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

APPLICATION OF OCCIDENTAL PERMIAN LIMITED PARTNERSHIP TO AMEND ORDERS R-4934 AND R-4934-E GOVERNING THE SOUTH HOBBS GRAYBURG-SAN ANDRES PRESSURE MAINTENANCE PROJECT TO ALLOW THE INJECTION OF CARBON DIOXIDE AND PRODUCE GASES, TO MODIFY THE SURFACE INJECTION PRESSURE, TO OBTAIN OTHER RELIEF, AND TO QUALIFY THIS EXPANSION FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE NEW MEXICO ENHANCED OIL RECOVERY ACT, LEA COUNTY, NEW MEXICO.

CASE NO. 14981

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

COMMISSION HEARING

VOLUME 1 OF 2

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

May 9, 2013
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Commission on Thursday, May 9, 2013, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis Drive, Porter Hall, Room 102, Santa Fe, New Mexico..

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EXHIBITS MARKED, IDENTIFIED, OFFERED AND/OR ADMITTED

(9:03 a.m.)

COMMISSIONER BAILEY: Next, we have been asked to take the cases slightly out of order that were listed on the docket. So first we will call Case 14981, which is the application of Occidental Permian Limited Partnership to amend Orders R-4924 [sic] and R-4934-E governing the South Hobbs Grayburg-San Andres Pressure Maintenance Project to allow the injection of carbon dioxide and produced gases, to modify the surface injection pressure, to obtain other relief and to qualify this expansion to the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act, in Lea County, New Mexico.

Call for appearances.

MR. FELDEWERT: Madam Chair, Members of the Commission, my name is Michael Feldewert from the Santa Fe office of Holland & Hart. I'm appearing today on behalf of Occidental Permian Limited Partnership. I have seven witnesses.

MS. GERHOLT: Madam Chair, Commissioners, Gabrielle Gerholt on behalf of the Oil Conservation Division.

MR. ALVIDREZ: Madam Chair, Commissioners, Rick Alvidrez on behalf of Malcomb Coombes. He is an adjoining landowner to the property at issue in this case.

COMMISSIONER BAILEY: Mr. Feldewert, do you have an opening statement?

MR. FELDEWERT: I do.

OPENING STATEMENT

MR. FELDEWERT: You are going to learn about OXY's South Hobbs Unit. It's been an -- it is an existing waterflood. It's been an existing waterflood for almost 40 years. OXY Exhibit 4 that I'm going to present to you is the approval order for that waterflood back in 1974. The injection occurs in the Grayburg and San Andres Formations at around 4,000 feet.

And as you can tell from the application that OXY seeks to do today is to convert to a tertiary recovery project with the injection of CO2 and the injection of produced gases and water.

You're also going to hear about the North Hobbs Unit. It is adjacent to the South Hobbs Unit, same area, same reservoir. Since 2003, it has been operating safely as a tertiary recovery project. So at the 30,000-foot level, what OXY seeks to do at the South Hobbs Unit is exactly what it is doing with the North Hobbs Unit.

I have a total of seven witnesses.

Rick Foppiano, sitting to my right, is the

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director of Regulatory Affairs. He's going to be our first witness. He's going to talk about OXY's experience with these types of projects. He's going to go over through the life cycle of a reservoir and why you move to a tertiary recovery project. He's going to talk a little bit about how these types of projects work and how they differ from disposal wells, which I know have been before you previously. He's going to outline the relief that we seek, and he's available to address whatever questions you may have about that requested relief. I anticipate his testimony's going to take a little over an hour.

Our second witness is going to be Jerad Brockman. He's an engineer, and he is the project manager for the South Hobbs Unit. He's a bright young guy.

He's going to give you a general overview of the project, the location of its facilities, the costs, the timeline of events. He's going to address briefly the gas-oil ratio issue, if it's an issue for the Commission. And, quite honestly, I'm puzzled as to whether a gas-oil ratio even applies to a tertiary recovery project. I can't really find anything in the rules that tell me one way or the other. My assumption is that it would not, but if that is an issue, then we're prepared to address that. I guess what I'm saying is, we'll save a little time if the gas -- if a gas-oil ratio does not apply to a tertiary recovery project like this.

He's also going to talk about the requested injection pressures, how they were determined for this project. He's going to address the packer-setting issue that we raised, and he's going to discuss their downhole corrosion mitigation efforts. His testimony is going to take about an hour and a half.

So I think it's going to take most of the morning, but you're going to have a good feel of the project by the end of the morning.

Our third witness is going to be Randy Stilwell. He's a geologist. He's going to talk about the structure of the injection zone. And the best way he described it to me is, it's a very -- that I can understand. It's a contained structure. He's going to discuss the location of the freshwater zones and demonstrate that these freshwater zones are indeed protected by layers -- layers of impermeable material. His testimony is going to take about a half hour.

Scott Hodges is going to be our fourth witness. He lives in Hobbs. He's the operations leader for the South Hobbs Unit. He's going to discuss OXY's

SCADA System that he utilizes in the North Hobbs and South Hobbs Units, very interesting system. Does a lot of things, but what he's going to focus on is how it monitors temperature and water content, how it monitors pressure, how it monitors H2S levels, and how it does a gas analysis on a consistent basis. He's going to talk about their realtime monitors, and the automatic shutdown systems that are associated with them. His testimony is going to take about an hour.

We're going to have Krishna Chokkarapu as our fifth witness. He is part of OXY's Facilities and Construction group, which is part of a group within OXY that addresses all of their worldwide projects, including big projects like this. He is an expert in design and engineering and construction of CO2 flooding surface facilities.

He's going to talk about what his group does and how they are involved in the design and material selection for these surface facilities, how they are involved in fabrication and construction and how they are involved in the maintenance, a cradle-to-grave concept through this group that draws on their worldwide experience.

He's going to talk about the surface facilities that's going to be used at the South Hobbs

Unit and how the standards -- the industry standards and the method that they use resulted in the material selection and the fabrication and construction -- what will be the fabrication and construction of these facilities all designed to obviously maintain the mechanical integrity. His testimony is going to be about an hour.

Kelley Montgomery is our sixth witness. She's a production and environmental engineer with OXY. She's actually the person who put together both the C-108 and the area of review notebooks that you have in front of you.

She has met with the Division about this project, addressed their concerns. She will quickly initially run through the data that I think we have to run through as part of the tax incentive request. We can do that fairly quickly. She's then going to do an analysis of the proposed injection wells. She's going to talk about the wells within the area of review. She's going to address the MIT frequency issue that we have raised in our application, as well as the cement bomb [sic] law requirement that currently exists in Rule 15 under the Division order that governs this project. Because of how she has organized the area of review, I think we can get her testimony in in about an hour and a half.

Finally, our last witness is Pat Sparks, and he's our landman. He's an experienced landman who has testified before the Division, and -- I know the Division, previously. He is the one that led OXY's six-month effort to address the extensive notice requirements for this project, and he's going to talk about that. He's going to demonstrate that OXY fulfilled the notice requirements for this application. His presentation is about ten minutes.

So if we have a period of time right before a break, perhaps he's a witness we can move up and fill that time, because it's only about 10 or 15 minutes.

This is an important project to OXY. It's a $600 million effort to extract additional oil from the ground that's otherwise going to be wasted. It's important to the city of Hobbs. You're going to find that they're behind this effort. It's important to Lea County. They're behind this effort.

The company and its employees have put forth a substantial effort into this project, and they're here today to provide you with the information you need to fulfill your regulatory oversight over these types of projects. And I'm confident that after this presentation you're not only going to have a complete understanding of the project itself, but you're going to find that's it's going to prevent waste and protect correlative rights and that it can be done safely, just like it's being done safely at the North Hobbs Unit.

A couple of housekeeping matters: You have three notebooks in front of you. The first notebook is the Form C-108. I would like this considered as OXY's Exhibit 1, for ease of reference in the record. So this notebook (indicating), "Occidental Permian South Hobbs Project, Form C-108" can be OXY's Exhibit Number 1.

The "Area of Review" notebook, which is the second white notebook you have, I would like to have considered as OXY Exhibit Number 2.

And then I have structured our presentation to sequentially admit additional exhibits from 3 on.

So with your permission -- I think I can do this given that they've been filed -- I'd like to move the admission of OXY Exhibits 1 and 2, and our witnesses can begin their presentation, and we can admit the exhibits as we go along.

COMMISSIONER BAILEY: Any objections to the admission of Exhibits 1 and 2?

MS. GERHOLT: No objection.

MR. ALVIDREZ: No objection.

COMMISSIONER BAILEY: Then they are so

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admitted.

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

MR. FELDEWERT: We're prepared to begin whenever you are.

COMMISSIONER BAILEY: Let's see if Ms. Gerholt has an opening statement.

OPENING STATEMENT

MS. GERHOLT: Thank you, Madam Chair.

The Oil Conservation Division has been charged by the legislature to prevent waste, protect correlative rights and protect public health and the environment. The Oil Conservation Commission also shares this charge. A recognized and accepted method to prevent waste is through enhanced recovery projects.

The Commission and the Division have the statutory authority to permit the injection of natural gas or any other substance into any pool in this state for the purpose of repressuring, cycling, pressure maintenance, secondary or any other enhanced recovery.

OXY filed a C-108 application for a secondary recovery and pressure maintenance. Richard Ezeanyim, Chief Engineer at the OCD, reviewed the application and determined that waste will be prevented and correlative rights protected if the expansion of the

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South Hobbs Unit is permitted by the Commission.

The Division has the duty to protect public health and the environment by regulating the use of hydrogen sulfide. Chief Engineer Ezeanyim reviewed the C-108 and determined that additional conditions were needed to be included to protect public health and the environment. The conditions the Division asked to be included require a one-way automatic AC valve, fiberglass line tubing and nickle-plated packers, MITs every two years for injection wells, operations to be conducted in a closed-loop system, and the use of corrosive-resistant cement. By including the requested conditions, the Commission would protect public health and the environment.

The Division will not be calling Mr. Ezeanyim today, but, instead, will proffer his testimony as Exhibit A. Neither OXY nor Mr. Coombes objected to that, and, therefore, the Division will be relying upon that exhibit today.

Thank you.

COMMISSIONER BAILEY: Mr. Alvidrez?

MR. ALVIDREZ: Yes, Madam Chair.

OPENING STATEMENT

MR. ALVIDREZ: Members of the Commission.

Just very briefly, as I indicated upon

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introduction, Mr. Coombes is an adjoining landowner. He is not opposed to this project. He certainly does, however, want to make sure that it's carried out in such a manner that protects his interests as an adjoining landowner, protects the health and safety and environment as well. And we are also fully supportive of the additional safety conditions and environmental protection conditions that the Division has advocated before the Commission. But primarily we're here to learn, ask a few questions, and Mr. Coombes may say a few words to the Commission at the appropriate time.

Thank you.

COMMISSIONER BAILEY: I have an announcement to make. We were told that there were some people who wanted to make public comments. This is an adjudicatory hearing. It is not rulemaking. OCD rules do not provide for public comments during adjudicatory hearings, so we will not be taking public comments, if that is anyone's intent here. We will be deciding this case on the facts of the case.

Thank you.

You may call your first witness.

MR. FELDEWERT: We will call Richard Foppiano.

COMMISSIONER BAILEY: Would you swear in

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the witness, please?

RICHARD E. "RICK" FOPPIANO,

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

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your full name and identify by whom you are employed and in what capacity?

A. Yes. My name is Richard E. Foppiano, Rick Foppiano. I am currently director of Regulatory Affairs for OXY in Houston.

Q. Do your employment responsibilities include involvement in the regulatory issues associated with the CO2 injection project?

A. Yes, they do.

Q. Does your employment include the regulatory efforts associated with the South Hobbs Unit?

A. Yes, they do.

Q. Were you involved in the North Hobbs Unit?

A. I was, yes.

Q. Do you have experience in Texas and New Mexico?

A. In regulatory matters and production engineering, yes, and other matters.

Q. As a result of your employment, are you familiar with the South Hobbs Unit -- the current South

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Hobbs Unit Waterflood Project?

A. Yes, I am.

Q. When was that waterflood commenced?

A. In the mid-'70s, shortly after. It was approved by the New Mexico Oil Conservation Division.

Q. Did you oversee the preparation of the C-108 application, which has been marked as OXY Exhibit 1, and the Area of Review notebook, the area of review, which has been marked as OXY Exhibit Number 2?

A. Yes, I saw those.

Q. Mr. Foppiano, have you also put together a series of slides to assist you in your presentation here today?

A. I have, yes.

Q. Are those contained in the third notebook, under tab three, in what has been marked as OXY Exhibit Number 3?

A. Yes, they are.

Q. And it contains a total of ten pages or ten slides?

A. Yes, it does.

Q. Let's go to the first slide, if we could, please. Does slide one accurately summarize your educational background, your work experience and your personal professional affiliations?

A. Yes, it does.

Q. I want to focus a little bit on your experience in petroleum engineering. How much experience do you have in that particular area, and what have been your primary areas of focus?

A. I started out as a civil engineer, graduating from Georgia Tech in 1977. And then I went to work for Halliburton as a field engineer, where I designed frack jobs, acid jobs, cement jobs and supervised them in the field. So I acquired a fair amount of experience in that aspect of oil and gas operations.

Then following that short stint, I went to work for an oil company, City Service Oil Company, as a drilling production engineer, and I was in charge of drilling and production activities in a multistate area that included shallow gas, deep gas, sour gas, including some very, very sour gas in south Mississippi, south Alabama and other places, East Texas. And I eventually became the chief production engineer for a five-state area for the City Services operations.

And then I moved into the regulatory part of oil and gas -- my oil and gas career, and then later on became a Registered Professional Engineer, petroleum engineer, in Texas in 1977, through experience and by tests. So that pretty much sums up my petroleum engineering experience and background.

Q. Did that include -- your five-state area, did it include New Mexico at that time?

A. It did not.

Q. It did not. Okay.

You focused on Texas and other --

A. It was East Texas, Arkansas, Louisiana, Mississippi, Alabama, Florida.

Q. And you mentioned that you had experience, at that time, with sour gas. What kind of experience?

A. Well, we operated a well, I believe, in Florida, and I think it had in excess of 20 percent H2S. It was a gas reinjection type project. And then in East Texas, I remember I was in charge of a waterflood operation we had up in -- trying to think of the exact name, of the city where it was. But it was a waterflood project that involved eight percent H2S in that reservoir. It was a limestone reservoir that we were waterflooding. And then there were various other gas wells in Smackover and other places in East Texas where we -- I was in charge of production operations where we were handling, you know, very significant quantities -- high rates of gas containing H2S.

Q. Did you then use that petroleum engineering experience to kind of move into, then, oil and gas

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regulatory compliance issues?

A. I did. The company decided to broaden my experience level and move me into regulatory compliance issues about the middle part of my career, and that's when I became a lot more focused on dealing with regulatory -- interpreting regulations, assisting our various operations throughout the United States in hearings and getting regulatory approvals, and then ultimately migrated into positions with associations where I worked with them to develop comment and feedback through regulatory bodies on proposed rules, regulations. I even migrated a little bit into the government-affairs arena with the lobbyists for a period of time here.

So I did this pretty much throughout the United States. You can see a listing of some of the states where I was involved in regulatory projects of one type or another. And so I did that for about 17 years.

And in the course of that, obviously I dealt quite often with hydrogen sulfide issues, writing hydrogen sulfide safety plans, obtaining regulatory approvals for projects such as these and other types of issues associated with those projects that involved compliance with the various rules and regulations of

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that state for those type of operations.

Q. From your bio here, it appears your oil and gas regulatory experience included Texas and New Mexico, correct?

A. Yes. Probably most of my experience and most of the time I spent on regulatory compliance issues was in Texas and New Mexico, and most of that in the Permian Basin.

Q. Were you involved in the development of New Mexico's H2S Rule?

A. Actually, yes. I was chairman of the Regulatory Practices Committee with the New Mexico Oil and Gas Association, and we had the opportunity to work with the New Mexico Oil Conservation Commission in revamping that H2S rule. And that was, I believe, because of -- right after our North Hobbs Unit hearing. So we worked with them to upgrade that rule, and based on what I have seen recently, it's still pretty much in the same form as what it was back then, what we developed back then. We used Texas Rule 36 as a starting point, but I like to say that we did it one better in New Mexico.

Q. What experience do you have with health and safety issues associated with oil and gas projects?

A. Yes. After -- my regulatory career took a -- I

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guess it was put on hold a little bit when I was asked to go be in charge of our health and safety issues associated with our emerging operations in Libya. So I was one of the safety managers.

Q. When was that?

A. That was about mid-2000- -- 2005.

Q. Okay.

A. So I went to Libya in charge of all health and safety matters and bar [sic] operations there in Libya, which was quite interesting because we started from scratch. And amazingly enough, we ran into H2S issues with some of our production there in Libya. So we were able to provide some guidance to the host government there on how to handle some of these issues. They seemed, you know, quite interested in our experience in that area. And then following that -- I did that for a year, dealing with those health and safety issues, writing regulations -- not regulations -- I'm sorry -- policies, and ensuring compliance with the host government's requirements around environmental issues primarily.

And then following that, I went to our Colorado office and was in charge of our Colorado operations, including our regulatory matters for Colorado, which involve regulatory compliance.

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And then after that, I was asked to head up our Auditing Department in Houston. The company has a very robust auditing -- internal auditing program for health and safety issues that is actually driven by our board of directors. And they required that we internally go out and audited our operations on some frequency for compliance with health and safety requirements.

And so I headed that program for a little over five years, which resulted in me participating in audits as an expert -- subject-matter expert in health and safety issues and also leading audits and then directing the entire program to comply with our internal requirements that were defined by our board.

Q. Did some of the operations that you were auditing include operations that had to deal with H2S?

A. Yes, they did, throughout the world.

Q. Did that experience allow you to meet what I would call the experience requirements that are necessary to apply for a certification as a professional health and safety auditor?

A. Yes. I decided, before I got out of that field, I would at least get the certification for that. And since I met the experience qualification, which, much like a professional engineering certification, are quite extensive. There's an experience qualification; there's a training qualification, and there is a work history-type qualification. So I met all of those qualifications, applied for it, and now I'm just in the process of taking the test. And I've already taken one of the three tests, and I'm scheduled to take the next two tests. And then following that, assuming I pass them, I should be certified as a professional health and safety auditor.

Q. You have been a member of the Society of Professional Petroleum Engineers for how long?

A. Since early in my career, so 30-plus years.

Q. And you've been a Registered Professional Engineer for over 15 years?

A. Yes.

Q. Are you familiar with OXY's application in this case?

A. Yes, I am.

Q. And are you familiar with its overall project to convert its waterflood -- existing waterflood operations to a tertiary recovery project?

A. Yes, I am.

MR. FELDEWERT: I would tender Mr. Foppiano as an expert witness in petroleum engineering, oil and gas regulatory matters and health and safety issues

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associated with oil and gas projects.

COMMISSIONER BAILEY: Any objection?

MS. GERHOLT: No objection.

MR. ALVIDREZ: No objection.

COMMISSIONER BAILEY: He is so accepted.

Q. (BY MR. FELDEWERT) Mr. Foppiano, you touched on some of your worldwide experience. I'd like to move to, if we could, slide two and discuss briefly with the Commission the company's worldwide experience in oil and gas operations.

A. Yes. I thought it would be helpful to give a little perspective of OXY, in particular as it relates to its experience dealing with H2S production.

This is a picture, obviously, of the world titled "Worldwide Oil And Gas Producing Areas," and shown in yellow are active operations where we're directly supervising those activities. And shown in the other color, brown, I would suppose, are other operations that we're involved in, and those are generally joint ventures with host governments or other international oil companies.

So starting out in the United States, obviously we're very active in the Permian Basin, and I'm going to talk a little bit more about that in a minute. And you can see, we're also in North Dakota,

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Colorado, Kansas and Oklahoma, but our primary U.S. operations are the Permian Basin, and then we are very, very active out in California. But with respect to H2S issues in the United States, it's pretty much the Permian Basin. And I'll talk a little bit about how prolific H2S is in the Permian Basin.

We're very active in Colombia and Bolivia. Not really any H2S issues there. It just brings a different international perspective to our operations.

And then going over to the Middle East, we operate -- I know it's hard to see there -- in Qatar, Oman and Yemen. And with respect to H2S issues, Qatar is a very interesting project. It is all offshore, and it's approximately -- it's a little over 100,000 barrels a day, and it handles gas with H2S concentrations close to seven percent. And when we say -- we're going to be talking about H2S concentrations in terms of parts per million and percentage. And to give you a flavor, one percent H2S is 10,000 parts per million. So seven percent H2S is 70,000 parts per million.

And what's interesting about that Qatar project offshore is that it involves a lot of workers, not very -- not in proximity to the public. It's proximity to workers, and we're talking 100 to 150 workers, offshore platform, and they're in close

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proximity to the hazard of H2S in an offshore facility. So we're very, very keen on ensuring the safety of those workers through training, through proper selection of equipment, mechanical integrity, a lot of the same things you're going to see here today that we do because of the uniqueness of that operation.

Q. I mentioned to the Commission that Mr. Chokkarapu is going to be talking later and that he's part of this Facilities and Construction group that draws on the worldwide experience. Is this the type of experience that we're talking about?

A. Yes. Exactly. We not only -- when we are designing those type of facilities and operating them, we draw worldwide experience from our worldwide experience in other areas to ensure that we're doing the best that we can do based on our own knowledge and experience and industry practice and standards. We try to keep it state-of-the-art.

And, in fact, the audit process works to make sure that there is a good technology transfer going on in our company, because we bring subject-matter experts from, say, the Permian Basin to go audit our operations in Qatar, and there is a very robust and very good exchange of information about how to best manage the hazard associated with handling H2S.

Q. Now, you mentioned that your company operates in a lot of different regions, a lot of different environments, some more challenging than others. What has been the company's overall safety record?

A. The company is a safe company. We measure -- like every other company does in the United States, we measure incidents that occur with our employees, and we record a rate based on criteria set by the Occupational, Safety and Health Association. And those numbers are reported annually to, I believe, the Bureau of Labor Statistics, BLS. In short, it's called -- in industry parlance, it's called the IIR, the OSHA reportable rate -- or OSHA incident rate. And IIR stands for illness and incident rate.

And a rate of one means that there was one incident that met OSHA's criteria for every 100 workers for that year. So an incident can be nothing more than someone got a cut on a finger, went to the emergency room and got it sutured or got some prescription medication. That's an incident that would show up on that record. In 2011, our employee incident rate was .29, I believe, which indicates that only a third of an incident per 100 workers for an entire year.

And we're very proud of that rate. That's not just an anomaly. That's the range of IIR rates that the company has had for many years, and that is well below the companies that do the same type of work, you know, as compared in the API statistics, because we do look at how we do compared to other companies, particularly companies that are operating in the same areas, performing the same activity. And we are well below the average for our peer companies.

Q. Let me ask you, you and I talked earlier and you mentioned the loss [sic] on the CO2 project. Where is that located?

A. It's in the Permian Basin.

Q. Would it make sense to go to the next slide, then?

A. Well, one other comment I'd like to make about our safety record.

Q. Sure.

A. Obviously, we do a lot of work through contractors, and even though we're not required to do so, we monitor our contractors' safety records just like we do our employees. And contractors' safety record is also well below one throughout the Permian Basin, throughout our worldwide oil and gas operations. So we're very proud of that. We work very hard to ensure the safety of our contractors, the safety of our workers. And obviously they are our first line of defense to ensure that we do our operations and not present a hazard to the general public.

So I just wanted this Commission to know that the company that's before you today asking for your permission to inject this substance in the Hobbs field is a safe company. We have a good, safe record of operating in this kind of environment.

Q. Let's move to what's been marked as slide number three on OXY Exhibit 3. Would you please first orient us to what's shown here and run through what you want to discuss using the slide?

A. Okay. This is a picture of OXY's CO_2 floods in the Permian Basin. And for reference, the Permian Basin is, essentially, west Texas, southeast New Mexico, and shown along here is the state line between Texas and New Mexico. So there are a couple of things that are shown on this map, on this slide, that I'll just go through.

First of all, you can see there are a number of red and green areas identified. Those are active CO_2 projects, and you can see a bunch of lines. Those are CO_2 lines -- CO_2 supply lines, where we're bringing CO_2 into the Permian Basin from Bravo Dome, Sheep Mountain, Camel Dome, those areas. So that's what makes these projects viable. We bring that CO_2 in, and

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we inject it; and when it gets produced out, then we handle it.

So the difference between the red and the green is primarily CO2 floods that either remove the sulfur at the surface or reinject the sulfur with the CO2 back into the ground. And the Wasson field that you were talking about -- looks like they're in the middle -- that's the largest CO2 flood in the world, and it's been operating for a very long period of time. I'm going to say about 30-years-plus. And it's a premier CO2 flood, and we operate that. You can see that the yellow arrow marks the location of the Hobbs field, so it's kind of on the western edge of the Permian Basin.

But these -- the CO2 floods in the Permian Basin, almost all of them handle H2S in some form or fashion because H2S is prevalent in the Permian Basin. Some of the statistics that I saw showed that over 2,000 fields in the Permian Basin contain H2S.

So these projects, as they initially got started, the standard operating mode was to -- was to install sulfur recovery as part of the CO2 flood. So even though the produced gas would come out of the well with CO2, oil, methane and other constituents and H2S, in those floods, the H2S was actually removed before the CO2 was reinjected into the ground.

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Now, we've had a number of years of experience with these sulfur recovery units, and as many people may know, they are a challenge to operate. They're -- they have emissions issues. They have operational issues, and they're very expensive, too. So as the CO_2 floods have sought out -- as we have sought out smaller and smaller targets for CO_2 flooding, we have determined that it is actually better to reinject the H_2S back in the ground with the CO_2 than it is to try to recover it.

One of the problems with sulfur recovery, obviously, is the market. There really is no market for this sulfur. So you generate a waste product at the surface that you have to figure out what to do with.

So utilizing the H_2S in our CO_2 flood has turned out to be something that has allowed more CO_2 floods to be developed, and we have determined that we can do that safely. So that's why you see, in red, a number of CO_2 floods in the Permian Basin that involve the reinjection of the produced gas instead of sulfur recovery.

Q. Let's -- let's get into some of the -- how many active CO_2 floods is the company operating in the Permian Basin?

A. We operate 28 CO_2 floods.

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Q. And how many of those involve the reinjection of produced gas?

A. Fifteen of those involve the reinjection of produced gas, and in those 15 projects, that involves more than 2,500 injection wells. So we're looking at 2,500 produced-gas injection wells. And of those 2,500, 65 percent are injecting CO2 with H2S greater than 100 parts per million.

Q. How old are some of these floods?

A. Oh, at least 40 years old. This has been going on in the Permian Basin for a very long period of time, since they discovered how to be successful.

Q. And with respect to the gas injection, do you know how old some of those are?

A. I permitted one of the first ones for OXY in the Welch field, and that was about, I want to say, the mid-'90s.

Q. Now, the arrow there points to the area that comprises both the North Hobbs Unit and the South Hobbs Unit?

A. Correct. That's identifying the Hobbs field.

Q. And I'm not sure we touched on this yet. What exactly is going on in the North Hobbs Unit?

A. Well, in the North Hobbs Unit, we are -- we started out much like we're talking about doing here,

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injecting pipeline-quality CO_2, and then as the CO_2 started coming back and being produced -- since the Hobbs field is a sour-gas field, it does contain H_2S. When the CO_2 became -- started to come back in the producing wells, it contained H_2S, and we turned right around and removed the oil. And we're now removing the liquids, and then we're recompressing the gas. And we are putting the produced gas back into wells that are permitted as produced gas injectors. And we're doing that in the north -- kind of the northeast part of the Hobbs field, outside the city limits.

Q. How long has that operation been going on, the injection of CO_2 and then the reinjection of produced gas?

A. I believe the injection of CO_2 commenced about 2004, so we've been doing it about ten years now.

Q. And as I said earlier in my opening statement, am I correct in, essentially, the company's seeking now to do in the South Hobbs Unit what it is currently doing in the North Hobbs Unit?

A. Yes. One feature of the CO_2 floods from our standpoint that we have is, we don't do produced gas injection inside city limits. We don't want to locate those facilities inside city limits. We didn't do it in North Hobs. We're not proposing to do that at South

Hobbs, and we don't do that anywhere in the Permian Basin. And it's not because we can't do it or it's prohibited. That's just an internal decision that the company has made to locate those facilities outside of the city limits area. So what we're producing here in the South Hobbs Unit is that same concept continued.

Q. Let's go to slide four and talk a little bit more in comparison with what OXY's done compared to other companies.

A. Yes. As I mentioned, OXY operates a number of CO2 floods. This slide shows, obviously, the number of floods, on the left, and I've taken the companies' names out so we don't embarrass them. But as you can see, we operate 28 CO2 floods in the Permian Basin, and it's more than half of the active CO2 floods that are going on in the Permian Basin. These floods have been around for, some of them, at least 40 years. But there are other companies that are operating CO2 floods.

Q. So one of the things that I didn't know before being involved in this project is, these are -- am I correct, Mr. Foppiano, that these are long-term, capital-intensive projects?

A. Yes. The only project that we have that has been shut down in the last 40 years was an unsuccessful CO2 projects. So projects that were initiated 40 years

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ago that have been successful, have many, many more years of life left in them, they are long-term projects.

Q. Let's turn, then -- I'd like to turn now to a different topic and that is, give us a general understanding of the life cycle of the reservoir and why you end up going into a tertiary recovery project. So if you'll turn to slide five -- there is an animation associated with this, correct?

A. I hope so.

Q. Shall I hit the button?

A. Yes.

Q. Go.

A. Okay. I'll start with a very simple diagram of an oil zone trapped underground. And this presentation is really designed to put basic concepts before the Commission to help put things in perspective as you hear more detailed testimony and more technical testimony later on.

But we start with an oil zone trapped in a -- in a -- in a geologic trap underground. And in the case of South -- or actual Hobbs field, this oil zone had a little gas cap with it. So it existed there with gas sitting on top, oil sitting on the bottom and permeable strata on top, and it's what we call a trap. That oil is trapped there. It always starts out at an

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original pressure, what we drilled before any well is drilled and before any production. It indicates, in the Hobbs field, it had an initial H2S concentration on the order of about four to five percent. So it's important to understand, the H2S for this type of reservoir in the Hobbs field was already there. We're not bringing it in from outside. We didn't create it by what we're doing. It was already there. It's part of the native characteristics of this oil reservoir.

Now, if you'll go to the next click.

Q. (Complies.)

A. As an oil zone begins producing, a well is drilled, obviously, and the volume is starting to be produced out of this oil zone. We'll see what happens to the reservoir pressure, if you'll click, please.

Q. (Complies.)

A. The reservoir pressure declines. And this is exactly what happened in the South Hobbs Unit. Our reservoir pressure started out at about 15-, 1600 PSI, and primary production brought this field down to a reservoir pressure on the order of about 400 pounds. And the H2S concentration during this phase stays fairly well constant because it's a constituent of the gas.

It's important to note that when a reservoir pressure drops like this, that's more of an indicator that it's contained. There's nothing moving in from outside. We're just pumping this oil straight out of a contained area. So as the volume is withdrawn, the pressure will drop, and that's exactly what we're seeing here.

Q. Let me ask you something. Is that where a gas-oil ratio comes into play, to help maintain that reservoir pressure as long as possible?

A. Yes. It's typical in an oil reservoir that would be producing oil if wells were drilled downdip or below -- and completed below the gas cap. Those wells would be producing at a much lower GOR than a well drilled in the very top of the gas cap, which would be producing a very high gas rate.

So it's typical from a regulatory standpoint to have GOR limits for protection to allow some production from the gas cap, but primarily to preserve the gas cap in the reservoir as long as possible to maximize the recovery. Because what happens is, the pressure begins to drop. The gas expands, and it pushes oil to the wells. So by controlling GOR in a reservoir like this -- and every regulatory agency I know does the same thing -- it maximizes the recovery of oil from a reservoir such as this.

So at the end of what we call the primary phase or the phase of an oil reservoir where we're utilizing the natural energy and pressure of the reservoir, we get to a point where we begin to study the reservoir to see if it has -- it's a candidate for waterflooding. And not every oil zone is a candidate for waterflooding. It depends on the characteristics of the oil. It depends on the quality of the reservoir, the size of the tank, a number of things.

But in the case of the Hobbs fields, it was a very viable candidate for waterflooding, so companies, at that time, looked at it and said, We believe that we can pump water into the reservoir, use it to push oil to the producers and increase the recovery of hydrocarbons in this reservoir and, obviously, make money doing so.

So this is what happens. If you'll click again, you'll see, injection wells are drilled, and pressure has started to increase with the introduction of this water injectate, because you're trying to actually force some of this gas back into solution with the oil to improve the sweep efficiency of the waterflow. And so reservoir pressure will be built back up. It actually achieves -- like in our case, we're at about 1,200 now in the waterflood in South Hobbs Unit. And this is what's going on right now. We're just pumping water in and using it to push oil to the

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producers and then producing it. And the H2S concentration during this phase stays constant.

Q. Now, to put it in perspective for this project, what we're talking about here, the waterflood was started in the South Hobbs Unit almost 40 years ago, correct?

A. Correct, in the mid-'70s.

Q. At some point in time, then, as the company has done here, do oil and gas companies look at whether a particular zone qualifies for a tertiary recovery project?

A. Exactly. They do the same type of analysis. Quite frankly, a CO2 project is much more extensive than a waterflood project. So it is screened very carefully to determine if it's a candidate for a tertiary type of process. Not every waterflood is a candidate for a tertiary project or a tertiary process for one reason or another. But in the case of the Hobbs field, we find this reservoir here to be -- to be a good candidate.

And so the company will analyze it again. They'll -- and you'll hear from one of the later witnesses about some of the modeling that's done, and I believe OXY has got some of the state-of-the-art modeling technologies and experience for CO2 flooding. It's a complex type of environment to try to simulate.

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And, quite frankly, what you're doing is, you're saying, Well, okay. If I drill wells and I pump CO_2 in the ground, what can I expect to get out of it in terms of production? When will I get this production, and then how much money can I sell all this for? How much money is it going to cost me to do all this, and is this a good investment?

Q. So you have a reservoir component to the screening of the project, and then you have an economic component to the projects?

A. Yes. Yes.

Q. All right. Let's assume that the project qualifies. Then what happens?

A. Well, if the project does qualify and the CO_2 --

Q. Go ahead.

A. -- the CO_2 starts again, a couple of things start to happen. CO_2, typically in an almost liquid phase but it's produced out of a gaseous phase, it dilutes the gas that is produced. So what happens to the H_2S concentration is, in the producing wells, it drops dramatically. In fact, it drops dramatically in the reservoir. The order of magnitude we're talking about here in the South Hobbs Unit, or the Hobbs field, four to five percent. Initial H_2S concentration, we're estimating it to be around one percent very quickly when CO2 starts to come out of the reservoir.

Q. Now, is that estimate based on your experience at the North Hobbs Unit?

A. Yes, it is, and in other floods throughout the Permian Basin.

The other thing that happens is, we continue to build the reservoir pressure up to a target reservoir pressure. And this target reservoir pressure -- and you'll see a little bit more in a minute about this concept. This target reservoir pressure is known as the minimum miscibility pressure. What that is is a pressure in the reservoir at which CO2 becomes miscible with the oil, and it's where a CO2 flood is operated. It's operated at a reservoir pressure at or above the minimum miscibility pressure.

And that's a very important concept in the CO2 flood, because if the reservoir is allowed to -- if the reservoir pressure is allowed to drop below the minimum miscibility pressure, the CO2 starts to come out of solution. It doesn't -- you don't get the swelling and the lower viscosity effects that you need to have an efficient CO2 flood.

So we work very hard to, first, understand, what is this minimum miscibility pressure for our flood.

It's different from flood to flood. And then secondly, as we prosecute the flood, how is our reservoir pressure? What is it -- how is it responding to the injectate, and what is that reservoir pressure in each one of these different patterns that you'll see in a minute that we use to operate the flood.

In short, we operate the CO2 flood based on the reservoir pressure, and we maintain it in a range above the minimum miscibility pressure. We don't want it to get too high because that's a waste of CO2, and we're putting more CO2 in the ground than we need to. And we obviously don't want it to get too low.

So as an additional witness will testify to, this range is going to be somewhere on the order of, I think, about 4- to 500 pounds above the minimum miscibility pressure.

Q. So let me see if I'm understanding this. So you have side -- in a CO2 flood, you have sideboards, essentially, on your reservoir pressure that you -- correct?

A. Absolutely.

Q. You don't want it to be too low?

A. Yes.

Q. And you don't want it to get too high because there's no benefit there?

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A. That's correct.
Q. So you have an economic incentive in an EOR project to maintain what essentially becomes almost a constant pressure; is that right?
A. Correct. And we'll show how we do that here in a later slide.
Q. Anything else about this slide?
A. No.
Q. Okay. Then let's move to what's been marked as slide number six in OXY Exhibit Number 3. What are you showing here?
A. Well, this slide puts in to perspective one of the main drivers of CO_2 flooding and, actually, waterflooding.
We start out with, like in the case of the Hobbs field, the oil trap that we're operating in today, and it has a certain amount of oil in place. We talked a little bit about how we drill a well and we use the reservoir energy to produce oil from that trap. And a typical recovery of that original oil in place utilizing that mechanism is 15 percent. So if all we did was produce until the wells couldn't produce above the economic limit anymore -- we didn't waterflood; we didn't CO_2 flood or anything else -- we could expect to recover around 15 percent of the oil that is in place

there in the rock.

If we did waterflood, which, in fact, is what we did in the Hobbs field, the recoveries there, where the oil zones are actually contacted by the water, can be increased all the way up to double what primary was. So that's obviously why waterflooding is a very common practice in the Permian Basin and other areas, because you do get a lot of extra oil out if you're able to do that.

But even at the end of waterflooding, you may be looking at 45 percent of the oil recovered, so you still have over half of the oil left in the ground. And it's why operators like OXY look very closely to see if there is enough oil and enough potential recovery available to justify a CO2 flood like what we have here.

And a CO2 flood recovery, as you can see, is typically 15 percent. So even after the end of all of this, primary waterflood and CO2, you still have as much as 40 percent of the oil left in the ground for future technologies to become available to recover.

Q. Does this slide help demonstrate the financial risk associated with moving from a waterflood to a CO2 flood?

A. Yes. It demonstrates that the recoveries that you might expect from a CO2 flood, 15 percent of the original oil in place, is -- it's substantial, but it means you have to have a very big target to go after. And because of the expense of a CO_2 flood, which you'll hear a lot about -- it's about $600 million for just the South Hobbs Unit loans. These are very, very expensive projects. And so it is a -- it is a challenge to economically justify to your shareholders and investors that this project is worth investing it.

Q. And a 15 percent additional recovery, if you get it, is going to be spread out over a lengthy period of time, correct?

A. As you've just seen, many of these CO_2 floods operate for many, many years. So these recoveries typically occur over a very long period of time.

Q. Now I would like to turn, Mr. Foppiano, to slide seven, which I think will assist in kind of briefly demonstrating how the CO_2 floods work.

A. Okay.

Q. Now, as I understand it, there is some interesting animations associated with this?

A. Yes, there is.

MR. FELDEWERT: So bear with us as we change the animation.

Q. (BY MR. FELDEWERT) So this (indicating) is going to go on for a time?

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A. Six or seven slides.

Q. Six or seven slides. Okay. While that's going on, let's talk about this slide.

A. Well, a CO_2 flood is conducted, in many cases -- not all, but in many cases, in what's called a WAG type of operation. In other words, we start off in a -- like we would here, we start off injecting CO_2 behind the water that's already been injected, and then we will use water alternating with CO_2 to decrease the use of CO_2 but also to improve the sweep efficiency through the reservoir to recover as much oil as we can. We call this a WAG operation, water alternating with gas.

And what goes on in the reservoir -- this is a side view of our injector-to-producer, kind of, environment. And you can see the reservoir here (indicating). Starting at the producer, what's coming out of the reservoir from a CO_2 flood at this stage is the additional oil that's being pushed, a gas that's being -- you know, that is part of the oil or that was trapped in the pore spaces, so it's being produced. So you still have -- if it's an H_2S -- a reservoir with H_2S, you still have H_2S coming out of the well, and then you'll have some water. So you're pushing all this to the producer.

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Right behind that is this miscible zone. I talked about miscibility of CO_2 with the oil, and this is where the benefits of the CO_2 floods really occur in the reservoir. When CO_2 becomes miscible with the oil, the oil swells, and it becomes thinner and easier to flow through the rock. So we're able to push it more easily with the water when it actually undergoes that change.

And so as it swells and expands, it obviously pushes more oil to the producing wells. So that's how we recover more oil, by injecting CO_2 into our reservoir.

So as you can see behind that, you'll have a CO_2 bank. So between the oil and the CO_2 bank, you have this zoned miscibility that is sweeping through the reservoir, and then we're using water to push the CO_2 through. The water is also sweeping oil. So we still have a sweeping mechanism going on here, in addition to a chemical reaction going on with the oil itself.

And then, finally, behind it is drive water. So we will create this CO_2 bank with these alternating CO_2 and water slugs that we're pumping in, and then when we're finished putting CO_2 into that portion of the reservoir, we switch it back to water and continue on pumping water.

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Q. Okay. Now, one of the things that this slide doesn't do a very good job of showing is that, as I understand, Mr. Foppiano, as you're doing this waterflood, the fancer [phonetic] goes into the wellbore on the right of slide seven. It's not just oil, but you're going to have CO_2 flowing in, you're going to have produced gases, and you're going to have water flowing in, correct?

A. Yes. As we can picture this, these banks moving towards the producing well, the miscible zone will reach the producing well, as will the CO_2, and so forth. So everything that's in the reservoir is being produced, H_2S, methane, NGLs, oil, water, and you can see, CO_2 starts to break through. So in a producing -- so in a reservoir -- a CO_2 reservoir that has produced gas injection, what's going on here is, the gas that's coming out, the CO_2, methane, H_2S -- we're removing the oil and, in some cases, maybe the NGL, but we're turning right back around, and putting it back in. So we're cycling the CO_2 and the produced gas back to increase the oil recovery.

Q. And that's what's going on in North Hobbs?

A. That's exactly what's going on in North Hobbs.

Q. With this sweeping in mind, let's turn to how these injectors are produced and located in the field.

So let's turn to slide eight.

A. Yes. If you'll flip one more.

Q. This is animated as well?

A. This is animated.

The way a CO_2 flood is prosecuted is much like a waterflood. We do it in patterns, patterns of injection and producing wells. So what I want to show you is how this pattern actually works.

A CO_2 flood is, essentially, a group of patterns inside of a reservoir. In the case of the South Hobbs Unit, our pattern will have the injection well in the middle and the producing wells on the outside. And you'll hear one of our witnesses talk about 80-acre five-spot, 40-acre five-spot. Well, this is a five-spot pattern that he's talking about, with the injector in the middle. So you can change the shape of it a little bit to make it 80-acre or whatever, but it's still a five-spot pattern. And if you'll click it, I'll start the animation.

Q. (Complies.)

A. This is what happens when injection just starts in a five-spot pattern. If you're looking at it from, let's say, overhead looking down, you're seeing the injectate radiate out towards the producing wells in pretty much a circular fashion. And as you continue your injection, the injectate starts to preferentially migrate to the producing wells because they're producing. They're withdrawing fluid from the same reservoir that you're injecting into. So this is what the shape of your sweep patterns would look like about midway through this flooding operation.

And then if you continue, you've had injectate break through to the producers, and this area of the reservoir is pretty well swept by this flood, and you can see that it is all contained within this pattern. And that's the design of a flood like this is on a pattern basis.

We know how much is coming out of these producers. We measure it. We know how much is being injected into the injection well. We measure it. And so we're able to balance these injectates to maintain this reservoir pressure at a constant level. But we're not satisfied with that. We'll do other things to measure the pressure in these patterns to ensure that we are maintaining the reservoir within this five-spot pattern at a target reservoir pressure.

Q. So that's different from a disposal well in the sense that you are monitoring what's going in and what's coming out for purposes of maintaining your minimum miscibility pressure?

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A. Oh, yes, it's very different from a disposal well because you're not withdrawing anything in a disposal operation.

Q. There have been some concerns raised by, I think, Mr. Coombes and perhaps others about the horizontal flow of injectates. Does this five-spot pattern assist in the control of the horizontal flow of injectates?

A. Yes, it does. And, in fact, our whole design of the CO2 flood is designed -- is created to control horizontal movement of the -- of the injectate. The injectate is very expensive. We want it to be used to recover oil, and so the patterns are all designed to do exactly that, to recover oil within a pattern by producing the injectate that is in that pattern.

And so that's what we've done here. These patterns are set up as part of our design. It's what we're doing in North Hobbs. It's what we do in any CO2 floods. And we may actually alter the pattern in some cases to put line drives in place to create additional barriers if we are trying keep the CO2 contained in a certain area, like a water -- water cushion or something like that. So that's another type of pattern. But all told, patterns are utilized to contain the injectate within that one small area.

Q. But from an economic perspective, then, for EOR projects like this, you have an economic incentive to maintain your injectates within a tight pattern, correct?

A. Absolutely.

Q. And, secondly, to maintain a constant pressure?

A. Absolutely.

Q. Which may not -- those economic incentives may not exist in a disposal well?

A. Yes. A disposal well is just a completely different operation.

Q. What's the pattern going to be at the South Hobbs Unit?

A. I believe the design pattern is 80-acre five-spot, which just makes this a little rectangular instead of a square, but it's still injector-centered.

Q. Now, you touched on a little bit about how these projects differ from disposal wells, but I'd like to move now to slide nine and talk about that in a little more detail. Can you run us through why EOR projects and disposal wells are really different animals?

A. Yes. I know this Commission has heard testimony and had discussion about acid-gas disposal operations and maybe not as much about EOR injection

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operations. So my slide here is attempting to show the major differences between these two activities.

Let's start with H2S concentrations. Typically, these acid-gas disposal wells are handling H2S gas in very high concentrations. My research indicated that these wells were -- the lowest, I believe, had ten percent H2S gas, and some of them had H2S concentrations in their disposal fluid, in their waste gas, as high as 60-some-odd H2S. And that is important from the standpoint of how facilities are designed and how the public can be impacted and so on and so forth. When we're talking about those kind of operations, it's a different regime entirely from EOR, which involves very low H2S concentrations.

As we've seen here, we're talking about H2S concentrations starting out at four percent, but because of the injectate, dropping to as low as one percent. And that's our experience throughout the Permian Basin.

I looked at our 2,500 wells that we operate that involve -- that have injectate containing H2S, and the highest concentration on those 2,500 wells was 2.5 percent, and the vast majority of those wells operate with about one percent H2S gas. So when we look at that, just the H2S concentrations that are being handled, it's just apples and oranges completely. It's a different regime entirely.

Q. Now, Mr. Foppiano, I don't think we have to go through every line on here. I mean, you kind of talked about the native and non-native nature of the H2S.

What about, for example, the target reservoir and things of that nature?

A. Well, the target reservoir -- and I have permitted disposal wells before. So I'm familiar with what you're looking for in a disposal zone versus an EOR zone, and they're almost opposite.

In a disposal zone, you're looking for a zone that is laterally very extensive. It's nonproductive. It doesn't even, hopefully, have the potential to produce, because you're disposing of a waste into that zone, and hopefully, if you've done your research properly, you're not going to adversely impact somebody's future oil and gas production out of that same reservoir.

So you're looking for a reservoir that has no potential for production. It's laterally extensive. It's as big as possible, so you can put as much waste into that reservoir as absolutely possible. And so it's -- and it's generally undeveloped. Meaning, there's not a whole lot of penetrations of wells through that type of reservoir. So that actually impacts the

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amount of information you may have available.

If you contrast that with an EOR injection, the zone that we are putting this injectate in is productive. In fact, that's the intent, to enhance its productivity, enhance the recovery.

It's a contained reservoir. You want to do a CO2 flood only where you can contain that CO2, because the injectate is just very expensive. You will know a lot about that reservoir. We have hundreds of well penetrations in the Hobbs field. We have logs. We have lots of information which we can adequately and very accurately determine where the reservoir exists and if it is contained or not. And so we have a lot of good information on our reservoir, and it's because it is well developed and it's been producing for many, many years. So they're just -- they're just completely different reservoirs that you're operating.

Q. And that kind of just dovetails into our next line, the affected area, which we touched on a little bit.

A. Yeah.

Q. Part of that is controlled by the reservoir and then the pattern sites, correct?

A. Yes. Obviously, for a disposal zone, you're -- the area that's affected by your disposal is based on how much you're putting in the ground and how big the container is, which relates to porosity, permeability, size of the reservoir, so forth and so on. Whereas, as you've just seen, in our EOR project, it's based on your pattern size. You are operating within a tight pattern. You're monitoring everything that goes on in that pattern, in this case, 40 acres. So you're staying within a 40-acre area for affecting your -- that reservoir.

Q. And as you move into the South Hobbs tertiary recovery project sites, it's going to be 80 acres?

A. Correct. I'm sorry. 80 acres, yes.

Q. Now, what's your point on the number of wells in the area of operation?

A. Well, the number of wells is a -- just another perspective, and it may relate more to experience. There are very few of these acid-gas disposal wells in operation in New Mexico. They serve a very valuable purpose. Obviously we operate one, with our Indian Basin Gas Plant. But they're typically associated with a plant. In other words, it may be that the plant personnel are the ones that are actually in charge of that well.

Whereas, with an EOR operation, we have thousands of these wells. We've operated them for many,

many years. We have a very high level of experience with these wells, and the people that operate these wells are oil and gas well operations people, and you'll hear from some of them today. And so there is a big difference in that operation, you know, the waste disposal associated with a plant versus the EOR injection wells that are associated with an oil and gas production operation operated by people with years of experience in well operation. So I think that speaks to, you know, some of those issues.

Q. From a regulatory perspective, are the pressure concerns different between an EOR project than an acid-gas disposal well?

A. Yes. As we've seen, there are no withdrawals, or you're designing your disposal project to hopefully have no withdrawals of this waste from the zone you're injecting into, as opposed to the EOR project where you're maintaining the injectate within a pattern. And we are operating our CO2 floods by measuring and monitoring our reservoir pressure. And the only way you can really do that with a disposal well is to, you know, shut it down and do a pressure check, because you're pumping into a closed tank.

And so that pressure in that reservoir is going to increase over time solely based on reservoir characteristics and how much you're putting in. And that's not what affects the pressure in the injection pattern of an EOR project because it's based on how much you're withdrawing, how much you're putting in, essentially the voidage in that reservoir in that particular area. And then as I've mentioned, we maintain it within a specified range. So we don't let it get above a certain point.

Q. So, Mr. Foppiano, from a regulatory standpoint, is there a need to monitor or really be concerned between the starting and the ending reservoir pressures for an EOR project like there might be, for example, in a disposal well?

A. No, I don't think so.

Q. Do other states monitor the starting and ending reservoir pressures for an EOR project?

A. Not that I'm aware of.

Q. Is that because, as you talked about, your economic incentive is to maintain a constant pressure, correct?

A. Exactly. Yes.

Q. In your opinion, given what we've talked about, is it practical to proceed with an EOR project as a company if it's going to be subject to some type of regulatory termination date or re-evaluation period?

A. Having a termination date can render the project uneconomical from -- from our standpoint. And let me say a little bit more about this.

When we do a project like this, as I mentioned, we're estimating how much it's going to cost to do it and how much is going to be produced as a result of the project, how long it's going to take to get that production. And as you've seen, that can take a very long period of time, and what you will see, we're expecting 40 years or more for this project. And then the price at which we will sell that -- that product could be sold at. So the company is undertaking a substantial risk of correctly estimating the cost and correctly assuming a price of the production.

So when we put all these things together and we run our economics, if we introduce the concept of regulatory uncertainty, about how long we would be able to prosecute the project, if we introduce that into the equation or into the analysis, then that makes the production beyond that point something that we may not be able to have as part of our analysis. And as a result, we might have to discount that production, and that can affect the viability of the project. And so ultimately, we may decide not to do it because -- you know, depending on where that termination date would be set.

So, in my experience, I'm not aware of any EOR project and CO2 injection project that operates with a termination date.

Q. In your opinion, would the introduction of a term limit or some kind of re-evaluation period for your approval create an uncertainty that would run the risk of discouraging these types of projects and resulting in waste?

A. That's correct. It just adds additional risk. A project like this really can't stand a whole lot more risk than what it already has.

Q. I want to go over our last topic, and it involves the last slide of Exhibit Number 3, slide ten. And I want to walk through the relief that the company is requesting and get a general understanding. Okay?

A. Okay.

Q. First off -- and we can kind of skip over this one. But because of the nature of the project, you're seeking authority to inject not only CO2 but produce gases and waters as a result of the sweeping that we just saw; is that correct?

A. That's correct.

Q. If we go to OXY Exhibit Number 4 in the notebook, is this the order from 1974 that initially approved the current waterflood operations in the South Hobbs Unit?

A. Yes, it is.

Q. And if I go to page 3 of this order, on Exhibit Number 4, and I look at paragraph two on page 3, it indicates that the company's authorized to inject water into the Grayburg and San Andres Formations. Do you see that?

A. Yes, I see that.

Q. So by this application, do you seek to expand that authority to include not just water but CO2 and produced gas and produced water?

A. That's correct.

Q. Now, there are certain injection wells listed here. Since this order, have there been additional injection wells that have been approved administratively by the Division?

A. Yes, there have.

Q. While we're here, if we look at Exhibit Number 5, this is Order Number R-4934-E, as in Edward. Is this the most recent order governing your South Hobbs operations?

A. I believe it is, yes.

Q. And towards the end of that order, we'll see it contains a number of rules that are specific to this operation; is that right?

A. Yes, it does.

Q. A total of 17?

A. 17.

Q. 17.

A. Yes.

Q. And some of those rules your application seeks to amend; is that right?

A. That's correct.

Q. For example, if I look at Rule 11, right now it indicates that your surface injection pressure is based on point -- 0.2 psi per foot?

A. Correct.

Q. First off, has that rule been modified through an administrative order for the injection of water?

A. Yes.

Q. If I look at OXY Exhibit Number 6, is that Administrative Order IPI-340 that was entered in 2009 that approved a municipal surface injection pressure for water at 1,100 psi?

A. That's correct.

Q. Now, a couple of things. It refers to the wrong rule, unfortunately, within this particular order, so don't be confused by that.

And, secondly, it references that that was

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based upon some step-rate tests that were done by the company in 2008?

A. Yes.

Q. Now, the company seeks, through this application, to modify the surface injection pressure limits, then, for CO2 and produced gases that would normally be dictated by that Rule 10 that we previously saw?

A. Correct.

Q. So it's already been approved for water at 1,100 psi. What are the corresponding injection limits that the company seeks for CO2 and produced gases? Would it be -- does 1,250 psi sound correct --

A. That sounds correct.

Q. -- for CO2?

A. Yes, it does.

Q. And then produced gases at 1,772 [sic]?

A. Yes.

Q. Is that based, first off, on the 2008 step pressure test -- step-rate test?

A. Yes, they are.

Q. And is it also then based, as I understand it, on the differences between the density of water versus gas and other factors that go into play?

A. Yes. And let me explain in a little more detail. The 1,100 psi limit that we're currently operating under with water is based on a parting pressure, obviously, from the step-rate test and a -- and a bottom-hole pressure limit based on that measured parting pressure.

All we're really asking for here is, since we're going to be injecting a fluid that has a different density than water, is that the surface pressure limits applicable to those different injectate be adjusted, but at no point will they exceed that bottom-hole pressure limit that is the same that we have for the water injection wells. So I hope I explained that.

It doesn't go above the limit that is contemplated with this step-rate testing. It just adjusts the surface pressure limit because there is a density difference from water to produced gas and then CO2.

Q. So as I understand it, the maximum surface injection pressures that you request for CO2 and produced gases should be the equivalent of what it would be for what's already been approved for water?

A. That's correct.

Q. And as you already mentioned, I believe, that's just the maximum surface injection pressure that you request. That's really going to be controlled by that

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minimum miscibility pressure in terms of how you're operating your wells?

A. Well, yes. These surface pressure limits will allow us to operate at or above the minimum miscibility pressure.

Q. Finally on this point, have these rates that we seek under this application already been approved for the North Hobbs Unit?

A. Yes, they have.

MR. FELDEWERT: And I believe that was, Madam Chair, under Commission Order R-6199-B relating to the North Hobbs Unit.

Q. (BY MR. FELDEWERT) And the South Hobbs Unit involves the same formation?

A. Same formation.

Q. Same basic project?

A. Same basic project.

Q. Now, the third request in the application involves increasing the GOR limit, and this is the one -- well, let me ask you: From a regulatory perspective, okay, based on your expertise, should there be a GOR limit for a tertiary recovery project?

A. I don't believe so, no.

Q. And why is that?

A. Well, particularly like in the case of

New Mexico, where the gas production that is reported to the State, which is used to calculate the GOR, would actually include -- a large part of that would be CO2 that we're pumping into the reservoir. So in a sense, the CO2 flood artificially raises the GOR and based on how it's reported to the State.

So what we've done, and similar to what we did in North Hobbs, we've asked for an increase in the GOR limit that might or might not be applicable to this project. And, once again, this gets back to the uncertainty level. We really don't know if the GOR limit would operate to restrict production from this reservoir or from this tertiary recovery project.

So we're just trying to remove any uncertainty that it might, because -- my understanding may be inaccurate -- that a 2001 GOR limit statewide rule might apply. But since most of that gas that's coming out of the reservoir actually is CO2, we're, out of an abundance of caution, asking the Commission for an increase in that GOR limit to allow us to operate the flood with wells producing a GOR that is up close to 70,000 standard cubic feet per barrel, understanding that that GOR calculation is based on CO2 being the primary component of that gas.

So we're just, out of an abundance of

caution, trying to remove what might be down the road, artificial limits on the production from this CO2 project.

Q. Mr. Foppiano, before this hearing today, did you have a chance to review the affidavit that was submitted by the Chief Examiner, Richard Ezeanyim --

A. I did.

Q. -- for the Division?

A. Yes.

Q. He says in there, and I quote, on page 2 of his affidavit: "Therefore, during the EOR stage, the pools should not be subject to limiting GOR." And he goes on to explain why. Do you agree with Mr. Ezeanyim that from a regulatory perspective this project should not have a limiting GOR?

A. I agree, yes.

Q. You also, then, under this application, seek an exception to the requirement that the injection is within one year. Now, you have a witness that's going to talk about the timeline associated with this project, correct?

A. Correct.

Q. When do you anticipate commencement of injection out in this field if this is approved, and you can get these facilities in?

A. Today we are estimating September of 2015.

Q. And is there some investment that needs to be made in advance of the commencement of the injection?

A. Yes, a substantial amount of investment in facilities that are necessary to be able to commence the CO_2 flow.

Q. And is that why, therefore, you seek an exception to the normal requirement that injection under a Division or Commission order commence within a year?

A. Yes. We're just asking for, in our particular case, more time to commence injection because of the scope of what we're trying to do in the South Hobbs Unit, new facilities that would be constructed, new lines that would be installed, and we just need more time. The business is -- the oil business is very active right now. Equipment availability impacts this schedule. And as you'll see from the next witness, it is -- we're fixing to commit a lot of money to this project, assuming that it's approved, so that's why we're a little -- we're two years ahead of when we're actually planning to start injection, because it takes that long and we need the regulatory approval to have that certainty that would allow us to go ahead and start ramping up our spending.

So at this point, we're estimating two

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years, but we're asking for three years of time from the date the order is issued to give us the flexibility in case that start date starts to the slide.

Q. Now, you also ask for some relief with respect to the extensive area of review analysis that has been done and which is contained in what has now been marked as OXY Exhibit Number 2. What's the thought process there?

A. Well, the thought process is that we've just concluded a very extensive area of review process with the Commission, and it is upwards of close to 400 wells that have been analyzed, virtually all the wells in the South Hobbs Unit and nearby, as you will see when that witness discusses it.

So we have looked at all the wells in the area, based on how they are currently constructed, to determine if there are any concerns with respect to confining the injectate to the injection zone. So we've done that analysis.

And then going forward, what you'll see is, we have detailed information on the wells that we're going to be converting, the wells that we're going to be drilling for injection. They're going to be constructed in such a way that they wouldn't be a concern.

So we're asking for the Commission, similar to what we did in the North Hobbs Unit, to allow this area of review to be good, essentially, for at least five years.

And one of our witnesses will actually testify about the very low level of non-OXY activity out here, which I think would also give some comfort to the Commission about, you know, what else might be going on out there. There's not very much. This is it for the Hobbs area.

So we're saying: Give us five years; let these areas of review be good for five years. And then after five years, for any well that has not started injection yet -- and some of these wells that we're asking for approval will not have started injection by then because this is a phased project. For those wells that haven't started injection by then, then we would review the information that was submitted, and if there is no change to the area of review information, then just allow us to submit a statement saying there is no change to the area of review information; or if there is, then we can just update that.

This process was proposed and accepted by the Commission for our North Hobbs project. And in discussions with the OCD staff, they seemed to like it; they don't see a problem with it. And we like it

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because it does streamline the process a little bit. So we're asking for the same thing. Instead of three years that we asked for the North Hobbs Unit, we're asking for five years here, because we're starting a little earlier, and there is such a low level of activity. So we think five years is appropriate.

Q. And you're an expert in petroleum engineering, and you have expertise in health and safety issues associated with oil and gas projects, correct?

A. Yes.

Q. And you're familiar with the area of review analysis that was done in this case?

A. Yes, I am.

Q. In your expert opinion, is it necessary to conduct another area of review analysis for wells that commence injection within the next five years?

A. It wouldn't be necessary to resubmit the same data we've already submitted, no.

Q. The next request you seek is to allow for a five-year mechanical integrity test frequency for any temporarily abandoned well that is equipped with realtime pressure monitoring. Do you have a witness that is going to discuss these realtime pressure monitors that are currently on the OXY injection wells?

A. Yes.

Q. And is OXY, over time, planning on installing similar realtime pressure monitoring devices on its temporarily abandoned wells in the South Hobbs Unit?

A. Yes.

Q. And so the relief you seek here is only for those temporarily abandoned wells that will have these actual realtime pressure monitors, correct?

A. That's correct, yes. We think this is an excellent opportunity to create a system utilizing our automation that will be in place for this project, to provide better monitoring of the mechanical integrity of our temporarily abandoned wells than what is provided through periodic MIT testing. So we're asking the Commission to let us do that. And on those wells that are so equipped and monitored, that a five-year frequency for MITs would be appropriate.

Q. And in your expert opinion, would your proposal avoid unnecessary mechanical integrity tests for both the company and for the Division?

A. I believe so, yes.

Q. The company also seeks to change the current rule governing the packer-setting depth. And just to put it in perspective, go to Exhibit Number 5 and go to Rule 10, which would be towards the back of the exhibit on page 5. So, again, this is a rule that currently

governs your South Hobbs Unit project?
A. Correct.
Q. And if I look about halfway through this rule, it says that the "packer shall be set as near as is practicable to the uppermost perforation or, in the case of an open-hole completion, to the casing shoe." Has that created some operational difficulties for the company over time?
A. Yes, it has. It's necessitated several exceptions -- exception requests, which have been subsequently granted by the district office or the OCD.
Q. And we're going to jump ahead a little bit. If we jump to Exhibit 8, tab eight, in the third notebook, and if we then, once on Exhibit 8, go to slide 22.
MR. FELDEWERT: And I will represent to the Division that this is a, quote, "order that was entered in 2012, Order R-5897-A."
Q. (BY MR. FELDEWERT) And, Mr. Foppiano, if I look through this, the language in this particular slide, 22 of Exhibit 8, about halfway down, it says: "So long as the packer set point remains within the Unitized Formation, as defined in the Unit Agreement, or as the same may be subsequently modified." Do you see that?
A. I see that.
Q. Is that the language that the company requests

the Commission adopt into the current rule, then, that governs your packer setting?
A. That is, yes.
Q. Will this provide the flexibility that you need to perform your operations in a safe manner?
A. Yes, it would.
Q. And will the inclusion of this language, where it says: So long as the packer remains within the Unitized Formation, in your opinion, will it provide a similar level of protection to what currently exists?
A. It will, yes.
Q. The company then also asks that Division remove the requirement concerning cement file [sic] logs as it -- as it exists under the order governing the operation and as it exists currently under Rule 15 of that order. So if I go back to OXY Exhibit Number 5 and I go to current Rule 15 on page 6 of OXY Exhibit Number 5 --
A. Yes.
Q. -- what's the problem being created, or what's the issue here with this rule?
Let me ask you this first: Does this rule exist in the North Hobbs Unit?
A. Not to my knowledge, no.
Q. Secondly, what's the problem with this current

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rule?

A. Well, the problem at the present time is that we believe the part related to injection wells is unnecessary given the information we have put forward on the area of review and about the injection wells that will be utilized.

And, also, the part related to the requirement on the producing wells is, quite frankly, odd, because it requires multiple CBLs on a producing well, and I, quite frankly, don't understand what the rationale would be with requiring multiple CBLs on the same well over time. But that's the requirement; that's the way it reads. And we're also asking for that to be removed, because, as I mentioned, the area of review -- we've already analyzed the casing and cement for all the wells in the area, and we know where the one issue is. And so we don't need to continue running cement bond logs on these existing wells because they're constructed in such a way to confine the injectate.

And, in fact, the future wells that will be drilled will all be constructed in such a way that the cement should not be an issue. They're going to be circulated. So we just don't see the need for this requirement to be in place any longer.

Q. And as this rule currently is crafted, as you

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pointed out, in your opinion, it appears to require cement bond logs on the same well each time you pull the tubing for a producing well?

A. That's the way I read it, yes.

Q. If I stay on this -- if I go to the prior page in Exhibit Number 5, the current Rule 8 allows for administrative approval of additional injection wells within the project area. Do you see that?

A. I do, yes.

Q. So what the company requests is that the Commission clarify that this same process would apply to additional injection wells that involve CO2 or produced gases; is that right?

A. Correct, within the project area being proposed.

Q. And the final relief that you seek in this application is, you seek, at least at this time, qualifying the project for the recovered oil tax relief, assuming and hoping you won't have to use it. But while you're here, you want to qualify the project for that recovery oil tax rate, and there are certain procedures that have to be followed, correct?

A. Correct.

Q. And you have a witness who is going to address the requirements necessary to qualify for that rate?

A. That's correct.

Q. Let me ask you this, Mr. Foppiano: In your expert opinion -- let me step back.

You're completely familiar with this project; is that correct?

A. I am, yes.

Q. With all aspects of it, how you're going to locate your facilities, the type of materials that are going to be utilized, how it's going to operate; you're familiar with all that?

A. Yes.

Q. Based on your opinion, will the approval of this application prevent waste?

A. Yes.

Q. Will the approval of this application protect correlative rights?

A. Yes, it will.

Q. And will the approval of this application and the relief requested result in a reasonable level of safety to the public health and the environment?

A. I believe it will, yes.

Q. If I turn to what's been marked as OXY Exhibit Number 7, would you please identify that for us?

A. Yes. It's a resolution from the City of Hobbs regarding our project, and it was passed on the 15th of

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April of this year.

Q. Now, did the company have various meetings with the Hobbs' city officials about your South Hobbs Unit project?

A. Yes, we did. We have, in the past and will continue to do so, developed a very good working relationship with the local community in Hobbs, and we approached this project from that same -- same direction, to maintain that good relationship. And so we educated them. We brought them in, gave them many tours of our project to the local community and officials, so they could see what was being discussed, because there will be -- they will see some impact, some construction, pipelines being laid in the city. So we wanted them to be aware of what was going on. And they've been very supportive of this project all along. They were obviously very interested in the North Hobbs project, and they've had the experience of that operating, and so they -- they passed this resolution just to evidence the support that they have for this project. And, in fact, they've been involved and are knowledgeable about what we're proposing to do.

MR. FELDEWERT: If I may approach? I have one additional exhibit that we just received yesterday that I'd like to put into the record, if I may.

COMMISSIONER BAILEY: Okay.

Q. (BY MR. FELDEWERT) Mr. Foppiano, I've handed you what's been marked as OXY Exhibit Number 17 because of the exhibit sequences that we're working with here. Would you identify this document for us?

A. Yes. It's a resolution that was passed by -- very recently by the Economic Development Corporation of Lea County, and it was passed on May 6th, just this week.

(OXY Exhibit Number 17 marked.)

Q. And it reflects that the Lea County Economic Development Corporation is also in support of this effort to convert your South Hobbs Unit waterflood into a tertiary recovery project?

A. Yes, it is. And our South Hobbs project extends outside the city limits in the Lea County area, so they wanted to go on record with their support of our project.

Q. Are the slides that comprise OXY Exhibit 3 compiled by you or under your direction and supervision?

A. Yes, they were compiled by me.

MR. FELDEWERT: I would move admission into evidence of OXY Exhibit 3.

MS. GERHOLT: No objection.

MR. ALVIDREZ: No objection.

COMMISSIONER BAILEY: Exhibit 3 is admitted.

(OXY Exhibit Number 3 was offered and admitted into evidence.)

MR. FELDEWERT: And then OXY Exhibits 4, 5 and 6 are orders from the Oil Conservation Division. I would move admission of OXY Exhibits 4, 5 and 6.

MS. GERHOLT: No objection.

MR. ALVIDREZ: None.

COMMISSIONER BAILEY: They are admitted.

(OXY Exhibit Numbers 4, 5 and 6 were offered and admitted into evidence.)

MR. FELDEWERT: OXY Exhibit 7 is the resolution from the City of Hobbs. It's attested to in the bottom, left-hand corner. It's a public document, so I would move the admission of OXY Exhibit 7 as well.

MS. GERHOLT: No objection.

MR. ALVIDREZ: No objection.

COMMISSIONER BAILEY: It is admitted.

(OXY Exhibit Number 7 was offered and admitted into evidence.)

MR. FELDEWERT: And finally, I move the admission of OXY Exhibit Number 17, which is the resolution adopted by the Economic Development Corporation of Lea County.

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MS. GERHOLT: No objection.

MR. ALVIDREZ: No objection.

COMMISSIONER BAILEY: It is admitted.

(OXY Exhibit Number 17 was offered and admitted into evidence.)

MR. FELDEWERT: Madam Chair, that concludes my examination of this witness.

COMMISSIONER BAILEY: Then why don't we take a 15-minute break?

(Break taken, 10:48 a.m. to 11:05 a.m.)

COMMISSIONER BAILEY: We'll go back on the record.

You were finished with your witness?

MR. FELDEWERT: Yes, Madam Chair.

COMMISSIONER BAILEY: Time for cross-examination, Ms. Gerholt.

MS. GERHOLT: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MS. GERHOLT:

Q. Good morning, Mr. Foppiano.

A. Good morning.

Q. It is my understanding from your testimony that it's the carbon dioxide which is assisting in the recovery of the oil and not the reinjection of produced gas; is that correct?

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A. Well, it is in combination with everything. The project involves, obviously, the injection of CO_2, but also returning the produced gas back to the reservoir. It's part of the entire project. As far as assisting, the H_2S component of the gas actually does have some positive benefit to the miscibility pressure. It lowers it slightly. So there is some slight benefit to the inclusion -- to the reinjection of produced gas containing H_2S.

Q. So it does lower that miscibility pressure?

A. Slightly, yes.

Q. If I could direct your attention to slide five, I'm interested in how does the carbon dioxide dilute the concentration of the H_2S?

A. Okay. The carbon dioxide goes into the injection well and into the oil reservoir pretty much in a liquid phase. In other words, it goes in almost as a liquid. And because of the temperature and pressure that it exists at, as it migrates to the producing well, the pressure drops and this gas, much like you open a bottle of coke, this liquid becomes a gas and starts to enter into a gaseous phase. And when it does, it dilutes the native gas concentration that's in the reservoir, and by diluting the gas concentration in the reservoir, it dilutes the H_2S component.

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Q. Just because there is now an increase of gas, the concentration is less -- sorry. I'm trying to remember my basic chemistry here.

A. Yes. The gas that comes out of the well when the CO_2 breaks through can be as much as 80-percent CO_2. And so the 20 percent that's not CO_2 would be native gas that contains H_2S.

Q. Right.

A. So it may be easier to think of it that the native gas still has its full-percent concentration, but you've added a component to that which now dilutes it such that the total amount of it is -- if you measure the H_2S concentration of the produced gas, which includes the CO_2, your H_2S concentration would be on the order of one percent instead of four percent.

Q. Those are my only questions for you.

COMMISSIONER BAILEY: Mr. Alvidrez?

MR. ALVIDREZ: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. ALVIDREZ:

Q. Good morning.

A. Good morning.

Q. If I understand this, you've got a very intimate familiarity with this entire project; is that correct?

A. I'm familiar with it, yes.

Q. And you also have an extensive background in health and safety matters?

A. Yes.

Q. And I think you testified earlier that for these types of operations, OXY has made a policy decision that it doesn't allow these type of operations or doesn't pursue these operations within the city limits; is that correct?

A. Yes.

Q. And I take it that's because of health and safety concerns and the population that's in proximity to a facility like this?

A. It's just a policy that our management has felt like, at this time, they do not see the need to do that, to have these operations in such close proximity. And so we're able to prosecute them outside of the city limits, and that's what we're doing as a matter of policy.

Q. That's what I'm trying to get at. Why don't you pursue these -- why doesn't OXY pursue these within the city limits?

A. Well, operations inside of city limits, facilities, whatever, they're just in closer proximity to the public, and so we feel like we can prosecute these projects without having some of these facilities in such close proximity. Understanding, there is still an oil field here. There has been production, as there is in many other places, within the city limits. So there are already facilities, wells, pipelines within the city. It's just that these particular types of facilities, the company, at this time, has decided that we don't need to do this inside of the city limits, so as a matter of policy, we don't.

Q. With regard to this project, can you tell us what type of safety mechanisms or policies are going to be in place to address potential exposure to H2S?

A. I'm sorry. I'm not sure I understand your question. Would these be regulations you're asking about or --

Q. No. I'm really talking about -- I'll break it down. That was kind of a compound question.

Are there going to be any policies and procedures that OXY is going to implement with regard to the health and safety pertaining to H2S?

A. OXY has internal policies relating to these kind of operations. They also involve H2S operations.

Q. Can you describe those for us a little bit?

A. They're very similar to the rule that is in New Mexico and Texas, Rule 36, for example. And we have

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that policy primarily because we have operations in foreign countries and other places that don't have such a robust H2S regulation as what we have here in New Mexico or Texas. But we do have that internal policy, so we maintain a worldwide standard of care of our operations and consistency throughout in how we handle H2S. And they deal with all the same issues.

First, it's important for us to know the H2S concentrations in our -- in our production, to measure them on a periodic basis and to determine applicability of local regulations to ensure we're complying with them.

But, also, we have additional requirements related to risk assessment that may be required for some of these operations and the implementation of additional risk mitigation measures. And some of what you'll hear in testimony from the other witnesses are these additional mitigation measures that the company imposes on itself as a matter of just the type of operator we are. We feel like it's prudent to do some of these things, and that's why we're doing them in Hobbs and elsewhere throughout the world.

Q. And just so we're clear on the record, H2S is a poisonous gas; is that correct?

A. In certain concentrations, yes.

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Q. And in the concentrations -- as I understand it, the anticipated concentrations of H2S gas in the gas stream is about one percent to maybe two-and-a-half percent on the high side? Did I understand your earlier testimony?

A. Well, in the current production, it's four percent. In the CO2 flood, after CO2 breaks through, it's projected to drop very quickly to one percent.

Q. That's the concentration I'm talking about.

What concentrations does H2S present to a health risk?

A. I believe the immediately dangerous to life and health limit is 100 parts her million, and I believe that's the same limit that OSHA uses.

Q. And expressed in percent, what would that be?

A. One hundred parts per million would be .01 percent. I'd have to --

Q. So we are talking about concentrations, at least in the CO2 flood, at levels that would be dangerous?

A. Yes.

Q. Are you planning to put any alarms up, H2S alarms, anything like that, in the event there is a failure somewhere that would result in the escape of gas?

A. Yes.

Q. What steps are you taking with respect to neighboring landowners with regard to any type of early warning system or alarming their property, if any, with respect to this project?

A. Well, the first step we've attempted to take is the location of the facilities in as remote an area as practical. In this case, we've made the decision to locate the surface facilities for produced gas injection outside of the city limits. So that's moving them into a more remote area.

We've also been working with landowners to acquire land in the South Hobbs Unit to further control development encroachment into these facilities, because we've seen over time that that represents a challenge in some of these floods, is the community development. So we've spent a considerable sum of money purchasing surface land in the South Hobbs Unit.

Also, as you've heard, we've had numerous meetings with numerous governmental officials, city officials to educate people about the hazards. We've developed emergency response plans in conjunction with local emergency responders, and we'll continue our efforts to educate the public about the hazards and what to do in the event of any indication that there might be

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a problem.

But I think we need to remember that this oil field has been in Hobbs since 1929, so many of the landowners and residents are very familiar with oil field operations. In fact, many work in oil field operations.

Q. Are you familiar with the proximity of Mr. Coombes' property with respect to this area where you're conducting these activities?

A. Other than, I believe -- other than the fact I remember seeing that his property is inside the boundaries of the South Hobbs Unit. I can't recall exactly where his property is, but I believe it is within -- inside the South Hobbs Unit.

Q. Are there any plans to, you know, put alarms or an early warning system with respect to Mr. Coombes' property?

A. We have plans to install alarms and a variety of devices intended to alarm us if there is any kind of a problem throughout this whole system. I can't tell you if they'll be located on his property or not, but one of our witnesses is going to go into that extensively, about all the alarms and systems we're going to have in place to ensure the integrity of the equipment and to be able to provide a quick response in

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the event there is a leak.

Q. Now, you were asked some questions about the affidavit that Mr. Ezeanyim has submitted in this case from the Division. I assume you've read the whole affidavit?

A. I have, yes.

Q. And he makes some recommendations on the part of the Division with respect to certain aspects, I guess, design and operational aspects. And I wasn't quite clear. Are those proposals that Mr. Ezeanyim has set forth in his affidavit acceptable to OXY?

A. I believe generally so, but I don't have a copy of the affidavit in front of me, and I can't read exactly which proposals you're referring to.

Let me rephrase my answer. We have no objection to the recommendations that Mr. Ezeanyim made.

MR. ALVIDREZ: Madam Hearing Examiner -- Madam Chair and Commissioners, those are all the questions I've got.

I've also had a chance to talk with counsel for OXY and the Division. And Mr. Coombes is here in an intervenor status, and as I said, he doesn't oppose this project. We wanted to get a little bit more information and insight into what exactly was going to happen. I think the presentation this morning has been very helpful in that regard.

And what we would ask is that we be allowed to be excused. We would waive our right to present any testimony in this matter or other evidence in this matter, but would reserve all other rights that we might have. And I've talked, as I said, with counsel, and I understand that that would be acceptable for them, if it's acceptable to the Commission.

COMMISSIONER BAILEY: Commissioners, Counsel, do you have words of wisdom?

MR. BRANCARD: You may participate at whatever level you would like.

COMMISSIONER BAILEY: Whatever level you would like to participate. That's fine. You may be excused.

MR. ALVIDREZ: Thank you very much for your time this morning.

Thank you-all.

(Mr. Alvidrez and Mr. Coombes exit the hearing.)

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

COMMISSIONER WARNELL: Yes, a couple of questions.

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. Good morning. It was very informative. Thank you.

A. Thank you, sir.

Q. My first question would be that you mentioned something about the one unsuccessful CO_2 project that had been shut down.

A. Yes.

Q. Could you elaborate a little bit on that?

A. Actually, I cannot. I was just advised that we did have one that was shut down because it wasn't successful. I believe we may have another witness who may have more information on that, Mr. Brockman.

Q. Mr. Brockman?

A. Yeah. He follows me.

Q. Thank you.

I think you had also testified or you mentioned the expense of the project?

A. Yes, sir.

Q. And how limiting that would be if there was a time constraint?

A. Yes, Commissioner Warnell. As I mentioned, we perform these economic analyses assuming a certain -- a certain amount of production over a certain period of time. In this case, we're estimating at least 40 years.

So an order that limits the project in its -- you know, say the order limits the amount of injectate that goes in or the time it can be injected would cause us, from an engineering standpoint, to assign a higher risk to continuing the project beyond that point, because we just wouldn't have the certainty of knowing that the injection authority is still there. So we would assign some level of uncertainty to that, which then assigns an uncertainty to the amount of production associated with that. And the result of that, which is to reduce the rate of return that is expected from the project, and for projects like these that are close to the minimum -- the rates of return that we require, that can be very significant in whether we decide to go forward or not.

Q. When you're doing your economics, then, your ROI, what number are you looking at there? What is the target for return on investment?

A. That's a confidential number.

Q. It is?

A. Yes, sir.

MR. FELDEWERT: Commission, I've run into this before.

COMMISSIONER WARNELL: Well, that's good to know.

THE WITNESS: We have competitors in the audience (laughter).

MR. FELDEWERT: Usually the recommendation [sic] to identify the rate of return is what is used in economic models.

COMMISSIONER WARNELL: I'll take that question back.

MR. FELDEWERT: If you really want to know, perhaps we can do it in some confidential format.

COMMISSIONER WARNELL: No, that's not necessary. Let me make one other stab, one other question.

Q. (BY COMMISSIONER WARNELL) You testified about no injection within -- inside the city limits?

A. No surface facilities associated with produced gas injection inside the city limits, yes, sir.

Q. What percentage of the South Hobbs Unit and, I guess, the North Hobbs Unit would you estimate inside the city limits?

A. I believe the subsequent witness is going to have some very good slides that show the outline of the city limits in relation to the project and actually the location of the facilities. And that might be a lot more helpful than me trying to answer that without those

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slides.

Q. Very good. Thank you.

A. Thank you, sir.

COMMISSIONER BAILEY: Mr. Balch?

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. I might be able to help. What's your predicted incremental recovery?

A. I believe it's about 30 million barrels plus.

Q. And your capital investment for that?

A. The capital investment? The numbers, I believe, will show -- there's going to be some subsequent numbers that are actually going to put all that into the record, but it's about, I want to say, 300 million.

Q. What's the MMP for the North and South Hobbs? I presume --

A. The MMP -- and the person who can really testify to that in more detail is the project manager testifying behind me. But the MMP depends on where in the reservoir we are and what fluids we're talking about, CO2 without any produced gas in it or produced gas. But I believe the range I've heard in meetings is around 1,600.

Q. And it was initially around 1,200, you said?

A. The initial reservoir pressure was about 1,500 psi, and the reservoir was produced during primary production to about 400 psi. We started waterflooding, built the pressure back up, and it is currently around 1,200.

Q. You mention, of course, that the Permian Basin has sour fields. You have 18 reinjection floods, I believe? 15?

A. 15.

Q. Fifteen reinjection floods in the Permian Basin. What's the -- the highest initial concentration of H2S in those fields that you've dealt with?

A. Without doing the research, I hesitate to answer accurately, but I believe the range is going to be very similar to what we're seeing here. This is San Andres, and we're working within the San Andres -- throughout the Permian Basin. So we're talking about CO2 concentrations of five percent, six percent, seven percent. Nothing much more than that.

Q. Currently you're producing this on a waterflood that's been there for 40 years, I guess?

A. That's correct. Yes, since 19- -- mid-'70s, yes.

Q. What's being done with the H2S right now?

A. The gas is being produced, and I believe is

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being sent to a processing plant.

Q. I'm sorry. I forgot to thank you for your testimony this morning and say good morning.

A. Oh, thank you.

Q. The next few questions are -- I tend to be a curious person, so if you can tell me about how much CO_2 is allotted to the Hobbs fields?

A. There is going to be a subsequent slide which will show the volume that CO_2 was planning to be injected.

Q. Well, a rule of thumb, whatever number you have is fine.

A. I'm trying to -- I can't --

Q. Let me ask you an easier question.

A. Okay.

Q. About how many new patterns do you think are going to be put out a year?

A. I haven't counted them, but there is a slide that shows exactly the patterns we're planning to do. I apologize. I just -- I don't have that in front of me, and I can't count them.

Q. About how many total patterns are in North and South Hobbs? Do you think you'll run over the next 40 years or so?

A. I didn't count the patterns. I apologize.

Q. There's [sic] how many wells right now in the field?
A. Can I refer to additional exhibits that haven't been introduced yet?
Q. I can ask later, as long as you know --
A. Because we have all the information that we're putting into the record. I don't have it in front of me. I hesitate to guess and be wrong and have one of my witnesses point that out to me.
Q. So when you're recycling CO2 -- I just want to clarify a little bit on the process. You have an invert five-spot pattern, and your injector in the middle. You start to put CO2 in, full of water --
A. Yes.
Q. -- and you may repeat that sequence a number of times throughout the life of the well. Once you have breakthrough, you're producing the majority of that CO2 and then recycling it back in?
A. That's correct.
Q. How long is an injector in this pattern kept -- typically kept running? Is it the entire life of the project? Is it some, a few years in the project, until the CO2 [sic] is completely swept?
A. Well, this project, as most CO2 projects are prosecuted, is done in phases. So the first phase

actually involves the injection of pipeline-quality CO_2 into certain patterns. And so that starts the process in those patterns. And then as we get produced gas back, then we'll take that and reinject it in additional patterns.

So we pretty much walk our way through the unit, and as the first patterns -- as the monitoring indicates that we no longer need to inject any more CO_2 into the reservoir because of, you know, just what we're seeing in that particular pattern in terms of production and reservoir pressuring and our modeling, then we can switch to water, and we'll keep it on water even though there's CO_2 production in that pattern for many, many years. And then we just migrate these patterns all the way through the flood.

Q. All right. So across your 28 floods in the Permian Basin, what's the -- the life span of injection of the CO_2 into an injector, kind of just an average?

A. Well, as I mentioned, we -- we -- these projects are still going on. So in many cases --

Q. Sure. There's a lot of this, and those patterns will eventually convert fully to water.

A. Yeah. We have -- we have, yeah, switched them back on to water, but I don't know. Until I look at the numbers, I hesitate to guess.

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I'd also suggest it may be very reservoir specific, that in some reservoirs, those injectors may still be running a WAG cycle that was running 20, 30 years ago, and others, it may be a much faster process.

Q. All of it incremental --

A. Yes, exactly. That's the whole -- that's the whole process here. As long as we see benefit to injecting CO2 into that pattern, then we'll continue to do it based on our modeling, and then we'll switch to water.

Another aspect of these floods is that we may utilize that injection well to actually start to inject in different parts of the San Andres reservoir. As you've seen here, this unit comprises the Grayburg and the San Andres Formations, and so there are potentially other areas of the San Andres that might lend themselves to CO2 flooding. So we might utilize the same pattern, but just move it to a different section of the reservoir that wasn't previously flowing.

Q. Can I ask you if OXY is looking at ROZs?

A. Yes (laughter).

Q. That's all.

COMMISSIONER BAILEY: Yes, you may ask, or yes, you may get an answer?

(Laughter.)

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MR. FELDEWERT: It was a good answer.
THE WITNESS: I'm going to get in trouble with my management.
Q. (BY COMMISSIONER BALCH) So was that a yes, I can ask?
A. Yes, we are looking at that as a potentially --

CROSS-EXAMINATION

BY COMMISSIONER BAILEY:
Q. At the beginning of your testimony, you gave some conversion factor for percentage of parts per million of H2S. Could you repeat that for me, please?
A. Yes. One percent H2S is 10,000 parts per million.
Q. So even though the concentration of H2S is reduced to one percent, the parts per million is still at a level that would be harmful --
A. Correct. Yes, ma'am.
Q. -- to the public?
A. Yes, Commissioner Bailey.
Q. I understand that a contingency plan for both the North and the South Hobbs Units has been approved by the Division; is that correct?
A. That's correct, yes.
Q. So the concerns that Mr. Coombes had about alarms would have been covered in that contingency plan?

A. Yes, Commissioner Bailey, in addition to some of the information you'll hear today, which are additional protective measures.

I believe Mr. Coombes probably didn't have the opportunity to see the contingency plan, even though one was on file at the district office. But we have -- we spent a considerable effort to bring that plan up to, basically, best-in-class emergency action plans in our entire operations worldwide by working with the local first responders and our own internal review process, our own internal experts on emergency response, and then through extensive discussions with the OCD here in Santa Fe. And so, quite frankly, what I believe we have is a model for other parts of our operations worldwide in terms of emergency response.

Q. So with 10,000 parts per million, there's not been any disregard for public safety?

A. Oh, absolutely not.

Q. I was looking at an aerial image of the city of Hobbs, and it was difficult to tell, but it appeared as though the population density to the south of the city limits was probably just as concentrated as the population density within the city limits. Is that a true statement?

A. I believe that's accurate. I think there is some significant development to the outside of the city limits and to the south, yes.

Q. Okay. So just because you have the policy of not having injectors within the city limits doesn't mean that the population density -- the population is not as greatly impacted as though you did have these facilities within the city limits?

A. Well -- and I apologize. I could have put more detail about that policy, but it drives us to locate our facilities in as remote an area as possible.

And so what you'll hear in the testimony of, I believe, the next witness is, we did exactly that. We located these facilities initially outside the city limits, but even then, as far away as we could from population that might be impacted by any sort of release. And that's in addition to all the safety measures designed to keep the injectate, keep that produced gas within vessels, pipelines, wells, whatever. But an extensive amount of work was done, based on dispersion modeling and radius of exposures, to locate our facilities throughout the South Hobbs project.

And in addition, as I mentioned, we even purchased a significant amount of surface to locate these facilities on that purchased land for the reason -- to keep it remote and also to prevent

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encroachment from development. So we -- it was a lot more than just locating it outside the city limits.

Q. But remote still doesn't mean very far away from a significant number of people, according to the area?

A. As far away as we could practically locate it. There is still public within the radius of exposure from a release -- an accidental release, yes, ma'am.

Q. You brought up Exhibit 8, page 22, the Order R-5897-A --

A. Yes, ma'am.

Q. -- in which the packer could be different from what the current rule requires for the location of a bridge plug within an injector. I was curious about this particular exhibit, so I looked up the order and saw that there were findings as to why the Division would have changed that. And I think, since you brought it up, then we really should see the findings that say that "about half of the injection wells in this unit" -- and I'm quoting from R-5897-A, page 2, Finding 7F: "About half of the injection wells of this unit are conversions of older producing wells, some of which were drilled in the 1930s. The other injection wells were drilled in the 1980s specifically for the purpose of injection."

And then in G, it says: "Due to corrosion and wear on the casing in these old wells, it is often necessary, when resetting the packer, to move uphole in order to secure a reliable packer" --

A. Yes, ma'am.

Q. I think that's the other half of the story, as Paul Harvey would say.

And those are all the questions I have for you.

COMMISSIONER BAILEY: Do you have any redirect?

MR. FELDEWERT: I do not, Madam Chair. And on your last point, we do have a witness who is going to talk about the reasons for seeking this particular change, and, if I'm thinking right, he's our next witness.

COMMISSIONER BAILEY: Okay.

Then you may be excused.

THE WITNESS: Thank you, Commissioners.

MR. FELDEWERT: We will call Jerad Brockman.

And while he's going to the stand, we will be working off of OXY Exhibit 8 in the notebook.

JERAD BROCKMAN,

after having been first duly sworn under oath, was

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questioned and testified as follows:

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Please state your name, by whom you are employed and in what capacity.

A. My name is Jerad Brockman. I'm a production engineer. I work for OXY.

Q. And have your employment responsibilities included both the North Hobbs Unit and the South Hobbs Unit?

A. Yes. I've been a production engineer on the South Hobbs Unit since January of 2010, and a production engineer on the North Hobbs Unit, in addition to the South Hobbs Unit, since August of 2010.

Q. As a result of your job responsibilities, have you been part of the current team to convert the South Hobbs Unit waterflood to a tertiary recovery project?

A. Yes, I have.

Q. What will be your responsibility at the South Hobbs Unit once this conversation is completed or as it's being done?

A. I'm currently the project manager and plan to continue in that role.

Q. What's your educational background? When did you get your degree, and what is it in?

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A. I have a bachelor's degree in chemical engineering from Louisiana State University in December of 2009.

Q. And once you graduated in December of 2009, did you commence work for OXY at that point in time?

A. Yes, I did.

Q. As a production engineer?

A. Yes.

Q. Are you familiar with -- let me step back. Since your -- since the commencement of your employment with OXY as a production engineer, has that been in connection specifically with the South Hobbs Unit and the North Hobbs Unit?

A. Yes, entirely so.

Q. Are you familiar with -- and you've reviewed and you're familiar with OXY's application in this case?

A. Yes, I am.

MR. FELDEWERT: I would tender Mr. Brockman as an expert witness in oil and gas production, as an engineer.

MS. GERHOLT: No objection.

COMMISSIONER BAILEY: He is admitted.

Q. (BY MR. FELDEWERT) Mr. Brockman, did you prepare a series of slides to assist in your presentation today?

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A. Yes, I did.

Q. Have those slides been put together and comprise what has been marked as OXY Exhibit 8?

A. Yes, they do.

Q. And does that exhibit contain a total of 24 pages?

A. Yes.

Q. What topics are you going to be talking about here today?

A. I'll go through the project, general overview, highlights of the project. That'll be most of my presentation. I'll also go through the GOR issue, what happens to GORs in CO2 floods. I'll talk about service injection pressures that we require and are asking for. I'll talk a little bit about the packer setting issues, and I'll talk a little bit about the downhole corrosion mitigation, which are kind of in connection with what the chief engineer testified to.

Q. Let's start with a general overview of the operations. Does slide one of OXY Exhibit 8 depict the boundaries with the current North Hobbs Unit and the current South Hobbs Unit project area?

A. Sure. So what this slide isis kind of in the right-hand corner of the Permian Basin. This dark black line is the state line between Texas and New Mexico.

This dot right here is the Hobbs field. This aerial is kind of blown up of that insert.

So the Hobbs reservoir is made up of two units that we've talked about, the North Hobbs Unit, which is here in black to the north, outlined in black, and then the South Hobbs Unit here outlined in red on the southern portion of the field. These unit maps are -- these unit outlines are overlaid on the street maps, and that's what all these yellow lines are. You can see that in parts of the North Hobbs Unit and in the South Hobbs Unit there is, you know, significant in-town development.

Q. Now, both of these units, do they operate in the same production zone?

A. Yes. Both these units are produced out of the Grayburg-San Andres formations.

Q. What is currently going on in the North Hobbs Unit?

A. If you'll click to the next slide, it will come up to be an outline of our total operations in Hobbs and what we're trying to do.

Q. Does this slide have some animation associated with it?

A. Yes, it does.

Q. So what are we starting with with respect to

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the first animation?

A. Sure. So again, outlined in black is the North Hobbs Unit. I think they will be a little easier to see on your printouts, but the animations will come through. In green are the Hobbs city limits as they relate to both South Hobbs and North Hobbs. And, again, outlined in red is the South Hobbs Unit outline.

So if you'll click the slide.

Q. (Complies.)

A. One more time.

Q. (Complies.)

A. So currently in North Hobbs, we're undergoing both the CO_2 flood and waterflood. All of our produced gas injection is to the northwest. It's outlined here in this red polygon.

If you click again.

Q. (Complies.)

A. We also have pure CO_2 injection, and that extends closer to population centers and inside the city limits.

And if you'll click again.

Q. (Complies.)

A. Currently the rest of the field -- the rest of the North Hobbs Unit, all of South Hobbs is under waterflood. Now, our project here today that we're talking about is expanding the South Hobbs Unit into the waterflood.

So if you'll click.

Q. (Complies.)

A. You see, when we go -- when we go to CO2 flooding in South Hobbs, we're going to do the same concept that we did in North Hobbs. We're going to keep our produced gas injection outside the city limits.

So if you'll click.

Q. (Complies.)

A. That's shown here in red. When we go to a flood [sic], we produce gas injection outside the southern portion of the field.

Click again.

And these will be -- excuse me. Before we go on, these will be surface areas. Any surface location will have to be -- with produced gas injection will be located outside. And I'll talk a little more in detail, but we'll have some directional injectors that we target patterns underneath the city with produced gas, but their surface location will be pulled back away from everything.

So if you'll click again.

Q. (Complies.)

A. Any surface location injecting inside the city limits will only inject pipeline CO_2.

And then just for completeness sake, if you'll click again.

Q. (Complies.)

A. In the future, we plan to expand the CO_2 flood throughout the rest of North Hobbs as well. But, again, today, we're just going to focus on the South Hobbs project.

Q. So your design, your projections, et cetera for the South Hobbs Unit is essentially what is going on with the North Hobbs Unit?

A. That's correct.

Q. Do we have some general highlights about the project --

A. Yes, we do.

Q. -- kind of a numbers overview?

A. Sure.

Q. If we go to -- start at slide number three.

A. Yeah. So I think Rick touched on this a little bit. This is a -- this is a big project. Capital investment is $312 million. In addition to that $312 million, we anticipate operating expenses of $317 million in addition to the current waterflood operation expenses over the life of the flood. For all that money, we do expect to get 33.2 million barrels of oil equivalent in additional recovery. To do this, we're going to be doing a lot of work, with 60 workovers, 32 new drills, in a plan with a life of 40 years.

Q. And then what are you showing in slide number four?

A. Slide number four kind of shows, you know, our current operation in South Hobbs today, and then where we will be at when we're fully up and running in regards to the flood in the future.

So currently, South Hobbs has an average reservoir pressure of about 1,200 psi. As we go in to the CO2 flood, we anticipate that reservoir pressure to rise to an average of 2,000 psi.

Currently, our producing well count is 69 wells. As we go through this project, we're actually up-spacing. We're going from 40 acres to 80-acre spacing, so our producing well count and injection well count will both decrease. So currently, those are both at 69 wells apiece. We'll go down to 57 producing wells and 53 injection wells. In doing so, once we inject the CO2, again, we expect to get some oil for it. So our current production rate is about 1,100 barrels per day. We expect peak production to get up to 6,500 barrels of oil per day. And then our H2S concentrations, again, we

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expect these to fall from four percent to around 1.1 percent.

Q. Let me ask you about the reservoir pressure, that projected rate in the second column on slide four. Is that what you -- is that what will provide the miscibility pressure that was previously discussed? Is that what you anticipate?

A. It'll be above -- that will ensure that we're above miscibility pressure throughout the entire reservoir, that is correct.

Q. And is it true that -- that number that you showed, is that what you anticipate the average reservoir pressure over the life of this flood tertiary recovery project?

A. That's correct.

Q. So previously you had a 40-year cycle. This is what you anticipate, a fairly constant pressure rate over that period of time?

A. That's correct.

Q. Then does the next slide give some of the objectives that you had in mind when you were working on this project in locating the facilities?

A. Yes, it does.

Q. Okay.

A. So I'll run through these. When we designed the South Hobbs Unit to be a project, we had three main objections -- or three main objectives. And the first one was, we were going to reinject all our produced gas and water for enhanced oil recovery. CO_2 and produced gas is very expensive, and there is a lot of benefit from it, so we wanted to use it as many times as we possibly can.

Also -- I think it's been touched on before -- no produced gas injection inside the city limits. And then, also, we're going to reduce our operational exposure inside the city limits. Two ways we plan to do this. One, we're going to have directional injectors from remote multiwell pads outside the city limits targeting reservoir volumes underneath the city, and then also we're going to increase our well spacing from 40 to 80 acres.

Q. And starting with this last point, do you have some slides that will show the Commission how this is going to be accomplished?

A. I do.

Q. So turn, then, and start with slide number six. What does that depict?

A. Sure. So slide six right now is the current South Hobbs Unit active wells in our 40-acre waterflood. So, again, I'll walk through this slide. These blue

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outlines for reference, each one of those boxes is a section. The South Hobbs Unit is outlined in red, towards the southern half, with North Hobbs above it. Each one of these smaller black squares, if you will, are our 40-acre waterflood patterns. They're injector centered patterns, so they have a blue injector in the middle, and then green producers are located to the outside.

Q. Now, you said that this was a 40-acre pattern. Is this similar to the five-spot pattern that was previously discussed?

A. Yes, it is.

Q. And now you are going to make some changes, correct?

A. That is correct.

Q. Does the next slide get us towards those changes?

A. Yeah. The next couple of slides I'll walk through those.

Q. Okay. Move to slide seven.

A. So this is the same map -- they're not the same map but a similar map. Again, South Hobbs is outlined in red, and then I've added the approximate city limits -- here is the city limits of Hobbs as they relate to the South Hobbs Unit, shown in this dark blue.

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Again, you can't really see the colors, but green are active producers. Blue are the active water injectors, and then gray are any inactive wells, be it temporarily abandoned or permanently abandoned.

I mentioned that as we go from 40-acre to 80-acre, our well count is going to go down, and so we're also going to be having a significant amount of drilling.

So if you'll click the slide, you'll see that we plan to temporarily abandon some of these wells.

Q. Now, the wells that you show on here were part of the overall waterflood that's been going on for the last 40 years; is that right?

A. That's correct.

Q. So with the second animation on slide seven, what are you going to be doing?

A. So as we go forward from 40-acre to 80-acre, we'll be temporarily abandoning a large amount of wells.

So if you'll click again, it will depict those wells. You'll see that the number of wells -- you'll see that a lot of these wells are located inside the city limits. And so, again, it's one of our objectives to have less operational exposure inside the city. We plan to have less active wells, active flow lines in this area.

Q. So actually you'll be reducing both inside and outside the city the number of active wells to get to your 80-acre pattern?

A. That's correct.

Q. One of the questions that was asked by the Commissioners is: How many patterns in the CO2 project do you anticipate?

A. There will be 53 patterns in this project.

Q. And how many patterns were previously in the waterflood project; do you know?

A. 69. Let me rephrase that. There are 69 active patterns. I don't know what the peak pattern was when this thing was up and running. I don't know off the top of my head.

Q. Okay. But are those numbers -- actually, as I think about this, those numbers are reflected in slide four that we previously went through.

A. That's correct.

Q. The injection well count?

A. That's correct.

Q. That would dictate essentially how many patterns you have?

A. That's right.

Q. Anything else about this slide?

A. That's it.

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Q. Let's move to what's been marked as slide eight in Exhibit 8. Is this the same starting point as the prior slide?

A. Yes, it is.

Q. And then what are we going to show on this particular slide?

A. Sure. This slide has quite a bit of animation, so we'll have to walk through it. But, basically, this will show, when it's all said and done, what our 80-acre pattern is going to -- what our 80-acre CO2 flood is going to look like both inside and outside the city.

So if you'll click.

Q. (Complies.)

A. Going forward, each one of these green dots will be a corner of one of the patterns. These will be all of our CO2 flood producers in the South Hobbs CO2 project.

Go ahead and click again.

Q. (Complies.)

A. Inside the city limits, we'll have these vertical pipeline CO2 injectors. As we start this project, we'll start with these patterns first. We'll start injecting pipeline CO2 into them. As this gas is produced back, we're going to need to inject it.

So go ahead and click again.

Q. Now, wait a minute. You're talking now about the orange triangles?

A. That's correct.

Q. I'm clicking, and we're adding some black squares.

A. And click one more time.

Q. Okay.

A. So each one of these black squares located outside the city is a remote multiwell pad. And off of these pads, you'll see that there is anywhere from three to five arrows. And each one of these arrows is going to represent a directional produced gas injector. So what this allows us to do is, from this one pad located outside the city, we can target these four patterns just north of it with produced gas. This allows us to use this produced -- this CO2 that we buy, we can recycle it and use it, this produced gas, over and over again, because we have more patterns to use it.

And so, again, as -- as these new patterns start to produce this gas, we're going to need -- we'll also have some vertical produced gas injectors.

So click again.

Q. Let me stop you right here. This injection pattern shown on here using directional wells -- directional drills, is that -- is that something you need for the South Hobbs Unit? Are you doing that currently in the North Hobbs Unit?

A. No. This is a -- this is a different -- this is the difference between the North Hobbs and South Hobbs projects. Currently, in North Hobbs, we do not utilize this directional drilling concept.

Q. Now, how much -- how many arrows are on -- there's a number of arrows shown by these black blocks. How many are there?

A. There's 17.

Q. How much additional cost is associated with adding the directional well component for each well?

A. They're about a million dollars apiece.

Q. So if my math is right, the investment in all of these directional wells is about 17 million?

A. That's correct.

Q. And this will then assist you in getting your five-well pattern within the city limits?

A. That's correct.

Q. If I click, what am on here?

A. So this will be the completion of the project. These are produced gas injectors, these red triangles. And, again, these will be vertical wells located outside of the city.

So if you click one more time, it'll be the

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same there. Go ahead and click, and I'll talk to it.

Q. (Complies.)

A. So this is the same map as shown before, but I've added the pattern outlines to clean it up a little bit. So you can see that, when we're all said and done, we'll have, you know, 80-acre patterns with CO2 injectors with produced gas injectors. The bottom-hole location is located in the middle of them.

Q. And this is depicted on slide nine?

A. That's correct.

Q. And this pattern that we've talked about, Mr. Brockman, is this going -- I think you mentioned, this is going to allow you to reuse the injectors that you put into the ground?

A. That's correct. All the -- all the produced gas will be recycled, recompressed, dehydrated and reinjected into these produced gas injectors shown on the map.

Q. And do you believe that this also will have a benefit in the confinement of the injectors?

A. Yes, it will.

Q. So it will assist in maintaining those injectates within that 80-acre pattern?

A. That's correct. We -- we -- we inject that CO2 or produced gas, whichever one it is; we just basically

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produce it back, so we can use it again. So we'll be confined within this --

Q. We've discussed the wells. Shall we now move to the surface facilities?

A. Sure.

Q. Is that depicted on what is marked as slide ten?

A. Correct.

Q. Why don't you walk us through this -- I guess what amounts to a flow diagram.

A. Sure. I'll start with the -- what this slide is, it's just a simplified diagram of all the surface facilities that we plan to install as part of this project. I'll start in the top, left corner with the producing wells and kind of wiggle my way through it until I get to the end of oil sales and then the reinjections and injection wells.

So, again, we'll have our producing well located -- which is represented by the green dot in the top left. It'll produce both oil, water and gas. That'll be transferred by a new pipeline to our production satellite. At this new production satellite we'll be installing, all the produced gas will be separated and sent to the reinjection compression facility, and all the oil and water will be sent to the tank battery.

At the reinjection compression facility, all the produced gas will be dehydrated, recompressed back to injection pressures, and then shipped to the injection satellites, where it will be combined with either produced water or additional CO_2 from pipelines, and then sent to each of the injection wells by a new injection line.

At the tank battery, you'll get your oil and water. Again, the water will be separated and sent to your injection satellites, and then the oil will be sent to sales.

Q. Now, are a lot of these facilities new facilities for the area?

A. Yes. The -- as part of this, all the satellites -- there will be four new satellites, production satellites; four new injection satellites; one new reinjection compression facility; and we're going to upgrade our existing central tank battery.

Q. And for the record and people like myself, when you talk about satellites, you're talking about a battery or location, correct?

A. That's right. It's basically just a gathering system for -- many wells feed into it, and then we can just -- it's a multiwell separation facility, I guess is

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the way to put it.

Q. And you're going to have four new facilities like that for production and four new facilities, injection satellites, as you call them, for injection?

A. That's correct. They're actually two separate systems that would actually be located in the same surface location.

Q. If you turn in the notebook to what's been marked as Exhibit 10 -- so keep your finger here and flip over to Exhibit 10. Exhibit 10 has a cover picture on it, the first slide. When you're talking about satellites, each individual satellite, is that an accurate depiction of what you're talking about?

A. Yeah. So what's shown on this picture in Exhibit 10 is both an injection satellite and a production satellite. Where it says "Injection Header," off to the left, that's the injection side, and then the production header and the associated separators that you see, that's the production satellite. So, again, we'll have four of these, and there will be a combination of both a new production satellite and injection satellite.

Q. So this picture here that we see, the first page of Exhibit 10, is actually a picture of an existing -- one of the existing satellites of the North Hobbs Unit?

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A. That's correct.
Q. Now, the four that you are going to be developing for the South Hobbs Unit, where will they be located?
A. They'll be located outside the city limits.
Q. Now, in addition to these four satellites, you're going to have -- is it going to be one reinjection compression facility?
A. That's correct.
Q. Where is that going to be located?
A. It'll be located on OXY M [sic] property outside the city limits.
Q. And do you have a facility like this in the North Hobbs Unit?
A. Yes, we do.
Q. And in the absence of that facility, what would you have to do with the gas?
A. Without the reinjection compression facility, the gas would not be fit for EOR. It would be too overpressured, so it would have to be vented, flared, disposed of in some fashion. It cannot be recycled and used again.
Q. So that's the facility that is important to the recycling of the produced gas?
A. That's correct.

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Q. Now that we have an understanding, let's go to the next slide of Exhibit 8, which is slide 11. And let's talk about the timeline that's associated with all of this facility development effort.

A. Sure. So what's shown in this slide is basically a key milestone start date as far as this project. And we intended it to kind of get a feel for how much work is about to go on and how long it's going to take to do all this work.

So currently, we started our detailed design engineering of all of our facilities in March of 2013. Beginning in July, we'll start all of our major procurement for the field and the RCF. We plan to start construction on the RCF in January -- there on the field in January. Excuse me. We'll start construction on the RCF in June. You know, it's a lot of stuff to build. We're planning to have the field, which would be the satellites and tank battery and the flow lines up and ready to go in May. Once that's ready to go, we'll go ahead and start our well workovers and our drilling.

If we stay on schedule, we anticipate the first CO2 injection in September of 2015. We'll inject that CO2 in our first wells. It will take it some while to break through and permeate through the reservoir. We expect to see our first gas response sometime between

January and February, so we'll have our RCF commissioned in January of 2016. And we expect to have enough gas broken through to start it up in February of 2016.

Q. So you can actually start your injection before you have your compression facility up and running --

A. That's correct. I mean, these wells are 80-acre -- 80-acre spacing. It takes awhile for the CO2 to be injected into the injector and make it all the way to that corner producer.

Q. To complete this subject, now move to slide 12 of Exhibit Number 8. We've talked about the timeline. Let's talk about the capital expenditure. What does this show us, slide 12?

A. Sure. If you'll click.

Q. I'm sorry.

A. No problem.

So this slide is just a capital expenditure profile of the project over the next, you know, almost ten years. So what's shown on the left axis is thousands of dollars per month that we're planning on spending. Shown on the right is the total cumulative capital spent. On the X-axis is the -- is the date. Obviously, we're here in May of 2013. This black line is the cumulative spending. It starts at zero, and, of course, peaks at about almost $320 million, with 312 as

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we stated earlier. These individual bars represent the monthly spent. And so the red bars are going to be the RCF. The green bars are going to be the surface facilities, which will be the satellites, the tank batteries, the flow lines. And then the blue will be the well working and drilling.

Q. You said RCF. That's the recompression facility?

A. Reinjection compression facilities.

Q. Reinjection. Okay.

And then you have your anticipated start date of injection of September 2015?

A. That's correct.

Q. Does this help to demonstrate why the company is seeking approval now and then also requesting that there be an exception to the one-year commencement of injection that may apply under the Division rule?

A. That's correct. If you -- if you look where we are right now, May of 2013, and you look on this expenditure profile, we're -- we're about to really ramp up our spending. And, you know, it's -- it would be nice, before we started ramping up all of our spending, if we knew that we would be able to inject and not have to go through this effort again. And so we'd like to get our approval to inject now, before we go through

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significant investment.

Q. In fact, I would suspect your companyis not going to go through a significant investment without the authority, correct?

A. I would assume so.

Q. Finally on this particular topic, we can move to slide 13, and I believe this was actually attached to our application. Once these facilities are in place and injection commences, is this what you hope to anticipate will happen over time in terms of the production forecast?

A. Click.

Q. (Complies.)

A. Yeah. Sure. So what this plot is is a very simple production plot. It's on semi-log scale. Time on the X-axis, and then amount on the Y. Blue is water production. Green is oil production, and red is gas production. You see the field started production back in the late '20s, early '30s. You know, it went on with primary production until about the mid-'70s. You can see the start of waterflooding. We reversed its oil decline. Really, you know, ramped up, got a good waterflood response.

In addition to oil response, you saw a large increase in water production, which was to be

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expected. As you're pumping all this extra water in, you expect to see it back.

Here we are today in 2013. You can see we're again on a, you know, pretty good decline from our, you know, peak of about 8,000 barrels per day. We're expecting to start injection of -- in 9 of 2015, we expect our oil response to increase, again, similar to what we saw when we started water injection.

Also similar to when you [sic] started water injection, now that we're going to be injecting all this gas, we're expecting to see a big increase in overall gas production as part of the field.

Q. Then one aspect we haven't touched on is, what happens to the CO2 injection over time. Let's turn to slide 14.

A. Sure.

COMMISSIONER BAILEY: Is this a good place to stop for lunch?

MR. FELDEWERT: I was going to stop right after this slide, Madam Chair.

COMMISSIONER BAILEY: Okay.

Q. (BY MR. FELDEWERT) What is going to happen in terms of your actual CO2 injection if you need the CO2 over the life span of this project?

A. Sure. So what this plot shows is on the -- on

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the Y-axis is the overall gas injection MCF per day. On the X-axis, it's time. There are two curves shown here. One is the CO2 injection, and that's shown in red. And the blue curve is the produced gas injection. See, you can see that we start out at a pretty good rate of 45 million cubic feet per day of CO2 injection, and over time, as we get less and less oil for that CO2 to inject, our CO2 injection drops off to eventually nothing, around 2,035.

But as we inject the CO2, we get quite a bit of produced gas back. And since we're going to be reusing all this produced gas for EOR -- our produced gas injection clients [sic] are nothing at the start. And as we see more and more response, turn on more patterns, our produced gas injection will climb, peaking around 75 million cubic feet per day and then declining as we inject less and less, as each one of these patterns goes to chase water injection.

Q. So under this slide, do you anticipate injection commencement 2015, about 20 years, you will no longer need to acquire new CO2 for the project to continue?

A. That's correct.

Q. And is that part of the economics that comes into play in analyzing and determining whether this project is economically viable for the company?

A. That's correct. I mean, essentially, you keep buying CO2 until the oil that you get out for it is less, which even the oil that's produced from additional CO2 is less than the cost of the CO2 injecting.

Q. But you will continue to get benefit by reinjection of the produced gas in oil recovery as you move forward?

A. That's correct.

MR. FELDEWERT: Madam Chair, I'm about ready to go into a new topic, so this is a good time to break.

COMMISSIONER BAILEY: Okay. Why don't we break for lunch. Come back at 1:15 -- 1:20 would be fine.

(Lunch recess, 12:06 p.m. to 1:20 p.m.)

Q. (BY MR. FELDEWERT) Mr. Brockman, before we took a break, we were talking about the amount of expenditures you're looking at for this project over a number of years and the timeline associated with it. I just want to talk, you know, on the other side, briefly, about the risks. There was a question about the CO2 project that was shut down. Are you familiar with that project?

A. Yes. It was the South Wasson Clearfork Unit.

Q. Can you tell us a little bit about that?

A. Yeah. Basically, they couldn't get the injection through. They could put the -- they couldn't get enough CO2 into the ground to see the response of the producers due to reservoir quality and essentially didn't make any money, and so it was discontinued.

Q. So these are risky ventures?

A. That's correct.

Q. We just finished up with the fact that over a period of time, you hope to be able to discontinue the CO2 injection.

The other aspect I want to turn to now is the gas-oil ratio issue. And can you just explain, using slide 15 of Exhibit 8, what happens to the gas-oil ratio in this kind of project over a period of time?

A. Sure. So this plot is the well test -- average well test for individual wells in the North Hobbs Unit currently. On the left is the gas-oil ratio in standard cubic feet per barrel, and then on the X-axis, it's just the well numbers that are plotted. And these wells are plotted in order of increasing a gas-oil ratio, from the left to the right.

You can see that while some -- while some wells have very low gas-oil ratios, 2,000, certainly less than 10,000, eventually you get in this range where we have several wells and good wells that have gas-oil ratios approaching at the 50-, 60-, 75,000 standard cubic feet per barrel.

Q. Now, this is actual data on the North Hobbs Unit?

A. That is correct.

Q. And if we go to slide 16, is this, again, the historical actual data from the North Hobbs Unit about the gas-oil ratio?

A. Yes, it is.

Q. What does this show?

A. Sure. This is a semi-log plot, the entire North Hobbs Unit gas-oil ratio historically through time. The mid-'80s, I believe it starts. So, again, on the Y-axis, on the left, I have standard cubic foot per barrel. It begins the semi-log scale, so each one of these -- this would be -- this would be 10,000, and this would be 100,000, this line right -- I'm sorry. This would be 1,000, and this would be 10,000. Excuse me.

And so basically you can see that as this is waterflooded throughout the '80s, this gas-oil ratio stayed pretty constant. And then as the CO2 flood started, in 2003, the gas-oil ratio increased. So where we are today, a field watt gas-oil ratio is approximately 13,000 standard cubic foot per barrel.

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Q. Now, did you take this information and create a similar graph of what you project for the South Hobbs Unit?

A. Yes, I did.

Q. Let's turn to what's been marked as slide 17 of Exhibit 8.

A. This is a very similar plot to the one just shown. Again, it's a semi-log plot with the gas-oil ratio on the left and standard cubic foot per barrel, and then time on the X-axis. And you can see that throughout South Hobbs -- this is zoomed in a little more than the last one, but, essentially, the gas-oil ratio has been fairly constant in the mid-'80s. When we go to CO_2 flood starting in September 2015, we expect that gas-oil ratio to increase, and it will continue to increase throughout the life of the flood.

Q. In your opinion, Mr. Brockman, is the gas-oil ratio limitation necessary to protect correlative rights in an EOR project?

A. No, it is not.

Q. In your opinion and based on your experience, will a -- could a GOR limitation negatively impact the efficiency and effectiveness of an EOR project?

A. Yes, it would.

Q. And thereby potentially lead to waste?

A. Yes.

Q. Let me then turn to the next topic, and that is surface injection pressures. Did OXY conduct some step-rate tests in 2008 in the South Hobbs Unit to determine the appropriate surface injection pressures for water?

A. Yes.

Q. And did this result in -- did those step-rate tests result in an increase in improved injection pressure for water in 2008?

A. Yes, they did.

Q. And that was the order that I think we've already looked at that's been marked as OXY Exhibit Number 6? I'm sorry. OXY Exhibit Number -- yeah, OXY Exhibit Number 6?

A. Yes, it is.

Q. If I look at the first page of that exhibit, it references step-rate tests. Is that what -- is that what you discussed here?

A. Yes.

Q. If I turn to slide 18 of OXY Exhibit Number 8, does this identify the wells in the South Hobbs Unit that were subject to that 2008 step-rate test?

A. Yes. They're depicted in the large red circles on this map.

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Q. If I go to slide 19 of OXY Exhibit Number 8, does that provide the data that was obtained?

A. Yes, it does. This slide was actually one of the exhibits from OXY Exhibit Number 6 back in 2008, and this is a plot showing all the step-rate tests that were conducted and the average surface parting pressure of 1,277 psi.

Q. Now, you said this was one of the exhibits that was submitted as part of the request for the approval that was obtained in 2009 [sic]?

A. Yes.

Q. When I looked at that order, it referenced -- it referenced eight wells, and I see nine dots on here. Do you have any understanding as to what happened there?

A. Yeah. This outlier at 700 pounds was not included in the analysis.

Q. So what did this reflect in terms of the average parting pressure?

A. The average surface injection parting pressure?

Q. Yes.

A. 1,277 psi.

Q. And what was approved, then, was 1,100 psi?

A. As a surface injection on [sic] water, yes.

Q. So that was -- those wells were below the parting pressure?

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A. Yes.
Q. Now, did you undertake an effort to use the same analysis -- or, essentially, to convert that approved 1,100 psi for water to what the equivalent would be for both CO2 and then produced gases?
A. Yes, I did.
Q. And if we turn to what's been marked as OXY -- or slide 19 of OXY Exhibit 8, does that contain the analysis?
A. Yes, it does.
Q. Why don't you walk us through it, please?
A. Okay. I'll kind of walk through this table fairly slowly and try and convey what I'm trying to get to.

So in the left column is the various injectates that we plan to inject as part of the South Hobbs CO2 flood project, both water, CO2 and produced gas. The second column is the surface parting pressure with water that was demonstrated with the 2008 step-rate test; 1,277 psi for all three of them.

Now, because CO2 and produced gas have a lower density than water, to obtain the same bottom-hole pressure, we need a higher -- we need to adjust for the difference in the hydrostatic column. And so the second column -- or the third column -- excuse me -- attempts

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to account for the differences in density. So the hydrostatic column of water is given a zero adjustment. The one with CO_2 is given 390 pounds, and this accounts that that column of CO_2 weighs 390 pounds less than a column of water. The same thing for produced gas. A column of produced gas will weigh 900 pounds less than a column of water.

This is -- basically, the CO_2 -- the reason why the produced gas is higher than the CO_2 is just the gas concentration. The methane and the ethane are lighter than CO_2, and so it lightens it up just a little bit more. So we need a little bit higher pressure for produced gas.

And so if you add the first two columns together, the surface parting pressure and the hydrostatic adjustment -- hydrostatic pressure adjustment, we're getting what we call an adjusted surface parting pressure for each injectate. So, again, 1,277 for water, 1,667 for CO_2, and then 2,177 for produced gas.

However, to ensure that we -- we want to be below our parting pressure, so we could walk back, request surface pressure limits for each injectate asked -- that were asked for in the application, 1,100 psi for water, 1,250 for CO_2 and 1,750 for produced gas.

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Q. Mr. Brockman, are these requested surface pressure limits necessary to attain the miscibility that is needed to make this project successful?
A. Yes.
Q. And in your opinion, will the adoption of these surface pressure limits pose an unreasonable risk to the public or the environment?
A. No, they will not.
Q. How does OXY intend to monitor and control these pressure limitations?
A. Sure. So on the --
Q. Next slide?
A. Yes, please.
Q. So slide 21.
A. Sure. So what this slide is is a schematic of our injection well location. And so here is your injection well. Here's your injection line right at the wellhead. It goes below grade right -- for about 100-feet allocation, and then it pops back up above grade at the edge of location. At the edge of location, we're going to have a pressure and temperature transmitter that will record our injection pressures, rates and temperatures in realtime. It'll transmit that data back by a fiberoptic cable to choke our injection manifold that will control our rate and pressure to make

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sure we stay below the parting pressures.

Q. So this is realtime monitoring?

A. Yes.

Q. With controls in the event that parameters are not met?

A. That's correct.

Q. Is this the configuration that you're going to have on all of your injection wells at the South Hobbs Unit?

A. Yes.

Q. In addition to this, will the company itself be monitoring reservoir pressures as part of the overall EOR project in South Hobbs?

A. Yes. Part of our reservoir management is for us to know our reservoir pressure at all times.

Q. How are you -- how will OXY monitor the reservoir pressure?

A. We'll keep track of our reservoir pressure in a number of different ways. The first and most basic way is the injection-withdrawal ratio, which is the amount of fluids you're injecting into each injector divided by the amount of fluids that are produced by each of your producers. We want that number to be approximately one, which would be that the reservoir -- they're no voidage in the reservoir, and our reservoir pressure is

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constant.

Other ways that we'll monitor our reservoir pressure is, we'll do a periodic dip into our injectors once every year. And so we'll shut in injection, let the well stabilize for a day, and go on and actually measure the pressure.

Also, on our producing wells, we'll have -- most of them are electric submersible pumps which will have downhole pressure gauges. And so whenever one of those pumps goes off and we start to build up a fluid column, we'll monitor that pressure, so we know what our pressure is throughout the entire reservoir.

Q. Let me ask you: In your opinion, should a regulatory body be as concerned about starting and ending reservoir pressures in an EOR project as perhaps they may be for disposal wells?

A. No.

Q. And why is that?

A. Well, we want to keep it constant. We don't want to pull out what we -- what we inject, and so we shouldn't have this large just buildup over time of pressure. We should just -- whatever we put in, we're trying to take out.

Q. And where do you try to keep your pressure at?

A. We try and keep it above the minimum

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miscibility.

Q. Do you go way above the miscibility pressure, or how far do you go?

A. Not very far. We want to keep it, you know, a couple hundred pounds above miscibility pressure. And the reason why is, your reservoir pressure is rising a lot. You're injecting a lot more CO2 or produced gas than you're pulling out, so you're wasting a lot of money on unnecessary injectables.

Q. I now want to turn to the packer setting issue that Mr. Foppiano touched on earlier. And during that discussion, there was a reference to the order that has been entered, and it's been referenced on slide 22 of Exhibit 8. Have you actually reviewed that order?

A. Yes, I have.

Q. That order references the fact that there are -- well, let me step back first.

Is the language that we see towards the middle of this slide -- and I'll quote it: "So long as the packer set point remains within the Unitized Formation, as defined in the Unit Agreement, or as the same may be subsequently modified." Is that the language OXY seeks to have added to Rule 10 that is currently governing its South Hobbs project?

A. Yes.

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Q. In your opinion, do you need that flexibility to provide a good seal for the packers that you are dealing with out there in the South Hobbs Unit?
A. Yes, we do.
Q. Why is that?
A. Similar to this order -- you know, a lot of our injection wells were drilled in the 1930s or the 1980s, more towards the '80s than the '30s. And, you know, each time that packer is set, the slips dig into your casing just a little bit, and it becomes very difficult to get a good packer seat and for the rubber to swell and seal on that casing each and every time. And so each time a packer is pulled, it's common practice to set it just a little bit higher up the hole.
And so if you're constrained within 100 foot or close as practically possible of your top perforation, eventually you're going to run out of room in these wellbores, because, you know, even that casing, you have just one seat set at a time. And so we'd like to go all the way up to the top of our unitized interval to give us just a little bit more flexibility.
Q. But only as needed, correct?
A. Yes, only as needed.
Q. Now, the order that is referenced here in slide 22 also discussed the geology that resulted in the

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approval of this change. Do we have a similar geologic circumstance in the South Hobbs Unit?

A. Yes, we do.

MR. FELDEWERT: And I'll preface that by the fact that we are going to have a geologist follow his testimony.

Q. (BY MR. FELDEWERT) But have you actually looked at the geologic type logs for this area?

A. Yes, I have.

Q. And based on your education and background, are you able to read and interpret these type logs?

A. Yes.

Q. If I turn to what's been marked as OXY 23, would you explain to us what this exhibit is?

A. Sure. These are two type logs in the Hobbs field. One is from the North Hobbs Unit well. One is from the South Hobbs Unit injector. To the North Hobbs Unit well, on the left, is actually the marker that the top of the unit is defined by. And so I'll just walk through this type log on the right from top to bottom.

So this red line is the top of the unitized interval. Going down to this blue line below is the top of the San Andres. So in between the red and the blue is the Grayburg. Now, you know that the Grayburg is split into two different shades of color, one white and one kind of a brownish color. The brownish color is historically productive, but the white is impermeable and has never been productive, and it's a seal for the reservoir.

Going farther down the type log, through the San Andres, that's predominantly where most of the production has come from and where our main flood target will be. And you can see that the type log porosity is on the right, and on the left is the gamma ray.

Q. So do you see a similar seal in the reservoir that you're dealing with as was involved in the reservoir that led to the entry of Order R-5897-A that's reflected in slide 22?

A. Yes.

Q. And in your opinion, will the addition of the language that we have referenced out of this order provide -- continue to provide a reasonable level of protection to public health and the environment?

A. Yes.

Q. I wanted to address our last topic, Mr. Brockman, and that is corrosion mitigation. Now, first off, is it common to convert waterflood injection wells to produced gas injection wells when you are moving to an enhanced oil recovery project?

A. Yes.

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Q. Is that standard practice?
A. Yes.
Q. Does it almost always occur?
A. Yes.
Q. Will the same tubing and packers be used for the converted injection wells as you will use with any new-drilled injection wells?
A. Yes.
Q. Now, you've been involved with the North Hobbs Unit, correct?
A. Yes.
Q. Have you noticed any -- and the North Hobbs Unit has been operating as a CO2 injection area since 2003?
A. Yes.
Q. And as here, did the company convert existing injection wells into -- existing waterflood injection wells into CO2 and produced gas injection wells?
A. Yes.
Q. And has there been any differences in the safety record between new injection wells and injection wells that were converted from waterflood injection to CO2 injection?
A. No.
Q. Now, going to what's been marked as slide 24,

would you please explain to the Division what material is going to be used both for your conversion of existing injection wells, as well as newly drilled injection wells?

A. Yes. On all of our injectors, be it new drills or conversions, all of them will be combined with NACE MR0175. All of our injection tubing will be fiberglass lined. Our packers will be nickel-plated carbon steel, and in the annulus between the tubing and casing, we will fill that with an inert packer fluid.

Q. Now, I want you to keep your finger on here. Okay? I want to go to what's been marked as OXY Exhibit 11, and I want you to, if we could, just take a look at slide four. Okay? The first bullet point that you just referenced says it's going to be compliant with NACE MR0175. What is that? Is that a standard that is currently reflected in the rules that the Division has for governing equipment that may be exposed to hydrogen sulfite?

A. Yes.

Q. So you are going to meet that rule --

A. Yes.

Q. -- for all of your material downhole in your injection wells?

A. That's correct.

Q. In your opinion, will the steps that are reflected in what is slide 24 of OXY Exhibit Number 8 provide a reasonable level of protection to the public health and the environment?

A. Yes.

Q. In your opinion, will the design and composition of the facilities in the South Hobbs Unit allow for the -- allow for the additional recovery of oil that may otherwise be wasted?

A. Yes.

Q. And in your opinion, will the design and composition of the facilities in the South Hobbs Unit provide a reasonable level of protection to the public health and the environment?

A. Yes.

Q. Were the slides that comprise OXY Exhibit Number 8 compiled by you or under your direction and supervision?

A. Yes.

MR. FELDEWERT: Madam Chair, at this point, I would move admission into evidence of OXY Exhibit Number 8.

COMMISSIONER BAILEY: Any objection?

MS. GERHOLT: No objection.

COMMISSIONER BAILEY: It is admitted.

(OXY Exhibit Number 8 was offered and admitted into evidence.)

MR. FELDEWERT: And that concludes my examination of this witness.

COMMISSIONER BAILEY: Do you have any cross-examination?

MS. GERHOLT: I do. One moment, please.

CROSS-EXAMINATION

BY MS. GERHOLT:

Q. Good afternoon, Mr. Brockman.

A. How's it going?

Q. Good. Thanks.

If I could draw your attention to slide four, the slide that has "current" reservoir pressure and "projected with CO2," in regards to the current reservoir pressure of 1,200 psi, where is that measured at? For instance, is that measured at the bottom hole of a producing well, or is it measured at the surface?

A. Yeah, it's measured at the bottom of our injector wells. As I described our process will be with the CO2 flood injectors, we'll take a periodic dip into them. We'll shut them in for injection, and then measure the bottom-hole pressure.

Q. And then in regards to the projected pressure of 2,000 with the CO2 flood, does that pressure present any potential harm to the formation?

A. No.

Q. If I can now draw your attention to slide seven and specifically my question is about the temporarily abandoned wells. So these are wells that you're projecting to become temporarily abandoned, correct?

A. That's correct, as part of the project.

Q. And does OXY have any idea how long those wells would remain temporarily abandoned?

A. We're going to keep these wells for future development opportunities. As far as the time frame for those, I wouldn't know that off the top of my head, what that projected time frame would be.

Q. And would these temporarily abandoned wells have the -- and I'm probably not going to cite it quite correctly -- pressure monitoring devices on them?

A. Yes. These are the wells that Rick mentioned that we would equip with realtime pressure monitoring on the casing.

Q. Okay. And how, mechanically, would these wells be temporarily abandoned?

A. Sure. We would set a cast-iron bridge plug within 100 foot of the top perforation and cap it with 35 foot of cement, as per the regulation.

Q. And do you know, on this realtime pressure monitoring, would that data be collected and stored by OXY for a certain period of time?

A. Yes, it would.

Q. And would that information -- would it be possible for that information to be made available to the Division if the Division requested it?

A. Yes, it would.

Q. If I can now draw your attention to slide number nine and I believe on direct you were talking about the pattern, and that the pattern is designed to confine the injectates; is that correct?

A. That's correct.

Q. Does that confinement of the injectates assure that it will be confined into the permitted injection interval?

A. Yes.

Q. And now if I could direct your attention to slide 21, "Injection Pressure Control." So this will record in real time the pressures; is that correct?

A. That's correct.

Q. And that will assure OXY that they're staying at or below the permitted pressures?

A. Below the permitted pressures.

Q. Below the permitted pressures.

Slide 22. I think it's pretty clear I'm

not an engineer, so I'm trying to understand kind of the basics of this. My understanding is, typically when you set a packer within 100 feet from the uppermost perf and try to get it close to that uppermost perf, the regulatory body wants you to have it as close to that uppermost perf as possible; is that correct?
A. That's correct.
Q. And in this instance, OXY is requesting, like Conoco did, the ability to be beyond that 100 feet from the uppermost perf, correct?
A. Yes. We'd still like to be as close as possible at top perforation. It's because each time you move it up, you can't get back down below because of these setbacks that slipped and using that casing a little bit; you can't get your rubber seal. So we would still be as close to the perf as possible, but because these are older wellbores, we're running out of room in between that top perf and under -- so we just want the flexibility to be able to go higher and make it easier on operations.
Q. Okay. So that kind of helps.
Does that then mean that you might not immediately be 300 feet from the uppermost perf? You might work your way up to that, sort of, distance?
A. Correct. We'd like to work our way up there.

Q. Because when you set a packer, there is the potential that you won't be able to set below it again?

A. Right.

Q. If I can now direct your attention to slide 24. By implementing these downhole corrosion measures, would that potentially extend the life of an injection well?

A. Well, it would extend the life between -- if your -- if your -- if your packer isn't nickel-plated or if it's exposed to the high-pressure CO2, hydrogen sulfite and the produced gas, it will fail prematurely. You'll be pulling these wells over and over again. So not only will this, you know, be more protective to the public, having all the correct materials in place, but it will also extend the length of that material inside the wellbore, the service life, if you will.

Q. Because the fiberglass and the nickle are less reactive with H2S?

A. That's correct.

Q. And what sort of inert packer fluid does OXY intend on using?

A. I don't know the chemical makeup of it, of that fluid.

Q. And prior to insulation of the injection tubing will OXY be pressuring the casing from the surface to the packer setting depth to assure casing integrity?

A. Once the packer is set -- I get confused on what the order is. Sometimes they'll -- they'll drop a blanking plug and test the casing before they run the dual-line tubing. Sometimes they'll run the tubing and then run another casing test. But before any injection is started, we'll -- we'll test the back side, test the casing.

Q. To make sure it has integrity?

A. Yes.

Q. And I did skip one slide, slide 18, in regards to the step-rate tests.

A. Yes.

Q. Those nine wells which were tested, do you know if OCD had any involvement in determining which wells to test or any approvals of the step rate?

A. I do not know, if they were involved, which wells were selected. I do not know that.

Q. And then do you know if the -- so I've seen the order. Presumably the results of those step rates were provided to the Division, and the Division reviewed those step rates.

A. Yes. In addition to the map of all the step-rate tests, the actual plots showing the parting pressure were included in the order -- or the application, whatever it was.

Q. I have no further questions. Thank you.

A. Thank you.

COMMISSIONER BAILEY: Commissioner Warnell?

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. Good afternoon, Mr. Brockman.

In the South Wasson Clearfork Unit --

A. Yes.

Q. -- how long, do you know, did they try to inject in that before they --

A. I don't know how long they -- they gave it.

Q. Can you venture a guess?

A. I would not venture to guess.

Q. Okay. Thank you.

Dip-ins. I think they're slide 21. You had mentioned or testified that you would do dip-ins once a year for every injection?

A. As part of the reservoir surveillance, we try to get in once a year. That's our target, yes.

Q. And your line has a pressure bomb?

A. Yeah, on wireline.

Q. Wireline or slickline?

A. I believe it is on a wireline.

Q. Slide 23. One of the things that Ms. Gerholt referred to -- I didn't want to leave by itself because it's one of my favorite subjects. In the depth trap -- this is the well, the South Hobbs Unit, or either of the wells, I guess, those little scratches, are those perforations, or what are those in the depth trap? Do you see what I'm talking about?

A. These red ones at the bottom?

Q. No, the ones on the left- and right-hand side at the depth trap. That looks like casing collars or something. They're in real small print.

A. At the very bottom? I believe that's on the -- I believe those are marking every ten feet.

Q. I don't think so. Do you have perforations on these logs?

A. Yes. They're shown in red on the outside of the green. So, for instance, on the co-op ten on the right, you see where the Lovington Sand is in yellow? There are two sets of perforations below that. One set of perforations in red in the middle of it --

Q. Oh, I see.

A. -- and then two perforations above that.

Q. So then in this particular example, the Grayburg is about 250 feet from top to bottom, more or less?

A. Yeah, more or less.

Q. And the same end -- what would you say the interval from the top of the San Andres down to the bottom would be?

A. The bottom of the San Andres, I believe, in South Hobbs I believe around 52- or 5,300 feet. This track cuts off way above that. But the top of San Andres is usually around 4,000 feet.

Q. So it's a good 1,000-feet interval or something?

A. Yes.

Q. You were asked, I believe, about the inert packer fluid. Will there be anyone testifying today that will know what kind of inert material you're using?

A. I don't know if we have --

Q. In the annulus?

A. In the annulus?

Q. Yes. I'm sorry. In the annulus.

A. As to what the actual chemical is?

Q. Yeah.

A. I don't know if we do or not.

Q. As far as today or yesterday or in the past, what happens when you can't reset a packer within 100 feet of that top perf?

A. Usually we have to go to the local OCD office, ask for an exception, and a lot of times that is sent to the Santa Fe OCD Office. And those are always granted.

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We'll provide a type log, similar to this one, with some sort of description as to why we were unable to set it within 100 foot.

Q. And do you know of any incident where that's ever been denied?

A. No, I do not.

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

COMMISSIONER BAILEY: Commissioner Balch?

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Good afternoon, Mr. Brockman. I keep asking about this packer fluid pattern.

A. Okay.

Q. Without knowing its exact constituents, do you know if it does include anything for corrosion inhibitors?

A. Oh, sure, it's got corrosion inhibitors. And I believe it's -- I hesitate to say that, but it does have corrosion inhibitors in it.

MR. FELDEWERT: If I may, Commissioners, I just got word that Mr. Scott Hodges is going to be testifying. Our next witness is a geologist, and then Mr. Hodges will be testifying. He can address the questions that both of you just raised.

Q. (BY COMMISSIONER BALCH) We have seen cases where injectate has gotten in between and corroded through the pipe above the packers.

A. Okay.

Q. So those are -- so your produced water right now from your existing waterflood -- your produced gas from existing waterflood, you ship that off. What is the methane cut in that?

A. I don't know the exact cut.

Q. What is that approximate makeup? It's CO2 -- you don't have CO2, but H2S; maybe a little CO2.

A. Yeah. A little CO2, a little H2S, and then a little methane, ethane, et cetera, but it's predominantly hydrocarbon gas.

Q. And you talked about trying to take off the liquids, right, the higher order?

A. We do not process the gas. All the produced gas goes through third-party processors.

Q. So with this project, you're going to instead take out the produced gas, maybe remove the heavy liquids from it and dehydrate it, compress it, put it back down into the reservoir?

A. That's correct.

Q. Unless they're a large difference in the weight of the CO2 and the produced gas, I'm thinking when you're talking about CO2 and H2S, you actually have a

component of methane, ethane --
A. It's the methane that lightens it up.
Q. On your slide two, just want to make sure I'm clear on what is being injected and where.
A. Okay.
MR. FELDEWERT: Is this the one with the animation?
THE WITNESS: Yes, it is.
COMMISSIONER BALCH: You can run the animation through.
MR. FELDEWERT: Tell me when to stop.
COMMISSIONER BALCH: All the way.
MR. FELDEWERT: (Complies.)
Q. (BY COMMISSIONER BALCH) So within the city limits of Hobbs, you're going to run some vertical injectors that will most always be pure CO2?
A. Or produced water.
Q. Or produced water.
A. Right.
Q. The areas in red, those are going to be vertical injectors that produce gas?
A. As well as the surface locations of the directional injectors that are targeting the reservoir under the --
Q. Next question on slide eight. Except for what

is going underneath with the directional wells?

A. Correct.

Q. When we were talking about slide eight, you mentioned that you might expect to see the first CO2 from September to January or February, something like that?

A. That's correct.

Q. What do you anticipate for a full breakthrough?

A. For the full --

Q. How long do you think it's going to take to flow patterns where you're seeing 80 percent of the CO2 come back out?

A. Eighty percent of the CO2 that we put in to come back out? That would probably be when the produced gas stream gets backed up. As far as the gas composition being 80 percent CO2, that would be very quickly, because the amount of gas that these individual wells make right now is very low, so it doesn't take a whole lot of CO2 breakthrough to dilute it to that 80-percent mark.

Q. Okay. I guess that wasn't exactly my question. That wasn't the answer I was looking for.

From the beginning of injection, how long do you think you're going to be injecting with your primary pure CO2 source before you reach the point where

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you're primarily injecting produced gas?

A. Oh, sure. If you go to -- slide 14 was intended to -- I'll kind of walk through that. And so I'll walk through this again, but, again, the red line would be the pure -- the pipeline CO2, and the blue line is the produced gas.

Q. This is fieldwide?

A. Right.

Q. For an individual pattern, the first pattern you put on?

A. So an individual pattern will be one or the other. It'll do produced gas or CO2.

Q. Not mixed?

A. Not mixed.

Q. So approximately how long do you think a pattern is going to be on pure CO2?

A. Sure. About 20 years.

Q. One pattern -- the initial pattern, initially it will be 20 years before it switches to produced gas?

A. The pure CO2 will not switch gears [sic]. The other 20 years will go to straight water injection.

Q. A vertical injector -- that's what you're talking about?

A. Right.

Q. I'm trying to get a handle on how long a

pattern s going to be active with --
A. Produced gas --
Q. CO2 and/or produced gas.
A. Right. So each pattern will probably go about 20 years before we stop injecting either any produced gas or any CO2, and it goes to straight water injection.
Q. Thank you.
If you don't mind going to slide 23. Your main production is down there in the San Andres?
A. That's correct.
Q. Is that where all the primary and secondary productions come from, or are there other producing intervals that are active in some wells in this feed?
A. They're been some primary and secondary production on the Grayburg as well.
Q. On the Grayburg?
A. The lower half of the Grayburg that's shaded in brown.
Q. So your economics of 32-22 [sic] million additional barrels of oil, what is that taking into account?
A. Sure. That's taking into account portions of the San Andres where most of the production has come from. They're not a count for the Grayburg or all of the San Andres.

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Q. Or potential ROZ or anything else?
A. Correct.
Q. There are things that could significantly extend the life of the project?
A. That's correct.
Q. Those are my questions. Thank you very much.

CROSS-EXAMINATION

BY COMMISSIONER BAILEY:
Q. Go to slide six. I notice all of the leaseline injectors up in the northeast quarter without producers. Is there an impact to the east from all of those CO2 injectors?
A. So you're talking about these leaseline injectors in the northeast?
Q. Uh-huh.
A. Yes. There are North Hobbs producers there that aren't shown on this map. We would expect to see some benefit from -- the North Hobbs Unit would see some benefit from them, as would South Hobbs see some benefit from the North Hobbs injectors, which also are not shown on this map.
Q. On page 7, you show quite a few wells that will be temporarily abandoned?
A. That's correct.
Q. But this doesn't count the number of wells that

have already been temporarily abandoned in this area, does it?

A. It does not. They're shown on the small gray dots, but you can't really see them on here. Really, the slide is to focus on the wells that will be temporarily abandoned.

Q. So what is the number that are already TA'd, and what is the number of those you expect to TA, so I can have some idea of how long and how many --

A. Sure.

Q. -- wells will be in that category?

A. I do not know the current number of TA'd wells in the South Hobbs Unit, nor do I know how many of those we're going to return to production as far as this project. I do know that there are 82 wells in this project that we plan to temporary abandon.

Q. So you do have plans to reactivate some of the wells that have already been TA'd, at least one every 26 years?

A. Yes. Wells that have been TA'd in the South Hobbs Unit, there are some wells we plan to reactivate, yes.

Q. What is the criteria for either plugging or reactivating the TA'd well?

A. A lot of it has to do with where is the well located in configuration to our pattern scheme. For instance, when you go from 40-acre to 80-acre -- you've got 40-acre waterfloods and 80-acre CO_2 floods. You've got two injectors now, and you're only going to need one. So one of those injectors we're going to TA for sure, depending on which one. And we'll look at wellbore condition, which ones have better cement circulated to the surface or higher cement tops, what we think our larger casing size is. So it's some combination of wellbore schematics and where they are in the field.

Q. Probably an equal number to the 18. So there would be like at least 150 TA'd wells both within the city limits and outside the city limits.

A. On this map, some of the inactive wells in gray are plugged and abandoned as well, so it's some combination of TAs and PAs.

Q. When do you make that decision to TA a well or leave it TA'd for such a long period of time?

A. I don't think we have a given set of guidelines as to when to plug and abandoned a well, as opposed to leaving it TA'd. Most likely when we see no future use for it.

Q. The arrows that are coming out of these directional produced gas injectors, are those laterals off of a directional wellbore?

A. So each one of the arrows is an individual wellbore, and it won't be a lateral. It's more of a slant. And so these five slant wells -- so we'll go down for so far, and then we'll kick off directionally for our target bottom-hole location.

Q. Okay. But you have five arrows coming from one wellbore.

A. No. We have five arrows coming from one well pad. So on that pad, there will be five wellbores.

Q. Okay. That explains it. Thank you.

Page 10. Would you discuss the use of fresh water as part of your waterflood operation?

A. We do not have any fresh water.

Q. One-hundred percent produced water being used?

A. We have effluent water from the city and then produced water from the San Andres and Grayburg, but no freshwater wells.

Q. The gas for injection -- this is between you and the royalty owners, but I'm curious as to whether or not the royalty owners have voiced a problem with the rejection of the produced gas rather than save it [sic], as you're currently doing.

A. I wouldn't be able to answer that question. I haven't heard from royalty owners. We have another

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witness who is going to do that.

Q. Who would that be?

A. Ms. Montgomery.

Q. Is OXY the owner or the operator of Bravo Dome these days?

A. We operate Bravo Dome.

Q. So when you're buying the CO2, you're actually buying from yourself?

A. I'm not exactly sure how the CO2 networks. Most of the CO2, as far as I'm concerned -- or aware, goes to the Denver City hub. And it's a mix of CO2 from the McElmo [sic] Dome, Bravo Dome and Sheep Mountain, and we get ours from the Denver City, on the top of the Trinity pipeline.

Q. No plans to take it directly from the pipeline [sic]?

A. Not at this time.

Q. Page 20. When you're talking about parting pressure with water, are you talking fresh water or produced water at that point, because there is that difference?

A. Sure. This is our produced water from the San Andres.

Q. So no fresh water that accounts for any of the calculations?

A. That's correct.

Q. And the last question, back to page 22, Order R-5897-A. Now, I understand you're asking for the ability to set the packer not only in older wells where the casing may already have been damaged in some way, but also for the newly drilled wells?

A. That's correct.

Q. So that would be like a blanket exception to our Rule 25 for MITs that require the packer to be set within 100 feet?

A. That's correct.

Q. Even for the new wells?

A. Yes, because with the new wells, you know, the same scenario will eventually happen. We'll set and reset that packer and move up the hole each time, and so eventually we're going to come to the same point we are now with the existing wells, that there just isn't a lot of room between 100 foot above the top perf and when the last time we set the packer. And so it's just with a little bit of foresight that we're trying to ask it for all the wells.

Q. Have you talked with the district -- the OCD district office about establishing notification parameters for the information you're gathering for the annulus pressure and tubing and casing differentials?

A. Could you repeat the question? I'm not sure I understand.

Q. There have been issues for casing leaks and tubing casing leaks. Would you be willing to work with the district, if you have not already, to establish immediate notification parameters for annulus pressure and tubing and casing differential?

A. I'm not aware if we have spoken with the OCD on whether we let them know immediately if we see high casing pressure. I'm not aware if they have done that or not.

MR. FELDEWERT: Madam Chair, Kelley Montgomery will be testifying. She can answer your question.

COMMISSIONER BAILEY: Good. Will she also be the best person to talk to about cement use for drilling of these injectors wells, or is Mr. Brockman able to answer whether or not acid-gas-resistant cement will be used in completion of the new wells?

A. It will be.

Q. (BY COMMISSIONER BAILEY) Those are all the questions I have.

CHAIRPERSON BAILEY: Do you have any redirect?

MR. FELDEWERT: I think I just have --

REDIRECT EXAMINATION

BY MR. FELDEWERT:

Q. On slide seven, you talk about the temporarily abandoned wells. First off, the exception that you seek to the normal MIT procedures are only going to be for those wells that have pressure-sensor devices on them, correct?

A. Correct.

Q. And OXY's efforts in the South Hobbs Unit to install these pressure-sensor devices are going to apply not only to the temporarily abandoned wells that are going to result from the conversation process, but also other existing TA'd wells out there, correct?

A. Yes. Eventually, we endeavor to put them on all the wells.

Q. Okay. So I didn't want to leave the impression that you're only going to put them on these wells. On all TA'd wells?

A. Correct.

Q. Number two, how much does it cost to drill one of these wells down to the depth that we're talking about here?

A. A little less than a million dollars, and then another couple hundred thousand dollars to complete it, so probably $1.1-, $1.2 million.

Q. So a substantial investment?
A. That's correct.
Q. And is the goal in deciding whether you're going to temporarily abandon the well or permanently plug and abandon it, is it with the knowledge that these wells that you're replacing will cost over a million dollars?
A. Yes. That's part of the consideration.
Q. And so as a company, do you try to ascertain whether there is any potential lease for that well in your current or future operations before you actually plug and abandon it?
A. Yes.
Q. So as I understand it, what you're trying to do is avoid wasting existing surface facilities if they have potential for future use?
A. Yes.
Q. Now, if you have any problems with these TA'd wells, such that the integrity has been lost and they're beyond repair, then what will you do?
A. We'll plug them, plug and abandon them.
Q. On the packer issue, the exception that you seek is to give you the flexibility operationally as you're dealing with setting and resetting these packers, correct?

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A. Correct.

Q. There is no incentive for you as a company to set that packer all the way up to the top of the -- top of the formation and start there, correct?

A. No, they're not, because then we'd be -- we'd be very constrained as to how much -- we can't go any higher, and so it would be the exact situation we're trying to avoid in going straight to the very top of the interval.

Q. The rule says "as close as practically possible," which can be rather vague in terms of implementation. Would you agree?

A. I agree.

Q. But as a company, you will be setting it as close as practically possible; is that right?

A. We will be.

Q. But sometimes -- as a result of the operations that have been conducted on the well, sometimes that cannot be done within 100 feet of the well or even within the distance that's required by Rule 25?

A. Correct.

Q. So you're just seeking an exception to have the flexibility that in those circumstances -- you will set it as close as practically possible, but it may be beyond those currently allowed by the rules?

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A. Correct.

Q. I think that's all the questions I have.

COMMISSIONER BAILEY: You may be excused.

THE WITNESS: Thank you.

MR. FELDEWERT: Madam Chair, we will be calling our next witness, Randy Stilwell, who is a geologist.

RANDY STILWELL,

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

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your name, by whom you're employed and in what capacity?

A. My name is Randy Stilwell. I work for OXY, and I'm employed as a senior -- my title is senior geologic advisor.

Q. How long have you been a senior geologic advisor?

A. I've been a senior geologic advisor for 5 years and a geologic advisor for 10 years prior to that. I've been in the petroleum industry for over 30 years.

Q. How many years of experience -- as a geologist for 30 years?

A. As a geologist.

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Q. How many years' experience do you have as a geologist in the Permian Basin?
A. A little over 21 years working -- not continuously but cumulative, about 21 years.
Q. Now, are you familiar with OXY's application that has been filed in this case?
A. Yes, I am.
Q. And have you conducted a geologic study of the area that is the subject of that application?
A. Yes, I have.
Q. Now, have you, likewise, provided some slides to assist you in your presentation of your testimony today?
A. Yes, I have.
Q. If I turn to what's been marked as OXY Exhibit Number 9, does that contain the slides that you have prepared?
A. Yes, it does.
Q. And it has a total of nine pages?
A. Correct.
Q. If we turn to the first slide -- or the first page of OXY Exhibit Number 9, does this page accurately reflect a summary of your educational background and your work experience?
A. Yes, it does.

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Q. Is shows your degree on here. When did you obtain your degree?

A. My bachelor's degree was obtained in 1977, and my master's degree in 1979.

Q. And then it goes on to explain, then, your 33-year history as a petroleum geologist?

A. Yes, both as an exploration geologist and as a production geologist.

Q. If I turn to what's been marked as -- I'm sorry. Did you tell us when you got your master's degree?

A. Yes. It was '79.

Q. If I turn to what's been marked as slide number two, does this accurately reflect your professional affiliations and certifications?

A. Yes, it does.

Q. How long have you been a member of the societies reflected up here?

A. I've been a member of the AAPG for over 30 years, a member of the Houston Geologic Society for over 20 years, a member of the West Texas Geologic Society for over 15 years, and the Permian Basin SEPM for over five years.

Q. And in terms of your certification as a Texas Licensed Professional Geoscientist, how long have you had that certification?

A. That was since 2003, when the program was initiated in Texas.

Q. So since the initiation of that program, you've been a certified professional geoscientist?

A. Yes, that's correct.

MR. FELDEWERT: At this point, Madam Chair, I would tender Mr. Stilwell as an expert witness in petroleum geology.

COMMISSIONER BAILEY: Any objection?

MS. GERHOLT: No.

COMMISSIONER BAILEY: He is accepted.

Q. (BY MR. FELDEWERT) Now, Mr. Stilwell, I want to turn to what is slide three on Exhibit Number 9. Would you please describe to us what this is and what it shows us?

A. This is a type log from the South Hobbs Unit. And when we say a type log, it represents an average -- a depiction of the formations within the South Hobbs area. This particular type log goes all the way from the surface at the top, down to the Tubb Formation, and it includes the authorized injection interval, which is denoted on the left side of the type log.

This is a gamma ray porosity log, with the gamma ray being depicted on the right -- I'm sorry -- on the left, and the porosity log depicted on the right.

Q. Is there animation associated with this?

A. Yes, there is.

Q. Should I go to the first --

A. Yes, you can go to that.

And one thing I wanted to point out is that the primary objective for the CO2 portion of the flood is the San Andres interval, which is typically found at a depth of approximately 4,000 feet, and the top of the San Andres is going to be the focal point for the structure map that I show on the next slide.

Q. Let's turn to what's been marked as slide four, and I believe they're some animation associated with this as well.

A. There is. Before we do that, though, I'd like to explain exactly what we're looking at here.

This is a structure map on top of the San Andres Formation that was compiled from over 800 data points in the entire Hobbs area. And what you're looking at here is basically a two-dimensional representation of the structure and the subsurface. And so the contour lines represent lines of equal depth. And so in this particular map, the contour interval is 50 feet. So as you would go from one line to the inside of the map, each line you would be climbing 50 feet in

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elevation.

This is why I like to use the concept of looking at this kind of a structure, which is known as an anacline. I like to called it a buried hill. A lot of people have an easier time understanding when you try to explain an anacline in that sense.

So what I've got is a couple of profiles that cut across this structure that give you a cross-sectional view of a schematic profile. The first one --

Q. Let me ask you this: What's the green line around that?

A. The green line is the historical producing oil-water contact. It goes completely around the field, and you can see that it is primarily contained within the -- at or near the unit boundaries. So this would be the depth -- a two-dimensional representation of the depth that these wells have been historically completed in. And the reason for that is, below this point, you would not have commercial production because you would have such a high water content that the well wouldn't be commercial.

Q. Shall I hit the first animation?

A. Yes.

So there is a line that showed up on the map going from the northeast in North Hobbs, down to the southeast in South Hobbs.

One other thing I wanted to point out is that Hobbs field is made up of one structure. Even though it's been divided up into two units, it is one geologic structure, one trap. And so what you're going to see here is a profile going from the northwest to the southeast.

And if you'll hit that again.

Q. So we're dealing with the blue line?

A. Yes, the blue line that has shown up on there.

So what you're looking at in the lower, left corner here in this box is this profile in which I've drawn the structure on top of the San Andres Unit. And you can see, as I was speaking, you will climb as you go from one contour to another, and then as you go to South Hobbs, you climb back down the structure at the other end, which is down on the southeast end of the structure.

And if you'll hit it again.

Q. (Complies.)

A. I've got another profile drawn that cuts across, predominantly, the South Hobbs area, the red line, going from southwest to northeast.

And if you'll hit it again, you'll see the accompanying profile that goes along with that. And you can see that, you know, there is approximately on the order of 3- to 400 feet of structure shown on these profiles.

And, also, I didn't point it out before, but on both profiles, the green line that's shown at the bottom of the hill is the producing -- historical producing oil and water contact that was shown on the two-dimensional structure map.

Q. Is that where the oil is?

A. Basically, the oil accumulation is within this hill, from the green line up to the top of the red line, and the one on the bottom left, from the green line to the top of the blue line.

Q. Have you observed any faults penetrating this hill?

A. No. No, I have not seen any faults that penetrate through the San Andres Formation that would have any effect on the trapping mechanism of the structure.

Q. And if that is where the oil is contained, is it likewise true, then, that any fluids that you would inject into this area are likewise to stay confined?

A. Yes. The whole concept of a structural trap is that it does contain fluids within the closing contours.

And one concept -- or one other piece of the trap, that I'll address in the next slide, is, in addition to having this three-dimensional structure for the oil to accumulate in, you need something to hold it in at the top. You need a top seal.

Q. Before we get to that, there was some testimony about the five-well pattern as assisting in containing the horizontal migration of the fluids.

A. Yes.

Q. In terms of what you're showing here, is there, then, a structural component to this area that will likewise confine the horizontal migration of any fluids?

A. Yes, there is. Fluids will tend to want to come up to the highest part of the structure, as well as any other fluids that are injected to it. So from a geologic perspective, you will not get fluids that want to go downdip. Fluids don't want to resist gravity and go downdip. So any fluids would want to stay within this trapping mechanism in this structure.

Q. And the trapping mechanism that you're talking about, does it more or less follow the boundaries of both the North Hobbs and the South Hobbs Unit project areas?

A. Yes, it does, in general. I would agree with that, yes.

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Q. And let's go to what you were talking about, the vertical separation. Let's go to what's been marked as slide number five. Would you identify this, and explain it to us, please?

A. Yes. This is a more detailed version of the same slide we were looking at. Again, it has a gamma ray on the left side, a porosity log on the right side. And I focused in on the authorized injection interval, which is shown here on the right portion of the type log. So we are looking from the top of the Grayburg, down to the just below the top of the Glorieta Formation. That encompasses the already authorized injection interval for the South Hobbs Unit.

And what I've also denoted on here with this green arrow on the right portion of the log and the green wording is the historical production that we've seen in the South Hobbs field, extends from the very lower part that Mr. Brockman referred to previously; that sometimes is known as the basal Grayburg, down to the producing oil-water contact.

Q. What is the porosity of the area that you have shaded in green?

A. What I've highlighted on here -- the scale of this porosity log goes from zero, on the right, to 30 percent, on the left. What I have shaded in green here

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is 90-percent cutoff. Meaning that anything that is in green is 90 percent or greater. And that typically is the cutoff that we use to calculate pay to determine what zones to complete in the Hobbs area.

Q. So where does this show zero porosity?

A. Zero porosity -- immediately above the basal Grayburg and the upper part of the Grayburg, you enter into a zone of very tight rock, which is anhydrite and tight limestones, and that is for about 150 feet above the porous portion of the Grayburg.

Q. I mean, is that -- maybe I asked and answered my own question. Can that be penetrated? Is that going to -- will fluids migrate through there?

A. Fluids will not naturally migrate through that tight zone. This upper portion of the Grayburg is what is commonly known as the hydrocarbon seal. This prevents hydrocarbon fluids from migrating vertically out of the trap.

Q. What about gas?

A. Any fluids, gas, water.

Q. All right. Anything else about this slide?

A. I will highlight this detail area on cross section on the next slide, so you will be able to see the variation across the field.

One other thing I wanted to highlight is that even though on my schematic profiles that I've shown, I show it as one pool of oil, if you might think of it. In reality, these are layers of rock of different reservoir quality. And so what you have is a stacked series of layers of rock that make up the higher accumulation in the Hobbs field in the San Andres.

Q. Does your next slide show that as well?

A. Yes. Yes, it does.

Q. So let's go to next slide six. Does this have some animation associated with it?

A. Yes. Yes, it does.

Q. I believe the way this is set up, slide six is the initial animation, and slide seven is the ending result after the animation is done.

A. Yes, that's correct.

On the initial slide here, I just wanted to show you that as opposed to the first profile that I showed you, which was just a cartoonish line that went through the structure, what I've done here -- and the reason it jumps around is, I've actually connected it to actual wellbores to make a point here across the structure, and it goes all the way from the northwest corner of North Hobbs, to the southeast corner of South Hobbs.

Q. Is that the green line?

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A. That is the green line that kind of squiggles through both of the units there.

So if you'll hit that slide again, we'll minimize that.

Q. (Complies.)

A. This is the line of wells that you saw on that previous slide extending from North Hobbs, all the way down to South Hobbs, to the southeast on the right side of the cross section. As I denoted at the very top portion of the wells, you see both the North Hobbs Phase I CO2 flood area marked, as well as the proposed South Hobbs CO2 flood area.

A couple of things that you can see on here, first of all, is, the blue area kind of starts in the middle of the cross section here. This is the top of the San Andres, which is also the zone that I made the structure map on that I showed initially.

At the top of the San Andres, there is, very commonly, a tight impermeable dolomite. It usually is anywhere from 10 to 50 feet thick. It is not the seal for this accumulation. However, over the historical production of the field, we do believe that it has acted as a barrier for CO2 migrating. Where we already had started, at North Hobbs, you don't see migration into the basal Grayburg.

However, the ultimate seal for this field, as I was talking about previously, is this Upper Grayburg Unit, which is seen in purple. It's anywhere from 150 to 200 feet thick of impermeable anhydrite and tight limestone. This forms the top seal for the field and, in conjunction with the anticlinal structure, forms the trap that makes up the Hobbs oil field.

Q. So these zones correlate across the North Hobbs Unit into the South Hobbs Unit?

A. They do. You probably can see, on the well logs themselves, a series of lines that connect from wellbore to wellbore. These are zones that we were able to pick off of the -- off of the well logs that are basically zones of equal lithology or characteristic based on their well log character. And you could correlate those across the entire field.

If you remember the profile that I showed previously that showed the anticlinal structure on that schematic, when you look at it in real well -- a real well profile here, you can see that same anticlinal structure here.

And what I've highlighted in green within the San Andres interval is basically the oil accumulation from the top of the San Andres, down to the producing oil-water contact.

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Q. Anything else about this slide?

A. I guess the only other point that I would like to make is, the fact that you have a structure, the fact that you have a top seal and the fact that you have an oil field also is indicative that this is a -- that the seal on top of the San Andres is an impermeable barrier. Otherwise, you would have not still had this oil field in existence.

In the South Hobbs area, we've produced already over 90 million barrels of oil that would not have been in existence if either the structure didn't contain it or if the top seal was not able to hold the fluids in vertically.

Q. Did you, Mr. Stilwell, in addition to this, also conduct a study to determine the freshwater zones in the area?

A. I did.

Q. Turn to what's been marked as slide eight. Would you walk us through this slide, please?

A. Yes. So what I did was, in looking at the freshwater zones in the Hobbs area, as noted in the very upper portion of this -- upper right portion of the cross section, I utilized an online database of the New Mexico State Engineer, which has records of all the water wells that are drilled by county. You can go into

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it and look.

I looked at over 500 freshwater wells that were drilled in the Hobbs area and specifically in the vicinity of South Hobbs. And, of course, the great majority of them only penetrate a few hundred -- less than 100 feet from the surface, until they found enough fresh water to complete.

However, what I've summarized on this map in the little white boxes on the sections are approximately 23 wells which I believe completely penetrated the freshwater section and entered into the Triassic Red Beds, which are typically assumed to be the base of the freshwater zones. And you enter into those -- those true red shales of the Triassic Red Beds.

So what I've summarized on here are the number of wells and the depth of the base of the freshwater zone. For example, Section 3 here -- and, again, each one of these boxes is one square mile of section. There was one well within that section where the base of the fresh water was encountered at 220 feet. There are other sections just adjoining the South Hobbs boundary and just outside of it that indicated that the base of the fresh water in the South Hobbs area is anywhere between 190 to 262 feet below the surface.

Q. And you mentioned the Triassic Red Beds. Those

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are shales?

A. Those are very distinctive red shales, yes.

Q. And what you're saying is that the bottom of those, that would be the deepest location for fresh water?

A. Yes.

Q. And did you identify the deepest zone as being fresh water?

A. Yes. The deepest zone that I found on record was 260 feet below the surface.

Q. Using that information, did you import that into another type log?

A. Yes.

Q. Turn to what's been marked as slide nine. Does that contain --

A. This is actually the same type log that I had before, and what I've done is annotated it showing the freshwater zones at the very top of the log, the upper -- a couple hundred feet.

And then if you remember, the San Andres -- the top of the San Andres is typically, on average, about 4,000 feet depth. And what I've noted are the impermeable layers that you would encounter between the freshwater zones and the proposed injection interval -- the authorized injection interval.

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Down at the very bottom is this 150-foot impermeable anhydrite and limestone that I showed on the previous cross section, which looked very thick there when you compare it to the total thickness, because there are over [sic] lime zones which are even thicker, the Salado salt and shales, the Rustler anhydrite, and even the Triassic Red Beds themselves are impermeable shales.

So they're quite a number -- they're over 3,500 feet of section here of predominantly impermeable formations between our authorized injection interval and the freshwater zones in the South Hobbs area.

Q. The impermeable anhydrite and limestone that you show on here at the top of the Grayburg, is that alone sufficient to, I think you testified, contain the injectates?

A. I believe it is. The basis for that is that I believe that it's big enough to contain the hydrocarbon accumulation, and, therefore, it would be enough to contain the injectates that we're producing.

Q. So, for example, then, based on your -- injectates, for example, from migrating into the seven -- anyone was producing out of there?

A. Yes, that's correct.

Q. So what conclusions have you drawn as a result

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of the study in addition to what you've spoken about?

A. Well, first of all, it is that the Hobbs field is made up of one geologic structure found in approximately 4,000 feet deep. The producing oil-water contact for the San Andres is contained primarily within the unit boundaries that have been shown on the map. Also, there is a very distinctive top seal that has maintained accumulation over time and that that top seal would be enough to hold in any injectate that we would be producing with this project. And, also, the last thing is that all of these zones above the San Andres are enough to protect the freshwater zones from any of the injectates that we are proposing.

Q. So you see no freshwater concerns here whatsoever?

A. No, I do not.

Q. Were the slides comprising OXY's Exhibit 9 compiled by you or under your direction and supervision?

A. Yes, they were all compiled by me.

MR. FELDEWERT: At this time, Madam Chair, I'd move for admission into evidence of OXY Exhibit 9.

COMMISSIONER BAILEY: Any objection?

MS. GERHOLT: No.

COMMISSIONER BAILEY: It is admitted, then.

(OXY Exhibit Number 9 was offered and

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admitted into evidence.)

MR. FELDEWERT: That concludes my examination.

COMMISSIONER BAILEY: Cross-examination?

MS. GERHOLT: I have no questions of this witness.

COMMISSIONER BAILEY: Commissioner Warnell?

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. Mr. Stilwell, good afternoon.

A. Good afternoon.

Q. If we could go to slide five, please, the top of the San Andres there where you've got your nine percent porosity greater marked in green.

A. Yes.

Q. What's the permeability in that area?

A. In general, the nine percent cutoff in the San Andres is the equivalent of a .2 millidarcy cutoff. So anything that's in green is at least .2 millidarcies. Anything that is less than that, you know, would be extremely tight.

Q. How do you come up with permeability?

A. Permeability is derived from examining the number of cored wells we've taken in the field, of which there -- in the South and North Hobbs, all together,

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there are approximately 16 wells that have cored some portion of the San Andres.

We analyze that data. We actually take mechanical porosity measurements of that rock that we've recovered. We also do measure permeability in a laboratory, and we come up with, basically, a cross plot of permeability and porosity that we can then apply to other wells in the field where we don't have the core data. So as long as we have a porosity log and the accompanying cross plots for the San Andres in this area, then we can assume that our permeabilities are also going to be reflective of that.

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

COMMISSIONER BAILEY: Commissioner Balch?

CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Good afternoon, Mr. Stilwell.

A. Good afternoon.

Q. Is there any potential production below the San Andres in the South or North Hobbs Units?

A. Below the San Andres? There is production below the San Andres interval currently.

Q. From the --

A. Not within the units, I assume. Outside of the unit.

Q. Outside of it.

Do you know if there is any plan by OXY to ever go after those?

A. There have been other operators that have produced wells below the San Andres interval. I believe we actually have one or two wells that produce from intervals below the San Andres.

Q. On slide four, this is generated from top picks?

A. Yes, that's right, from log picks of the top of the San Andres.

Q. By you?

A. Yes. Correct.

Q. And that same goes for all --

A. Everything that you see here is all generated from my correlations and from my three-dimensional modeling of the fields that I've done in the last -- I've worked Hobbs the last ten years.

Q. Thank you.

COMMISSIONER BAILEY: I have no questions. Do you have redirect?

MR. FELDEWERT: I do not.

COMMISSIONER BAILEY: You may be excused.

THE WITNESS: Thank you.

COMMISSIONER BAILEY: Shall we take a

break?

(Break taken, 2:44 p.m. to 2:54 p.m.)

COMMISSIONER BAILEY: Mr. Feldewert, would you like to call your next witness?

MR. FELDEWERT: Yes. Call Mr. Hodges to the stand.

SCOTT HODGES,

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

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Would you please state your full name and identify by whom you are employed and in what capacity?

A. My name is Scott Hodges. I'm employed by OXY, and I am a supervisor of surface operations in the North and South Hobbs Units.

Q. How long have you been responsible for those surface operations in the North Hobbs Unit and the South Hobbs Unit?

A. I transferred to Hobbs in March of 2011, so just a little bit over two years.

Q. And do you currently reside in Hobbs?

A. Yes, I do.

Q. Have you been part of the team here to convert the South Hobbs Unit Waterflood Project to a tertiary recovery project?

A. Yes, I have been.

Q. And did you assist in the design of this particular project?

A. My part in the design is -- we have to operate and actually build it, and so our experience has been able to operate the North Hobbs. They use some of our experiences on things that went well and things that we'd like to change. So in that aspect, we have been part of the design process.

Q. So you have been -- I think you mentioned that you are actually going to run these operations once this system is put in place?

A. That is correct.

Q. Turning the keys of this $600 million Ferrari over to you?

A. That's right, and expecting us not to wreck it (laughter).

Q. What part will you be addressing today?

A. I'll be addressing some of our SCADA System that we have in Hobbs.

Q. If I show you -- let me step back. Did you create slides to assist in your presentation here today?

A. Yes, I did.

Q. And are they contained under what has been marked as OXY Exhibit 10?

A. That is correct.

Q. So let's turn to tab ten in the white notebook. It consists of 13 pages; is that correct?

A. That is correct.

Q. And if we look at slide one, we saw this -- we went through this earlier. What does -- are you familiar with this picture?

A. Yes, I am.

Q. And is this some of the facilities that you currently operate?

A. Yes, it is.

Q. Why don't you tell us what we have out there?

A. Okay. This is one of our North Hobbs CO2 satellites that we currently operate, and if I could direct your attention to the picture there on the screen. In the top, left-hand side, you've got an injection header, and that's comprised of this piping and equipment right here.

On the bottom part is a production header. And you can notice right here in the bottom, right-hand part of the screen, you've got a bunch of flow lines coming in from our production wells. This is all contained inside a security fence that is six foot, chain link with barbed wire around it. So we try to secure it so we don't have anybody in there.

The building right here that I'm pointing to up by the injection header also contains a state-of-the-art automation system that we control, we monitor, we alarm, and we gather data here, historical data, for further analysis or for current analysis, whichever one pertains. Right here in this building is actually the heartbeat of this satellite.

Q. Now, a couple of things. One, when we talk about injection header and production header, I assume that you have -- injection satellites or production satellites, correct?

A. Right.

Q. Secondly, this is actually a picture from the North Hobbs Unit. Are the plans -- does OXY plan to build a similar facility for the South Hobbs Unit?

A. Yes, we do. This facility in North Hobbs has been in operation for ten years. We've had really good success with it. We've had no failures. It's been almost trouble free, and so we plan on taking this design and implementing it in South Hobbs, also.

Q. In fact, I think there are supposed to be four of these built?

A. Yes. There will be four identical to this.

Q. Now, you said this automation system is kind of the heartbeat of the operation. Is that equipment all connected together through your SCADA System?

A. Yes, it is.

Q. So let's go to slide two.

First of all, what does SCADA stand for?

A. If you'll look at the top of the slide, it's an acronym for Supervisory Control and Data Acquisition. SCADA is a system that uses information technology to provide realtime monitoring and control of remote facilities.

Q. Now, you're going to be focusing on the operational aspect of the SCADA System; is that correct?

A. That's correct.

Q. Is there more to SCADA than what we're going to go through today?

A. Oh, yes. SCADA, if I could describe it, is kind of like a spreadsheet. You know, in Excel, we use a very small part of this huge monster, and that's kind of what SCADA is. We use a very small part -- or we'll talk about a very small part of what we use today, but I think it's relevant to the safety and the operation efficiency of the CO2 flood.

Q. Now, on the left-hand side of this exhibit, does this identify the aspects of the SCADA System that we're going to be talking about today?

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A. Yes, it does. I'd like to talk about temperature and water content. I'll talk about pressure monitoring, H2S monitoring and control and also gas analysis.

Q. And then you've got a diagram here. Is this depicting that SCADA kind of ties in with everything together?

A. Yes, it does. Through our SCADA System, we can take data, and we can control devices. We can monitor real time, which will give us that control. We can get human notification on it. SCADA is a communication system that works throughout the field, and this gives us just a tremendous amount of data that we can actually manipulate or control, but it also does a lot of things without our intervention.

Q. And part of which -- I see the shutdown valves. Are those automatic?

A. Yes, they are.

Q. And this is all controlled by SCADA?

A. Yes, it is.

Q. As well as the alarms, for example, could be triggered after certain parameters are met?

A. That's correct.

Q. You have this system in place at North Hobbs?

A. Yes, we do.

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Q. And you have this SCADA System -- you're going to have this same SCADA System in place at South Hobbs?

A. Yes, we will have the same system in Hobbs.

Q. Let's go to the first -- discuss the first bullet point on the left, "Temperature and Water Content," by moving to slide three. Why do you monitor temperature and water content?

A. The purpose of measuring and monitoring the temperature and water content is to hydrate the formation and primarily corrosion management within our system.

We have water and temperature sensors at our dehydration unit downstream -- our dehydration unit at our decompression -- reinjection and compression facility, and it lets us know the water saturation after it comes through hydration for dehydration. And when that gas leaves the RCF, it then travels to our injection headers, which is at the injection satellite. We, once again, measure the temperature there, and then we measure it again at the injection well.

Q. I'll tell you what, let's -- while we're talking about that, if we could just keep a finger on here, let's go to Exhibit -- in Exhibit 8, there is slide ten. So Exhibit 8, slide ten is a field flow diagram that we've seen before. Tab eight and then go

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to slide ten.

So where does your SCADA System -- I know it's not on the slide, but using this flow diagram, where does it measure water and temperature content?

A. On your diagram there, we measure at the recompression facility, up in the top, right-hand corner of that flow diagram. Directly below it, on the injection satellites, we measure temperature there. And then at the very bottom, in the middle, you've got that pyramid there on the injection wells. We measure the temperature there.

Q. So you've got various redundant monitoring devices?

A. Yes, we do.

Q. Now, what happens if, for example, at any one of these sites, the temperature or water content exceeds your parameters?

A. Well, at the injection wells or injection satellites, it will alarm us. It would notify us if there is a temperature change, so we can go out and check and find out what the problem is.

At the reinjection compression facility, if we see a water saturation or a temperature change that's outside the parameters of that facility, it will alarm them first, and then it can also initiate a shutdown at that rejection compression facility.

Q. This would be an automatic shutdown?

A. That's correct.

Q. No human intervention; it triggers itself?

A. That's right.

Q. And that's how you have it set up in the North Hobbs Unit?

A. Yes.

Q. Will you have the same setup at the South Hobbs Unit?

A. That's correct.

Q. You have all these devices to measure temperature and water content, but have you observed major fluctuations in temperature, for example, at the North Hobbs Unit?

A. No, we have not. In the time that we've been there -- that I've been there, in the last two years, we have not had an alarm on a temperature differential, and I know that we have not had a shutdown at the RCF because of the water saturation or temperature fluctuation.

Q. Is there an operational component to monitoring this water content and temperature content in addition to corrosion management?

A. Yes, there is. Trying to keep our injectates in a certain phase, the temperature of that is crucial. So it really increases our operational efficiency in our injectate to know what the temperature is and make sure it doesn't drop below a certain temperature and change the phase of the injectate.

Q. And as you mentioned, this is also part of your corrosion management efforts. Does corrosion start with reducing or monitoring your water content?

A. Yes. You know, water in a pipeline with corrosive gases can accelerate corrosion.

Q. Now, if we flip back to Exhibit 10, let's get a picture on this. If I turn to slide four, for example, in OXY Exhibit 10, is this a type of monitoring that you've been talking about at your -- where is this located?

A. This device is a water saturation analyzer, and it is located at the reinjection compression facility. It takes a reading of the gas coming off the dehydration unit, and then brings that reading back to this device here. This device records that and keeps it in history. Also, this is the device that will talk to the SCADA System and alarm the operators who are -- also initiate a shutdown if it gets outside certain parameters.

Q. And this is always on?

A. This is always on, 24 hours a day.

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Q. Always monitoring?

A. That's correct.

Q. Then let's talk about the next bullet point, and that is your pressure monitoring at these facilities. If we go to slide five, does this assist in identifying where you have your various pressure control monitors?

A. Yes, it does. We do everything off of pressure. So we monitor pressure in several different places, and we use pressure in several different ways. We use it in calculations for flow calculations. We use it to make sure that we don't overpressure. We use it to make sure that we don't have a low pressure situation, which would indicate a leak for us.

And so we have pressure sensors at the well site. We have a tubing pressure sensor and a casing pressure sensor on both injection and production wells. We have a pressure sensor on injection lines and production flow lines.

So the thing to note about these pressure sensors -- for instance, on the tubing, we've got it set up on parameters to where if it doesn't stay within certain parameters built into the logic of our SCADA System, it will indicate that we have a leak. And if it indicates we have a leak, it will automatically shut off

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a value that will stop any injectate from going to the well.

Q. So it has an automatic shutoff valve that would minimize any release or stop a release?

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

Q. And it's automated?

A. That's automated, yes, it is.

It'll also alarm us when we have a shutdown condition, and it is a callout alarm. So if it happens at 2:00 in the morning, it's going to shut it down. It's going to call us, and we're going to react and go find out what the problem is.

The casing -- one of the things we've talked about here is casing, realtime casing pressure monitoring on the injection wells. We have them set up on the casing in injection wells to where we actually get an alarm at a certain pressure to let us know that we've got an increase in pressure.

And then another pressure that's well below, you know, any type of dangerous situation, we'll actually get a shutoff. We'll stop injecting, you know, gas or water at that point in time, and we will get a callout for that.

Q. Okay. If I go to slide six, do we have a picture of what you just talked about?

A. Yes.

Q. Why don't you walk us through what is depicted here on slide six?

A. Okay. This is part of the injection pattern. Each -- if you'll look on the picture there, I've got a line right here that's a stainless steel injection line going out to our well. And right here we have a multivariable transmitter that actually measures pressure, and then it takes a temperature from a temperature probe right here in that header to calculate a flow rate of injectate toward that well.

And then this choke right here is controlled by a programmable logic controller, which is in those sheds at the satellite.

So any condition that we deem is undesirable or suspect that we have a leak or something of that nature, it will shut this choke valve off, and that eliminates all flow from leaving that header going into that injection well.

Q. So keep your finger here. We'll go back to that first slide we were looking at in Exhibit 10. It's all the way back. This picture here on slide six is a picture of one of your injection headers that is shown in slide one, correct?

A. That is correct.

Q. And this is at the North Hobbs Unit. And, again, we're going to have this same feature at the South Hobbs Unit?

A. That is correct, we will.

Q. Anything else about this picture?

A. I don't think so.

Q. So if we move to, for example, an injection well in slide seven, does this also contain an example of the various redundant monitoring devices that you have?

A. Yes, it is. The picture here is two pictures put together. They're actually on the same location. Didn't get very good photography there on my part. But you can see -- the direction of the flow here on the left is actually the injectate coming from the RCF, and it goes through this isolation valve on the edge of location. And right downstream from that isolation valve, we have a separate pressure and a separate temperature transmitter. Those two transmitters communicate via fiberoptic cable back to the injection header. So it's as close to realtime pressure and temperature that you can actually get. I mean, it's within a -- less than a second that we get that data back to the injection header.

The flow continues, as Mr. Brockman showed you on injection, underneath the ground and over to the wellhead and comes up and goes into the wellhead.

Right here on the casing, we have a transmitter that actually -- it reads realtime pressure from the casing annulus, and it will alarm and shut off the well if we get outside the parameters here. Outside the parameters here, it will alarm and shut off the well.

Q. This is your typical setup at the North Hobbs Unit?

A. Yes, sir. Everything we have in North Hobbs is set up exactly like this.

Q. And that's going to be true at the South Hobbs Unit?

A. Yes, that's correct.

Q. That's the injection well.

Now, WAG is the water and gas?

A. Yes, the water and gas, alternating.

Q. The alternating thing?

A. That's right.

Q. Then if I go to slide eight on Exhibit 10, does that also depict your transmitters in your production wells?

A. Yes. This is your production wellhead, and this is an electric submersible pump well, which is the

ESP, acronym. It's all contained in the bottom of the well, with a motor and a pump at the bottom of the well. But it actually comes up -- this line up here on the top is your tubing line. This is your casing line. And this is where they come together to go into the flow line.

Because you can see we have a casing transmitter, a pressure transmitter on the casing. We have a tubing pressure transmitter, and we have communication towers here that communicate back to a local PLC at one of our satellites. Everything on this -- at this location -- if this casing transmitter or tubing transmitter was to get outside the parameters that we have set up for safe, efficient operation, then this panel back here in the backis an ESP panel, and it will send a signal directly to it to shut the producing equipment off. So it will actually shut all the artificial lift equipment off. And when that happens, it will give us an alarm to let us know it shut that well down.

Q. I want to quickly go back to the injection -- in addition to the automated device shown on here, does OXY also have, on its injection wells, check values to prevent any backflow if there is an incident?

A. Yes, it does. Depicted right here in this picture is actually a flapper-type back pressure -- or a check valve. I'm sorry.

And if we had any leak in the system right here, to keep fluids from flowing or gas from flowing back from the well into the flow line, that check valve would automatically close based on pressure differential.

Q. Let's move to your third topic, and it is H2S. First off, what is your -- what is your primary device that you have out there for monitoring any potential release of H2S?

A. Since we know we have H2S in our gas and in our liquids in the San Andres, our primary indicator that we could potentially have a gas release or an H2S release is our pressure sensors, because they're going to pick it up. It's really quick in this system. So that's our primary device for alerting us that we might have a release.

Q. Connected to your automatic shutdown?

A. Yes. Everything with pressure is connected to the automatic shutdown.

Q. That should tell you if there is a problem before there is a release, correct?

A. Yes, it should.

Q. But in addition to that primary constant

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monitoring system, are you also going to have some additional H2S monitoring devices at the South Hobbs Unit?

A. Yes, we do.

Here is an example of what we have in North Hobbs right now, and this is actually on some of our tank batteries and our satellites. This is an H2S monitor. The monitor is actually down there on the bottom, because H2S is heavier than air, so it will go to ground level.

But this device is set up with automation tied into our SCADA System, that if we sense ten parts per million of H2S, this monitor -- this blue beacon will go off. It will alert you that there is an H2S condition at that monitor. It will shut down whatever it needs to in that facility to stop flow, whether it's an ESD on our production headers --

Q. What's an ESD?

A. An emergency shutdown valve.

Q. Okay.

A. When it shuts off, it triggers a series against our SCADA to shut all the wells off coming into that facility. So we shut off all flow. And it will call out OXY personnel whenever we have an H2S condition.

Q. So this is all tied into SCADA?

A. Yes, it is.

Q. And it's almost like a domino effect, if I'm understanding. You get the trigger, and then there is a series of shutdowns that occur?

A. Yes, that's correct.

Q. Then will you also, then, be -- the last topic -- doing periodic gas analysis, which will also give you a read to the H2S component on the --

A. Right, it will.

Q. So go to slide ten. What does this depict?

A. The gas analysis here -- this is an automatic gas chromatograph, and it's located at the reinjection compression facility. And it takes a sample -- a representative sample throughout the day to determine the gas composition and includes an H2S concentration. Everything it measures during the day is recorded at midnight, and then it starts over again for the next 24 hours. Along with the gas that comes into the RCF, they run a monthly Tutwiler analysis. It's a type of industry-accepted test for H2S and gas.

And also at the RCF -- it's not on a slide, but they actually pull a Draeger tube every day, also, and it's a same tube-type method. And it's an indicator that you have H2S. It's pretty close, but it's not as accurate as the Tutwiler or the chromatograph. At each

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production satellite, once a year, we pull a representative sample of all the wells coming into that production satellite, and we run an annual Tutwiler on it, also.

Q. So you'll have daily test analysis and then also got monthly analysis using other test methods?

A. Yes, that's correct.

Q. Now, you mentioned how everything is tied together with SCADA, and I want to move now to slide 11. With everything being tied together, how is it then accessed and utilized?

A. Well, all this communication from all the satellites, the wells and everything that has any type of animation, which is just everything we have, all communicates back to a host system in our office, and it does this via a radio system.

And the host system is graphically represented by GraphworX. It's just a computer program called GraphworX. And through GraphworX, we can sit at our desk in the office. We can be in our pickup with a laptop. We can be sitting at home. Recently, I was out of town, and I can take my laptop, and I can login from wherever I'm at in the country. Mr. Brockman is our production engineer, and he looks at GraphworX in Houston all the time.

But it allows us to see realtime conditions that are going on in our field all the time. It allows us to see trends of things that are happening. We can head a lot of things off. If I see a pressure start to climb somewhere, we can proactively attack that before it becomes a situation or a shutdown. So we use GraphworX. It's kind of our -- the heartbeat of our operation to keep things working.

Q. And slide 12 is a picture of that GraphworX?

A. Yes, it is. It has a lot of stuff on the screen, but on this picture, these boxes in the top part of the screen are all of our injection satellites that we have in North Hobbs. Of course, we can click on any one of those satellites, and it drills down to the wells on an individual basis. And we can see everything that's being monitored with every well, every injection header at that satellite as a whole.

Right here we have -- in the middle of the screen on the left-hand side, we have a -- it's a little hard to read, but it says "West Injection Battery." We can also do that on our tank batteries that bring the oil and water in there, when we actually sell the oil. So we can see our tank levels. We can tell how much oil and water and everything has gone through there in a day's time. We can tell how much we've injected from that facility. And we've also got, on the bottom left, our central tank battery, and then our bottom right is our north injection battery.

So everything in North Hobbs is contained on this screen, and our guys can look at this, and they can tell what everything is doing and how well we're operating. We even get up-to-date production so that we can combat, you know -- or go back -- not combat, but go out and switch wells in the test, find out which wells are not pumping as good as other ones. This screen of GraphworX just allows us to do whatever we need to do to efficiently, safely and effectively operate our whole field.

Q. Now, you said access by all personnel. Is that 24-hour monitoring?

A. Yes, it is. We have a well analyst that looks at this -- looks at all of our wells and facilities, and he's got it set up in GraphworX to where, during his monitor -- he watches it 24 hours a day. They run shifts over there. And if anything alarms, I mean, he immediately gets an alarm. And he has the ability to change some things in here to mitigate certain effects that we might have.

We also have personnel that are physically in the field 24 hours a day. We call them night riders.

And, you know, they primarily do surveillance, but they're there in case we have any type of alarm that we need immediate personnel on locations.

Q. What about if you have a loss of power?

A. If we have a loss of power, depending on where that loss of power is, it initiates a shutdown throughout the system. So if we lose a capacitor bank somewhere or we lose -- what am I trying to say -- a reclosure and we lose power to one of our satellites, it initially -- I mean, immediately initiates a shutdown -- an emergency shutdown on that satellite.

If we have an injection well that doesn't communicate back to the injection header, it automatically -- I mean, just immediately we initiate a shutdown of all injectate going to that well, until we can get communication back. And these aren't -- if it doesn't communicate within an hour, this is -- if it doesn't communicate within 30 seconds, then we initiate a shutdown, and then we get a callout. Usually it's a night rider that goes out to find out what the problem is, and it usually involves having to get an automation tech out to restore communication.

But we have decided that it's not to our benefit or anybody's benefit to try to run blind in Hobbs. So if we can't see it, we don't operate it. I mean, we shut it down.

Q. Now, the last slide, 13, what does that depict?

A. This is one of our -- we use the acronym PLC. I'm sure you-all have heard of PLC. It actually stands for Programmable Logic Controller. And these are at each one of our satellites. That's what's in that tan building that I was referring to on the first slide.

On the top screen -- we have a screen up there, and we refer to that as an LOI. It's a lease operator interface. So anything that our lease operator does on this touch screen is communicated back to the SCADA and will either trigger the automation to work or -- you know, whatever he sets in their parameters, he sets in there, that's the way the piece of equipment is going to work.

On the bottom, you have the same type screen for the production side. So we look at our injection on one screen. We look at our production on another screen. And this is all done through Allen-Bradley computers and logic, and it's a very reliable system. We very seldom have problems with it, and what problems we have are minor fixes.

Q. Have you been using this SCADA System at the North Hobbs Unit since injection commenced in 2003?

A. Yes. It has been in service since 2003, yes.

Q. And has it been successful?

A. Yes, it's been very successful. It's reacted at times we needed it to react. It's saved us from -- it's kind of similar to the old plant mentality. You know, used to -- in plants, you'd have to have 50 or 60 people working to keep everything operating. And the same way with the field. We've got so much involved here that it would take a lot more people to operate it. We can operate it more efficient, safer and more effectively with this automation unit than we could with human intervention.

Q. Mr. Hodges, were the slides comprising OXY Exhibit 10 compiled by you or under your direction or supervision?

A. Yes, they were.

MR. FELDEWERT: Madam Chair, I would move the admission of OXY Exhibit Number 10.

COMMISSIONER BAILEY: Any objection?

MS. GERHOLT: No objection.

COMMISSIONER BAILEY: Exhibit 10 is accepted.

(OXY Exhibit Number 10 was offered and admitted into evidence.)

MR. FELDEWERT: And that concludes my examination of this witness.

COMMISSIONER BAILEY: Do you have any cross?

MS. GERHOLT: I have a few questions.

CROSS-EXAMINATION

BY MS. GERHOLT:

Q. You mentioned that you have these night riders, the people in the field. Approximately how many night riders do you have?

A. We usually try to run two night riders.

Q. How long are their shifts?

A. They're 12-hour shifts.

Q. And how many people are reviewing the SCADA information or reviewing the GraphworX information?

A. Every morning I have three production techs and a production field specialist. So I've got four guys looking at the production side, and I've got two guys that come in every morning to review all of the injection stuff.

Q. And what are the length of their shifts?

A. They are -- it depends. Most of the time they're eight hours. If we've got a guy on call, then he covers that difference, you know, between the 12-hour night guy and the 8-hour. So it could be 12 hours; it could be 8.

Q. But it adds up to 24 hours of --

A. Yes, that's correct.

Q. You mentioned that the SCADA System gathers data, and it can record data; is that correct?

A. Yes, it does.

Q. How long is that recorded information maintained?

A. I pulled some data here awhile back, and I actually got about four years of data. That's all I asked for, so I don't know. It could go all the way back to 2003, but I couldn't verify that.

Q. And if the Division asked for any of that information, would OXY object to sharing it?

A. I don't know any reason why we would.

Q. And then I have a question that I hope you can answer for me. In regards to the injection wells, if I can draw your attention to slide seven.

A. Okay.

Q. And I want to talk about the WAG injection. I think I'm slightly confused. Are some of the injection wells produced water and carbon dioxide, and other injection wells are produced water and produced gas?

A. Yes.

Q. So you don't have an injection well that's produced water, CO2 and produced gas?

A. No. We do have wells in North Hobbs still that

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are still under that waterflood, and they're strictly water. And I think Mr. Brockman showed that on his slide. In the produced gas area -- okay? In the produced gas area, what we do is, we WAG those wells, and we WAG them on cycles. You might have a three-day water cycle, and then we switch that over to three days of produced gas, and then back to three days of water. So that's the WAG in there.

Now, the wells that we've had on CO2 in water and produced water are the wells that are not in that produced gas phase. So anything that we produce in close proximity to town is purchased or pipeline CO2.

Q. Thank you for clarifying that for me.

I think those are all my questions.

A. Thank you.

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. Mr. Hodges, you repeatedly testified that SCADA can shut down the valves automatically, seems like, temperature pressure, whatever. I'm more interested in how those valves are turned back on. I know they're shut down automatically by SCADA. Are there boots on the ground that you have to go out there and do that?

A. It's a great question, and I'm glad you asked that, because I didn't bring that up.

Anytime we have a shutdown situation, we do not turn them back on automatically. We send personnel to the site to see what the problem is, to make sure that everything is safe to put it back on, and then we will manually put that back into service, yes, sir.

Q. When something is shut down, when is the public notified, or are they? What would create a notification to the public? What kind of shutdown would have to happen?

A. Notification to the public would be if we had a situation where we had a gas release, and we enacted our H2S contingency plan; and that's when the public would be notified, with the activation of the contingency plan.

Q. Your H2S sniffer out there, it goes off at, did you say, ten parts per million?

A. Yes, sir.

Q. At ten parts per million.

Are there alarms that go off there, or that just goes back to your control center or your people?

A. That blue beacon will come on, and it will alarm us by radio and by phone.

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

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CROSS-EXAMINATION

BY COMMISSIONER BALCH:

Q. Good afternoon.

A. Good afternoon.

Q. You mentioned that it -- with these columns [sic], the system shuts down?

A. Yes, sir.

Q. That's at the well head with deadman switches, or do you try and do that -- I mean, if you have no communication from the main facility, it has to be at the site, right, at the injection or the battery?

A. I'm not an automation expert, but I do know that we have a system at our Hobbs office, and it communicates through what they call a heartbeat with these radios. And if it misses a heartbeat for 30 seconds, then it initiates shutdown on a no comm. It says that the host system couldn't communicate with the end device, and when that happens, it initiates that shutdown.

Q. And then everything shutdowns at the satellites?

A. Yes.

Q. In the event of a power failure, same thing, right?

A. Yes, that's correct.

Q. It looked like everything was on the grid. Do you have backup generation?
A. Yes, we do.
Q. What about for the H2S sensors, in particular?
A. All the H2S sensors are backed up with a battery for a 24-volt system. And as you can see in that picture right there, they're all solar-paneled, solar panels that have -- you know, generate --
Q. Photoelectric for the battery?
A. Yes.
Q. Those are maintained on a regular schedule?
A. Yes, they are.
Q. Where does all this SCADA data go? I mean, it looks like it goes to the Hobbs main office.
A. Right.
Q. And also can be accessed remotely by permission to get into the system using your GraphworX or --
A. Correct.
Q. -- AlarmWorX protocols, right?
A. Yes, it is.
Q. At any one time -- I think I'm wondering if people are actively looking at the system, looking for alarms or are available to hear an alarm. How many people do you have on a shift?
A. I have ten employees that are there on a daily

basis.

Q. That's throughout the 24-hour period?

A. Throughout the 24-hour. After the eight-hour shift, I'm going to have, for a short time, three, and then two during the nighttime.

Q. So at night, you have double redundancy; people sitting there in the control room, looking at the data, and that's two people, not just one?

A. I've got one guy in the control room, one guy in the field.

Q. That's your night rider?

A. That's correct.

Q. Do they communicate?

A. Oh, yes, sir.

Q. Keep in touch with each other?

A. Yes.

Q. So if one knows, the other one knows pretty quick?

A. You bet. They do.

Q. Those are my questions.

A. Besides the guys in the field, I actually have one of my eight-hour guys on first call and then another guy on second call. So we have a lot of redundancy as far as personnel being available.

Q. Thanks.

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A. You bet.

CROSS-EXAMINATION

BY COMMISSIONER BAILEY:

Q. You said check valves on injectors. Do you have downhole check valves?

A. No, ma'am, we do not.

Q. Is there a reason why not?

A. I would have to defer that question to the engineering -- worldwide engineering as far as their reasons for not having downhole check values.

Q. I'll save that question for another person. That's all I have.

COMMISSIONER BAILEY: Do you have any redirect?

MR. FELDEWERT: I do. I missed one topic that you were interested in. I forgot about it.

REDIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Hodges, are you familiar with the fluids that are placed into the annulus as part of downhole corrosion mitigation efforts that were discussed briefly with Mr. Brockman?

A. Yes, I am.

Q. Can you address that, please?

A. I cannot give you exact parts per million, but

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I know that -- I have worked with our chemical company before, and when they -- when we actually put packer fluid in a well, what they do is, they use fresh water. It's all water-based. They have a certain part-per-million corrosion inhibitor that they mix in there. They have a biocide that they put in there, and they put a small amount of oxygen scavenger. So that's kind of the mix, I guess, we've used in the oil field with the water-based fluid for protection of piping in those annulus, if that answers your question.

MR. FELDEWERT: No further questions.

COMMISSIONER BAILEY: You may be excused.

THE WITNESS: Thank you.

MR. FELDEWERT: Madam Chair, I do have a witness who can address your concerns about downhole check values. We can certainly put him back on now, since that seems to be timely.

COMMISSIONER BAILEY: That would be a good thing to do, yes.

MR. FELDEWERT: We will recall Jerad Brockman.

COMMISSIONER BAILEY: You're still under oath. You may be under oath until this --

THE WITNESS: That's great.

COMMISSIONER BALCH: Just don't get pulled

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over on the way home.

JERAD BROCKMAN,

after having been previously sworn under oath, was recalled and was questioned and testified as follows:

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Brockman, we have on the screen what is slide seven -- yes, slide seven of OXY's Exhibit 10.

A. Okay.

Q. And there was a discussion earlier about the check valve that exists on the right-hand side of this picture, towards the top of the wellbore.

A. Yes, I see it.

Q. Were you here for that testimony?

A. Yes, I was.

Q. There was a question raised about whether there should also be downhole check valves on these types of facilities. Have you looked at that? Have you considered that?

A. Yes, we have.

Q. And what's your opinion based on your expertise that you bring to the table?

A. We feel they are not necessary and, in fact, create greater operational issues than what they are designed to prevent.

Your first line of defense at the downhole check valve -- sort of leak coming back up the wellbore. Well, this surface valve will prevent that same leak. So, one, we think we're covered there. Also, we think that the proper metallurgy is our first line of defense as well to prevent all this backflow from the reservoir up the wellbore.

Also, to operate a subsurface safety valve, you actually have to have a hydraulic -- hydraulically actuated -- hydraulically actuated valve, and so you have to have a hydraulic power fluid to actuate that valve. And so to get there, you have to actually drill holes and compromise your wellhead integrity. So we don't feel that's the right thing to do in an onshore operation.

Q. So do you believe, Mr. Brockman, that it actually poses an operational risk to try to install and utilize these downhole check valves?

A. Yes, it does.

Q. Are you aware of any such downhole check valves for any of the injection wells that OXY operates in the Permian Basin?

A. No, I'm not.

Q. In your opinion, if someone came to you and said, Let's put a downhole check valve, would you be wanting to do that given the operational concerns you have expressed?

A. No, I would not.

MR. FELDEWERT: That's all the questions I have.

MS. GERHOLT: I have no questions.

COMMISSIONER BAILEY: Thank you very much.

THE WITNESS: No problem.

COMMISSIONER BAILEY: You may call your next witness.

MR. FELDEWERT: Madam Chair, call Mr. Chokkarapu.

KRISHNA CHOKKARAPU,

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

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Chokkarapu, could you please give us your full name, identify by whom you are employed and in what capacity?

A. My name is Krishna Chokkarapu. I'm employed by OXY Oil & Gas and working in Houston. I work for Permian Business Unit in the Facilities and Construction Department as a facilities engineer senior advisor.

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Q. And how do you spell your last name, slowly?
A. Chokkarapu, just like the way it is written, Chokkarapu.
Q. How do you spell it?
A. C-H-O-K-K-A-R-A-P-U.
Q. And how long have you been a part of the Facilities and Construction Department with the Permian Basin?
A. I've been involved with the F&C, Facilities and Construction, from 2008. Presently that is five years.
Q. Did you participate in the design of the surface facilities for the injection of CO_2 and produced gases in the South Hobbs Unit?
A. Yes, I did.
Q. Are you part of a larger group within OXY that is tasked with corrosion management when it comes to CO_2 flooding surface facilities?
A. Yes. The way OXY is structured, it has multidisciplinary subject-matter expert groups within OXY, like Mr. Rick Foppiano has described, working for the worldwide engineering, all the way to the U.S. business onshore units. And we all collaborate on a functional disciplinary level, where we pull in subject-matter experts for a particular project.
And as being responsible for the

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implementation and execution of the South Hobbs facilities, I pull in subject-matter experts and get their opinion and make sure they are delivering safety and that other safety parameters are implemented. So that is how I keep the mechanical integrity team, which is spread from the U.S. business to the worldwide, incorporated into the design.

Q. So is your pool of subject-matter experts worldwide?

A. Yes.

Q. And do they bring their experiences worldwide to the table?

A. Yes. And that's how we -- when we communicate back and forth, we have periodic meetings, periodic information exchange between the business unit and the worldwide. So we share operational experiences, operational efficiencies learned in the system.

Q. Is this group tasked with maintaining the mechanical integrity of OXY's facilities, particularly dealing with CO_2 flooding?

A. Yes. As being a part of the overall operational group, they are tasked to maintain and meet the objectives for the MI, mechanical integrated team.

Q. Have you prepared slides to assist in your testimony here today?

A. Yes, sir.

Q. And are those slides contained within what's been marked as OXY Exhibit Number 11?

A. Yes.

Q. Does that exhibit contain 14 pages?

A. Yes.

Q. Then let's turn to what's been marked as slide one of OXY Exhibit 14. And does it contain an accurate summary of your educational background, your work experience and professional affiliations?

A. It does.

Q. With respect to professional affiliations, it indicates that you are a former member of the American Institute of Chemical Engineers. What happened?

A. Yes. It's an oversight on my part to continue to pay the membership.

Q. So you met all the qualifications; you just didn't pay your dues for this particular year?

A. And this happened about two years ago, so --

Q. Now, it also indicates that you have a Certification of Engineer in Training, an EIT. Are there various components of that certification?

A. Yes. This particular certification is a first step in the many steps required for professional engineer license requirement in any state. So I have

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already taken the EIT certification completely.
Q. And you're in the second phase of it now?
A. Yes. I'm working towards the second phrase, where I'm gaining expertise in the respective areas of my P.E. license.
Q. What was the award you received from OXY in 2008?
A. I have -- it was an award in my 15 years of oil and gas experience working in special -- majority of it is in CO2 floods. I have developed a technology using CO2 -- an innovative way of using CO2 to increase efficiency of -- in water operations. And it was a project involved in 2006 -- 2006-2007 frame, and that led me to achieve this award.
Q. Let's talk about your 15 years of experience in the industry. This indicates that roughly since 1998, you've worked as a process engineer, a plant engineer and a facilities engineer and a project manager, correct?
A. Yes.
Q. What type of projects?
A. Starting from 1998, I started out as a process engineer dealing with oil and gas operations and gas processing operations.
After three years of experience, then I

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moved into West Texas, which is predominantly enhanced recovery operations. From that time until now, I've been involved in the CO2 enhanced recovery operations South Hobbs facilities.

Q. So the CO2 floods in the Permian Basin?

A. That's right.

Q. Do you have any -- do you have any international experience?

A. Yes. I'm considered a subject-matter expert in process design and facilities engineering, and I periodically get called in to participate in peer reviews, participate in root-cause analysis, participate in any troubleshooting of gas processing equipment. So that's how I get involved into international operations where OXY presently operates, like Bahrain, Qatar, predominantly.

Q. Are you familiar with the design, engineering and construction of the facilities that OXY has installed at the North Hobbs Unit?

A. Yes. And as a matter fact, when I was working in Denver City, which is West Texas, for the 7 years of my 12 years, I've been working as a plant engineer, supporting all the plants within the West Texas area. And that's how I was involved in the North Hobbs CO2 flood operations.

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Q. And are you familiar with the design, engineering and construction of the facilities that OXY intends to utilize at South Hobbs?

A. Yes, I am.

MR. FELDEWERT: I would tender Mr. Chokkarapu as an expert witness in the design and engineering of CO2, produced gas, surface facilities and enhanced recovery oil project.

MS. GERHOLT: No objection.

COMMISSIONER BAILEY: Then he's so accepted.

Q. (BY MR. FELDEWERT) Can you tell us a little bit about when they come to you and say, We're going to do this in South Hobbs? What do you do? How do you get involved?

A. One of my previous witnesses, Jerad Brockman, he is from the Development Management Team. That is where most of the projects that OXY develops start from. The concept and the basic fundamental framework of the project starts with the Development Management Team. They look at the amount of crude oil, the amount of CO2 that needs to be used. They generate the life-cycle cause and give us a framework of CO2 flood projects. And from there, we take the -- that forms our basis of design for all our CO2 flood operations, and we get all

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the multidisciplinary groups involved in the initial design.

And the entire facilities development process can be described as a cradle-to-grave concept, where we involve all the subject-matter experts at every phase of the project.

Q. And you say cradle to grave. You're involved in the design?

A. Yes.

Q. What about the fabrication and construction?

A. It is. And we make sure, during the design phase, we take into consideration the objectivity of the project, which is supplied by the Development Management Team. In coordination with the regulatory requirements, in coordination with the state and district practices, in coordination with the economics of the project, we come out with the framework of the CO_2 surface facilities.

We incorporate these things and start to design the facilities. Once the design is done, we go through the fabrication process, where, again, the requirements, which are identified during the design phase, are again implemented back in the fabrication and construction phase of the project. And we use the same philosophy when it is handed over to Operations Group and maintained for the rest of the project.

So when I describe the cradle-to-grave concept, we identify the requirements that need to be met, and we make sure the concept is maintained from the beginning to the end of the project.

Q. Pursuant to the standards -- the industry standards?

A. That's right, yes.

Q. And in all of that process, on each of those phases, do you draw upon OXY's worldwide expertise, draw on your support team?

A. That's right. And to give you an instance, during the design phase, as I mentioned, we call in the multidisciplinary people. We do a peer review on the project, where the project team is hot [sic] spaced as a -- as an information provider, but the artisans [sic] are from a worldwide review and critique the work. That's how we get multidisciplinary support from other departments.

Q. Let's turn now to what's been marked as slide two of OXY 11. You created a slide dealing with the design aspect, fabrication and construction and then the maintenance aspect. Is this pretty much the layout of what you just talked about?

A. Yes. And this kind of gives a framework for the cradle-to-grave concept, where during the design phase, we look at what is the present -- what is the operating environment for the system, the CO2 surface facilities that are going to be operated.

In this phase, we gather all the information about what kind of crude oil, what kind of gases are involved, what kind of water, any other companies that are -- and we also look at the operating panel [sic], like pressure, temperature, pH and composition. And we take these into consideration in connection with the regulatory requirements and industry standards or guidelines. We formulate the design, and that's how we start using all of these standards into maintaining -- or selection of the materials to begin with, and then we use industry standards to fabricate.

Q. Let's talk a little bit about that. I'm going to skip a slide. Let's go to some of the standards you were talking about. Were you familiar with the New Mexico standard when you began your design of this project?

A. Yes.

Q. And did you pay particular attention to the NACE standard MR0175?

A. Yes.

Q. What is that?

A. NACE standard MR0175 is the standard developed over a period of 30 years by various industry groups and corrosion engineers. Primarily, NACE standards stipulates or provides guidelines and requirements to meet in the fabrication -- design, fabrication and operational equipment associated with hydrogen sulfite to mitigate any sulfite -- any cracking-type corrosion mechanisms are mitigated. So in a nutshell, this is a standard developed to make sure corrosion mechanisms associated with H2S are mitigated.

Q. So bringing it down more to my level, does this tell you what materials to use based on the operating conditions?

A. Yes. It allows us -- or it lays the framework of how do we select the materials based on the operating environment, based on the temperature pressure, based on how long this equipment is going to be used. That gives us the guidelines to select the materials.

Q. Does this NACE MR0175 also provide procedures for the installation, fabrication of these devices?

A. Yes, it does. And it really stipulates the process of fabricating the piping components, pressure components or any other components within the CO2 surface facilities so that the requirements which are stipulated to mitigate the corrosion mechanism are well maintained and mechanical integrity is maintained.

Q. Does NACE standard MR0175, then, also agree [sic] with the maintenance of these facilities?

A. Yes, it does. And it provides guidelines on periods of testing, periods of inspection and also any engineering controls that need to be put in place.

Q. In your expert opinion, Mr. Chokkarapu, are the NACE MR0175 standards required by this rule protective of public safety and the environment?

A. Yes, it does.

Q. In addition to the NACE MR0175 standards, does the company also then utilize additional standards recognized in the industry to assist in the design, fabrication and maintenance of these surface facilities?

A. Yes. And there is a list of industry standards OXY utilizes in addition to the NACE standard MR0175.

Q. If I go to slide five, will that provide us a list?

A. Yes.

Q. So you've listed here various standards OXY utilizes in addition to the standards recognized in the Division rules?

A. That's right. And what I have listedis, in addition to the NACE MR0175, we use the ASME Section VIII, Division 1 code.

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Q. Let me stop you right there. What is ASME?

A. ASME stands for Association -- American Society for Mechanical Engineers.

Q. And the other acronym I see up there is API.

A. American Petroleum Institute.

Q. Okay.

A. And these are various industry -- various standards developed.

API is a set of guidelines developed by the American Petroleum Institute for various operating environments. In particular, API 650 provides guidelines in fabrication, operation of surface facilities involved with hydrogen sulfite.

ASME Section VIII, Division I provides guidelines in connection with NACE MR0175 in fabrication of pressure vessels which can withstand not only the corrosive effect of hydrogen sulfite fluids, but also maintain the safety and integrity of the pressure vessel and maintain the fluids within the vessel or the component when the operating environments deviate from its normal operating conditions.

Q. Are these standards based on years of industry experience?

A. Yes. All these standards are developed over 30-plus years of industry experience.

Q. Now, what do they do on top of what NACE MR0175 provides? I mean, what do they give you in addition to what that rule provides?

A. Yes. I mean, I can probably -- I can take a specific example like a pressure vessel or a pipe to try to explain the additional things.

Q. Let's go to slide seven -- or slide six.

A. What this slide shows is all the components within the CO2 surface facilities that are required to be fabricated and they put into operations for successful implementation of CO2 flood.

As I've identified here, pressure vessels -- in addition to the NACE MR0175, ASME Section VIII, Division 1 provides guidelines in calculating the thickness of the plate or thickness of the material that is required to maintain the fluids for the operating conditions it is designed for, for example, 100 pounds of pressure inside the vessel. So it stipulates the proper calculation methodology and the guidelines so that we come out with the proper thickness so that the fluids are contained and safety is established.

Q. Let me stop you there. For example, then, on that example, NACE MR0175 is saying, Here's the thickness you should use?

A. NACE MR0175 tells us what kind of materials need to be used to minimize or mitigate stress of sulfite, stress corrosion cracking, hydrogen -- or sulfite -- stress corrosion cracking and some other cracking mechanisms.

So we take that in the initial phase, where we select the materials, and we use those materials which are based on the operating conditions, and use the ASME or API or ASME B31.3 to incorporate and integrate with regards to safety.

Q. So does it give you like a guideline to follow to make sure you the meet the requirements that are imposed by MR0175?

A. Yes.

Q. Is that a good way to think about it?

A. Yes.

Q. So it gives you an additional checklist?

A. Checklist, yes.

Q. And is that true, then, throughout these examples?

A. Exactly.

Q. With this knowledge, then, let's go back to slide three of this exhibit, and I believe there is some animation associated with this, is there not, Mr. Chokkarapu?

A. Yes, there is.

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Q. With this background, this worldwide group that you bring together and using these industry standards that you've just identified, explain how you then apply that to, for example, in this case, the facilities that are going to be -- which are going to be used at the South Hobbs Unit project.

A. What we do before we get into the complete detail engineering of any of the CO2 facilities, we come up with simple flow diagrams like these for CO2 facilities, and segregate or group the entire flow diagram into several groups based on operating conditions.

For instance, in this diagram, we have grouped the entire flow schematic into four different groups. There is the operating pressure, temperature and the composition of the gas.

Next slide.

Q. (Complies.)

A. There is the group number one type of components, which are basically -- I will be having more slides which shows more --

Q. So you're going to identify the groups and then have a slide for each group?

A. Yes.

And group one is the group of all the

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components for the production system. That is called group one. Group two is a group of components, which comprises a decompression facility and injection facilities. Group three is where all the water is processed and reconditioned for injection. And group four is what we call WAG injections, where we differentiate between the -- injection intervals.

Q. Let's move to the slide that will deal with group one. Okay? So then explain how you took the industry standards, the operating conditions and came to your conclusions with respect to group one, which is depicted on slide seven of OXY Exhibit 11?

A. As previously mentioned, we gather all the information in that particular flow diagram, all the operating conditions like pressure, 375 pounds of pressure, which are the producing wells --

To back up, this group of equipment and piping are associated with gathering all the fluids produced from production wells into what we call these production satellites. And what you see here depicts the pressure, temperature and water of that particular flow scope.

We take this data and use the NACE MR0175 to identify the materials, what we can use and -- what we can use and also maintain -- which will allow us to meet our safety requirements.

When we use the operating data, we came up with carbon steel, two types of materials that can be used here. One is -- we identified it as "A" and "B," which is piping, basically. "A" is internally coated carbon steel, and the carbon steel is a NACE carbon steel. And the second, "B," is a poly-lined carbon steel. Again, the carbon steel is a NACE component [sic].

Q. And this is all driven by NACE MR0175, right?

A. Yes. That forms the basis of all the selections.

Q. Now, in terms of the material that you have chosen for circumstance "A" and "B" on slide seven, is there any difference in the level of protection provided by that material?

A. No. They both give the same level of protection.

Q. So then what caused a distinction in one case to choose option "A" and the other case to choose option B?

A. There are several factors which go into the selection of whether you use "A" or "B." For example, you look at the size of the pipe that is used. In this case, it's a six-inch pipe for "A." For "B," it is 18

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inches or 12 inches. And there may not be piping components available in 12 inches which are already internally coated, so we use the alternative mechanism of laying the pipe, welding the pipe and pulling a poly-lined through it.

Availability also comes into play and also the ability to construct. The areas where these lines are laid out also comes into play when we select these type of materials.

Q. Then if we move, then, to the next grouping of facilities on slide number eight, again, this is what your group came up with when applying the NACE MR0175 standards in terms of materials, correct?

A. That's right. This is the group two of components -- pressurized components in CO2 surface facilities which operate under 1,800 pounds of pressure. One thing to note here is, the components here are not subjected to saturation levels of water. In the decompression facility, we utilize dehydration technologies to remove the water to the level of seven pounds or less to minimize or mitigate corrosion and hydrate operation mechanisms. So that is one of the things that comes into play in the selection of these components.

And then since the water -- presence of

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saturated water is not there, NACE -- by following the guidelines of NACE, it allows -- or it stipulates the use of carbon steel under -- by following the manufacturing processes and fabrication processes. So that allows us to use bare [sic] carbon steel in the --

Q. Now, in this particular circumstance, you had a material selection that you made by applying NACE MR0175. Would you, for example, then have requirements that are imposed by that same rule when it comes to the welding of this pipe together?

A. Yes. NACE MR0175 stipulates how the piping components are combined to the welding process. It stipulates what kind of welding procedure is required, what kind of welding materials have to be required. All these come into play so that we maintain the primary objective of keeping the material resistant to any corrosion mechanisms.

Q. Let's run in to slide nine. And, again, we probably don't have to spend a whole lot of time on here, but this will be what is dictated by NACE MR0175, given the operating conditions that are reflected on slide nine?

A. That's right.

And here, predominantly, all the water which is separated in the satellites is treated. All the gas is -- dissolved gas is liberated, and basically you have a produced water, which is repressurized for injection services. And, again, since it is considered a sour water, since trace quantities of H2S carbon dioxide are present, we treat that as a NACE-required piping, and we use a poly-lined carbon steel pipe, which is, again, stipulated by NACE.

Q. If we go to slide ten, this deals with the injection?

A. This is the fourth group of component -- pressure components. We call this the WAG injection systems. Here, again, we have remote-area injection wells and also city-area injection wells. Primarily the difference is that it is a produced gas injection or a pipeline CO2 injection.

Q. Let me ask you a question about this. You have two different types here, C and D. Okay? Is there any difference in the level of protection between what is shown on here on C and D?

A. No. Both these two materials provide you the same level of corrosion resistance and safety design as required by NACE MR0175.

Q. And you recognize you're going to be working in a city area, correct?

A. That's correct.

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Q. So what about -- what is it about stainless steel that applied, at least with OXY, to this city area?

A. There are a couple of reasons why we chose or we decided to use stainless steel in city-area injection. One is, stainless steel provides one additional layer of protection. Coupled with that, we have tremendous advantages in reducing the exposure during the construction process, as well as maintenance of this project.

To give an example, in a city, while we are laying an injection line, if I use a poly-lined carbon steel, I have to dig a ditch which is about six feet long, six feet wide, probably 400 feet to 500 feet, keep it open until the entire carbon steel pipe is welded, pressure test it, ND test it. And then I have to pull a liner, again pressure test it, before I can fill this one. So that creates one more level of exposure to any --

Q. I'm sorry. Go ahead. When you say -- in terms of exposure, that means I've got a larger -- I've got an open trench that's longer and open for a longer period of time?

A. Yes.

Q. Someone could fall in; accidents could happen?

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A. Exactly. And that is what we're trying to mitigate.

But if I use stainless steel, stainless steel pipes are available in 80 feet or random lengths. All we have to do is weld it up, do the ND testing, fill the ditch. So that tremendously reduces [sic] our exposure to safety.

Q. Now, by the same token, if some maintenance needs to be done on that type within the city limits, you can then minimize -- your trench length as well?

A. That's right.

If we have used carbon steel -- poly-lined carbon steel in the city and we encountered a leak and we had to make a repair, we need to dig at least 200 feet of ditch to replace the whole pipe and pull the liner. With the stainless steel, we can dig a 5-by -- 6-by-6 ditch and make the repair and put them together.

So the use of the poly-lined is a little bit more laborious, and it raises exposure to safety hazards. And that is a primary concern that we have taken into consideration to decide stainless steel in city areas.

Q. Now, if I then go to what's been marked as slide 11, in addition to your material selection, as you've described in the previous exhibits, are there other measures the company takes to mitigate corrosion?

A. Yes. As previously mentioned, NACE predominantly stipulates the requirements to meet or mitigate sulfite stress corrosion mechanisms. Whereas, all other engineering -- all other standards provide guidelines to minimize or mitigate general corrosion. And we put together corrosion-mitigation methods to prevent any corrosion from happening. One of that is the material selection, and then we use cathodic protection to mitigate the corrosion.

There are two types, sacrificial anodes or impressed current. Based on the type of the component in either field we service, whether it be in a pressure vessel or a contained vessel, we use sacrificial anodes. In simple terms, we can described sacrificial anode as a place where, if corrosion happens, it eats the anode first rather than eating the actual pressure component, which will compromise the safety.

Q. So it kind of attracts those --

A. Strengthens [sic], yes. As the fluids are moving through these components, stray currents are doubled up, which create corrosion, and those corrosion mechanisms act on as anode and eat that.

An impressed current is technology we use on pipelines where we apply a certain quantity of

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current and monitor it on a periodic basis or on a continuous basis. As the use of the current increases, that demonstrates that there is a corrosion mechanism happening, and we react to it.

And the second type of engineering controls that we utilize is, first, to remove the water, which is the primary source of corrosion. We remove it by proper dehydration technologies. And then after the removal is done, we make sure enough corrosion monitoring devices are in place to alert us or even to give us the condition of the components which are handling these hazardous fluids.

Q. So that would be the monitors that we already talked about --

A. Yes.

Q. -- that have a connection to the automated shutdown system?

A. Yes. Like the water -- water measurement component, like Scott Hodges has mentioned, that is our engineering control which is linked to our shutdown valves, which cut off the CO2 or produced gas back to the fields, in convention with other parameters that we look at.

Q. Let me ask you about one aspect we haven't talked about previously, and it's the last one on here.

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It's "monitor and mitigate corrosion using coupons," and then there is an arrow pointing to the picture. First off, where is this picture from?

A. This is an actual installation of corrosion called a corrosion coupon in the North Hobbs decompression facility. This is located on the fluid which is pressurized to 1,800 pounds after it is dehydrated and sent back to the satellites for reinjection. And the coupon which is shown in the blue component is inserted using a probe. Basically, you can imagine, the probe is always in the fluid. It is in contact with the fluid continuously.

We take out this coupon periodically, every 30 days or based on how much corrosion is there or any evidence of corrosion, and we monitor and look for the weight loss, which gives us a measure of corrosion happening. So that provides a controlled mitigation method.

Q. Now, we then talked about material selection and how the industry standards are used, any other corrosion methods that you move into. Let's talk a little bit about -- getting back to the cradle-to-grave concept, let's talk about how these industry standards are then utilized in the fabrication and construction aspect of these facilities. So let's move to slide 12.

A. During the fabrication and construction phase of the project, NACE MR0175 stipulates the type of materials and the type of composition of the materials that needs to be procured for fabrication of the pressure components. And we put in the QAQC procedures to make sure the materials that we procure are meeting the NACE standards, and then we also use other supplementary specifications which are part of the ASME or API or ANSI standards.

Q. So they give you that additional checklist?

A. Yes. We follow that additional checklist where we maintain the integrity of the component.

Q. And I think we've already talked previously about the example -- the welding example.

A. Yes.

Q. So let's move, then, to -- continuing the cradle-to-grave concept, let's go to a topic that we haven't touched on, and that is the maintenance aspect.

A. Yes.

Q. So let's move to slide 13. How do these industry standards come into play, then, and how are they applied when you're dealing with it when the facilities are in and you're now maintaining them?

A. Yes. Once the facility is designed, fabricated, constructed and installed, there is the final phase where the facilities are going to be used for the life of the project. Based on the 30-plus years of industry experience, ASME, API, ANSI, NACE has provided guidelines to make sure that the equipment is meeting the fundamental -- fundamental objectives that it was previously designed for.

And we have a robust mechanical integrated program which takes into consideration all the guidelines provided by the industry standards, and we categorize them into two types of programs. One is regular interval-based testing and inspections. And the other one is risk-based inspection focused on damaged mechanisms.

Interval-based mechanism or inspection is like you inspect the component in a one-year, five-year or ten-year based on your experience.

Q. Let me stop you there. Is it also based on industry standards?

A. Yes. And industry standards, especially API, stipulates the periodic inspection of these components based on information and the composition of these components.

And risk-based inspections are a type of inspections based on previous failure mechanisms or any -- developed for operating in close proximity to the public. So these two types of mechanisms are used.

Q. And, again, it's governed by --

A. Governed by the API.

Q. Industry standard?

A. Industry standard, yes.

Q. This maintenance and these standards, is it a proactive process?

A. It is a proactive process, and to quote an example, North Hobbs CO2 surface facilities were installed in 2003. In the 2011-2012 time frame, we took the entire CO2 operations down for five to seven days, where we have inspected every component of the CO2 surface facilities, by the requirement by the industry standards.

Q. So nothing happened?

A. Nothing happened, no.

Q. But this is a proactive maintenance that is dictated by NACE MR0175 industry standards?

A. Yes.

Q. Then I think we're about ready to wrap up here. Turn to what's been marked as slide 14. There has also been -- I think it was referenced in the prior slide -- a recordkeeping component, is there not, through this whole maintenance process, correct?

A. That's right.

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Q. Why don't we -- this slide has animation.

A. It has some animation.

Q. Let's talk about that.

A. Since the maintenance can be 20 years or 30 years, the knowledge that we have gathered during the initial phase of the project needs to be available to personnel who are operating 20 years down the road or 30 years down the road. Actually, the API industry standards stipulate some of these requirements. We do that by construction document recordkeeping of all the construction documents, where we gather all the vessel data reports, hydro [sic] data reports, calculation reports, selection process of material and the welding procedures that are used in the fabrication process. We store them in an electronic database.

Next slide.

And after the South Hobbs facilities are fabricated and installed, we gather all the inspection documentation. The industry standard API and the MR0175 stipulate as to inspect, pressure test the components before they're put into service so that they can be assured that the system is built to withstand the corrosion. And those type of reports go into the inspection documentation, which form the basis for subsequent inspection. And based on the operating

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environment, previous history of failures, we subdivide the entire CO2 operations into various groups where we can plan on one year, five-year or ten-year or an RBI-based [sic] plan. All these are provided again on the guideline by API five-ten documentation.

Q. When you talk about this inspection plan, some of these inspections that result from all of this information, do they require a complete shutdown of the facility at times?

A. Yes, they do. And during that time, all the wells, injection wells, production wells, and the compression facilities are shut down, and the pressure components are opened for internal and external inspection.

Q. Is there also then a fourth aspect?

A. In order to manage and make sure there is a continuity of the documents, availability, we use database programs which comprise all this documentation and provides our inspection planning methodology and also provides snapshots of where we stand on integrity status.

Q. Now -- so this is real time?

A. This is all real time.

Q. Did you apply these same concepts that we just talked about today to the design, fabrication and

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maintenance of the facilities at the North Hobbs Unit?

A. Yes, we do.

Q. And that has been operating as an injection site since 2003, correct?

A. Yes.

Q. Have you been successful at the North Hobbs Unit in avoiding corrosion issues?

A. Yes, it has been extremely successful.

Q. What was the result of a recent North Hobbs Unit mechanical integrity inspection?

A. We -- we have -- we have pressure tested all the production flow lines. We have guided -- we have tested all the injection lines, and we have externally tested all the pipelines. We have done pressure-vessel inspections internally and externally, and we have not found any failure mechanism associated with the corrosion fluids being handled.

Q. In your opinion, do OXY's plans for the design, fabrication and maintenance of the South Hobbs Unit surface facilities provide a reasonable level of protection to the public and the environment?

A. It does.

Q. Were the slides comprising OXY 11 compiled under your direction or supervision?

A. Yes.

MR. FELDEWERT: Madam Chair, I move admission into evidence of OXY Exhibit 11.

MS. GERHOLT: No objection.

COMMISSIONER BAILEY: Exhibit 11 is accepted.

MR. FELDEWERT: And that concludes my examination of this witness.

COMMISSIONER BAILEY: Do you have cross-examination?

MS. GERHOLT: No questions for this witness.

COMMISSIONER BAILEY: Mr. Warnell, do you have questions?

CROSS-EXAMINATION

BY COMMISSIONER WARNELL:

Q. Mr. Chokkarapu -- is that correct?
A. Yes, that's correct.
Q. I just wanted to see if I could say it (laughter).
A. You are one of the few who said it right (laughter).
Q. Oh, boy, I'm feeling better already.

I did have a question. On slide number five, one of the little blue coupons -- slide number 11. Excuse me. You said that that's pulled every 30 days?

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A. That's right.
Q. A 30-day frequency, it's pulled?
A. Yes.
Q. And once you pull that and you look at the deterioration, is it re-used or --
A. No. A brand-new sample, which has been fabricated according to the NACE requirements, is used in place of the old one.
Q. Thank you.
COMMISSIONER BAILEY: Commissioner Balch?
CROSS-EXAMINATION
BY COMMISSIONER BALCH:
Q. Good afternoon --
A. Good afternoon.
Q. -- Mr. Chokkarapu. I probably missed it.
A. A little bit, but that's okay.
Q. These projects tend to be rather long-lived?
A. That's right.
Q. I imagine the person that drilled -- the person that owned the first well in the Hobbs Unit drilled it in 1935. If they were still alive, they'd be very shocked that 78 years later it's still doing something.
A. Yes.
Q. So when you design a facility for CO2 injection -- I think there are already some that have

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gone since the '60s.

A. 1970s, 1920s [sic], yes.

Q. Okay. So some have already been going for 35 years. You could always add in and beyond what you're originally specifying your design for. You could be going after a reduced oil zone. You could be going after other production intervals that would be in the same field. It may just be more successful and long-lived than you expect?

A. That's right.

Q. So when you're designing one of these facilities, what do you do when you're considering design life?

A. NACE MR0175, Section 8.2 stipulates that while we are selecting the materials, it stipulates that identify known operating conditions and unknown operating conditions and try to select the materials. That is our basis when we start. And we make sure we try to anticipate as much as we can to incorporate in the first phase, first initial fabrication itself so that the equipment can be used. And when we try to use the subject equipment for a different project or for a different phase of the project, we come back and we re-evaluate the condition of the equipment for the operating conditions. By that time, we will be knowing what the operating conditions are. So we will evaluate and make necessary adjustments. If we have to replace the equipment, we will replace the equipment.

Q. So for designing a project that you think is going to last 30 or 40 years, technologies change.

A. Yes.

Q. You also have 27 other CO2 floods which give you experience on what works, what doesn't work.

A. Yes.

Q. Is there ever -- or, is there a periodic review of overall operations to decide if you need a facility upgrade or anything like that, a big overhaul?

A. Yes. Not at a whole complete -- like a facility. But we -- we -- we look at the areas where -- we first gather where the developments are made based on the industry publications or industry -- by following the industry standards. And we see where they apply and combine that with our own internal operating experiences, and try to evaluate and make a judgment whether we need to use those materials and what kind of advantages would that provide us in addition to what we already have. So that's how we make that judgment call.

Q. Okay. Thank you very much.

COMMISSIONER BAILEY: I have no questions.

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Do you have redirect?

MR. FELDEWERT: I have no further questions.

COMMISSIONER BAILEY: You may be excused.

THE WITNESS: Thank you.

COMMISSIONER BAILEY: Shall we call it a day and begin tomorrow with Kelly Montgomery?

MR. FELDEWERT: Yes.

COMMISSIONER BAILEY: We will continue this hearing until tomorrow morning at 9:00 here in Porter Hall.

MR. FELDEWERT: Thank you.

(Evening recess, 4:32 p.m.)

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STATE OF NEW MEXICO

COUNTY OF BERNALILLO

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