STATE OF NEW MEXICO
DEPARTMENT OF ENERGY, MINERALS AND NATURAL RESOURCES
OIL CONSERVATION DIVISION

ORIGINAL

APPLICATION OF OCCIDENTAL PERMIAN LTD TO AMEND ORDER R-6199-B TO EXPAND THE NORTH HOBBS GRAYBURG-SAN ANDRES UNIT PHASE I TERTIARY RECOVERY PROJECT, TO MODIFY CERTAIN OPERATING REQUIREMENTS AND TO CERTIFY THIS EXPANSION FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE NEW MEXICO ENHANCED OIL RECOVERY ACT, LEA COUNTY, NEW MEXICO

Case No. 15103

TRANSCRIPT OF PROCEEDINGS
EXAMINER HEARING

BEFORE: CHAIRWOMAN JAMI BAILEY

March 13, 2014
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, JAMI BAILEY, Chairwoman; TERRY WARNELL, Designee of the Commissioner of Public Lands; and ROBERT S. BALCH, Designee of the Secretary of Energy, Minerals, and Natural Resources Department, on Thursday, March 13, 2014, in Porter Hall, Santa Fe, New Mexico.

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I N D E X

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MADAM CHAIR BAILEY: I will call Case 15103, which is the application of Occidental Permian, Limited, to amend Order R-6199-B, to expand the North Hobbs Grayburg-San Andres Unit Phase I tertiary recovery project, to modify certain operating requirements, and to certify this expansion for the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act, Lea County, New Mexico.

Appearances?

MR. FELDEWERT: Madam Chair, members of the commission, Michael Feldewert, with the Santa Fe office of the law firm of Holland & Hart, appearing on behalf of the applicant.

MADAM CHAIR BAILEY: Counsel, do we have other appearances?

MR. BRANCARD: We have at least two parties who sent notices to the commission for entries of appearance. These were parties that received the notice that was required by the company.

And we have an entry of appearance by David Ellison, personal representative of the estate of George Rittenhouse Ellison.

And then we have an entry of appearance by

Tom Mehs, if that's how you pronounce his name, M-E-H-S, on behalf of Cornelia England, Gerald Carl Golden, Sharon Aileen Mehs, and Thomas Mehs.

These are done strictly for the purpose of establishing themselves as a party of record. They do not express an opposition or support for the application at this time.

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

MR. FELDEWERT: I do, Madam Chair.

OPENING STATEMENT

BY MR. FELDEWERT:

I have up on the screen what is actually Slide 1 of Exhibit 4. And the reason I have that up there now is because last May we were before this same commission on an application involving the South Hobbs Unit, which is outlined in red.

And at that time you may recall we sought approval to convert the South Hobbs Unit from a waterflood to a tertiary recovery project in the Grayburg-San Andres formation.

And actually, Exhibit 3 in our exhibit notebook is the order that was entered by the commission approving the injection of CO2-produced gas and produced water into the South Hobbs Unit for that tertiary recovery project.

I have many of the same witnesses back here today as testified in May. But today our subject is the North Hobbs Unit, which is outlined in black on that Slide 1 of Exhibit Number 4.

Within the North Hobbs Unit there's an area called the Phase I area. And that was approved for a tertiary recovery project, the injection of CO2, the injection of produced gas, and the injection of produced water.

Back under Division Order 6199-B, which is actually Exhibit 2 in our notebook -- and that was, at that time, entered by the division in 2001. It covered the Phase I area.

So the rest of the North Hobbs Unit was operating as -- and is still operating -- as a waterflood.

So I think the first point I want to make is what we're seeking here today is really not anything new with respect to that North Hobbs Unit. We are seeking to expand the current tertiary recovery project geographically to include most, but not all, of the North Hobbs Unit. And the remainder of that North Hobbs Unit will continue to operate as a waterflood.

The other thing that we're seeking here is to change a few of the operating requirements, many of which you are familiar with from your decision in the South Hobbs Unit.

As a matter of housekeeping, we've provided two notebooks. And unfortunately, they're both white. I think next time I'm going to make one black and one white.

But we have -- the first white notebook is entitled Application Form C-108. That, we would submit as Oxy Exhibit Number 1. It contains the application, it contains the exhibits, it contains the C-108, it contains the area review information.

The second notebook is really our notebook of the additional exhibits which start as Exhibit Number 2. So the first notebook being Exhibit Number 1, the second notebook containing what is now Exhibits 2 through 15.

Before we move through the -- you know, before our presentation here today and move through the witnesses and the exhibits, I thought it might be helpful to just kind of walk through the relief that we requested.

And for ease of the commission, it's actually in that white notebook in our application, starting on the first page. And I thought it might be helpful just to walk through it, to give you an idea of what we're looking at. And so it would be the notebook that has the C-108 application.

On the first -- the first page of that should be our ap- -- in that notebook -- should be our application. And there's going to be a series of paragraphs A through J. That comprises the relief that we seek.

And the first one is fairly straightforward.

The first relief that we seek, as reflected on the first page of the application in the front of that first notebook, we seek to expand the geographic area of the North Hobbs Unit. And the acreage that we -- which we seek to expand is identified in paragraph A of that application.

The second relief that we seek is paragraph B. And it is to add -- I guess no surprise -- additional injection wells. And that would be additional injection wells in the current Phase I area as well as the expanded geographic area.

The -- and those are actually listed as Exhibits A and B to the application.

Exhibit A, we identify those injection wells by quarter-quarter section, because those will be new drills. We're not exactly sure where we're going to put them.

And then Exhibit B identifies the wells that are going to be converted from producing wells to injection wells.

The third relief we seek is really -- I put it in here only because there's some confusion in -- I believe in the rules.

We just want to confirm that for a tertiary recovery project you can have more than four wells per 40.

The reason there's some confusion is because Rule 19.15.15.9(A) currently states that you can have more than four wells -- and I quote -- for secondary recovery projects.

I think the division meant to include tertiary, but the word tertiary is not in there, although in another rule you will see that they differentiate between secondary recovery projects and tertiary recovery projects. So we're asking the commission to clarify that. Like secondary recovery projects, you can have more than four wells in a 40-acre spacing unit for a tertiary recovery project.

The fourth relief that we seek in paragraph B of our application is we ask for authority to locate wells closer than 10 feet to the quarter-quarter section lines within the expanded Phase I area.

The unorthodox well rule currently states that in -- and it says secondary recovery and tertiary recovery projects -- wells are to remain 10 feet from the quarter-quarter line.

Now, I'm not quite sure of the origin of that requirement. I don't quite understand it. And -- but it seems rather odd to me, when we're dealing with that kind of a -- this kind of a project, that you have to maintain that distance.

But Oxy's working with existing wells. They want to keep their 5-spot pattern. And there's going to be -- they believe there's going to be circumstances where, because of the location of wells and in order to keep that 5-spot pattern, they may need to encroach on closer than 10 feet to the quarter-quarter line. So we ask for some relief there with the location of the wells.

We -- on -- in paragraph E we ask for an exception to the notice requirements for the approval of any additional injection wells as this project moves forward.

We attempted, in Exhibits A and B, to identify what they are going to need on a go-forward basis, but this project is going to be a long-term project. And we may -- there may be instances where they need to locate injection wells that are not set forth in Exhibit A and Exhibit B.

And so we ask for the ability, if that occurs, to ask for administrative approval without notice and hearing, because we've already done an extensive study.

And if you look -- if I may indulge you to take a look at Exhibit 3 in the notebook.

And I'm actually going to start kind of flipping back and forth here in that exhibit notebook for the remainder of the relief.

But if you will turn to Exhibit E, that is the order that you entered last year for the South Hobbs Unit.

And if you'll turn to page 11 of that order, paragraph -- page 11, paragraph 3, the last sentence is what -- last year you authorized the administrative approval of additional injection wells without notice and hearing for the unit.

That's -- we seek the same type of relief now for this expanded area in the North Hobbs Unit.

The next item of relief we seek is, because there is a long lead time in this project -- it's very capital intensive, it's going to take a long time to put in. They are still going to be working on wells, they project, into the year 2020. Some of these wells may not commence injection for -- until two years from now.

And so we are essentially asking for a five-year grace period on the extensive area of review analysis that has been done and which we are going to go over with you today. It took a lot of time and a lot of effort.

And what you will find out from the witnesses, that much of this area that they had to review has been reviewed over and over again in connection with South Hobbs Unit, North Hobbs Unit expansions, et cetera. So it's had a lot of analysis. And there have been very few changes, because Oxy is the only operator.

And so because of this work that's already been done, we would ask for that five-year grace period.

And if you stay with Exhibit Number 3 and if you will go to page 11 where you're at and you look at paragraph 5, that I call the five-year grace period that you entered for the South Hobbs Unit, we're just asking for the same language, the same relief as is in paragraph 5 now for the North Hobbs Unit. We'll just need to change the description from south -- the statement from South Hobbs to North Hobbs.

If you then turn to Exhibit Number 2, which is Order 6199-B.

So Exhibit 2 in our notebook is the order that was entered by the division back in 2001 governing the North Hobbs Unit, the current Phase I area.

And we were -- what -- when we were going through that, what surprised me is -- if you go to page 12 of that order that was entered back in 2001.

If you go to page 12, paragraph 17, the order in paragraph 17, it has a limiting gas/oil ratio.

I think the division and the commission have recognized that, really, that doesn't make a lot of sense in any gas injection project like this. And so we ask that that GOR limitation be eliminated. And if -- actually, if you look at --

back at your order from last year, Exhibit 3, paragraph -- ordering paragraph 21.

For the South Hobbs Unit it's on page 13 of your order from last year, paragraph 21. It says that no limiting gas/oil ratio or oil allowable applies to this enhanced oil recovery project.

We just ask for the similar statement in the North Hobbs Unit, so that we don't have this restriction that really should not apply to a -- at least in our opinion -- to a tertiary recovery project like this.

Staying with that -- with that order where you're at now on Exhibit Number 3, if you go to page -- you're on page 13. If you go to paragraph 16 of that order, you provided the relief that for TA wells that are equipped with those realtime pressure monitoring divisions that Oxy has, that are connected to their SCADA system, that you provided that for those -- only for those wells that are equipped with that realtime pressure monitoring device, you said that they could have -- granted the five-year period before there has to be another mechanical integrity test.

We ask for that same kind of relief for the expanded area of the North Hobbs Unit. And we will have a witness who will again talk about that SCADA system, about those realtime monitors, and why that makes just as much sense for the North Hobbs Unit as it does for the South Hobbs Unit.

Finally, the final aspect of the relief that we request is really something that Oxy hopes it never has to use. But that would be to certify this expanded area for the tax -- the recovered oil tax rate under the New Mexico Enhanced Oil Recovery Act. And we will have a witness who will hit all the touchstones necessary to certify this expansion for that tax rate.

So that's the universe of relief that we seek under this application. As you'll see, much of that was addressed by the commission last year. And in fact, since we have the same commission and no other parties here today, I -- and because we referenced this actually as an option in our application, I think it might be helpful to incorporate the record from Case Number 14981 involving the South Hobbs Unit into the record of this case, because I didn't bring all of the witnesses. You know, we had that testimony.

We have five witnesses here today, but we didn't bring all of them because -- only because we wanted to be as efficient as possible. We think we can cover what they covered last year. But also, if we incorporate that record we have that additional backup.

And now that the commission has a better understanding of what -- of what Oxy is doing out there, I guess, you know, I just felt like we could cut down on some time and take less of your time, and I brought five witnesses here today.

It's still going to take us about three hours, at least for my portion is what I estimate, to get through what they have to say.

But we're confident -- I'm going to move along as efficiently as possible, but at the same time provide you all the information that I think you need to make an informed decision on this matter.

So with that said, I think we're ready to proceed with our first witnesses -- our first witness. I don't know if you want them all to be sworn at the same time or individually.

MADAM CHAIR BAILEY: Individually works.

MR. FELDEWERT: Then at this point with your permission, unless you have any questions about the relief we seek, I can start with our first witness.

MADAM CHAIR BAILEY: Commissioners, do you have any objection to incorporating the record of the South Hobbs?

COMMISSIONER BALCH: I have no objection.

COMMISSIONER WARNELL: No objection.

MADAM CHAIR BAILEY: Then that will be accepted.

MR. FELDEWERT: I guess the second thing, as a matter of housekeeping at this point if I could, I would introduce Oxy Exhibit Number 1, which is the notebook containing the application and the Form C-108 in the area of review.

Oxy exhibit -- and then Oxy Exhibits 2 and 3, which are the orders that we just reviewed.

MADAM CHAIR BAILEY: Those exhibits are admitted.

MR. FELDEWERT: Madam Chair, with your permission, we will call our first witness.

MADAM CHAIR BAILEY: Please do.

JERAD BROCKMAN,

after having been first duly sworn under oath,

was questioned and testified as follows:

EXAMINATION

BY MR. FELDEWERT:

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

A. My name is Jerad Brockman. I'm employed by Oxy as a production engineer.

Q. And how long have you been a production engineer for Oxy?

A. Four years -- just over.

Q. Do your employment responsibilities include the North Hobbs Unit and the South Hobbs Unit?

A. Yes, they do.

Q. Are you actually the project manager for those units?

A. Yes.

Q. Okay. And involved in the -- and operating as a production engineer for those two units?

A. Yes. I've been the production engineer for the South Hobbs Unit since January of 2010, and then for the North Hobbs Unit since August of 2010.

Q. And, Mr. Brockman, did you have the opportunity to testify before this commission with respect to the application that resulted in the approval of a tertiary recovery project for the South Hobbs Unit?

A. Yes, I did.

Q. Were your credentials at that time as an expert in petroleum and production engineering accepted and made a matter of public record?

A. Yes, they were.

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

A. Yes, I am.

MR. FELDEWERT: Madam Chair, at this point I would re-tender Mr. Brockman as an expert witness in oil and gas petroleum and production engineering.

MADAM CHAIR BAILEY: He's accepted.

Q. (By Mr. Feldewert) Mr. Brockman, I want to turn to the notebook that has Oxy's exhibits.

I want to go to exhibit number -- Oxy Exhibit Number 4.

Does this Exhibit Number 4 contain the slides that you prepared in your presentation to the commission here today?

A. Yes, it does.

Q. And it consists of a total of 10 slides.
Is that correct?
A. Yes.
Q. If I turn to Slide 1 of Exhibit 4, would you please discuss with the commission the location of these units and then what you're showing here on this first slide?
A. Sure. Slide 1, there are two maps on it. The smaller map off to the right is the Permian Basin.
So the smaller map to the right is the Permian Basin.
This is the state line between Texas and New Mexico. New Mexico is to the northwest, and then Texas everywhere else.
All of these green little blobs on this map are major Permian fields that Oxy operates.
This field in Lea County with the red square around it is the Hobbs field.
A blowup of the Hobbs is shown in the larger map to the left.
The Hobbs reservoir is actually made up of two units, the North Hobbs Unit and the South Hobbs Unit.
The South Hobbs Unit is shown here in red,

and then the North Hobbs Unit is shown in the black outline.

Also shown in here is an approximation of the Hobbs city limits. This is in green. You can see that a portion of both the North Hobbs Unit and South Hobbs Unit are inside of the city limits of Hobbs.

Q. Now, in -- what's the formation into which you are conducting -- or engaged in your waterflood operations?

A. The Grayburg-San Andres formation.

Q. And is that the same formation that is currently subject also to the tertiary recovery project in both the North Hobbs and the South Hobbs Units?

A. That's correct.

Q. Then today, our focus now is on the North Hobbs Unit, correct?

A. Correct.

Q. Why don't you turn, then, to what's been marked as Slide Number 2 of Exhibit 4.

And will that assist you in discussing with the commission what is the current operations in the North Hobbs Unit?

A. Yes. So I'll walk through this slide

also.

Shown again in black is the outline of the North Hobbs Unit.

This red outline inside of it is the current Phase I injection area. In the Phase I area we have CO2 and produced gas injection. The produced gas injection wells are shown as the red triangles kind of off towards the northwest.

And then the orange triangles, as you move farther southeast, are the purchased CO2 injection wells.

The green dots located around all of the injection wells are our producers.

The blue triangles farther southeast are the current water injection wells. And you can see that a portion of those are actually inside of the Phase I area and a portion of them are outside of the Phase I area.

All of the gray circles I have labeled as inactive wells. Looking at it now, I probably should have relabeled that. Those are either temporary abandoned or plugged and abandoned wellbores. I made no distinction between the two on this map.

Q. And with respect to the waterflood

operations in the North Hobbs Unit, when did they first commence in the Grayburg-San Andres formation?

A. The waterflood in North Hobbs started in 1980.

Q. Okay. So you've had, roughly, almost 35 years of development as a waterflood?

A. That's correct.

Q. At what time frame, then, did the Phase I area of the North Hobbs Unit move to a gas injection project, a tertiary recovery project?

A. The order was adopted or approved in 2001, and then the first injection started a couple of years later, in 2003.

Q. Okay. So we've had more than ten years of gas injection within the Phase I area of the North Hobbs Unit?

A. That's correct.

Q. Let's turn, then, to Slide 3 and discuss what the company -- what you are going to address with the division -- or with the commission -- with respect to the relief that is sought under this application.

A. Sure. So the first thing I will testify to is the expanded Phase I geographic area.

As part of that, I would like to testify to the -- to expand the injection authority to include new wells on a quarter-quarter section or the conversion of existing wells to CO2 or produced gas injection wells.

We would like the grant exception to allow wells to be closer than 10-foot to the interior quarter-quarter section.

We would also like to confirm that the well limitation for quarter-quarter sections does not apply to a tertiary recovery project.

And then finally, to modify the packer setting depth requirement to allow the injection packer to be set anywhere within the top of the Grayburg formation.

Q. With that in mind, let's turn to a discussion of the geographic expansion of the Phase I area and the new injection authority.

And I think it would be of assistance to turn to Slide 4.

A. Okay.

Q. And is an animation, at least on the screen, associated with Slide 4?

A. Yes, sir, it is.

Q. Okay. What are we showing in the first animation?

A. Sure. So in purple this time is the -- again, the North Hobbs Unit outline.

Each of these boxes is a section line, so it's a mile east and west and a mile north and south.

Shown in this dashed line is an orientation, just the difference between Township 38S, Range 37E and 38E. That's what this dashed line depicts.

If you'll click.

So this green shaded area is the current Phase I geographic area.

Click again.

This blue portion is the geographic expansion that we're asking for.

Q. Now -- so you're not seeking to expand the gas injection for the entire North Hobbs Unit, but a larger portion of it, correct?

A. That's correct.

Q. What will happen with respect to the remaining aspect of the Hobbs Unit to the east -- North Hobbs Unit to the east?

A. It will continue to operate as the waterflood with the wells that we have left in that part of the field.

Q. Okay. What's this next animation?
A. Sure. So shown here in triangles are all of the additional wells that we have asked for in the authority to inject into.
The same color scheme as before. The orange triangles are purchased CO2 injection wells. And the red triangles off to the northwest are produced gas injection wells.
You can see on the northwest, where these patterns are a lot more regular, these are the quarter-quarters that we have asked for.
And then as you move towards the southeast, where our current waterflood operations are, these are the conversions of existing wells that we're talking about predominantly.
Q. And why do you identify certain locations by simply quarter-quarter sections?
A. Sure. There are a lot of existing wells there. That's where our current flood is.
And to -- we're going to be targeting a deeper portion of the San Andres with this project. And to realize a better suite efficiency, we're going to have to drill additional injection wells.
We're not sure where exactly we could put those wells, just because there are so many wells

out there. So we want the flexibility to be able to stick them -- or place them within that quarter-quarter.

Q. Now with respect to the bottom right-hand corner of this depiction, the -- there's a number of wells that don't follow that pattern.

Are those specific wells?

A. Yes, those are existing wells.

Q. With API numbers?

A. Yes.

Q. Okay. And if I look at the application that was filed by Oxy, there is an Exhibit A of that application which is actually in the -- Oxy's Exhibit Number 1.

Under the tab "Application," there should be an Exhibit A. So if you would turn to that book, Mr. Brockman, and go to the tab under "Application." It should be the first tab. There's an Exhibit A.

A. Okay.

Q. And does that list all of the wells of the injection authority that you seek by quarter-quarter section?

A. Yes, it does.

Q. And does that correspond with the -- a number of the triangles, then, that are shown on

Slide 4?

A. Yes.

Q. And if I page through that, at -- after the fourth page there is an Exhibit B, correct?

A. Correct.

Q. And that is entitled "List of proposed project injectors, existing wells"?

A. That is correct.

Q. And it provides the API number of those wells?

A. Yes.

Q. And is that -- are those the wells that you know that you're going to convert to -- or that you hope to convert to injection wells?

A. That's correct.

Q. All right. And again, then, those correspond to -- most likely, I guess it would be the orange triangles more towards the bottom right-hand corner of the Slide Number 4?

A. That's correct.

Q. All right.

Will some of the proposed wells be directionally drilled?

A. Yes, they will.

Q. On this particular exhibit, did you then identify the surface locations of those wells?

A. Yes.

Q. And I believe there's one more piece of animation on this slide.

A. Yes, one more.

Q. With that said, let's go to the last...

A. Click one more time.

So my map is kind of busy here, so I didn't depict this on the actual map. I had this depiction to the right instead.

So each one of these injection wells will be surrounded by four producers in our 40-acre 5-spot pattern. So if you can imagine throughout this map there will be a producer here and a producer here.

As part of this project, a majority of these producers already exist. We're going to deepen them or convert them and, you know, get them ready for CO2 injection.

At other points we're going to have to drill new producers as well.

But you can imagine that along this map there will be a corresponding core of producers around every triangle.

Q. Now, will the -- this 40-acre 5-spot

pattern, in your opinion, will that assist in confining the horizontal migration of the injection?

A. Yes.

Q. And allow the company to reuse the produced gas -- or capture and reuse the produced -- the injected gas and the injected water?

A. Yes.

Q. All right. I want to talk about, then, the next topic. And that is the number of wells per 40 acres.

In your opinion, Mr. Brockman, in order to properly implement this 40-acre 5-spot pattern, given the number of wells that currently exist, is it going to be necessary at times to have more than four wells per 40 acres?

A. Yes, it will.

Q. And so do you seek to confirm the authority to exceed the four-well limitation for tertiary recovery projects?

A. Yes.

Q. The other aspect of the relief that you seek is you ask that they allow the company to, as necessary, locate a -- either a producer or an injection well closer than 10 feet to the quarter-quarter line.

A. That's correct.

Q. Can you discuss the need for that exception?

A. Yes. As we're going to be drilling a substantial amount of wells on this part of the field where we already have several wellbores, we're going to need the flexibility to put these wells in unorthodox locations. And we don't want to be drilling the well and run a directional survey and realize that we're going to project our bottom hole location out to 10 -- right on an anterior boundary and have to trip out and go back in with directional tools to move it away from a boundary inside of our own unit.

Q. And so in your opinion, do you think that -- are you going to need that flexibility, as you move forward with this project, in order to maintain the integrity of your 5-spot pattern?

A. That's correct.

Q. Okay. Then I want to move to a new subject.

A. Okay.

Q. And that is reflected in Oxy Exhibit 4, Slide 5.

Now, we are talking about an expansion of an existing tertiary recovery project, correct?

A. Correct.

Q. Expanding the Phase I area.

With the assistance of this exhibit, would you just please orient the commissioners as to what is -- currently occurs with respect to the surface facilities for the existing operation?

A. Yes. So this flow diagram is both what we have now and what we'll be adding on as part of this project.

If you will start in the top left corner you see producing wells represented by the green circle.

At the producing wells we have the flow line to them. At that flow line, the oil, water, and gas produced from the wellbore is transferred to a production satellite.

At the production satellite the liquids, the oil and water, are sent to a tank battery, and the produced gas is sent to our existing reinjection compression facility.

Q. Okay. Let me stop you right there, because I think we have a picture of one of those satellites. If we just keep a finger on this portion of the notebook and we flip over to

Exhibit 6, the first page.

A. Yes.

Q. Is that a picture of a current -- what you call a satellite?

A. Yes, it is.

Q. Okay. And that's currently -- that's an existing picture in the North Hobbs Unit?

A. Yes.

Q. How many of those satellites do you currently have?

A. I don't know the exact number. It's six or seven, I believe. But...

Q. And this is the -- this is the area where both the produced product comes in and the injection liquids and gas go out?

A. That's correct. The production site is a gathering system, which we gather all the production from individual wells. And the injection side of the unit is the distribution center, where we take all of our injection from the RCF or from our produced water, and it's distributed to all of the individual injection wells.

Q. Then -- I interrupted you. Would you continue on with your discussion of your surface facilities that are necessary to implement these projects?

A. Sure. So after the produced gas is sent to the RCF, or the reinjection compression facility, it's dehydrated and compressed and sent to the injection satellites that we just saw.

Also at that satellite, CO2 from the pipeline is sent to those, as well as produced water that is separated at our tank battery.

From there the injection satellites -- all of the injected fluids are sent to individual wells to -- which are depicted in the orange triangle there.

At the tank battery we separate the oil and water. The oil we sell, and the produced water is sent to the injection satellite.

Q. Now these current facilities out there, they allow you to capture and reinject produced water?

A. That's correct.

Q. They allow you to capture and reinject produced gases?

A. That's correct.

Q. And then they also, then, allow you to add additional CO2 from other sources when needed?

A. That's correct.

Q. Would the expansion of the Phase I area require additional facilities?

A. Yes. We'll have to add new satellites. We'll expand compressions of the existing rejection compression facility. We have to upgrade our tank batteries and add new injection satellites as well. And then every well will, obviously, need either a producing flow line or an injection line.

Q. And is that a substantial capital investment for the company?

A. Yes, it is.

Q. Does it a take a while to get these facilities designed, constructed, and built?

A. That's correct.

Q. If I turn to what has been marked as Slide 6 in Exhibit Number 4, does that -- is that a graph that gives the commissioners at least a depiction, from a graphic standpoint, of the amount of money and the time line that is involved with this expansion project?

A. Yes, it does.

Q. Okay. Why don't you orient us to the axes and the colors please?

A. So on the X axis this time every year is depicted.

On the left axis is millions of dollars spent per month.

And on the right axis is the total spent.

Each of the bars corresponds to the monthly spend. And then if you go to the left axis and then the dark black line is the cumulative spend, and it goes to the right.

The bar charts are color coded between well work and drilling in green, and then filled in RCF facilities in red.

So you see that our anticipated start of injection for this project is in September of 2016. So you can see that preceding year and a half before, then, we ramp up quite a bit of spending on the facility and just all the construction.

And then going forward through the next five years after that we continue to add patterns and wells, which you can see in the green columns going all the way to the right of the graph, and then their associated facilities continue to stretch out until 2020.

Q. So you're going to be doing well work past, what, 2021?

A. That's correct.

Q. And then the dark line is your estimated total capital expenditure?

A. That's correct.

Q. And that's millions of dollars?

A. That's in millions of dollars.

Q. Anything else about this exhibit?

A. No, that's it.

Q. Then let's turn to Slide 7 of Exhibit Number 4.

Does this give the commission a projected time line of, really, the major milestones of this expansion project?

A. That's correct. In August we plan to begin our detailed design engineering. Once that gets underway we'll be able to start procurement at the end of this year, in December.

We'll actually start construction on the field in August of 2015, and then the expansion of the RCF in April of 2015.

We expect to start most of our well workovers and drilling the first part of 2016, with the additional compression and first injection of the expansion area ready to go in September of 2016.

Q. Then if I move on to Slide 8 of Exhibit 4, what does this show us?

A. This is just a production plot of the

North Hobbs Unit since discovery, as you go through primary to waterflood to the tertiary.

Q. So that first well was sometime back in the 1930s?

A. I think the discovery well in the Hobbs field was in 1928.

Q. Okay.

A. Shown in green is oil. In blue is water production. And in red is gas production.

You can see that the waterflood started with this black line in 1980, and you can see the corresponding increase in both water production and oil production.

The Phase I CO2 flood started in 2003. Again, you can see that with the large increase in gas production and then the subsequent oil production response as well.

The forecast going forward, starting with the Phase I expansion, is shown in this final black vertical line. And again, you can see the large increase in oil production and the increase in compression and gas production also.

Q. Why is the gas line in red flat after you start your Phase I -- or shortly before and after you do your Phase I expansion?

A. Yes. So our gas production is limited by the amount of compression we have available. And so these patterns are timed in so that we keep -- we don't want to build too many compressors in size for a peak. And so we limit the amount of compression we have and stage these patterns in over time. It becomes more capital efficient.

Q. Now, do you require any makeup water for this project?

A. Currently, North Hobbs takes in the makeup water.

Q. You use all just produced water?

A. Produced water. Historically, North Hobbs has taken water from the City of Hobbs, the fluent water, but we don't do that anymore.

The South Hobbs takes water from the City of Hobbs.

Q. And at some point do you anticipate that you will no longer need to produce -- or purchase CO2 to provide enough gas to keep this project moving forward?

A. Eventually it becomes uneconomic to continue to purchase CO2. You just don't get enough oil for the cost of each molecule of CO2 that you are purchasing, so it becomes an economic decision to quit injection -- or quit CO_2 purchases.

Q. You would just continue to reinject produced gas?

A. That's correct.

Q. Okay. In your opinion, Mr. Brockman, has this -- speaking a little bit on the tax credit side.

In your opinion, has this application been prematurely filed?

A. No, it is not. We're about to start spending, you know, all the money going into the detailed design engineering. And it's nice to have the authority to inject already granted at that point.

Q. Is -- the area that's subject to the Phase I expansion, has it been depleted to a point where it is prudent to begin moving from a waterflood to a tertiary recovery project?

A. Yes, it has.

Q. And in your opinion, is this expansion project economically and technically reasonable?

A. Yes, it is.

Q. And just as a matter of housekeeping here, we've talked about the approval of additional injection wells and the other relief that the company is seeking.

Is Oxy in any way seeking to change the maximum surface injection pressures that have been previously approved by the division for the Phase I area?

A. No.

Q. Okay. Now, the -- those surface injection pressures will allow the company to maintain the reservoir pressure just above the admissibility pressure?

A. That's correct.

Q. The last topic, Mr. Brockman, I want to talk about is the packer setting depth issue.

If you would be so kind as to turn to Oxy Exhibit Number 2, which is the current order governing the North Hobbs operation.

And in Exhibit Number 2, if you could flip over, then, to page 9.

So if I'm looking at Exhibit Number 2 at page 9, paragraph 3, the first sentence indicates that the -- a packer is to be set within 100 feet of the uppermost injection perforation in each well.

Do you see that?

A. Yes, I do.

Q. Okay. Has that operational restriction caused issues and problems for the company over time, now that we're moving forward with this project?

A. Yes. Since the waterflood has been going on since 1980, a number of these injection wells have been worked over several times.

Each time you work over an injection well you have to move the packer just a little bit higher up the hole in order to get a good seat on some casing that's not been exposed to injected fluids.

Over time you just run out of room between 100-foot of your top perforation -- or between your top perforation and 100 feet -- to move up this packer.

And so we find situations in wells where we cannot get packer seats within 100 feet, and we have to ask for exceptions to this rule.

Q. So you're looking for smooth casings to get good seals.

Is that about right?

A. That's correct.

Q. If I then turn to Oxy Exhibit Number 3, which is the order that was entered by the commission last year, and if I turn to page 9 and I go to paragraph 27 of that order -- and I also note that it's depicted as Slide 9 of Exhibit Number 4.

That addressed the -- this packer setting depth issue for the South Hobbs Unit, did it not?

A. Yes, it did.

Q. And if I look at paragraph 27, it gives you some flexibility in setting the packer so long as it is below the top of the Grayburg formation?

A. That's correct.

Q. Does Oxy seek the exact same relief here for this phase and expanded Phase I area in the North Hobbs Unit?

A. Yes, we do.

Q. Now last year, when you were here before the commission, did you testify at the hearing in support of this language?

A. Yes, I did.

Q. Did you understand, Mr. Brockman, the geologic testimony that supported this particular provision?

A. Yes, I did.

Q. As part of your work do you routinely realize and analyze pipe -- well pipe logs?

A. Yes, I do.

Q. Because this particular provision reflects that there was geologic and other evidence presented to indicate that this kind of change would not pose a threat.

And are you familiar with that evidence?

A. Yes.

Q. If I turn to the next slide, which is Slide 10 of Exhibit Number 4, does this contain the same pipe logs that were presented to the commission last year to support the packer setting language that was adopted for the South Hobbs Unit?

A. Yes.

Q. In fact, the same pipe logs?

A. Yes, the same slide.

Q. Okay. It shows a well from the North Hobbs Unit and a well from the South Hobbs Unit, correct?

A. That's correct. The North Hobbs Unit well is on the left.

Q. And the South Hobbs on the right?

A. That's correct.

Q. Okay. And this is one -- basically, a similar geologic structure?

A. Yes.

Q. And does the company have a geologist that will testify further in connection with the barriers that exist between the injection interval and the shallower formations?

A. Yes.

Q. Okay. Based on your understanding of that geologic evidence, will the adoption of a packer setting flexibility that we see in the South Hobbs Unit, if that was applied to the North Hobbs Unit as well, is that going to pose an unreasonable risk to the public health or the environment?

A. No.

Q. And will it give the company the operational flexibility to set these packers that it needs as it moves forward?

A. Yeah. We'll set them as low as practicably possible. But moving forward, it will give us a little more flexibility as we work over these wells into the future.

Q. Now, I think you've mentioned that the current Phase I injection in the North Hobbs Unit commenced back in 2003.

A. That's correct.

Q. Okay. Since that period of time has the company been successful in recovering additional oil without endangering the public health and the environment?

A. That's correct.

Q. And does Oxy intend to monitor and operate the new facilities necessary for the Phase I expansion in the same fashion as it has for its current facilities over the last ten years?

A. Yes.

Q. And in your opinion, will the granting of the relief sought in this application allow for the recovery of additional oil that may otherwise be wasted?

A. Yes.

Q. And will the expansion of the Phase I area and the approval of the relief requested in this expanded Phase I area continue to provide a reasonable level of protection to the public health and the environment?

A. Yes.

Q. Were the slides that comprise Oxy Exhibit Number 4 compiled by you or under your direction or supervision?

A. Yes.

MR. FELDEWERT: Madam Chair, at this point I would move the admission into evidence of Oxy Exhibit Number 4.

MADAM CHAIR BAILEY: It is admitted.

MR. FELDEWERT: That concludes my

examination of this witness.

MADAM CHAIR BAILEY: Why don't we take a 10-minute break before we have commission questions.

(A recess was taken from 10:13 a.m. to 10:24 a.m.)

MADAM CHAIR BAILEY: Mr. Balch, do you have questions of this witness?

COMMISSIONER BALCH: I have a couple of questions.

Good morning, Mr. Brockman.

THE WITNESS: Good morning.

COMMISSIONER BALCH: Going back to the 10-foot question. It really seems like a very short distance from the line.

But are you essentially saying that you want to be able to drill wherever you need to within your unit boundaries? It doesn't matter where the TA is compared to the line, the pattern line?

THE WITNESS: That's correct.

COMMISSIONER BALCH: And is that pretty typical for flooding operations?

THE WITNESS: It doesn't occur very often. You know, usually we can seg these wells off and it's not a problem. It's just a few times it does happen, you know. It requires extra -- you know, extra work on the drilling rig, extra work on us to permit it properly.

And we don't -- we don't anticipate a lot of them happening, but when it does happen we don't have to, you know, drop everything to comply with that.

COMMISSIONER BALCH: You mentioned you were going to do some deeper portions of the reservoir.

THE WITNESS: Yes.

COMMISSIONER BALCH: I'm sure I asked you last time about whether or not that incorporated some ROZs, residual oil zones.

THE WITNESS: It does, yes.

COMMISSIONER BALCH: It does?

THE WITNESS: Yes.

COMMISSIONER BALCH: Is that part of the official Phase I test as well?

THE WITNESS: The initial Phase I did not flood the residual oil zone. It only went down to the water contact.

COMMISSIONER BALCH: It just gives you the option to do that going forward?

THE WITNESS: That's right down to the base of the unit.

COMMISSIONER BALCH: You mentioned at some point at the end of the design you will stop purchasing CO_2 and just recycle for some period of time.

Kind of my understanding is, on an injection cycle you have a loss of CO_2 in every pass. You get oil that goes into the residual water and gets stuck in the core space for the MOIOL, things like that.

And initially, that can be around 20 percent, but I imagine that pass loss is reduced over time.

THE WITNESS: It would measure in our CO_2 retention, and that's correct. That's an amount of CO_2 you inject and you have not recovered.

Initially, when we start these provisions it's a very high number and it begins to drop off rapidly, as you start to see right through the response. And then you know over time it, you know, goes away or goes to a certain limiting number.

COMMISSIONER BALCH: Okay. So when do you stop purchasing CO_2? What's your -- how close to the end of the design line for the field is that?

THE WITNESS: Yes. Again, that -- the -- you know we initially plan these things for a certain slug size of CO_2. And that's going to be the amount of pour volume we're going to inject the CO_2. And it's typical to start out with a 60 or 80 percent slug, depending on the reservoir.

You know, some slugs of greater than that can be economic and some slugs less than that cutoff because they're not economic.

And so it really just, you know, depends on whether or not the additional CO_2 you're injecting is contacting new portions of rock that you haven't contacted in the past.

COMMISSIONER BALCH: All right. On your satellites, the picture you have on Exhibit 6, I think I saw 23 or 24 production wells going into that?

THE WITNESS: Yes. So you limit the number of wells based on the test separation you have there. We want to get at least one well test per month per well. And so if you have, you know, 24 wells, you can, you know, have a little room to spare.

Some of these satellites, you know -- North Hobbs, we're actually currently adding test separators to some of our satellites because we want more than one well test per month.

COMMISSIONER BALCH: So you just have one-day well tests?

THE WITNESS: It depends. In North Hobbs now we don't get very many 24-hour tests. Usually we get 12-hour, 8-hour tests. We think we're at -- at that point we can get more frequent tests and actually a better depiction of what the well's doing. We extrapolate three 8-hour tests every month as opposed to one 24-hour test.

COMMISSIONER BALCH: I was just curious about that.

THE WITNESS: Yeah.

COMMISSIONER BALCH: Those are all my questions.

MADAM CHAIR BAILEY: Mr. Warnell?

COMMISSIONER WARNELL: Thank you.

Good morning, Mr. Brockman.

THE WITNESS: Good morning.

COMMISSIONER WARNELL: Along the lines of the CO2 questions, you've mentioned purchased CO2.

Where does the purchased CO2 come from?

THE WITNESS: We get it off the Trinity Pipeline. It runs from the Denver City hub into Hobbs.

COMMISSIONER WARNELL: We looked at a

slide -- I don't recall which slide it was, but of the North Hobbs Unit -- and we talked about a few wells on the eastern side of the unit that were old waterflood wells.

THE WITNESS: Yes.

COMMISSIONER WARNELL: You've mentioned that there were just a few of them.

THE WITNESS: Yeah. On that part of the field, you know, it's the -- the reservoir pinches out considerably. And we have a few active producers left, but we are -- we have a -- I don't think we have any active injection wells on that side of the -- I believe it's Section 34, and I can't think of the section to the north of it -- 27, I believe.

COMMISSIONER WARNELL: So could you venture to give us a number as to how many wells, active wells, that are there?

THE WITNESS: In those two sections, active wells, it's less -- it's less than 10, but I can't give you the exact number off the top of my read.

COMMISSIONER WARNELL: Okay. Thank you. I appreciate it.

THE WITNESS: Yeah.

COMMISSIONER WARNELL: And then on Exhibit 4, page 5, the field flow diagram, we looked at a nice picture or photograph of the injection satellite.

But up where we're -- in the top left-hand corner up there by producing well, we go into the first satellite.

Can you tell me what that satellite looks like? I mean you've got -- is that just a -- what I would commonly think of as a separator?

THE WITNESS: It's actually on the same picture. We actually locate our injection satellite --

COMMISSIONER WARNELL: They are both on that same pad?

THE WITNESS: -- on that same pad.

And if you look towards the -- on that same picture, the -- I guess the part closer to the bottom is the production header. And you can see the test separator and the actual production separator.

MR. FELDEWERT: You're looking at Exhibit 6, page 1?

THE WITNESS: Yes.

COMMISSIONER WARNELL: We didn't really

talk any about pressure. Have you ever done any separate tests?

THE WITNESS: Yes. Separate tests were done before -- I don't know when exactly they were done. They were done before the hearing, and initially for the Phase I.

And it -- I know South Hobbs did separate tests, several of them, in 2008.

COMMISSIONER WARNELL: So you don't have any concerns about reaching too high a pressure and cracking the rock or...

THE WITNESS: No. We -- we set our limits below the parting pressure. We give ourselves a couple hundred pounds of cushion to ensure that we don't do that.

COMMISSIONER WARNELL: And you feel you've got a good handle on the parting pressure?

THE WITNESS: Yes.

COMMISSIONER WARNELL: Those are all my questions.

MADAM CHAIR BAILEY: Operationally, it would be very convenient to have the same orders for the North Hobbs Unit as for South Hobbs Unit, wouldn't it?

THE WITNESS: Absolutely.

MADAM CHAIR BAILEY: And you've covered many of the orders -- the ordering paragraphs of Order Number R-4934-F, which was for the South Hobbs, and that you show as Exhibit 3 --

THE WITNESS: Yes.

MADAM CHAIR BAILEY: -- in your notebook.

I just want to go through those ordering paragraphs to ensure that what you have said and what our previous order says are meshed together.

THE WITNESS: Okay.

MADAM CHAIR BAILEY: The first ordering paragraph, the 4934-F says -- it talks about ongoing waterflood operations in the South Hobbs Unit.

You've also talked about ongoing waterflood operations in the North Hobbs Unit.

So would you agree that the governing provisions for the waterflood remain in operation for that part that is not being expanded?

THE WITNESS: Yes.

MADAM CHAIR BAILEY: Then ordering paragraph 2 talks about the acreage, which is obviously very different, and would have to be substituted for what your application covers.

The ordering -- let's skip down to ordering paragraph 4. It talks about injection authority for three years after the date of this order because of the scope of the operations that you do intend.

Would three years be the same that you are recommending as in paragraph Number 4 for the wells that were shown on Exhibit A?

THE WITNESS: Otherwise, they would be administrative approval.

Is that correct?

MADAM CHAIR BAILEY: Well, injection authority usually terminates after two years if there's not been --

THE WITNESS: I'm sorry. Yes. After three years, yes.

MADAM CHAIR BAILEY: Okay.

And then paragraph 5 you did cover about five years for injection wells in tertiary operations.

Do you agree with that, the ordering paragraph Number 5?

THE WITNESS: Yes, we would like to be consistent between the two.

MADAM CHAIR BAILEY: And in ordering paragraph 6, you said that you do not want to have a change of the injection pressure.

But in the -- as I recall, injection pressures are discussed in the C-108.

THE WITNESS: Yes, they are.

MADAM CHAIR BAILEY: So you would adopt those injection pressures as clarified in the application, C-108?

THE WITNESS: Yes.

MADAM CHAIR BAILEY: And then, of course, there would be the administrative authorization for any requested increase, which is ordering paragraph Number 7 on the South Hobbs Unit.

THE WITNESS: Yes.

MADAM CHAIR BAILEY: Okay. We also discussed -- or did we discuss how injection would enter only the Grayburg-San Andres and not permitted to escape to other formations?

THE WITNESS: Randy can talk about the geological...

MADAM CHAIR BAILEY: Okay. That's not your area, then?

THE WITNESS: Correct.

MADAM CHAIR BAILEY: Okay.

And Number 9, that's not your area, then.

But ordering paragraph Number 10, you referenced the finding paragraph in this order concerning placement of the packer, but you didn't reference the ordering paragraph.

Of course we look to the ordering paragraph, which says that so long as the packer, as set, remains below the top of the Grayburg formation.

And you would agree with that?

THE WITNESS: Yes, I would.

MADAM CHAIR BAILEY: Okay. And then injection through tubing and packer, that's somebody else that will talk about that?

THE WITNESS: Yes.

MADAM CHAIR BAILEY: Okay.

I guess we would then skip down to paragraph 14 for pressure testing before commencing injection operations throughout the interval from the surface down to the proposed packer center.

Is that your area?

THE WITNESS: Yes. We will do that.

MADAM CHAIR BAILEY: And you would agree to that.

And then the MIT conducted on injection wells every two years.

Did you talk about that?

THE WITNESS: I believe we will have

another witness talk about that.

MADAM CHAIR BAILEY: Another witness for that one? Okay.

But you did talk about MITs for TA wells that were equipped with pressure monitoring?

THE WITNESS: I believe we'll have another witness talk about that one also.

MADAM CHAIR BAILEY: Okay.

Skipping on down to paragraph 21, where you're asking for no limit on the gas/oil ratio. But you -- did you talk about the oil allowable, for no limit on oil allowable for the enhanced recovery?

THE WITNESS: We did not mention that.

MADAM CHAIR BAILEY: Is that somebody else?

THE WITNESS: But we would like that.

MADAM CHAIR BAILEY: You would like those?

THE WITNESS: Yes.

MADAM CHAIR BAILEY: The H2S contingency plan, I'm assuming somebody else?

THE WITNESS: Yes, ma'am.

MADAM CHAIR BAILEY: And then paragraph 23, request to certify an enhanced recovery project. That was yours, right?

THE WITNESS: No. Someone else will tell

the details of that.

MADAM CHAIR BAILEY: That's somebody else?

THE WITNESS: Someone else.

MADAM CHAIR BAILEY: Okay.

Those are all my questions.

Do you just want to make sure that operationally you have consistent requirements --

THE WITNESS: That's correct.

MADAM CHAIR BAILEY: -- across the two tertiary units?

THE WITNESS: Yes.

MADAM CHAIR BAILEY: That's all I have, then.

Do you have any follow-up questions?

MR. FELDEWERT: No. The only thing I would point out, Madam Chair, and it's -- I guess it gets to more of a legal nature on the qualification for the -- or certification of the Enhanced Oil Recovery Act.

Mr. Brockman's role was to demonstrate that it wasn't prematurely filed and will not result in recovery of additional wells. So he did touch that aspect of it.

But as you know, there's a couple of other touchstones that we have to hit, and we will with another witness.

MADAM CHAIR BAILEY: Okay. Thank you.

You maybe excused, sir.

MR. FELDEWERT: We will call our -- with your permission we will call our next witness.

MADAM CHAIR BAILEY: Please be sworn in.

RANDY STILWELL,

after having been first duly sworn under oath,

was questioned and testified as follows:

EXAMINATION

BY MR. FELDEWERT:

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

A. My name is Randy Stilwell. I'm a senior geologic advisor for Oxy.

Q. And how long have you been a senior geologic advisor for Oxy?

A. For over 20 -- I'm sorry. Since the year 2000.

Q. And how much experience do you have with the Permian Basin?

A. Over 20 years' cumulative time working the Permian Basin.

Q. Did you, Mr. Stilwell, testify before the commission for the application that resulted in the order approving the tertiary recovery project in the South Hobbs Unit?

A. Yes, I did.

Q. And at that time were your credentials as an expert witness in petroleum geology accepted and made a matter of public record?

A. Yes, they were.

Q. You have conducted a geologic study of the area that is the subject of this application?

A. Yes, I did.

Q. And did you, Mr. Stilwell, prepare some slides to assist in your presentation?

A. Yes, I did.

Q. If I turn to what's been marked as Oxy Exhibit Number 5, it contains nine slides.

Is that correct, Mr. Stilwell?

A. Yes, that's correct.

Q. And are these the slides that you prepared?

A. They are.

Q. And do Slides 1 and 2 accurately reflect your educational background, your work experience, your affiliations, and certifications?

A. Yes, they do.

Q. Okay.

MR. FELDEWERT: Madam Chair, I would re-tender Mr. Stilwell as an expert witness in petroleum geology.

MADAM CHAIR BAILEY: He is accepted.

Q. (By Mr. Feldewert) If we then, Mr. Stilwell, turn to the structure of the area and the injection zone, does Slide Number 3 provide us a good starting point?

A. Yes, it would.

Q. Okay. Would you identify this exhibit and explain what it shows?

A. This is a general pipe log from a well in the North Hobbs area.

What you see on this log is -- and down the middle a depth track with a gamma ray to the left and a porosity log to the right.

This shows all of the formations from the surface down through the authorized injection interval, which is into the San Andres interval.

On the left are all the formations that are penetrated down to that point.

And the -- one of the things I wanted to point out is that the San Andres, which will be the focal point for the map that we'll see on the next -- on the next slide -- generally comes in at about 4,000 feet depth.

Q. And what is the injection zone for the North Hobbs Unit project?

A. The authorized injection interval is the entire Grayburg-San Andres interval down to a depth of 4,500 feet.

Q. And I may have missed it. But what is the significance of the yellow shading on this particular pipe log?

A. The -- on this particular log display the yellow actually is a very thick salt section which will come out a little bit later, when I discuss the communication upwards with the freshwater zones or lack of communication.

But it -- it just shows up as a very obvious barrier between the injection interval and the freshwater zones up at the top.

Q. Now, did you prepare a structure map of this field?

A. Yes, I did.

Q. Is it hung on the top of the San Andres?

A. Yes. The structure map is on the San Andres interval. And this...

Q. So we would move to Slide Number 5 of --

A. 4.

Q. I'm sorry. Slide 4 of Exhibit 5.

A. Slide 4 is a two-dimensional structure map that was made from approximately 800 data points that penetrated the San Andres interval.

And what you see here is a two-dimensional representation of the subsurface structure.

These lines are what -- first of all, in purple is the North Hobbs Unit outline.

In blue is the South Hobbs Unit outline.

These are square sections, one-mile-square sections here.

The black lines are contours representing increasing elevations of 50 feet contour interval. So as you go from one contour up to the next you go 50 feet higher in elevation to the very crest of the structure, which actually is in the Phase II -- I'm sorry -- the expansion area, Phase I expansion area of North Hobbs.

And if -- I've got a couple of profiles that show what the structure looks like in cross-section.

Q. Did you -- what is the green? Maybe I am missing that -- the green dashed line?

A. The green dashed line is the historical producing oil/water contact in the field.

Q. Is this one continuous structure?
A. Yes, it is. Yes. It's one continuous -- we call this kind of a structure an anticline. This is one of the more simple hydrocarbon traps that you will find in the Permian Basin.
And it's one continuous structure about eight miles long containing both the North Hobbs and the South Hobbs Unit.
Q. Okay. Then I think the next animation on this is you -- it brings in a blue line.
What does that indicate?
A. So this is a line of section going along what we call the strike of the field, the length of it.
So we're going to look at a profile, so you can see what this -- what this anticline looks like in cross-section.
Q. So I'll bring in the profile, right?
A. Yes.
Q. Okay.
A. So this goes from northwest -- the very northwest end of North Hobbs to the very south end of South Hobbs. And you can see the anticlinal structure as it continues to rise to the crest and then drops off on the flanks.

Q. And that's the blue line in the bottom left-hand corner of Slide 4?

A. That's correct.

Q. Okay. And then do you have a cross-section that goes the other direction?

A. Yes. There is another line of section, we call it a dip section, that goes across the narrowest part of the field. That's the red line on here.

And if you'll pull up the profile across there, you'll see that it's a more narrow -- it goes across the more narrow portion of the structure. But you see the dips on the side, and going up to the crest of the field on top.

There's --

Q. And how -- I'm sorry.

A. There's about 300 feet of what we call closure on this structure, from the -- from the base of the structure to the top.

Q. Do you recall how many data points went into your profile line?

A. A little over 800.

Q. Okay. Do you observe any faults penetrating in this anticline?

A. No. There were no -- no mapped faults that penetrate the San Andres-Grayburg interval in the Hobbs area.

And so that -- that's what makes this structure a complete hydrocarbon trap, in that you have an anticlinal structure that's not faulted.

And as I'll show on the next slide, the last component of the trap you need is the top seal.

Q. Before we get to that, there were some tes- -- you talked about the lack of faults.

There was also some testimony from Mr. Brockman that they intend to utilize a 5-well spot pattern.

A. Yes.

Q. Do you agree that that will assist in preventing the horizontal migration of fluids?

A. Yes, I do.

Q. Okay. If we then go to your next slide.

Would you please identify and explain what it shows?

A. This is a -- this is the same pipe log that I showed before, just a detailed version of it focusing in on the authorized injection interval, basically from the top of the Grayburg down to 4,500 feet.

And again what you see on here is the top of the Grayburg, the top of the San Andres, and the producing oil/water contact historical that we saw on the previous map that includes the lower part of the Grayburg and the San Andres down to this point.

Q. That's the historical production zone?

A. Yes.

Q. Okay.

A. Yes, it is.

And if you'll notice above that point, above what we call this basal Grayburg, is a very tight section in the remainder of the Grayburg. This is several hundred feet of anhydrite and tight limestones. This forms the ultimate seal for the hydrocarbon trap as well as for any other fluids that would be entering into the system, to prevent them from going up higher.

Q. In your opinion, is that a direct dramatic change in porosity that you see here?

A. Yes, absolutely.

Q. There was a -- there was a discussion about these -- these -- this pipe log and other pipe logs in connection with the closed packer setting depth.

Do you recall that?

A. Yes, I do.

Q. Do you agree that the relief that is sought by the company, with respect to the packer setting depth, will that cause any threat to groundwater?

A. No, not at all. Because we would be setting the packer up in this -- basically this zone of no porosity that's mostly composed of anhydrites and tight limestone. So that's actually an ideal setting to put the packer.

Q. Okay. The -- now, did you do some additional cross-section work with respect to the structure?

A. Yes, I did.

If I could just point out a couple of other things.

On this pipe log you'll notice there are several other lines on here. These are zonations that we pick, correlations for various zones within the San Andres, that we can correlate across the field.

And if we go to the next slide, we can see how those carry across the field.

Q. Okay. Now, is there some animation associated with this particular slide?

A. Yes, there is.

Q. And ultimately, I guess, it results in Slides 6 and 7 --
A. Correct.
Q. -- for Exhibit 5?
A. That's exactly right.
So this slide starts out showing the field, both units. And what we're going to be looking at here is the actual cross-section composed of approximately 24 wells in both the North Hobbs and the South Hobbs Unit.
And so it -- it snakes a little bit more erratically as I try to connect some of these deeper wells through both of the units.
Q. And that's the green line that's shown in the middle of this exhibit?
A. That's correct. It goes from northwest to southeast.
Q. And the next animation, I think, takes that away, correct?
A. Correct.
Q. Down into the left-hand corner?
A. That's right.
Q. Okay. And what do we show now?
A. So what we're left with here is this cross-section that is a structural cross-section.

This is the way that it would actually be in the subsurface.

And what you see here is -- the top of the Grayburg interval is this purple line. And so between there and the yellow line, the lower Grayburg, is this impermeable anhydrite and limestone interval. And you can see that it's very continuous across the field.

You get down past the Grayburg into the San Andres interval, there is a thin tight zone at the top of the San Andres.

And then you get into this green area here, which is all the San Andres interval that's within the historical producing oil/water column or contact.

Q. How thick is that impermeable line, approximately?

A. It's approximately 200 feet thick.

Q. Does that include the --

A. Oh, I'm sorry. Let me correct myself.

Are you talking about the dolomite or --

Q. Yes, the dolomite.

A. The dolomite is anywhere from 10 to 50 feet thick.

Q. Okay. And then I think you were

representing what was around 200 feet there?
A. Yes. That's the upper Grayburg anhydrites and tight limestones.
Q. Okay. And again, these barriers exist, why? Because you show the North Hobbs Unit over to the left and then you show the South Hobbs Unit over to the right of this exhibit.
A. Yes, that's correct. I've denoted here on the top of the cross-section the actual area that includes the North Hobbs Phase I flood, the previously-approved South Hobbs Phase II flood -- I'm sorry -- the South Hobbs flood.
And then the area in between would be a portion of the Phase I flood expansion area.
Q. And some of the Phase I expansion area would go to the left, correct?
A. That's correct.
Q. The left of this particular exhibit?
A. Yes.
Q. Okay. Anything else about this?
A. No.
Q. Okay. Then I think you did an analysis of the freshwater zones, correct?
A. I did.
Q. If I go to what's been marked as Slide 8

of Exhibit 5, would you orient us to this exhibit, please?

A. Yes. This is a summary of all the freshwater analysis data that I accumulated from the office of the state engineer.

So what you see here is a map of the sections that encompass North Hobbs. And within each of the sections is a box that summarizes the data that is examined for this area.

So what I did was, there were over 1,250 water well data records in the vicinity of North Hobbs that I examined. And the majority of these were very shallow wells that reached their total depth in, typically, what would have been in the first water sand that they encountered. So a lot of those were discounted, as far as trying to define the base of the freshwater zone.

So by continuing this kind of analysis, I'm looking at seeing which wells actually penetrated all of the water sands and got down to what we call the Triassic red beds, which are a very distinctive red shale, red clay interval that pretty much defines the base of all those freshwater zones.

And so there were 179 of these deeper wells that are highlighted in all of these little squares on the sections that I believe penetrated the entire freshwater zone.

And in summary, in the North Hobbs area, this ranges from the depth of 190 to 245 feet from the surface.

Q. And that result -- that conclusion results from an analysis of 179 wells that met your criteria of going all the way into the -- through the entire freshwater zones?

A. That's correct.

Q. Okay. Then if we will turn to Slide Number 9, is this, again, a pipe log from the North Hobbs Unit that adds the location of the freshwater zone?

A. Yes. This is the same pipe log that I showed in the first slide. And again, it's a gamma ray porosity log and then the formation is on the side.

And what I've -- what I've noted here on the right side of the log are annotations regarding each one of those major zones.

Starting from the surface you've got your freshwater zones in the top, basically, 200-foot interval.

Below that are the Triassic red beds,

which are predominately impermeable shales.

You have your Rustler anhydrite, which is an impermeable anhydrite.

And below that is this very thick solatto salt section that we discussed previously, which are impermeable salts and shales.

And then finally, the discussion that we had previously on the detailed log, the 200-foot thick anhydrite and tight limestone section, sitting at the very top of the Grayburg section.

Q. Is that the primary seal for this injection zone?

A. It is. It's the primary seal for the hydrocarbon accumulation and for the injection.

If that -- if that seal weren't competent there would not be an accumulation here at Hobbs.

Q. Okay.

A. So my conclusion from all of this would be that there -- because of all of the -- there's about 3,500 feet, approximately, of formation rock between the injected interval and the surface. The great majority of that is comprised of impermeable formations.

And so there should be no natural occurrence of any vertical communication going on between the injected interval and the freshwater zones at Hobbs.

Q. Okay. Were the slides comprising Exhibit 5 compiled by you or under your direction and supervision?

A. Yes, they were.

MR. FELDEWERT: At this point, Madam Chair, I would move the admission into evidence of Oxy Exhibit Number 5.

MADAM CHAIR BAILEY: It's accepted.

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

MADAM CHAIR BAILEY: Commissioner Warnell, do you have any questions?

COMMISSIONER WARNELL: I think I have one question for Mr. Stilwell.

When you look at the -- let me figure out which slide you were on. I guess the cross-section, page 6, the upper Grayburg.

THE WITNESS: Yes.

COMMISSIONER WARNELL: If you're going to allow the packer to be set anywhere below the top of the Grayburg, I believe --

THE WITNESS: Yes.

COMMISSIONER WARNELL: -- how does -- I

mean, the top of that Grayburg varies from the northwest down to about the middle of it, the North Hobbs Unit and the South Hobbs Unit.

There's quite a variance there, like 4- or 500 feet?

THE WITNESS: As far as thickness goes?

COMMISSIONER WARNELL: Yes.

THE WITNESS: Yes.

COMMISSIONER WARNELL: As far as the top goes.

THE WITNESS: Well, we would -- we would use the adjacent log -- I mean, we would look at the log information.

COMMISSIONER WARNELL: You would take an offset log --

THE WITNESS: Absolutely.

COMMISSIONER WARNELL: -- closest to the well that you were getting ready to set your packer on?

THE WITNESS: Yes. And that's typically what we do whenever there -- any time the production engineers are having to reset the packers, typically they'll come to me and we'll pull up a cross-section of the adjacent wells, and we'll look and see, you know, what the formations look like around there.

COMMISSIONER WARNELL: Thank you.
I have no further questions.
MADAM CHAIR BAILEY: Mr. Balch?
COMMISSIONER BALCH: Just one. Maybe just a clarification, Mr. Stilwell.
THE WITNESS: Yes.
COMMISSIONER BALCH: And good morning.
THE WITNESS: Good morning.
COMMISSIONER BALCH: So you have four seals in your primary seal that prevent migration of any injected fluid from the reservoir up to the freshwater interval?
THE WITNESS: Yes.
COMMISSIONER BALCH: And there's no faulting in the anticlinal feature which defines the field boundaries?
THE WITNESS: Correct.
COMMISSIONER BALCH: So really, the only possible avenue -- and I know you can't address this -- would be through penetrations of wellbores.
THE WITNESS: Yes. That's exactly right.
COMMISSIONER BALCH: And I presume that will be addressed by a later witness?
THE WITNESS: It will.
COMMISSIONER BALCH: That is all I have.

MADAM CHAIR BAILEY: Exhibit 5, page 8, has the basin freshwater zone?

THE WITNESS: Yes, ma'am.

MADAM CHAIR BAILEY: In particular, I'm looking at 18 South, 38 East, Section 33.

THE WITNESS: Yes, ma'am.

MADAM CHAIR BAILEY: Where it shows the base of the freshwater 193 to 227 feet?

THE WITNESS: Correct.

MADAM CHAIR BAILEY: One of the wells that was listed in the C-108 is 84 years old and doesn't cover the entire water zone.

THE WITNESS: And that will be addressed in detail.

MADAM CHAIR BAILEY: Okay. That's a later witness?

THE WITNESS: Yes, it is.

MADAM CHAIR BAILEY: Okay.

Then I will go through the same exercise with you that I went through with the previous witness, Mr. Brockman, concerning the order for the South Hobbs Unit to ensure that the order is consistent --

THE WITNESS: Sure.

MADAM CHAIR BAILEY: -- between the two

units.

And I'm looking for those requests, or that testimony that you gave concerning these ordering paragraphs.

Okay. We were down to paragraph 8.

You did not talk about escape to other formations, or did you, to the surface from injection?

THE WITNESS: Yes. I believe the last slide, Slide 9, addressed that issue.

MADAM CHAIR BAILEY: Okay. So ordering paragraph 8, where it says the operator shall take all necessary steps to ensure that the injected gases and fluids enter only the Grayburg and/or San Andres and are not permitted, you agree to that one?

THE WITNESS: Yes, I do.

MADAM CHAIR BAILEY: Okay. I don't, right offhand, see any of the other ordering paragraphs.

MR. FELDEWERT: That's paragraph 10, dealing with the packer setting.

MADAM CHAIR BAILEY: Yes.

The injection will be accomplished through fiberglass tubing and nickel-plated packers.

You did talk about the packers. So is

that going to be a nickel-plated packer?

THE WITNESS: That is probably not best addressed by myself. I think the packer setting was in reference to the formation.

MADAM CHAIR BAILEY: Top of the Grayburg?

THE WITNESS: Yes.

MADAM CHAIR BAILEY: All right. Okay.

THE WITNESS: And that it would be a competent formation to set the packer in, that whole interval.

MADAM CHAIR BAILEY: Okay.

Those are all my questions.

Do you have any followup?

MR. FELDEWERT: I do not.

MADAM CHAIR BAILEY: Then you may be excused.

THE WITNESS: Thank you.

MADAM CHAIR BAILEY: Would you call your next witness?

MR. FELDEWERT: Yes, Madam Chair.

We'll call our third witness.

SCOTT HODGES,

after having been first duly sworn under oath,

was questioned and testified as follows:

EXAMINATION

BY MR. FELDEWERT:

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

A. My name is Scott Hodges. I'm employed by Oxy, and I'm operations team lead in the North Hobbs and the South Hobbs Units.

Q. How long have you been responsible for the operations at the North Hobbs Unit and the South Hobbs Unit?

A. I've been there right at three years.

Q. And exactly what are your responsibilities as the operations team lead?

A. As operations team lead, I oversee the operations on a daily basis to make sure -- for the monitoring and the safety and the wellness of people around us that -- our employees.

I'm also involved in these projects on a design basis, the installation and initiation of the project, as well as operations after those phases are through.

Q. And then are you also involved in the monitoring of that?

A. Yes, I am.

Q. Did you, Mr. Hodges, testify before this commission last year in connection with Oxy's application to convert the South Hobbs Unit from a waterflood to a gas injection project?

A. Yes, I did.

Q. And at that time, did you discuss with the commission in detail the SCADA system that's used by Oxy to monitor the operations out there?

A. Yes, that is correct.

Q. And the SCADA stands for what?

A. Supervisory control and data acquisition, an acronym.

Q. What will you be addressing with the commission here today?

A. I'll be talking about the operations, the monitoring that we do, the safety aspects that we have in place.

I'll also be talking about the frequency of the MIT testing for the TA wells, and also our corrosion mitigation program.

Q. Okay. And in preparation for your testimony here today, did you prepare the slides or assist in preparing the slides that have been included in Oxy Exhibit Number 6?

A. Yes, I did.

Q. And that contains approximately 14 slides? Or it contains 14 slides, correct?

A. That is correct.

Q. If I turn to Slide 1 -- there's already been some discussion about this.

This depicts a current -- what you call satellite facility at the North Hobbs Unit.

Is that correct?

A. That is correct.

Q. Why don't you give the commission -- first of all, do you know how many of these currently exist in the North Hobbs Unit?

A. Yes. We currently have seven satellites constructed in this same manner.

Q. So they are all constructed in the same fashion?

A. That's right.

Q. And they are all fenced?

A. Yes, they are.

Q. Okay. And why don't you give the commission an idea of what types of equipment are on each of these existing satellites.

A. Okay. On these satellites, as it was mentioned, they are all fenced with a chain link fence. They have razor wire above them for security.

As you'll see on this -- in this picture, the injection header, this is a combination of lines that go to each well in our injection system, but the header is all located in this one spot right here on one side of the satellite.

On the bottom part of it is where you have all the producing wells that come into one location.

This vessel right here is a production vessel. And the smaller vessel to the left of it is our test vessel.

This -- this building right here contains all of the automation for the injection system. It has an Allen-Bradley programmable logic controller, or PLC, as we call them.

It also has LOIs, which are lease operated interface, where our employees can go into this building and they've got full access on a touch panel of that PLC.

On this side of it, for the production side of it, we have a number of monitoring devices and safety devices along with the injection.

And for the production side, this panel right here contains that -- the PLC for the production side.

Q. Now we have some additional pictures, for example, of the injection headers, correct?

A. Yes, we do.

Q. Okay. Before we get to that, I want to touch a little bit on the SCADA system, which is -- as I understand it -- isn't part of what you have in the shed.

A. That's correct.

Q. Is that right?

A. Yes.

Q. Okay. And why don't we turn to what's been marked as Slide Number 2.

And would you just -- and I know you talked about this last year. But why don't you just remind the commission again about what the SCADA system actually does within the company and for the unit, I should say.

A. The SCADA system uses information technology to provide realtime monitoring and control of remote facilities.

On the graph, you can see on the left -- we have input from sensing devices on our equipment.

And these consist of the temperature and water content pressure monitors, H2S monitors, and also gas analysis.

These -- these devices speak to a radio system. Sometimes they are gathered through radio telemetry. Some are gathered through a fiberoptic cable.

They speak to the SCADA system, which will go back to the control devices which include shutdown valves, chokes, pumps, compressors. All of our equipment has some type of automated control.

And then we also get a human notification. We get alarms to let us know that something is -- is outside the parameters we've set on it. We get callouts on those.

We also have graphic screens in each one of our production techs' pickups through a laptop computer. They can pull this all up. They can operate everything from their pickup, from their house, from the office, or from the location through these graphic screens.

We also gather historic data. So if -- we can look and we can trim things based on the history, to see if we've got stuff that's moving outside the parameters or aging equipment or whatever we need to look at. But we can see that on our historical data.

Q. And does the -- does this system also trigger automatic shudowns if the parameters are exceeded?

A. Yes, it does.

Q. And SCADA is basically what ties everything together?

A. That's right.

Q. All right. Then let's talk a little bit about your sensing devices that are on your equipment and tied together with the SCADA system.

If I turn first to what's been marked as Slide Number 3, this is at -- this is a depiction of your injection facilities at one of these satellites?

A. Yes, it is.

Q. Okay. Why don't you explain to us what is depicted here.

A. Well, in this picture right here you have got this -- this -- every one of these are designed the same, so I'll just stick with this one closest to us.

You've got a stainless steel line that takes the injection fluids and sends it to the well through this system right here.

Right here on this, you have a meter with a multivariable transmitter on it. And this calculates several different things based on pressure differential, temperatures, and actually sends a signal back to a -- to the PLC which, in turn, sends a signal back to this choke right here to adjust it for -- to make sure we stay within the parameters of that injectant that we want going downhole.

The system is set up for a failsafe design. So if we lose power, we lose communication, whatever we lose, this choke right here will automatically go shut to eliminate any more fluids or gas to go into the injection line.

The things that we get alarmed on, as operators, is either a low or a high manifold pressure at this facility, a low or high tubing pressure at the well because the -- as we'll see in the next slide, I believe, we have a well site that has fiberoptic coming back to the same PLC to let you know what's going on at the well, so we get realtime information, data from the well, in the transmitters at the well.

A power loss or communication failure, and

then also a transmitter fault.
Q. Okay. Now, this is a -- is this setup the same for all of your satellites?
A. Yes, it is.
Q. And will it also -- will you also have these same control measures at all of the new facilities?
A. Yes, we will.
Q. Okay. When you mentioned the wells, the injection well sites, let's go to Slide Number 4.
And is this a depiction of a typical injection well site at the North Hobbs Unit?
A. Yes, it is. If we follow this yellow flow line here, this is the actual gas or -- or liquid coming from the -- this injection satellite.
It comes aboveground here because we have a pressure and a temperature transmitter on the line. It gives us an idea of what this tubing pressure is and what the temperature of that injectant is.
It is communicated to a PLC located on this location, and then fiberoptic back to the satellite.
So we, as close to realtime as you can possibly get, the fiberoptic tells us what's going

on at the well site so we can make the adjustments at the injection header.

This gas continues back underground across the location, and then it comes up and goes into the tubing here on the well site.

This -- this transmitter on -- the casing pressure transmitter is tied also into the SCADA system and lets us know, if we did have a tubing failure or a packer failure on this well, the pressure would go up on your -- on your annulus and it would send a signal to immediately shut any injectant off going to that well.

Q. Do you also have devices to prevent backfill?

A. Yes. If we happen to -- had a leak, a breach of this line, we do have a very robust designed check valve here at the top of the well that would prevent any fluids from coming back -- flow back from the well.

Q. And, Mr. Hodges, will the company have a similar setup for all of the new injection wells at the expand- -- in the expanded Phase I area of the North Hobbs Unit?

A. Yes, sir. In a sense of consistency, everything will be designed the same for the new equipment as we currently have in place.

Q. Okay. Then let's turn to the next facility, which will be the production well setups.

And that's Slide 5 of Exhibit 6?

A. That's correct. This is one of our typical ESP wells, and that's an electronic submergible pump.

And this well runs -- the pump actually runs in the bottom of the well via an electric cable that is banded to the tubing all the way down. And I'm sure you-all are familiar with that.

But all of our -- 95 percent of our wells right now in Hobbs are pumped with an ESP.

So we've got a well here that is pretty much contained and doesn't have a polish rod, doesn't have -- you know, the pumping unit on it.

As you can see, we have a casing pressure transmitter that reads our casing pressure on a continual basis, and we also have a tubing pressure transmitter. These two come together to go into the flow line.

On each one of these, these transmitters communicate via radio and these towers right here back into our SCADA system. We capture those in our -- on our laptop, so it's visual screens that we have. We have a program called Graph Works. I think we've got a picture of that later.

But actually, we have several different functions. We can capture that data in Graph Works, we can trim it.

But we also have alarm points set on these that will notify us, as operators, if we have either a high or a low pressure in either place.

And then it's -- it's not just notification to us, but this ESP panel in the background here is the electrical source for your ESP pump. And if we do have one of these transmitters that gets outside the logic that we have programmed into them, it will shut off the electricity to that pump and shut that pump down.

Q. Now, these pressure monitoring devices that we see both at your -- on this equipment -- your injection headers, your injection wells, your production wells -- does that also assist the company in monitoring or guarding against any H2S releases?

A. It alerts us when we have a potential problem. And it will let us -- we can -- we can trend it and see what's happening there. And -- but yes, it will notify us.

Q. Okay. And then in addition to these realtime monitors, does the company also have H2S detection devices at strategic locations?

A. Yes, we do.

Q. And if I could turn to what has been marked as Slide Number 6, does this depict one of those detection devices?

A. Yes, it does.

This is a remote H2S monitor. And at each one of our facilities, our satellites and our batteries, we -- we have them strategically placed around to pick up any fugitive emissions of H2S.

Q. Okay. Let me stop you right there, because you mentioned at all of them.

Because when I look at the first bullet point, it says at the RCF and then at selected CO2 flood satellites and batteries.

Was that the wrong word selected?

A. Yes, it is. We have placed these CO2 -- or H2S monitors at all of our facilities.

Q. Okay.

A. And we will continue that in our new design. All of them will have the H2S detection.

Q. And this -- when these -- if this alerts, you have shutdown procedures?

A. Yes, we do. The monitor, when it reaches 10 parts per million, it initiates an emergency shutdown of that facility.

It will -- this, for the people that are -- might possibly be on location, this has a blue beacon that goes off to alert you that there is an H2S condition.

And we also get a callout to all of our Oxy personnel to respond to this site for a potential H2S, for leaks.

Q. And all of these monitoring devices that you've mentioned, it's all tied together with SCADA, right?

A. That's correct.

Q. Okay. Then let's turn to Slide 7 and discuss how you access that and utilize that data.

A. Okay. Well, some of the communication in our SCADA system is fiberoptic, but it's also via radio.

And this communication comes through these systems, goes to Graph Works as a host system there at our office.

When we get that alarm we also have a server. It's is an alarm server. It sends an alarm to our answering service, which notifies us that we have an alarm.

But at the -- at the facilities, all of our alarms -- I mean all of our communication is via hardwire. We don't -- we don't have any of our H2S stuff that's wireless. We do everything by hardwire. It's -- that way we don't have any interruption of a radio system. It's all tied in solid, so we will get that shut down.

Q. And then this indicates that you reference all of this information through Graph Works?

A. Yes.

Q. So what is that, a -- well, if you will go to Slide Number 8, is that a depiction of the Graph Works screen?

A. Yes, it is. This is just a graphical presentation of all of our facilities and what we bring in through our automation and our monitoring system.

And we have every well in North and South Hobbs come into Graph Works, every tank battery, every tank that we have, every pressurized vessel. And even some of our lines are -- are on this, come in as data acquisition points.

Q. And can this system be accessed both with laptops and desktops?

A. Yes, they can be. A laptop, desktop. I can even access it on my iPhone. It's a little tough because it's small, but we can get access through any communication system that will hit -- hit the internet or a network system.

Q. Do you remember those sheds that you saw on the satellite that you pointed out?

A. Yes.

Q. Okay. If we turn to Slide Number 9, does this depict some of the monitoring equipment that is within each one of those sheds?

A. Yes, it does.

Q. Okay. What does this do?

A. This is the PLC that I talked about earlier. It's a programmable logic controller. And it is a computer that works on-site. These screens right here are -- are just a, you know, display of what's going on in the computer, much like your monitor on your computer at your desk.

It is a touchscreen, so we can -- we can do anything we want to, scheduling -- you know, we can't change the parameters in here. That's -- we can if we have the proper documentation, the proper analysis done.

But this is a -- this is where our

production techs and injection techs come on a daily basis to change wells and WAG cycles and to monitor their equipment on location with these screens.

Q. What is WAG?

A. WAG is a water alternating gas or water and gas. I don't know the exact.

But when we inject into these injection wells we have different cycles. We'll pump so many days of just water into this well, and then we'll switch it over to gas for so many days. So we call that a WAG cycle.

Q. Now, you've mentioned you have constant monitoring of this data through your Graph Works?

A. Yes, we do.

Q. It is done by your field personnel?

A. That's right.

Q. What do you do at night?

A. We actually have personnel in the field 24 hours a day. So we have night riders that work at night to monitor this equipment.

But along with that we also have a well analyst that is at a remote location. He also sees a lot of this data.

And then we have, you know, our alarms coming into a 24-hour manned alarm center.

Q. How long has this monitoring system been in place at the North Hobbs Unit?

A. This was a -- this was put in place with an initiation in 2003 of the CO2 flow.

Q. And has it worked well for the company?

A. Yes, it has. We have a very good success rate. It's a very state-of-the-art. We -- most of our transmitters are things that -- solid state. So if we have a failure it gives us a notification that we have a failure of that piece of equipment or that transmitter.

So we -- we have a very, very low failure rate on this equipment.

Q. And does the company intend to continue to use this type of equipment for the expansion of it?

A. Yes, we do.

Q. Okay. Now, I want to talk a little bit about corrosion management.

And first off, is the monitoring that you do with your SCADA system, does that assist with, you know, managing corrosion issues?

A. Yes, it does.

Q. And how is that?

A. Well, temperature and water content are -- you know temperature can -- fluctuations, we've got parameters we keep that in to keep condensation down. And so monitoring the temperature, water -- water content at the RCF, and the gas analysis at the RCF, we monitor those so we can -- we can determine whether we are creating a situation that might be a potential corrosion point.

Q. In addition to that, does -- no, let me step back.

You mentioned that you were -- as the operations manager, you're involved in the design, the fabrication, and essentially the management and maintenance of this equipment?

A. That's correct.

Q. Okay. So in addition to monitoring the water content and the temperature in the system, does Oxy, at the outset, follow certain standards when they are designing or when they are fabricating and then maintaining this -- these surface facilities?

A. Yes, we do.

Q. Okay. And were you present last year when Mr. Charpoy testified at length before the commission about the standards that Oxy uses in the design, fabrication, and maintenance of their facilities?

A. Yes, I was.
Q. Okay. And do you recall that he also testified that Oxy's major capital projects like this utilize a team of subject matter experts that draw from their worldwide expertise?
A. Yes.
Q. And is that same team, Mr. Hodges, involved in the design, the fabrication, and installation of the equipment that's going to be used for this expansion project?
A. Yes, they are.
Q. As the operations manager, are you familiar with NACE Standard MRO 175?
A. Yes, I am.
Q. If you'll turn to what's been marked as Slide 10, is this the provision from the division rules that require those standards to be followed when you -- when you are dealing with potentially hazardous hydrosulfide volumes?
A. Yes, that is correct.
Q. Okay. And does that standard essentially identify the materials and the procedures that are to be used for the installation of surface equipment?
A. Yes, it does.

Q. In addition to MRO 175 does Oxy, as a company, draw upon other standards?

A. Yes, we do.

Q. And if I turn to what's been marked as Oxy Exhibit Number 11, does this outline the various standards that the division utilizes -- I'm sorry -- that Oxy utilizes when it is designing and fabricating the -- its equipment for these types of projects?

A. Yes, we do.

Q. And for example, what is ASME on this Oxy Slide 11 of Exhibit 6?

A. That's the American Society of Mechanical Engineers.

Q. And then API is American Petroleum Institute?

A. That is correct.

Q. Okay. And do these additional standards essentially provide guidelines and checklists that assist in maintaining the integrity of this surface equipment?

A. Yes, they do.

Q. And does the -- will these provisions be utilized in the design, fabrication, and maintenance of the additional facilities that Oxy will install as part of the Phase I expansion?

A. Yes, they will. They will follow the same standards that we have previously in the field.

Q. Now, the maintenance standards that the company utilizes.

Is your group responsible for those procedures?

A. We don't write those procedures. Worldwide engineering hands those procedures down to us, the mechanical integrity, and we ensure that these maintenance procedures are followed and conducted on a periodic basis.

Q. Okay. Now, this deals with surface facilities.

How does the company intend to address corrosion mitigation downhole?

A. The methods we use downhole are the same, with compliance with NACE.

Q. So if I go to Slide 12, does this identify the provisions that the company utilizes?

A. Yes, that is correct. We use injection tubing that is fiberglass line that prevents corrosion on that tubing.

Injection packers are nickel-plated carb steel. I know you asked that question before. And they are nickel plated.

And then our annulus is filled with an inert packer fluid which includes a combination of corrosion inhibitors and biocide.

Q. Is that being done now for the North Hobbs Unit?

A. Yes, it is.

Q. And will that continue to be done as you move -- expand the gas injection in the North Hobbs Unit?

A. Yes, it will be.

Q. If I have you turn to Oxy Exhibit Number 3, the commission's order that was issued last year.

And if you would go, Mr. Hodges, to page 12 of that order.

These would be watering paragraphs.

And I want you to look at watering paragraph 11. That talks about the -- filling the casing tubing annulus with inert packer fluid.

Do you see that?

A. Yes, sir.

Q. And will it contain biocide and corrosion inhibitors?

A. Correct.

Q. Okay. And then if you will look, for example at paragraph 12, there's provisions in there that require the use of a special type of cement.
Do you see that?
A. Yes, I do.
Q. Okay. And does Oxy intend to follow those procedures with respect to its -- these injec- -- these new injection wells?
A. I have been informed that that's -- that is the procedures in our drilling program.
Q. Okay. You mentioned that -- well, I think there's been testimony that the gas injection in the North Hobbs Unit started in 2003, right?
A. Correct.
Q. And the company has followed its protocols and the standards that we just reviewed in the design, fabrication, and maintenance of those facilities since that time?
A. That's correct.
Q. So we're talking about ten years, right?
A. Right.
Q. Did the company conduct an extensive MIT -- mechanical integrity inspection, I guess, right?
A. Right.

Q. Recently?

A. Yes. In August of 2012 we took every pressurized vessel that we have in North Hobbs in the CO2 project. We externally inspected those with a V-scan program.

We went internally and did a grid test inspection of the internals of each vessel that we have in North Hobbs.

During this time we had had a shutdown in North Hobbs to do some other work, so we took that opportunity. But it was also in compliance with the ten-year inspection period.

But during all of the inspection we did not -- we found no anomalies and no variances to the specifications that they were looking for. So we had no corrosion on any of those vessels for a ten-year period.

Q. Then I want to talk about the last topic you were going to address, and that's the mechanical integrity test frequency for TA wells.

A. Right.

Q. And if I turn to Slide 13.

Mr. Hodges, this is the division's current rule that provides that -- that you can place a well in temporary abandonment status following an MIT for a period of up to five years.

Do you see that?

A. Yes.

Q. Okay. So that rule, at least, contemplates that in some circumstances a well can remain in TA status without an additional MIT for a period of up to five years?

A. Right.

Q. Does Oxy intend to place realtime pressure monitoring devices on TA wells as you move forward with this expansion project?

A. Yes, we will.

Q. And do those -- are those realtime pressure monitoring devices connected to your SCADA system?

A. Yes, they are.

Q. And will they provide constant realtime pressure information?

A. Yes, they will.

Q. Okay. And does Oxy, therefore, request that for those wells which are TA, and which they have these types of equipment installed, that the division allow up to five years before another mechanical integrity test is done?

A. Yes, we do.

Q. And if I turn to Slide 14, is that the -- kind of the outline of the request that you seek with respect to these -- this MI -- MIT testing period?

A. Yes, that is correct.

Q. Now as part of that, though, the company, as it states in here, is going to continue with this annual Bradenhead test.

Is that right?

A. That is correct.

Q. Okay. Then if I go to Exhibit Number 3, and I go to page 13 of the -- of the division's order from last year, and I turn to -- and I look at ordering paragraph 16 on page 13.

A. Yes.

Q. Is that the relief that the company likewise requests for the expanded Phase I area in the North Hobbs Unit?

A. Yes, that is correct.

Q. All right.

Then are these slides that comprise Oxy Exhibit Number 6, were they compiled by you or put together under your direction and supervision?

A. Yes, they were.

Q. Madam Chair, at this point, then, I would move the admission into evidence of Oxy Exhibit Number 6.

MADAM CHAIR BAILEY: It is admitted.

MR. FELDEWERT: That concludes my examination of this witness.

MADAM CHAIR BAILEY: Commissioner Balch, do you have any questions?

COMMISSIONER BALCH: It's still good morning, Mr. Hodges.

THE WITNESS: I'm sorry?

COMMISSIONER BALCH: It's still morning, so good morning, Mr. Hodges.

THE WITNESS: Good morning.

COMMISSIONER BALCH: I know we had this discussion with regards to the South Hobbs last summer.

But the composition of the produced gas, do you have a -- could you outline that composition for me?

THE WITNESS: The composition of the produced gas?

I don't know it all. I know that we've got -- it's about 82 percent CO2 coming back. We do have, you know, the NGLs in it that we extract at our RCF. I don't know the exact composition of that, but I know we do have a gas chromatograph that reads that composition.

COMMISSIONER BALCH: What about the H2S?

THE WITNESS: H2S? We have about 1 percent H2S coming into the RCF and about 1 -- 1.1, 1.2 leached.

COMMISSIONER BALCH: So you strip out the liquids, and then you are reinjecting methane, H2S, and CO2?

THE WITNESS: Yes.

COMMISSIONER BALCH: Primarily CO2?

THE WITNESS: Yes, sir.

COMMISSIONER BALCH: The separator tests that go on at the satellites.

Mr. Brockman indicated those would be about 12-hour tests?

THE WITNESS: Right.

COMMISSIONER BALCH: Typically speaking?

THE WITNESS: Right.

COMMISSIONER BALCH: In your opinion, is that enough time to get an adequate separation of all of those fluids and gases?

THE WITNESS: Yes, I think so. It's pretty -- it's indicative of what's going on. And we -- when we get those shorter tests sometimes what we're trying to see is the gas rate, and is the GOR out of line for what we want to produce.

Can we find a more economical well, you know, with a lower GOR that will -- so within 12 hours -- and we usually see it pretty quick. But I would say that 12 hours is very representative of what that well will produce for a 24-hour period.

COMMISSIONER BALCH: On your injection planning map, most of the new CO2 is coming in kind of on the southeast portion of the North Hobbs Unit, and it looks like it's being injected along that southeast mar- -- or south/southeast margin of the North Hobbs Unit, and all of the reinjected produced gas is going in northwest of there.

Is there a particular operational reason why all of the new CO2 is coming in on one end of the field and the reinjected gas on the other end?

THE WITNESS: Well, Mr. Brockman might be better to answer that.

But I do know that we have an internal policy with Oxy that we do not inject any sour CO2, which is produced gas with CO2, inside the city limits.

COMMISSIONER BALCH: Okay. So all the fresh CO2 is going in where you're --

THE WITNESS: The sour produced is going in outside the city limits.

COMMISSIONER BALCH: Thank you, Mr. Hodges.

MADAM CHAIR BAILEY: Mr. Warnell?

COMMISSIONER WARNELL: Just one or two questions, I believe, for Mr. Hodges.

What's the electrical backup system if the grid goes down in Hobbs and you lose all power?

THE WITNESS: If the electrical supplier goes down?

COMMISSIONER WARNELL: Yes.

THE WITNESS: Everything in our field will go to a failed closed position, so we are completely down.

COMMISSIONER WARNELL: Do you have generator backups to bring them back up, or you're just at the mercy of the power company waiting for...

THE WITNESS: Right now our -- all of our PLCs in the field have battery backup that are solar powered.

Our server at our Hobbs office and our tower that contains our SCADA both have generators for backup.

COMMISSIONER WARNELL: So if you did get an alarm in the middle of the night or on the weekend or holiday and something shuts down, what happens then? Who gets notified? You don't have people out in the field, you have people working 24/7, 365, monitoring remotely?

THE WITNESS: Yes. sir. Well, we actually have somebody in the field 24/7, 365.

COMMISSIONER WARNELL: So there would be boots on the ground. Somebody would go out to that particular well site or well?

THE WITNESS: That is correct.

COMMISSIONER WARNELL: And then does he have the ability, the responsibility, to get that system back up and running or who turns the alarm off and the system back on?

THE WITNESS: That person that's in the field, when he gets the notification, he will go to that location.

But he will also call -- we have two other people on call. We have a first out and a second out for weekends and nights.

And he will call for a backup. We don't go into an environment that might have potential H2S without a backup, and we'll air up and look for the situation.

Once they -- they find and mitigate the situation, then they have the ability to clear that alarm and go ahead and bring that system back online.

So it's really not -- that one person is first on the scene to assess it visually from a safe distance, and waiting on -- and our response time in Hobbs is, with a backup, with a first out and a second out, is -- since we're so close it's five to seven minutes.

COMMISSIONER WARNELL: Thank you.

I have no further questions.

MADAM CHAIR BAILEY: You have razor wire around the satellites. But how bad is vandalism, since you're so near a population center?

THE WITNESS: Vandalism and theft are a problem. And you know we lock our facilities but, you know, people will cut fences and get in. We don't have it happen very often.

But most of -- most of our vandalism is, you know, where people are stealing small pieces of copper. As far as anybody sabotaging any of our facilities, we have never had that happen.

MADAM CHAIR BAILEY: Following up on

Commissioner Warnell's questions, I vaguely recall that you had two night riders when there was testimony for the South Hobbs Unit.

Are you planning on increasing the number of night riders?

THE WITNESS: Yes, ma'am, we are. I -- I haven't got complete approval on that yet, but that is our plan whenever we go into South Hobbs and initiate that CO2 flood.

MADAM CHAIR BAILEY: Okay. Let's go through the exercise of the orders.

THE WITNESS: Okay.

MADAM CHAIR BAILEY: On paragraph 9 of Order Number R-4934-F concerning the South Hobbs Unit, there is a requirement for a one-way automatic safety valve installed at the surface of all injection wells to prevent flowback.

Do you agree with that for the North Hobbs Unit?

THE WITNESS: One-way safety valve?

MR. FELDEWERT: That's on page 12?

MADAM CHAIR BAILEY: On page 12 of the order.

MR. FELDEWERT: Then paragraph 9.

THE WITNESS: I don't believe that that's

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the same for the -- for the remote injection wells that we're going to have in this North Hobbs expansion.

MADAM CHAIR BAILEY: What are the provisions to prevent flowback during an emergency startup or shutdown?

THE WITNESS: That would be our robust design of the check valve on our wellhead.

MADAM CHAIR BAILEY: The check valve is an automatic safety valve?

THE WITNESS: No, ma'am.

MADAM CHAIR BAILEY: What is the difference?

THE WITNESS: I'm trying to absorb this, if you'll just give me a second.

MADAM CHAIR BAILEY: Sure. Take your time.

THE WITNESS: Well, in looking at the way -- we will have an automatic safety valve on each one of our injection lines.

MADAM CHAIR BAILEY: At the surface of all injection wells?

THE WITNESS: It will be at the injection header.

MADAM CHAIR BAILEY: Will it accomplish

what paragraph 9 here is attempting to do?

THE WITNESS: No, ma'am. I believe that the automatic safety valve that that's referring to is the check valve at the wellhead.

MADAM CHAIR BAILEY: So --

THE WITNESS: And that will be installed on each and every injection well. That is correct, in that terminology.

MADAM CHAIR BAILEY: Okay.

Are you the right person to talk about paragraph 13 for cement bond logs run prior to injection, or is that somebody else?

THE WITNESS: No, ma'am. That would be somebody else.

MADAM CHAIR BAILEY: Okay.

Paragraph 15 of that order says the mechanical integrity test will be conducted on all injection wells every two years.

THE WITNESS: That would be somebody else also.

MADAM CHAIR BAILEY: Okay.

You did discuss failure potential. And we're looking for a commitment to notify the OCD district office immediately in any of the injection wells, et cetera, to take all steps necessary to correct such failure.

THE WITNESS: That's correct. Are you looking at 19, ma'am?

MADAM CHAIR BAILEY: Yes, I am.

THE WITNESS: Yes, ma'am.

MADAM CHAIR BAILEY: So you could commit to that?

THE WITNESS: Yes, ma'am.

MADAM CHAIR BAILEY: Okay. Can you commit to Number 20 concerning maintenance of reported data from SCADA?

THE WITNESS: Yes, ma'am.

MADAM CHAIR BAILEY: How about paragraph 22, that the hydrogen sulfide contingency plan shall be reviewed and amended as necessary?

THE WITNESS: Yes, ma'am. I can commit to that.

MADAM CHAIR BAILEY: Okay.

I think that's all the questions I have.

Do you have any followup, Mr. Feldewert?

MR. FELDEWERT: I do not, Madam Chair. And just -- our next witness is probably going to take an hour of direct, maybe a little less.

MADAM CHAIR BAILEY: Well, why don't we have lunch first and come back here at 1:00.

(A recess was taken from 11:46 a.m. to 1:01 p.m.)

MADAM CHAIR BAILEY: It's 1:00. It's time to go back on the record.

Mr. Feldewert, I think you were about to call your next witness.

MR. FELDEWERT: Thank you, Madam Chair.

We will call Kelley Montgomery.

KELLEY MONTGOMERY,

after having been first duly sworn under oath,

was questioned and testified as follows:

EXAMINATION

BY MR. FELDEWERT:

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

A. I'm Kelley Montgomery. I'm employed by Oxy, and I'm currently a regulatory consultant.

Q. And do your employment responsibilities include the North Hobbs Unit and the South Hobbs Unit?

A. Yes, they do.

Q. And I believe, Ms. Montgomery, you've testified before the commission in connection with the application that was filed for the South Hobbs

Unit a year ago, correct?
A. Yes, I did.
Q. And at that time, had you prepared the C-108 application and supervise the area of review that was part of that application a year ago?
A. I did.
Q. And have you, likewise, prepared the C-108 and supervised the area for review analysis for this application to expand the Phase I area in the North Hobbs Unit?
A. I have.
Q. And the area of review analysis is actually -- and your C-108 is actually contained in a notebook that has been marked as Oxy Exhibit Number 1.
Is that correct?
A. That's correct.
Q. And did you meet with the division's engineering department concerning your C-108 application and your area of review analysis?
A. Yes, I did.
Q. And did you have more than one meeting?
A. Yes.
Q. Did you also have telephone conversations?
A. Yes, I did.

Q. Okay. Did you prepare slides to assist you in your presentation?
A. Yes, I did.
Q. If I look at Oxy Exhibit Number 7, are those the slides that you prepared for today?
A. Yes, they are.
Q. And it comprises 19 separate slides, correct?
A. That's correct.
Q. All right. Now, Ms. Montgomery, are you also an engineer?
A. Yes, I am.
Q. And if I look at Slide 1 of Exhibit 7, does that accurately summarize your educational background and your work history?
A. Yes, it does.
Q. And it reflects, does it not, that you've been a registered professional engineer since, what, 1998?
A. Yes. That is correct.
Q. And you have roughly 23 years as a -- experience as a production engineer and an environmental engineer?
A. Yes. That's correct.
Q. Do you have experience with CO2 floods?

A. Yes. All of my career has been spent in the CO2 floods. And as a production engineer, all of my fields were CO2 floods.

Q. And when you previously testified before the commission, were you qualified as an expert witness in oil and gas production engineering and environmental engineering?

A. Yes, I was.

MR. FELDEWERT: Madam Chair, I would re-tender Ms. Montgomery as an expert witness in oil and gas production engineering and environmental engineering.

MADAM CHAIR BAILEY: She is accepted.

Q. (By Mr. Feldewert) Ms. Montgomery, what topics will you address for the commission here today?

A. Today I will address three topics: We'll talk about the -- qualifying for the tax incentive, we'll go over the C-108 and the injectors, and then the area of review.

Q. Now, Ms. Montgomery, turning to the tax incentive information first of all, are you familiar with Division Order R-9708 that identifies the information necessary to qualify this expansion for the tax relief afforded in the Enhanced Oil Recovery

Act?

A. Yes.

Q. Okay. Let's see if we can -- in the interest of time -- kind of quickly skim through that information. Okay?

A. Okay.

Q. If we turn to what's been marked as Slide Number 2 in Exhibit 7, does that accurately depict the geographic area of the expansion?

A. Yes, it does.

Q. If I turn to what's been marked as Slide 3, does that accurately identify the acreage in the project area?

A. Yes.

Q. Does it identify the pools and formation of all of that area?

A. Yes, it does.

Q. And then it identifies the current operations in the proposed expansion?

A. Yes, it does.

Q. Okay. Then if I turn to what has been marked as Slide Number 4, it provides an accurate estimate of the capital costs of these additional facilities?

A. Yes.

Q. And then the total project capital cost?
A. Yes.
Q. And does it also provide an estimate of the additional production that you would expect from this expansion project?
A. Yes, it does.
Q. As well as the type of injectants and anticipated volumes?
A. Correct. Yes.
Q. And then if I turn to Slide 5, that notes that Section 3 in your C-108 application provides a list of current production in injection wells, does it not?
A. Yes, it does.
Q. So if we put this aside for a moment and go to Oxy Exhibit Number 1, if we go to the tab that's labeled -- that's the C-108 in Exhibit 1.
A. Yes.
Q. Okay. Are you there?
A. Yes.
Q. Okay. And in Exhibit 2 --
A. I actually think that's in the application section.
Q. Okay. So if we go to the application section.

We are looking for Exhibit D, correct?

A. That's correct, yes.

Q. So if I go into the first tab and I go one, two, three, four, five, six pages, we get to a map. And then following the map is Exhibit D, as in dog?

A. Yes.

Q. And is that an accurate list of the current producing wells?

A. Yes, it is.

Q. And then if I page through four pages of Exhibit D and I get over to Exhibit E, is that an accurate list of the current injection wells?

A. Yes, it is.

Q. Okay. And then as I continue through this and I get to Exhibit F, which we also have in our notebook as Slide 6, does this provide the historical production from the North Hobbs Unit?

A. Yes, it does.

Q. And then the next page, which would be Exhibit G, which also corresponds to Slide 7, is that the estimate of the anticipated production with the expansion into the Phase I area?

A. Yes, the incremental forecast production.

Q. Okay. Now, did you assist in preparing these exhibits and these graphs?

A. Yes, I did.

Q. And do they accurately summarize the historical performance and the expected future performance?

A. Yes, they do.

Q. Okay. Now, I want to talk about the proposed expansion area and the proposed injection wells. Okay?

A. Okay.

Q. If you look at Exhibits A and B to this application -- so if we go back to the tab and we go to Exhibit A, that's a list of the injection wells by quarter-quarter section in the expanded area?

A. Yes, it is.

Q. And does this follow, Ms. Montgomery, the authority that was provided by the division in 2001, when the Phase I area was initially approved?

A. Yes.

Q. Okay. In other words, at that time was there an exhibit to that order that identified the well locations by quarter-quarter section?

A. Yes, there was.

Q. Okay. And they would then list what each one determined at that point?

A. That's correct.
Q. And in coming up with your list of additional injectors for the expanded area you followed the same format?
A. Yes, we did.
Q. Okay. And how many of the proposed injection wells are listed on Exhibit A by quarter-quarter section?
A. 141.
Q. And that comprises the four pages of Exhibit A?
A. Yes, it does.
Q. Okay. And then if I go to Exhibit B, is this the list of wells that you would -- that you anticipate converting from producers into injectors?
A. Yes, but some of them are water injectors. The majority are water injected, but they will be converted to CO2 injection.
Q. Okay. And it looks like one of them is a temporarily abandoned well.
Is that correct?
A. That's correct. And one is a producer.
Q. And you were able to identify those wells by API number?
A. Yes.

Q. And how many of those wells do we have?
A. 22.
Q. So these would be 22 conversion wells?
A. That's correct.
Q. Okay. Then I would like to talk initially about these 22 conversion wells that are listed on your application Exhibit B.
And to do that, let's move to Slide 8 of Exhibit Number 7. Okay?
A. Okay.
Q. Now, what did you do with respect to these 22 wells that you were converting to gas injection?
A. What I've done with these wells, when we were looking at them, is -- well, of course all of them have individual wellbore diagrams, so we attempted -- I attempted to group them into three categories based on their well construction, how they -- the type of casing, the amount of casing they have.
So those are my three categories here.
Q. And I hate to flip back and forth too many times.
But if we look at Exhibit Number 1 -- so let's keep this open and look at Exhibit Number 1, and we go to the tab that says "Injection Well Data

Sheets."

That first 22 wells correspond to your Exhibit B, correct?

A. Yes, they do.

Q. And then the last entry on this first page, this pullout page under the injection well data sheet, would correspond to all of your proposed new drills in the quarter-quarter section, right?

A. Yes. That is correct.

Q. And behind this sheet, then, you have information on each of the 22 wells that you seek to convert?

A. Yes, we do.

Q. And then behind that you have individual well diagrams for each of those 22 wells?

A. Yes. That's correct.

Q. Okay. Now in breaking this group down into groups, or this 22-well -- these 22 wells in the group, or bucket, what did you do? How did you group them?

A. Okay. I tried to find -- to group them into things that they had in common, so that we could talk about them here.

All 22 wells, their surface casing is cemented to surface.

16 of those 22 wells -- that's up here.

16 of them are constructed with surface and production casing. And of those, 6 of them the production casing is cemented to surface, and 10 of them have, minimum, 1,070 feet of cement above our unitized interval.

Three of the 22 existing wells are constructed with surface casing, intermediate casing. They have production casing, and they also have a full liner.

Of these three wells, all of them have at least a thousand feet of cement above the unitized interval.

We have three wells that are constructed with surface intermediate production, and then a partial liner that covers the injection interval.

And of these wells, they have at least 660 feet of cement above our unitized interval.

Q. Okay. So let's now move forward and address each one of these three groups. Okay?

A. Okay.

Q. If you turn to Slide 9, does this correspond to the first grouping of the wells? That would be 16 of the 22 conversion wells.

A. Yes, it does.

Q. And explain to us the colors and the depictions on here, please.

A. Okay. This is our existing wells, and there's 16 of them of the 22. And they have surface and production casing. So the black set of casing is your surface casing.

In all of these wells, it's set between 1,510 feet and 1,664 feet.

All of these have cement circulated to surface. And we -- and that's depicted with the gray behind the pipe and the dotted -- the dots in it.

The next string of casing is depicted in red, and that's your production casing.

All of the production casing in this grouping of wells is set between 4,370 and 4,510.

6 of these have cement all the way to surface, and 10 of them have at least 1,070 feet of cement above the unitized interval.

The way I've tried to depict this is where you see the gray with the dots, that is solid cement that all of them have.

Where you see the hashmarks, that means that these wells will have cement somewhere in between -- all of those 16 wells will stop somewhere in this interval.

So right here is where your 1,070 feet is above the unitized interval.

Q. Okay. Then your next group of wells would have been 3 of the 22?

A. Yes.

Q. Okay. And if I turn to Slide 10, does that depict the condition of that group of wells?

A. Yes, it does.

Q. Okay. And walk us through these colors and the markings, please.

A. Okay. This has a little bit -- a little bit more to it.

The surface casing, again, is in black. The surface casing on these wells is set between 205 and 296, and the cement is circulated to surface on all of them.

All of these wells also have an intermediate string of casing that's depicted in green. These are set between 2,750 and 2,760. And there's 1,600 feet of cement above the casing shoe on all of these wells -- a minimum of, excuse me.

There's also the red, which is our production casing. It's set between 3,825 and 3,968 on these wells. The top of it -- let's see.

There's at least a thousand feet of cement above the unitized interval on the production string.

These 3 wells also have a full liner depicted in blue. And it's set between 4,226 and 4,244. And there's at least a thousand feet of cement above the unitized interval in the liner.

Q. Okay. So we've covered 19 of the 22, right?

A. Yes.

Q. All right. Of the three left, you broke those down into a group of two and then a single well?

A. That's correct.

Q. All right. Let's go to the next group of two, which would be Slide 11 of Exhibit 7.

A. Okay. Yes. On these two wells you have surface casing, again in black, set between 242 and 246, with cement circulated to surface.

You have an intermediate string set between 2,850 and 2,800. And there is at least 440 feet of cement above the casing shoe here.

You have production casing in red set between 3,955 and 3,975, and at least 660 feet of cement above the unitized interval.

These also have a partial liner where the cement is -- is to the top of the liner across the injection interval.

Q. Okay. Now, you were here for Mr. Stilwell's discussion of the protectable water zone in this area?

A. Yes.

Q. Okay. In your opinion, are these wells that we've reviewed, Ms. Montgomery, do each of these wells have sufficient casing and cement to prevent migration of injected fluids out of these proposed injection intervals?

A. Yes, they do.

Q. And in your opinion, would utilizing these wells for gas injection pose an unreasonable threat to groundwater or environment?

A. No, it will not.

Q. Okay. Now there was a last well in your initial group of 22 conversion wells, correct?

A. That's correct.

Q. And I believe this is the well that Ms. Bailey referenced earlier?

A. Yes, I believe so.

Q. Okay. If you turn to what's been marked as Slide 12, does that deal with the -- with that particular well?

A. Yes, it does.
Q. And what -- what is this -- the status of this well? What's it currently being used for?
A. It's currently a water injector.
Q. And how long has that been operating as a water injector?
A. About 20 years, I believe.
Q. Okay. Is it similar to the prior wells that we've just reviewed?
A. It is. It's similar, in the fact that it has surface casing cemented to surface. We have an immediate string, where you have 1,770 feet of cement above the casing shoe to prevent any migration of fluids into the base of freshwater.
A production string with at least 830 feet above the unitized interval, and then a partial liner across the injection interval.
Q. But there is a difference, correct?
A. There's a difference in this one, which we discussed with the chief engineer of the division.
In this particular one the base of the freshwater comes below where the surface casing is set, and there's not cement behind one of the strings of pipe on this well.
Q. In your opinion, Ms. Montgomery, looking

at this diagram and taking into account the existing cement and the casing, are there sufficient measures in place to prevent migration of fluids out of the injection zone?

A. Yes.

Q. Okay. And it's actually been operating as a water injection well without incident, correct?

A. That's correct.

Q. Okay. Nonetheless, after having met with the division examiner, are there steps that the company is going to take before this well is converted to a gas injection well?

A. Yes. We would like to put -- or we have agreed to put cement behind one of the strings of casing such that you have an added layer of protection across the base of freshwater.

Q. And you visited on that point with the division's chief --

A. Yes.

Q. -- engineer?

A. Yes, I did.

Q. Okay. That deals with the conversion wells, correct?

A. That's correct.

Q. Now, let's look at -- that dealt with the

22 conversion wells. But we have 141 wells that are going to be eventually new drills?

A. That's correct.

Q. And if I turn to what has been marked as Slide 13 in Exhibit Number 7, does it describe the design for these -- maybe I got my figure wrong. It says 163. Is that...

A. Well, of the total 163 injectors, 141 are new wells.

Q. Okay. And so does this describe the design for your 141 new drills?

A. Yes, it does.

Q. And what do you -- what does the company plan to do?

A. Our design is the same on all wells. We'll set surface casing at 1,550 and cement that to surface.

And then we'll set our production casing around 4,500, and also plan to cement that to surface.

Q. Okay. And will that be the same whether it's a new -- vertical new drill or a directional new drill?

A. Yes, it will.

Q. Okay. And if I turn to Slide 14 of

Exhibit 7, is this a graphic depiction of your design for those 141 wells set forth on Exhibit A to the application?
A. Yes, it is.
Q. And in your opinion, Ms. Montgomery, will the proposed design have sufficient casing and cement to prevent migration of the injected fluids out of the proposed injection interval?
A. Yes, it will.
Q. And will this proposed design create an unreasonable threat to groundwater or the environment?
A. No, it will not.
Q. Okay. Now I would like to move, Ms. Montgomery, to your area of review analysis. Okay?
A. Okay.
Q. First off, as reflected in Slide 15, that analysis is contained in Oxy Exhibit 1. And in this case it's under a tab labeled "Area of Review," correct?
A. That's correct.
Q. All right. And the first thing that we see under that tab in Exhibit 1 is a large map that's currently in a sleeve.

Is that map also duplicated for ease of the commission in Slide 16 of Exhibit 7?

A. Yes, it is.

Q. So they can either look -- take out the big map or we can look at Slide 16?

A. That's correct.

Q. All right. Beyond that, then, how is this -- the remaining portion of this area of review organized? Can you just walk us through it real quick?

A. Sure. After the review map I've included an 11-by-17 paper, and that is a flow chart of the way I grouped the area of review.

And if you'll see at the bottom there are boxes that say group one, group two, all the way through group nine. It explains what is in each group.

So after that 11-by-17 page you'll see tabs corresponding to each one of the groups. So group one all the way through group nine.

Q. And then under group nine you have broken -- group nine deals with what?

A. Group nine are the P&A wells. And they have -- they are each grouped by the section that they are in, and they are the diagrams of the P&A'd

wellbores.

Q. Ms. Montgomery, it took a lot of effort to put all of this together?

A. Yes. We took about a year to pull all of this information together, going through the NMOCD online files, to pull our information.

Q. And did you -- I guess you reviewed this number a few times, correct?

A. That's correct.

Q. Okay. And in preparation for this hearing here today, you actually went through and reviewed it all again?

A. I did.

Q. Okay. And in that final review did you find that there was a mistake in one of the wellbore diagrams under the tab group nine?

A. I did.

Q. Okay. And where would that exist?

A. Okay. If you go to group nine, your P&A wells under Sections 21 through 29, I believe it's the fourth one -- well, actually, on mine, it's the third page. This wellbore diagram has been corrected.

Q. Is it the third page or the fourth page?

A. Well, in mine it's the third. It's API

30-025-07392.

Q. Okay. You noticed a mistake in that diagram?

A. Yes. The top of cement, that was calculated incor- -- or drawn -- depicted incorrectly.

Q. Okay. And while everybody is there, do we have a substitute diagram that we can provide to the commission?

A. Yes.

MR. FELDEWERT: If I may approach, Commissioner Bailey, to make that substitution?

MADAM CHAIR BAILEY: Yes. Go ahead.

Q. (By Mr. Feldewert) Okay. Now having made that substitution, do the diagrams that you have provided to the commission accurately reflect the condition of the wellbores within the area of review?

A. Yes, they do.

Q. Okay. All right.

So let's go back, and let's start, then, the discussion with your area of review map, which is shown on Slide 16 of Exhibit 7.

Can you explain to the commissioners what all of the colors mean?

(Discussion off the record.)

Q. (By Mr. Feldewert) And what's the API number, just for the record?

A. 07392. Is that correct? Yes.

Q. Okay. Ma'am, would you explain to the commissioners your area of review map, all the colors and what it shows here?

A. Okay. What you're looking at here is a -- shaded in yellow is an outline of the North Hobbs Unit project area. So this blue dotted line is actually the North Hobbs Unit. So there's a portion of the North Hobbs Unit right in here that's not included in the project area.

Q. Now, that project area includes the existing Phase I as well as the expanded area?

A. That's correct.

Q. Okay.

A. The small blue dots that are hard -- on here -- are all of the North Hobbs Unit wells.

These pink dots here are wells that are part of our South Hobbs Unit.

This red line here is a half mile outside the North Hobbs Unit expansion project area.

So every well inside this red area was included in our area of review.

Q. Okay. So that would include North Hobbs Unit wells within that red line area, correct?
A. That's correct.
Q. It would include, in fact, because of the half-mile area of review, South Hobbs Unit wells?
A. Yes, it does.
Q. Some South Hobbs Unit wells?
A. Yes.
Q. And it included a few wells that, because of the half-mile nature, would be actually outside the North Hobbs Unit?
A. There are a few of those as well, yes.
Q. Okay. Had a number of these wells already been reviewed previously by the division or the commission in connection with prior expansion approvals?
A. Yes. Actually, the majority of the wells have already been reviewed.
Q. And that would have been, for example, under the 2003 -- 2001 North Hobbs Unit order?
A. Yes.
Q. And then additional injection well approvals for the North Hobbs Unit?
A. That is correct.
Q. And then last year, of course, for the

South Hobbs Unit order?
A. Yes. That's correct.
Q. How many wells, in total, are within this area of review?
A. There's a total of 699 wells.
Q. What was the source data for your -- for your review of these wells?
A. We used the online NMOCD web flow files to pull our information.
Q. And did you employ individuals to assist you in an audit of these wells?
A. Yes, we did. We employed two consultants. Mr. David Catanach and Mr. Ben Stone assisted in helping to pull the information and analyze it with us.
Q. And you worked with them in putting this together?
A. Yes, I did.
Q. Okay. Given that you had 699 wells, you came up with a mechanism to group them, correct, for discussion?
A. Yes, I did.
Q. And if we turn to Slide 17 -- and I think you discussed this briefly earlier. This reflects your effort to group these 699 wells into nine

separate groups for analysis purposes?

A. Yes.

Q. Okay. All right. And if it's easier to read, there's a larger version of this in Exhibit Number 1 under -- just past -- under the tab that says "Area Review." And just past the big map there's that pullout that identifies nine groups.

Correct, Ms. Montgomery?

A. That's correct.

Q. Then why don't you turn to the first group and explain what you did with respect to that particular group.

A. Okay. Group one is the largest group of wells. There's 522 in this group. These are wells that had been previously reviewed by the NMOCD in filings by Oxy that have had no change in their well status.

Q. Okay. So then if I go to the tab in Exhibit 1 that says group one --

A. Yes.

Q. -- does that identify -- the first page, does it identify the proceedings under which these wells, this 522 wells, would have been previously reviewed by the division?

A. Yes, it does.

Q. And what is, then, set forth in the remainder of the pages under tab group one in these -- Oxy's exhibit book?

A. After that is a listing of each of the 522 wells, their well name, API number, and their location and status.

Q. And did you and your audit team confirm that there had been no change in the status of these wells since the previous review by the division or the commission?

A. Yes, we did.

Q. Then the second group of wells is comprised of what?

A. The second group contains 52 wells. And this is wells that had been previously submitted and reviewed by the NMOCD. However, these did have a change in status, so we listed those in group two.

Q. So if I go under the tab in Oxy's Exhibit Number 1 that says group two, there's a pullout there.

Does that list these 22 wells?

A. 52.

Q. I'm sorry. 52 wells?

A. Yes.

Q. And where do we find the change in status?

A. In two places. In kind of the middle of the spreadsheet there's a previous well type and status, and then there's a current well type and status.

And then the last column of the spreadsheet details out what the changes were since it was previously reviewed.

I can see in the majority of the cases they are now TA since the previous review.

Q. And in your opinion, Ms. Montgomery, having reviewed this information, did any of these changes affect the integrity of the wells previously reviewed by the division or the commission?

A. No, they did not.

Q. Okay. Then what do we have, then, in the remaining groups? I guess we'll go three through eight.

A. Okay. Groups three through eight are wells that we reviewed that have not -- have not been previously reviewed by the division or commission, and we've included them here.

I categorized them similarly to the -- as I did in the South Hobbs Unit, by their well construction, so that we could get it in more manageable chunks.

Q. Okay. So let's go to an example, first off in the notebook itself, Oxy Exhibit Number 1 under group three.

We show a schematic for 40 wells.

Is that right?

A. Yes. That's correct.

Q. Okay. Walk us through this schematic for group three.

A. Okay. This is group three, Grayburg-San Andres wells with surface and production casing. There are 40 wells in this group.

The black casing is your surface casing. I've got a solid line for the shallowest surface casing, which is set at 1,467. And I have a dotted line down to where the deepest surface casing is set at 1,655.

So in all 40 of these wells you have surface casing set between those two depths.

You also have cement. They are all cemented to surface.

The red is your production casing. I've done something similarly there. The shallowest is set at 4,304, which is the solid line.

I have a dotted line to the deepest at

5,161, which is a measured depth.

And the dotted line will show that there's casing set of the 40 wells in between those.

The cement behind pipe on all of these, the top cement ranges from the deepest to 1,021 to surface. So...

Q. And then behind this schematic would be the actual data on each of the wells that are within your group three?

A. Yes. That is correct.

Q. And did you do a similar analysis, then, for your remaining groups three through eight?

A. Yes, I did.

Q. And provide, first, a schematic representative of those wells and then the actual data for the wells behind them?

A. Yes. That's correct.

Q. Okay. And then when it came to group nine, which is your P&A'd wells, and looking at Exhibit 1 under that tab, how does that differ from what you previously did?

A. The P&A wells all have an individual wellbore diagram associated with them. So they have tabular data shown on the 11-by-17 sheet. And then each of -- then there's several of the P&A'd wells, and they are organized by section number.

Q. Okay. Did you review all of this information with the division's engineering bureau?

A. Yes, I did.

Q. And that would comprise your numerous meetings and telephone calls?

A. Yes. That is correct.

Q. And what conclusions did you reach after having met with the division about this information?

A. That the area of review, the wells that -- in our area of review were protective of -- we would not have migration into the freshwater, and you would confine in the injectant.

Q. Okay. So no problem wells were found?

A. We didn't have any problem wells that we found.

Q. Okay. I want to go over one thing, Ms. Montgomery.

If I go back to Oxy Exhibit Number 2 in the exhibit book, that's the Order 6199-B for the North Hobbs Unit, correct?

A. That is correct.

Q. And if I go to that order that was entered in 2001 and I look at page 10 of that order, there's a discussion in paragraphs 7 and 8 about the extensive review that was done at that time, and as a result of that they had found two wells that needed some remedial work.

Do you recall reading this?

A. Yes, I do.

Q. Okay. As part of your audit in this case, did you go back and ensure that the work that had been requested in paragraphs 7 and 8 had been done?

A. Yes, I did.

Q. And has that work -- was that work completed prior to injection commencing around those wells?

A. Yes, it was.

Q. Okay. In your opinion, are the wells within the area of review sufficiently cased or cemented to prevent migration of injected fluids out of the proposed injection interval?

A. Yes, they are.

Q. And do any of these wells present an unreasonable threat to groundwater or the environment if the Phase I area in the North Hobbs Unit is expanded as proposed by Oxy?

A. No, they don't.

Q. Okay. I want to turn now to another topic, and that is the issue of updating this area of review analysis.

If I go to Slide 19, the current division order governing the Phase I area provides a three-year grace period for this area of review analysis for future injection wells -- or did provide, correct?

A. Correct.

Q. All right. Does Oxy request that this -- because of the effort that went into this -- that this grace period be extended to five years?

A. Yes, we do.

Q. Okay. And you're talking about this grace period for wells that -- in which injection does not commence until more than five years from now?

A. Yes. That is correct.

Q. And if I look at Oxy Exhibit Number 3, which is the South Hobbs Unit, and I go to page 11 and I look at the bottom of page 11, paragraph 5 for the South Hobbs Unit, does that provide what I called a five-year grace period for the area review analysis?

A. Yes, it does.

Q. And does Oxy request that that same grace period be provided for your North Hobbs area of review given the time and effort that went into this?

A. Yes, we do.

Q. And in your opinion, having analyzed this data and recognizing that it's been reviewed a number of times, is that request going to pose an unreasonable risk to the public health or the environment?

A. No, I don't think it will.

Q. Okay. While we are on Exhibit Number 3, I want you to look at page 12.

And I'm looking at paragraph 13 at the bottom.

A. Okay.

Q. It deals with cement.

A. Yes.

Q. Have you reviewed that provision?

A. Yes, I have.

Q. Do you request similar relief for the North Hobbs Unit?

A. Yes, we do.

Q. Okay. And if you look at paragraph 15 on the next page of this order, on page 13, paragraph 15 --

A. Uh-huh.

Q. -- is the company going to conduct a

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mechanical integrity test on all injection wells at least once every two years?

A. Yes, we will.

Q. Okay. In your opinion, would the granting of Oxy's application be in the best interest of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes, it will.

Q. And in your opinion, will the relief that has been requested by Oxy's application pose an unreasonable risk to the public health or the environment?

A. No, it will not.

Q. Were the 19 slides comprising Oxy's Exhibit Number 7 compiled by you or under your direction and supervision?

A. Yes, they were.

MR. FELDEWERT: Madam Chair, I would move the admission into evidence of Oxy's Exhibit 7.

MADAM CHAIR BAILEY: It is accepted.

MR. FELDEWERT: That concludes my examination of this witness.

MADAM CHAIR BAILEY: Commissioner Warnell, do you have any questions?

COMMISSIONER WARNELL: Ms. Montgomery, a good presentation.

THE WITNESS: Thank you.

COMMISSIONER WARNELL: Undoubtedly, a tremendous amount of work and effort has gone into that. I appreciate it.

One flag that was raised, and I don't know why. Maybe you can help me out here.

On one of your slides you showed that the 52 wells that were P&A'd.

THE WITNESS: 52 wells. Is that -- let me just make sure I have that.

Is that the group -- I guess that's right. The group two wells that have changed status?

COMMISSIONER WARNELL: Yes, the status change.

THE WITNESS: Yes, sir.

COMMISSIONER WARNELL: So they had gone -- they had almost all exclusively -- I think there was one well out of those 52 that was maybe an injection -- saltwater injection well, and all the rest had gone to P&A?

THE WITNESS: Yes, sir.

COMMISSIONER WARNELL: What's in the future for those 51 P&A'd wells?

A. I don't know that I can address each one specifically. But I know in Mr. Brockman's presentation, as we expand this -- this flood, that's part of -- a lot of the wells on the outskirts were P&A'd. And so the hope is to utilize these wellbores again as we expand our flood with this Phase I extension.

COMMISSIONER WARNELL: I thought that was the case.

THE WITNESS: Yeah.

COMMISSIONER WARNELL: That's all I've got. Thank you.

MADAM CHAIR BAILEY: Commissioner Balch?

COMMISSIONER BALCH: On the 22 wells that we first discussed, they don't have cement, necessarily, all the way to the surface?

THE WITNESS: Right.

COMMISSIONER BALCH: It looks like the majority of those are going to cover your primary seal intervals except for the one where you're going to do a squeeze job, and that will be checked off on our log, and that will be available to the division?

THE WITNESS: Absolutely.

COMMISSIONER BALCH: The other wells where you -- where you don't necessarily have cement behind all of your pipe all the way up --

THE WITNESS: Uh-huh.

COMMISSIONER BALCH: -- those are going to be very dependent upon the integrity of the packer and the production or injection tubing and the -- and the measurement of the -- and the continuous measurement of the pressure in the annular space?

THE WITNESS: All of them will have that -- will be equipped with that, yes.

COMMISSIONER BALCH: Okay. In the group three wells that you have listed, there's only two of those that were cemented to surface. Those are both active producers.

THE WITNESS: Okay.

COMMISSIONER BALCH: Is there a reason why they were -- I mean, you could have had that whole group cemented to surface except for those two wells.

Are those two going to be switched to injection at some point? It didn't look like it from the data sheet.

THE WITNESS: Let me make sure I'm correct.

Is this in the area of review under --

COMMISSIONER BALCH: This is group three.

THE WITNESS: Group three?

These are wells that are just within the area of review. So none of these --

COMMISSIONER BALCH: Oh, these are not your wells, right.

THE WITNESS: These are not the proposed injectors. So I mean, I -- we just tried to categorize them as they -- as they were and show that they were protective and could confine the injectant.

COMMISSIONER BALCH: All right. But those two wells won't have your pressure monitoring of the annular space?

THE WITNESS: Can you point out which two wells they are? Are they North Hobbs Unit wells?

COMMISSIONER BALCH: The two wells I was looking at were -- the cement top.

THE WITNESS: Oh, I could probably find it quickly right here.

COMMISSIONER BALCH: It's the cement top. It's North Hobbs.

THE WITNESS: Okay. 40822 is the first one, cement top at 979?

COMMISSIONER BALCH: That's right.

THE WITNESS: Okay.

COMMISSIONER BALCH: And the other one is on the next page near the top, the cement top at 1,021.

THE WITNESS: All right.

Both of those are -- both of those are producers. Let me check this one.

Yes. Both of those are producers.

COMMISSIONER BALCH: And they are both Oxy wells?

THE WITNESS: And they are both Oxy wells.

As Mr. Hodges testified, showing our producing wells that have the ESP, we also have monitors on the tubing and the annular space on those producers.

COMMISSIONER BALCH: Even wells that are not involved in your -- directly involved in your North Hobbs Unit or North Hobbs expansion, but are adjacent to?

Because these are area of review wells, right?

THE WITNESS: These are area of review wells. That's why I wanted to see if they were our North Hobbs Unit wells. So they're within the unit.

I guess I probably shouldn't speak to those specifically. I do know that we have -- we do monitor our production wells as well, though, especially if they have ESPs on them, so that, you know, we know what the annular pressure and the tubing pressure is on those.

But back to your original question, we won't go back and try to squeeze these to put cement to surface.

COMMISSIONER BALCH: Right. I guess my concern was there may not necessarily be a mechanism in place to observe that those wellbores failed.

THE WITNESS: I believe there is, but I -- we can always recall Mr. Hodges to confirm that on these wells if we need to. But...

COMMISSIONER BALCH: Okay. Thank you.

MADAM CHAIR BAILEY: Let's make it easy for the lawyers.

The C-108 application, Section 7, Number 3, asks for proposed average and maximum injection pressure.

Could you point to where that is in C-108 so that they can cross-reference for the board?

THE WITNESS: Sure. Okay. Let me find that. And then I'll...

I actually don't see it. The intent is for the injection pressures to remain the same as they currently are in the North Hobbs Unit and in the South Hobbs Unit.

So I believe that it would -- I don't -- I don't actually see here, but that is what we -- that's what we are asking for. I'm surprised it is not right here.

MADAM CHAIR BAILEY: I was looking for it, and I didn't see it there in C-108.

THE WITNESS: I don't see it. But the intent is that that's what it should be. That's what we would be asking for. It would be that -- no change in injection pressure that is currently in the Phase I area.

MADAM CHAIR BAILEY: Okay.

That's all I have.

Do you have any other questions?

FURTHER EXAMINATION

BY MR. FELDEWERT:

Q. So, Ms. Montgomery, if we look at Oxy Exhibit Number 2 -- and I'll look at page 9, so that would be the Order 6199-B.

A. Yes.

Q. Page 9, paragraph 4.

A. Yes.

Q. You don't seek any change in those?

A. We don't seek any change from what is currently in the order, correct.

Q. Have you previously checked to make sure that those are the same approved -- let me -- injection pressure limits as are in the South Hobbs Unit?

A. Yes, they are.

Q. Okay. So it would all be the same.

A. That is correct.

Q. Okay.

MR. FELDEWERT: That's all the questions I have.

MADAM CHAIR BAILEY: Thank you. You may be excused.

THE WITNESS: Thank you.

MR. FELDEWERT: Madam Chair, with your permission we'll call our last witness.

MADAM CHAIR BAILEY: You may.

PATRICK SPARKS,

after having been first duly sworn under oath,

was questioned and testified as follows:

EXAMINATION

BY MR. FELDEWERT:

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

A. My name is Pat Sparks. I'm employed by Oxy as a landman.

Q. And, Mr. Sparks, how long have you been a landman with Oxy?

A. A little over 30 years.

Q. How long have you been involved in the Permian Basin?

A. 22 to 23 years.

Q. Now, you've testified previously before the commission in connection with the application for the order converting South Hobbs Unit to a tertiary recovery project?

A. Yes, sir.

Q. Have you also had the opportunity to testify before both the division and the commission on other matters over the years?

A. Yes, sir.

Q. And were your credentials as an expert in petroleum land matters accepted and made a matter of record?

A. Yes, sir.

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

A. Yes, sir.

Q. And did you conduct a study of the lands

that were affected?
A. Yes, sir.
Q. And finally, were you responsible, Mr. Sparks, for coordinating and compiling a notice list for all of the -- the parties affected by this application?
A. Yes, sir.
MR. FELDEWERT: Madam Chair, I would re-tender Mr. Sparks as an expert witness in petroleum land matters.
MADAM CHAIR BAILEY: He's accepted.
Q. (By Mr. Feldewert) Mr. Sparks, are there federal or state lands involved in the proposed expansion area?
A. Yes, sir, there are. As a matter of fact, the North Hobbs Unit is comprised of 45 percent state lands.
Q. And as a result, is the New Mexico State land office the largest royalty owner out there?
A. By a long shot.
Q. Okay. And did you discuss this application with the BLM?
A. Yes, sir.
Q. And did you discuss this application with the New Mexico State land office?

A. Yes, sir.

Q. Looking at Oxy Exhibit Number 8, does this identify the noticed areas for your proposed expansion of the Phase I?

A. Yes, sir.

Q. Now first off, in Oxy Exhibit Number 8, we have a one-page version that is marked page 1. And then behind that there's a map in a sleeve.

Is that correct?

A. That's correct.

Q. Is the map in the sleeve the same as that which is depicted on the first page of Exhibit 8?

A. Yes, sir. It's just to a larger scale.

Q. Okay. Would you -- using this Exhibit 8, would you please identify for the commission the areas that you analyzed for purposes of coming up with your notice list?

A. Okay. The solid green line is the unit boundaries for the North Hobbs Unit.

The solid green color is the Phase I expansion area.

The hatched areas on the outside are the half-a-mile notice area that we did the research on.

Q. Did you -- you said you put together a team to determine the ownership in this area?

A. Yes, sir.

Q. How many people were involved?

A. I had -- in addition to the people periodically in house, we had two fieldworkers in the field for four and a half to five months.

Q. Okay. And as a result, were they -- you were able to identify, first off, the North Hobbs Unit interest owners, correct?

A. Yes, sir.

Q. And then the South Hobbs Unit owners, because your hatched area extended into the South Hobbs Unit, right?

A. Correct.

Q. Okay. And then were you able to identify all the tracts in the hatched blue area around your proposed expansion area?

A. Yes, sir.

Q. And within those tracts did you identify the operators or lessees of record?

A. Correct.

Q. And if it was undeveloped, did you determine the mineral owners?

A. That is correct.

Q. And then finally, with respect to your proposed injection wells, did you identify the owners of the surface estate, first for the quarter-quarter sections where you intend to utilize injection wells?

A. That's correct.

Q. And then also for the owners of the surface estate, where the company was able to identify the proposed injection wells by API number?

A. That's correct.

Q. Okay. If I go to Oxy Exhibit Number 9, does this depict the surface locations for all of the proposed injection wells?

A. That's correct.

Q. And it corresponds with Exhibits A and B to the application?

A. That's correct.

Q. And again, behind this first page of Exhibit Number 9 would be a much larger map showing the same thing as depicted in the first page?

A. That's correct.

Q. All right.

If I then go to Oxy Exhibit Number 10, is this a list, Mr. Sparks, of the North Hobbs Unit working interest owners that you were able to identify from your company records?

A. That's correct.

Q. Then if I go to Exhibit Number 11, is this a list of the South Hobbs Unit working interest owners?

A. That is correct.

Q. And then if I go to Exhibit Number 12, is this a list of the affected operators, lessees, or mineral owners in the blue hatched area shown on Oxy Exhibit Number 8?

A. Yes, sir, it is.

Q. And finally, is Oxy Exhibit Number 13 a list of all the surface owners?

A. That is correct.

Q. Okay. And if I turn to Exhibit Number 14, is this an affidavit prepared by my office with the attached letter providing notice of this hearing to all of the parties listed in Exhibits 10, 11, 12, and 13 for whom we had an address?

A. That's correct.

Q. Now, what efforts were undertaken to locate an address for all of the parties that are listed in Oxy Exhibits 10, 11, 12, and 13?

A. First of all, we used County records in Lea County. We used the local abstract plats in Lea County. We used the tax roles in Lea County.

We also used our internal records. Since

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we operate both of these units, chances are some of those people were in our system as a royalty owner under one of the units, so we found some of them there.

We did internet searches, and then any personal knowledge that we had of any of the people.

And there were just some that aren't -- have not had any activity on those tracts since the 1930s.

Q. Now with that in mind, if I go to Exhibit Number 15 -- and I want to skip the first page for now and go to the second page.

Does that provide -- the second-to-the-third page of that exhibit, does that provide a list of the entities or individuals within your area of notice that you just simply could not find an address for?

A. That's correct.

Q. Okay. And finally, Mr. Sparks, for the parties that we were able to find an address on, we sent out the letter and kept the return receipts.

Is that correct?

A. That's correct.

Q. Okay. And is that contained within this Redwell binder that we put together as Oxy

Exhibit 16 --

A. That's correct.

Q. -- and the returned green cards?

MR. FELDEWERT: Madam Chair, I only have one copy because it's voluminous. I didn't want to burden your notebooks with this information.

With your permission, we would like to put this one copy of Exhibit 16 into the record.

MADAM CHAIR BAILEY: That's fine, thank you.

Q. (By Mr. Feldewert) And then finally, Mr. Sparks, were Oxy Exhibits 8 through 16 compiled by you or under your direction and supervision?

A. Yes, sir.

MR. FELDEWERT: In that case, Madam Chair, I would move the admission into evidence of Oxy Exhibits 8 through 15. I think we've already admitted 16.

MADAM CHAIR BAILEY: They are admitted.

MR. FELDEWERT: That concludes my examination of this witness.

I do have one issue I need to raise with the commission concerning this notice when you are finished with your questioning.

MADAM CHAIR BAILEY: Commissioner Balch?

COMMISSIONER BALCH: I have no questions.
MADAM CHAIR BAILEY: Mr. Warnell?
COMMISSIONER WARNELL: I have no questions.
MADAM CHAIR BAILEY: And I have no questions.
MR. FELDEWERT: Then, Madam Chair, the only thing I have left is, if you will look at Exhibit Number 15, you'll see that there is an affidavit of publication on the first page of our Exhibit Number 15.
The second and the third page is comprised of a document that we sent to the Lovington Leader for purposes of having it published in the newspaper, in the County newspaper, for purposes of this hearing.
When we asked for the affidavit of publication back from them we got it -- I think it was the day before yesterday.
We noticed that -- you'll see that the affidavit of publication that they sent to us was -- it appears to be the notice that the commission sent to the newspaper for purposes of publication and did not include the list of names that we had sent to them, comprised of the pages 2 and 3.

When we called them, we were informed that they were confused and thought that they only needed to publish the one that was sent by the commission; and, therefore, did not publish the one we had sent to them.

The rules on this are somewhat vague, in terms of whether you actually have to list the parties in your -- in your notice.

But I visited with the company. We would like to be able to get this list published in the newspaper. We can accomplish that by the next commission meeting. And with your permission I would like to come back at that time and present an affidavit of publication which would be in the form reflected on the second and the third pages of our Exhibit 15.

MADAM CHAIR BAILEY: Could we just send it in as part of the record and not have to wait until the next commission hearing to present it?

MR. BRANCARD: We can leave the record open and allow submittal with an affidavit of publication from the -- has the notice already been sent to the paper?

MR. FELDEWERT: We are in the process -- well, they have it, and they indicated to us that they would publish it as soon as possible. But obviously, that didn't cure the issue that we have for this particular hearing.

It will cure it and be published in time for the next commission docket.

MR. BRANCARD: Okay. But the notice talks about a hearing today.

MR. FELDEWERT: Yes.

MR. BRANCARD: And gives a deadline two days ago to respond.

I mean, effectively, we are leaving the record open if any of these people appear, that they can make an appearance between now and I guess the next -- whenever you want to give it -- 30 days from now?

MADAM CHAIR BAILEY: Yes.

MR. BRANCARD: So perhaps we need to rephrase the notice to say that a hearing was held, but the record is open until 30 days from now.

MR. FELDEWERT: We certainly can do that.

MR. BRANCARD: By the way, you had the wrong time for the hearing on the notice. We didn't start at 8:15 this morning.

MR. FELDEWERT: We'll correct that.

So, Madam Chair, with your permission,

that -- with that one minor issue, that concludes our presentation.

MADAM CHAIR BAILEY: You don't have any final comments?

MR. FELDEWERT: No. I certainly can answer whatever questions you may have, but -- and if there's any confusion about the relief that we seek, but I don't have anything further to provide to the commission.

MADAM CHAIR BAILEY: Okay.

Then we will take it under advisement.

Commissioners do you want to go into closed hearing to debate on this case?

COMMISSIONER BALCH: If it's possible, I would like to ask Mr. Hodges another question, just on my cross-examination.

MADAM CHAIR BAILEY: You would like to recall Mr. Hodges?

COMMISSIONER BALCH: Yes.

MADAM CHAIR BAILEY: You are still under oath, Mr. Hodges.

THE WITNESS: Yes, ma'am.

SCOTT HODGES,

after having been first duly sworn under oath,

was questioned and testified as follows:

COMMISSIONER BALCH: I'm sorry to make you work after lunch.

THE WITNESS: That's okay.

COMMISSIONER BALCH: So I just want to clear up some confusion I may have with group three.

Those are wells that are in the area of review, but not in the North Hobbs CO2 expansion, right?

THE WITNESS: Right.

COMMISSIONER BALCH: And there were two wells in there that didn't have cement all the way to surface in at least one of the casing strings.

They both appear to be operated by Oxy, and they are production wells. They'll probably remain production wells going into the future.

So in your presentation, you showed us that similar wells inside the operating unit would have active measuring of pressure, so you know if there's a failure in the wellbore.

THE WITNESS: That is correct.

COMMISSIONER BALCH: Wells that are in the area of review that are operated by Oxy, is that also the case?

THE WITNESS: That's not our plan right now. We feel like that if we had a breach of that casing that we could pick that up on a Bradenhead survey.

COMMISSIONER BALCH: Okay.

THE WITNESS: So if we did breach that casing, we would have pressure on that Bradenhead, and that would be an indication of that.

COMMISSIONER BALCH: That's my only question.

MADAM CHAIR BAILEY: Okay.

MR. FELDEWERT: Can I ask one question, ma'am?

MADAM CHAIR BAILEY: If you would like some followup on that?

MR. FELDEWERT: Please.

FURTHER EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Hodges, if the wells in group three, okay, are within the Phase I area of the North Hobbs Unit, and if they are currently producing wells, do they have the pressure monitors that you previously discussed?

A. Not -- the Phase I, not the expanded

Phase I?

Q. Not the expanded, but within the Phase I area. If they are currently producing wells within the Phase I area, do they have the pressure monitors that you previously discussed with the commission?

A. They have casing annulus pressure monitors.

Q. Okay.

A. Yes.

Q. Okay. So all of your producing wells have that -- those monitoring devices.

A. That's correct.

Q. If they're within the Phase I area?

A. Right.

MR. FELDEWERT: That's all.

MADAM CHAIR BAILEY: Satisfied?

COMMISSIONER BALCH: Satisfied.

MADAM CHAIR BAILEY: Then you may be excused.

THE WITNESS: Thank you.

MADAM CHAIR BAILEY: Commissioners, would you like to have a motion to go into closed session in accordance with New Mexico Statute 10-15-1, and the OCC resolution to open meetings?

COMMISSIONER BALCH: I'll make that

motion.

COMMISSIONER WARNELL: I second that motion.

MADAM CHAIR BAILEY: All those in favor?

COMMISSIONER BALCH: Aye.

COMMISSIONER WARNELL: Aye.

MADAM CHAIR BAILEY: Aye.

If you could leave, we will debate the case, and we will come back into session shortly.

(A recess was taken from 2:11 p.m. to 2:37 p.m.)

MADAM CHAIR BAILEY: We will go back on the record.

Do I hear a motion to come back on the record?

COMMISSIONER BALCH: I'll make a motion to come back on the record.

COMMISSIONER WARNELL: I'll second that motion.

MADAM CHAIR BAILEY: All those in favor?

COMMISSIONER BALCH: Aye.

COMMISSIONER WARNELL: Aye.

MADAM CHAIR BAILEY: Aye.

The only thing that was discussed was this case.

And, Bill, would you explain what our decisions were contingent on, with the assumption that there will not be any response from the later notice?

MR. BRANCARD: Thank you, Madam Chair. Yes.

Contingent on no additional entries into the record, the commission proposes to approve the application of Occidental Permian, Limited, to amend Order R-6199 to expand the North Hobbs Grayburg-San Andres Unit Phase I tertiary recovery project.

The commission approves the expanded area for tertiary recovery listed in the application.

The commission approves the injection for the wells listed in the application.

The commission will certify the enhanced oil recovery pro- -- as a tertiary project under the Enhanced Oil Recovery Act.

This approval is subject to the following conditions:

The conditions that are listed for the South Hobbs Unit in Order R-4934-F are repeated here, except for conditions relating to specific wells in that unit.

In addition to those conditions the commission requires the proposal to place additional cement in well 30-025-07545 and a cement bond log for that cement project.

The commission also will approve the allowance of greater than four wells in a quarter-quarter section, and states that Rule 15.9(A) applies to tertiary as well as secondary projects.

The commission also will allow variance from the unorthodox well location limitation in Rule 15.13(A), that -- the limitation that does not allow a well within 10 feet of a quarter-quarter line.

Did I catch all of the conditions?

This approval is subject to the commission record remaining open for a period of 30 days after the publication of the notice that has not been repeated yet by the applicant. We will have a proposed order from commission counsel that embodies this, and I guess we will address it at the May hearing.

MADAM CHAIR BAILEY: Did you want Mr. Feldewert to submit a proposed order?

MR. BRANCARD: That would be lovely.

MR. FELDEWERT: Certainly.

MADAM CHAIR BAILEY: All right. The case is concluded, then.

Other business before the commission?

MR. BRANCARD: I don't know if you want any updates on the latest on the pit rule appeal litigation.

We had a motion filed, I believe at the end of last week, by the petitioners in the current pit rule appeal, on the 2013 appeal, where this case is now, as you are aware, before the court of appeals.

It was originally filed in district court, and we had the court of appeals judge certify it to the court of appeals.

And at the same time -- or around the same time another district court judge agreed to certify the older appeals from 2008 and 2009 also up to the court of appeals.

The court of appeals has issued a briefing schedule for the current pit rule appeal which will have the petitioner's brief due by the end of this month.

The commission also placed the old appeals on what's called the general calendar, which is a briefing calendar. However, they then, in their order, said they didn't want to see any briefing on those old cases subject to the briefing on the current case.

So it's the 2013 case that's going forward.

We received a motion late last week from the petitioners asking that the Court take notice -- I'm not quite sure of what that means -- of the record from the old appeals in the new appeal.

That issue was raised during the hearing of the current case, and the commission did not agree with that and rejected that idea. So we are opposing that motion to the Court.

We have a record that's close to 9,000 pages of your-alls exhibits, transcripts, deliberation. And that was what you considered in making your decision.

To suddenly have these records from these old appeals that you didn't really even look at be part of the record the Court looks at does not seem like something that we would want to support, so we're going to oppose that motion and will be filing something soon with the Court. We have 15 days to respond to the motion.

They have also -- given that they are

nearing their deadline in a couple of weeks for their brief, they've asked the Court for a little more time, depending on when the Court issues a decision on this motion, and we did not oppose that. So...

MADAM CHAIR BAILEY: 15 days is pretty short.

MR. BRANCARD: Yes. So that's where we are on those appeals.

I've been trying to keep you-all updated by -- you know, by e-mail, and I will do that as things pop up.

COMMISSIONER BALCH: What do you think the long term time line is?

MR. BRANCARD: Well, I think it's 45 days between each brief. So you know, the briefing is not going to be done for another four months or so. The Court's not too bad about turning cases around, but it would probably be a year from now before we hear anything.

MADAM CHAIR BAILEY: Thank you.

Is there any other business before the commission today?

Then do I hear a motion to adjourn?

COMMISSIONER BALCH: I will make the

motion to adjourn.

COMMISSIONER WARNELL: I second that motion.

MADAM CHAIR BAILEY: All those in favor?

COMMISSIONER BALCH: Aye.

COMMISSIONER WARNELL: Aye.

MADAM CHAIR BAILEY: Aye.

(Proceedings concluded.)

CERTIFICATE

I, Paul Baca, RPR, CCR in and for the State of New Mexico, do hereby certify that the above and foregoing contains a true and correct record, produced to the best of my ability via machine shorthand and computer-aided transcription, of the proceedings had in this matter.

Paul Baca

PAUL BACA, RPR, CCR
Certified Court Reporter #112
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