

Q. And Mr. Smith, where do you live?
A. I live between Carlsbad and Hobbs.
Q. All right. How are you employed, Mr. Smith?
A. I work for Transwestern Pipeline.
Q. What do you do for Transwestern?
A. I am an operator.
Q. And how long have you worked for Transwestern?
A. Twenty-five years.
Q. Mr. Smith, do you own land in the vicinity of Duke's proposed injection well?
A. Yes.
Q. And where is that located?
A. Just north of where they propose to put it.
Q. All right. If you want to refer to Duke's Exhibit 1, their C-108, there's an ownership plat -- Well, let's refer to that. Let's refer to Exhibit 1 in our notebook. Exhibit 1 indicates some land owned in fee in the west half of the northeast quarter and the northwest quarter of Section 30; is that you?
A. Yes, that's me.
Q. Do you own land in addition to that?
A. Yes, I have two sections above that with another 160 acres, and those two -- 18 and 19, you don't see them on here, but that is state lease. And then there's 160 acres, then I own more land to the west, total of about

three sections is what -- with my lease and my private land.

Q. All right, let's turn to our Exhibit 3. Let me ask you, how are you using your land presently?

A. Cattle, I raise cattle, and I have what a cattle farm, I grow stuff for cattle to eat. I have two pivots right -- just right north of where they propose to put this well.

Q. When you say pivots, is that irrigation?

A. Irrigation pivots.

Q. And what are you raising under the pivots?

A. I grow wheat in the wintertime. In the summertime I'll put what they call hay grazer and -- mainly just to feed my cattle.

Q. I see. If you would refer to Exhibit 3, the aerial map, do you have a farm house on your property?

A. Yes.

Q. Is it possible to locate this on your -- on the aerial photograph?

A. I don't know if you all can see it, but my house is -- Okay, you've got the L-shape where they're going to put the well, and then if you just go -- you can actually see the road going up to my house, and it's in the middle of -- well, it's hard for me to explain it, Scott, but I can show you better. There's a little white spot there.

That's my house.

Q. And you're referring to --

A. Section 18.

Q. -- immediately to the north of Section 30?

A. Right.

Q. Now, let's talk about the section to the west of Section 30. What is located there?

A. The what?

Q. Refer to the section immediately to the west of the proposed injection well.

A. Oh, to the west?

Q. Yes.

A. That's the Maddox power plant.

Q. All right. And there is a dark spot -- Well, let's back up a minute. Is the Maddox power plant on the eastern boundary of that section?

A. Right where you've got the orange of Mr. Cobb's, there's a white spot there. That's the Maddox plant. And then just to the west of that is a fishing lake, a New Mexico Game and Fish fishing lake.

Q. Does the public use that for --

A. Yes --

Q. -- recreational purposes?

A. -- there's some people out there. And my land goes right up to that and maybe just a little further past that.

Q. Okay. Mr. Smith, let me ask you, how did you become aware of Duke's proposed injection well?

A. I seen the survey markers --

Q. Did you --

A. -- they were out there surveying.

Q. I'm sorry

A. They were out there surveying, and I seen the markers. And that's when I called Mr. Cobb and was asking him if he knew what was going on, if he had heard anything.

Q. And how did you find out they were proposing to locate an acid gas injection well there?

A. I found out through one of their employees.

Q. All right. Did you ever receive any sort of written notification?

A. No, I never did.

Q. Did you ever see an advertisement in the Hobbs newspaper about the facility?

A. No, never did.

Q. Mr. Smith, based on your experience with Transwestern do you have some familiarity with the industry's handling of hydrogen sulfide and carbon dioxide?

A. Yes, I do.

Q. Do you believe Duke's Application ought to be treated like a saltwater disposal well?

A. No, it sure shouldn't --

MR. CARR: I'm going to object to this. I mean, first of all, we haven't established what Mr. Smith's knowledge is with H_2S. He's also being asked now to basically render an opinion on whether we have a Class II well, and I think we've gone far beyond his expertise.

CHAIRMAN FESMIRE: Mr. Hall, if he's going to go into that, you probably ought to develop his credentials.

MR. HALL: We'll do that.

Q. (By Mr. Hall) Mr. Smith, do you understand that hydrogen sulfide is a hazardous material?

A. Yes.

Q. And how did you come to that understanding?

A. Well, the pipeline that I work for, we won't let four parts per million get into our pipeline. And we have -- every year we go over hydrogen sulfide, how dangerous it is. We actually -- the pipeline I work for, we take plant gas into our main line, and then we pump it down south to Texas and to California.

Q. Does Transwestern provide you and its employees with safety training with respect to the handling of H_2S?

A. Yes.

Q. Mr. Smith, when you discovered that Duke was proposing to dispose of hydrogen sulfide on Section 30, did you undertake to do some research about hydrogen sulfide?

A. Yes, I've learned about it for the last two or three months, way more than I knew.

Q. All right. Let's look at Exhibit 7, if you would. What is Exhibit 7? Can you identify that?

A. Yeah, that's the Air Quality Bureau of New Mexico environmental -- I pulled this off the Internet.

Q. And is that a list of hazardous pollutants --

A. Yes.

Q. -- published by the New Mexico Environment Department?

A. (Nods)

Q. Mr. Smith, is that a list of hazardous pollutants published by the New Mexico Environment Department?

A. Yes.

Q. And if you will look on page 3, is hydrogen sulfide on that list?

A. Yes, it is.

Q. Let's look at the next exhibit, Exhibit 8. Would you identify that, please?

A. This is an OSHA list of hazardous chemicals.

Q. And did you pull this list off the Internet as well?

A. Yes.

Q. And if you'll look at page 3 of that list, is hydrogen sulfide listed on OSHA's list of hazardous chemicals?

A. Yes. Page 2 has also got the carbon dioxide.

Q. All right. And let's look at Exhibit 9. Would you identify that, please?

A. The Agency for Toxic Substances and Disease Registry, CERCLA.

Q. Is this a list you also pulled off the Internet?

A. Yes.

Q. And is Exhibit 9 a priority list of hazardous substances?

A. (Nods)

Q. Mr. Smith, I didn't hear your answer.

A. Yes, it is.

Q. And is hydrogen sulfide shown on page 7 of that list?

A. Yeah, 193.

Q. Let's see if we understand how this list works. The left-hand column -- if you'll refer back to the second page, does the left-hand column refer to the 2005 rank on the list?

A. Yes.

Q. And if you work your way to the right, does it also show the 2003 rank?

A. Yes.

Q. And what was the rank for hydrogen sulfide in

2003?

A. 197.

Q. All right.

A. It's coming up.

Q. All right, let's refer to Exhibit 16. Would you identify that, please?

A. I believe, Scott, this is just a safety program we pulled off the OSHA safety on hydrogen sulfide.

Q. All right.

A. Sometimes in my -- our safety meetings that we have, it will be on hydrogen sulfide, and we will have this kind of information.

Q. And does Exhibit 16 reflect the health effects on the body from breathing hydrogen sulfide?

A. Right.

Q. And from your research, including Exhibit 16, did you conclude that hydrogen sulfide is a dangerous substance?

A. Very, very dangerous.

Q. If you'll look at the first page of Exhibit 16, it refers to what will happen to you with exposure from two to 15 minutes at 100 parts per million. Do you see that?

A. Yes. We have a meter that goes off at 20 parts per million, and we're to clear out as soon as it goes off, to get back.

Q. All right. And how many parts per million of hydrogen sulfide are we talking about in connection with Duke's facility; do you know?

A. They're talking about 235,000 parts per million. And 1000 parts will kill you instantly.

Q. Let's look at Exhibit 17. Could you identify that, please?

A. Yeah, that's another -- that we pulled off the Internet on OSHA, U.S. Department of Labor , Occupation Safety and Health Administration.

Q. And what does that table show you?

A. How long you can work in a hazardous atmosphere.

Q. All right. And if you'll refer to page 2, does that show the maximum peak volumes and exposure times that OSHA will permit you to be exposed to?

A. Right.

Q. And what are those? What is the maximum peak for hydrogen sulfide?

A. Fifty parts per million.

Q. And for what duration?

A. Ten minutes.

Q. Let's look at Exhibit 18, please. Would you identify that?

A. Yes, this is a report about the natural gas pipeline that blew up south of Carlsbad, killed 12 people.

Q. And where did you get this publication?

A. We got it off the Internet. This come off a corrosion -- about the pipeline explosion in Carlsbad.

Q. All right. If you'll look at the very last page, the very last paragraph, was hydrogen-sulfide corrosion implicated in that explosion?

A. Yes, it was.

Q. Let's look at Exhibit 19. Would you identify that, please?

A. This is from the Michigan Land Use Institute, and it come out of a -- like a land and water website. And you basically -- you can just type in H_2S on the Internet and you can get lots of information.

Q. What did you understand the Michigan Land Use Institute was analyzing in this study?

A. They were looking at their state, kind of like what we're doing here today, and to be sure that they were protecting the citizens and all the safety aspects of H_2S.

Q. And if you'll look at the second page of that, is the Michigan Land Use Institute advocating the adoption of a public health exposure limit for H_2S?

A. Yeah, "A new public health exposure limit of 0.1 parts per million must be established for H_2S."

Q. All right. Let's look at Exhibit 20, if you would identify that, please, sir. What is that?

A. This is R&M Energy Systems. They do samples, from what I understand, and they're talking about their guidelines. They do fluid samples.

Q. And these are their recommended guideline for handling hydrogen sulfide?

A. Yes.

Q. And at the bottom of that tabulation, do they also reflect the OSHA-permissible exposure limits?

A. Yes.

Q. And what are those?

A. Ten parts per million, eight-hour time-weighted average; 15 parts per million, 15-minute short term exposure limit.

Q. All right. Let's refer to Exhibit 21. It's a compilation of pages. Would you identify Exhibit 21, please?

A. This is a New Mexico One Call. Anytime they have a leak or somebody gets into the pipeline, you get these. And these are just for my area around Carlsbad, and we go to Hobbs, and so these are just the ones that our pipeline would get, just where our pipeline are. These are not all the leaks, these are just in our area.

Q. And for what period of time do these notices cover?

A. This is for 2005.

Q. All right. And in each case were they emergency notices?

A. Yes.

Q. And in each case were the pipelines where the leak occurred operated by Duke Energy Field Services?

A. Yes.

Q. And how many of these notices are there?

A. There's 15, I think, right here.

Q. If you know, are any of the emergency leak notices a result of pipeline corrosion?

A. I would say most of these are.

MR. CARR: I'd like to object to that. I'd like -- before he asks those questions, he needs to lay some sort of a foundation so that this witness isn't just speculating.

THE WITNESS: Well, it says right here --

CHAIRMAN FESMIRE: Mr. Smith, why don't you let your --

THE WITNESS: Okay.

CHAIRMAN FESMIRE: -- your attorney answer?

MR. HALL: Mr. -- Well, I'll lay a foundation, if you like Mr. --

CHAIRMAN FESMIRE: Please.

MR. HALL: -- Chairman.

Q. (By Mr. Hall) Mr. Smith, in your capacity with

Transwestern Pipeline, have you become familiar with the One Call notices --
A. Yes.
Q. -- that are utilized in the industry?
A. Yes.
Q. And is there any indication on these one-call notices about the causation of the leaks?
A. This one here says --
Q. Which one are you referring to, first of all?
A. Okay, it's -- it would be the fourth one.
Q. All right, go ahead.
A. Emergency gas leak repair.
Q. All right. Any indication on here that these are a result of a backhoe?
A. No, no.
Q. Let's turn -- I'm sorry, go ahead.
A. Normally when a backhoe --
MR. CARR: Again, I want to renew my objection to this. I think we need to lay a foundation before we start just making -- drawing conclusions on what the problem with these would be. Some say they're digging pipelines, some say gas repairs, some say water line. I mean, we don't deny that periodically something happens, but it would seem to me that we should have a proper foundation before we just start marching through this sort of stuff.

CHAIRMAN FESMIRE: Mr. Hall, I think you need to elaborate on Mr. Smith's qualifications, other than being an operator for Transwestern. How does he know what One Call is? What is One Call? And how did he come and -- and where did he go to get this information?

MR. HALL: We can do all that.

CHAIRMAN FESMIRE: Then let's, please.

Q. (By Mr. Hall) Mr. Smith, would you explain the source of the documents that comprise Exhibit 21?

A. That's New Mexico One Call.

Q. And what is New Mexico One Call?

A. It is -- If you have a leak on your pipeline or you're going to be putting in another pipeline or a phone line, you have to call New Mexico One Call, tell them where you're going to be working and -- or like these, if you have a leak, you have to call New Mexico One Call so that when you go out there, when they send a crew in to dig these leaks up, that they don't get into our pipeline.

Q. Mr. Smith, in the course of your responsibilities for Transwestern, have you become familiar with the operation of the New Mexico One Call system?

A. Yes, yes.

Q. Does Exhibit 21 indicate to you that there are numerous pipeline leaks in the Duke Energy Field Services system?

A. (Nods)

Q. You need to indicate verbally for the court reporter, please.

A. Do what?

Q. You need to indicate verbally for the court reporter, please.

A. Yes.

Q. Let's refer to Exhibit 22. What is Exhibit 22?

A. These are letters that I took around to get the land owners around this injection well familiar with what was going on. They didn't know.

Q. These are some of your neighbors?

A. Yes, these are my neighbors.

Q. If you'd refer back to Exhibit 3, the aerial map, can you indicate to the Commission where the lands of some of these neighbors are?

A. Okay, the first one is Jim Davis, and just -- he's the third the third section up from the L-shape --

Q. All right.

A. -- north, he's north.

Mr. Jim Cooper, he has a farm one section from where they want to put the injection, to the east.

Mr. Squires, Larry Squires, he has -- he has the section to the west of where they want to put...

Q. Mr. Smith have you been out on the surface of

Section 30, where the well is proposed to be located?

A. Yes.

Q. And are you familiar with the old wells that are out there?

A. There's a lot of old wells out there, but yes, I've been right to where they've got the markers that says this is where the injection well is to be drilled.

Q. All right. Are you aware of any wells out there that are not currently plugged?

A. We have a picture of one. I can't remember -- Exhibit 4?

Q. Okay.

A. On the left-hand side. That well is not plugged.

Q. How do you know that?

A. There's pressure on that line there.

Q. Okay. And where is that well located in proximity to where Duke is proposing to locate their well?

A. I believe it's maybe 50 to 100 feet to the east.

Q. And how do you know there's pressure on that well?

A. I opened that valve.

Q. All right.

A. I cracked it.

CHAIRMAN FESMIRE: Did you bleed it off?

THE WITNESS: No, I just opened it, it spewed, I closed it back off.

Q. (By Mr. Hall) Why are you personally concerned about the location of the Duke Energy Field Service proposed acid gas injection well compression facility?

A. Well, the first thing, I hated to see them come across the highway with another H_2S line. A four-lane highway that -- that's the main oilfield traffic, and there's of vehicles go down that highway a day.

Then the next thing was the Maddox power plant. I see 13 to 15 cars sometimes, people working over there, and they're just a half a mile from this site.

And then the third thing is me. I'm 230 steps from that well site.

Q. All right.

A. And I know how deadly this stuff is. And if they have any kind of malfunction, I'll be dead.

Q. How do you travel to your farmhouse?

A. I go by this well.

Q. How close?

A. We had a map that showed my road. I don't remember -- but yes, I go right by this well to get to my house.

Q. Is there a county road that runs along the western boundary of Section 30?

A. Yeah, that's the Maddox road.

Q. And is that the road you utilize to get to your farmhouse?

A. Yeah, that's how I go to my farm.

Q. All right. And how close will Duke's facility be to this road that you utilize?

A. It's within a half a mile there.

Q. All right.

A. The road is right on that section line of the...

Q. And Mr. Smith, has Duke Energy Field Services attempted to obtain from you the right to utilize your subsurface for acid gas disposal?

A. No, they haven't.

Q. Are you denying Duke Energy Field Services permission to use your subsurface?

A. Yes.

Q. And are you placing Duke Energy Field Services on notice not to trespass on your subsurface with their acid gas?

A. Yes.

MR. HALL: That concludes my direct of the witness, Mr. Chairman.

I'd move the admission of Exhibits 7, 8, 9, 16, 17, 18, 19, 20, 21 and 22.

MR. CARR: And we object to 21 and 22. There was no foundation laid for these exhibits. These reports are just miscellaneous documents. We don't know the original source, we don't know how they were kept, we don't have a proper foundation for the admission of those. The letters are undated. They're just simply rank hearsay, and we object to the admission of 21 and 22.

CHAIRMAN FESMIRE: Exhibits 7, 8 and 9 will be admitted. I think while it was weak, there was a foundation laid for the New Mexico One Call reports, but I agree with Mr. Carr on 22. I think they're rank hearsay, and I don't think there's any exception that will allow us to admit them, is there?

MR. HALL: That would be correct, Mr. Chairman.

(Laughter)

MR. HALL: I'm not going to argue with you on that one.

CHAIRMAN FESMIRE: So 7, 8, 9 and 21 are admitted; 22 is not.

MR. HALL: We'd also move the admission of Exhibits 16, 17, 18, 19 and 20.

MR. CARR: No objection.

CHAIRMAN FESMIRE: 16, 17, 18, 19 and 20 will be admitted if there's no objection.

MR. CARR: Not from me.

CHAIRMAN FESMIRE: Any other party?

MS. O'CONNOR: (Shakes head)

MR. HALL: And that concludes our direct of Mr. Smith.

CHAIRMAN FESMIRE: Mr. Carr?

MR. CARR: Just a few questions.

THE WITNESS: Okay.

CROSS-EXAMINATION

BY MR. CARR:

Q. Do you have three sections, is approximately the property that you own that around your house?

A. (Nods)

Q. Did you tell me that -- tell us that some are state grazing leases and --

A. Yes, two, 19 and 18.

Q. Sections 19 and 18?

A. Nineteen and 18.

Q. And you own one section in fee?

A. Yeah, I own part of 30 and 25.

Q. And you have the mineral rights under those?

A. No, I do not.

Q. You do not, you just have the surface?

A. I just have the surface.

Q. Do you have any mineral rights?

A. I don't have the oil and gas lease, but I own the land.

Q. Do you have -- Do you own any of the minerals below your property, or do you have just surface?

A. Well, if I wanted to sell caliche or anything, yes, I do.

Q. Were --

A. I feel like I own from that land to the center of the earth.

Q. But not the oil and gas?

A. No.

Q. Would you own any other minable minerals down there, do you know, or not?

A. No.

Q. Are there oil and gas wells on these three sections of land?

A. Yes.

Q. Do you know if there are sour gas wells on that acreage?

A. No.

Q. Do you know, or there's no --

A. There's no operating wells on my place.

Q. All right. You got on the Internet and -- Are you the person that pulled these documents?

A. Yes.

Q. Other than reviewing these documents, do you have any expertise in the handling of H_2S?

A. Do I?

Q. Yes.
A. Personally?
Q. Yes.
A. Well, we tie on to plants that -- like Linam --
Q. Uh-huh.
A. -- that -- yes, we do.
Q. And what is your responsibility in that regard?
A. I pump natural gas.
Q. Are you --
A. We gather it up, we pump it.
Q. Are you involved in any decisions in terms of how to safely design a facility to handle acid gas?
A. Not acid gas.
Q. Would you -- Do you have any experience in trying to develop safety measures for injecting this gas? I'm just trying to get an idea what your area of expertise is.
A. Well, I did go look at Agave's injection well.
Q. Do you have any professional training? Are you an engineer?
A. Well, I don't know if 25 years -- you know, I don't have an engineering degree, but I've been working in the gas -- natural gas business for 25 years.
Q. When I heard your testimony, isn't it that what you do and your company does is, you move this stuff away; isn't that right, when you find it?

A. We transport it.
Q. Are you involved with injecting any of it anywhere?
A. No.
Q. I'd like to look at Exhibit Number 21 with you. these are the One Call --
A. Right.
Q. -- pages. How did you get these?
A. They come to our fax machine from New Mexico One Call.
Q. Are these all of the One Call reports that you've gotten?
A. No.
Q. How many did you get, do you know?
A. Several hundred.
Q. And you pulled just the Duke Energy Field Services.
A. I pulled just the emergency Duke Energy.
Q. Does Transwestern also have emergency One Call reports like these?
A. When we are doing a project, yes. But as far as a leak, no.
Q. When we look at these, do you know on any of them whether the leak involved sour gas?
A. I did -- not on these, but in 2006 I went out

where H_2S had ate up the line on Duke Energy, and --

Q. My question, now, is as to these reports, did you --

MR. HALL: Let him finish his answer.

MR. CARR: Well, I think he should --

CHAIRMAN FESMIRE: Let's go through --

MR. CARR: -- answer a question asked. You can redirect.

CHAIRMAN FESMIRE: Mr. Carr, let's go through the Chairman here.

MR. CARR: Yes, sir, Mr. Chairman.

CHAIRMAN FESMIRE: Okay. You were going to object to --

MR. HALL: No, sir, I was asking that the witness be allowed to finish his answer.

CHAIRMAN FESMIRE: Okay.

MR. CARR: Mr. Chairman, I would suggest that he answers the questions asked. Mr. Hall can redirect him on anything he wants.

CHAIRMAN FESMIRE: Go ahead and re-ask your question.

Q. (By Mr. Carr) Any of the One Call forms here, as I looked at them I couldn't find anything that indicated that these were -- any of these were sour gas. Is there anything on any of these documents that says they are?

A. Well, I just know that they are.

Q. The question was, does there -- is there anything here that shows --

A. No, there's nothing here.

Q. Were you involved with the first one, the leak that occurred at 6:59 a.m. on August the 18th, 2005?

A. No.

Q. If we go back three, we see that there was an emergency at 9:15 on June 1st, 2005. Do you see that one, the third one in the book?

A. Third one?

Q. Yes, sir. Third page, it says Emergency, and then right below it at the time is 9:15 a.m.

A. Yeah.

Q. And if we go down and it says Type of Work, it says Water Main Link --

A. Yeah.

Q. -- Leak. Was that sour gas?

A. No, it wasn't.

MR. CARR: That's all I have.

CHAIRMAN FESMIRE: Ms. O'Connor, do you have any questions?

MS. O'CONNOR: No, Mr. Chairman.

CHAIRMAN FESMIRE: Commissioner Bailey?

COMMISSIONER BAILEY: Just one.

EXAMINATION

BY COMMISSIONER BAILEY:

Q. Do you believe that the current practices for H_2S at the Linam plant are safer than an injection well?

A. I do, yes.

Q. With the flaring to the air?

A. Yes. It's a proven -- What they're doing there is proven. They've been doing it for 40 years, or 30 years. It's a good system. Nobody's got killed. Now -- These injection wells -- I went out to -- can I go ahead and --

CHAIRMAN FESMIRE: Answer the question.

THE WITNESS: I went out to Agave. Theirs is not even on line. I go out to Duke's, and they can only put half of what they wanted to put down there. What they've got now, they're burning -- they're taking one-third of that H_2S and running it through that sulfur plant and burning the rest of it up. It's a pretty good system. 95 percent, I think, he testified.

COMMISSIONER BAILEY: That's my only question.

CHAIRMAN FESMIRE: Commissioner Olson?

COMMISSIONER OLSON: No questions.

EXAMINATION

BY CHAIRMAN FESMIRE:

Q. Mr. Smith, on Exhibit Number 3 -- I'm sorry,

Exhibit Number 4, the house in the back -- or I guess it's a truck in the background, isn't it?

A. Yeah, it's a truck.

Q. Where is your house from here? I'm assuming that this stake is the location of the injection well, right?

A. Yes.

Q. Where is your house from there?

A. It would be straight -- the direction that that -- if I'm looking at that -- that that pickup is pointing straight north.

Q. Okay, and is that pickup on your road?

A. No, he's out in S.G. Cobb's pasture.

Q. Okay. Where is your road from here?

A. It's to the west of this. So I would come in on the west and turn -- We've got a good picture, or a good drawing of my road.

MR. HALL: Mr. Chairman, the Exhibit I had planned on utilizing to show the location of Mr. Smith's access, his roadways, is on Duke Energy Exhibit 13. It's on of their pages they had withdrawn. It's titled the radius of exposure, the quantitative risk assessment, and it shows some radii of risk of exposure zones. But it depicts the road.

Q. (By Chairman Fesmire) How far is the road from this well location, at its closest point?

A. Which road, the road on my farm or the road -- the county road?
Q. The road to your farm?
A. Well, the county road, you know, is running north and south --
Q. Uh-huh.
A. -- and it's within -- it's right on the section line of this. So it's a half a mile.
Q. Half a mile?
A. Yeah.
Q. Half a mile from this location to your road. How far is this road to your -- I mean, is this location to your house, then?
A. It's a mile and a half.
Q. A mile and a half. You said it was 238 steps?
A. Yeah, I just -- I was out there the day I was looking at this, and I said, Well, I'm just going to -- I just stepped off across there --
Q. So it's --
A. -- 230 steps, and there's my road.
Q. Okay. But it's about a mile and a half to your house?
A. Yes.
Q. Okay, so that's 7500 feet?
A. Yes.

MR. HALL: Can I --

CHAIRMAN FESMIRE: Mr. Hall, you get a chance at redirect.

MR. HALL: -- add some clarification about the location of his roads?

CHAIRMAN FESMIRE: Okay.

MR. HALL: I think there's some confusion.

CHAIRMAN FESMIRE: Without using that exhibit?

MR. HALL: I believe so.

CHAIRMAN FESMIRE: Okay.

MR. CARR: I'd really like the witness to testify, not Mr. Hall.

MR. HALL: Well, I intend to ask him questions and he can respond. How about if we do it that way?

CHAIRMAN FESMIRE: That's the way it's customarily done.

MR. HALL: Right.

CHAIRMAN FESMIRE: Okay.

MR. HALL: That was my plan.

REDIRECT EXAMINATION

BY MR. HALL:

Q. Mr. Smith, you access your farm from the Carlsbad highway.

A. Right.

Q. Do you take County Road 41 to the north from the

Carlsbad highway?

A. The Maddox road, is that County 41?

Q. Does that road -- does that county highway go just to the immediate east of the Maddox plant?

A. Yes.

Q. And then when you turn -- what direction do you turn to get --

A. I go back east.

Q. Back east. And where is that turn to the east located on Section 30?

A. I'm -- Okay, it is in the middle of Section 30.

Q. All right.

A. I may have misstated -- I go right down the middle of Section 30 till I hit this "L" part of Mr. Cobb's, and then I turn north to go to my house.

Q. And you're referring to Exhibit 3 again, the aerial photo?

A. Yes.

Q. So if I understand correctly --

MR. CARR: Maybe we could have the witness mark on Exhibit 3 where his house is?

CHAIRMAN FESMIRE: Yes.

THE WITNESS: I can show you.

MR. HALL: Why don't you use this copy here, Mr. Smith?

MR. CARR: Here's a clean one, Scott.

Would you put an X on it, please?

THE WITNESS: Right there.

MR. CARR: Okay, you'd better show the Commission.

CHAIRMAN FESMIRE: And we will -- Okay, on Exhibit 3 --

THE WITNESS: Right there is my house, and this is the road that I come up to go to my house.

CHAIRMAN FESMIRE: Okay, and the well is going to be located right there?

THE WITNESS: No, the well is going to be right there.

CHAIRMAN FESMIRE: Okay, in that "L" --

THE WITNESS: Well, it -- right here.

CHAIRMAN FESMIRE: Okay, so you're a mile and a half due north --

THE WITNESS: Right, my house, but the road is right there.

CHAIRMAN FESMIRE: Okay. Let the record reflect that the witness has marked a copy of Exhibit 3 that will be transmitted to the court reporter for inclusion as Exhibit 3, and on it he has marked his house, and I have put an arrow showing where he marked the house. And that will go to the court reporter for inclusion in the record.

Okay. Mr. Hall, do you have any other redirect of the witness?

MR. HALL: That concludes our case, Mr. Chairman.

CHAIRMAN FESMIRE: Commissioner Bailey, any last --

COMMISSIONER BAILEY: No.

COMMISSIONER OLSON: No questions.

CHAIRMAN FESMIRE: Mr. Smith, thank you very much.

MR. HALL: Mr. Chairman, I believe there are some employees from the Xcel Maddox plant that would like to address the Commission.

CHAIRMAN FESMIRE: Okay. Ms. O'Connor, is that okay with you, if we do that?

MS. O'CONNOR: Do you want Bill to go before us? Is that what you're saying?

MR. HALL: I'm sorry, I didn't -- didn't realize you're putting on any witnesses, Cheryl, so --

MS. O'CONNOR: Yes.

MR. HALL: -- have at it.

MS. O'CONNOR: We still would like to put on two witnesses, Mr. Chairman, but we would also request, if we could, to have a very short break to try to streamline our questions.

CHAIRMAN FESMIRE: Okay, why don't we take a five-minute break?

MR. CARR: And Mr. Chairman, I mean, the people from the Maddox plant would like to make their statement. I wouldn't have any objection, I mean, if they want to do that now.

CHAIRMAN FESMIRE: Oh, Mr. Helmsley, are you all here for the night, or do you need to get back to Hobbs? And I'm real sympathetic to folks that have got to drive a long way.

MR. HENSLEE: We'd like to make that trip.

CHAIRMAN FESMIRE: Okay.

MR. HENSLEE: We'll do whatever we need to do.

CHAIRMAN FESMIRE: Okay. We'll take a five-minute break, then we'll allow them to speak, and then we'll go into your case-in-chief.

(Thereupon, a recess was taken at 4:40 p.m.)

(The following proceedings had at 4:46 p.m.)

CHAIRMAN FESMIRE: Mr. Henslee, since the OCD contingent is still out in the hall, I'm going to go ahead and ask you to start and make your statements and introduce your people.

MR. HENSLEE: Should I sit over here or --

CHAIRMAN FESMIRE: However you're most comfortable.

MR. HENSLEE: However we want to do it, okay.

We brought copies of written statements from myself and the other people that are in our contingent, and I've got a business card here.

CHAIRMAN FESMIRE: Mr. Carr, Mr. --

MR. HALL: -- Hall.

CHAIRMAN FESMIRE: -- do you all have any objection to receiving written statements that were not --

MR. HALL: We have no objection.

MR. CARR: As long as they are only written statements and not sworn testimony.

MR. HENSLEE: We've heard a lot of testimony today regarding a whole lot of different things. Some of them follow fairly closely with some of the concerns that we had at Maddox Station.

CHAIRMAN FESMIRE: Mr. Helmsley, would you state your --

MR. HENSLEE: Oh --

CHAIRMAN FESMIRE: -- your name --

MR. HENSLEE: -- excuse me, I'm sorry.

CHAIRMAN FESMIRE: -- for the court reporter and who you represent.

MR. HENSLEE: I'm Gale Henslee, I'm the principal environmental analyst for Xcel Energy. I'm out of Amarillo, Texas. Xcel Energy is the parent corporation of Southwestern Public Service Company, and Southwestern

Public Service Company is a New Mexico Corporation. They operate the Maddox Station power plant that is about a half mile to the west of the proposed facility, and they also operate Cunningham Station, which is three miles due west of that, and then a number of other interconnected plants in Texas and New Mexico.

As an electric utility, if we were handling hydrogen sulfide, it would be treated as a hazardous waste under RCRA. It's listed as an extremely hazardous substance under CERCLA, RCRA and numerous other federal regulations.

So when we heard about this, our first reaction was that that sounds like a Class I hazardous waste well. Normally that kind of waste would be regulated under the UIC program and under the water commission, and they have regulations that prohibit the installation of those kinds of wells in the State of New Mexico. We understand that as oil and gas wastes these are exempted from RCRA.

But our concern is that the public notice and the handling of these kind of wastes deserve the kind of attention that should be given to an extremely hazardous substance. And in relation to Maddox Station, we have 14 employees on site there during the day, there's two shifts at night, with two employees, and it's manned 24 hours a day.

We're concerned about why the surface land owners in a reasonable radius around the facility haven't been included in the notification or provided with enough information to understand the potential hazards that might be involved.

We want the Commission to know that we also have a drinking water system for Maddox Station. It comes off of our power plant water system, and there's eight wells interconnected. Four of them are within that two-mile radius that they studied, and one of them is very near the half-mile radius from the facility.

Those wells are all noted on the USGS map. We think they should have found those and probably should have inquired a little more closely as to what they represented.

If the well is permitted, we would like to see more safety measures, perhaps a direct link into alarms in the control room at our plant from the monitoring system that's proposed around the injection well and in the vicinity of the wellhead.

We're not quite sure at this point how an emergency response would be organized from Maddox Station. A catastrophic release of hydrogen sulfide could be deadly, and our employees would be unaware of any potential hazard in a case like that.

Also, our employees work out in the field, they're not always in the plant, and we'd like to see more information or a better warning system developed to deal with that kind of a situation.

There's also some -- you know, we noted there are several old faults located in the area. They're located deep, they don't appear to be active. We'd like to see a little more study as to whether the injection into that formation might reactivate some of those faults and potentially impact our wells or other facilities there, some kind of mechanical damage to our wells or our plant.

Now we're also -- we're customers of Linam Ranch, and we'd like to see that continue. I think we want that -- we believe that additional time and communications are needed, and we'd urge the Commission to consider potential public hazards, that hazard being to people besides the employees of the Linam Ranch plant and in particular us and the people that work in the vicinity of the plant.

Now that's the end of my testimony. We also have Bobby Gonzales, who is a safety consultant for our plant, and he'd like to talk a little bit about the hazards of hydrogen sulfide.

And then Jeffrey Parham. He's the plant engineer, and he would like to talk a little bit about some of the things that we have to do to safely shut down the power plant and some of the things that could potentially go wrong that could cause, you know, interruptions of electric supply and that kind of thing.

MR. CARR: May it please the Commission, I object to these next presentations. If they were going to make technical presentations on the danger of hydrogen sulfide or these other issues, they fall within the definition of someone who desires to present technical testimony. And under our Rules of Procedure here, they must have become a party and they must have prefiled their exhibits, and they must have done it no later than five business days before the scheduled hearing date.

We don't object, as I stated, to this being accepted just like a -- just a statement, like any member of the public can make. But to come in at five o'clock on the day of the hearing and then start announcing they want to start calling someone to really present technical testimony, they're outside the rules, and it cannot be allowed.

MR. HALL: Mr. Chairman, simply respond to that.

MR. CARR: I don't know why Mr. Hall is responding. He is not representing the Maddox Station or this group, and they're not going to be bridging into the fact that he filed for Mr. Cobb and start now trying to come in and start cross-examining and playing the role as if they had properly appeared as a party. There is a reason we have procedural rules in Commission Hearings, and they didn't comply.

MR. HALL: Mr. Chairman, under Rule --

CHAIRMAN FESMIRE: Hang on just a second. Mr. Carr, your point is well taken. I am going to let Mr. Hall respond, but I do want him to understand that not as a representative of Xcel or the people who wish to speak.

MR. HALL: That's correct, Mr. Chairman. Simply wish to point out that under Rule 1208.C, you have the discretion to allow technical testimony at a late point in time like this. That's all I have to say.

CHAIRMAN FESMIRE: Mr. Gonzales, I have a tendency to lean towards Mr. Carr's view on this, that if you were going to present this technical testimony, that you probably should have entered an appearance and prefiled your exhibits to give the parties time to study those exhibits and be prepared to respond.

I don't think that there's anybody in this room who doesn't understand the dangers of H_2S and CO_2 and the mixture. So if that's the gist of your statement, I'm going to rule that we not take that statement.

If you have a personal statement or nontechnical testimony, we'd be glad to receive that. But technical testimony, it's -- it should have followed the Rules, the prior Rules.

MR. GONZALES: Okay, Mr. Chairman, members of the Commission, I can certainly testify to my position as a safety consultant with Cunningham/Maddox Station without expressing my opinion as far as the technical matters of H_2S. That's already been established.

What I would, if I may, with all due respect, is just simply state what our emergency evacuation procedures may be, or the lack of in this particular case, simply since we do have a -- our main access road to our facility, and just express my opinion relative to that and not in the realm of expert testimony with regards to H_2S.

CHAIRMAN FESMIRE: Like I said, I would accept a personal statement, but I don't want to get into technical testimony.

MR. GONZALES: Okay, sure.

CHAIRMAN FESMIRE: Come on up.

MR. GONZALES: Again, my name is Bobby Gonzales. I'm the safety consultant for Xcel Energy at Cunningham/ Maddox Station in Hobbs, New Mexico, and I've issued my statement as an addendum to Mr. Henslee.

I would just merely like to point out that we have approximately 60 employees at both power plants. While we may have on an average day 14 at Maddox Station, which is approximately a half mile to a third mile away from the proposed site, my concern as a safety consultant and safety person for these employees are not only the 60 employees that regularly work for Xcel Energy but the contractors as well, because we on a regular basis have contractors that come in and perform various duties on our turbines and our steam systems, on our various systems within our facility.

And my concern would be, how are we going to alarm or alert or let our people know that there may be a malfunction or that there may be perhaps a false alarm, if you will? How are we going to get our people out? How are we going to adhere to the respiratory potential problem that we may have? Are we going to provide self-contained breathing apparatus for all our employees? How are we going to deal with this? Are we going to provide them with personalized monitors? Are we going to have a monitor at our facility, which is within close proximity of the proposed site?

And so with that said, I would just like to basically point out the fact that if, in fact, we do have an emergency situation, not all of our employees are capable of donning SCBA or self-contained breathing apparatus, if you will, because of their particular health issues.

So my concern is one of emergency preparedness. Having retired as a public servant for Albuquerque Fire

Department some eight years ago, I can certainly relate to various hazards in an emergency situation, the panic involved, not to mention the dry environment of which we are currently experiencing in southeastern New Mexico. We had fire yesterday. How is the flame impingement going to affect this particular site if, in fact, we have a wild land fire similar to what we had on New Year's Day, which was already addressed?

We have an emergency response team of approximately 10 employees within our complex. And if, in fact, we do have an emergency situation, we're trained to a certain extent to respond to an emergency situation, render aid to our own individuals, perhaps suppress a fire to a certain extent. But a lot of our people don't have the expertise needed to deal with various other types of hazardous hazards.

And so with that said, I think I would be remiss if I would be remiss if I didn't point out the fact that we do have a number of employees at our complex that are extremely concerned.

CHAIRMAN FESMIRE: Okay, thank you, Mr. Gonzales.

Mr. Parham, given that we're into personal statements and not technical testimony --

MR. PARHAM: Yes, sir, Mr. Chairman. All my stuff is basically technical that's in there. I guess if you're just able to read it --

CHAIRMAN FESMIRE: Well, that --

MR. PARHAM: -- whatever. I don't know what you all can do, to be honest with you. My main concern was to let Duke know what kind of liabilities we have in the plant as far as shutting it down in an emergency situation.

Anyway, everything is technical, so I probably can't get up there and speak.

CHAIRMAN FESMIRE: Okay. Well, I would suggest that you open a dialogue with Duke's plant superintendent and --

MR. PARHAM: Sure --

CHAIRMAN FESMIRE: -- talk about that --

MR. PARHAM: Yeah.

CHAIRMAN FESMIRE: -- sort of issue if we -- you know --

MR. PARHAM: Absolutely, yeah --

CHAIRMAN FESMIRE: -- if we --

MR. PARHAM: -- yes, sir, that would happen.

CHAIRMAN FESMIRE: -- go ahead an approve that. Okay.

MR. PARHAM: Thanks.

CHAIRMAN FESMIRE: You bet.

MR. CARR: Mr. Chairman, Duke is ready to meet with them and talk with them. We had a public meeting, they attended.

They have in their statement suggested some things that they think would be appropriate, and we're happy to meet with them and discuss that.

CHAIRMAN FESMIRE: Thank you, Mr. Carr.

Ms. O'Connor, would you -- If there are no other statements, Ms. O'Connor, if you're ready to present your case-in-chief?

MS. O'CONNOR: Thank you. And if I could just trade places with perhaps --

MR. CARR: Do you want me to move?

MS. O'CONNOR: No, that's fine.

MR. CARR: It is your one chance.

(Laughter)

MS. O'CONNOR: Thank you, Mr. Chairman.

The OCD would call for its first witness Will Jones.

CHAIRMAN FESMIRE: Mr. Jones, you've been previously sworn; is that correct?

MR. JONES: Yes, sir.

CHAIRMAN FESMIRE: Have a seat and tell us what you know.

MS. O'CONNOR: Do I get to ask questions, or do you just want to know everything he knows?

MR. JONES: Won't take long.

WILLIAM V. JONES, JR.,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. O'CONNOR:

Q. Could you state your name, please?

A. William V. Jones.

Q. And who are you currently employed by?

A. The Oil Conservation Division.

Q. And what is your position?

A. Petroleum engineer.

Q. How long have you worked for the Oil Conservation Division?

A. Four years and two days, I think.

Q. Could you review for the Commission your education, please?

A. Bachelor's of science in geological engineering and civil engineering, New Mexico State University.

CHAIRMAN FESMIRE: Fine program, fine program.

(Laughter)

Q. (By Ms. O'Connor) And very briefly, could you tell the Commission about your work history before coming to the OCD?

A. I worked 20 years for Texaco and -- 10 years in Hobbs and 10 years in Denver, in exploration and exploitation in the Williston and the Piceance and the Uintah Basins.

Q. Okay, and how long have you been working for the OCD?

A. Four years --

Q. Okay.

A. -- and two days.

(Laughter)

Q. And not counting at all.

(Laughter)

Q. Mr. Jones, have you testified as an expert in front of this Commission before?

A. Yes, I have.

MS. O'CONNOR: Mr. Jones, based on -- or, the Commission, based on Mr. Jones' educational and work experience the OCD would move that he be permitted to testify as an expert witness.

MR. CARR: No objection.

MR. HALL: No objection.

CHAIRMAN FESMIRE: He'll be so accepted.

Q. (By Ms. O'Connor) Mr. Jones, if you would turn to the OCD's Exhibit C, do you have that with you? Did you lose that already?

A. I did.

MS. O'CONNOR: If you would permit --

THE WITNESS: Thank you.

(Off the record)

Q. (By Ms. O'Connor) Mr. Jones, as part of your duties with the OCD are you also a Hearing Officer?

A. Yes, I am.

Q. And were you originally assigned to hear this matter?

A. I originally received Duke Energy Field Services' Application for consideration administratively as a Class II injection well.

Q. When you received the Application, did you write a letter to Duke Energy regarding their Application?

A. Not initially, I didn't. I -- Initially I had several conversations with Mr. Gutiérrez about this, and I had additional concerns -- the geology was extremely well thought out, but I had additional concerns, mainly safety, that I thought the -- I needed to discuss this with the Division Director about whether he wanted it to be done administratively or not, and he said he didn't. So it got set to hearing.

Q. Okay. Did you write a September 16th, 2005, letter to Duke Energy?

A. Yes, I did.

Q. And why did you write that letter?

A. I wrote the letter after -- I had already reviewed the administrative Application. I talked to Mr. Gutiérrez, and I had concerns that I thought the hearing body that heard the case might be interested in, and I thought I would summarize them in a letter to Duke before I forgot all about them.

Q. And did you get a response from Duke Energy to that letter?

A. You know what, I wrote the letter and it was -- it got set to hearing, and the response came and it got stuck in the -- I have reviewed the response, and they responded to every one of my questions.

Q. Okay. I'm going to refer you to Exhibit C, and I realize on our copies it didn't necessarily come out, but it's part of the Department's -- what I mean is, the title, "Exhibit C", did not necessarily come out. It's the last two pages of the OCD's exhibits in the packet that they submitted. And Mr. Jones, do you recognize Exhibit C?

A. Yes, I do.

Q. And what is Exhibit C?

A. Exhibit C was a -- it was just a list of concerns or potential items that might be addressed as Duke was -- if they got approved in this matter, to -- while they were drilling, after the well was drilled to total depth, different completions.

Q. Mr. Jones, did you prepare Exhibit C?

A. Yes.

Q. And is it fair to say, then, that these are your concerns --

A. Yes.

Q. -- regarding the operation, in the event that Duke gets approved for this permit?

A. Yes, these are operational concerns in the condition that they get approved --

Q. Okay --

A. -- this Application.

Q. -- let's go over those concerns. And could you tell the Commission what concerns that you have -- and I apologize, I have to put on my reading glasses here -- what concerns that you have while the proposed well is being drilled? And this is your first issue in your summary; is that correct?

A. Yes.

Q. Okay, and could you address the Commission about those concerns?

A. Mr. Chairman and Commissioners, I had concerns at different stages of the well, and I listed them here, and I understand that Duke Energy has looked at all of these, and they -- as they previously testified today -- you heard their testimony about these already today, so we can go over them really quickly, go over the -- While drilling --

Q. Well, just address at this point what concerns that you have, yes, while the well is being drilled --

A. Well --

Q. -- that you would like to see addressed by Duke.

A. -- while it's drilling, I recommend a mudlogger crew be on location from above the target -- the first target horizon, to the total of the well, which is pretty standard.

I recommend that they run some sort of a test as they're drilling of the second bailout horizon so that they won't -- this information can be gathered while the well is drilling, either while it's being drilled through or as trail packers after the well is TD'd to total depth.

Q. Okay. And would you -- the recommendation that you're just making, are you requesting that the Commission make that as part of -- requirement of the permit, or were these just suggestions that you're making to the Commission for Duke's benefit and the OCD's benefit?

A. The latter, except in the -- if the Commission considers any of these to be important enough to put in your ordering paragraphs, then I would request that you do so. I have a couple of these that I do think that you might consider to put in the ordering paragraphs.

Q. Okay, let's hold off for a few minutes until you can make your suggestions to put into the ordering paragraph, but do you also have some concerns or recommendations about -- to Duke regarding the hole once it is drilled to total depth?

A. Yeah, once it's drilled to total depth I recommend that they run at least a -- standard resistivity and porosity logs, which would be standard.

But in addition, there's been enormous improvements in the last 10 or 15 years on fracture finders and fracture-orientation logs. And as we all know, we always assume that injected fluids, injected liquids, whatever, go in a -- are going to go in a basically radial pattern around an injection well.

But we don't always have to assume that. If we're drilling a well, we can gather some data that will possibly lead us to draw some sort of an ellipse and an azimuth of an ellipse around the well. And the fracture-finder logs are available now. They are more expensive, as Mr. Gutiérrez has -- already knows that. So most people, when they run them, they just run them over the target depths that they're interested in.

And the second cost of the -- not just the cost of running them, is the cost of analyzing them and getting an analysis of them. I would recommend that if these logs are run, or if this -- some sort of a fracture-orientation log is run, that it be run from a little bit below the injection depth would be to a little bit above the injection depth.

And one of the main for that -- There's two main reasons. There's a lateral/horizontal reason, and there's a vertical reason. The vertical reason would be to look for fracture extensions down below or above injection zone, which these logs can actually identify nowadays.

And I think what happened on the last Duke Energy well -- I think it was in the Devonian, and the injection could not -- they couldn't quite get enough injection without -- at the .2 or .3 limit that we put on. So they needed to go to more pressure, surface pressure.

In order to justify the additional surface pressure, we normally require step-rate tests. So the step-rate tests sometimes are real conclusive, and sometimes they're not. Even if they are real conclusive, the fracture orientation log or the dipole sonic, which shows your stresses above and below your injection interval, can be used to justify an increased injection pressure.

In my opinion, the -- keeping this injection of acid gas in the Bone Spring is preferable over a bailout into the Brushy Canyon. So if we can do the science now to show that if an increased injection pressure is needed, then it can be used in the Bone Spring instead of automatically bailing out to the Brushy Canyon, I think we should do that.

The horizontal reason is that these -- this -- especially these oriented fracture logs can tell you the major stress direction and actually the wellbore breakout which will tell you the major stress direction in your well, which is implying the direction of the fractures. And as you inject the fluid, it's going to go in the injection of fractures. So if this is going to last for 20, 30 years, it might be very good information to have for the future.

So if you do have any kind of ordering paragraph, you might consider adding this to it, for that reason.

One thing is, on evaluating injection permits, we try to look at not only invasion of freshwater but also, is -- causing waste of hydrocarbons. And if you inject acid gas, we don't know exactly how far it will go. That's why I suggested they notify everybody within a mile radius, like we do on Class I wells.

But this would tell a little bit more about where somebody might be careful about drilling in the future, if they drill to the Ellenburger or an equivalent depth of the Bone Spring or deeper in the future. I think we don't really have a way to flag something like this, but -- and as someone else has -- if you're drilling a well in a radius of the saltwater disposal well, you don't worry about danger from saltwater disposal. But if somebody's out there drilling in the future and they drill through this injected acid gas, they might want to know that. Drilling engineers of any competence should be checking things like this out anyway, but that would give some kind of indication about maybe it's not exactly in a radial direction.

Q. Mr. Jones, I'm unsure whether you've covered this in your previous answer, but do you have a recommendation as far as completion of the primary objective formation of the Bone Springs?

A. I think the Bone Springs should be totally evaluated. As far as the equipment, I think they have testified -- Duke Energy has already testified to adequate safety devices. I was suggesting maybe some kind of a gas sniffer in the annulus, because the gas will migrate to the top and -- but as the question was earlier, the Commission already has their answer on that, that they're looking for pressure increases on the surface. And that would probably suffice in that regard also.

Q. Do you have a recommendation as far as the surface injection pressure

A. Surface injection pressure, they supplied surface -- specific gravity of the liquids -- or the fluid, I should say, that's going into the well is around .8, which is consistent with what OXY has used out on their -- on some of their wells in the North Hobbs Unit. And those were for enhanced recovery purposes and not at this high concentration. But .8 -- I recommend that .3 p.s.i. per foot be used as the maximum surface pressure while injecting that fluid.

Q. And why do you make that recommendation?

A. Well, it would -- trying to balance out the same pressure on the bottom, with neglecting friction, of course, as water would be at .2, you adjust it from .2 to .3 if you go from a 1 specific gravity to a .8 specific gravity.

Q. And specifically, what are you trying to -- what is your concern or what are you trying to --

A. Oh, the concern would be migration out of zone. We try to prevent migration out of zone of the injected fluid.

Q. Now, are you again making the recommendation to the Commission to make the .3 pressure the requirement, versus the .8?

A. I think that would be -- I would make that recommendation, yes, while injecting at .8 specific gravity of liquid -- of a fluid, specific gravity, not a gas specific gravity.

Q. Okay. If the Commission decides to permit this well, do you have any recommendation of reports that the Commission should require of Duke Energy?

A. I was thinking more in line of an annual report or some kind of a periodic report of the well, maybe listing the volumes and the pressures for the previous year on that well, something that will come in regularly on the well so the well is not forgotten as time goes on.

Q. And you want the reports to be sent to whom?

A. Probably the Engineering Bureau, with reference to any permit number that would be issued in this case.

Q. And for what period of time should the reports continue?

A. For as long as the well is in operation.

Q. Okay. If at some point in time the Bone Spring formation cannot be injected, do you have any recommendations to the Commission?

A. Well, I recommend -- I actually recommend that the Commission insert an ordering paragraph allowing us to be administratively amended to the Brushy Canyon.

Q. Okay. Would this require a public hearing in that event?

A. Any kind of injection permit, whether it's amended or not, does always require a newspaper notice and notice to all affected parties. So it would be then the notice that's required in Rule 701, plus any notice that the reviewing OCD person would require at that case.

Q. Okay. With your recommendation and the fact that it would require this public hearing, do you have any concerns in this event, that you could be going into the Brushy Canyon?

A. I do, not as -- not more than can be handled administratively. I think -- When I looked at this before, I think I found three wells within a mile that were -- either penetrated the Bone Spring or are close to the Bone Spring, and I'm not sure if even all of those even penetrated the Bone Spring, but they were close enough to require a wellbore diagram of them to make sure that they were adequately cemented.

Those wellbore diagrams, I think, came in after I wrote that letter, so I would urge the Commission to look at those before -- and take into account other testimony here, before they decide this case.

But is your question -- if you bail out to the Brushy Canyon, there was more potential wellbores to consider, especially if you go a mile away, there's more wellbores to consider.

And there's also -- there was also two very good injection wells that have been used in the past, and I think those were approved through the Commission, and I think they were lower San Andres/upper Glorieta, but they were extremely good injection wells. A vast amount of water has been injected in this area in the past.

So that doesn't mean that there might be a potential hydrocarbon-paying horizon like the upper San Andres or maybe -- obviously some Queen wells in this area, or as Mr. Gutiérrez said, maybe the Ellenburger at some point might -- But as he said, there's been a well that was drilled deeper than the Bone Spring that didn't find anything out here, real close to this well.

Q. Now turning to a slightly different issue, Mr. Jones, is there any potential waste issues that may exist when permitting an acid gas injection well?

A. Yes, and I had talked about that a bit earlier. You always have to be careful approving an injection permit to make sure that -- We usually use a half-mile radius area of review, but I think that was instituted back in 1980, 1981, to mainly prevent any wellbore from being a conduit up and maybe getting fresh water or in the salt zone.

As far as invading hydrocarbons, we can look further than that, especially if you're injecting gas. Or if you're injecting into a gas zone, we try to restrict that. But this is not a gas zone, this is a water-bearing zone, as I understand it.

Q. Okay, and so do you have any recommendations to the Commission regarding that issue?

A. I didn't see any hydrocarbon-bearing horizon in the Bone Spring, from the -- any wells that I could see in the area.

Q. Okay. Well Mr. Jones, you heard earlier, there was some testimony that touched on the feasibility of drilling a deviated or horizontal well from the existing Duke facility to where the end of the hole is to be; is that -- were you here during that testimony?

A. Yes.

Q. Do you have an opinion on the feasibility of Duke drilling a deviated well from the plant location to the bottomhole location, the proposed bottomhole location?

A. Okay, I can tell you what my experience has been on deviated wells, is that they do cost more. But they're more and more feasible.

And I did talk to Baker a couple years ago or a year ago, and it's amazing, the advances that have been made in drilling deviated wells with downhole motors to almost any target.

But it would have to be driven by the geologic concerns or the geologic target here. If the Brushy canyon is to be considered as a target, Mr. Gutiérrez would need to sit down with a company that specializes in designing deviated wells and consider the depth of the salt here and also the targets that he's going for and at that point see if it's feasible to hit -- if he wants to hit both targets, they're going to have to design a well to hit both targets from the plant, drilling from in the plant.

I think it is feasible. I know there seems to be a fault that's around that are, but I think people drill through those on occasion and -- I know they drill through fractures. And with current technology, I do think if the money was spent it could probably be done. But I would defer to a company that specializes in designing deviated wells to sit down with the geologist. And if the Bone Spring is the only target, it makes it a lot more of a potential here.

Q. Would you have a recommendation to the Commission regarding any feasibility studies regarding a deviated well prior to or as a condition to granting this permit?

A. I think it should be considered. I realize that's not your -- that's not the issue at hand here, but I think it should be considered in light of an expert.

Q. And why do you believe it should be considered?

A. I think it should be considered because I have seen more and more capabilities of deviated wells. I know fracturing a 45-degree well is really difficult. And cleaning the hole before you cement a certain angle is more of a problem.

So you want to get a good cement job, you have to be real careful about deviated wells. Deviated wells have more of a potential for total failure, and you could lose the whole well. But you don't always have to drill a straight deviated well; you could drill an S-shaped well or something.

But I think the Commission can decide for themselves about what they want to do on that regard. They've heard testimony from both me and Mr. Gutiérrez about that today.

Q. Okay. Do you have any other concerns that we haven't already covered that you would like to raise for the Commission's benefit?

A. Not that I can think of right now.

Q. Do you have anything that you would like to comment on that you have heard Duke Energy present regarding this permit?

A. No, I'm -- No, I don't.

Q. Okay.

A. I think it's great --

Q. Okay.

A. -- the way they --

MS. O'CONNOR: Okay, thank you. I have no further questions.

CHAIRMAN FESMIRE: Mr. Carr?

EXAMINATION

BY MR. CARR:

Q. Mr. Jones, if you recommend a deviated well, other than just having the surface location at the plant, is there any other benefit that you see?

A. Absolutely not.

Q. And you do agree that it would increase the risk of losing the well?

A. Yes.

Q. And a success would depend upon a detailed study of the geology involved?

A. Yes.

MR. CARR: That's all I have.

CHAIRMAN FESMIRE: Mr. Hall?

EXAMINATION

BY MR. HALL:

Q. Mr. Jones, when an operator makes application for an AGI well under Rule 701 and the C-108 process, what puts that operator on notice that the provisions of Rule 118 apply?

A. I'm sorry, can you tell me again about Rule 118?

Q. What puts an operator on notice -- an operator comes in and makes application for an acid gas injection well under Rule 701 and under the C-108 process. What puts that operator on notice that the provisions of Rule 118 apply?

A. Nothing.

Q. Mr. Jones, are you satisfied with the Duke Energy Field Services response to your request for an H_2S contingency plan?

A. I put that in as one of the 12 or 13 questions I had in that letter, and then this got sent to the Commission, and we immediately notified our environmental group, which would be Mr. Wayne Price. And so I think I would defer to him on that issue.

Q. In view of the fact you made the request to Duke, would you like to have seen an H_2S contingency plan?

A. Yes, I would have preferred that to be all in the package, all wrapped up when the initial Application came in, along with some specifications about plastic-coated tubing, diesel backside, safety features on the well. But...

Q. Mr. Jones, as the individual in the Engineering Bureau principally responsible for the administration of the Division's UIC program, you're familiar with Rules and Regulations pertaining to waterflood projects and pressure-maintenance projects?

A. Yes.

Q. In each of those cases, isn't the Applicant required to establish and the Division required to approve a project area?

A. Yes.

Q. Were you present for Mr. Gutiérrez's testimony earlier today?

A. Yes.

Q. Is it your understanding -- What's the project area for this project? What's your understanding?

A. I couldn't get that from the testimony today, the project area, except it would be the -- this is not a hydrocarbon-producing project, but it does affect any potential hydrocarbons in a -- this is my opinion -- in a radial or an elliptical area. So I would consider that to be the project area, if you -- if we can talk in terms of project area.

Q. Do you have any reason to disagree with Mr. Gutiérrez's testimony to the effect that the acid gas will flow approximately in a 1900-foot radius from the wellbore? Do you disagree with that at all?

A. 1900 feet within a certain amount of years; is that correct?

Q. Yes, sir.

A. I didn't put a number to that. Actually, I think it would be -- what we normally consider as an affected area is if the well -- if your injection zone has salt water in it or some other water that's -- or some other fluid that you don't want to be pushed away, well then you look at how far you're going to push it, or any wells that you can push it out of.

In this instance, the acid gas would be -- by far, trump the danger of any displacement of water. So you would need to consider. But it's -- would be very difficult to calculate from even a pore volume how it is displaced, if it is a one-to-one displacement of water. In other words, what the radius of it is.

And I would -- I can't really speculate right now on whether it would be a straight displacement or whether it would be a fingering through of acid gas into the salt water that's in the well right now.

Q. It may be, in fact, elliptical as you indicated earlier, right?

A. Yes.

Q. Mr. Jones, were you present for Mr. Randy Smith's testimony?

A. Yes.

Q. Are you concerned at all about the well that Mr. Smith identified that seemed to have some pressure on it?

A. The well itself -- I don't remember the name of the well. If it is one of the wells that is at the Bone Spring or below the Bone Spring, then I would be more concerned about it. If it's one of the shallow wells that don't come within thousands of feet of penetrating the Bone Spring, I'd still be concerned but not concerned for this Application itself.

Q. You just don't know?

A. I don't know.

MR. HALL: Nothing further, Mr. Chairman.

MR. CARR: Can I just follow with a couple of questions?

CHAIRMAN FESMIRE: Mr. Carr?

MS. O'CONNOR: Actually, I have one.

MR. CARR: Go for it. Or do you want me to go next?

MS. O'CONNOR: No, but if we can just stay in the same order I guess that would be better.

FURTHER EXAMINATION

BY MS. O'CONNOR:

Q. Mr. Jones, you were talking before about some testing. Would a fall-off test be appropriate in this situation?

A. I think -- In my opinion, any kind of pressure testing for purposes of total system permeability or for finding a boundary out there should be done before any kind of injection of acid gas, and I think everyone agrees with me here about that.

So in that case it should be done either -- drill stem testing might give you a system permeability, but it's not as good as a longer-term test, which would mean a swab test. I think it should be swabbed and a fluid sample caught of the formation, once it's completed -- or perforated. And then -- with some memory gauges in the hole.

And then it should be some sort of -- some long-term -- or longer-term injection and a fall-off, to get more of a pressure wave out there, to look for a boundary, and that should be done with water that's got a similar mobility to the water in the formation itself, so you have more of a chance of analyzing -- not just for safety purposes, but if you analyze the test, you can't analyze it if you have multiple phases in the formation.

So for purposes of looking for that fault that everybody's talking about, sure, it would be good, but I'm not sure that it would be useful more than one time, actually, to tell you the truth.

Q. Okay, and would that be a condition that would need to be added to the permit, to require that fall-off test?

A. It's going to be to the operator's disadvantage if they don't know the system permeability, and they're going to do an injectibility -- an injectivity test anyway, in relationship to the fall-off. So it's -- as far as the

Commission knowing if there is a boundary out there, I think that would influence the shape of the -- what Mr. Hall calls the project area here.

So I -- that would be useful to have.

Q. So is it your recommendation that the Commission make that a condition or a requirement of the permit, if they desire to grant this permit?

A. It would be close. I -- Actually, I really like that fracture-finder log also. But I think at least the first -- right off the bat, an injection fall-off test would be useful.

MS. O'CONNOR: Okay, those are all the questions I have.

CHAIRMAN FESMIRE: Okay, Mr. Carr, you indicated you had one other question?

MR. CARR: I have a couple of other questions. It grows, the longer it takes.

CHAIRMAN FESMIRE: Okay, you realize Mr. Hall will get a chance to follow up?

MR. CARR: I do.

CHAIRMAN FESMIRE: Okay.

FURTHER EXAMINATION

BY MR. CARR:

Q. Mr. Jones, did you testify that based on your review of the date on this area, that you have no concerns that there are hydrocarbon shows in the lower Bone Springs? Was that your testimony?

A. Yes.

Q. Now, when we talk about a disposal well, are you familiar with Rule 701.E?

A. That's way down in 701. I don't remember exactly.

(Laughter)

Q. Let me ask you this --

A. Comes after A.

(Laughter)

Q. You were talking about project areas.

A. Yes.

Q. In a pressure maintenance project, you're injecting a fluid into a potentially productive horizon; isn't that correct?

A. Yes.

Q. If you are conducting a waterflood project, you are again injecting a fluid into a potentially productive horizon?

A. Yes.

Q. If you are conducting a disposal operation, you generally are putting the fluid in a nonproductive horizon; isn't that right?

A. Unless the royalty owner is getting the bad end of the stick, that's right.

Q. Okay, but when we're looking at the formation that you're talking about, and we're talking about injecting into, you see no sign of a hydrocarbon show in that zone; isn't that right?

A. That's right, I still think they should swab the well.

Q. But if -- We're talking now about project areas. I'd like to talk -- Rule 701.F for a pressure-maintenance project expressly talks about a project area. Would you agree --

A. Yes.

Q. -- on a check?

A. Yes.

Q. It's the same thing with a waterflood project, there is a project area.

Would it surprise you that Rule 701.E that covers disposal does not require a project area?

A. Actually no, it wouldn't surprise me.

Q. Okay. And this is an injection well, a disposal well we're talking about, right?

A. Still considered a Class II well by the EPA.

Q. But if -- we are disposing of these substances into a nonproductive horizon, correct?

A. Correct.

CHAIRMAN FESMIRE: Mr. Hall, did you have anything to follow that?

MR. HALL: Just one question.

FURTHER EXAMINATION

BY MR. HALL:

Q. Can you refer me to the source where we can establish that the EPA regards an acid gas injection well as a Class II well?

A. The EPA told us that in our last meeting. We -- as far as the -- what is it, the CPR or the CAR, the -- there's -- 142-something is the number that -- it defines the classes of wells.

We had EPA -- one of the managers of EPA, Region 6, here for our review in, I think, August of last year. And we asked him point-blank, Why are these called Class II wells?

And he said, Because they are, they're Class II wells. They're oilfield waste, injection of oilfield waste.

Q. Would you like to see them handled in some different fashion?

A. I would like to see them handled more -- I am uncomfortable doing them administratively, actually. And as far as the Commission, the way they handle them, it's up to them, but I think it would be useful to have some sort of review on how these wells are handled, especially since a lot more plants seem to be applying for these wells.

MR. HALL: Nothing further, Mr. Chairman.

MR. CARR: We could go all night. If I promise one, only, question?

CHAIRMAN FESMIRE: Remember, the Commissioners still get a shot at him.

MS. O'CONNOR: Watch out, Will.

CHAIRMAN FESMIRE: Mr. Hall, would you be so kind as to not object to Mr. Carr's last question?

MR. HALL: If it'll get me anywhere, sure.

(Laughter)

CHAIRMAN FESMIRE: Mr. Carr?

MR. CARR: No, I'm not going to -- I won't ask the question.

CHAIRMAN FESMIRE: All of that, and you're not going to ask it?

(Laughter)

CHAIRMAN FESMIRE: Okay. Commissioner Bailey, do you have any questions of this witness?

COMMISSIONER BAILEY: No, I don't.

CHAIRMAN FESMIRE: Commissioner Olson?

EXAMINATION

BY COMMISSIONER OLSON:

Q. Yeah, I just had a couple questions. One was on the Exhibit C, your recommendations. There was a couple in there I don't know if I heard you mention, and I just wanted to clarify for my own mind if you are still recommending these. One is under -- the title is Bone Spring completion, there's a second paragraph there about step-rate tests. Is that still -- Are you still recommending that the Commission require that as part of any permit?

A. Mr. Commissioner, as far as what the Commission requires, I think it should be run with water before any injection is started in this well with acid gas. I don't think it would hurt for the Commission to put that, because time and again we see the operators coming to us asking for more pressure increase on their wells. The reservoir doesn't always -- isn't always as injectable as we all hope it would be.

So I think it's in Duke's best interest to do this right off the bat, and it wouldn't hurt to put it in an ordering also, since -- I would like to make the point -- one other comment about any tests on these wells after they're injected -- injecting. All the other wells have been in our District 2, which is Artesia, and I've talked to Van Barton, our supervisor of inspectors in District 2, and he does not like his inspectors going out and doing mechanical integrity tests on these acid gas wells.

And so I think it's to everybody's advantage if this well is plumbed, from the beginning to have continuous monitoring and mechanical integrity so that our inspectors are not put at risk of going out and running some kind of an open-valve injection test on the well.

Q. Well then you may have just answered my second question. Is that what -- the other recommendations you had here on -- if the Bone Spring interval is considered adequate, and I'm assuming you're just talking there about continuously recording tubing rates; is that -- So this is also an issue that you think should be included as part of the permit?

A. I think it would be very important, because we do require -- or we normally require an injection well to maintain mechanical integrity, and to require it to be set up from the beginning, to be -- mechanical integrity, without inspectors always going out there and risking their lives.

Q. Okay --

A. And also there's one other main reason here, for the people that are living close to this well. I think continuously monitoring injection pressure to prevent surges of pressure on the well itself, which would stress valves and tubulars and put the people living close to the well in more danger should be avoided.

Q. Okay, thank you. And you had a recommendation on the fracture -- looking at the fracture orientations, and you said that that should be done above and below each zone with the Bone Spring and the Brushy Canyon. But I guess, do you have a recommendation to what distance above and below each zone that should --

A. The more you run that log, the more it's going to cost, it's just a -- and the more you process it, the more it costs. It's about as expensive to process as it is to run. Definitely should be -- I would consider 50 feet above, 50 feet below, or over a competent -- what looks like a competent stress rock, below and above. They might could skip a little area there and just run it over a shale or something that's above, but --

Q. Okay. And then you were talking about the -- on the notice for the radius of review, going to -- looking at -- or the -- the radius of review is really just looking at the wells that are within the area, not really affecting the notice, I guess, is it?

A. It -- I did intend that to be -- also affect the notice. And I think -- All I had to go by as far as ownership was the operators of record of any wellbores that are in that, and I think we required the operators of record of those three wells to be noticed. But I did intend it to be similar to a Class I well, which is a one-mile radial look, and I'm not familiar with the notice requirements on Class I wells, to tell you the truth.

Q. Well, okay, because that was going to be my next question.

(Laughter)

THE WITNESS: Wayne Price is -- will be up here next.

COMMISSIONER OLSON: Okay. Well, I think that's all I have.

EXAMINATION

BY CHAIRMAN FESMIRE:

Q. Mr. Jones, you seem the be the engineer with the most knowledge of this Application and the proposal. If the Commission were to grant a permit for this well with the changes that you recommended, with the monitoring and with the alarming that has been mentioned, can this be done safely?

A. I'm more of a downhole guy than a surface plumbing guy, or a surface person. It did seem -- Mr. Root's testimony earlier did seem extremely detailed. The more mechanical parts that go onto something, the more chances are something's going to go wrong.

Personally, I would rather see them drill a deviated well from the plant site down to an acceptable horizon. But there have been other acid gas wells already approved, and I'm not sure I'm totally competent or able to answer that question.

Q. But from what you've seen, what is your opinion of the installation?

A. I like it, I like what they propose. I think it's -- It's a world different than what was originally sent administratively, and I like that fact, that it did -- I don't regret at all I'm not handling this administratively, or at least requesting it not be handled administratively.

CHAIRMAN FESMIRE: Okay, I have no further questions.

Ms. O'Connor, do you have anything to follow up on?

MS. O'CONNOR: Just one, Mr. Chairman, and that is, at this point the OCD would move for the admission of Exhibit C into evidence.

CHAIRMAN FESMIRE: Any objection?

MR. CARR: No objection.

CHAIRMAN FESMIRE: Exhibit C is admitted into evidence.

MS. O'CONNOR: That's all that we would have of Mr. Jones. We would next call -- or call as our next witness Mr. Wayne Price.

CHAIRMAN FESMIRE: Thank you, Mr. Jones.

MR. JONES: Thank you.

CHAIRMAN FESMIRE: Mr. Price, you've been previously sworn?

MR. PRICE: Yes, sir, I have.

<u>WAYNE PRICE</u>,

the witness herein, after having been first duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. O'CONNOR:

Q. For the record, could you please state your name?

A. Wayne Price.

Q. And by whom are you employed?

A. The New Mexico Oil Conservation Division.

Q. And what is your position with the Oil Conservation Division?

A. I'm the Environmental Bureau Chief.

Q. And could you briefly review for the Commission your educational background?

A. I have a degree in electrical engineering from New Mexico State University. And from there I went to work for the Goodyear Tire and Rubber Company. That's where I had my first environmental project. I helped design the oil/water separator system from -- keep from us from putting oil into the Cuyahoga River.

After that, I was a plant superintendent at the

Maddox Generating Station, and then from there I went into the oil business. I've been in the oil business for some 20, 25 years, mainly in the environmental field, worked for the Division for 13 years.

Q. Have you -- Let me rephrase that question. Do you -- How long have you currently worked for the OCD?

A. Thirteen years.

Q. Thirteen years? Okay, have you ever testified in front of this Commission as an expert in environmental issues?

A. Yes, I have.

Q. Have you testified in front of state or -- and federal court as an expert in environmental issues?

A. Yes, I have.

MS. O'CONNOR: At this point, the OCD would tender Mr. Price as an expert in environmental issues, based on his educational and work experience background.

CHAIRMAN FESMIRE: Any objection?

MR. CARR: No objection.

CHAIRMAN FESMIRE: Mr. Price is so -- Yeah, okay.

(Laughter)

Q. (By Ms. O'Connor) Mr. Price, we've heard a lot of discussion since we've been here about the classification of this gas injection well. In your position with the OCD, do you have a knowledge of classifications of wells?

A. Yes, I do.

Q. Could you discuss for the Commission what the classification of this well is, and discuss with them also the issue of making it a different classification?

A. Right. Well, pursuant to EPA's definition CFR 40-142.something, I can't exactly get the number there, but this particular well would be classified as a Class II injection well. We have a higher-rated class, we also -- I happen to be the permit writer for all of the Class I wells in New Mexico and all the Class III wells. I generally don't handle Class II wells, that's the Engineering Bureau. But our department handles the more stringent controlled Class I and Class III wells. And Class IV wells are hazardous waste wells that have been banned, and then Class V wells are all other wells.

Q. I'm sorry, is it Class I wells that are -- that have --

A. No, Class IV wells are banned.

Q. Class IV wells are banned.

A. Right.

Q. Okay. And why is this not a Class III well?

A. Well, a Class III well is a mineral extraction well --

Q. Okay.

A. -- by definition.
Q. Okay.
A. So they're not extracting any minerals out of there, so it wouldn't be classified a Class III well.
Q. Okay, and do you have a -- in your position, would you like to see the acid gas injection well classified as a different type of --
A. Well, I don't -- you know, by federal regulation, I'm not sure, that would take some sort of promulgation from the federal government to do that. However, I would like to see Class II acid gas injection wells be a subset with maybe different requirements.
Q. At this point in time, though, is there -- At this point in time, it is classified as a Class II well?
A. It is a Class II well.
Q. Okay. And the rules for Class II wells would apply; is that correct?
A. That is correct.
Q. Okay. You've heard the testimony here today that Duke Energy currently is operating a facility out by Hobbs; is that correct?
A. That's correct.
Q. And is that facility permitted by the OCD?
A. Yes, it is.
Q. Tell me what the impact of the proposed acid gas

injection well would be on that permit.

A. Well, I need to back up a little bit. We had a technical meeting with Duke and Duke's attorney, and at that point in time we had -- the technical meeting discussed whether there would be additional water discharges or water created during this process. At that point in time, I don't think -- we probably didn't have the proper players involved in that meeting. It would have been nice to have some of the other technical people there. At that time we thought that it would probably be handled under a minor modification, and that was actually our decision.

However, we received -- and we asked for them to submit a minor modification for their discharge permit --

Q. And let me stop you, just for a point of clarification.

A. Right.

Q. Why would the acid gas injection well be considered a minor modification?

A. Because the waste is being generated at a Water Quality Control Commission-regulated-type facility in which we have delegated authority. So therefore we have authority to regulate all wastes that are generated in those downstream-type facilities. So therefore it comes under our regulations as a constituent agency to the Water

Quality Act.

Q. Okay. And Mr. Price, if you could continue with your discussion of you had this meeting with Duke Energy?

A. Yes. At that time we really thought it would be a minor modification, and it still may be a minor modification. The bottom line here is that the permit has got to be retro-fitted, it's got -- Duke has to apply for a modification to this, because they have actually -- it appears they've actually increased their waste stream from a water-generation standpoint.

Q. And what will be requirements that -- additional requirements that Duke will have to do, to apply for or get a minor modification?

A. Basically, it would be a notification letter to us, telling us, the Division, that they are wanting to retro-fit their plant, ask for a modification of their permit. We would want to see detailed drawings, best management practices that they're going to use to prevent groundwater contamination, and also any controls that would be put in place to help protect public health and the environment.

Q. Okay. And this the water discharge plan --

A. Yes.

Q. -- that you would like to see?

A. It's actually a comprehensive groundwater protection plan, or an environmental protection plan.

Q. And at what point in time in this permit process would you like to see that discharge modification plan?

A. Well, by the regulations they have to submit that modification before they can actually start work. Then they would have to get approval from the OCD that the modification is approved. And if we have conditions, then we would send those conditions and make those conditions part of the discharge permit.

Q. In your opinion, can the -- or should the Commission -- if they desire to approve this permit, is it your recommendation that the permit be approved prior to this discharge plan being received and reviewed by the OCD?

A. Actually, I think it can be approved, because what they're asking is an APD to be approved for a well. And so from that standpoint they're going to go out there and they're going to drill a well. That's strictly a permit process that this Commission is probably taking a look at right now.

And once they have proven that the well will work, then, and only then, they're probably going to come back and come to us and say, Okay, this is what we need to do, we need to do all of the retrofit. And so that is where the additional generation of waste under this permit would have to be handled.

So yes, I think the well could be permitted first. I think that's the logical step, because if the well doesn't prove to be a beneficial well for them, then they would have no reason to come in for -- to modify their discharge permit.

Q. Okay. And is there -- in the event the Commission decides to issue this permit, do they need to make a condition to the permit regarding the discharge plan, or is that adequately covered under the rules?

A. Actually, if I understand your question, I think you're asking, Does the Commission have to take into consideration the discharge permit process up front? If that's your question, then I say the answer to that is no.

However, if they do approve the plan, they go out there and they make a well, and then -- before they can ever actually discharge from that plant, then the permit would have to be modified.

Q. Mr. Price, you've been here for the entire hearing today, have you not?

A. I have.

Q. And there has been a lot of talk about safety concerns?

A. Right.

Q. The safety concerns on this permit, is that covered by any OCD Rule requirement that would require a safety plan or contingency plan?

A. Yes, it would be covered under our Rule 118 for hydrogen sulfide contingency planning.

Q. Okay, could you tell the -- Well, first let me ask you, do you have any concerns about the safety plan and the safety issues regarding this acid gas injection well?

A. I haven't seen the plan, so it's kind of hard for me to say if I have concerns if I haven't seen the plan. However, I can say that when we were at the public meeting -- and I think Duke did a really good job -- I did see a number of deficiencies that I thought were not appropriately planned out. And I think those things can be handled in the contingency planning process.

Q. Could you review for the Commission what deficiency that you believe exists in the proposed plan by Duke?

A. Well, one of the things that I didn't see is that the plan did not include some sort of hard-wired alarm system to the Maddox Generating Station, nor did it have a hard-wire to Mr. Smith's house. And so those two -- his household and then the Maddox Generating Station, in my opinion, will be a requirement that they'll have to have some sort of hard-wired alarm system, and not just strictly rely upon telephone systems. They're close enough, it can feasibly be done.

Q. Okay, there's been prior testimony that Mr. Smith's home is a mile and a half from the proposed --

A. Right.

Q. -- facility. Would it be your recommendation that all work facilities or places of businesses or homes within a mile-and-a-half radius be hard-wired, as you have discussed, for an emergency?

A. Well, I think we maybe need to go a little bit further than that. I think we need to take a look at the radius-of-exposure calculations, and we'll have to see what the H_2S radius of exposure is at what levels. I've heard numbers as high as 4000 feet. If that's the case, then you have a potential area there that, you know, could be fatal for anyone within that area. And so therefore, if you have houses or if we have the public, we need to have some sort of hard-wired systems to those type of facilities or homes, and maybe even along the highway there, there should be some sort of public awareness, flashing light or something.

To continue with the question, you had also asked what deficiencies did I see? I didn't see, at the time, where they actually were going to -- at what levels they were going to activate and at what level management would actually be the one who would make the call. I have found out later on, though, that some of those systems they were planning on doing, there is some activation levels at 90 parts per million. I would recommend that those be lowered.

Q. To what?

A. To 50 parts per million.

Q. Okay. Now, would the --

A. I mean, I'm talking about shutdown at 50 parts per million.

Q. Okay, and when you say shutdown, you mean shutdown of the --

A. Shut in the well and shut down the complete system.

Q. Do you have any concerns about where that decision of shut-in will be made?

A. I really do. I think the contingency plan would have to have a decision-making tree in there so, you know, if you can't get ahold of a high-level management-type person, that it doesn't get shut in. So I think there should be some automated shut-in levels, decision levels that no matter what, when they hit those levels, the system's shut in.

Q. Okay. Now, you were also talking about the radius of exposure. Would that radius of exposure be set out in the contingency plan?

A. It would have to be, yes.

Q. Okay, and so that is something that Duke will determine, where the radius -- what the radius of exposure is?

A. With our help.

Q. And what do you mean by "with our help"?

A. Well, they're going to submit their calculations, and we're going to review that. And if they have a modeling program that they -- we'll have to have a copy of it. I heard earlier that it's proprietary, but if they can't give us a copy of it, then we can't use it.

Q. Okay. Now you also spoke about the possibility of having some kind of an alarm system along the public roadways?

A. Yes.

Q. And could you explain to the Commission what it is that you would expect that to consist of?

A. Well, you know, it's not uncommon to see that. Down in the Eunice area they have some alarm systems like that, where they have flashing lights that if the light's flashing, you know, there is possible poisonous gas in the area. It's just a public-awareness thing.

The other deficiency that I kind of saw at the public meeting is that they have this public highway going right beside the plant and the lines going underneath there. I didn't see anywhere in there where if they do have a leak, I didn't see them talking about how the highway would be shut down.

Q. Is that something you would like to see addressed in the plan?

A. It would have to be.

Q. Okay. Do you know what a de-gasifier is?

A. Yes.

Q. And what is that?

A. Well, on a drilling rig it's when you're circulating the mud, you have a de-gasifier on the drilling rig. It would basically take that gas out and flare it.

Q. Okay.

A. And that's used in H_2S areas where they're drilling.

Q. Okay. Is that something that you would like to see for this acid gas injection well?

A. Yes.

Q. And could you explain to the Commission why?

A. Well, I think that's a known area. Just east of there, there's -- in the North Hobbs field that Will was talking about, there's some extremely high H_2S areas there. And so when they're doing the drilling they just need to have a contingency plan for the drilling, to basically -- when they submit their APD, they need to submit a drilling contingency plan to take care of any possible occurrences of H_2S that they might encounter. They may not encounter any, but I would think we would make sure that they had one in case they do encounter H_2S.

Q. Are there any other recommendations you would like to make regarding a drilling contingency plan?

A. Well, just abide by Rule 118. It's pretty well spelled out in there, it's a pretty logical, step-by-step process. They'll have to have, you know, BOP's, they'll have to probably have a rotating head in case they do go through a pocket of gas that's there, they'll have to flare, have to have an on-site flare with -- they'll have to have fuel gas, in case they do get into some H_2S that may not burn, they have to have additional fuel gas so they can burn it.

When you burn H_2S, it's basically much less harmful. You do have some air emissions there, but it's not the acute toxic gas that you have when you have -- just the raw H_2S.

Q. Now, with the contingency plan, you said you have not yet seen it.

A. I have not.

Q. When under the requirements of the OCD would the contingency plan be required?

A. I think when we review the discharge modification, we would want to see the plan there.

Q. And my question is going to be, do you -- about the contingency plan, as it was with the discharge plan. Do you believe that you need to see the contingency plan before the Commission can decide on whether to issue a permit, or can the contingency plan be worked out subsequent to the permit being granted?

A. Well, my opinion is that as long as they have an H_2S contingency plan for the drilling, I wouldn't see any reason why the Commission couldn't go ahead -- not to tell the Commission what to do, but I don't see any reason why they couldn't go ahead and approve it.

However, before they actually build the facility, build the pipeline, do any injection, and then we'll have to see a comprehensive contingency plan.

Q. Once these plans are submitted to the OCD, you'll be reviewing them, correct?

A. Yes, that's correct.

Q. And even though the permit may have been given at that time or by the time you're going to get the plans, a permit will have been given. Can you add conditions at that point in time, even though the permit has been given?

A. I can add conditions to the discharge permit process. I don't think I could add conditions for the well site.

Q. Okay. And Duke would have to acquiesce to those conditions, or the permit would not be in effect; is that

correct?
A. That's correct, that's correct. And the reason I say that -- Let me explain myself about that. The Water Quality Act -- the Water Quality Control Commission has delegated the OCD as a constituent agency. By law, we are only allowed to administer those regulations for downstream-type facilities. Those -- We do not apply those regulations to upstream facilities. In this particular case, the well site itself would be an upstream facility.
Now I will say this, that the pipeline going out there will probably be under the pressure conditions of the permit. We'll make sure that the pipeline is pressured -- there's a pressure-maintenance plan and so forth. The actual well itself will be under separate oil and gas regulations.
Q. Okay. Mr. Price, from what we've heard here, the testimony today, it appears that there are other permitted acid gas injection wells in the Hobbs area; is that correct?
A. There's several.
Q. Okay. Compared to those existing acid gas injection wells, could you comment on how you're perceiving the safety issues of this current request for an acid gas injection well?
A. Oh, it's state-of-the-art.

Q. So in your opinion, do you believe that at this point there will be more safety concerns that are met in the current proposal than in what currently exists out there?

A. Yes.

Q. Now you were here also for Chris Root's testimony?

A. Yes.

Q. Do you recall his testimony regarding the piping system that would be installed?

A. Yes, I do.

Q. To your knowledge, has the proposed piping system by Duke been used by anyone else in New Mexico?

A. Yes.

Q. And who is that?

A. Navajo Refining has a very similar system.

Q. Okay. Have there been any problems with that piping system?

A. Yes.

Q. And could you explain to the Commission what those are?

A. They had a total failure of the system, it didn't work, and so they basically had to abandon it.

Q. Do you have a proposal or recommendation to the Commission regarding the piping system that Duke is proposing to use?

A. Well, I think -- you know, as with any engineering system, the OCD is not in the business of telling people how to design systems. But I certainly think we have the obligation to make sure whatever they put in is going to work. And so I think there should be a lot of scrutiny on how they design that system and so forth, and make sure that we have a good track record of those type of systems that they're going to put in.

Q. Now, you said the OCD isn't in the business of telling a company how to design their project, but yet you've expressed concerns here. How are those going to get -- Is there any resolution between your concerns and what actually is used out there?

A. Oh, I think so, I think there is.

Q. And what is that?

A. Well, I think it -- just open up a good dialogue, have their top technical people come in and basically show us their design system and show us a track record of what they've done in the past.

Q. Is there anything that you believe that the Commission needs to take into consideration or conditions that they would need to add to the permit, to address the concerns that you've just raised?

A. For the permitting of the well?

Q. For the permitting of the well, correct.

A. No.

Q. Mr. Price, do you have any other concerns that you would like to discuss with the Commission that we have not already raised?

A. We have a -- I have a little bit of concern with -- after the technical meeting, it was my understanding that we were going to get a letter telling us that Duke was going to apply for a modification to their permit. But we got a letter, but the letter was more of a letter saying that -- what they're going to do, and that they didn't think that the Water Quality Act or the WQCC Regulations applied in this case. And so that's an issue we have to work out.

Q. Is that an issue that you believe should delay the approval of this permit?

A. I think that's a decision for the Commission to make.

Q. Do you have a recommendation for the Commission regarding that issue?

A. Well, yes, I do. I think maybe Duke should go ahead and submit their modification in good faith and make sure that we know that we can get a letter from them stating that they want to modify their permit and that they understand that those regulations do apply to them.

MS. O'CONNOR: I have no further questions for Mr. Price.

CHAIRMAN FESMIRE: Mr. Carr?

EXAMINATION

BY MR. CARR:

Q. Mr. Price --

A. Yes, sir.

Q. -- you understand why Duke wants to develop this project --

A. Yes, I do.

Q. And you understand that we're here today seeking approval for the injection well, having filed a C-108 Application?

A. Yes.

Q. And you agree that this is a Class II injection well?

A. Yes, it is.

Q. It is a well that disposes of fluids associated with the production of natural gas?

A. Exempt RCRA fluids, that's correct.

Q. You and the OCD and other people in the agency have reviewed the Application?

A. Yes.

Q. And you at the very outset wrote and enclosed additional requirements on this particular Application;

isn't that right?

A. Primarily Mr. Jones.

Q. But there were additional notice requirements --

A. Yes.

Q. -- and there were a number of points that were basically required by the OCD, one of them being coming to this hearing?

A. That is correct.

Q. And so within the current framework, you do as an agency have ability to make site-specific determinations to assure that when an application comes before you, if it's approved, it's safely -- it's going to be a safe operation; isn't that fair to say?

A. Yes, we do. And I'd like to follow up. I want to make sure that -- a while ago when I said that the two systems are separated, they really are from the standpoint of regulations. What I didn't mean to imply was -- is that we don't have the ability to have Duke perform certain conditions or do certain things at the well site that's going to be protective of public health and the environment. We certainly have that authority.

Q. And we're not challenging that --

A. Right.

Q. -- you understand that?

A. Right.

Q. What I see is, first of all an application was filed, and then with your authority you imposed some additional requirements on Duke, one of them being this hearing?

A. Right.

Q. And now, then, we came in and met with you concerning the Water Quality Control Commission permit and whether or not it was needed to be -- whether or not a major modification or a minor modification was required?

A. That is correct.

Q. And at that meeting it was my understanding that we were in agreement that it was a minor modification?

A. With the knowledge that we had, yes.

Q. All right. And following that, we wrote you and sent you a letter which was a notification of what we were going to do?

A. Yes.

Q. That isn't inconsistent with what was understood at that meeting, is it?

A. The only -- Mr. Carr, the -- what I don't think -- what I think did not come out in the meeting was the additional 20 to 100 barrels of sour water that was going to be generated, and that did not come out in our meeting.

Q. And I just wanted to be sure. You said that it was time for Duke in good faith to file a modification.

You're not suggesting what we're doing here has been in bad faith, are you?

A. I'm sorry, say that again?

Q. I mean, you're not suggesting that by filing this letter there was anything on our part that was in bad faith?

A. Oh, absolutely not. It's not uncommon to have two or three letters go back and forth to basically find out the details of the system and so forth.

Q. And there are several issues or several things that must be done before the project is finally approved. One is getting the C-108 Application approved and being authorized to go forward with the well?

A. Correct.

Q. Before we do that, we would have to have an H_2S contingency plan for the drilling of the well?

A. That is correct.

Q. And under the Rules, that -- Rule 118, you have to have that before you commence operations?

A. That is correct.

Q. So that's one thing we would have to do, and we have to do it under the Rule whether it's ordered or not; that's a precondition?

A. Yes, it is.

Q. And that's not on any well, but in an H_2S area?

A. Right.

Q. And then we are going to drill the well, and then we're going to finalize the facility design, and then at that time there's another more comprehensive H_2S contingency plan that needs to be approved by the Division?

A. That is correct.

Q. And you have the authority to negotiate and to talk with Duke and to listen to their engineers and technical people and develop that so that before it's approved you're satisfied that it protects public health, fresh water, safety, the environment, all of the things that you're charged to?

A. That's correct.

Q. As to the permit modification, whether it's a minor modification or a major modification, we again still have to come to you and get that before we can go forward with --

A. That is correct.

Q. -- that project --

A. That is correct.

Q. -- isn't that right?

And typically -- I mean, the Application to drill the well was called to hearing. If we hadn't come to hearing, like some of the others, we still would have been negotiating with you on a water quality control permit, perhaps, and an H_2S contingency plan?

A. That is correct.

Q. And we would have been doing that in your office and not before the Commission; isn't that correct?

A. That's correct.

Q. And don't you recommend that that's how we go forward now?

A. I do recommend that.

MR. CARR: Thank you.

CHAIRMAN FESMIRE: Mr. Hall?

EXAMINATION

BY MR. HALL:

Q. Mr. Price, will Duke Energy be required to get an air quality permit for their compression facilities at the injection end of the project?

A. I don't know the answer to that question. I'm not an air-quality expert.

MR. HALL: Nothing more.

MS. O'CONNOR: No further questions.

CHAIRMAN FESMIRE: Commissioner Bailey?

COMMISSIONER BAILEY: I have no questions.

EXAMINATION

BY COMMISSIONER OLSON:

Q. I just wanted to clarify a few things. I guess that's what's getting confusing to me today. We spent a lot of time talking about H_2S today from surface facilities, and I want to make sure I've got this clear. What we've got today is this Application in front of us solely for -- this what I think you were just testifying to -- solely for the purpose of drilling this well?

A. That's my understanding.

Q. And that any of the surface facilities that come in will be governed separately and are not an issue of this hearing? That would be the subject of some other hearing?

A. That's my understanding.

Q. Well, that clarifies a lot for me right there.

(Laughter)

Q. I guess, then, to follow up on that, a lot of these issues, then, we're going over today on contingency plans and all this will come up as part of this other -- of the discharge permits for the actual surface facilities, the pipeline and the compression facility?

A. That's correct.

Q. Okay. And that will have its own public participation process that goes along with that as well?

A. Maybe. And the maybe there is, is this going to be a major modification or a minor modification? When we had our technical meeting, as Mr. Carr knows, it was determined that would be a minor modification because there was going to be no additional waste produced at the plant.

However, when I get the letter I see it's 20 to 100 barrels per day. Now, that does change the issue of a major or minor modification. If it's a major modification, there'll have to be a public notice issue. If it's a minor modification, no.

Q. So a lot of the issues here today seem to be about the contingency plan, though. Is there some type of public participation process for the contingency plan?

A. It is my plan to incorporate the contingency plan into the discharge permit for that facility. We have done that at other gas plants where we had acid gas wells.

Q. I guess my concern is that -- the big part of the public concern is about what happens in the event of a release.

A. That's right.

Q. And I wanted to make sure that --

A. And that's --

Q. -- there would be some type of a public process. I don't believe Rule 118, as it's written, requires a public participation process.

A. Unfortunately, it doesn't.

Q. It does not. So if the contingency plan is attached to the discharge permit, which is regulated under WQCC regulations --

A. Yes.

Q. -- where would appeals of the contingency plan go to? Would they go to the WQCC, or would they go to the OCC?

A. Well, I think it could go to both, to be honest with you, because we certainly -- we're a constituent agency, and we can apply either one of the regulations. We've always had that authority. And so if they're going to appeal the WQCC permit aspect of it, it would go to the WQCC. If they were going to strictly just appeal the H_2S contingency part of it, under Rule 118 it would go to the OCD.

Q. Well, I think I'd agree with you, because I don't know that the Water Quality Act has any language in it for protection -- does it have the broad language for protection of public health that exists in the Oil and Gas Act?

A. I can assure you that our department is going to do everything in its power to make sure that it protects public health.

Q. So the Division wouldn't have a problem, then, if the Commission added some language that any contingency plan for the surface facilities would go through a public participation process?

A. Not at all, I'd recommend it.

Q. And then you mentioned that Navajo Refining had installed a similar pipeline system?

A. They installed a pipeline system that had an HTEP liner with the tell-tale systems like Duke is talking about, and they -- that is a Class I well, which is a lot more stringent than a Class II well from a construction standpoint, from a monitoring standpoint, and so forth.

We also require fall-off tests every year on -- we require a MIT every year on those, and -- So yes.

And that pipeline -- the reason we're required -- or they came to us and proposed double walls because they were going underneath the Pecos River with it. And we approved that system, but it failed within a year. And now they've asked for some sort of alternate design.

Q. Why did it fail?

A. According to Navajo, at the point where the polyethylene is inside of the pipe, at the point where it made the joints, is where it failed. And so from day one it pressured up between the microannulus, and they never could tell if they had a leak or if it was from the original problem that they had. So there was no way of actually telling if there was a continuing, ongoing problem.

Now, the water -- or it never leaked out of the pipe, but the microannulus tell-tale system failed, it wouldn't work.

Q. Then I guess just would be one last question. Would it be your recommendation that these Applications go administratively in the future with the potential that then get appealed to the Commission? Because I think right now it seems like -- this seems like a difficult process to be hashing out a full application at a Commission hearing, and obviously that's why I think we've been here --

A. I'm going to answer your question in two ways. I'm going to tell you what I think we should do in the future. I think we should have a rule for acid gas injection wells.

And then to answer your other question, until we have that, I think -- in order to have public participation I think it's got to come in front of the Commission.

Q. So there's not a mechanism at the moment for it to be done administratively with an appeal to the --

A. I think there is.

Q. -- to the Commission?

A. Yeah, I think there is. But what I wonder about is, the public notice participation.

Q. Okay.

A. Yeah.

CHAIRMAN FESMIRE: The reason this one came to the Commission is that we determined that there was a need to --

THE WITNESS: Right.

CHAIRMAN FESMIRE: -- make public input --

COMMISSIONER OLSON: Right.

THE WITNESS: Right.

CHAIRMAN FESMIRE: -- on this.

COMMISSIONER OLSON: Right, I can see that.

THE WITNESS: Right.

COMMISSIONER OLSON: That's all the questions I had.

EXAMINATION

BY CHAIRMAN FESMIRE:

Q. Wayne, to clarify a little bit on the Navajo pipeline question which you were just answering --

A. Yes, sir.

Q. -- how is that going to be different on this state-of-the-art facility?

A. Well, in all fairness to Duke, I don't know if that system that they're designing is exactly -- has all the engineering requirements, all the specifications that the Duke had.

So you know, in all fairness to them, they might have a system that is totally different than the Navajo -- I'm just telling you, they sound very -- they sound almost identical. They sound -- they have the microannulus, they have the HDPE inside of a metal pipe, and all I can tell you is, it failed.

Q. Okay, and when you say it failed miserably, it didn't fail to the point that there was a release, it just failed to the point that --

A. Well, actually there was a release out of the tell-tales, out of the -- where they actually check for releases, yes, that is the head fluid coming out of there. I'm saying the pipeline didn't lose integrity and thousands of gallons of product come out and so forth --

Q. So it wasn't a catastrophic failure, but it was a failure of the system?

A. It was a failure of the system to the point that it could not be relied upon.

CHAIRMAN FESMIRE: Okay, I have no further questions.

MR. BROOKS: Mr. Chairman, I'd like to ask Mr. Price just two questions.

CHAIRMAN FESMIRE: Okay.

MR. BROOKS: I apologize for doing that this late in the afternoon, but I have kept admirably quiet the whole day.

(Laughter)

EXAMINATION

BY MR. BROOKS:

Q. Mr. Price, you understand, do you not, that the

701 permit is a permit -- not merely a permit to drill an injection well, it's a permit to inject also?

A. Yes.

Q. And in view of the confusion that exists about these two intersecting regulatory schemes, would it not be -- would it not possibly be advantageous for the Commission to put into a 701 permit, that they would issue one in this case, a condition that the surface facilities associated with this injection system be properly permitted under the facilities discharge permit prior to the commencement of injection?

A. Yes, I think that's very appropriate.

MR. BROOKS: Thank you.

CHAIRMAN FESMIRE: Any further questions?

COMMISSIONER BAILEY: I have no questions.

MR. HALL: Just one.

(Laughter)

CHAIRMAN FESMIRE: Turnabout's fair play. Mr. Hall?

FURTHER EXAMINATION

BY MR. HALL:

Q. Mr. Price, what notice do you envision the agency would require for public participation in the H_2S contingency plan review process?

A. Well, like Commissioner Olson pointed out, under

Rule 118 there is no public notice requirements in Rule 118. There is a public notice requirement under the discharge plan mechanism, if it's a major modification.

MR. HALL: That's my only question.

CHAIRMAN FESMIRE: Mr. Carr?

MR. HALL: That's my one question.

CHAIRMAN FESMIRE: Oh, okay. Mr. Carr, I'm assuming you don't have anything to follow up?

MR. CARR: I don't, I'm just puzzled by Mr. Brooks. He said he had two questions. I think he only had one.

(Laughter)

MR. BROOKS: Well, it was two questions. I've had a lot of experience with lawyers. When they say they're going to ask one or two questions, they mean they have one or two lines of questioning. I meant literally two questions.

CHAIRMAN FESMIRE: At this time we're going to go ahead and continue this hearing until next Monday. At that point in time I intend to probably go into executive session and discuss the evidence that's been brought before the Commission today.

Would either attorney -- would any of the attorneys -- I'm sorry, I keep forgetting you, Cheryl -- would any of the attorneys have an objection to continuing it until next Monday?

MR. HALL: We don't object.

CHAIRMAN FESMIRE: Mr. Carr?

MR. CARR: No, sir.

CHAIRMAN FESMIRE: Okay. So at this time we'll adjourn until next Monday the 20th, March 20th, at 9:00 a.m. in this room. Hopefully in this room.

Thank you all very much, and thank you for your patience.

(Thereupon, these proceedings were concluded at 6:38 p.m.)

* * *

CERTIFICATE OF REPORTER

STATE OF NEW MEXICO)
) ss.
COUNTY OF SANTA FE)

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Commission was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL March 21st, 2006.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2006