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

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

ORIGINAL

APPLICATION OF OCCIDENTAL PERMIAN LIMITED PARTNERSHIP TO AMEND ORDERS R-4934 AND R-4934-E GOVERNING THE SOUTH HOBBS GRAYBURG-SAN ANDRES PRESSURE MAINTENANCE PROJECT TO ALLOW THE INJECTION OF CARBON DIOXIDE AND PRODUCED GASES, TO MODIFY THE SURFACE INJECTION PRESSURE, TO OBTAIN OTHER RELIEF, AND TO QUALIFY THIS EXPANSION FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE NEW MEXICO ENHANCED OIL RECOVERY ACT, LEA COUNTY, NEW MEXICO — Case No. 14981

APPLICATION OF OCCIDENTAL PERMIAN LTD. FOR APPROVAL TO ADD THE NORTH HOBBS G/SA UNIT WELL NO. 431 AS AN INJECTION WELL FOR WATER, CARBON DIOXIDE AND PRODUCED GAS IN ITS NORTH HOBBS GRAYBURG-SAN ANDRES TERTIARY RECOVERY PROJECT LOCATED WITHIN THE HOBBS GRAYBURG-SAN ANDRES POOL, LEA COUNTY, NEW MEXICO — Case No. 14976

RECEIVED OCD
2013 MAY 24 A 10: 46

REPORTER'S TRANSCRIPT OF PROCEEDINGS
COMMISSIONER HEARING

BEFORE: JAMI BAILEY, Chairman
DR. ROBERT BALCH, Commissioner
TERRY WARNELL, Commissioner

May 10, 2013
Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Commission, JAMI BAILEY, Chairman, on Friday, May 10, 2013, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis Drive, Room 102, Santa Fe, New Mexico.

REPORTED BY: Jacqueline R. Lujan, CCR #91
Paul Baca Professional Court Reporters
500 Fourth Street, N.W., Suite 105

A P P E A R A N C E S

FOR THE OIL CONSERVATION COMMISSION:

BILL BRANCARD
Assistant General Counsel
1220 South St. Francis Drive
Santa Fe, New Mexico 87504

FOR THE APPLICANT:

HOLLAND & HART, LLP
MICHAEL H. FELDEWERT, ESQ.
ADAM RANKIN, ESQ.
P.O. Box 2208
Santa Fe, New Mexico 87504
(505)988-4421

FOR THE OIL CONSERVATION DIVISION:

GABRIELLE A. GERHOLT
Associate General Counsel
Oil Conservation Division
1220 South St. Francis Drive
Santa Fe, New Mexico 87504
(505)476-3451

ALSO PRESENT:

Florene Davidson, Commission Clerk

CHAIRMAN BAILEY: We'll go back on the record this morning. It's Friday, May 10th. This is a continuation of Case 14981, which is the application of Occidental Permian Limited Partnership to amend Orders R-4934 and R-4934-E governing the South Hobbs Grayburg-San Andres Pressure Maintenance Project to allow the injection of carbon dioxide and produced gases, to modify the surface injection pressure, to obtain other relief, and to qualify this expansion for the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act.

All three Commissioners are here, so there is a quorum of the Commission.

When we left off yesterday evening, we were ready for Kelley Montgomery to stand as a witness. Is she -- would you like to call your witness?

MR. FELDEWERT: Madam Chair, just one matter of housekeeping. Ms. Montgomery is going to be going through what has been marked as Oxy Exhibit Number 12. In reviewing the information since this exhibit was filed with the Commission, we noticed that there was a typographical error on Slides 8, 9 and 10 of Oxy Exhibit 12. We ask that they be substituted. And I provided the Commission with substitute slides, as well as the record.

So with your permission, we would like to substitute Slides 8, 9 and 10 in what is Oxy Exhibit Number 12.

CHAIRMAN BAILEY: Is there an objection?

MS. GERHOLT: No objection, Madam Chair.

CHAIRMAN BAILEY: Then we will accept substituted Slides 8, 9 and 10.

MR. FELDEWERT: Thank you.

We are prepared to call Ms. Montgomery to the stand.

CHAIRMAN BAILEY: Would you please stand to be sworn and to sit at the witness stand?

KELLEY MONTGOMERY

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. FELDEWERT:

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

A. Kelley Montgomery.

Q. By whom are you employed?

A. By Oxy.

Q. And what are your current job responsibilities?

A. I'm a regulatory consultant.

Q. How long have you been with Oxy?

A. Twenty-two years as a consultant and as an employee.

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

A. Yes.

Q. Are you part of the team at Oxy that has been tasked with converting the South Hobbs Unit from a waterflood to a tertiary recovery project?

A. Yes.

Q. Did you prepare the C-108 application that has been marked in the record as Oxy Exhibit 1?

A. Yes, I did.

Q. Did you also prepare and supervise the area of review analysis that has been marked as Oxy Exhibit Number 2?

A. Yes, I did.

Q. Were you involved in meetings before the Division concerning your area of review analysis?

A. Yes. We had two meetings with the Division going over our area of review.

Q. What subjects will you be discussing with the Commission today?

A. We'll be discussing the C-108 in the area of review. I believe there's also talk about our TA'd wells and the cement bond logs.

Q. And I think at the beginning you and I will quickly go through the data that's necessary for the tax incentive?

A. Yes.

Q. Did you prepare slides to assist you in presentation here today?

A. Yes.

Q. If you'll take out that white notebook and turn to what's Tab 12 --

A. Okay.

Q. -- what's been marked as Oxy Exhibit Number 12. Are these the slides that you have prepared for your testimony?

A. Yes.

Q. Does it comprise 23 pages?

A. Yes, it does.

Q. Okay. Let's turn to the first slide. Does this accurately summarize your educational background and work history?

A. Yes, it does.

Q. How long have you been a Registered Professional Engineer?

A. Since 1997.

Q. And it indicates that in 22 years you served as an engineer in oil and gas matters related to production engineering?

A. Yes.

Q. As well as environmental engineering?

A. As well as environmental, yes.

Q. What experience do you have with CO2 floods?

A. All of my production engineering experience has been in CO2 floods. And the most recent production engineering stint was with a reinjection -- CO2 reinjection flood. And then all of my environment experience has been in the Permian Basin, so that was also with CO2 recovery plants and with CO2 fields.

Q. As an environmental engineer, were you involved in health and safety compliance audits?

A. Yes. During my environmental engineering, we did audits, we did compliance, permitting and dealing with regulations and reading the regulations and helping our employees understand them and comply with them.

Q. Were you involved in planning for CO2 floods?

A. Yes.

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

CHAIRMAN BAILEY: Any objection?

MS. GERHOLT: No objection.

CHAIRMAN BAILEY: She is accepted.

Q. (By Mr. Feldewert) Are you aware that there is a Division order that governs the information that must be presented to qualify for the tax relief afforded by the Enhanced Oil Recovery Act?

A. Yes.

Q. Was that information provided in Oxy's application that has been filed with this Commission?

A. Yes, it was.

Q. Do we have some slides that will allow us to quickly go through that particular information?

A. Yes.

Q. Turn to Slide 2. Does this provide us with a legal description of the project area?

A. Yes, it does.

Q. It notes at the bottom that there was an error in the legal description that currently exists in R-4934-E. Are you aware of that?

A. I'm aware of that.

Q. On this Slide 2 of Oxy Exhibit 12, do you identify the area where the error occurred in the order by way of an asterisk?

A. Yes. There are two asterisks noted.

Q. Does this slide accurately reflect the legal description of the project area?

A. Yes, it does.

Q. If I go to what's been marked as Slide Number 3, does this accurately set forth and summarize the amount of acreage that's involved in the project area?

A. Yes, it does.

Q. Does it accurately set forth the pool and formation that's involved?

A. Yes.

Q. Does it identify the orders that are currently governing this project?

A. Yes.

Q. As this reflects, this is a current waterflood operation?

A. That's correct.

Q. At the bottom of this slide, does it identify the proposed operation that is being heard by the Commission?

A. Yes.

Q. If we then go to what's marked as Slide Number 4, does it accurately set forth what you anticipate to be the capital cost of additional facilities?

A. Yes.

Q. Does it identify the total project capital cost?

A. Yes.

Q. You also provided an estimate of the

additional production that you intend to recover?

A. That's correct.

Q. What's the anticipated start date for your injection?

A. September 2015.

Q. Does Slide 4 at the bottom accurately summarize the type of injected fluid and the anticipated volumes?

A. Yes, it does.

Q. If we move on to Slide Number 5, there's one point that we need to make with Slide Number 5. The actual list of the current injection and production wells is not contained in Section 3 of the application. It's actually provided as Exhibits B and C to the application; isn't that correct?

A. That's correct.

Q. Section C, which we incorrectly referenced here, actually deals with the proposed injection list?

A. That's right. That's the list of proposed injectors.

Q. So the list of the current injection and production wells have been provided to the Commission as Exhibits B and C to the application?

A. Yes, that's correct.

Q. Finally, if we go to what's been marked as

Slide Number 6 in Oxy Exhibit 12 -- we've seen this before -- is this the historical and forecasted production history that has been provided to the Division?

A. Yes, that's what it is.

Q. This was actually Exhibit D to Oxy's application; is that correct?

A. That's correct.

Q. Having fulfilled the requirements for the Tax Incentive Act, let's now turn to a discussion, if we could, of the proposed injector wells, okay?

A. Okay.

Q. First off, perhaps what we should do is, if we go to -- put this notebook aside and go to what's been marked as Oxy Exhibit 1, which should be the smaller white notebook, which is the C-108 application.

Ms. Montgomery, if we go to the second tab in that notebook, I believe it contains a list of the proposed injectors that you foresee currently for the South Hobbs Unit?

A. Yes. There's a list of 53 total injectors.

Q. Now, can you just explain to us briefly how this particular portion of the notebook that's marked as Oxy Exhibit 1 is organized?

A. Sure. What you're looking at on this first page is -- in the left-hand column you have the well name. And as you move to the right through the columns, you'll have the API number of that well. The next few columns are the locations of the well. The next column is the proposed injectant.

So the two differences there, you've got the purchased CO2 and water, and then you also have your produced gas, CO2 and water. And this differentiates between the different injectors.

And then the final column talks about the current status of the well. The first 30 are currently active wells, and then the new drills are summarized just below that. So if you turn the page --

Q. We'll go to the second page under Tab 3?

A. Yes. What you have there, there's three 11-by-17 sheets. On the first one, it's labeled, "Injection Well Information for Existing Wells," what you have on here on the left-hand side column is your well number. And this is all of the casing and cement data for each of the existing wells as they are today.

So it goes from conductor cases to surface casing, if they have intermediate casing, production casing, and if there's a liner.

Q. So this is the information on the 30 existing wells?

A. That's correct.

Q. And then what follows this spreadsheet?

A. On the next page we continue with Injection Well Information for Existing Wells. And this talks about -- you have your well numbers on the left-hand side, and then the tubing to be used, a packer description, proposed setting depth, and the injection interval proposed.

On the next page if we continue on, this discusses our new drills, and it's labeled, "Injection Well Information for Proposed New Drills," and all of the information for the new drills is on this one sheet. You've got your well name on the left-hand side column, and then your proposed casing, tubing, packer description, and the injection interval.

Q. There are 23 of these?

A. That's correct.

Q. That's reflected on the third -- actually the fourth page under Tab 3 of this Exhibit 1?

A. That's correct.

Q. And that's broken down into your vertical new drills and then the directional new drills?

A. That is correct.

Q. And then what follows these spreadsheets? There's a series of schematics. What do those relate to?

42113bfd-9cf9-4ebc-b20e-60f9995d1a12

A. These are the individual wellbore schematics for each proposed injector, so all of our current injectors. There will be 30 pages showing those. And then the last two sheets in that are the proposed schematics for the new drills.

So if you go to the last two sheets in that section, the first one says, "Example Wellbore Diagram of Proposed Vertical New Drills." It shows where we'll set the casing and circulate the cement. And on the next page, it's identical, and it's our Proposed Directional New Drills.

Q. Now, being the detailed person that you are, you noticed recently that there is a particular -- there's a typo at the bottom of the second-to-the-last page under Tab 2 of Exhibit Number 1; correct?

A. Yes. This is the Example Wellbore Diagram of the Proposed Vertical New Drills. The total depth says, "4,572." It's actually 4,500, which is consistent with all the tabular data that was presented.

Q. And really there's no -- as I understand it, there's no difference between the two schematics shown on the last two pages?

A. They both have the same true vertical depth.

Q. In terms of their configuration as shown on the schematic, is it basically the same?

A. It's basically the same. The directional -- all of our directional injectors will be at different lengths, so they're not depicted here. They're just depicted as their true vertical depth.

Q. Now, we had this data. Did you undertake an effort to try to organize or summarize these wells in some format?

A. Yes, I did.

Q. If you'll turn to what's been marked Slide 7 of Oxy Exhibit 12. This deals with 53 injection wells that we just briefly reviewed; correct?

A. That's correct. What we present to the Division and talked to the Division about was each individual -- we went through each of the individual wellbore diagrams. But for purposes of this hearing, I tried to summarize that for presentation.

So what we have here is 30 existing wells. All of these wells have surface, and some have intermediate casing, and that is cemented to surface. Twenty-six of those 30 existing wells are configured with surface and production casing. Of those, we have 23 that have the production casing that's cemented to surface. Three of those remaining wells have, at minimum, 600 feet of cement above the injection interval, above the top of Grayburg.

Q. One group or bucket of these 30 existing wells is the 26 wells that you just described? And we have two more groups?

A. Two more groups to summarize the 30 existing wells.

So the second group, there are three wells that I lumped into this group. Two of those have surface, intermediate casing, production casing and a full liner, and one of them has surface production casing and a full liner.

To note on those three, all of these have, at minimum, 720 feet of cement above the top of the Grayburg or above the injection interval.

Q. And the last group?

A. It just consists of one well. It's just configured a little bit differently. It's got surface, intermediate casing, production casing and also has a partial liner at the bottom. This well has at least 1,470 feet of cement above the injection interval.

Q. Do you have a representative schematic of each one of these three groups?

A. I do, if you turn to the next slide.

Q. Slide 8?

A. Yes.

Q. This is for the group of 26 wells?

A. That's correct.

It's easier for me to look at these in the wellbore schematic. So I tried to go ahead and summarize it based on the wellbore schematic. This is summarizing those 26 wells that are existing injectors that were going to be part of the project.

This group, as I said previously, has got surface and production casing. If you look at this wellbore schematic, the black line represents the surface casing. The surface casing on all 26 wells, the shallowest is set here about 302, and the deepest is set at 1,670. All of them have cement circulated to surface.

So what that means is those 26 wells all have production -- excuse me -- surface casing set in this interval and have cement circulated to the surface.

And then the production casing, that is in red, right here, it's set between 4,114 and 4,498. So all of the 26 wells have casing set in between these two intervals.

And then as I said previously, 23 of those 26, the cement is circulated all the way to surface. And then of the three remaining, they have, at minimum, 600 feet of cement above the injection interval. That's just a summary of 26 of the existing injectors.

Q. Ms. Montgomery, in your opinion, do these groups of injection wells have the proper casing and cement to prevent migration of the injected fluid out of the proposed injection interval?

A. Yes, they do.

Q. Let's turn to your second group, which would be on Slide 9.

A. This is -- bear with me. There's a lot of strings of casing on this set.

These are three wells that have surface casing that's shown in black. Two of them have intermediate casing shown in green. And then you move to the production casing in red. And then they also have a full liner in blue.

So this is similar to what we looked at before. The way I set this up is your surface casing on this group of three wells, the shallowest is at 144 and the deepest is at 250. That means you've got those three wells that your casing shoe is set in between here. The cement is circulated to surface.

Q. What's the significance of the hatched lines?

A. Like for example, on this -- right here, on the surface casing, it's all consistent right here. The gray, that shows there's continuous cement all the way to surface, and that's consistent also on the intermediate casing.

But if you look at the production casing, I've got the hatch marks. So what that means is on some of these wells, you're circulated all the way to surface. And the deepest that you would have the top of the cement is in this area right here. So your cement tops are in between this area. So there's always cement up to this point in all this group of wells.

Q. Okay.

A. Then we can walk through this. Intermediate casing was set between 1,653 and 2,768, again, cemented to surface. Production casing set between 4,038 and 4,147. The top of the cement ranges, as I mentioned before, 2,975 all the way up to surface. So the shallowest top of cement would be at 2,975. That's greater than 720 feet of cement above your injection interval.

All of these have a full liner, as well, that is set somewhere between 4,159, to the deepest at 4,202. And the cement on their liner, the lowest cement is at 994, and it ranges all the way to surface.

Q. The intermediate casing that you've identified in green on Slide 9, does that apply to all three?

A. It applies to two of the three. One does not have that intermediate casing. On that particular well, that's the one that has the surface casing that's the deepest at 250. So that well will have surface, production and the liner.

Q. Is that the only difference between that well and the other two wells? In other words, does all the other information on this slide apply equally to that third well without the intermediate casing?

A. That's true.

Q. In your opinion, does this additional group of wells have sufficient casing and cement to prevent migration of the injected fluids out of the injection interval?

A. Yes, it does.

Q. Let's go to the last well.

A. This is the last well. This is the only well with this configuration.

Q. This is depicted on Slide 10?

A. This is Slide 10, yes.

So in this well, your configuration is, you have a surface casing, you have intermediate casing, you have production casing, and then you'll have a partial liner here across the injection interval.

So your surface casing is set at 198 and cemented to surface. Your intermediate casing shown in green is set at 1,630, and you also have cement to surface. Production casing is set at 4,057, and the top of cement is at 2,222. That's like 1,470 feet above your injection interval. And then the liner here, there's cement all the way to the top of the liner, and it's set at 4,260.

Q. In your opinion, does this well have sufficient casing and cement to prevent migration of the injected fluids out of the proposed injection interval?

A. Yes, it does.

Q. That deals with the 30 existing injection wells?

A. That's correct.

Q. Now let's turn to the remaining 22 proposed new wells. Do you have schematics for them, as well?

A. I do.

Q. Let's go to Slide 11.

A. This is just a summary of those 23 proposed new drills. Of those, six of them we propose vertical wellbores, and 17 are the directional wellbores that we talked about yesterday.

The proposed surface casing on all of these is to be set at 1,550 and cemented to surface. And proposed production casing will be set at 4,500 and also cemented to surface.

Q. And then if we go to Slide 12?

A. This is just a picture representation of what that slide just said. You've got -- on all of our proposed new drills, there will be two strings of casing. Your surface set at 1,550 and cemented to surface, and your production in red set at 4,500 and also cemented to surface.

Q. I got behind on the animation.

A. Or I got a little ahead.

Q. This same design is going to apply to both your proposed vertical new drills and your horizontals; correct?

A. Directional.

Q. Or directional. I'm sorry.

A. Yes, that's correct.

Q. In your opinion, will the configuration of these new drills have proper casing and cement to prevent migration of the injected fluids out of the proposed injection interval?

A. Yes, it will.

Q. Okay. Then let's go to the subject of your area of review analysis --

A. Okay.

Q. -- as depicted on Slide 13. That is contained in what's been marked as Oxy Exhibit Number 2; correct?

A. That's correct.

Q. Why don't you -- if we turn to that notebook, would you first walk through it and just tell us how it is organized?

A. Okay. First you'll see a sleeve and there's an area of review map inside of that sleeve. If you turn the page, there's an 11-by-17 paper, and this is the flowchart or overview of how the entire AOR was organized. There are quite a few wells.

COMMISSIONER BALCH: One moment.

MR. FELDEWERT: This is the larger of the white notebooks.

COMMISSIONER WARNELL: What tab?

THE WITNESS: You have the map, and then you have an 11-by-17 paper.

This is a flowchart that just talks about how everything is organized.

MR. FELDEWERT: Let's go through it, and then we'll come back.

THE WITNESS: If you see on the bottom of this flowchart, there's different groups, Group 1, Group 2, Group 3, and how I organized, and I'll discuss that in a moment.

But behind the 11-by-17 page, that corresponds in tabs to each one of those groups. And they're listed here, "Group 1, Group 2, Group 3 and Group 5," all the way to "Group 10."

Q. (By Mr. Feldewert) What is Group 10?

A. Group 10 is all of our P&A'd wells that were included in the area of review analysis, and includes wellbore schematics of each of the P&A'd wells. Those are organized by section.

Q. If I'm looking at the notebook at Oxy Exhibit Number 2, there's a tab that has Group 10, and then behind it are some additional tabs that identify the sections?

A. Yes, the section the well is located in.

Q. Those all correspond to the 121 wells that are the subject of Group 10?

A. That is correct.

Q. Now, with that general understanding, let's go back to the beginning. Let's pull out this bubble map.

Once we get that out, would you just walk us through how this was created? Get us oriented first, and then tell us how this, what we call a bubble map, was created.

A. What you're looking at is titled, "South Hobbs Grayburg and San Andres Unit Area of Review Map." So this is basically -- the South Hobbs Unit is outlined in this magenta dotted line. It's basically the center of your map. It encompasses the entire South Hobbs Unit.

You'll also see some green dots that are scattered around the unit. Some of them are just a green dot and some of them are a green dot with dotted lines coming off of them. All of the green is our proposed 53 injectors.

So the ones that are just a single dot are a vertical. And then like, for example, if you look up in Section 5 in the middle, you'll see a green dot, and there's five directional wells coming off of that. So you can see the surface location and you can also see the bottomhole location depicted for each of the directional wells.

Now, all of the wells in pink are part of the South Hobbs Unit. The wells to the northwest are in purple. Those depict the North Hobbs Unit wells. And then there are also a few scattered around in black, and those are other operators.

So you'll also notice that there's a big shaded area. What we've done is taken from each one of the wellbores surface location and/or bottom location, whichever was the most conservative, and do a half-mile radius around each one.

Q. Let me stop you there. For your existing vertical wells or your injection wells, you can do the half-mile radius out of its surface location?

A. Correct.

Q. Your directional wells are shown in green with the dashed lines going out?

A. Yes.

Q. Explain what you did there with respect to the bubble map for those directional wells.

A. We looked at both the surface location and the bottomhole location and drew a half-mile radius. And whichever one extended further, we used that to include our area of review.

Q. After you had those circles, what did you do then, line them all into this bubble map?

A. Everything you see shaded is included in our area of review, and those are all of the wells that were reviewed for the area of review.

Q. Down in the -- you have to help me. There was a letter that was sent in by an oil company by the name of Big Al Oil?

A. Yes.

Q. Great name. Where are Big Al Oil's wells located?

A. If you look in Section 9 -- and where that is is basically in the middle of the map, if you go up, there's Section 21, Section 16, and then you go up and you see Section 9 right in the middle. Outside the unit boundaries to the southwest, there are two wells in black that are -- it says, "Bradley McInroe d/b/a Big Al Oil & Gas." There's two listed there, the Well Number 1 and Well Number 2.

Q. This bubble map indicates that Big Al Oil's wells are included within your area of review analysis; correct?

A. Yes, they were.

Q. Then having identified your large area of review and having undertaken your analysis, then you tried to, for purposes of presenting it, group the wells into various categories; correct?

A. That's correct.

Q. Unless there's anything more about this map, let's put this away and go into your grouping.

A. Okay.

Q. If I go to Oxy Exhibit Number 1 and I then go to the second -- the first page being the bubble map we just looked at. If I go to the second page, you have your 8 1/2-by-11 sheet entitled, "Occidental Permian South Hobbs Grayburg-San Andres Unit Area of Review Methodology"; correct?

A. That's correct.

Q. Would you walk us through the methodology that you utilized to examine and then group the numerous wells that you were required to look at?

A. The first thing we did was we identified the 53 injectors that will be included in the project and drew our half-mile radius so we knew all of the wells that would be included in this area of review. That totaled 397 wells. Of those, 276 were active or TA'd wells, and 121 wells with P&A'd.

This process began over a year ago. And the first step was to -- we hired a consultant, Mr. David Catanach, to pull the data off the NMOCD well files, and that was our first task. And we also asked him his opinion as he collected the data on each of the wellbores.

Q. Let me ask you something about your data sources. It was the OCD website?

A. Yes.

Q. At times, with some of these wells, was there some -- was it always clear what was going on with that particular well from the data on the OCD website?

A. No. There were a few wells that Mr. Catanach was not able to find. There was a well file mix-up, or there were a few things that he had questions on. So with those few wells, we looked through the Oxy information, and we then sent that information to the -- I guess in the form of a sundry, sent that into the NMOCD to update those files.

Q. So whatever additional data that you had within the company to help deal with the -- and clarify the circumstance of the well, you took that into account in your analysis, number one?

A. Yes.

Q. And you also filed it by way of a sundry notice with the Division? So now all of this data is in the OCD website?

A. That's correct.

Well, then I took the data, after we received it back from our consultant, and reviewed each well. There was a large number of wells. So for me, it was the easiest thing to group them by well construction so that it was easier to analyze the individual wellbores. So that's what I've done.

When you see these nine groups -- for example, you have like Group 1. Those are shallow wells. Those actually did not even penetrate our Grayburg-San Andres, but they were included just to make things complete. There are only two wells in that group.

So I did that for each one. So you can see the same thing. Group 2, there are some deeper wells with surface and production casing. You can go ahead and read through these.

But bottom line, what was done, if they had a

42113bfd-9cf9-4ebc-b20e-60f9995d1a12

similar well construction, for example, they were cased with similar strings of casing and they were at similar depths, I grouped them into a group so they would be easier to analyze.

So if you go to Group 1, Tab 1, on each one of these tabs, what you'll find is wellbore schematic where I tried to summarize the data. And then if you turn the next page, you'll see the actual tabular data as was provided to us. This tabular data has got everything on it, and this was the individual information that was used to analyze each well.

Q. Now, if we look at your -- let's focus right now on Groups 1 through 9. It looks like the largest group was Group 4?

A. Yes. That contained 166 wells, so that was our largest bucket.

Q. So let's -- I think we have a slide for that that's marked in Oxy Exhibit 12 as Slide 14.

Why don't you -- just by way of example, let's just walk through Group 4.

A. I wanted to walk through this group because it contained our largest number of wells, so I can show you how I tried to summarize the data.

In this group it has two strings of casing. You have surface casing in black and production casing in red. In this particular group, all the surface casing was set between 281 feet and 1,718 feet. So all the cement in this group behind the surface pipe was cemented to surface either by the initial cement or through subsequent remedial cementing. So all of your casing is set in between these two depths.

Now, all the production casing you can see in red. These are set between the depths of 3,983 and 5,370. All 166 wells are in between these two casing shoe depths. The top of the cement ranges from 3,225 all the way up to the surface in these wells. At minimum, you have 470 feet of cement above the Grayburg-San Andres formation in this particular group.

Q. You did this type of analysis and grouping for each of the groups identified as 1 through 9 on the second page of Oxy Exhibit 2?

A. Yes, I did.

Q. How did you go about putting together this schematic for each group? What was your methodology?

A. You have to look at each individual wellbore to do this, so they're all in a spreadsheet. So the first pass was to go line by line and look at each one. And then I was able to import them into a spreadsheet and try to sort it so you can look at top of cement or any anomalies like that. But really, there was no -- we still had to go through line by line in the tabular form for each one of the wells.

Q. All of this information that we see -- let me step back. With Group 10, rather than try to organize it by group, how did you approach the P&A'd wells in Group 10?

A. The P&A'd wells, we identified initially. And we hired a consultant, Mr. Ben Stone, to construct the P&A diagrams and go through the NMOCD online database to pull the information.

Q. You have all that information, diagrams, individual wellbore diagrams, by section under Tab 10?

A. Yes.

Q. You mentioned that you had visited with the Division about your area of review information. I think you mentioned a couple of meetings?

A. Yes. We had two meetings. Mr. Ezeanyim was in both of those meetings.

Q. Did you review all of this information with Mr. Ezeanyim?

A. We did. We walked through this type of analysis. But we also got into individual wells, and we walked through many P&A'd wellbore diagrams with the Division.

Q. After all this analysis, how many -- I guess we'll call them problem wells. How many did you find?

A. We found one potential problem well that we identified.

Q. Do we have a schematic on that?

A. Yes.

Q. Turn to what's marked as Slide 15.

Why don't you tell us what's going on with this particular well.

A. Okay. This one is a well that we identified. It's not operated by Oxy. It was a Chesapeake Operating Company, but they recently sold this well to Chevron. It was drilled in 2002, and it's located on the southwest corner of -- I think it's actually southeast. Anyway, on the south part of the South Hobbs Unit.

This well has two strings of casing. The surface casing looks fine. It was set at 1,723 and the cement was circulated to the surface. But if you look, this is a -- production casing was set at 7,787. It's a deep well producing from a different horizon. And the top of cement was calculated to be 4,454, which was not adequate to cover our injection interval.

Q. Did you have enough -- we labeled this as a problem well. But do you have enough information to know if it really is a problem yet?

A. No. We contacted both Chevron and Chesapeake to see if they had any more information in their well files, and they indicated they did not. So I guess we would probably need to run a CBL to ascertain exactly where that cement top is. And then if it's not adequate, then it would have some type of remedial cement to get it to Division's standards.

Q. Is it the company's intention to do some analysis to ascertain whether there is a problem with this well?

A. Yes.

Q. And if there is, to undertake whatever remedial efforts are necessary to ensure that the injectants do not migrate out of the zone?

A. Yes.

Q. Does the company intend to inject within a half mile of this well before this analysis and remediation is undertaken?

A. No, we do not.

Q. So the company will not engage in any injection operations within a half mile of this well until it has been reviewed, analyzed and any problems dealt with; correct?

A. That's correct.

Q. Putting aside this well, this particular well on Slide 15, in your opinion, are all of the remaining wells within the area of review sufficiently cased or cemented to prevent migration of the injected fluids out of the proposed injection interval?

A. Yes, they are.

Q. Now let's go to the next topic, and that is dealing with bringing these injection wells on line.

There's been testimony yesterday about the time frame that is associated with getting this project up and running and in commencing this tertiary recovery project. First off, as you know, or as I understand it, you don't anticipate the injection to commence for another two years?

A. That's correct.

Q. And then after that point in time, there's going to be additional injection wells that -- at least 53 that are going to be brought on line gradually as you're able to get the facilities in and get the work completed?

A. That's correct.

Q. Given that timeline, is the company requesting that there be a period of time in which this area of review would essentially remain in place so that you don't have to repeat this extensive analysis two or three years from now?

A. We're requesting five years.

Q. If I go to Slide 17, as I understand it, you are requesting two things. That is there would be no update to the area of review for wells that commence injection within the next five years?

A. Yes.

Q. What about the wells that would commence injection greater than five years from now?

A. What we propose is to re-look at the wells, and any wells within the area of review that we already examined and we've already had the Division review, we would not update those AORs. But we would update anything that was new in that area of review, anything within that half mile.

Q. What's your rationale behind that request?

A. There are several reasons that we -- like you just mentioned, this project is going to be phased in over many years, and we won't even begin with injection for two more years. So there's -- we've already reviewed everything, every well in the South Hobbs Unit at that time, so it would be duplicative if we submitted area of review twice for these wells -- I'm sorry. I just got ahead of myself. We've already done the area that covers everything.

This is a concept that was adopted in the North Hobbs Unit, and we're doing it today. And it really streamlines the process. For anything that's already been submitted and reviewed and accepted by the Division, we would only update things that have changed and conditions that have changed.

I also looked at this current area of review. And in the last 10 years, there were four wells drilled in this area. There's not a lot of activity. Two of them were by Oxy. The activity in this area is really going to be associated with the CO2 project, and Oxy is the one driving that, so we will know if there's any changes going on in the area of review.

Q. In your opinion, is there anything to be gained from redoing and resubmitting this entire analysis contained in these two notebooks for this area over the next five years?

A. No.

Q. In your opinion, will this request by Oxy pose an unreasonable risk for the public health or the environment?

A. No.

Q. I now want to turn to a discussion of the TA'd wells, in particular, the mechanical integrity test frequency that currently exists for the wells in the South Hobbs Unit. What is Oxy requesting?

A. What we're requesting is for our temporarily

42113bfd-9cf9-4ebc-b20e-80f9995c1a12

abandoned wells to have an MIT frequency of five years on those wells that we installed pressure monitors and we have real time monitoring on those wellbores.

Q. So it's only for these wellbores that Oxy gets these real time monitors on that Mr. Hodges talked about?

A. That's correct.

Q. That would be connected to your SCADA system?

A. Correct.

Q. Until those real time monitors are on those wells, this exception that you're requesting would not apply?

A. That's correct. We would just be at the frequency that is prescribed by the Division or the District Office.

Q. Let's go to Slide Number 17 first. Under the current regulatory environment, there's two rules that provide MIT frequency. One is for temporary abandoned wells and one is for injectors; correct?

A. That's correct.

Q. The rules for the temporary abandoned wells essentially, at least, seem to contemplate in circumstances a five-year cycle; correct?

A. That's correct.

Q. Given that, if we go to what's been marked as Slide 18, what is the current frequency for your TA'd wells in the South Hobbs Unit?

A. These were pulled down from the -- per the NMOCD District Office, the data. So what you see on the left-hand side shaded in purple are the wells that are on a five-year -- currently on a five-year MIT test frequency in the South Hobbs Unit. That's 24 of our wells.

In the blue shading, there are 16 wells, and those wells are on a one-year test frequency. And then we have a few that are on -- I think one well is on a two-year test frequency, and three wells are on a four-year test frequency.

Q. That's going on currently in the South Hobbs Unit?

A. Yes. I believe this was pulled in March, this data.

Q. Obviously, you have to have personnel devoted to this, and the Division has to have personnel devoted to this; correct?

A. That's correct.

Q. If you turn to Slide 19, this is what you are -- to maybe put it in written language, this is what you are essentially proposing; correct?

A. That's correct.

Q. This would be your alternative to the current

MIT schedules that are in place for the South Hobbs Unit by the District Office?

A. That's correct.

Q. You are going to do an MIT when the well is initially TA'd; correct?

A. Yes.

Q. For example, as Mr. Brockman pointed out, there are some additional TA'd wells that are going to occur as a result of your development plan?

A. Yes.

Q. Before those go into TA status, you're going to do an MIT per the Division standards?

A. That's the plan.

Q. And only for those wells where you installed a sensor device are you asking for this five-year frequency?

A. Yes, that's correct.

Q. If it's requested, you will share this data with the Division office?

A. Yes. And I also spoke with Mr. E.L. Gonzales about this, and we talked about having data available to the District Office on all these wells that we have pressure monitors on.

Q. Is he -- what was his reaction to this alternative that Oxy has proposed?

A. He was in favor of it. We talked about how we could make it work and how it would work for both Oxy and the District Office. But he was in support of this.

Q. Now, in addition to what you are proposing here, you will also do annual Bradenhead tests on your wells; correct?

A. On the injectors and on the TA'd wells, that's correct.

Q. What I'm going to do is skip -- let's go to Slide 21. Does Slide 21 identify your Bradenhead testing program?

A. Yes, it does.

Q. Why don't you walk us through this.

A. The Bradenhead, as you know, is the annular space between the surface casing and the production casing. This test that they do is designed to indicate that there's casing integrity between the surface and the production casing. And all of our injectors and our TA'd wells do this annually, and the results are submitted to the District Office.

Q. So you have this annual Bradenhead testing program reflected on Slide 21. And then in addition to that, for these TA'd wells, you will have sensor monitors like those depicted on Slide 22?

A. Yes. You're looking at an injection well.

This is not a TA'd well. But the point of this slide was to show what the pressure sensor monitor would look like. It's the same one that we have on our injection wells currently.

Q. Does the request that -- in your opinion, does the request that Oxy seeks here as reflected on Slide 19, will that provide a reasonable level of protection to the public health and the environment?

A. Yes, it will.

Q. Do you believe that that is an equally safe alternative to the MIT frequencies that currently exist for your TA'd wells in the South Hobbs Unit?

A. I do. And it also -- because it is tied to a SCADA system and you have pressure monitoring, so you also will know, on a higher frequency, very quickly if you've got any pressure issues. Whereas with MIT frequency, you have to wait for the test to know.

Q. Now, on the slide I skipped, Slide 20 -- before we talk about Slide 20, let's go back to that Slide Number 17.

You mentioned that the Division rules contemplate a five-year frequency for both temporary abandoned wells and also for injectors; correct?

A. Yes.

Q. At the bottom of Slide 17, the rules state that at least once every five years thereafter, the operator shall test an injection well?

A. That's correct.

Q. If we go to what's marked as Slide 20, what is the purpose of the slide?

A. The purpose of this is to show that we do have an MIT program for the injection wells; that we also have pressure monitoring on our injection wells; and that we have data that would be available to the District to show any type of casing issue or tubing packer issue, because we've got the pressure monitors on our injection wells.

Q. In your opinion, given the -- and you do your annual Bradenhead test?

A. Yes.

Q. Both on your TA'd wells and on your injectors?

A. That's correct.

Q. Given that circumstance, in your opinion, is it necessary for the company and the Division to be involved in an MIT on these injection wells on a yearly basis?

A. No.

Q. Did you meet with the Division about a frequency that would be appropriate for your injection wells given the real time monitoring devices that you have available and given the fact that you conduct your

42113bfc-9cf9-4ebc-b20e-60f9995d1a12

annual Bradenhead testing?

A. Yes, we discussed this.

Q. What was the result of those discussions?

A. When we talked to the Division, with Mr. Ezeanyim, he mentioned that he would recommend a two-year frequency for the MIT on the injectors. We did not object or disagree with that recommendation. The purpose of this is just to show that we will be equally protective on our injections and will have monitors on our injection wells.

Q. In your opinion, given the circumstances reflected on Slide Number 20, in your opinion, do you believe a reasonable level of safety is provided if the MIT program for injectors was every five years, as contemplated by the rule, or at least as -- within the contemplation of the rule?

A. Yes.

Q. And do you believe that that would provide a reasonable level of protection to public health and the environment?

A. Yes, I do.

Q. Let's turn to the last topic, and that is the Rule 15 that currently exists under Division Order 4934-E. First off, do the requirements that are depicted here in Rule 15 exist for the well in the North Hobbs

Unit?

A. No, it does not.

Q. And in your opinion, is this rule, as it currently exists with the South Hobbs Unit, is it necessary to protect the public health and the environment?

A. I don't believe so.

Q. Why is that?

A. We've analyzed all of our wells in the South Hobbs Unit and we've looked at the cement, we've looked at the cement tops, and we've determined them, also with the Division, to be adequately cemented. So we feel like they're already protective. Any new injectors will have cement circulated to surface.

And this rule here, the way it's written, it contemplates running multiple CBLs anytime you pull a well, and I don't think you get anything different if you run multiple CBLs on the same well.

Q. Do you believe that this rule, if it remains in effect, will result in the running of CBLs for existing wells that are unnecessary?

A. I do.

Q. Is there anything to gain by running cement bond logs on a production well, for example, every time you pull the rod and the tubing?

A. No, I don't think there is.
Q. Are you asking the Commission to essentially strike this Rule 15?
A. Yes, that is what we are asking.
Q. In your opinion, will the striking of this Rule 15 pose any threat to the health and safety of the public?
A. No, it will not.
Q. If I turn to what's marked as Oxy Exhibit Number 4, this is the original order that was entered by the Commission in 1974; correct?
A. Correct.
Q. For the waterflood operation?
A. Yes.
Q. If I go over to Rule 13, which is on page 7, that's the same rule that we're talking about here on Slide 23?
A. Yes, that's correct.
Q. Then in 4934-E, because of changes in the numbering of the rule system, it became Rule 15?
A. That's correct.
Q. So essentially this rule was put in place back in 1974?
A. That's correct.
Q. At a time when we knew very little or didn't

42113bfd-9cf9-4ebc-b23e-60f9995c1a12

know as much as we know now about the wells that exist within the South Hobbs Unit area?

A. Yes.

Q. Based on the knowledge that we know now about all of the wells in the South Hobbs Unit area, in your opinion, do you see any reason to retain this rule any longer?

A. No, I don't.

Q. In your opinion, will 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.

Q. In your opinion, will the granting of the relief requested by Oxy pose an unreasonable risk to the public health or the environment?

A. No, it won't.

Q. Were the slides comprising Exhibit 12 compiled by you or under your direction and supervision?

A. Yes, they were.

MR. FELDEWERT: Madam Chair, at this time I would move the admission of Oxy Exhibit Number 12.

MS. GERHOLT: No objection.

CHAIRMAN BAILEY: Then it is admitted.

(Oxy Exhibit 12 was admitted.)

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

CHAIRMAN BAILEY: Do you have any questions for this witness?

MS. GERHOLT: I do, Madam Chair. Thank you.

CROSS-EXAMINATION

BY MS. GERHOLT:

Q. Good morning, Ms. Montgomery.

You were the individual who submitted the C-108 on behalf of Oxy?

A. That's correct.

Q. And according to the first page of the C-108, Oxy has applied for a secondary recovery and pressure maintenance; is that correct?

A. That's correct.

Q. Why did Oxy apply for both?

A. I guess in discussions with -- when we were filling out the application, what it is is a tertiary recovery project. And I guess there were some discussions between us and our legal counsel about which one was the appropriate box. We checked them both. But our intent is this is a tertiary recovery project.

Q. I noticed on this form -- this is a Division form; correct?

A. Yes.

Q. -- that there isn't a place for a tertiary recovery project; is that correct?

A. That's correct.

Q. If you will educate me a little bit this morning. My understanding about pressure maintenance is that it retards the reservoir pressures and the actual decline; is that correct?

A. I guess that's what it -- yes.

Q. Does pressure maintenance describe anything else in terms of enhanced recovery?

A. As we saw on the exhibit that showed the production, not only it retards the decline, you're going to have quite an increase in production based from the EOR project.

Q. That's the EOR project generally?

A. Yes.

Q. I'm interested in pressure maintenance. Does that pressure maintenance piece help to increase it?

A. I mean -- yes, it will.

Q. Is it your understanding that a secondary recovery project can include injection of natural gas or other substances into a pool?

A. Typically, when you refer to something as a secondary recovery, it's your waterflood phase, after your primary. And then it's called tertiary, when you have your EOR project.

Q. And an EOR project can include injection of other substances?

A. That's correct.

Q. And it is into a pool?

A. That's correct.

Q. And the Grayburg-San Andres is a pool?

A. That's correct.

Q. Just some more housekeeping questions for you. Currently Oxy is operating the South Hobbs Unit. Is Oxy reporting the monthly volumes and types of injectants on the C-115; do you know?

A. I don't know, because I'm not in charge of filing that. I assume so, but I wouldn't know that.

Q. Would that be possible for you to find out and maybe relay back to your counsel?

A. Absolutely.

Q. The reason I'm asking is the Division does have a reporting requirement of a C-115. And if Oxy is not already doing it, would Oxy be willing to meet that reporting requirement?

A. I'm sure we would.

Q. Okay. If I can now draw your attention to Slide 15, the problem well?

A. Yes.

Q. Am I understanding from your testimony on direct that Oxy reached out to both Chesapeake and Chevron to ask for information from their well files if their well files were more complete than the Division's; is that correct?

A. Yes, we did.

Q. And based upon that, Oxy has determined that they need to run a cement bond log?

A. Correct.

Q. And the potential, depending upon what that log results, that additional cement may need to be used for this well?

A. Yes.

Q. My question is: Will either the cement bond log, or if additional cement is needed, will those be communicated to the Division?

A. Yes.

Q. Would that be in the form of a sundry, most likely?

A. Most likely a sundry. I guess I'm not sure how that works. We work with the District Office. But it would have to be done to show that it's protective.

Q. Slide 16, updating the AOR for future injection wells, a point of clarification. Oxy is willing to update the half-mile area of review. Is that when a different injection well is proposed by Oxy, or just every five years to see if a new well by some other operator has been drilled?

A. What we would propose is that this area of review consist for five years because we've done an extensive review. It took over a year. And we have looked at every well. And there's very, very little activity, other than Oxy, in the South Hobbs Unit.

So during that first five years, we would not conduct another AOR. We would rely on this area of review.

After that five years, if a well is drilled, injectors -- even if it's in here, if it's after that five years, what we would do is look at that half mile again. If we've already submitted and have the area of review data, that wouldn't be -- we would just submit a statement saying that it's already been looked at in this case and reviewed and that the area of review is good.

If there's anything new in there, we would certainly look at that and provide any information for anything new in that area of review, is our proposal.

Q. Thank you for that clarification.

Now, if I can draw your attention to Slide 18, the currently TA'd wells?

42113bfc-9cf9-4ecc-b20e-c0f9995c1a12

A. Yes, ma'am.
Q. There's 44 wells that are currently TA'd; is that correct?
A. Per the information we pulled in March, that's correct.
Q. As you stated on direct, certain wells are on a one-year test frequency and other wells are on five years, and there's a variation between. Do you know why certain wells are on a one-year test frequency?
A. I don't. It's set by the District Office. I'm sure it has to do with how long a well is TA'd. But I really don't know. It's set by the District Office.
Q. The District Office was provided a list of the 44 wells by Oxy. And in review of that list, there appears that the wells that are on a one-year test frequency have been TA'd for at least 20 years and one up to 26 years. Does that surprise you or --
A. I wasn't aware of that.
Q. So given that at least one of these wells has been temporarily abandoned for 26 years, does Oxy intend to place pressure monitoring equipment on these 44 wells?
A. That is the intent, yes.
Q. Does Oxy have a timeline for placing these pressure monitors?
A. I have not discussed the timeline on those

42113bfc-9c9-4ebc-b20e-60f9995c1a12

yet. I guess we're going to see if it was approved and how that works. And then I'm sure we will get a timeline and discuss that with the District Office.

Q. And would allowing for the District Office to have some input on that timeline be acceptable to Oxy?

A. Yes.

Q. I do have a question about the pressure monitoring data. On direct, you stated that Oxy would be willing to share that with the OCD for the Division's review; is that correct?

A. Yes.

Q. How long is that information maintained by Oxy?

A. I don't know the answer to that. I don't know how long it's in our SCADA system.

Q. Obviously, you don't necessarily need to maintain it for 40 years in the Division. But if there is some sort of set time for maintenance, whether it's five years or -- but to have it maintained for that period so the Division could ask for it, maybe you'd be able to provide your counsel with the time the SCADA keeps that information?

A. We could do that.

Q. Thank you. Then you also stated on direct that you met with Chief Engineer Richard Ezeanyim at

least twice in regards to this application?
A. That's correct.
Q. Have you had an opportunity to review his recommendations?
A. I have.
Q. Does Oxy object to any of those?
A. No, we do not.
Q. My final question is in regards to Slide 23, about the cement bond logs. My understanding is there are times where cement can't be circulated to surface. Is there -- I understand Oxy plans on circulating cement to surface on all of these wells. Is there any contingency plan in place if that fails to occur --
A. I don't --
Q. -- since the cement bond logs won't be run?
A. I don't know of a contingency plan if something is not circulated to surface. Certainly it's our intention to circulate to surface.
Q. Of course Oxy does report to the Division on C-103s that work has been done on a well; correct?
A. We do. And we also report when we run a cement bond log.
MS. GERHOLT: I have no further questions for this witness.
CHAIRMAN BAILEY: Mr. Warnell?

42113bfa-9cf9-4ebc-b20e-60f9995c1a12

EXAMINATION

BY COMMISSIONER WARNELL:

Q. Good morning, Ms. Montgomery. I'd like to continue along the same line that Ms. Gerholt was talking about with cement bond logs. We talked a lot about cement tops. Some of these wells we were looking at the cement tops, they were drilled back in the '30s, '40s, pretty old wells?

A. Um-hum.

Q. How did they determine cement top?

A. Well, if there was a temperature survey or CBL, that's how the cement top was determined.

But for purposes of this AOR, we used a formula and derated it by -- as a 70 percent fill to give it a conservative nature on calculating the cement top.

Q. So when you refer to cement tops being a certain depth, that's calculated cement top?

A. Some of them, yes, are calculated, if we did not have a temperature survey or CBL indicating the cement top.

Q. I assume that very few wells had temperature surveys or CBLs?

A. I wouldn't know the exact number. But I did review all of our AOR in just the South Hobbs Unit wells, and we had over 77 percent that either had some type of a

42113bfd-9cf9-4ebc-b20e-6...

log or were circulated.

Q. What's the best method that Oxy uses today to determine cement top?

A. Well, on a new drill, we attempt, of course, to circulate, and then you could calculate it or do a cement bond log to determine the height of that cement.

Q. If your intentions were to circulate to the surface and, for some reason, you weren't able to circulate to the surface, you could run a cement bond log and determine that --

A. Yes.

Q. -- exact cement top?

A. And we do. I've seen that in cases, that we do.

COMMISSIONER WARNELL: Thank you. That's all I have.

CHAIRMAN BAILEY: Mr. Balch?

EXAMINATION

BY COMMISSIONER BALCH:

Q. I'm also curious about cement bond logs.

So on a new drill, is this something that's done as a standard part of the wire line?

A. A cement bond long?

Q. Yes.

A. If the cement is circulated, I don't believe a

42113cfc-9cf9-4ebc-b20e-6c79995c1a12

cement bond log would be run, because you would see the cement on surface.

Q. So you have a calculation on how much cement it's going to take -- oh, I see. It comes out?

A. Right.

Q. So if Rule 15 is stricken from the existing rule, it sounds like, from Mr. Warnell's questions, that some of these wells will never have a cement bond log?

A. That could be the case.

Q. And I imagine, under normal circumstances, you don't really run repeat cement bond logs. But these are wells that, in some cases, have been running for almost 80 years, and they run for another 40 or 60 years, and during part of that, have some corrosive, acidic components to the injectate. Do you think it would be appropriate at any point to check the status of cement in these injection wells?

A. I know that we -- there is a -- you can run a cement bond log if there's a reason to run it, like if you have some casing integrity issues.

But you also have a problem running a cement bond if you have a well that's cased and you have another pipe behind that, and you run a cement bond, you're really not going to see -- it's not going to give you the reading that you want to see because you've got too much

42113bfa-9cf9-4ebc-b20e-60f9995c1a1c

behind that. You're not going to get a true reading.

So there are also issues with running cement bonds on existing wells depending on how they are configured.

Q. I would be more concerned with your production casing, the stuff that you're trying to seal off the producing interval from everything above it. That would be a case where you probably have one casing and one cement?

A. On several of the wells.

Q. Right. So that portion of the well -- there's also the part that would be vulnerable to any sort of a leak of either CO2 or your produced gas injection or your water. It might be vulnerable to corrosion.

So if I got you correctly, you're saying if you saw a problem with a well, that's when you would check that, but you wouldn't do it as a matter of course at the beginning of injection?

A. That's correct.

Q. Do you think it might be appropriate for this sort of a long-term injection project to at least check the portion of the production casing above the injection interval?

A. On the injectors?

Q. Right, before you start injection.

A. If a well is circulated, I see no reason to run a cement bond log. If the cement was lower, you could run a cement bond log to determine the top. But on a well that's already circulated, I don't really see an issue with that.

Q. On a completion log, I guess -- I don't know what you call it. But when these wells were drilled, somebody would have noted if they had seen the cement circulated to the top?

A. It's noted. And if a cement bond log was run, because several were run, multiple bond logs are not going to be beneficial, I don't believe.

Q. Okay. I looked up the Big Al wells, the two in Section 9. One of them looked like the casing had been cut. Was that plugged back?

A. Yes, with cement.

Q. So that's producing from Seven Rivers, and it's now isolated from the reservoir?

The other one was in Group 4. It didn't have that information, so I'm assuming it's producing from -- or has not been plugged back?

A. It's producing from the Seven Rivers, as well, and has cast iron bridge plugs isolating it from the San Andres.

Q. Do you think that both of those wells are

42113bfa-9c19-4ebc-b20e-60f9995c1a12

going to be isolated from the injection program at the South Hobbs Unit?

A. I do.

COMMISSIONER BALCH: Thank you. Those are my questions.

CHAIRMAN BAILEY: I have a couple of questions.

EXAMINATION

BY CHAIRMAN BAILEY:

Q. The cement bond log not only shows top of cement, but it also shows channeling behind the pipe, doesn't it?

A. I believe that it does. I'm not overly familiar with all the different things in the cement bond log.

Q. Even though the comments have been concerning the top of the cement, the problem of channeling may also arise for injectors, wouldn't it?

A. I don't know the answer to that. If you don't have a good cement bond with your pipe. But -- I guess it could. I don't know.

Q. A couple of other questions. The areas of review where you did look at the cement bond logs, was there only one problem well for those existing injector wells? Or did your review indicate that there were other issues that need to be addressed when this unit is approved?

A. No. There was just that one well that was at issue.

Q. The directional wells that will be drilled from the produced gas injectors, will they be perforated only under the city limit areas? Where would those perfs be?

A. The perfs will be down in the San Andres, which is, I think, like around 4,410-foot depth is the only place you would have perforations.

Q. And the angles of each of those directional wells will be varied according to what direction and the length of that wellbore?

A. That is correct.

Q. There was no discussion on the kind of cement that is anticipated for the new drills. I understand that there is an acid-resistant cement that is available. Is that contemplated to be used for completions of these new wells?

A. It will be used.

Q. There was one slide that showed water. I just want to reconfirm that no fresh water will be used in this unit?

A. That's correct.

Q. The slide that showed the incorrect legal description that was on the order, was that -- with the correction of the legal description, does that increase or decrease the acreage that was described in that order?

A. I believe it increases it. But our next witness will be able to talk to that.

CHAIRMAN BAILEY: Okay. I'll ask him about that.

That's all I have. Thank you very much.

Do you have any redirect?

MR. FELDEWERT: I just have a couple.

REDIRECT EXAMINATION

BY MR. FELDEWERT:

Q. On the area of review analysis issue, the updating of that area of review, any new well, as you put it, that was drilled by Oxy over the next five years, is going to comply with all the design requirements that have been approved for both its injectors and producers; correct?

A. That's correct.

Q. So to the extent that you're adding wells to the area of review, we know the design that's going to go into those and we know that they're going to be adequately designed to prevent migration of fluids from the injection interval -- outside of the injection

4213afa-9cf9-4ebc-b20e-60f9995a1a12

interval?

A. That's correct.

Q. With respect to the mechanical integrity request, to the extent that you have a well that's on a one-year frequency or a two-year frequency or something like that, under your proposal that frequency is not going to change until you get a pressure sensor device on that well and it's connected to the SCADA system?

A. That's correct.

Q. So any concerns about the existing wells that are on a more consistent frequency, you've got the incentive, if this is granted, to get the pressure sensors on those wells so you can avoid the frequencies that are less than five years?

A. That's correct.

Q. Commissioner Balch talked to you about the cement bond logs issue. There's actually two parts to this current rule; correct?

A. Yes.

Q. The first one says, "Prior to placing a well on injection, a cement bond log shall be run on said well"; do you see that?

A. Yes.

Q. Prior to placing a well on injection, the new drills, you're going to be circulating cement; correct?

A. That's correct.

Q. And if you don't get the correct circulation to the surface, what are you going to do as part of your design?

A. We typically run a cement bond log to see what the top of the cement is.

Q. If you're successful in getting cement run to the surface, there would be no reason to run a cement bond log?

A. That's correct.

Q. The second part of this rule that's been left over from the '70s, says, "Also, anytime the rods and/or tubing are pulled from any producing well in the project." Does that aspect of the rule make any sense to you?

A. No.

Q. Is that -- I mean essentially, the way it's written, it would result in running the same CBL on the same well?

A. That's correct, as written.

Q. In addition, any concerns about casing, perhaps channeling, as I understand it, won't those be picked up in your annual Bradenhead tests?

A. Yes. Because any fluids that would migrate to the surface or would cause pressure on the Bradenhead

42113bfc-9cf9-4ebc-b26e-60f9...

will be caught in the Bradenhead testing.

Q. So you have a mechanism in place already to ensure, with your annual Bradenhead tests, that there are no issues?

A. That's correct.

MR. FELDEWERT: I think that's all the additional questions I have.

CHAIRMAN BAILEY: Then you may be excused.

Why don't we take a 10-minute break.

(A recess was taken.)

CHAIRMAN BAILEY: If you'd like to call your next witness?

MR. FELDEWERT: I would.

I visited with Oxy about what they're requesting with respect to Rule 15 in light of the questions that you posed.

And what they would like to see is that we retain essentially the first clause, "Prior to placing any well on injection, a cement bond log shall be run on said well, unless cement has been circulated to the surface," and then strike the remaining aspect of that rule. I think in light of the questions, that makes sense to us, and we hope that it makes sense to you.

With that said, we can move on to our last witness.

CHAIRMAN BAILEY: Okay.

MR. FELDEWERT: We'll call Mr. Pat Sparks.

PATRICK SPARKS

Having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. FELDEWERT:

Q. Mr. Sparks, could you please state your full name for the record and identify with whom you are employed and in what capacity.

A. Yes. I'm Patrick Sparks. I'm employed by Oxy as a landman.

Q. How long have you been with Oxy as a landman?

A. Forty-two years. Or as a landman, a little over 30 years, but with Oxy, 42.

Q. Prior to being a landman, what were your responsibilities?

A. I came through the accounting and finance group doing planning and budgeting.

Q. How long -- you said you've been a landman with Oxy for 30 years. How long has your responsibilities included the Permian Basin?

A. A little over 20 years.

Q. Have you had the opportunity to previously testify before the Oil Conservation Division?

A. Yes.

Q. And were your credentials accepted and made a matter of public record?

A. Yes, sir.

MR. FELDEWERT: Madam Chair, I would tender Mr. Sparks as an expert witness in petroleum land matters.

CHAIRMAN BAILEY: Any objection?

MS. GERHOLT: No objection.

CHAIRMAN BAILEY: He is accepted.

Q. (By Mr. Feldewert) Mr. Sparks, are you familiar with the land circumstances associated with the South Hobbs Unit?

A. Yes, sir.

Q. Are there any federal lands in the South Hobbs Unit project area?

A. No, sir.

Q. Are there any state lands?

A. Yes, sir.

Q. If we pull out -- turn to what's been marked as Oxy Exhibit Number 13. It's a rather large map. If we pull that out, can you describe what it depicts?

A. This is a relatively current -- the most current, that we've had access to, aerial photo of the Hobbs area, showing the city of Hobbs and the surrounding areas, with the South Hobbs project area being outlined

42113ofa-9cf9-4ecc-b20e-60'9995a1a12

in blue, and our North Hobbs Unit being outlined in green.

Q. Let me ask you a question since we have this map out. There was a discussion earlier about the change that needed to be made to a description of the project area?

A. Yes, sir.

Q. Are you familiar with the changes that occurred -- let me back up. Are you familiar with how the area description needed to changed to conform with the actual boundary of the South Hobbs Unit?

A. Yes, sir. During our review, we reviewed an area and found a discrepancy in the description of the previous area.

Q. Did that result in enlargement of the unit area or a subtraction?

A. This was a voluntary unit, and there was one operator that owned two 80-acre tracts that did not ratify the unit. So those two 80-acre tracts came out of the unit. Subsequently one of the 80-acre tracts was included in the North Hobbs Unit.

Q. So the acreage description that has been previously depicted as Slide 2 of Oxy Exhibit 11, does that now accurately reflect the project area for the South Hobbs Unit?

42[illegible]3bfc-9cf9-4ebc-b26e-60f9995c[illegible]a[illegible]2

A. Yes, sir.
Q. This map that's been identified as Oxy Exhibit 13, does it also give a picture of the areas that were subject to the notice requirements for this hearing?
A. Yes, sir.
Q. What essentially was your notice area?
A. We started our notice research prior to having all the injection locations. So we took the approach of anything within a half mile of the unit boundary, we put on the notice list.
Q. So as it turned out, with the bubble map, you were a little more expansive with your notice area than, perhaps, the rule requires?
A. Correct.
Q. Basically, you went a half mile outside the blue line that's shown on Oxy Exhibit 13?
A. That's correct.
Q. Did you lead a team to do the land research that was necessary to provide this notice?
A. Yes, sir.
Q. How many employees and how much time and effort went into identifying and acquiring the information you needed to send out the appropriate notice for this hearing?
A. We worked a little over six months. I had two

full-time and one half-time people in the field at all times, plus our internal people.

Q. For how long?

A. A little over six months.

Q. Quite a project?

A. Town lots are tough.

Q. In your analysis if you had a tract that touched within a half mile of the unit boundary, was that tract included in your notice and data pool?

A. Yes. Anything within a half mile of the unit boundary was in the data pool.

Q. Did you undertake efforts to identify the operators and lessees of record for each of those tracts?

A. Yes.

Q. And in the event it was an undeveloped tract, did you undertake to determine all the mineral interests?

A. Yes.

Q. In addition, did you identify the surface owners for each of the proposed injection wells?

A. Yes, sir.

Q. Did you then also identify all of the working interest owners in the North Hobbs Unit?

A. Yes, sir.

Q. And all of the working interest owners in the South Hobbs Unit?

A. Yes, sir.

Q. If I then turn to what's been marked as Oxy Exhibit 14, is that an affidavit with the attached letter providing notice of the hearing to the parties for whom you were able to locate an address from your extensive record search?

A. Yes, sir.

Q. If I then look behind the letter in Exhibit 14, there begins a series of pages that are grouped by various headings. Does that contain the list of all of the effected parties that you identified in your notice area?

A. Yes, sir.

Q. How many, roughly, different individuals or companies were involved?

A. Roughly, 600.

Q. And to the extent you had an address, was notice provided to these individuals by Certified Mail?

A. Yes.

Q. Did it include the New Mexico State Land Office?

A. Yes, sir.

Q. At the end, the last three pages of this exhibit, there is a list of parties for whom you were unable to find addresses; is that correct?

A. That's correct.

Q. What efforts did you undertake to locate an address for these individuals?

A. We initially went through the county records and abstract county records looking for their last known addresses. We went through the tax records of Lea County. We did Internet searches. We searched our internal databases where we distribute revenues on the North and South Hobbs Unit, as well as other properties in Lea County, and looked for them in there.

Q. Then with respect to this list of parties, were they then -- for which you did not have an address, were they then listed by name in the notice of the hearing of this matter?

A. Yes, sir.

Q. If I turn to Oxy Exhibit Number 15, does that contain an affidavit of publication in the Hobbs News Sun of this hearing that is preceded by a list of all of the individuals for whom you were unable to find an address?

A. Yes, sir.

Q. Now, with respect to -- there was a question about royalty owners in the South Hobbs Unit. First off, one of the royalty owners would be the State Land Office; correct?

A. Correct.

Q. Did the State Land Office sign this voluntary unit?

A. Yes, sir.

Q. Does the unit agreement provide or contemplate and provide for this type of tertiary recovery operation?

A. Yes, sir.

Q. And in your opinion, is there a benefit to the royalty owners in moving from a waterflood project to a tertiary recovery project?

A. Yes, sir.

Q. If you were a royalty owner, would you want Oxy to move to a tertiary recovery project here?

A. Yes, sir.

Q. Why is that?

A. If our assumptions on the project are correct, my royalty checks would then go up significantly.

Q. Is there -- with respect to the gas that's being utilized for this particular project, is that being wasted?

A. No, sir.

Q. It's being reinjected back into the reservoir?

A. The gas will be reinjected back into the producing unitized interval.

Q. Thereby, subject to potential production in the future, if operators deem that to be appropriate?

42113bfa-9cf9-4ebc-b20e-80f999bcfa12

A. Correct.

Q. Were Oxy Exhibits 13 through 15 compiled by you or under your direction and supervision?

A. Yes, sir.

MR. FELDEWERT: Madam Chair, I move the admission of Oxy Exhibits 13 through 15.

CHAIRMAN BAILEY: Any objection?

MS. GERHOLT: No, Madam Chair.

CHAIRMAN BAILEY: They are admitted.

(Oxy Exhibits 13 through 15 were admitted.)

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

CHAIRMAN BAILEY: Do you have any questions?

MS. GERHOLT: Not of this witness.

CHAIRMAN BAILEY: Commissioner Warnell?

COMMISSIONER WARNELL: I have no questions.

CHAIRMAN BAILEY: Commissioner Balch?

COMMISSIONER BALCH: I always have one question for every witness so they don't feel left out.

EXAMINATION

BY COMMISSIONER BALCH:

Q. What percentage of the land mineral rights is State Land Office?

42113efc-9cf9-4ebc-b20e-60f9995c1a12

A. It's right around 30 to 35 percent.

COMMISSIONER BALCH: Thank you.

EXAMINATION

BY CHAIRMAN BAILEY:

Q. My only question is: When was this aerial photo taken?

A. I'm not sure of the exact date of the photo. We prepared it -- it was probably last fall in the June, July, August time frame.

Q. Okay. It's not 15, 20 years old or anything?

A. No, ma'am. We got the new photos when we started our review.

CHAIRMAN BAILEY: That's all I have.

Any redirect?

MR. FELDEWERT: No, Madam Chair.

CHAIRMAN BAILEY: You may be excused.

MR. FELDEWERT: Madam Chair, I have one additional matter. Mr. Sparks testified to the list of parties to whom Certified mailing was provided. As you can imagine, given the number of people involved, the return receipts were quite extensive, and to be honest with you, are still being received as of this week.

But what I have marked as Oxy Exhibit 16 is a bound copy of the Certified receipts that the company has received to date. And I think it would be prudent for the company to actually have this admitted into the record as Oxy Exhibit Number 16.

I did not provide copies I think obvious reasons for everybody, so that's why I did not previously submit them to the Commission. I didn't want to kill any more trees. But for the record, I would like to introduce what has been marked as Oxy 16 as the Certified receipts to date received by the company.

CHAIRMAN BAILEY: Any objection?

MS. GERHOLT: No, Madam Chair. Oxy had discussed this prior to the hearing. We knew it would be an exhibit.

CHAIRMAN BAILEY: Commissioner Warnell or Commissioner Balch, do you want your own personal copies?

COMMISSIONER BALCH: I have plenty of stuff.

CHAIRMAN BAILEY: That's what I thought.

Let's admit that exhibit for the record.

(Oxy Exhibit 16 was admitted.)

MR. FELDEWERT: If I may approach, I'll give this to the court reporter?

With the submission of that final exhibit, which results in Oxy submitting a total of 17 exhibits to the Commission, that concludes our presentation in this case.

CHAIRMAN BAILEY: All right. Do you have any closing that you would like to make?

MS. GERHOLT: Yes, Madam Chair.

As you have heard, Oxy is proposing a tertiary project. And the Division does not object, because it will prevent waste and protect correlative rights.

The Division also believes, with the additional requirement as set forth in Richard Ezeanyim's affidavit of testimony that was provided to the Commission --

CHAIRMAN BAILEY: It has been admitted, hasn't it?

MS. GERHOLT: I can move to admit it now formally.

CHAIRMAN BAILEY: Yeah. Make sure --

MS. GERHOLT: Okay. I would move Exhibit A into the record.

MR. FELDEWERT: Oxy has no objection.

CHAIRMAN BAILEY: It is admitted.

(OCD Exhibit A was admitted.)

MS. GERHOLT: Thank you.

Per the additional requirements set in Richard Ezeanyim's written testimony, the Division believes human health and safety would be protected, as required by statute.

42113bfc-9cf9-4ebc-b20e-60f9ee5a1a12

In addition, the Division would request that Oxy work with the District Office to determine the time periods of holding the data that it gathers from SCADA in order for OCD to review that, whether that's on a five-year time period, less or more. But we'll leave it to Oxy and the Hobbs District Office to decide upon that.

We would also request that Oxy report on C-115s, as they're required to do per Rule 26 and as they are currently doing for the South Hobbs Unit.

And finally, when action is taken on the problem well, for Oxy to report that on a C-103 filed with the District Office. Thank you, Madam Chair.

MR. FELDEWERT: I really don't have a closing. I had my opening statement.

But on the points that were just raised by the Division, Oxy has no problem with their requests. The only issue that arises, I believe, is with respect to the filing of a C-103 for the potentially problem well. We don't know if it's a problem well or not.

And the reason for that is because it's not a well that's operated by Oxy. We have to work with the current operator, Chevron. We would hope that there would not be any issue there, but I don't think Oxy is in a position to file the C-103. I guess my thought, perhaps, would be that hopefully the companies could visit with the District Office and decide how the District Office would like to address whatever remedial issues are necessary as they move forward with that study and those efforts.

CHAIRMAN BAILEY: Okay.

MR. BRANCARD: I don't know whether Mr. Feldewert doesn't have a closing, but it may be useful if Oxy could simply list the relief they are requesting from the Commission at this point, before we --

COMMISSIONER BALCH: It's primarily in Exhibit 3, and then there are some other issues that were addressed by Richard Ezeanyim's testimony. I think between those two, we could cover most of them.

MR. FELDEWERT: I would also add that it's listed in the application. And as I said, I think the one modification has to deal with Slide 23 of Exhibit 12, where Oxy has proposed a modification -- give me one second here.

Our proposal would be that Rule 15 be modified as follows: The first clause be retained, and then after that, that there would be a clause inserted that would say, "unless cement has been circulated to the surface." That would be what we would propose, and I probably read it in an inartful form. And the remainder of that rule be stricken as unnecessary, given the testimony that's been submitted here today and yesterday.

CHAIRMAN BAILEY: Then we should deliberate this case, and the results of those deliberations can be announced in open session. And then we will take up the remaining case, which could be impacted, possibly, by the decisions made during the deliberations made on this case. That's my understanding.

So do I hear a motion from the Commission to go into closed session for the sole and only purpose of deliberating Case Number 14981 in accordance with the Open Meetings Act and the statute governing closed sessions for commissions?

COMMISSIONER WARNELL: I make that motion.

COMMISSIONER BALCH: I will second.

CHAIRMAN BAILEY: All those in favor?

So we will go into deliberations now and come back out -- let's say we just come back into session at 1:00. That should give us adequate time to deliberate and have lunch for everybody.

(Whereupon the Commission went into executive session.)

(A lunch recess was taken.)

CHAIRMAN BAILEY: Do I hear a motion for the Commission to come back into open session in

42113bfc-9cf9-4ebc-b20e-60f…a 2

accordance with New Mexico Statute 10-15-1 and the OCD resolution on open meetings?

COMMISSIONER WARNELL: I make the motion.

COMMISSIONER BALCH: I second.

CHAIRMAN BAILEY: All those in favor?

The only thing discussed during our closed session was deliberations on Case 14981.

And Counsel, would you please explain what the Commission decided?

MR. BRANCARD: Well, if you'll refer to the application submitted by Occidental Permian Limited Partnership. And I will also be referring to the Prehearing Statement from the Oil Conservation Division.

In the application, Occidental made a series of requests, and I will go through each of these in order here. A, the Commission proposes to adopt the request to expand the injection authority and to permit this as an enhanced oil recovery project under its own authority, which involves a tertiary project with injection of carbon dioxide and reinjection of produced gases. The produced gases shall be limited to those produced gases that come from the field to which this order applies to.

This order applies to the legal description of the unit that was provided at this hearing, which is a different legal description than was provided in the original Order R-4934.

Request B was to modify the surface injection pressure limits set forth in the prior order. The Commission adopts those pressure limits set forth in the OCD statement for CO_2 injection, water injection and produced gas injection.

C was a request to increase limits on the gas/oil ratio provided by Commission Rule 19.15.20.13. The Commission adopts the position of the Division that this gas/oil ratio will not apply to this project.

D was a request to allow an exception to the one-year commencement of injection required by 19.15.26.12(C). The Commission approves extending the commencement of injection period to three years. However, once injection has begun, the provision in that rule that provides that any one-year period of continuous noninjection will result in a termination of injection authority remains.

E, the request was to provide that for any injection well covered by this application that commences operations within five years after the date of the order, that the area of review will be limited to a statement from Oxy that there either have been no substantive changes to the area of review information in the application or a statement describing such substantive changes. This is provided in more detail in the North Hobbs Unit Order R-6199. The Commission approves this request for five years.

F was a request that the frequency for mechanical integrity tests required for temporarily abandoned wells be five years for those wells that are equipped with real time pressure monitoring devices. The Commission approves this request, which would come into play after such real time pressure monitoring devices are installed on each well.

G, the request was to modify to set a new packer setting depth requirement to allow for the packer to be set anywhere above the uppermost injection perforations or casing shoe, provided the packer was set below the top of the Grayburg formation. Commission approves this request.

H, the request was to modify or eliminate the cement bond requirement provided in the prior order, The Commission approves a cement bond log requirement that reads the same as that found in Rule 15 under the prior order, except that the second clause of the first sentence is deleted, that is, beginning at the words, "Also at anytime," and extending to the end of that sentence is deleted.

I, Occidental requests approval of the

additional injection wells. The Commission approves those additional injection wells that are identified in the C-108 and the application.

J was a request that this project qualify for the authority for the recovered oil tax rate. The Commission finds that this project does qualify for that tax rate status, and the proper findings shall be placed in the order that would justify such finding by the Commission.

In addition, if you'll go to the OCD statement, page 6, the Commission proposes to adopt the additional requirements listed as 3, 4, 5, 6 and 7. In addition, the Commission proposes the following additional conditions: First, that Occidental work with the local OCD District Office on providing access for the Occidental records termed SCADA in this application, and on a schedule for the retention of those records.

Second, that in the annular fluid provided in wells, there will be biocides and corrosion inhibitors.

Third, the well identified in the OCD statement, the Aradora Well Number 3, the Commission proposes that no injection be allowed within a half mile of this well until and unless Occidental provides a cement bond log that shows adequate cement access or that remedial cement work is done to adequately confine the injectant to the injection zone.

Fourth, that Occidental maintain and update its hydrogen sulfate contingency plan in accordance with the hydrogen sulfide rule of the Commission.

Have I captured everything?

CHAIRMAN BAILEY: Yes, you have.

Would you like to discuss the draft orders and how you would like for that to be presented and at what date?

MR. BRANCARD: I would request that applicants submit a draft order within 30 days, okay?

MR. FELDEWERT: Yes.

CHAIRMAN BAILEY: As a new order, or as --

MR. BRANCARD: The Commission is requesting that this be done as a new order --

MR. FELDEWERT: So not a continuation of the prior orders?

MR. BRANCARD: -- approving this as an enhance oil recovery project.

MR. FELDEWERT: May I ask a couple of questions about that? So that would include, as part -- the existing order, of course, has Rules 1 through, whatever it is, 17. That would be part of any new order, as well, in addition to the modifications that have been discussed here today? That's the question I have.

CHAIRMAN BAILEY: The pertinent paragraphs should be retained.

MR. BRANCARD: To the extent that a number of those rules have been superceded by more general rules of the Commission, it would seem to be unnecessary. The Commission now has a Rule 26 regarding injection, et cetera. A lot of what was in that rule predated --

MR. FELDEWERT: I did, yeah. Let me think about that, and I'll look at it.

MR. BRANCARD: Okay.

CHAIRMAN BAILEY: And the attorneys can discuss this outside of the Commission hearing as to the form of that order.

MR. FELDEWERT: That would be great.

Can we ask for a clarification on your decision, since I'm going to be putting together an order?

My question relates to -- I think it dealt to allow for administrative approval of additional injection wells, so it was our relief I.

The relief we requested was to allow for the administrative approval of additional injection wells into the Grayburg and San Andres formation underlying the South Hobbs Unit project area pursuant to Rule 8 of the special rules.

MR. BRANCARD: I think what our conversation was was that the rules that you have -- the wells you have specifically identified in this application are approved and that the Rule 8 can continue over or words effective of Rule 8 can continue over into the new order.

MR. FELDEWERT: I think my assumption is that the -- I think as it's currently crafted, it may only say -- well, maybe it doesn't say "water," but I think we had an issue there. So what you're saying, Rule 8 as presently encompassed within the governing order would carry over into the new order, if I'm understanding you.

MR. BRANCARD: Rephrase it. There's a reference to an outdated Commission rule in that rule, which you would change to specify the new Commission rule.

MR. FELDEWERT: Then with respect to the cement bond log issue and the modification of Rule 15, if I'm understanding you, the first clause is retained and the remaining aspect of that rule would be struck?

MR. BRANCARD: No. The remaining aspect of that first sentence.

MR. FELDEWERT: Okay.

CHAIRMAN BAILEY: Is there anything further in this case?

MR. FELDEWERT: Not from Oxy.

CHAIRMAN BAILEY: Then I'll call Case 149 --

MR. BRANCARD: Do we need a motion?

CHAIRMAN BAILEY: A motion to what?

MR. BRANCARD: To adopt what I just provided. Or do we want to get the order and then we adopt?

CHAIRMAN BAILEY: To get the order and then we adopt.

So I'll call Case 14976, which is the application of Occidental Permian Limited for approval to add the North Hobbs Grayburg-San Andres Unit Well Number 431 as an injection well for water, carbon dioxide and produced gas in its North Hobbs Grayburg-San Andres tertiary recovery project located within the Hobbs Grayburg-San Andres pool in Lea County, New Mexico. Appearances?

MR. RANKIN: Good afternoon, Madam Chair. Adam Rankin on behalf of Occidental Permian Ltd. I have one witness.

MS. GERHOLT: Good afternoon, Commissioners. Gabrielle Gerholt on behalf of the Oil

REPORTER'S CERTIFICATE

I, JACQUELINE R. LUJAN, New Mexico CCR #91, DO HEREBY CERTIFY that on May 10, 2013, proceedings in the above captioned case were taken before me and that I did report in stenographic shorthand the proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

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

WITNESS MY HAND this 23rd day of May, 2013.

Jacqueline Lujan

Jacqueline R. Lujan, CCR #91
Expires: 12/31/2013