STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:	CASE NO. 12,722
APPLICATION OF OCCIDENTAL PERMIAN LIMITED PARTNERSHIP ("OXY") TO AMEND DIVISION ORDER R-6199 CONCERNING THE EXPANSION OF ITS NORTH HOBBS GRAYBURG-SAN ANDRES UNIT PRESSURE MAINTENANCE PROJECT, AND TO QUALIFY THE PROJECT FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE ENHANCED OIL RECOVERY ACT, LEA COUNTY, NEW MEXICO	ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

September 6th, 2001

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, DAVID R. CATANACH, Hearing Examiner, on Thursday, September 6th, 2001, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

September 6th, 2001
Examiner Hearing
CASE NO. 12,722

* * *

E X H I B I T S

Applicant's	Identified	Admitted
Exhibit 1	6	46
Exhibit 2	7	46
Exhibit 3	8	46
Exhibit 4	12	46
Exhibit 5	14	46
Exhibit 6	14	46
Exhibit 7	23	46
Exhibit 8	25	46
Exhibit 9	31	46
Exhibit 10	31	46
Exhibit 11	35	46
Exhibit 12	37	46
Exhibit 13	41	46
Exhibit 14	42	46
Exhibit 15	44	46
Exhibit 16	59	70
Exhibit 17	61	70
Exhibit 18	62	70
Exhibit 19	62	70
Exhibit 20	62	70
Exhibit 21	64	70
Exhibit 22	65	70
Exhibit 23	67	70
Exhibit 24	67	70
Exhibit 25	67	70
Exhibit 26	69	70
Exhibit 27	78	112
Exhibit 28	82	112
Exhibit 29	85	112
Exhibit 30	86	112

(Continued...)

E X H I B I T S (Continued)

Applicant's	Identified	Admitted
Exhibit 31	94	112
Exhibit 32	100	112
Exhibit 33	102	112
Exhibit 34	102	112
Exhibit 35	104	112
Exhibit 36	104	112
Exhibit 37	107	112
Exhibit 38	109	112

* * *

A P P E A R A N C E S

FOR THE DIVISION:

DAVID BROOKS
Attorney at Law
Energy, Minerals and Natural Resources Department
Assistant General Counsel
1220 South St. Francis Drive
Santa Fe, New Mexico 87505

FOR THE APPLICANT:

KELLAHIN & KELLAHIN
117 N. Guadalupe
P.O. Box 2265
Santa Fe, New Mexico 87504-2265
By: W. THOMAS KELLAHIN

* * *

WHEREUPON, the following proceedings were had at 12:40 p.m.:

EXAMINER CATANACH: At this time I will call Case 12,722, which is the Application of Occidental Permian Limited Partnership to amend Division Order Number R-6199 concerning the expansion of its North Hobbs Grayburg-San Andres Unit Pressure Maintenance Project and to qualify the project for the recovered oil tax rate pursuant to the Enhanced Oil Recovery Act, Lea County, New Mexico.

Call for appearances in this case?

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing on behalf of the Applicant. I have three witnesses to be sworn.

EXAMINER CATANACH: Call for additional appearances.

There being none, can the witnesses please stand to be sworn in?

(Thereupon, the witnesses were sworn.)

ANDREW FALLS,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Falls, for the record, sir, would you please state your name and occupation?

A. Andrew Falls, I'm a CO_2 project manager with Occidental Permian.

Q. And where do you reside?

A. Houston, Texas.

Q. On prior occasions have you testified before the Division?

A. I have not.

Q. Summarize for us your educational background?

A. I have a bachelor of science in chemical engineering from the California Institute of Technology, earned in 1978, and I have a PhD in chemical engineering with a mathematics minor and a petroleum engineering-related thesis from the University of Minnesota, earned in 1982.

Q. Summarize your employment experience for us, Mr. Falls.

A. Over the last 20 years I've been employed in the oil and nuclear industries in project management roles.

Q. Let me ask you to turn to what is marked as OXY's Exhibit Number 1 and identify that for us.

A. Exhibit Number 1 is a map identifying the location of the Hobbs field, both within east central Lea County, as well as within the subsurface structure of the Permian Basin. The Hobbs field is located on the northwest corner of the Central Basin Platform within the Permian Basin.

Q. Do you have another display that more closely defines where this project is in relation to other CO_2 projects?

A. Yes, I do. That would be Exhibit 2.

Q. Let me direct your attention to Exhibit 2. Would you identify and describe this display?

A. Exhibit 2 shows the locations within the Permian Basin of fields that have undergone CO_2 flood as well as the distribution of CO_2 supply pipelines within the Permian Basin.

It is common for oilfields in the Permian Basin to go through three stages of development, first a primary stage of development where the oil flows from the subsurface under the natural energy present, followed by a waterflood development in order to increase the recovery of hydrocarbons, and some fields would then go beyond that to a CO_2 flood to further increase the recovery of hydrocarbons from the resources.

So this map shows the locations of the floods that have gone to CO_2 flood. CO_2 flooding has been active in the Permian Basin for over 30 years. There have been over 50 floods in the Permian Basin. Occidental Permian operates 16 floods, the most of any operator.

Q. What has been your professional experience with other CO_2 projects?

A. I have managed the expansion of CO_2-flood projects in the Permian Basin, time period 1992 through 1996.

Q. You're about to sponsor a number of exhibits, conclusions and displays concerning the project. Do these represent your own personal professional opinions?

A. Yes, they were all prepared under my supervision, my direction, or by me personally.

MR. KELLAHIN: We tender Mr. Falls as an expert petroleum engineer.

EXAMINER CATANACH: Mr. Falls is so qualified.

Q. (By Mr. Kellahin) Let's turn to the map that shows the unit itself. My copy is marked Exhibit Number 3. Is that what yours is?

A. Yes.

Q. All right, let's take a moment and unfold it.

In addition, Mr. Examiner, we have a large copy of this same display which we'd like to leave on the easel to give you a point of reference as we make the presentation.

First of all, Mr. Falls, let's talk about how we identify on this plat what is the current boundary for the North Hobbs Unit.

A. Okay, on this plat the North Hobbs Unit boundary is denoted by the bold dashed line, and it's so labeled on the plat.

Q. Where is this project in relationship to the community of Hobbs, New Mexico?

A. It is located on the western-northwestern outskirts of the City of Hobbs and northwest of the City of Hobbs. On the plat the city limits is denoted by the blue chain dashed line on the plat.

Q. There are two colored areas, one colored in blue, one in grey. They're both captioned "Phase I". What do you intend the Examiner to understand by the phrase "Phase I"?

A. We believe that the entire North Hobbs Unit is a target for CO_2 flooding. We're coming today to propose a first phase of a CO_2 flood in the North Hobbs Unit, which is the combination of these two areas.

The area proposed for the Phase I flood is further subdivided into two subareas, one area which is proposed for pipeline CO_2 gas injection, which is colored gray on the plat on Exhibit 3; and a second area, which colored light blue, is proposed for the area in which we will reinject the gas that's produced from the project.

Q. Identify for us the types of gases produced from the project that will be reinjected into the gas reinjection area.

A. The gas produced from the project, as in many similar CO_2 floods around the Permian Basin, will contain mostly CO_2, will also contain methane, natural gas liquids and hydrogen sulfide.

Q. Is hydrogen sulfide currently being produced now in the unit?

A. Yes, it is.

Q. And what is being done with that substance?

A. Currently it's gathered and is shipped to a plant for processing, and ultimately sale.

Q. Can you give us a general idea of how OXY has developed the boundary between the gas reinjection area and the gas injection area?

A. Yes, the boundary between those areas has been identified and chosen based on the plan to further reduce the risk of exposure of the public to hydrogen sulfide. The area proposed for gas reinjection is located in the most remote portions of the unit.

Q. On Exhibit Number 3 there are some well symbols with numbers associated with them, and then they're circled by a green circle. What does that represent?

A. Those denote water injectors that exist around the boundary of the proposed CO_2-flood area, which serve to help contain the proposed CO_2 flood within the project area.

Q. Do you have a professional opinion as to whether there's any potential adverse consequences to operators or interest owners outside of the unit if this project is approved?

A. We believe there will be no adverse consequences to offset operators. There is the South Hobbs Unit, south of the North Hobbs Unit, which is also operated by Occidental Permian, and the row of waterflood patterns between the project area and the South Hobbs Unit will contain the CO_2 project within the project area within the North Hobbs Unit.

Most of the offsetting wells outside the unit have been plugged and abandoned. Our investigation has shown that there are still some wells that have not been plugged and abandoned, and -- on a couple of leases in Section 13 and 18 at the top of the unit. However, our visual observation indicates that those wells, operation is suspended, they're not active operations.

There's another offsetting well that is still available for production in Section 21, which through our visual observation it appears there are some active operations through that lease. However, the operator was notified about our intended operations and has given us no objections to our project.

Q. Has OXY estimated the cost associated with the development of Phase I within the unit?

A. Yes, we have.

Q. Do you have an exhibit that summarizes those costs?

A. Yes, I do. Before I get to that exhibit, let me first talk about some of the impacts and anticipated benefits that will accrue because of the project, which I direct your attention to Exhibit Number 4.

Q. All right, please do so. Thank you.

A. First of all, we expect that this project will provide a good boost to the local Hobbs/Lea County economy. This project will entail spending about $130 million on wells and facilities in order to implement the project. It will create between 200 and 300 construction jobs at the peak of construction activity. It will also increase the expenses for lease costs by about $10 million annually.

We also estimate that it will extend the field life, and therefore the economic activity in the area, by more than 20 years. And we also estimate there will be the reinvestment benefits as dollar spent in the community are then reinvested before they ultimately leave the area.

The project will also generate additional taxes and royalties. At peak we expect this project to add 14,000 barrels of oil a day incremental production, which represents over a 7-percent increase to the current New Mexico daily production.

In total we expect there to be an additional 76 million barrels of oil recovered by the project.

Now, as far as costs go, Exhibit 5 --

Q. Let me ask you this, Dr. Falls, can you rank this project in terms of its size with other projects that are utilizing carbon dioxide as a medium to increase ultimate recovery?

A. This would be the largest CO_2 project in New Mexico, and it would be the largest CO_2 project in the Permian Basin in the last 15 years.

Q. Can you give Examiner Catanach a general time frame for the construction of the additional facilities and the period of time over which you will commence actual injection into the various injection wells?

A. Certainly, provided we receive Division authorization to go ahead with the project, approving the project, we estimate that we could begin construction and activity associated with it in early 2002, in order to be ready to inject CO_2 in the fourth quarter of 2002.

Q. Let me direct your attention now to your next display, which subdivides the major cost component of the Phase I project. I show that as Exhibit 5.

A. Yes.

Q. Identify and describe that for us.

A. Okay, Exhibit 5 is a bar chart showing the breakdown of the major costs associated with the proposed project. As I mentioned previously, there's about $130 million that will be spent on capital for wells and facilities. We will also expend about $190 million for CO_2 purchases, about $80 million for incremental well and surface operating expenses, an incremental $20 for extra lifting costs, about $30 million for chemical costs which will be required to separate and perform corrosion inhibition and the like, and finally about $65 million will be spent to recompress and reinject the gases produced during the project.

Total expenditure for the project will be in the neighborhood of about a half a billion dollars.

Q. Mr. Falls, what in your opinion is need from the Oil Conservation Division to provide the opportunity to achieve this level of additional oil recovery from the unit?

A. I have those summarized on Exhibit 6. First of all, we're requesting that the Division grant us authorization to inject CO_2 and water and reinject produced gas -- which will contain CO_2 and methane, natural gas liquids and hydrogen sulfide -- and water into the North Hobbs Grayburg-San Andres Pool, into the wells that are listed in our C-108 Application.

Q. Let me ask you this, Mr. Falls: Why are you seeking permission to reinject these produced gases?

A. Our analysis has shown that in order to make the flood viable we need to handle the produced gases. We went through an examination of several alternatives, and this alternative is one that was found to be economically viable.

Q. As part of the analysis to determine the feasibility of effectively reinjecting produced gases, is there a safety plan component to that decision process?

A. Yes, as we'll describe later and a subsequent witness will give more details about, the entire flood design has been driven by the plan to safeguard and protect the welfare and safety of the public.

Q. Has OXY's safety plan been submitted to the Bureau Chief of the Environmental Bureau of the Oil Conservation Division for his review and approval?

A. Yes.

Q. And what result?

A. My understanding is, the Bureau Chief is a proponent of the project and is satisfied that the safety plan meets or exceeds the requirements to adequately protect the health and safety and welfare of the public. We do have another witness, Mr. Starrett, who will describe more of the details about that.

Q. You mentioned a while ago that H_2S is currently being produced within the unit and is being removed from the unit area?

A. Yes, sir.

Q. And the plan is economically viable only with the reinjection of that produced gas?

A. For the CO_2 flood, yes.

Q. Can you give us a general summary of what is the composition and concentration of the H_2S now and afterwards if this is approved?

A. Certainly. Currently, the H_2S concentration produced from the North Hobbs Unit is 65,000 parts per million. With the implementation of the flood, the produced CO_2 will dilute the produced gas stream considerably, such that our calculation, based on a reservoir-simulation model, indicates that the concentration of hydrogen sulfide in the produced gas will drop to 5000 parts per million.

Q. This is classified as a pressure maintenance project?

A. Yes, I mean, the pressure is maintained during the project.

Q. And you're going to continue to maintain a certain reservoir pressure balance, if you will?

A. Yes, that's very important for the displacement efficiency of the flood, to maintain adequate pressure within the reservoir.

Q. Let's go to the second part of your request and talk about the pressures you're recommending be utilized from a regulatory perspective concerning the project. What is your recommendation?

A. As we change this mode of operation to CO_2 flood, we'll obviously be injecting fluids that have different properties than water, and so to accommodate the density differences of the fluids and also frictional pressure losses that will erode the surface injection pressure, we're recommending that the Division approve and grant authorization to inject water up to 1100 pounds, CO_2 up to 1250 pounds, and produced gas up to 1770 pounds surface pressure.

Q. What is the current maximum surface injection pressure on a general basis for the unit?

A. Generally 800 pounds, which would be the .2-p.s.i.-per foot limit, although we do have on many wells authorization to inject at pressures above that currently.

Q. What is OXY's professional opinion about the current bottomhole pressure of the reservoir?

A. The current bottomhole pressure of the reservoir in the target zones is around 1100 p.s.i.

Q. What, in your opinion, is the bottomhole pressure fracture percentage for the unit?

A. The -- Based on our extensive amount of step-rate testing, the data indicate that the minimum fracture pressure, formation parting pressure in the unit, is 2600 p.s.i.

Q. How do we translate that minimum parting pressure of twenty- -- What did you say, 2600?

A. 2600.

Q. -- 2600 pounds, to a surface pressure limitation for the three substances that you're asking for limitations on?

A. As one of our subsequent witnesses will testify the details of, basically we go through a tubing flow model, which accounts for the hydrostatic as well as the frictional pressure losses in the tubing when the various fluids are injected, so that we can relate a surface injection pressure to a maximum or -- sand face or bottomhole pressure.

Q. In your professional judgment are the surface limitation pressures you're requesting here appropriate in order not to fracture the reservoir being injected into?

A. Yes, as Mr. Foppiano will testify, we have built in quite a bit of margin in estimating those maximum surface injection pressures.

Q. In addition, are you requesting an administrative procedure where you may petition the Division to increase those numbers for individual wells or population of wells based upon engineering data including but not limited to step-rate tests?

A. Yes, we are.

Q. And that may be necessary over time, right?

A. Yes.

Q. Let's turn to the third request. Would you identify and describe what the third request is?

A. The third request would be to increase the fieldwide GOR level from the present 3500 standard cubic feet per stock tank barrel to 6000 standard cubic feet per stock tank barrel, and this is to accommodate the large volumes of CO_2 that will be produced as we implement the project.

Q. Let's turn to the fourth item. Identify and describe what you're requesting here.

A. Yes, in order to allow us time to carry out the construction schedule and activities from when we receive approval, we're asking that the Division modify their practice requiring that injection commence within 12 months of approval, and we're asking that we be granted up to 18 months to begin injection. Again, this is a very large project, it will take a while to carry out the various activities to get it ready, so we would ask that that be up to 18 months.

We also ask that you allow for an administrative process whereunder we can request an additional extension in case we run into delays.

Q. It's obvious that you're not going to get all these injectors ready to actually inject within 18 months of approval, correct?

A. That's right, actually the surface facility construction schedule is more limiting, but that's correct.

Q. Why are you seeking approval for these injectors now, if it's apparent that you're not going to be able to get them actually into injection status within 18 months?

A. Well, we need approval for the entire project, because with an investment of this magnitude, we need to be sure that we can, in fact, implement it and carry it out.

Q. What is the status of your working interest owners' participation and cooperation in the project?

A. We have issued an authority for expenditure to our working interest owners. As of last week, 20 out of the 60 working interest owners had voted their approval for the project, we had not received any negative or nay votes from any of our working interest owners.

At this point we do not have a sufficient working interest to approve the project, however, we have been in steady communication and have been participating in the review of the project with our principal working interest owners, and they've indicated to us that they intend to approve the project.

One of them, it's very important to them that we receive Division approval before they want to approve the project.

Q. Who are your major working interest owner partners by percentage?

A. Chevron, which has a little over 18 percent of the unit, Texaco which has a little over 17 percent of the unit, and Exxon Mobil which has around 14 percent of the working interest in the unit.

Q. Let's turn to the last item in which you request Division action. Identify and describe what you're asking.

A. We request that the Division qualify the project for the recovered tax rate under the Enhanced Oil Recovery Act.

Q. At this time, Mr. Falls, I'd like you to assist me in correcting something that was filed in the Application. One of the items -- I think it was paragraph 5 in the original Application -- attempted to set forth what the volumes of production were in association with primary, secondary and then now this, if you will, tertiary project that involves CO_2. I think you've advised me that there's a way to describe this more clearly than I've done so in the Application.

Would you take a moment and just restate this for us?

A. Yes, evidently in drafting this we got -- confused some of the field production data with the North Hobbs data, so I would like to set the record straight. We're talking about the letter dated August 15th, 2001, from Thomas Kellahin to -- addressed giving notice of this hearing, and the attached Application. On page 2 of that Application, item 5, what I would like to do is just state the amended paragraph in its entirety as opposed to trying to correct what's there.

Q. Please do so.

A. That paragraph should read, "per unit oil recovery from the unit was 160 million barrels of oil. Under the current secondary recovery project, ultimate oil recovery is estimated to be 275 million barrels of oil. Total oil production from the unit as of January, 2001, has been 231 million barrels of oil."

Q. And then if the project is approved, your forecast for the incremental additional oil attributed to the CO_2 project is the 76 million barrels?

A. That's correct.

Q. Let's turn to a different topic now. That completes the request list.

Let's look at a general concept of how OXY has analyzed and believes the reservoir to exist in a structural relationship. Do you have a display that shows what you have concluded to be a structural picture?

A. Yes, Exhibit 7 shows the structure of the Hobbs Grayburg-San Andres Pool reservoir.

Q. Let's take a moment now, before we talk about Exhibit 7, and show the Examiner how Exhibit 7 fits to Exhibit 3, which is the unit boundary map.

A. Certainly. The project area in Exhibit 3 basically covers the majority of the crest of the structure, and the point of reference on the Exhibit 7 is the dark blue vertical/horizontal line which represents the Township 18/19 dividing line and the Range 37/38 dividing line.

Q. If we look at that point of intersection of the townships on Exhibit 7, help us find that same point on Exhibit 3.

A. Certainly. May I show you on the large map? That would be located right here, so the crest of the structure is basically what is proposed for the CO_2 flood project.

Q. So on Exhibit 3 he can find the coding that intersects the four townships at that point, overlay the structure map -- It's not on the same scale obviously, but you can make a general comparison as to where the Hobbs Pool structure is?

A. That's correct.

Q. Now, the North Hobbs Unit that you're operating is not the entire San Andres structure, is it?

A. No.

Q. There's a color code on Exhibit 7. Explain the color code.

A. Okay. First of all, the thinner black lines denote the contours of the structure mapped to the top of the San Andres. So you see them labeled, the first one, the shallowest contour, minus 400 feet subsea. Then we have a contour at minus 500 feet subsea, one at minus 600 feet subsea, and one at minus 700 subsea.

The other colored lines that are bolder, first of all, the gas-oil contact, original gas-oil contact at discovery, is shown by the dark bold red line, which was located at minus 365 feet subsea. There's currently not a gas cap in the San Andres, because supplemental operations, secondary operations have basically filled that gas cap up with water. But originally it was present.

The green line denotes the producing oil-water contact, which was the depth at which water -- in the hydrocarbon accumulation, water was first encountered.

That was at minus 635 subsea depth.

And finally, the blue contour shows what's referred to as a free water level, which is at minus 735 feet, which is the depth at which there is no more moveable oil.

Q. Do you have a display that illustrates the geology of the unit in a cross-sectional perspective?

A. Yes, that would be Exhibit 8.

Q. Let's turn to that exhibit. First of all, let's start -- Ignore for a moment the wellbore data. Let's start with the left scale in a vertical sense. Starting at the top, go down and give us a geologic summary.

A. Well, this is meant to illustrate the typical geology encountered in the Hobbs Grayburg-San Andres Pool. Beginning at the top of the pool is the Grayburg formation. And I might add, all of these sediments were deposited -- or consist of dolomite or dolomitic siltstones that were deposited in a shallow carbonate-shelf environment, and we see all the depositional facies and the field associated with that environment, the shallow subtidal shelf, the beach, the tidal flat, tidal channels and the like.

The Grayburg consists of a dolomitic siltstone. The top 200 feet of the interval are filled with a lot of anhydrite clay and quartz, and so the porosity and permeability is nonexistent. There's basically no porous and permeable zones at the top of the Grayburg.

The bottom hundred feet or so is called the basal Grayburg, and here the anhydritic content of the rock has diminished to where there is some porosity, about 10- to 12-percent porosity. But because it's basically siltstone the permeability is quite low, 2 millidarcies.

Next to the sequence is -- at the top of the San Andres, is a very tight, dense dolomitic cap which forms a seal between the accumulations in the San Andres and the accumulation in the Grayburg. And I might add, the Grayburg itself forms the total seal for the total hydrocarbon accumulation in the Hobbs Grayburg-San Andres Pool.

Q. All right, Mr. Falls, please continue.

A. The San Andres zone has been subdivided into three major intervals. The shallowest interval, referred to as Zone 1, is the most porous and permeable member. It's basically an extensively dolomitized colloidal and oolitic deposited carbonate. It has about an 18-percent porosity and averages 90 millidarcies of permeability, so it's quite permeable rock.

Below that in some areas of the field, although by no means is it extensive across the field, is a shaly streak that separates Zone 1 from Zone 2. And where it's present in the field, this shaly streak has been a good barrier to flow of hydrocarbons. The Zone 2 porosity and permeability is about 15-percent porosity and about 15 millidarcies permeability.

Below Zone 1 and 2 is a clay/sand field member, which is referred to as the "sandy break", and the Zone 3 San Andres below that has about a 15-percent porosity and a 12-millidarcy permeability. We show below that, of course, the producing oil-water contact and, even farther below that, the free-water level.

Q. Before we do the horizontal scale and talk about the development and the status of the project, identify for me now what vertical limits you're seeking injection authority for from Mr. Catanach by his action in this case.

A. We're seeking authority from the unitized interval, which runs from the top of the Grayburg down to 4500 feet, which is no change over the current authorized interval.

Q. That continues your current approvals as to allowing the operator the flexibility and the internal choice as to which if any of those are flooded and how?

A. Yes, sir.

Q. And you're seeking no change in that?

A. No, we're not.

Q. Let's start, then, on the left side and have you walk us through a summary of how development has taken place in the North Hobbs Unit.

A. Okay. Well, the field was discovered in 1928, and during early stages of primary development the practice typically was to drill a well to the bottom of the most productive zone, so the bottom of the Zone 1-2 interval, just above the sandy break, and case the well down to around the top of the basal Grayburg and then produce the well open hole.

In later stages of primary development, as the Zone 1 and Zone 2 became depleted, the practice was to deepen the wells down through Zone 3 to the producing oil/water contact and set a liner in the 7-inch casing and then complete the well in Zone 3 to gain the solution gas drive recovery from Zone 3.

As Zone 3 began to become depleted, the operators in the area saw the benefits of going to a pressure maintenance project and so made application to the Division to have a pressure maintenance project at North Hobbs, and in 1979 was granted an order approving water injection in the unit.

The waterflood that was done was a waterflood of, for the most part, Zone 3. And the reason for that was because Zone 1 was connected downdip to an active aquifer. And so during the primary recovery period, this natural water drive effectively did a natural waterflood of Zone 1.

And so as the waterflood has been implemented since 1979, the flood has been of mostly Zone 3. But in some areas of the field where I mentioned that we have the shaly streak separating Zone 1 and 2, it has also undergone waterflood where there's reserves there to be recovered.

Now, in the proposed flood, we would propose flooding both the Zone 1 and 2 and Zone 3 intervals by actually conducting two floods concurrently. And the reason for needing to flood both zones but not commingle injection is because of the disparity in reservoir properties between the zones. If we were to flood this as an entire package, we would not achieve very good vertical sweep efficiency of the interval. And so we will be conducting separate floods of the two zones, a 40-acre fivespot containing the current waterflood layout in Zone 3, and then flooding Zone 1 and 2 at a wider spacing because of the much higher productivity, much higher reservoir quality rock, flooding that on 160 acres with the ninespot, as is illustrated in the diagram.

Q. The 1979 order that the Division issued, I believe, is Order Number 6199?

A. Yes.

Q. Are you familiar with that order?

A. Yes.

Q. The current request involves a substantial change in operation and technology so that you can now have approval to utilize carbon dioxide?

A. Yes.

Q. That's the concept, right?

A. Yes.

Q. Take a moment, and let's talk about the flood pattern specifically that's shown on here. Summarize that for us.

Q. Okay, up at the top of the diagram it simply just illustrates the flood pattern that was used during the various stages of development. We ended up with about a 25-acre well spacing under primary, somewhat an irregular well spacing, but about averaging 25 acres.

The waterflood of Zone 2 and 3 is occurring on a 40-acre fivespot, which is illustrated about there on the exhibit, and in the case of the CO_2 flood, we would take the current water injector of Zone 3 and convert it into a CO_2-and-water or produced gas-and-water injector. And using the existing well penetrations in the field, we would on top of that have a 160-acre ninespot for flooding Zone 1 and 2.

Q. All right, sir. Do you have a tabulation or a sheet that summarizes the basic reservoir data that was utilized and available to you, as we begin to analyze the feasibility of the project and go on to develop the methodology for determining the opportunity to produce an additional 76 million barrels of oil?

A. Yes, Exhibit 9 summarizes the pertinent reservoir data for the Hobbs field.

Q. All right, let's turn past that and let's go into having you give us an illustration about the details for the carbon dioxide Phase I implementation, and if you'll start with the first of three areas -- that would be up in the top left with "Well Work" -- what are you describing here?

A. Okay, Exhibit 10 is meant to summarize the activities that will go on in order to implement a CO_2 flood in the North Hobbs Unit. First of all, we'll be needing to do some well work in order to configure the patterns, to get them right for implementing the CO_2 flood. This will involve drilling some new wells at locations that we would need to complete the patterns, sum total of around 60 new wells over the lifetime of the project implementation.

We will be required to reactivate about 30 currently temporarily abandoned wells in order to, again, fill out the desired CO_2-flood patterns. We'll also need to convert the function of some wells. Wells that are currently producers, we will need to make them injectors and vice-versa. And we'll also need to be opening up Zone

1 pay, which was basically, you know, scabbed off or plugged back at the time that the initial waterflood was implemented.

So the upper left-hand portion of Exhibit 10 kind of summarizes the well work associated with the project.

Q. Would you look at the bottom half of the display and describe for us what OXY recommends to be the illustration of facilities necessary to implement the flood?

A. Yes, this is a simplified block-flow diagram of the facility layout for the proposed flood. To carry out the flood we will need to bring in a supply of CO_2. We will build a lateral that will supply CO_2 from the existing CO_2 supply pipeline infrastructure in the Permian Basin over to the Hobbs field.

And so walking through this bottom portion of Exhibit 10 from the upper left, we will bring in the CO_2 supply into an injector and introduce it into the reservoir.

The produced oil, gas and water will be collected through a brand-new gathering system designed and constructed of the appropriate materials to handle the produced fluids and collect at a well test satellite where the oil and water will be separated from the gas.

The oil and water will go through a new flow line system to a tank battery and water injection station. We will use the existing tank battery of water injection stations, but because of the increase in the volumes of fluid produced as a result of this project we'll actually have to build one new battery and water injection station.

So you see the color scheme here, the gray indicates what is -- the system that we'll need to modify in implementing the flood, and the yellow denotes a new system that we'll need to build from scratch, and so that one is shown as both colors because we'll both be using existing facilities as well as building a replica of the existing facilities for the tank battery and water injection.

And the water, of course, then goes to injection wells for injection back in the project, and the oil goes to sales.

I might add that this project is self-sufficient in terms of water. We do not require any freshwater makeup or makeup from other areas, nor do we require disposal of produced water from the project.

Q. Are you currently utilizing any fresh water?

A. No, we're not.

Q. And the plan is not to utilize fresh water?

A. No, we will not.

Q. All right, sir. Please continue.

A. The gas from the satellite will go to a dehydration and compression unit which will remove the water from the gas and then recompress it up to be reinjected within the gas reinjection area of the project.

Q. Let's go to the third portion, which is in the upper right corner, and talk about some of the design components of the project.

A. Okay first of all, we have made safety our top priority in designing this project. As I mentioned earlier, one step we've taken to further reduce risk is to segregate the project area into CO_2 -- pipeline CO_2 gas injection area, which is closer to the populated areas, and reinjecting produced gas only in the most remote areas of the unit.

In addition, as a subsequent witness, Mr. Starrett will be prepared to testify the details of, we've built into the project the appropriate design and risk reduction measures and have set up operational practices to operate the flood in a safe manner.

Q. Is there a cost component directly attributed to the safety plan?

A. Yes, there is.

Q. And do you have an approximate number to share with the Examiner?

A. It's around $4 million.

Q. Talk about the project in terms of phasing it in over a given number of months or years.

A. Yeah, the project needs to be phased in over 10 years. That's to first of all level-load CO_2 purchases as well as the facilities, and also because we have to wait for gas to be produced from the gas-injection area in order to put on the patterns that exist in the gas -- produced gas reinjection area.

I also might note that around this project area the current waterflood will continue. And so we will not be changing the operation in the other areas, units that are outside the boundaries of the proposed Phase I CO_2 project area.

Q. Let me direct your attention, Mr. Falls, to the exhibit that illustrates the design limitations or constraints that you were dealing with when you began to analyze and decide if this project was feasible.

A. Okay, Exhibit 11 summarizes the major design premises or what -- the major things that form the framework or fabric for the CO_2-flood design.

First of all, we are asking for permission to reinject produced gas. As I mentioned previously we looked at some other alternatives, but they were not found to be economically viable.

Secondly, the flood is designed around a CO_2

purchase rate of 110 million cubic feet per day, which is limited by the existing CO_2-supply infrastructure in the area.

As also mentioned previously, we have designed the flood to separate the flood of the two major San Andres intervals in order to get adequate vertical sweep efficiency for the project.

And finally, we have been driven by a need to maximize the use of existing wellbores. The project has a hard time bearing, you know, drilling all brand new wells, so we must use existing wellbores.

Because of the existing well construction, we're limited to tubing size of about 3 1/2 inches. And this has a role in the project because in order to process the reservoirs at the desired or needed rates we need to put quite large volumes down this 3-1/2 tubing, which introduces the frictional pressure loss that's the motivation behind us requesting additional surface injection pressure to be able to accommodate that.

Q. What engineering method did you utilize in order to come to the conclusion that there was an opportunity to produce 76 million barrels of additional oil?

A. The backbone of our analysis is a comprehensive reservoir simulation model, which is summarized in the next two exhibits.

Q. Let's turn to Exhibit Number 12, and before you describe that, let ask you a couple of questions. Examiner Catanach has seen a number of modeling simulation presentations. Rank for him, if you will, the level of sophistication that was used by OXY in order to simulate what we believe to be the reservoir and then how we forecast recovery.

A. Well, we've tried to bring to bear the world-class and highest level of sophistication in designing this flood. We recently were privileged to have an external party come in and review our work and classify this work as being, you know, world class.

Q. What type of model are you using here?

A. Okay, we began -- We actually built two models for -- to describe the Hobbs field. The first model was one of the waterflood, because we needed to make sure we understood the reservoir characterization and the response of the field to water injection before going on to design the CO_2 flood.

Q. You've called this the full field model?

A. Yes, I have.

Q. Identify and describe for us, utilizing Exhibit 12, what you've done and what you've concluded.

A. Occidental Permian being the operator of both the North and South Hobbs Units has the opportunity to build a comprehensive integrated model for the entire Hobbs Grayburg-San Andres Pool. And so the full field model basically represents the simulation model that was built to incorporate the fundamental reservoir characterization data, as well as the injection and production history over the lifetime of production from the field, and be able to history-match that.

We used a simulation with 120,000 grid blocks to discretize or break up the spatial relationship of the geology and petrophysics in the field.

So the top panel shows the structure and permeability that was in the model, with the structure being shown, obviously, by the layout of the grid blocks. And the permeability, going from the cool colors would be the lowest permeability, down say 1 millidarcy in the top of the Grayburg, and the warmer colors being higher permeability, getting up in some layers up to 200 millidarcies in Zone 1 of the San Andres.

The bottom panel --

Q. The top portion of the display, then, represents the input of all the data you have available, and you now have what you believe to be an accurate geologic and reservoir depiction of the reservoir?

A. Yes, the geologist and petrophysical description was used directly in the model without manipulation or modification.

Q. The next sequence is then to run the model and try to match certain characteristics of the reservoir, right?

A. Uh-huh.

Q. What did you match?

A. We matched the oil, gas and water production over time from the entire field, and that's what's represented in the bottom panel of Exhibit 12.

Q. Describe for us how we read and understand that.

A. Okay, the graph shows over time the actual gas, water and oil production by the symbols, the gas being the solid-filled black symbols, the water being the diamond -- blue-filled diamonds, and the oil being the green solid circles. And the simulation shows the model history match of that actual data. And this is a very good history match, as judged by those that are schooled in the art.

Q. Okay, what then did you do?

A. Okay, having this full field model and the degree, quality of history match that we had, we felt that we had an adequate understanding of the reservoir in order to form the basis for a CO_2-flood design.

Q. Did you have to manipulate any of the parameters of the full-field model in order to achieve this quality of match?

A. Fortunately, not very much. That's because since OXY operates so many projects and fields around the Permian Basin, we have a good handle on the basic inputs for obtaining a history match, like relative permeability curves and the PVT description, et cetera, and those were used as we've used them elsewhere in this model.

The principal tuning parameter, if you will, in obtaining the history match was the completion interval. That is the depth to which -- and intervals in which wells were completed over time. That was the principal mechanism used to obtain the history match.

Q. Give us the transition from the full field model now to the simulation for the CO_2 flood.

A. Okay. Important in capturing the response and performance of the CO_2 flood is understanding how the CO_2 will go into the various layers. And so it requires a much finer discretization of the vertical direction than a waterflood.

Given that in order to obtain the degree of definition of the vertical strata there we would be unable to model the CO_2 flood using the full-field model, so we went to a proven approach, which is illustrated on Exhibit 13, which shows the approach we took in actually modeling and designing the CO_2 flood for North Hobbs.

Q. Why did you call it a proven approach?

A. Because in the other 16 floods that we've operated we've used that with success in projecting the performance of CO_2 floods.

Q. Summarize this Exhibit 13 for us, then.

A. Okay, we refer to it as a prototype simulation approach where we represent an element of symmetry within the existing or intended pattern of the flood, so that's illustrated here on the upper left-hand portion of the diagram where we subdivide the pattern into a quarter element of symmetry and develop a prototype simulation model.

As you'll note, that's shown by the colored diagram in the middle where we show the quarter element, ninespot or fivespot element symmetry. And you see that we've built a lot more vertical layers, 50 vertical layers instead of the 14 in the full field model. Because of the smaller area extent, though, the number of grid blocks in the prototype simulation model is low enough that the model is tractable and can be run to project various flood options and then evaluate them.

An input to the model is geologic and petrophysical characterization as determined, principally by well logs but also core, and a number of characterization data that we have available to us.

The prototype simulation model has been used to develop a dimensionless injection production functions, which form the basis and inputs to a scaling and scheduling algorithm that basically applies these element of symmetries and adds them together to build up the full field or full project area injection production functions.

Q. Do you calibrate or history-match this type of model as you did with the full-field model?

A. Yes, typically the prototype simulation model will actually be run itself on the waterflood performance data and calibrated that way.

Q. At this point in time, have you constructed the model in such a way and have it prepared that it can now forecast for you what would be the effect if you commence CO_2 injection?

A. Yes, that's been our experience.

Q. Do you have an illustration that forecasts for you what you believe will be the performance of the unit under Phase I CO_2 development?

A. Yes, that would be Exhibit 14.

Q. Let's look at that.

A. This exhibit shows the forecast of oil production response from the proposed flood in relationship to the historical performance history.

Again, the solid filled green symbols denote the actual production history through the primary and then post-unitization waterflood periods. And the solid line shows the forecast. First of all, the forecast that if we were to continue the existing secondary flood operations, the waterflood decline is shown beginning in the year 2002 as the solid line underneath the cross-hached area.

The open symbols show the forecast for the proposed CO_2 flood, and the shaded region in between is the total volume of oil expected to be recovered by the project.

Q. If the Examiner approves the project for the recovered tax oil rate, you will come back at some future date and prove to his satisfaction a positive response to that CO_2?

A. (Nods.)

Q. Is Exhibit 14 a display that he could utilize to know the baseline, if you will?

A. Yes, and I believe we've tabulated those numbers also in the Application.

Q. All right. So there will be a method that he can use this as the baseline to see what would have happened if you had not utilized CO_2?

A. Yes.

Q. And then he can compare it to what you present for a positive response?

A. Yes.

Q. All right, let's turn to the last display that you're presenting. Identify for us Exhibit 15.

A. Exhibit 15 shows the gas injection and production of the proposed project and forms the basis of our request to up the GOR for the unit.

First of all, this depicts in the magenta-colored curve with the solid diamonds the CO_2 purchase rates associated with the project. The CO_2 purchase will be about 110 million cubic feet per day for about five years. And then as patterns in the flood reach their designed slug size, the CO_2 purchases will be curtailed and fall off as the curve shows.

The gas produced during the -- by the project is shown by the -- indicated by the black line with the squares, and it shows that the project will produce about 70 million cubic feet of produced gas over about eight or nine years before it begins to decline.

The red curve with the triangles shows the total gas injected in the project, which is the sum of those two curves.

Also displayed against the right-hand Y axis is the unit GOR. We see it would rise, predicted to rise from the current 800 standard cubic feet per stock tank barrel up to about 5000 standard cubic feet per barrel as the CO_2 breaks through and is produced, and this is the basis for our request to allow up to a 6000 GOR to give us some margin on these projections.

Q. In conclusion, Mr. Falls, would you take a moment and summarize your opinions, conclusions and recommendations for Mr. Catanach?

A. Certainly. Mr. Examiner, OXY Permian has designed a CO_2 flood of the North Hobbs Unit Grayburg-San Andres Pool to safely protect the welfare of the public in implementing a CO_2 flood while increasing the recovery of hydrocarbons from the field.

We expect there to be substantial benefits to accrue by implementing the flood, first of all to the local economy, as well as the State of New Mexico, and to carry out the project we need your approval of several items which are listed in Exhibit 6.

We need you to grant authorization to inject CO_2 and produced gas into the project area, into the wells that are listed in our C-108 Application.

We need you to approve increased surface injection pressures to accommodate our density differences and frictional pressure losses.

We request that we be granted an increase in the fieldwide GOR, up to 6000 standard cubic feet per stock tank barrel.

We ask that you give us 18 months to begin injection from approval and also grant us an administrative process to request extension of that time period if we run into construction delays.

And then we ask that you qualify the project under the Enhanced Oil Recovery Act.

MR. KELLAHIN: Mr. Examiner, that concludes my examination of Mr. Falls. We move the introduction of the exhibits that he sponsored, which are Exhibits 1 through 15.

EXAMINER CATANACH: Exhibits 1 through 15 will be admitted as evidence.

A lot of information.

MR. KELLAHIN: Sir?

EXAMINER CATANACH: Lots of information.

MR. KELLAHIN: It's a big project, Mr. Examiner.

EXAMINER CATANACH: Okay, Mr. Falls, I have a few questions.

EXAMINATION

BY EXAMINER CATANACH:

Q. Initially, as shown on your map, the gas injection area on the right-hand side will be strictly CO_2 injection; is that correct?

A. Not just initially but throughout the lifetime of the project, only CO_2-pipeline gas will be introduced in the gas injection area.

Q. At some point during the operations do you -- Well, when the CO_2 purchase is reduced, are you still going to have enough CO_2 to inject into that area?

A. The CO_2 purchase will be reduced as the patterns in that area reach their ultimate designed CO_2 slug size. So they will be basically going on chase water at the time the CO_2 purchases are being curtailed.

Q. Okay. Within that area, do you alternate CO_2 and water injection in that area?

A. Yes, I didn't mention that, but the slug -- the flood is designed as what's called a tapered WAG injection strategy, where an initial slug of CO_2 is injected, followed by a slug of water, and then alternating CO_2 and water. But the CO_2 portions get progressively smaller, and the water injection portions get progressively longer until ultimately you chase the entire slug with a water drive.

Q. So initially, how long would your CO_2 injection phase last, in a given well?

A. In a given well, the CO_2 slug size is envisioned ultimately in Zone 1 to be 60 percent hydrocarbon pore volume. The design throughput for Zone 1 and 2 is 15 percent hydrocarbon pore volume per year, so within six to eight years, given that the WAG cycle is going on, will be what the Zone 1-2 injector -- how long it would be injecting CO_2.

Zone 3, as I mentioned, has tighter rock, and so the forecast throughput rate is only 10 percent hydrocarbon pore volume per year, so it's basically 50 percent longer. So it's projected to be nine to twelve years before chase water is introduced.

Q. Okay, in the other area, the gas reinjection area, that is going to be strictly produced gas?

A. Produced gas and water in the same WAG strategy.

Q. And that's throughout the life of the project?

A. Yes.

Q. What's the percentage of CO_2 that's going to be in that produced gas?

A. About 90 percent is what our model projects, once the CO_2 breaks through. I mean, it starts from the current 15-percent average, but it builds very quickly, especially from Zone 1-2, which is a very prolific zone.

Q. So do you envision that area as getting the same benefits or nearly the same benefits as the CO_2-injection area?

A. Yes. The presence of the hydrocarbons does diminish the displacement efficiency somewhat, but not greatly.

Q. Okay. Now, is your project going to be -- the CO_2 injection going to be limited to the area that you've defined on the map there?

A. Yes, Phase 1.
Q. Now, is there a Phase 2?
A. We envision if Phase 1 is successful, potentially coming back in the 2008 time frame and potentially expanding to other portions of the unit.
Q. Expanding CO_2 injection?
A. CO_2 injection, yes.
Q. Let me ask you whether -- The CO_2 injection, will that benefit the area outside the CO_2-injection area?
A. For the producing wells that are just adjacent, to some extent, yes, but not much beyond that as the, you know, ring of producers captures the CO_2-injection production.
Q. Okay. Now, on this particular map you don't have the injection patterns mapped. Is there an exhibit that has those mapped?
A. We do not have one prepared, Mr. Examiner, but we certainly can provide one for you.
Q. Okay. Now, I guess the H_2S is currently being produced from the San Andres zone?
A. Yes.
Q. And it's currently being processed at -- Where is it being processed at currently?
A. At nearby gas plants.
Q. And you have examined the possibility of

continuing that process and have found it uneconomic; is that correct?

A. Yes, the existing gas plants with the technology that is employed cannot accommodate large concentrations of CO_2, so the gas produced by this project cannot be processed by gas plant. There are some CO_2-recovery plants in the area, however we have investigated the Hobbs gas there and have found that the existing plants do not have sufficient capacity to handle the Hobbs volume, so it would require substantial expansion to that, and that's quite an investment that this project cannot bear.

Q. Now, does the H_2S in the produced gas, does that present some problems with the injection wells or the producing wells that you've had to deal with, or that we'll deal with?

A. I don't know if you'd classify them problems. It's a common practice to produce H_2S and CO_2 floods across the Permian Basin, and over the 30 years CO_2 floods have been implemented, the technology and operational procedures have been developed to handle it in a safe manner.

Q. So as far as the tubulars in the wells, you're not going to -- They're not going to be any different than what they are now?

A. Well, the injection wells will be -- the tubing will be a coating, coated, that will withstand the fluids.

And same thing on the gathering system. I mean, it will be a line system that will accommodate the produced fluids, and...

Q. How do you guys deal with the produced gas royalty issues? I'm just curious. I mean, do you pay royalty on the produced gas?

A. Generally we pay royalty on gas that's sold.

Q. So if it's reinjected you won't pay any royalty on it?

A. That's correct. However, I should add that the gas that gets contaminated by this project in proportion to total unit gas is fairly small, because we have gas production from the Grayburg currently that we intend to keep producing, as well as the gas from the waterflood in non-CO_2-flooded areas of the unit.

And in fact, the way we envision doing this is, you know, as we implement the flood, we will switch the production over to the new gathering and recompression system only as the CO_2 breaks through. We'll continue to market the gas until it goes out of spec for the gas plant.

Q. And that should only be for the CO_2-injected area?

A. Yes.

Q. Produced gas from there?

A. That's right, the current gas production will continue to be gathered and sold as it is right now.

Q. Okay. And do you know if Roger Anderson is going to sign off on anything or approve any kind of plan that you guys have?

A. The plan has been reviewed with him, and Mr. Starrett is prepared to give the details of those discussions in subsequent testimony.

Q. Okay. All right, you've requested certain fracture -- or certain injection pressures, and you've testified that the fracture pressure that you've determined in the field is approximately 2600 p.s.i.

A. That's the minimum of the data that's been collected.

Q. Which is my next question. What data did you use to determine that fracture pressure?

A. These were step-rate tests conducted over a several-year period over the lifetime of the unit, and Mr. Foppiano in his testimony will go through the details of that.

Q. Okay. I believe you testified the current GOR of the field is 3500 to 1?

A. That's the limit.

Q. The limit.

A. The current GOR, I believe, is around 800. It's been dropping recently.

Q. Okay. Your simulation shows a GOR that goes up to maybe 5000?

A. Yes.

Q. Are you just requesting a little leeway above that?

A. Yes, a 20-percent margin on the predictions.

Q. Now, are you guys seeking with this Application to convert additional wells to injection at this time?

A. Yes, as outlined in the Application, which Mr. Foppiano will go over.

Q. Okay. How many, do you know?

A. How many conversions to injectors? I believe I had tabulated in one of the exhibits the number of conversions but that's both ways, and I don't have that number -- don't know that number off the top of my head.

Q. Okay.

A. I can research it for you.

Q. That's okay. But that's through the life of the project, right? I mean, all of these will be converted --

A. Yeah, the red -- the wells that are color-coded red denote the proposed injectors for the project. There's red wells on Exhibit 3 that show the proposed injectors.

Q. Okay. Now, there are existing injection wells within that area too --

A. Yes.

Q. -- that will be utilized as well?

A. Yes, they will be converted to CO_2 injection, converted to production or, you know, temporarily abandoned, depending on how they're needed in carrying out the flood pattern associated with the CO_2 flood.

Q. Okay. You anticipate -- I guess under the unit agreement you need a certain percentage of the working interest owners to approve the project?

A. Yes.

Q. And that's 75 percent?

A. Sixty-five percent.

Q. Sixty-five. And you're not there yet, but you anticipate being there?

A. That's correct. This is a large project, and our major working interest owners have elaborate review and approval processes that they're currently going through.

Q. Okay. The Grayburg section is being produced in the field, right?

A. Yes.

Q. That's not in the whole field; is that in certain areas in the whole field?

A. Well, throughout the field the Grayburg has been produced either for gas or on the flanks. The oil column is in the Grayburg as well.

Q. Okay. Now, are you going to CO_2-flood the

Grayburg?

A. No.

Q. And the reason is -- ?

A. Well, the Grayburg is largely -- originally gas accumulation, and over at the flanks of the field the richness of the patterns is not sufficient to justify CO_2-flooding the Grayburg at this point. Right now our intention in Phase 1 is not to flood the Grayburg with CO_2.

Q. Okay. Now, tell me the injection is going to work. In some wells are you saying that just Zone 3 will be flooded, in some injection wells?

A. Yes.

Q. And in some injection wells 1 and 2 will be open and not 3?

A. Correct, we do not intend to commingle injection between Zone 1 and 2 and Zone 3, so the injectors will be dedicated to either Zone 1 and 2, or Zone 3.

Q. Now, producing wells will be open in all three zones?

A. Yes, we intend to commingle production.

Q. Okay, and the reason you don't want to commingle the injection fluid is what again?

A. The properties of the Zone 1 in particular are such that if we tried to commingle injection, inject, it would not effectively sweep Zone 3. We've run simulation models were we've commingled injection versus where we separate the floods, and it's much better recovery of the hydrocarbons by separating the two intervals.

Q. This increases the number of injection wells that are necessary?

A. Yes.

Q. What's the plan for South Hobbs?

A. South Hobbs is a CO_2-flood target. It's not as rich or as good a reservoir as North Hobbs. We envision beginning to design a flood for South Hobbs and hopefully one day we'll be in front of you asking for permission to conduct that one as well.

Q. Okay. What is your CO_2 source?

A. Well, we have several options there. We've already begun discussions and preliminary negotiations with various CO_2 suppliers. It could come from any one of the major CO_2 sources. In fact, our working interest owners have the option to deliver their share of CO_2 in kind, and so some of them have a holdings in one or the other.

So I imagine all the CO_2 sources, McElmo Dome, Bravo Dome, potentially Sheep Mountain, as well as the gas plants in the southern part of the Permian Basin will contribute to the CO_2 supply.

I might add that the CO_2 supply is food-grade CO_2, 99.9-percent CO_2 coming off the pipeline system.

Q. What do you anticipate the response time to CO_2 injection will be?

A. Because of the prolific reservoir in Zone 1, we're estimating we will see response in some wells in six months and definitive response most likely within a year. That has been common in the few reservoirs around the Permian Basin that have had high permeability, Salt -- Mobil's Salt Creek project for example, Exxon Mobil's Salt Creek Project, for example, saw an extremely fast response. And that's what we're expecting at North Hobbs, because of the high quality of the reservoir in Zone 1 San Andres.

EXAMINER CATANACH: I think that's all I have for now, Mr. Kellahin.

Are there any other questions of this witness?

MR. KELLAHIN: No, sir.

EXAMINER CATANACH: This witness may be excused.

MR. KELLAHIN: May we have a five-minute break?

EXAMINER CATANACH: Certainly.

(Thereupon, a recess was taken at 1:56 p.m.)

(The following proceedings had at 2:05 p.m.)

EXAMINER CATANACH: Okay, we'll call the hearing back to order, and at this time we'll -- Mr. Johnson, can I -- Never mind.

Go ahead, Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Examiner.

MICHAEL STARRETT,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Would you please state your name and occupation?

A. My name is Michael Starrett, and I'm an engineer with OXY.

Q. Mr. Starrett, on prior occasions have you testified before the Division as an engineer?

A. No, sir, I have not.

Q. Where do you reside?

A. Houston, Texas.

Q. Summarize for us your education.

A. I received a bachelor's of science in petroleum engineering in 1983 from the University of Texas, I received a master's of science in petroleum engineering from the University of Texas in 1988, I received a jurisprudence doctorate from the University in 1994, a registered professional engineer.

Q. Summarize for us your employment experience as an engineer.

A. I was hired by Amoco Production Company in the Permian Basin in 1988, and I've worked there in various engineering forms, production, reservoir. Since that time and for the last ten years I've worked in the health, environment and safety department.

Q. Summarize your experience as a safety engineer.

A. I have been more a project AGS engineer for major capital projects, acquisitions, divestments. How it bears on the CO_2 flood, every significant-sized project since 1991 I have worked to ensure that it's been appropriately risk-designed and -engineered to protect our workers and the public.

Q. Let's turn to what is marked as Exhibit 16.

A. Yes, sir.

Q. Would you identify that for me?

A. Exhibit 16 represents H_2S injection operations around the Permian Basin.

Q. Of these projects, how many involve OXY Permian?

A. The red-starred projects, outlined, scattered around the Basin, are the OXY-operated projects, the green are outside-operated projects.

Q. Of the projects shown in the Permian Basin on Exhibit 16, how many of these have you been personally involved with?

A. Quite a few. Starting at the north, the Anton Irish project, both phases; going down to the southwest, the Central Mallet Unit project; further south, the Bennett Ranch project; further southeast, the Cedar Lake project, both phases; way off to the east, the Cogdell project; down to the south, the North Cowden project; and the proposed Hobbs project in the outlined red star.

Q. What has been your task or responsibility with regards to the North Hobbs project?

A. As the health, environment, safety and regulatory team leader, I am responsible for ensuring that this project is appropriately designed, constructed and implemented in a safe manner.

MR. KELLAHIN: We tender Mr. Starrett as an expert petroleum engineer with expertise in safe planning for facilities such as this project.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) Mr. Starrett, let's have you express an ultimate opinion for me, if you will. In your opinion, has this project been designed to be constructed and operated in a safe manner?

A. Yes, sir, it is.

Q. Have you emphasized and focused on the handling of the H_2S component of the project?

A. As one of the most significant components, yes, sir.

Q. When we talk about a safety plan --

A. Yes, sir.

Q. -- can you identify and describe for us the major components of OXY's safety plan for the North Hobbs Unit?

A. Yes, sir, I've brought an exhibit with me marked Number 17, which describe three of the major safety-plan components.

Q. All right, go through that for us and summarize them.

A. Yes, sir. The first one is a construction safety plan. This is basically a communication plan for the actual installation of the project. This is a multi-year project involving many crews from different contractors. We want to ensure that the drilling and workover and facility construction pipeline all get coordinated and communicated and implemented safely.

The next plan is a close proximity operating plan. It is an operating plan for wells and facilities that are located in close proximity to people. That's roads, homes or businesses. It ensures the integrity of the facility design and operation, because it has increased material specification, hazard reviews, inspections and maintenance plans and management of change associated with it.

And then the third plan is the emergency action plan, which is an integrated emergency response plan that incorporates a wide potential hazards, and one of the major components of it is the H_2S contingency plan required under

Rule 118.

Q. Can you identify for us your exhibits that are associated to what you've summarized to be the three components of what we're characterizing as the safety plan?

A. Yes, sir, Exhibit 18, 19 and 20 are the draft versions of these three plans, and I will just quickly outline it.

The one marked 18 would be our construction safe work plan. It's summarized on the top portion of Exhibit 17.

On Exhibit 19 is the close proximity operating plan, which is summarized in the middle portion of Exhibit 17.

And the larger Exhibit Number 20 is the Hobbs emergency action plan, which is also summarized on Exhibit 17.

Q. Have those documents been submitted to the Environmental Bureau of the Oil Conservation Division?

A. All three of these documents have been reviewed and submitted with both the District and the Environmental Bureau of the OCD.

Q. What if any response have you received from the District Supervisor in Hobbs and from the Bureau Chief of the Environmental Bureau here in Santa Fe for the Division?

A. I would characterize their response as a strong proponent for the design plan of action to construct this facility and operate it.

Q. When you -- Can you categorize or characterize the quality and sophistication of this plan with the other plans that you've been involved in that you described in the earlier exhibit?

A. Yes, sir, about ten years ago, when we were first going into the H_2S injection concept, when the plant started to fill up and we didn't have the supplies and we needed to use reinjection, we started the concept of designing these plans and operating programs.

And over the last ten years we've learned a lot of lessons, we've gotten better, and I would characterize this one as the best and most sophisticated project we've put in, eclipsing all the others in terms of its degree of safety design and program implementation.

Q. When you're developing the three parts to what we characterize as the safety plan, there is an underlying technical basis that supports the plan as you've drafted it; is that not true?

A. That is correct, sir.

Q. Before we look at those documents, describe for us why these are simply called draft or preliminary plans. What does that mean?

A. Well, a safety plan is never complete until the project is actually implemented. Because we have not yet hired construction companies and individuals, we cannot specify the communication of who to call and do those kind of events.

Because the facilities have not been completely designed and implemented, i.e., right of ways may change due to surface obstructions or changes may occur in the design process, the plan is marked "draft" until we get the actual in-place, as-built drawings, so that we can finalize the plan and then implement it.

Q. That's simply inherent in all safety plans, is it not?

A. That's correct, sir.

Q. Let's turn to the documentation, then, you're prepared to submit to Mr. Catanach that supports the plan itself --

A. Yes, sir.

Q. Starting with Exhibit 21.

A. Exhibit 21 and 22 are kind of to be viewed together. One of the bases for designing that safety plan is to have a good understanding as to what the H_2S or hydrogen sulfide rates of exposures are for the project that we're implementing.

Exhibit 21 displays model results, the worst-case model results for each facility type that we're going to be installing in the unit.

Exhibit 22 is actually a technical manual for the dispersion model that we utilize for this particular flood.

Q. Do you have an opinion as to whether or not this unified dispersion model in Exhibit 22 is an appropriate model that meets all the API guidelines?

A. My opinion is that this unified dispersion model is the best model that would meet all the API guidelines for the substance that we are injecting in Hobbs, being a denser phase gas.

Q. You're familiar with the Division's current Rule 118 on H_2S?

A. Yes, sir.

Q. Does your plan and the technical documentation to support that plan meet or exceed all the current requirements of Rule 118?

A. Yes, sir.

Q. Are you aware that the Division has under consideration a work group that is studying making revisions to Rule 118?

A. Yes, sir.

Q. To the best of your knowledge, information and belief, does OXY's plan and supporting technical documentation in this case satisfy the requirements that are anticipated to be changed for Rule 118?

A. Since 118 is still under development there may be minor changes necessary, but I have no doubt that whatever ultimately gets proposed for Rule 118 we will be able to slightly modify and meet fairly easily.

Q. What are you asking Mr. Catanach to do with regards to the safety plan?

A. I just wanted to put -- OXY just wanted to put it into the record and to allow public comment on it if necessary.

Q. All right, there's no specific action he needs to take at this time as the Examiner in this hearing case?

A. No, sir, I assume all action will be taken by either Mr. Williams or Mr. Anderson, should that be necessary.

Q. And your understanding of the division of responsibility within the Division would require Mr. Anderson to approve and act upon your plan?

A. My current understanding is that Mr. Anderson is not required to act upon the plan.

Q. What is his responsibility?

A. Well, the Director asked that I review it with Mr. Anderson, and under the current rule the plan has to be available for inspection according to the Division's will, and so had our plan upon inspection not met Rule 118, he would then have the authority or obligation to correct it.

Q. All right, sir. Let's turn past Exhibit 22 and have you identify and describe for us what's contained in Exhibit 23.

A. Yes, sir. Exhibit 23 and its companion exhibit, 24, are an attempt to represent the risk management practices that were incorporated into the design of this flood.

Exhibit 23 is simply a summary of those by facility type, put on a three-page document.

Exhibit 24 is very much the same information drawn in a simplified flow diagram at each facility. So starting from a production well, following the flow through the entire battery satellite and back into an injection well, those are the drawings in Exhibit 24.

MR. BROOKS: Looks to me like Exhibit 24 is the summary and Exhibit 23 is the diagram, as they're marked in my set.

THE WITNESS: I'm sorry, did I have them in the wrong order? I did? Okay, excuse me, please switch those two numbers, yes, sir.

Q. (By Mr. Kellahin) All right, let's turn to a different topic, Mr. Starrett. Do you have an exhibit that summarizes the chronology of your contacts and efforts with regards to the safety plan itself?

A. Yes, sir, that would be Exhibit Number 25.

Q. Identify and describe what you're showing here.

A. This is the safety plan chronology of meetings between OXY and outside parties on developing the safety plan. Would you like me to go through it?

Q. Yes, sir.

A. On April 12th, OXY met with the NMOCD Hobbs Office, and at that initial meeting with Mr. Williams we proposed the delineation of the gas and gas reinjection areas as shown on the large map in front of me.

We also proposed hiring Det Norske Veritas, which is a world-class risk assessment company, to help us in the design of the safety mitigation measures on this flood.

On April 18th, OXY then met with the NMOCD Santa Fe Office, where the Director -- Mr. Anderson reviewed the project, and the Director requested a follow-up review with Mr. Anderson prior to coming to this hearing.

Then on July 10th through 11th, an independent project analysis is what IPA stands for. It's a third-party consultant which reviews major capital projects. They analyzed and made recommendations on our projects, and one of the prongs of their investigation was the safety plan on the project.

On July 25th, our major working interest owners, Chevron, Texaco and Exxon Mobil started a peer-review technical review of our flood, and they have -- one of the areas they are analyzing is the safety plan and practices proposed to be implemented.

Then on August 16th, OXY followed up with the NMOCD Hobbs office to review the -- basically the documents we're submitting here today, and Mr. Williams supported the plan, and he requested a follow-up review with the facility engineer and the construction supervisor after this hearing, before construction begins, so roughly in late October, I think, we're setting up that date for. And that's just to determine that we meet all of his expectations in the construction and implementation phase.

And then August 22nd, we had a follow-up meeting with the NMOCD Santa Fe Office where Mr. Anderson and Mr. Price reviewed all this same information, and they voiced their support for the plan, and they just want to request that we keep an open dialogue flowing during the multi-year development of this project.

Q. Let me turn to a different topic, Mr. Starrett. Do you have an exhibit that summarizes the efforts OXY has undertaken to inform the public, and particularly the public in the Hobbs community, about the project and the safety plan?

A. Yes, sir, I brought with me Exhibit Number 26, which is the North Hobbs Unit CO_2 flood highlights. As I've already talked about in the previous exhibit, we've had several briefings with the Hobbs and Santa Fe NMOCD Office, because we consider the NMOCD our primary push, that we get them educated so they can answer questions that come to them.

Then we've discussed with elected representatives from the city, county and state about our flood. We've also met with some community representatives, including the Hobbs city manager. We've had a couple of press releases and a couple of favorable news articles, two of which I've attached. I think there's quite a few more articles, but I attached some examples to this exhibit.

We are also in the process of sending out a CO_2 flyer to the City, "Oxy Permian and the City of Hobbs" -- the flyer is attached to the back of this exhibit -- discussing what a CO_2 flood does and basically CO_2 flooding.

And then of course as we implement the actual project and further develop our H_2S contingency plan over time, we will involve the affected residents in notice what we're up to.

MR. KELLAHIN: Thank you. Mr. Examiner, that concludes my examination of Mr. Starrett. We move the introduction of Exhibits 16 through 26.

EXAMINER CATANACH: Exhibits 16 through 26 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Starrett, was this flyer mailed to the residents of Hobbs?

A. No, sir, we printed up a couple of thousand copies for the affected people, and we're in the process of sending it out. I think we're -- imminent is the proper word. I'm not sure why it didn't make it out before the hearing, but it's making out as we speak, I think.

Q. You said affected people.

A. Well, obviously we're not going to send 30,000 or whatever the population of Hobbs is. What we're trying to do is give it to OCD so that they can have it on hand to distribute, give it to the community leaders.

We're actually going -- I think our plan is to prepare it in a letter to be published in the paper, the same information with a letter from our CEO, president, saying this is what we're up to. We're going to disseminate this information to the community at large, and then we're going to, I think, try to send it to -- I don't know if it's a door drop. We're still -- how we get the information out.

Q. Okay. I assume that when you had your discussions with Roger Anderson and his group and Chris Williams and his group that you went into great detail on some of the safety plans that you have proposed?

A. Yes, sir, those discussions with Roger and them lasted over three and a half hours the second time. The first time I don't know how many hours it was. It was very long, very detailed discussions.

Q. I just want to make sure that -- on my behalf, that I don't have to spend a whole lot of time dealing with the safety issues, because I think they're already covered by Roger and the Hobbs District Office.

A. That was my plan of action prior to this hearing, yes, sir.

Q. Okay. This -- As I understand it, the gas injection area is basically on the north and northwest side of Hobbs; is that correct?

A. That's correct, the city limits are not -- I don't know if they're shown on that map. They probably are, I can't see it from this far. But the City of Hobbs is generally on the southeastern portion there of the map.

Q. Okay.

A. The city limits would be denoted in the dashed blue line, if you can look at --

Q. Okay, I see it.

A. So it cuts through a portion of the pipeline quality gas injection area. It does not encounter any of the gas reinjection area.

Q. What -- It's been a while since I've been to Hobbs. What is in your area that you're -- What is in the gas reinjection area? Are there residences, houses, roads, things like that?

A. Yes, all of the above, sir.

Q. And that's throughout the whole area?

A. Yes, sir. The difference simply in the density. The gas reinjection area, as stated by Mr. Falls, is much more remote, much less populated area.

Q. But you probably have ranches out there and things like that?

A. Yes, sir, I've supplied the Division with the actual maps with all the homes on them and stuff like that for them, yes, sir.

Q. Now, is there going to be more involvement on OXY's part with residences and people in that area with regards to educating them on the safety plan or --

A. Absolutely. But you see, sir, some of that area doesn't get in that area until 2008 or 2010. So our plan would be to inform the residents that are affected kind of right -- more in close proximity to when they'd actually be affected. They can see the entire plan any time, but the point is, we would be -- I'd kind of feel bad if I thought I educated someone and then five years later I really got in their area, and that's when I really should have educated them on what to do.

Q. Basically all of the production facilities and storage and pipelines and things are going to be mostly located within the gas injection and gas reinjection area; is that correct?

A. The existing -- the proposed new tank battery and the proposed new reinjection facility are, yes, we picked absolutely the most remote area down in a portion of that blue section, so the new facility we construct, the major two facilities.

The individual CO_2 satellites that we're building today are going to be on the exact same location as today's waterflood production satellites are on. So there's ten of those spread throughout that area, sir, and they're within the colored phases there.

Q. You're currently producing H_2S?

A. Yes, sir.

Q. And is the danger in this area going to increase as -- with your proposal?

A. What will happen is, the H_2S concentration will go down dramatically, as Mr. Falls stated, from a current 65,000 parts per million to a probable 5000 parts per million later. But the volume of gas is going to go up dramatically, almost by the same -- because it is a dilution effect, almost by the same numbers.

So what will happen is, your rates of exposure, which is a function of the volume, will actually increase in areas, even though the concentration of H_2S has dropped dramatically.

Q. I know that OXY hasn't operated the North Hobbs Unit for very long. Do you know what the safety record so far has been with maybe Shell or Amoco?

A. Yes, sir, I pulled the records on the Hobbs Unit with Altura and then OXY, and it was previously operated by Shell prior to Altura. I think we have an outstanding safety record, would be the way to classify it, in terms of lost-time accidents and no lost-time accidents.

EXAMINER CATANACH: Okay, I have nothing further of this witness.

MR. KELLAHIN: Thank you.

RICHARD E. FOPPIANO,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Foppiano, for the record, sir, would you please state your name and occupation?

A. My name is Rick Foppiano, and I'm employed as a senior advisor for regulatory affairs for Occidental Permian, Limited.

Q. So what's that mean?

A. It means I get to do the C-108 for this.

Q. Where do you reside?

A. I'm in Houston, Texas, right now.

Q. All right. It has been your responsibility for the North Hobbs CO_2 project to do what, sir?

A. For the North Hobbs CO_2 project I was brought in to oversee some of the regulatory matters, in particular the preparation of the C-108, and as part of that to investigate and analyze the wells in the area of review, to identify any problem wells that may have existed, and also to analyze the step-rate pressure-test information and justify a recommendation to the Division for what the surface pressure maximum limits should be for our injection wells.

Q. You've testified before the Division on prior occasions as an expert in petroleum engineering, have you not?

A. Yes, I have.

Q. And you've testified before the Division with regards to the C-108, have you not?

A. I have.

Q. You were responsible for processing and testifying on a saltwater disposal well, I think it was the Government AD 9 well, if I'm not mistaken?

A. AB 9, yes.

Q. AB 9, all right. So you're familiar with the entire process?

A. Yes.

Q. And what we're about to look at is your work product and your recommendations?

A. Yes.

Q. In order to achieve this level of effort, have you utilized outside experts or additional technical support to develop to the fullest extent possible an accurate and reliable C-108 plus all their attachments?

A. Yes, I have. As you can see by the volume, it's a fairly large undertaking to identify and analyze and compile all this information, and so I utilized people who have tremendous experience in it, I utilized some of our own employees and others, anybody that I felt was qualified to help us prepare this filing.

Q. All right, sir. And you are, finally, a registered professional engineer, are you not?

A. Yes, I am.

MR. KELLAHIN: We tender Mr. Foppiano as an expert witness.

EXAMINER CATANACH: He is so qualified.

Q. (By Mr. Kellahin) All right. First thing I'd like to have you do, Mr. Foppiano, is have you identify

Exhibit 27. What is this?

A. Exhibit 27 is the C-108. And, Mr. Examiner, I'll point out that it's slightly revised from what was filed several -- almost a month ago, I guess. And I can walk you through it, but basically the revisions were just to update the well information that was contained in the spreadsheet. We continued to search for well information after the filing date and some more information became available, so I incorporated that into the spreadsheet and have that available as the exhibit today.

So what you have before you is a corrected C-108. It has corrected the AOR spreadsheet that's in it; it's the legal-size filing. And as a result of that, a couple of P-and-A schematics that were not available at the time of filing have now been added, and we found a couple of minor errors on the injection well data sheets, so we re-gen those, and those are also corrected and part of the filing today.

Q. If Mr. Catanach takes this Exhibit 27 and utilizes this to replace any previous filings of the C-108, he is using the best and most correct information?

A. Yes, he is.

Q. Let's turn to the C-108, and detach the map that you would like to utilize to show us the area of review. Which one of the two maps should we look at?

A. Give me a minute, I've got to -- Mr. Examiner, there are two maps attached to the C-108 filing. Because of the large size of this area, and to try to get all of this information on one map, I've attached two maps to the C-108 filing, and the first map is the map that shows the half-mile area of review and a two-mile circle for notice purposes. However, you can also see that it's -- the font is so small as to make the well information unreadable.

So the second map, which is entitled North Hobbs (Grayburg San Andres) Unit Area of Review Map, is a more zoomed-in version of the same map, and it shows the wells within a half mile -- it shows the proposed injectors first, and it shows all the wells that have penetrated the Hobbs Grayburg-San Andres Pool within a half mile. And it does not show anything beyond that, so it's just focused in on those wells that are the subject of the area of review.

Q. All right, let's take a moment, Mr. Foppiano, and unfold that map so that we can all look at the same thing. All right, let's identify the various things we're looking at, and then we'll focus in specifically on certain areas. First of all, how do we find the boundary of the unit?

A. The boundary of the unit is denoted by the heavy black dashed line, and it's obviously the same shape of the unit we've been using throughout the prior exhibits. And you see we're only showing the North Hobbs Grayburg -- I mean, sorry, the North Hobbs Unit operated by OXY Permian. To the south is the South Hobbs Unit. I think we show it there at the bottom, but we don't show the entire South Hobbs Unit. So we're just looking at the North Hobbs Unit.

Q. What's the significance of this scalloped in -- It appears to me to be green. Is that a green-scalloped unit area?

A. The line around the unit area is the one-half-mile area of review. You can see that obviously the first part of this area-of-review process was to locate all the proposed injection wells, and those are shown on this map as pink. And all the wells, every well that is shown on here in pink has got a -- is listed or is tabulated in the injection well data sheets.

Once we located those, we drew half-mile circles around all of those wells, and what you see with all the wells are all the wells that are within those half-mile circles.

Q. Will there be a tabulation presented to the Examiner where he can identify and know the exact injectors in the gas injection area, as well as a list of injectors in the gas reinjection area?

A. Yes, there is attached in the C-108 a listing of the injection wells, and they are denoted as to whether they are in the gas reinjection area or the gas injection area.

Q. Tell us the color-coding you've utilized for the other wells here, other than what you've just described for the injection wells.

A. Okay, the color-coding, as I mentioned, pink identifies the injectors that are either produced gas injectors or -- I'm sorry, gas reinjectors or gas injectors.

The purple shows all the other North Hobbs Unit wells that are active, and all of those obviously are Occidental Permian, Limited, wells.

Shown in green are other Occidental Permian wells that -- producing from other horizons. And there's very few of those, but they're shown on this map.

Light blue identifies the plugged and abandoned wells for which there are schematics attached in the C-108.

And shown in brown are the outside-operated wells. You can see a few of them in there that -- We're mostly looking at a Blinebry waterflood that operates below the North Hobbs Unit.

Q. To the best of your knowledge, Mr. Foppiano, have you identified all wells within the area of review that penetrate to or through the unitized interval?

A. Yes, I believe I have.

Q. Let's keep the locator available and turn your attention to Exhibit 28, and I would like you to summarize for us the research efforts that went into compiling and preparing the data that go into the area-of-review tabulation of wellbore information.

A. Yes, sir. As I mentioned before, the first step, obviously, was to locate all the injection wells, even the proposed ones, as part of this CO_2 project, and then construct the half-mile circles. And then after that we obtained exact well-location information, construction and cementing data, not only from our files but also the NMOCD files in Hobbs and Santa Fe. We used *Dwight's PI*, and we even used another operator's C-108 filings that proved to be valuable. That was basically the Texland C-108 filing, was helpful on some of the Texland wells.

So we spent several months and outside help, utilizing every available resource to us to acquire data n these wells to be sure that we were here today with the most accurate information available.

Q. Approximately how many wells are in the population of wells in the area of review?

A. In the area of review, just the wells that penetrate the Hobbs Grayburg-San Andres Pool, we're looking at approximately 400 wells.

Q. Of that population, when you've ultimately come down to making a professional opinion about potential problem wells, how many of those wells are we going to describe as potential problem wells?

A. There's three wells that I'm going to discuss that we're going to discuss as potential problem wells, two of which we'll illustrate remedial action that we'll perform on it.

Q. Why are there so few wells identified as potential problem wells in a population that large?

A. Well, in my opinion it's because this has been an ongoing waterflood since 1979. It was -- When it was originally authorized there was a significant amount of corrective action required by the operator Shell, and that information is detailed in the order authorizing the injection. I think there were 15 wells that Shell was required to re-enter and re-plug back in 1979.

Since then we have expanded the initial injection authority by adding injection wells and then filing subsequent C-108s, and those of course had associated area of reviews with those. And then we have a deeper waterflood, and they underwent an area of review.

And so what I think what we're coming to is, this area has undergone extensive area of review and we're down to the point where there just are few if any problem wells left.

Q. When we review the tabulation and look at the data for wells for which there is not the ability to measure top of cement, what is the methodology you have used to calculate the volume of fill-up in those wellbores for which you do not have measured tops?

A. I utilized the standard yield of 1.32 cubic feet per sack and 50-percent excess. And I'll point out that I only utilized calculated tops of cement where there was no other information available about where the top of cement was, either through a cement bond log or a temperature log or visual observation if it was circulated. Only then did I calculate the top of cement, and then I did it according to the parameters described here.

Q. Is the spreadsheet attached to the C-108 configured in such a way that Mr. Catanach can readily see the wellbores for which you have calculated top of cement?

A. Yes, the legal-size spreadsheet denotes when tops of cement were calculated, as opposed to determined by other methods, cement bond log or whatever. I think that's in the last -- It's under the column marked "Source", which is the third column from the right on the legal-size spreadsheet, and it says "CALC", meaning calculated top.

Q. All right, let's go through a presentation to show Mr. Catanach how you have organized an analysis of the area of review. I assume you've categorized these in terms of some type of wellbore?

A. Yes, sir, because this is such a large number of wells and I knew I would be sitting here today trying to describe this large universe, I decided to try to organize these wells into some sort of a completion type. And after looking at them closely, they appear to fall in one of five different types of well completions.

And then after I did that, I went through the analysis of looking at our unitized interval in the North Hobbs Unit, which comprises the productive portion of the Hobbs Grayburg-San Andres Pool, and I looked to see if that was isolated from the nearest uphole zone, which is the Byers-Queen at about 3650, or the nearest downhole zone, which is the Glorieta at approximately 5300.

And I'll Just point out, Mr. Examiner, that on the legal-size sheet in the C-108, the last column says "Completion Type", and that is either a type 1 through 5 for the non-plugged-and-abandoned wells, and so that will correlate to the next exhibit that I'm going to review.

Q. All right, let's turn your attention to Exhibit 29.

A. Yes, Exhibit 29 is just a pie chart that gives you a picture of the relative numbers of these different types of completions that I've categorized.

And the first group are the gray wells, they're the plugged and abandoned wells. You can see there are 63 total plugged and abandoned wells that fell within this area of review, and there are 63 schematics attached to the C-108. The Category-1 or Type-1 completions are basically open-hole completions, and Type 2 are those with production casing set into the San Andres. Type 3 have an intermediate with a liner, and Type 4 and 5 are wells that are deeper and either have a liner or deep production casing set through the San Andres. So you can see that for Type 1 there's 36 open-hole completions in this area of review.

And shown in red there's 160 wells with production casing set into the San Andres. That's by far the largest number of wells in the area of review, fall into that completion category. 108 of the intermediate-plus-liner-type situation. And then we have very, very few of the ones that just have a deep production casing set all the way through the San Andres, and the deeper wells are represented more by the deep production liner with an intermediate casing string.

Q. Let's take this to the next level of analysis, Mr. Foppiano. If you'll turn to Exhibit 30, let's have you identify and describe this display.

A. Exhibit 30 is entitled "Well Construction Analysis", and it's for the non-plugged-and-abandoned wells only. And because these wells -- the Type 1 through Type 3 don't penetrate below the San Andres, the analysis that I'll walk you through looks at isolation of the Hobbs Grayburg-San Andres from the Byers-Queen. But before I start there, I'll just mention that in terms of isolation of the fresh water, all these wells have a surface pipe, either down to about 200 or 300 feet, or they have a shorter surface pipe with a kind of a middle-level intermediate casing string set at about 1600.

Q. Let me interrupt you for a second. Am I correct in understanding that in the area of review you have not found a single wellbore that didn't have sufficient surface casing, string and cement to isolate the fresh water?

A. That's correct, I didn't find a single one.

Q. So the fresh water is protected?

A. Fresh water is definitely protected.

Q. Okay. Do you find any wellbore in which a lower interval below the San Andres 3 Zone might be communicated with in that wellbore if an injection occurs in the unitized interval? Are there any lower formations at risk?

A. There are lower formations, yes.

Q. But none of them are at risk, are they?

A. No, I'm sorry, I'm thinking about my schematic. Yeah, I don't believe we have any of those that are at risk.

Q. All right, so we don't have any of those kind of problems where a unique circumstance exists where injection into the San Andres is going to contaminate or reduce hydrocarbon production from a deeper zone?

A. That's correct.

Q. How about the other way? Do we have an opportunity in this area where injection takes place in the San Andres and there's a wellbore that's a conduit by which fluids would migrate into a hydrocarbon-producing zone above that interval?

A. There is one well.

Q. Okay. Is the availability of the Grayburg an opportunity to seal these wellbores and confine the injected fluids to the unitized interval?

A. Yes, as Mr. Falls testified, the Grayburg, the top 100 feet of it is nonproductive. It's dolomite filled with anhydrites, so it's actually a good seal, so there's a very thick vertical interval between even the productive portion of the Grayburg and the next highest pool up the hole, which is the Byers-Queen.

Q. Okay. Walk us through, from left to right, the various types now and the data on the bottom half of the spreadsheet and what significance that should have for us.

A. Yes, Exhibit 30, I'll just walk you through it a little bit. The upper part of Exhibit 30 shows some wellbore diagrams, and these are Type 1, 2 or 3. And what

I'm attempting to show is how the wells in that particular type are constructed in relation to the unitized interval, which is from the top of the Grayburg down to the 4500 feet.

And starting with Type 1, you can see by the short casing string there all the wells in Type 1 have surface pipe. And then the next smallest size casing down is shown with a dashed line. Some of those wells have that short intermediate, some don't, so it's not present in all of them.

But then the next smallest casing size down is the intermediate set into the Grayburg, and all the wells in this type have that intermediate set into the Grayburg. And then you have this open hole that is drilled out below the intermediate.

And the information below the schematic drawing, you can see in the first column that says "Section", and you see various numbers on it, those are the section numbers corresponding to the sections that have wells within the area of review.

And the next column over from that are the number of wells and some top-of-cement information about those particular wells in those sections. For example, Section 13 we see "4/2770-surface". What that means is, there are four wells in Section 13 that are Type 1 wells, and the lowest top of cement of all those four wells is 2770 feet, and the highest top of cement is all the way to surface.

And you can see as you go all the way down that that column -- there are a couple of wells in some sections, in some sections there are no open-hole completions -- getting all the way to the bottom where it says "Summary", you can see that the open-hole completions total 36 within the area of review, and the lowest top of cement on these Type 1 completions is 3125, and the highest top of cement is surface.

So what this is attempting to represent in a kind of summarized fashion is where the top of cement is on these wells that are categorized as Type 1, and what that says is that behind the intermediate casing string, the deepest, lowest top of cement of all those 36 wells is 3125 feet, indicating that the Grayburg, the top of the Grayburg or the Byers-Queen, is well isolated from the Hobbs Grayburg-San Andres Pool.

Q. All right, let's turn to Type 2 and have you reach your opinions as to whether all the wellbores in this type category are configured in such a way as to have isolated the Grayburg-San Andres.

A. Yes, sir. Type 2 are wells that have surface pipe, may or may not have that short intermediate string, but they have a production casing set all the way into the

San Andres and cemented, and you can see there's 160 of these total.

And so the analysis that I looked at there was, where was the top of cement behind the production string on these types of wells? And there's 160 of them, the lowest top of cement is 3624 feet, and the highest is surface. And I will just point out that the one well that causes that 3624 value to show up in here is a well in Section 32. It has a low top of cement. And I went in and -- I investigated that well in particular to look to see where the top of the Grayburg was on that well, and it's about 3700 feet. So in my opinion that is not a problem well because it has about 80 feet of cement above the top of the Grayburg, behind the production casing string.

And if you take that value out, the next deepest top of cement is 3112, so that was the only one that there might be some question about.

Q. Take us to Type 3 and identify and describe your conclusions.

A. Type 3 is very much like Type 1. The only difference is that these wells have a liner run in them, and the liner is cemented. The liner may or may not be run all the way back to surface. You can see there's 108 of these particular type of wells, and the top of cement -- the same type of analysis was utilized as the wells in Type

1, and the lowest one is 3460 feet behind the intermediate, and the highest is surface. So I didn't see any well that was a Type 3 that was even close to being a problem well.

Q. All right, turn the page and let's look at Type 4. Summarize your observations and give us your conclusions.

A. Type 4, we're starting to look at the deeper wells, and you can see surface pipe, you can see -- it may or may not have the short intermediate, but these wells have production casing string set all the way through the unitized interval down to 6000, 7000 feet, I think, as I recall, is the -- is a common TD for those wells. But there's very few of them, there's a total of four of them. And the top of cement behind that production casing string, the lowest is 2510 feet, indicating that those wells are well cemented to isolate our unitized interval from any uphole or downhole zones.

Q. And finally the last type, Mr. Foppiano, Type 5.

A. Type 5 wells are the deep producers that have a liner but also have an intermediate. All of these wells have intermediate casing strings set into the Grayburg and cemented, and then they have either a liner run down to a deeper horizon, 6000, 7000 foot, whatever, and that liner may or may not be cemented back -- I mean, may or may not be tied back to surface, as denoted by the dashed line.

And so the analysis there was first to look to see what the top of cement was behind the intermediate casing string. And we have a total of 37 of these wells, and the lowest top of cement observed on these wells was 3653 feet, and the highest was surface.

And I would like to point out that the well that has the 3653-foot value is a well in Section 33, and there again I looked at the top of Grayburg on that particular well, and the top of Grayburg on that well is 3684, so there's roughly 30 foot of cement above the top of Grayburg on that well. And in addition to that, the long string -- that is, down to the deeper horizon -- is cemented up into the intermediate.

And also what I've shown in the top of cement behind the liner, since it would be important to look at the isolation of the Hobbs Grayburg-San Andres unitized interval from any deeper horizons since these are wells that are completed in a deeper horizon, I looked at the top of cement behind the liner on these wells. And 33 of them, as you can see under the summary line, the liners are cemented all the way back into the intermediate, and on four of the wells they're not, but the tops of cement on those range anywhere from 4368 feet to 3945. But that's sufficient to get up to the San Andres and isolate the unitized interval from any deeper horizons, so I don't see any problem wells under a Type 5 at all, either.

Q. In fact, Mr. Foppiano, you see no problem wells in Type 1 through 5, do you?

A. That's correct. In my opinion, all of these wells have the unitized interval isolated from the Byers-Queen or the Glorieta, either by casing or by cement.

Q. Let's turn now to Exhibit 31 and talk about the three wells that require further discussion. All three of these wells are plugged and abandoned wells, right?

A. Almost. Two of the wells are plugged and abandoned, and one is an injector that will be utilized as a CO_2 injector.

Q. My list shows they're all abandoned and the injector is a proposed injector. Have I misunderstood this?

A. It's a proposed injector, but it's currently an injector, I believe.

Q. Ah, okay, all right. My question is, out of the population of P-and-A'd wells, you've examined all the P-and-A'd wells, and you pulled up two that need to be discussed?

A. Of the 63 plugged and abandoned wells, there are two of them that I'd like to discuss.

Q. All right. And then the third one is a current water injector?

A. That's my understanding, yes.

Q. All right, let's talk about that one first. I believe it is the first page of Exhibit 31?

A. Yes, it's the first schematic that you see on Exhibit 31.

Q. All right, that's where I'd like to start. And let's take that information and relate it back to the area-of-review map so that Mr. Catanach can find that wellbore and see what injection wells are within a half-mile radius of that wellbore.

Mr. Catanach, I think we have marked one of these area-of-review maps in such a way that you can easily find that potential problem well.

EXAMINER CATANACH: Are you talking about the 311, Mr. Kellahin?

MR. KELLAHIN: Yes, I am. It should be color-coded. Did we get you the right map?

THE WITNESS: It may be the other map that --

MR. KELLAHIN: Oh, this is it. Yeah, here it is, right there.

All right, let's talk about the 311, Mr. Stogner -- Mr. Foppiano. No, I recognize the difference. They wear the same kind of tie, but Mr. Foppiano has got glasses, and Mr. Stogner --

THE WITNESS: I take that as a compliment, Mr.

Kellahin.

MR. KELLAHIN: I'm getting tired, Mr. Examiner. Please do not tell Mr. Catanach -- Mr. Catanach, Mr. Stogner.

Q. (By Mr. Kellahin) Okay, let's look at Exhibit Number 31. What's the first page, sir?

A. Exhibit 31 is a schematic of the North Hobbs Grayburg-San Andres Unit Well Number 311. And if you look at the area-of-review map, this well shows up obviously as pink. It's a proposed CO_2 injector. It's located in about the middle of the north half of Section 19, almost in the middle of the area of review, and it is an injection well.

The liner, as you can see from the schematic, there's a liner down to 4200 feet, there's intermediate casing strings set to 3952 feet. This well is not a potential problem well from the standpoint that there's an avenue of communication from the San Andres to either the Byers-Queen or the Glorieta. It is just a well that it would appear that doesn't have enough cement to cover the San Andres and would need to be squeezed -- because it's a proposed injector, it would need to be squeezed before we utilize it for CO_2-injection service.

Q. So what's your recommendation?

A. Our recommendation will be that -- What we plan to do is to re-enter or go into this well and squeeze the top of the liner before it's placed on CO_2-injection service.

Q. Is that action going to be necessary, in your opinion, to take place before you can utilize any other injector within a half-mile radius of that wellbore?

A. Yes, I guess that would be the case.

Q. All right, so we'll fix this first and then either concurrently or thereafter we'll utilize the affected injectors?

A. Okay, that's --

Q. Is that right?

A. That's right.

Q. Is that okay?

A. That's okay.

Q. Okay, let's go to page 2. Help us find the Humble New Mexico State A 4 well, Mr. Foppiano.

A. The Humble New Mexico State A 4 well should be shown in light blue, and it's in Section 25, and I believe on the Examiner's copy it's also circled in yellow. It is in the -- about the middle of the east half of Section 25, right next to Well Number 431.

Q. All right, sir, I have it. What's the problem with this, or potential problem with this well?

A. This well is a problem well. It has 5-1/2-inch casing set to 3189 feet and cemented back. It's not deep enough to cover the Byers-Queen. And the top of San Andres in this well is determined to be about 4050. We do have a cement plug that was placed in this well at TD. It was a 25-sack cement plug, and it doesn't appear to be enough to isolate the unitized interval from the Byers-Queen. So this well will have to be re-entered and re-plugged in such a manner that the unitized interval is isolated from the Byers-Queen.

Q. And then what is your recommendation?

A. Our recommendation is that that work be done to the satisfaction of the NMOCD District Office before injection commences into the five wells that are circled in green on the Examiner's map.

Q. All right, sir. Let's turn to the last potential problem well. I have that shown as the Moran SM 20 Number 1 well.

A. Yes, sir, the Moran SM 20 Number 1 well is located in Section 20 in the northeast quarter. It's also shown in blue on your area-of-review map.

The two wells, the proposed injection wells that are within a half mile, are also circled in green, and there are two of them, the 120 DF and 431 A.

Q. Show us what is the potential problem with this wellbore and describe for us what if any action you're recommending take place.

A. As has been previously testified to the injection interval, we plan to inject into the San Andres. The top of San Andres in this well is about 4200 feet, and there was a plug set right at about 4200 feet on up the hole. So that doesn't appear to be enough to isolate below the top of San Andres from the Glorieta, which occurs at about 5300 feet.

Q. You are going to be isolated from other producing formations below the Glorieta, correct?

A. Yes, because of the cement plug at 5575.

Q. Yeah, so the potential area of concern is to determine what if any probability exists for production out of the Glorieta, and if that is in close proximity to this wellbore, then you might have to take remedial action?

A. Yes, sir, Mr. Kellahin, and in our investigation of this particular well, as you can tell, 8-5/8 casing was run to 305 feet and cemented, and then this hole was drilled and this well was plugged.

And so the well was drilled and abandoned, there was obviously no productive potential found in any of these horizons below -- in any of these San Andres, Glorieta, Byers-Queen, whatever, and in fact we've looked a little further and there's another deep penetration in the same section that there was no Glorieta production from. In fact, the nearest Glorieta production occurs about -- in

Section 32, which is almost a mile and a half away.

And so in our opinion, there's not any potential production that could occur from the Glorieta in the immediate vicinity of this well, and so there would be no need for us to re-enter this well and attempt to isolate the San Andres from the Glorieta, because there are no reserves that appear to be in danger, in our opinion.

Additionally, I'd like to point out that this early spotting of this well indicates that it could be very close to a highway. In fact, it may actually be under a business of some sort, and if we were required to re-enter this well there might be serious problems in trying to rig up on it. In fact, depending on where it exactly is located, it might be impossible to rig up and re-enter this well.

So in our opinion, given primarily the fact that we don't think anything is at risk in the Glorieta, we don't see the need for the Division to require that we do any remedial action on this well.

Q. Let's turn to a different topic, Mr. Foppiano. Let's turn to the documentation and technical support for OXY's request for certain surface pressure limitations in the project. If you'll direct your attention to what is marked as -- I have omitted one detail.

Before we get to that, there is Exhibit 32 which is the certificate of hearing. You were responsible for tabulating the interest owners affected that were required to be notified pursuant to Division rules?

A. The surface owners, yes.

Q. All right. In addition, were there any operators other than OXY within a half-mile radius for which notice was required?

A. Within a two-mile radius, yes, there were several operators that were found to be within the two-mile radius and were identified and given notice by a copy of the C-108.

Q. So you went as far as the two-mile radius with your notification?

A. Yes.

MR. KELLAHIN: All right. Mr. Examiner, I have a replacement for Exhibit Number 32 for your purposes. The one I have to replace includes, now, copies of all the green cards that were returned to us pursuant to that notification. We'd like to substitute that.

Q. (By Mr. Kellahin) To the best of your knowledge, Mr. Foppiano, has OXY received any objections for approval to their Application presented before Examiner Catanach this afternoon?

A. We've received no objections.

Q. Let's turn now to the topic of the step-rate test and the surface pressure limitations. If you'll look at Exhibit 33, identify that for me.

A. Exhibit 33 is once again an outline of the North Hobbs unit with some selected wells shown thereon, and these are injection wells. OXY has -- or actually Shell at the time these step-rate tests were performed, they did step-rate tests on approximately 50 wells in the North Hobbs Unit. And this exhibit just merely shows those wells on which step-rate tests were performed, and it indicates that they were all over the unit. So there's broad coverage of the North Hobbs Unit with this step-rate test information and in particular, coverage throughout the Phase 1 area.

Q. Let me have you turn to Exhibit 34, and let's look at the step-rate data.

A. Yes, Exhibit 34 is a tabular presentation of the step-rate test data, and in 1988 you can see by the top group of wells and information several step-rate tests were performed. The wells on which those step-rate tests were performed are identified in the first column.

And I'll point out the well nomenclature; it may be a little confusing. For example, 18-242 just merely says it's Section 18, Well Number 242. And then the middle column is the injection rate that the fracture occurred at, and the third column is the bottomhole fracture pressure observed during the step-rate test. The bottom group of wells are the step-rate tests that were performed in 1991.

And as you can see from analysis of this data, the minimum bottomhole fracture pressure experienced in 1988 was about 2587 p.s.i., and the minimum in 1991 was 2600 p.s.i. And this is obviously a wealth of data on which to base a request for surface pressure maximums, and that's why we analyzed it and utilized it in this fashion.

And so what we did in designing our request for surface pressure maximums for our project is, we looked at this data and then decided that we would impart a little conservatism to it, and we picked a design bottomhole pressure maximum condition of 2400 p.s.i., based on this data.

Q. Of all the -- is it 50, 51 tests? --

A. Approximately 52 tests.

Q. -- 52 tests, the lowest pressure in which you get fractures in the reservoir is 2587?

A. Correct.

Q. Everything else is higher than that?

A. Correct.

Q. So you back down from 2587 to 2400 pounds as the presumed conservative bottomhole pressure, parting pressure?

A. Correct.

Q. And from there, then, how do we make the calculation to get us to the surface pressure appropriate for the various substances to be injected?

A. If you'll turn to the next exhibit -- actually it's the exhibit beyond that.

Q. Well, let's do 35 first.

A. Okay, 35 is nothing more than a graphical presentation of the data that was tabulated on Exhibit 34.

Q. It simply shows that if we use 2400 pounds, all the data points on the fracture tests are above that, and some of them substantially above that?

A. Correct.

Q. All right. Take me through 36 and show me how you're going to use the parting pressure of the reservoir back down by 200 pounds, and confer that to an appropriate surface limitation for the various substances.

A. Yes, sir, as Andy Falls, the previous witness, testified to, we ran our tubing flow model to give us hydrostatic pressure information and friction pressure information at certain flow-rate conditions and based on the different types of injectant that we're going to experience in this project.

Starting with the -- Before I get there, though, this exhibit is an attempt to explain where the requested surface pressure maximums come from, how we derived them.

So starting at the column on the left, three different types of injectant that we'll be utilizing in this project: Obviously produced water will be reinjected with a specific gravity of 1.09; almost pure CO_2 coming off the pipeline, at about 80 degrees -- and the temperature is important in the density calculations -- and then produced gas, which is primarily CO_2 but 15-percent other components, and it comes in off the compression station at 110 degrees.

And so looking at these different types of injectants and starting with a design condition, a design maximum condition of 2400 p.s.i. at the bottomhole, which you've just seen how we derived that, we then went into the next two columns to represent the output of our tubing flow model, and they show the density differences and the friction differences that we'll be experiencing, and it also illustrates the reason for our requested surface pressure maximums.

The hydrostatic head, as you see for water, is just a hydrostatic head of water, 18, 19 p.s.i. But then going down and looking at CO_2, you can see it has much less hydrostatic head, and then when you get to the produced gas even much, much less hydrostatic head. And that's due to a couple of reasons.

One is the temperature. The hotter temperature of the CO_2 and the produced gas mixture results in a lighter density for that mixture, and those other components present in that stream also cause that mixture to have a lighter density. So one of the reasons why we have these surface pressure maximums we're requesting are the different densities, not only from water and CO_2 but between produced gas and pipeline CO_2.

And then the tubing flow model also gave us friction pressures at different rates, and what I've shown here on this exhibit are the friction pressures at the design rate for the different injectants, for, starting with water, 9000 barrels a day, we see a friction pressure of 507 p.s.i, which -- this is a fairly high rate of injection of water, as compared to normal waterfloods, and so it carries with it a correspondingly high friction pressure. You can see the friction pressures for the two gaseous mixtures are a lot less, a little less than 200 p.s.i.

So the third column is the surface pressure at design rate, and that's nothing more than the 2400 p.s.i. design condition, minus the hydrostatic head, plus the friction pressure.

And then the last column, which is the pressures that we're requesting, the maximum pressures we're requesting for the different injectants, they are just rounded up from the calculations.

So the sum of this exhibit illustrates that there are two reasons for these pressure maximums that we're asking for. It's different densities, and then it's the friction pressure caused by the high rates of injection.

Q. Does this calculation or presentation take into consideration the size of the tubing?

A. Yes, these calculations are based on injection down 3-1/2-inch tubing, which is from the standpoint of this presentation a worst case. It's a minimum-friction-type case. We're not going to have anything bigger than 3-1/2-inch tubing, but we do -- we will have 2-7/8-inch tubing in a number of these wells, but 2-7/8-inch tubing at the same rates will carry with it correspondingly higher friction pressures, which will result in correspondingly lower bottomhole pressures.

Q. Let's turn to Exhibit 37 and have you describe this display.

A. Exhibit 37 is the output from the tubing flow model for the different injectants at all rates between zero and the design rates.

And on the left, the scale on the left is the wellhead injection pressure, surface pressure, and on the X axis are the injection rates, a million cubic feet per day or a thousand barrels of water per day. And shown in blue is the profile for produced gas injection, and in red for pipeline CO_2 injection and then in green for water injection. And this is essentially the same data as what was on the previous exhibit except it's all different rates between zero and the design rate.

And also what I've shown on here, just for illustration, is the standard .2-p.s.i.-per-foot limitation, which it appears immediately obvious that the standard .2-p.s.i.-per-foot limitation won't allow us to inject at the rates that are necessary to conduct the project.

So this exhibit, what we're asking the OCD is to allow us to operate under these pressures, based on the type of injectant and that -- you know, this is designed for 3-1/2-inch tubing; we would ask that it apply to -- no matter what size tubing we have, because it is a worst-case condition, and it would be more conservative to apply to 2-7/8, and we're comfortable with that.

And we believe that this is not only necessary but that this will represent a situation that keeps us well below the fracture pressure, based on step-rate test data, based on the design condition of 2400 p.s.i. that is the basis of this analysis, and so our request is really that these surface pressure maximums -- we be allowed to operate under these surface pressure maximums, based on this analysis.

Q. Does OXY propose to construct facilities that will allow you to monitor and manage these various pressure limitations at the surface, based upon the type of substance being injected or moved through the system?

A. Yes, we will plan to have systems that keep our operations below pressures that will initiate a fracture.

Q. Do you have an exhibit that will illustrate for the Examiner this automated pressure-control system?

A. Yes, Exhibit 38 is a facilities diagram of our automated control system, and what this automated control system is, it's a system that will automatically keep us -- keep these injection wells, the pressures -- based on the pressures and the flow rates -- at conditions below the lines seen on the previous graph.

And I would point out, it's an automated system, it's an automatic system, it responds instantaneously, and this is what we believe, based on our experience in other CO_2 floods, the best way to keep the surface injection pressures at certain points, based on a flow rate and based on the type of injectant.

So this facilities diagram, there's two pages of it. The first page is the facilities diagram or the automated control system that will be set up at the WAG injection header at the satellite, and the second page is part of the automated control system that will be installed near the wellhead.

And just starting at the left and kind of moving to the right, you can see at the WAG header produced gas -- I mean, excuse me, produced water or CO_2 or produced gas, whichever the well needs to be, whatever we need to be injecting in that well for reservoir purposes -- that will be coming in. And we shut off one and open the other through these valves called MOV's -- that's just for motor-operated valves.

And then we come into the central part of the exhibit or the middle part of the exhibit where we'll be analyzing and calculating the flow rate of that injectant at that time, and then we'll be modulating based on that calculated flow rate, and our design flow rate for that particular well will be modulating a choke to keep it at that design condition.

However, the choke will have a maximum pressure limit, based on pressure monitoring that goes on at or near the wellhead. And what that will do is, if that pressure maximum is reached, then that choke will not open any more. So that will keep us below those curves shown on that prior exhibit, depending on the type of injectant that we're putting in the well and depending on the flow rate for that particular well.

And essentially this is the same type of system -- somebody described it to me as analogous to a cruise control on a car, and that's basically what this is. It's a cruise control with a governor. And it's saying that at a certain speed there is -- we can't speed up anymore because that's the pressure -- based on that flow rate that we cannot exceed, and that's the same that is the basis of the prior exhibit.

Q. In addition to requesting these surface limitation pressures, Mr. Falls testified a while ago that he's requesting an administrative process where he can apply to the Division and obtain increases above this pressure when he can submit appropriate engineering data, including but not limited to step-tests?

A. Yes.

Q. Do you support that opinion?

A. Yes, I do. I think that the data that we have here allows for certain pressure maximums to be set for the injection wells, and if the conditions warrant and we go out and run step-rate injection pressure tests and need a higher injection pressure on a particular well, then the performing of step-rate tests and utilizing the same methodology, the same approach as we've explained here, which is to account for the friction and the density, that we should be allowed to increase the injection pressure above what we're recommending here based on step-rate tests performed after this order is entered.

Q. Are there other types of data or tests that can be submitted to the Division, instead of a step-rate test, that can be utilized to satisfy the regulators that it's safe to increase the surface pressure limitation?

A. My understanding that there is, there are Hall and Hearn plots and maybe even some other data, Poisson's ratio and other things, based on the rock properties, to justify a bottomhole pressure limit that will not exceed a fracture pressure.

Q. So we would like an order that gives an administrative procedure to submit appropriate engineering data, including but not necessarily limited to step-rate tests?

A. That's correct.

MR. KELLAHIN: That concludes my examination of Mr. Foppiano. We would move the introduction of his Exhibits 27 through 38.

EXAMINER CATANACH: Exhibits 27 through 38 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Foppiano, initially how many injection wells are we adding at this time?

A. Well, we are asking for, I think it's approximately a hundred injection wells that will be CO_2 injectors, but we are asking for them to be authorized for -- all of them for water injection. Several of them currently are authorized for water injection, but none of them, obviously, are authorized for CO_2 injection. But some of them we're asking for authorization to inject just CO_2, and others we're asking for authorization to inject CO_2 and produced gas.

Q. Now, these are all -- Are there new conversions at this point that are not currently injection wells?

A. There are wells that are not currently injection wells, that will be in the future as part of this project, yes.

Q. Okay, how many of those? Do you know? Estimate?

A. No, I do not. I'd be happy to supply that information later.

Q. Does your proposal, your C-108, does it specify whether it's a new injection well or whether it's an existing injection well, things like that?

A. The tabular data shows existing condition, and so it will show it as a water injection well if it's currently a water injection well. And then the injection well data sheets, as I understand, are showing proposed conditions. And so I'm trying to remember. I can look to see. I don't think we put current status on the injection well data sheets, but I'll take a look at it real quick.

MR. KELLAHIN: Mr. Foppiano, maybe it will help, when we attached the Application to Mr. Catanach we had an exhibit that listed all of these wellbores and I think included their current status and proposed status. I've handed Mr. Foppiano those exhibits out of the Application, and with his assistance maybe we can answer your question.

THE WITNESS: Yes, I apologize. I didn't realize the current status was reflected on this exhibit. This is part of the C-108, and it's an injection well list, and it details the current status of all these proposed injectors, whether they're currently a producer or whether they're currently being utilized for water injection. And then it also show whether they'll be utilized for CO_2 injection or produced gas injection.

Q. (By Examiner Catanach) Okay, so from that list if a well is showing as currently a producer, I would assume that's a new injector that you're permitting for injection at this time?

A. That's correct.

Q. And also on that exhibit there's a reference to whether or not that well will be injecting water or CO_2 or both, or what it will inject, or are you asking for all of these wells to have authorization to inject CO_2 and water?

A. We're asking for authorization to inject water in all of these wells. And then in the wells that are shown on this exhibit as -- that are not shaded, I believe the shading on this list indicates wells for which we're requesting authority to inject CO_2, water and produced gases. And for the wells that are not shaded on this list, we're requesting authorization to inject water and CO_2 but not produced gas.

EXAMINER CATANACH: Mr. Kellahin, I may ask you -- I don't know, I haven't looked at that exhibit, I don't know if it's clear enough, but --

MR. KELLAHIN: We'll organize it for you sir.

EXAMINER CATANACH: -- can you --

MR. KELLAHIN: You bet.

EXAMINER CATANACH: -- summarize it --

MR. KELLAHIN: Yes, sir.

EXAMINER CATANACH: -- in a better fashion?

MR. KELLAHIN: Yes, sir.

EXAMINER CATANACH: Okay.

Q. (By Examiner Catanach) Mr. Foppiano, with regards to cement tops within the area-of-review wells, do you know, or do you have an estimate on how many of those were measured and how many were calculated?

A. I don't, the short answer to your question is no, I don't have a number. But I would venture a guess that on the top -- the cement tops that were critical, which are the ones either behind the intermediate or behind the long string if it was drilled through the San Andres, most of those, more than 50 percent, my feeling is, were measured tops of cement, as opposed to calculated. But I did not do an analysis to see which ones were calculated versus other.

Q. Okay, and those that were not measured you did calculations on?

A. Correct.

Q. Were factors such as the type of cement taken into account when you calculated tops, or was it just a uniform assumption?

A. The yield assumption was uniform based on -- applied to the number of sacks, because there just wasn't much information available about the actual yield of the cement that was utilized even when we had that information. We knew the sacks, we knew some description of the cement. But as far as what the yield, what the mix was of that cement, we didn't get into that level of detail on the different types of cement that were utilized.

Q. Okay. With regards to the -- You used a 50-percent efficiency factor?

A. Yes, sir.

Q. Do you have an opinion on whether or not that is a good number, or do you have a feel for that?

A. In my opinion, it was -- it resulted in tops of cement that were either close to ones that were determined by cement bond log or resulted in lower tops of cement. So it was a fairly, I think, pessimistic approach to use 50 percent. Generally, I think if the bond log was run, the top of cement might actually be farther up the hole than what was calculated using a 50-percent excess.

Q. Mr. Foppiano, I know that you've had some experience working in the South Hobbs Unit, but there are some -- in the North Hobbs unit as well, I'm sure some wells that were drilled -- what? -- in the 1920s, 1930s, or am I --

A. I know there were some wells drilled early in the 19th Century -- or the 20th Century. And I remember 1948, 1930 on some of the dates drilled, but I didn't remember seeing any 1920s.

Q. Okay.

A. And here again, the wells we've analyzed closely were only the ones that penetrated the Hobbs Grayburg-San Andres Pool, so the shallower -- some of the shallower wells, they may have been drilled later -- I mean earlier than the ones that I was looking at.

Q. Okay. The P-and-A'd wells that you've looked at, that were plugged maybe in the 1940s, do you have an opinion as to whether those were properly plugged or conventionally plugged?

A. My opinion is, based on the -- We actually obtained plugging approvals on all of those wells except one, where we could not find the data on how it was plugged. But in my opinion they were all properly plugged at the time they were plugged. They were approved by the local NMOCD office in the manner in which they were plugged.

The only well that we could not find plugging information on has casing set to a little over 5000 feet and cemented, so it was -- the Hobbs Grayburg-San Andres Pool, the unitized portion of it is isolated behind the casing in that well. So how it was plugged inside the casing, it didn't appear to be anything that related to the isolation issue.

Q. Did you find any wells that were unconventionally plugged? You hear stories about certain objects being thrown in the wellbores when they're plugged, and I just -- I mean, I don't know if that's true in this area or not, but did you come across any of those?

A. No, I didn't. I don't recall seeing any of those. There's all manners of plugging, as you can imagine. I know there were several wells that had dual strings of 3-inch tubing in the well, and they were left in place, cut off and left in place and cemented. So there's a large variety of plugging approaches on these 63 plugged and abandoned wells.

Q. When you looked at whether or not a well was plugged properly, you looked at it from the standpoint of the San Andres being isolated with respect to other producing zones?

A. That's correct, and fresh water.

Q. Okay, and fresh water?

A. Yes.

Q. So generally if a well, say a San Andres well, was plugged, if it had a plug above the San Andres it protected the formations above there as well as the fresh water?

A. Yes. I'm just trying to recall -- and obviously the schematics are all part of the C-108, but some of them had cut-off casing, and there was a plug in and out of where the cut-off stub was. So in my analysis I looked to see was the unitized portion of the Hobbs Grayburg-San Andres Pool isolated from the other pools, based on how the well was plugged? And in my opinion that was the case on those plugged and abandoned wells, except the two that I've described.

Q. Did you find wells that were not plugged to modern standards, say, did you find some wells that maybe didn't have a casing stub plug or a casing shoe plug or things like that?

A. I can't answer that because I didn't analyze it from the standpoint of modern plugging requirements.

Q. So basically in your analysis, if a well had a bottom plug which isolated the San Andres, was that considered adequate?

A. Either it had casing in the Grayburg and there was a plug inside that casing that isolated it on the inside portion of the casing, and so it was isolated by cement behind that casing, that condition...

But I basically looked for something to prevent the communication of floods from the San Andres to any of those other producing zones uphole or downhole, either through casing, cement, a plug set even up the hole where there was a cutoff on the casing. I looked for something on the schematics that showed me that there was -- it was there to prevent the movement of fluids from where we were going to inject and the Byers-Queen and Glorieta.

Q. Well, for instance, if a well had a bottom plug and it didn't have a plug from the bottom except maybe at a surface plug, I mean, is that -- In your analysis, is that considered adequate? If the outside of the casing was cemented and you had a plug inside the casing above the San Andres, I mean, would that be adequate?

A. In my opinion, yes, that was adequate.

Q. The current pressure out there that you guys are injecting at is -- I believe an earlier witness said that it was about 800 pounds?

A. It's about .2 p.s.i. -- Well, it is .2 p.s.i. per foot, and so it varies close to 800 pounds, unless it is increased by step-rate tests. As you see, we've run step-rate tests 52 times, and so those wells have higher authorized surface pressure limits.

Q. It's your opinion that a bottomhole pressure of 2400 pounds is not going to result in any fractures of the injection formation?

A. Yes, sir, it is my opinion. And another thing that gives me comfort in that is that I looked at the reservoir pressure about the time those step-rate tests were run and it was about the same as what it is today, around 1100 p.s.i.

And as Mr. Falls testified to, we're going to operate this CO_2 flood at a reservoir pressure of about 1300 p.s.i., which is a couple of hundred pounds higher. And as you know, the pore pressure affects the bottomhole fracture significantly, and the higher the pore pressure, the higher the bottomhole fracture pressure we're going to have.

So the fact that we're actually going to move from a condition of -- to a pore pressure that is going to result in a higher than 2600 minimum bottomhole fracture pressure gives me further comfort that using 2400 should keep us well below any possibility of fracturing the reservoir. That and our automation system will ensure that we stay at design -- we will stay at certain pressures based on the flow rate of that injector.

Q. When you look at area-of-review wells that have cement behind the production casing, do you give any consideration as to the type of fluid that will be injected, as to whether or not the cement will be able to prevent any migration, for instance water as opposed to CO_2 or produced gas? Is that any consideration?

A. No, sir, in our experience -- Obviously we've got a lot of experience injecting CO_2, and to my knowledge we have not seen a situation that it had an adverse impact on the cement. And certainly the type of cement we're using here and have used in constructing these wells, I think, will serve very well for the type of flood we're proposing here.

EXAMINER CATANACH: Okay, I'm sure there's some other stuff but I can't think of it right now. I may -- If in the process of writing this order, Mr. Kellahin, if I have further questions I may, in fact, call on you or OXY to help me out with that.

MR. KELLAHIN: We'll be more than happy to, Mr.

Examiner.

EXAMINER CATANACH: Other than that, I have no further questions of this witness.

MR. KELLAHIN: All right, sir. That concludes our presentation.

EXAMINER CATANACH: Okay, if there's nothing further in this case, Case 12,722 will be taken under advisement, and --

MR. KELLAHIN: Have you got one, Steve?

EXAMINER CATANACH: -- this hearing is adjourned.

(Thereupon, these proceedings were concluded at 3:40 p.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 12722 heard by me on 9/6 ~~19~~01

David R. Catanach, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

STATE OF NEW MEXICO)
) ss.
COUNTY OF SANTA FE)

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL September 13th, 2001.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 2002