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:	
APPLICATION OF BEACH EXPLORATION, INC., FOR STATUTORY UNITIZATION, EDDY COUNTY, NEW MEXICO	CASE NOS. 13,972
APPLICATION OF BEACH EXPLORATION, INC., FOR APPROVAL OF A WATERFLOOD PROJECT AND TO QUALIFY THE PROJECT FOR THE RECOVERED OIL TAX RATE, EDDY COUNTY, NEW MEXICO	and 13,973
	(Consolidated)

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REPORTER'S TRANSCRIPT OF PROCEEDINGS

SPECIAL EXAMINER HEARING

BEFORE: WILLIAM V. JONES, Jr., Technical Examiner
DAVID K. BROOKS, Jr., Legal Examiner

October 12th, 2007

Santa Fe, New Mexico

These matters came on for hearing before the New Mexico Oil Conservation Division, WILLIAM V. JONES, Jr., Technical Examiner, DAVID K. BROOKS, Jr., Legal Examiner, on Friday, October 12th, 2007, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South Saint Francis Drive, Room 102, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

October 12th, 2007
Special Examiner Hearing
CASE NOS. 13,972 and 13,973 (Consolidated)

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A P P E A R A N C E S

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* * *

ALSO PRESENT:

JULIE LEMOND
Beach Exploration

JOHN ORBAN
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* * *

WHEREUPON, the following proceedings were had at 8:20 a.m.:

EXAMINER JONES: Let's call this special Examiner Hearing. This is October the 12th, 2007, Docket Number 31-07. There's two cases on the cases on the docket, and we will combine the two cases for purposes of hearing.

Let's go ahead and all Case 13,972, Application of Beach Exploration, Incorporated, for statutory unitization, Eddy County, New Mexico; and at the same time call Case Number 13,973, Application of Beach Exploration, Incorporated, for approval of a waterflood project and to qualify the project for the recovered oil tax credit -- tax rate, Eddy County, New Mexico.

Call for appearances.

MR. BRUCE: Mr. Examiner, Jim Bruce of Santa Fe, representing the Applicant. I have three witnesses.

EXAMINER JONES: Other appearances?

MR. CARR: Yes, may it please the Examiner, my name is William F. Carr with the Santa Fe office of Holland and Hart, L.L.P. We represent Devon Energy Production Company, LP, and MYCO Industries, Inc. And I'm pleased to be able to advise you that it appears that we've reached an agreement, and we're just now in the process of having documents signed. So we're not -- We are in support of the Application.

EXAMINER JONES: There was a lot of things on your prehearing statement that --

MR. CARR: And we have -- and I've had a lot of conversations this morning --

EXAMINER JONES: Okay.

MR. CARR: -- some of them have been friendly.

(Laughter)

EXAMINER JONES: Okay, other appearances?

MS. GRAY: Yes, I'm Lisa Curry Gray, attorney here in Santa Fe, New Mexico. I'm representing Snow Operating. I'm here because they are a party to the -- oppose unitization, working interest owner, and just -- I have not witnesses, I'm here just here as an interested representative.

EXAMINER JONES: Okay, other appearances?

Will the witnesses please stand to be sworn?

(Thereupon, the witnesses were sworn.)

<u>ROBERT HINSON</u>,

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

DIRECT EXAMINATION

BY MR. BRUCE:

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

A. Bob Hinson, H-i-n-s-o-n.

Q. And where do you reside?

A. Midland, Texas.

Q. Who do you work for and in what capacity?

A. Beach Exploration, Inc., as executive vice president.

Q. Are you a landman by trade?

A. Yes.

Q. Have you previously testified before the Division?

A. Yes.

Q. And were your credentials as an expert petroleum landman accepted as a matter of record?

A. Yes.

Q. And are you familiar with the land matters involved in these two cases?

A. Yes, I am.

MR. BRUCE: Mr. Examiner, I'd tender Mr. Hinson as an expert petroleum landman.

EXAMINER JONES: Mr. Hinson is qualified as an expert in petroleum land matters.

Q. (By Mr. Bruce) Mr. Hinson, could you briefly summarize what Beach seeks in these two cases?

A. In Case 13,972 Beach seeks the statutory unitization of all interests in a portion of the Queen formation underlying 1040.1 acres of state land. In Case 13,973 Beach seeks approval of a waterflood project for the unit and certification of the project for the recovered oil tax rate.

Q. And what is the proposed unitized and injection interval?

A. It will cover the upper Queen formation from 2196 feet to 2470 feet, as defined in the unit agreement and C-108.

Q. Would you identify Exhibit 1 and describe its contents for the Examiner?

A. Exhibit 1 is the land plat which outlines the proposed unit area and identifies separate tracts which comprise the unit area. Attached to the plat is a legal description of the entire unit area. There are five tracts in the unit. Currently Beach does not yet operate any of these tracts. Eastland Oil and Gas operates four tracts, and MYCO operates one tract.

MR. BRUCE: Mr. Examiner, I forgot to attach the property description, although it is in the Application.

Q. (By Mr. Bruce) Could you move on to Exhibit 2 and identify that for the Examiner?

A. Exhibit 2 is the proposed unit agreement. The unit agreement is standard form mandated by the State Land Office and is similar to agreements previously approved by the Division. The unit agreement describes the unit area and the unitized formation. The unitized substances include all oil and gas produced from the unitized formation.

MR. BRUCE: Now Mr. Examiner, you may want to keep the unit agreement in front of you, especially Exhibit B to that agreement, which contains some of the information.

Q. (By Mr. Bruce) Next, what is Exhibit 3, Mr. Hinson?

A. Exhibit 3 is the proposed unit operating agreement which sets forth the authorities and duties of the unit operator, as well as the apportionment of expenses between the working interest owners.

Q. And does the agreement provide for a penalty against nonconsenting working interest owners?

A. Yes.

Q. And what is the penalty?

A. Two hundred percent.

Q. And that is cost plus -- or, I think it says Section -- Article 11.7, 300 percent. But that is the normal cost-plus-200-percent under Division statutes?

A. Yes.

Q. Okay. From a landman's standpoint, is that a reasonable and fair penalty?

A. Yes, it is.

Q. And why is that?

A. Because that's what the previous units we put together, as well as all the other ones we've seen, provide the same nonconsent penalty.

Q. And Beach has other Queen units in Eddy County?

A. We have two, two units we've previously put in and operated.

Q. In fact, outside of the statutory unitization scheme, many operating agreements provide for penalties in excess of cost-plus-200-percent, do they not?

A. Let's discuss ownership of the tracts in the unit area. First, would you please describe the tract ownership and how you determined the names of the working interests, royalty and overriding royalty interest owners in the unit area?

A. We were able to obtain division of interest from the oil purchaser, Navajo, that were provided to us by MYCO, and so we had a complete, 100-percent division of interest for all the tracts that we've included in the unit that we either got from MYCO or from Eastland.

Q. Okay. And so these names are current under the Division order files?

A. Yes.

Q. And in Exhibit B of the unit agreement, those interests are set forth in that exhibit, are they not?

A. Yes, they're divided out and then listed by tract.

Q. Okay. And the tracts are formed according to common interest ownership?

A. Yes.

Q. Have there been any changes to this Exhibit B since unitization was proposed?

A. One minor change in the -- One of the override owners was originally listed as Dominion Oil and Gas, and that was -- their interest was sold to Lobos Energy.

Q. Okay, and that's Tract 3 of the unit area, correct?

A. Yes.

Q. Now Mr. Carr, when he entered his appearance, said there was some agreement between Beach on the one hand and Devon and MYCO on the other. Just briefly, what is that, or why -- their interests?

A. We've reached an agreement with both MYCO and Devon to purchase their interest in the unit.

Q. Okay. It hasn't been finalized as of this point?

A. No, we've executed letter agreements to enter into a formal sale and purchase agreement.

Q. How many interest owners are there in the proposed unit?

A. There are seven working interest owners and ten royalty or overriding royalty owners, including the State.

Q. Okay. And does -- With respect to the working interest owners, does Exhibit 4 reflect those working interest owners?

A. Yes, it does.

Q. Now this also lists -- indicates who has ratified the unit as of this point. At this point does Beach still seek to unitize Devon and Myco, as well as Sharbro, for purposes of unitization?

A. Yes.

Q. When the documents are finalized with MYCO and Devon, will you so notify the Division?

A. Yes, we will.

Q. Okay, and this -- What is the current ratification status in terms of percentage of the unit agreement?

A. Presently we have signed ratifications by 83.636 percent.

Q. And so that's in excess of the statutory requirement of 75 percent?

A. Yes.

Q. Let's move on to the royalty owners. Are they reflected in Exhibit 5?

A. Yes.

Q. And what percentage of the royalty plus overrides have ratified the unit?

A. We have signed ratifications from 73.36 percent of the overriding royalty owners, not including the State who has a 12-1/2-percent royalty.
Q. Okay. One error on here, MYCO does not have an override; is that correct?
A. No --
Q. So --
A. -- just Devon.
Q. -- MYCO should be -- and does Sharbro have an override?
A. I don't believe so.
Q. So those two were listed in error on the overrides. But Devon does have an overriding royalty?
A. Correct.
Q. Okay. And in the purchase and sale Devon is retaining its overriding royalty, is it not?
A. That's correct.
Q. Okay. Do Exhibits 6 and 7 contain copies of all ratifications from working and royalty interest owners to date?
A. Yes, they do.
Q. And what is -- Has the Commissioner of Public Lands preliminarily approved unitization?
A. Yes, we've received their written preliminary approval.

Q. And is that reflected on Exhibit 8?

A. Yes.

Q. And once the Commissioner of Public Lands gives final approval to the unit, will there be voluntary royalty participation in excess of 75 percent?

A. Yes.

Q. And so again you will meet the statutory requirements for voluntary unitization?

A. Yes, we will.

Q. Let's just briefly discuss your efforts to obtain the voluntary unitization among the interest owners -- the working interest owners in the unit. Would you please identify Exhibit 9?

A. Exhibit 9 is our contact log, basically, which shows we've been in discussions with MYCO and subsequently Devon for a little bit over a year with phone calls, letters and e-mails, trying to discuss the formation of the unit, what their participation would be, and trying to meet about these matters as soon as we could.

Q. And although it lists MYCO, is Sharbro a related entity to MYCO?

A. That's our understanding, they have a very minor interest, approximately two percent, in those wells, and we understand they're represented by MYCO. The particular agreements we've entered into don't yet include Sharbro, but we expect them to in the sale and purchase agreement.

Q. But certainly your correspondence with MYCO also went to -- through MYCO to the Sharbro interest?

A. Yes.

Q. What is Exhibit 10?

A. Exhibit 10 contains the copies of correspondence that tie to our contact log with the various working interest owners.

Q. And again, on Exhibit 9, your contacts with Devon and MYCO were listed. You also proposed the unit to the overriding royalty owners and the other working interest owners in the unit, did you not?

A. Yes.

Q. And again, other than Sharbro, MYCO and Devon, the others have all ratified?

A. That's correct.

Q. Were any of the interest owners in the unit area unlocatable?

A. No.

Q. In your opinion, has Beach made a good faith effort to obtain the voluntary unitization of the unit area?

A. Yes, we have.

Q. And has written notice of unitization been given to all of the parties who did not voluntarily join in the unit?

A. Yes.

Q. And is that reflected on Exhibit 11?

A. Yes, it is.

MR. BRUCE: Mr. Examiner, I think in Exhibit 11 I actually notified everybody in the unit area.

Q. (By Mr. Bruce) Now regarding the waterflood project, what is Exhibit 12?

A. Exhibit 12 is a plat showing the offset operators or lessees in the Queen formation that are located within a half mile of the injection wells or the proposed injection wells.

Q. And are the operators in the area of review or the operators or mineral lessees in non-operated tracts listed on Exhibit 12A?

A. Yes, they are.

Q. And was notice given to all of those operators?

A. Yes, it was.

Q. And is that reflected in Exhibit 13?

A. Yes.

Q. In your opinion, will the granting of these Applications be in the interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes, it will.

Q. Were Exhibits 1 through 13 prepared by you or under your direction or compiled from company business records?

A. Yes.

Q. One final question, Mr. Hinson. We don't need an expedited order, but are there certain time deadlines that Beach has to meet?

A. Yes. I mean, approval as soon as possible would be greatly appreciated, and especially maybe -- possibly within the next six weeks. We have contracts to enter into for the water we're going to be using to do the flood with, as well as, you know, partner considerations. And with the length of time we've been getting to this point, we've very eager.

Q. And with respect to the water contract, you have an option that you would need to finalize. You need to finalize the unit before you can finalize the water option?

A. Yes, we can't purchase the water till we have somewhere to put it.

MR. BRUCE: Mr. Examiner, I'd move the admission of Exhibits 1 through 13.

EXAMINER JONES: Exhibits 1 through 13 will be admitted.

MR. BRUCE: And I have no further questions.

EXAMINER JONES: Well, I think I'll start the questions off, and David Brooks, I'm sure, will have some more.

EXAMINATION

BY EXAMINER JONES:

Q. These, I guess -- start from the outside and working in, the people within a half mile of the unit, you've got all the operators listed here. And Snow Oil and Gas is one of those operators.

A. Yes.

Q. Can you talk about your conversations with them?

A. Initially we had no conversation with them until we found out they had registered to appear before the Examiner. And then Jack Rose, our engineer who will be testifying, called Snow Oil and Gas and -- just trying to find out what their interest or what their position was.

Q. So you're not -- you --

A. We basically had one telephone conversation through Mr. Rose.

Q. Okay. You don't know whether they're producers up in the Seven Rivers or something like that, or --

MR. BRUCE: Mr. Rose could --

EXAMINER JONES: Okay, let me --

MR. BRUCE: Yeah, he has --

EXAMINER JONES: -- ask him later.

MR. BRUCE: -- yeah, he has spoken with them.

Q. (By Examiner Jones) Okay. So basically all the operators of active wells within a half mile are -- have been notified. And then all the leasehold within a half mile have been -- so --

A. Right.

Q. -- I take it every- -- everything within the Turkey Track-Queen -- or in the Queen formation, obviously, has been notified, everybody has been notified within a half mile --

A. Yes, sir.

Q. -- of the -- Are they all leased?

A. There was a little bit unleased, or -- well, or -- I don't think there's anything unleased. I think there's some HBP production, or HBP leasehold that do not have a well on it. I don't believe any of this was unleased, that I know of, so... And then we contacted the HBP leasehold owner in that case.

Q. And it would be -- if it wasn't leased, it would be State lands; is that right?

MS. LeMOND: (Shakes head)

Q. (By Examiner Jones) Not necessarily, I guess?

A. Right, I think we could have some -- I don't think this is BLM lands around this or not, do you recall? I'd have to have look -- I'd have to have an expanded land map, a little bit, to tell. But I don't believe there's any fee lands involved. And there possibly was some BLM lands, but none within the unit, within the half-mile boundary. But there was nothing unleased, so maybe we contacted the lessee.

Q. Okay. Within the proposed statutory unit you have several -- what, five -- is it five tracts? Is that right?

A. That's right. There's one subtract that the State requested we form, which was 2A, because of the -- it's common ownership, but it's different State base leases.

Q. Okay. And Snow Operating was the leasee of that one.

What about Eastland Oil? They signed right away?

A. We entered into an agreement with Eastland Oil approximately a year ago --

Q. Okay.

A. -- to purchase a certain amount of their interest, and then they're going to participate with a percentage of their interest also, which is reflected in the exhibit to the unit agreement.

Q. Okay. Well, let's -- What about any vertical separation of interest within the -- what the State calls the Turkey Track Pool in this area? Is there any interest different between the Seven Rivers and then the Queen?

A. Not that I'm aware of.

Q. So in other words, you guys want to do the waterflood in the Queen, but the interests are exactly the same --

A. I believe they are until --

Q. -- at least they will be until you --

A. And until you get -- We have not interest in the deeper rights either, you know, below the unitized interval.

Q. Like -- Would that be the Penrose, would be the next? Is that right?

A. I couldn't really tell you.

Q. I saw somebody --

A. Our geologist probably --

MR. BRUCE: -- our geologist.

THE WITNESS: Okay, he would know.

Q. (By Examiner Jones) He would know.

A. He would know, better than -- That's right.

Q. Okay. So there's exactly the same interests in the Turkey Track Pool?

A. Yes.

Q. Okay. What about the participation parameters? Are you going to talk about that later? I mean, how you come up with --

MR. BRUCE: The engineer will --

EXAMINER JONES: Okay.

MR. BRUCE: -- testify.

THE WITNESS: Based on cumulative production, and Mr. Rose can --

Q. (By Examiner Jones) But it's not this acreage, right?

A. No.

EXAMINER JONES: Okay.

EXAMINER BROOKS: Okay, these exhibits are only for your -- this is only the set of exhibits that applies to your statutory unitization; is that correct?

MR. BRUCE: That is correct.

EXAMINER BROOKS: And actually on the notice, the notice to offsets isn't required just for the statutory unitization, it's required for the --

MR. BRUCE: -- for the waterflood.

EXAMINER BROOKS: -- waterflood?

MR. BRUCE: Yeah, that's...

EXAMINATION

BY EXAMINER BROOKS:

Q. My questions would relate to this Exhibit Number 12, and I notice you have a number of operators identified with arrows to particular wells.

A. Yes, sir.

Q. Now are all those wells in the Queen formation?

A. I'm not sure. You know -- Okay, my engineer says no.

MR. BRUCE: They would be wells that at least penetrated the --

THE WITNESS: Yeah, right.

MR. BRUCE: -- Queen? They might be deeper?

THE WITNESS: Or might not be perforated in the Queen.

EXAMINER BROOKS: For the purpose of determining -- and what I always like to see in these type of cases -- since I haven't been examining that long people have haven't gotten accustomed to it yet, but what I always like to see in this type of case is a situation where is an explanation by tract of who the appropriate affected persons are. And this, of course, relates only to the injection case, because --

MR. BRUCE: We can provide that --

EXAMINER BROOKS: Yeah --

MR. BRUCE: -- Mr. Examiner.

EXAMINER BROOKS: -- for the -- for the -- statutory unitization, you only need to notify, as I understand it, the people in the unit.

MR. BRUCE: Inside the unit.

EXAMINER BROOKS: And it looked like you'd done all that.

Q. (By Examiner Brooks) It looks like you've drawn your circles around every well, so you probably have covered every tract, but I'd just like to see a breakdown.

A. We've got those. We've spent a lot of time digging out who these people were --

Q. Yeah.

A. -- and --

MR. BRUCE: We will provide that to you.

EXAMINER BROOKS: Okay, thank you.

EXAMINER JONES: Okay, I don't think I have any more questions, Mr. Hinson.

THE WITNESS: Appreciate it.

<u>SANDY BEACH</u>,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Will you please state your name and city of residence?

A. Sandy Beach, Midland, Texas.

Q. Who do you work for and in what capacity?

A. Beach Exploration, Inc. I'm the president and geologist.

Q. Have you previously testified before the Division?

A. Yes, I have.

Q. As a geologist?

A. Yes.

Q. And were your credentials as an expert petroleum geologist accepted as a matter of record?

A. Yes.

Q. And are you familiar with the geology involved in these cases?

A. Yes.

MR. BRUCE: Mr. Examiner, I'd tender Mr. Beach as an expert petroleum geologist.

EXAMINER JONES: Mr. Beach is qualified as an expert in petroleum geology.

Q. (By Mr. Bruce) Mr. Beach, could you please identify Exhibit 14 and describe the unitized interval?

A. Exhibit 14 is a type log from the proposed unit area. It's a gamma-ray density neutron log, and the log is from the Eastland Oil Company, PJ State A Number 5. It's located in Township 19 South, Range 29 East. It's 2310 from the south line and 2310 from the east line of Section 1.

It shows the top and bottom of the Queen -- proposed Queen unitized interval. It's also -- This particular interval is also known as the Shattuck member.

Q. And I don't know if this would be the time to discuss it or later, but what -- Above is the Seven Rivers. How many intervals are there in the Queen?

A. There's -- I break it into roughly three intervals. There's the Shattuck member, which would be this uppermost Queen sand, there's a zone called the middle Queen which on some of the wells close to the unit area have been perforated, and there's actually then the Penrose below that.

Q. Could you identify Exhibit 15 and discuss this exhibit for the Examiner?

A. Yeah, Exhibit 15 is a structure map on the Queen formation showing all the Queen penetrations. Also I wanted to back up and just describe the Queen.

The Queen sandstone is a very fine to fine-grain, well-sorted, subangular, buff-gray sandstone. It ranges from 46 to 78 feet thick in the proposed unit area.

And Exhibit 15 is a structure map that is made -- mapped on the top of this upper Queen formation or Shattuck member. It shows just -- in this area the Queen is regionally dipping, and it's a stratigraphic trap, so structure is not -- it's relatively unimportant for the trap, being that it's a stratigraphic trap.

Q. Is there a freshwater zone in this area?

A. Yes, there is, at approximately 230 feet deep. It's part of the Capitan water district.

Q. Are there any faults in this area which would connect the freshwater zone with the injection zone?

A. No.

Q. What is Exhibit 16?

A. Exhibit 16 is an isopach map of the upper Queen, again the Shattuck member. It's made on a -- using a 15-percent cutoff from open-hole density neutron and sonic porosity logs. If you'll notice the way it maps in this particular area, you have kind of a thick sandbody up on the northern end where the unit -- proposed unit is, and there's another one just south of the unit in the south half of Section 11 that goes over into 10. And we realize that we're not unitizing the entire reservoir in this case.

Q. And why did you cut it off in the north half of Section 11?

A. Based on the mapping -- several reasons, but -- first the geologic reasons. Based on the mapping, as you can see, the thicker sandbody up to the north and then the other one down in the south end of 11. In the north half of 11 it appears to be a bit of a transition zone, so we felt like to effectively sweep it we would be better off focusing on the north area.

Down in the southern area I believe there's probably a whole 'nother potential waterflood down there that the offset operator has the benefit of watching what we do here to potentially evaluate it for their own purposes.

There's also -- that's where it's -- north half of Section 11 is alternating ownership, and that was another reason that we felt like this was another good place to cut this off at.

Q. Okay. What factors were used to determine the unit outline, other than that transition zone?

A. Right. Porosity and permeability development within the reservoir that were determined from mapping, along with well productivity. The limits of the field are kind of determined by tight low porosity and permeability, and they do define the limits of the reservoir in this area, stratigraphically.

Q. And does it get tight over to the east of the proposed unit area?

A. Yes, it does.

Q. Okay. What is Exhibit 17?

A. Exhibit 17 is a cross-section hung on the top of the Queen. It's a stratigraphic cross-section hung on the top of the Queen or Shattuck member again. It shows -- It shows the proposed unitized interval and its continuity throughout the proposed unit area. It also shows perforations and cumulative production.

Also shaded, the porosity at various cutoffs.

One at a 15-percent cutoff, which is the isopach that I referred to, and one at -- and then also at 12 percent.

And if you'll refer back to Exhibits 15 and Exhibit 16, the index of where this cross-section goes is noted on those two maps, and it's noted as A to A'. And again, it just shows the continuity of the reservoir throughout the proposed unit area, the cross-section does.

Q. Geologically, is this a good candidate for waterflooding?

A. Yes, it is.

Q. Were Exhibits 14 through 17 prepared by you or under your direction?

A. They were.

Q. And is the granting of this Application in the interests of conservation and the prevention of waste?

A. Yes, it is.

MR. BRUCE: Mr. Examiner, I'd move the admission of Exhibits 14 through 17.

EXAMINER JONES: Exhibits 14 through 17 will be admitted.

EXAMINATION

BY EXAMINER JONES:

Q. So you've got -- Tell me about your rocks above and below this interval.

A. Okay. The rock above and below is anhydritic dolomite in both cases, very tight, very impermeable rock, extremely nonreservoir, very good barriers in trapping and helps form the trap in this case.

Q. Okay, so you go from anhydritic dolomite down into well-sorted sands; is that right?

A. You go in -- these sands are interbedded with siltstones, tight sands. It appears that in this area what controls porosity development in a lot of cases is grain size. The coarser grains have not been affected by anhydrite cement as much --

Q. Oh.

A. -- so we've got high-permeability zones where we've got coarser grain sizes and -- and then in this particular trend there's some minor marine processes, shoreline processes, that have winnowed out some of the cementation.

Q. So this is not a marine sand, it's a fluvial-type --

A. No, it's a marine sand, it's a shoreline sand, it's probably aeolian-derived.

Q. Okay.

A. So it's a shoreline lagoon complex, is what it is.

Q. So it was aeolian, but the sea moved up over it or something?

A. That's right, that's right. It was blown in from -- probably, you know, from the land right there. You're right on the shoreline, and then it's been reworked by shoreline currents and tidal currents --

Q. Okay.

A. -- forms these various traps.

Q. So you could possibly have all kinds of -- a non-geology term, stuff, filling up all this porosity then?

A. Well, that's right. The fact that you're in a dry, arid climate in this time, you have a lot of evaporitic-type things going on here. As a matter of fact, that's where a lot of the anhydrite is, so that's the pervasive cementation and a lot of the trapping mechanism.

Q. Okay. Okay, what about -- The porosity is really good, I guess, so that's -- so your -- but your effective porosity would be a lot less than this, right?

A. You know, what we found -- and I think Jack can speak to this to a certain degree -- we found that you need 15 percent -- the 15-percent cutoff seems to fit well when you start making ϕh and doing reservoir calculations on reservoir recoveries. It appears that a 15-percent number on these logs, anyway, seems to fit well with the recoveries. You start using a lot lower porosity than that, and you can't -- the numbers don't match.

The other thing is, of course, these are -- most of these are open-hole, nice open-hole, relatively modern logs, but they're all on limestone matrix. So these porosities that you see on these logs, it's a standard display that everyone uses. So these are a little optimistic. If you wanted to convert these to a sandstone matrix, these porosities would go down.

Q. Yeah. Do you have the digits on these logs, or did you digitize --

A. I didn't digitize them, no.

Q. But you can just base it on such as limestone -- limestone display here?

A. It's -- yeah, I think every- -- you know, I think everybody, just about, still runs everything on limestone matrix, and then -- We didn't go in and convert. I think it's all, you know, relative. If you use the same cutoff on a limestone matrix, you're going to come up with similar results. You just have to adjust your cutoffs.

Q. Okay. Is your engineer going to show a porosity-versus-permeability plot for this, or can you talk about it a little bit?

A. Well, we don't have any core data, so --

Q. Sidewalls or anything?

A. No, there's no core data available on any of these wells, so we don't have a firm handle on permeability. We just know, based on several other fields in this area, what you tend to have are real high-perm streaks in some of this stuff that can get up to, you know, 200-millidarcy-type perms. But we don't have any core data, so...

Q. So you can get some streaks of higher --

A. -- perm in this --

Q. -- perm?

A. -- that's right. Yeah, you get some of this stuff, it's typically laminated sands, and you get high porosity and perm intervals within this overall interval, and porosities can get up in the -- I mean perms can get up to 200 millidarcies.

And again, that's speaking from fields in this area that I've studied, that I was able to find permeability data on --

Q. Okay --

A. -- but in this -- I would assume this is similar.

Q. Okay. Can you use the gamma-ray at all for any kind of permeability inference on this?

A. What you can do is, typically these porosity -- you know, these porosity lobes that you see in here, you can actually -- I've actually gone in and mapped some of these porosity intervals, and I know that those are the intervals that have the perm in them, and you can carry them throughout the area that we want to unitize.

But I can't come up with any permeability numbers. Obviously, this isn't just extremely high-perm stuff in all cases because every one of these wells has to be frac'd to produce.

Q. Okay.

A. So it's not a situation where you just have fantastic reservoir. It's -- Queen that I know of -- I don't know of any Queen where you don't have to typically frac it to get commercial production out of it.

Q. Okay.

A. So you do have some high-perm zones, but not enough to make commercial completions, typically.

Q. Do you have any concerns about the completions, as a geologist, of the fluids used in the frac'ing and the drilling and all that stuff?

A. No, I don't. From what I've seen, these have been completed similar to all the other Queen fields and production in this part of New Mexico and in other areas where we have flooded. And this is a common completion practice, it doesn't seem to affect the floodability of a reservoir.

Q. That gamma-ray, is it potassium that we're seeing here, a big kick?

A. It's -- yeah, it's radioactive hot sands in here. I'm not even sure what mineral is causing the hotness, but that's real typical of Queen out here, it's -- there's some radioactive material in there that gives it that appearance.

Q. So there's no spectral gamma-ray data?

A. I don't have any spectral gamma rays on any of these logs either.

Q. Okay. Is there any -- then, any advances in logs in the last few years to look for permeability, through-pipe permeability?

A. You know, just in a relative sense, but not in terms of actually getting data. You know, you can identify what appear to be permeable intervals, but in terms of actually getting numerical data, I don't -- not that I'm aware of, you know, short of, like you said, getting sidewall cores or actual hole cores. I'm not aware of that, if there is.

Q. Okay. What about logs to, oh, look for the saturation, water saturation out here?

A. Yeah, there is certainly water saturation, and a lot of these --

Q. Through casing.

A. Oh, through casing. I believe that there have been some advances in that. I think that they have logs now where they're doing some of that.

Q. TDT logs or something --

A. Yeah --

Q. -- similar?

A. -- I think that's right.

Q. All right. So basically this is an interval that you can correlate across the unitized area, and it's got bounding rocks above and below. So you wouldn't be afraid of going up with your pressures a little bit on your injection?

A. No, and Jack can speak to our experiences in these other Queen units. You know, we want to stay below frac gradient of this particular sand, we don't want to get above that. But we think we need to get up close to that to be able to effectively get water in this stuff.

Q. Okay, as -- from your viewpoint, why didn't you include the Seven Rivers in this --

A. The Seven Rivers -- well, several reasons, but the Seven Rivers is primarily -- it's a much higher GOR reservoir. The actual oil reserves that have come out of the Seven Rivers are not that significant. It's mainly a -- more of a gas reservoir, which is -- you know, I don't think is quite as good a candidate for waterflood, the economics aren't quite as good, don't know that they're actually good enough to warrant it.

And the Seven Rivers, I don't know -- I think it's more discontinuous through this area. It doesn't appear to be quite as continuous as this Queen does.

Q. Is it a sand?

A. It is a sand. It's fairly shallower than this too, it's --

Q. Is that what we're seeing up here at 2100 feet?

A. No, it's -- that's a lower Seven Rivers, but the upper Seven Rivers is a fair amount higher than that. It's another -- oh, I'd say around 1700 feet, so...

Q. So that would dramatically lower your pressure that you could flood --

A. Well, that's true too, yeah.

Q. -- the Shattuck --

A. -- the Shattuck member.

Q. -- the Shattuck. Where did that name come from?

A. I don't know. That's -- you know, I've read it in geologic -- various geologic papers, but to be honest with you I don't know where the actual name is derived from.

Q. Is this the same interval -- The reason I'm asking, I used to work on the North Benson-Queen Unit --

A. Okay, this is --

Q. -- years ago --

A. -- very close to that.

Q. -- and -- Okay, is it the same --

A. North Benson-Queen is primarily flooded in the --

what I call again the middle Queen, the Penrose and some Grayburg sands below that.

Q. Okay.

A. There are very few wells, if any, that I know of -- I think on the very southern end there may be a well or two that actually perforated this sand. That sand is tight and not developed at North Benson --

Q. Okay.

A. -- so --

Q. So this is different?

A. This is different --

Q. Different --

A. -- it's a different sand than the one that's the main --

Q. What would be an analogy for this as far as other waterfloods, geologically speaking?

A. Turkey Track, which is the unit -- if you look on Exhibit 15 and 16, the structure map and the isopach map, you can see another unit outline just to the north and west of our proposed unit here. That particular unit was flooded in this same zone.

Let's see, Colwin is another unit that was flooded in this. There's actually several, the Young field was flooded in this one, Taylor unit, E.K. Corbin, Central Corbin --

Q. There's a lot of them.

A. There's -- and I'm just thinking these off the top of my head. We studied all of them -- or studied them -- at least looked at several of them and studied several of them in detail, but there's probably 12 to 15 that have been flooded in this exact same interval.

Q. Now this interval you're leaving out between the Turkey -- is it the Turkey-Queen unit or something? --

A. Yeah, the Turkey Track-Queen, uh-huh.

Q. -- and your proposed interval here in Section -- 2?

A. Two and 11 there, right.

Q. Was that -- are you -- that should be left out?

A. Yeah, it's tight right there, for one thing. You see the zero line on my isopach goes through there.

The other thing is, this unit boundary in the Turkey Track is a little misleading. The original Turkey Track unit was mainly up in Section 34, and then down into the northern part of Section 3. And then -- That was done, I believe, in the '50s, when that originally was flooded. And then at a later date different operators have come in and purchased that unit, and they've included more lands in that and have gone in and drilled deeper wells into the San Andres and completed the San Andres, the Grayburg, the Penrose, I just shot all this stuff. So some of the unit boundary is really not giving you a true picture of where the actual Queen was developed in this area. So there's definitely a separation, stratigraphic separation in terms of permeability and porosity between that area and this area.

Q. Okay. What about the -- You already talked about this in the southern part of 11, but it sure is -- it sure shows up on your net-pay isopach here. These lands were -- you just -- you think they should be unitized separately --

A. Well, that was --

Q. -- separate owners --

A. That's right. That's right, that's separate ownership down there. In the north half of 11 there's alternating standup 80-acre ownership, so the wells that -- Eastland, that we are obtaining, they have one 80, and then MYCO group has the next 80, and then Eastland and then MYCO. And that's the interest that we are in the process of trying to obtain that we think we've got, you know, agreement with to buy now.

But when you get to the south half of 11, yeah, that becomes completely different ownership, and -- and then geologically it just looked like, based on how we wanted to pattern this -- and Jack can get into some of those reasons also -- there was a kind of a transition zone. They very well -- these areas are probably in some kind of communication.

But to try and surround this better-developed area to the north and sweep it efficiently, we felt like that was a good place to pattern it, in this transition zone, if you will, between these two better developed area.

Q. So the north half of 11 was valid to include --

A. Yes, it was, there's certainly production that have come out of this, and a fair amount of production, some decent wells in there that we definitely want to try and get secondary reserves out of.

Q. Okay. Now I guess -- David will have to help me out here a little bit, but when you unitize this area in the Queen, are you speaking -- do you contact Bryan Arrant, our geologist in Artesia, very much? Do you talk to him?

A. No, no, I think we -- and I may not --

Q. Okay, well let me ask you this. Did you look at the vertical limits of the Turkey Track -- I guess it's the Yates-Queen-Grayburg; is that right?

A. I believe it's Seven Rivers- --

Q. Yates-Seven Rivers- --

A. -- -Yates-Queen-Grayburg, yeah.

Q. Did you look at that in relation to what we're calling -- the State is calling that a common source of supply. So did you consider maybe some nomenclature here about changing --

A. We haven't done that --

Q. -- the pool --

A. -- we haven't that. We can do that, because, yes, we're -- the interval we're interested in obviously is a member within that pool. So we have not attempted to do that. If that is something that we need to do, I think we can look into doing that. I --

Q. Well, how deep are these wells that are existing already in this unit? Are they only through the Shattuck member, or are they --

A. No, some of them have gone -- it varies, but some of them have gone down through some of the Penrose and Grayburg sands. I think a few wells have actually -- were plugged back from the Morrow. All the wells have been plugged back, but --

Q. Okay.

A. -- but -- and again, Jack I think can go through some of the wellbore sketches and --

Q. Okay.

A. -- go through that. But there are some that have penetrated some of these sands below there, but in most cases those sands we didn't feel like were developed to reservoir-quality sands.

Q. To be waterflooded or to be produced?

A. Well, to be produced or waterflooded. There's very few within the unit area other than, I believe several wells or -- there's several wells that have been completed in the Seven Rivers. But in terms of the Penrose and the Grayburg, I don't -- if I'm not mistaken, there's very few, if any, that have been perforated in those sands.

Q. Okay. Well, I guess our District Office, if that's not done -- they have to keep track of everything. And they do that on other occasions too, so...

But below this Shattuck is the -- the Paddock is the first --

A. The next thing I would call would be the -- again, would be the middle Queen, and that would be just -- if you look at a cross-section here, the cross-section, if you were to look at, say, the Eastland Oil PJA Number 17, if you see that log, that middle Queen sand would be roughly at 2330.

Q. Okay.

A. It's a little six-, eight-foot sand. And in some areas that sand develops quite a bit better and can be pretty good reservoir rock. But not really within the unit have I seen it develop.

Q. Okay, but the unit -- the Application said 100 feet above the Queen, 100 feet below the Queen. Now where would that be on this -- on this -- ?

A. Actually, I think what we did was, we specified the interval between the -- you know, where we're seeing on this cross-section, which would be the Shattuck member, but I think what we did was, we specified a depth from the shallowest top of the Shattuck member to the deepest bottom of the Shattuck member. So I think that's how --

Q. So you'll have a type log that will have that all defined vertically?

A. Yeah, the type log that -- you know, that's --

Q. Is that like on the Application, or is that --

A. Well, this is -- in this Exhibit 14, obviously, we have the unitized formation with the boundaries of it on there.

Q. Okay.

A. And then on the C-108 --

Q. Okay, that's the unitized interval?

A. Right, that's the unitized formation. We also -- I'll go into -- in the proposed unit area it ranges in depth from 2196 feet to 2470 feet, depending upon regional dip and surface elevation. But that is just to this Shattuck member.

Q. Okay. So if somebody -- Hm. So the wells that you're going to use for waterflooding purposes are going to be unitized wells; is that correct?

A. That's right.

Q. Those will be unitized wellbores?

MR. BRUCE: That is correct.
Q. (By Examiner Jones) So they won't be used for anything else above or below this --
A. No.
Q. -- until they're released from the unit somehow?
MR. BRUCE: That's correct.
THE WITNESS: That's correct.
Q. (By Examiner Jones) So the owners could then perforate other zones above or below?
A. That's correct.
Q. Okay. Okay, I know that -- I hope that -- The Benson-Queen injection withdrawal ratio was about nine to one, you know, and we tried cutting back the injection and we dropped off on oil, and so we had to crank it back up again. So is that what you're expecting here?
A. Well, the Benson is a lot different in that, from what I've seen, they unitize -- that particular unit was unitized in a lot larger interval, and there was probably -- you know, there was probably four, five, six different sands opened up in that particular flood --
Q. Okay.
A. -- and that's -- you know, that's one of the reasons that we wanted to -- you know, to limit it to this particular interval, so we could contain it and manage it much more efficiently. I think when you start opening up

four or five different zones you start having various problems that are harder to manage, so --

EXAMINER JONES: Okay, that answers that question. So I'm fresh out of questions, I think.

EXAMINATION

BY EXAMINER BROOKS:

Q. As I understood your testimony, and going back to what Mr. Jones was asking about the depth definition of the unit, as I understand it, you believe you've identified a depth range that is -- where there are barriers above and below so that it's not in -- probably not a lot of communication between the interval and the formations immediately above and below; is that correct?

A. That's correct.

Q. Okay. And you defined it -- you explained this to Mr. Jones, but you define it how? Have you identified particular points in particular wells?

A. Well, I basically just took -- when I -- actually, when I described it in the C-108, you know, I just took from the -- structurally, from a structural standpoint, I took the -- you know, the highest well where the Shattuck -- the top of the Shattuck member was in the highest well, and then took at the base of the lowest well so it would include that interval.

I don't know that I have gone through and set out the interval, the exact interval in every well within the unit. I certainly could do that.

Q. Well, you define it in the unit agreement. I assume there's a depth definition of it and I didn't look at it.

MR. BRUCE: Page 4 of the unit agreement.

THE WITNESS: Also if there's -- you know, in this case if it were to be -- and I don't know how it's described in there, but if it's described as 100 feet above and below it, there's nothing within 100 feet below it or above it, in my opinion, that would be affected. It's all typically nonreservoir rock in there.

And also, you know, these particular wells are perforated just in this member. So there's really no -- nothing open to get into anything above and below there anyway. I mean, we're going to isolate just this member, so we have no interest in putting water in anything else but this member, so...

Q. (By Examiner Brooks) Okay, it's defined as the stratigraphic interval occurring between a point 100 feet above the top of the Queen sand and 100 feet below the base of the Queen sand, said Queen sand interval occurring between 2355 and 2408, as shown --

A. Okay.

Q. -- on Schlumberger's compensated neutron litho density open hole log dated 6-18-87 when the Eastland Oil PJA Number 5 --

A. Okay.

Q. It's defined with complete -- with pretty good precision there. I do think, though, that Mr. Jones has a point, because I have not studied how the pools are defined there, and it might be -- If you have combined pools, you may get into some problems. So it might be good to work with the District Office to get a pool definition that is appropriate for this unit.

MR. BRUCE: One thing, Mr. Examiner. Mr. Hinson reminded me that this is all state land, and that's the way the State Land Office likes to define the unitized interval, take the specific sand and go --

EXAMINER BROOKS: Well, yeah --

MR. BRUCE: -- yeah.

EXAMINER BROOKS: -- the reason I had asked the questions is, I've seen those definitions drawn that way before.

That's all I have.

EXAMINER JONES: Yeah, if you just work with Brian a little bit, and just think about it internally in your company, about -- if there is any need that would make it easier for the District Office to keep track of things, because they -- he might feel that it needs to break that

Turkey Track Pool up into --

THE WITNESS: Okay.

EXAMINER JONES: -- into different pools, but maybe not, you know. I'm sure they're used to handling it that way within waterfloods all the time.

MR. BRUCE: Yeah, and of course that pool covers quite a large area --

EXAMINER JONES: Large area, so --

MR. BRUCE: -- and so it would have to be just for this unit area.

EXAMINER JONES: You'd have to contract it and everything. So it probably would not work. They probably keep track of it pretty --

THE WITNESS: What is -- Bryan -- What's his last name?

EXAMINER JONES: Arrant, A-r-r-a-n-t --

THE WITNESS: Okay.

EXAMINER JONES: -- in our Artesia Office. And I forgot the number of them here.

THE WITNESS: That's okay, I can get that.

EXAMINER JONES: Can we take a 10-minute break?

EXAMINER BROOKS: Sounds like a good idea.

(Thereupon, a recess was taken at 9:19 a.m.)

(The following proceedings had at 9:30 a.m.)

EXAMINER JONES: Okay, let's go back on the record.

JACK ROSE,

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

DIRECT EXAMINATION

BY MR. BRUCE:

Q. Would you please state your name for the record?
A. Jack Rose.
Q. And where do you reside?
A. Midland, Texas.
Q. Who do you work for and in what capacity?
A. I work for Beach Exploration, Inc., as a petroleum engineer.
Q. Have you previously testified before the Division as an engineer?
A. I have.
Q. And were your credentials as an expert accepted as a matter of record?
A. They were.
Q. And are you familiar with the engineering matters involved in the unitization and in the waterflood?
A. Yes, I am.
MR. BRUCE: Mr. Examiner, I'd tender Mr. Rose as an expert petroleum engineer.
EXAMINER JONES: Mr. Rose is qualified as an

expert petroleum engineer.

Q. (By Mr. Bruce) Mr. Rose, what materials did you examine in your study of the Queen reservoir for the proposed unitization?

A. I reviewed logs in the area, production histories, wellbore histories and schematics and offset flood results, primarily.

Q. And what is Exhibit 18?

A. Exhibit 18 is an area flood map. And what it's designed to present is other floods that have been done in this area in the Queen. Some of these are exclusively Shattuck-member Queen floods, some of them are flooded in different intervals of the Queen. They all include Queen to some extent. Some of them include other zones like the Seven Rivers or Grayburg.

And it's a map just to show you the trend of Queen floods and how successful that has been. I think the -- we'll probably get into a little bit more later on what particular Queen floods are of interest.

The Turkey Track, which is on the extreme left of the exhibit there, offsets our proposed flood, and Sandy talked about that earlier. That was a pure Shattuck-Queen flood in 1960, and it was a successful flood at one-to-one secondary-to-primary ratio.

Q. Okay. Have you made calculations regarding secondary recovery and the economics of the waterflood project?

A. Yes, I have. This exhibit is just a brief summary of some of those calculations.

Q. Exhibit 19?

A. Yes. This sheet is designed to show original oil in place, pore volume from -- we -- I went through and did a ϕh map on all of these logs over the unit area. We did -- when I did that, we did correct for sandstone matrix and the porosities, so we did develop a ϕh map based on a 15-percent cutoff. We did one on 12 percent, but the 15-percent seemed to match existing well performance, and so we really felt better about the 15 percent.

Original oil in place on this calculation sheet is about 5.7 million barrels. The primary recovery factor, primary we're calling, on the upper right side there, 734,000 barrels, and that's about 12.8 percent of the original oil in place, on the extreme upper right side.

The next few calculations, the current oil saturation, the free gas volume and the fill-up time, are basically calculations to see when we're going to see peak response. Once you've depleted a reservoir and you've got a gas saturation, you've got a lot of voidage in the reservoir and you have to fill that back up.

These calculations are designed to give us an estimate, once we start injecting at a certain rate, or assumption of a certain rate, and we're saying at 100 barrels per day in the fill-up time, with 13 wells that that pre-gas volume would be filled up in about 30 months, which is about two and a half years.

And at that point in time -- We should see response before that time, but at 30 months we ought to be at peak rate for secondary recovery.

And then the last is a theoretical waterflood recovery based on volumetrics and some sweep efficiencies. And just a rough calculation shows about 756,000 barrels of potential recovery there.

Q. Okay. Would you discuss the history of the development of this portion of the pool and refer to Exhibit 20?

A. Exhibit 20 is a plat of the proposed unit outline and the well status. There are actually two pools that are covered by this unit outline. The major pool is Turkey Track-Seven Rivers-Queen-Grayburg-San Andres. The other one is Turkey Track-Queen East. And Turkey Track-Queen East is not designated on this map, but the unit wells within the unit boundary that are included in the Turkey Track-Queen East are in the south half of Section 1. They would be Wells Number 5A, 6A, 8A, 9A and 11A.

EXAMINER JONES: So it's the south -- I'm sorry, it's the southeast of Section 1, or is it --

THE WITNESS: The south half of --

EXAMINER JONES: -- south half --

THE WITNESS: -- Section 1.

EXAMINER JONES: Okay.

THE WITNESS: These are all correlative zones in the Shattuck member. There's no really physical separation in these two pools at this boundary.

The Turkey Track was discovered in 1943, and it covers like 183 wells, have been in that pool. There's 112 in that pool that are active now. That whole pool has cum'd about 4.6 million barrels, 4.6 BCF and about 5 million barrels of water.

This particular portion of the pool -- and of course we include a little bit of the Queen East -- includes 29 -- There are 30 wellbores that are unit wellbores, 29 of those are active. We have one well that's inactive, it's in the southeast of the southeast of -- or no, excuse me, southeast of the northwest of -- well, it's that P-and-A Number 4.

Q. (By Mr. Bruce) Northwest of the southeast?

A. Yeah.

EXAMINER JONES: Southeast?

THE WITNESS: My norths and wests are --

Q. (By Mr. Bruce) Designated the Number 4 well --

A. Yeah, it shows just below --

Q. -- on Section 1?

A. -- Section 1, at the very corner of the boundary there. That well was a P-and-A'd well, and we're planning on re-entering that well and making it an injection well.

Q. Would you identify Exhibit 21 and describe production from the wells within the unit -- proposed unit area?

A. This is a production plot from public records of the unit area for the wells that we plan to unitize. Production history includes oil, gas and water production, and it also has a cum as of 6-1 of '07.

If you'll notice, this is -- the peak rate here is about 12,000 barrels a month, which is about 400 barrels a day. That occurred in December of '89. Currently we're at about 750 barrels a month, which is about 25 barrels a day, and we have 29 active wells, so we're pretty much in an advanced stage of depletion at this point in time.

The cum for this area -- and this includes a little bit of middle Queen, very little, a little bit of Seven Rivers, and mostly Shattuck-member Queen, and that cum is 690,000 barrels oil, 980 MMCF and 268,000 barrels of water.

Q. Okay. Was the waterflood project proposed as a method of extending the life of the wells in this portion of the pool?

A. Yes, it was.

Q. What is the drive mechanism of the pool?

A. We're assuming this is a solution gas drive reservoir. Almost all of these are, probably initially underpressured, and probably had a free gas -- the Queen -- the Shattuck member of the Queen, original GORs in that particular interval started out around 400 or 500, and then gradually they increased to about 1000.

But they get up to 1000 pretty quickly. If you look at a history on the Queen -- Shattuck-member, Queen only, the gas pretty much tracks the oil at about one to one.

Q. Referring to Exhibit 22, could you describe the injection pattern for the unit?

A. The injection pattern is a little -- a little strange. It's not a standard pattern. What it's designed to do is be a peripheral pattern. Our experience, we've done Queen floods in Martin County, Texas, we've done two Queen floods in -- north of Loco Hills in Eddy County, and they are -- one of those -- those are some Penrose floods.

And we've had some poor luck and some good luck with those. We had one that didn't perform very well, and we think part of the reason was, somebody came in and just put a standard fivespot pattern across a very small field.

And what we decided to do when we put in our West High Lonesome flood in 2002 was to identify where the oil has come from, sweet spots, and circle that area with injectors to -- and get a pattern around there and get water coming in toward the center portion of that sweet spot. Later on, after we've seen oil recovered and maybe some of the wells in the middle of those peripheral patterns flooded out, we might convert it to injection and create a little small pattern and get a little more efficient sweep.

The injection pattern that you see here in Exhibit Number 22 is basically a pattern that is concentrated on sweet spots. And we've defined sweet spots in two different ways, with our ϕh calculations and the maps that Sandy -- the ϕh map and the oil recoveries tend to show us that we've got a sweet spot in the center of Section 1, we have one in the southeast corner of Section 2, there seems to be a little sweet spot on the upper limit of the reservoir in the south half of Section 2, around 19 and 17A, those two wells; we also have a sweet spot in the east portion of the north half of Section 11.

And then in the south half of Section 11 -- and I think Sandy in his map, on his isopach map, showed a very big piece of isopach pay quality in the southwest of Section 11. That zone recovered -- These wells typically recover about, oh, 25,000 to 30,000, a good well is 45,000 barrels. And that's our experience in other Queen floods that we've seen. In the south half of Section 11, a couple of those wells have recovered 75,000 or 100,000 barrels. We see some geologic evidence that there's some different things going on geologically down there. It's obviously a lot better piece of rock down there.

And the north half of Section 11 seems to be a transition zone, and you can see our injection pattern there kind of gets a little weird, and the reason for that is, we're trying to -- we don't want to put water to the south, if we can keep from it. We're trying to flood that transition zone, and -- for two reasons. If we -- we're going to lose water to the south, and we're not going to efficiently flood the north half of Section 11.

The Phase I injection are the white injection symbols, and as those patterns start filling in then we will -- typically you'll see in Section 1, we have -- like on the northeast of Section 1, you'll have 7A, 12A and 22A, and we'll convert 7A and 22A to injection and hopefully get some oil out of 12A. And as soon as 12A waters out we'll convert it to injection.

Same thing would happen on the north line between the 2HL, the 3HL and the 7A.

And what we're doing there, a lot of these wells around the edges of these sweet spots are tighter wells, and we don't get as much water in them. But we don't have very many wellbores, and the sweet spots are not large. And rather than putting a pattern on them, what we have -- and we've been successful in our West High Lonesome doing this. That flood had 544,000 barrels primary, and we're expecting a one-to-one. We've already recovered 280,000, we've reached a peak response very similar to what we projected, and it's doing -- it's on track to recover a little bit greater than one-to-one. So I think the theory and the idea works well.

Q. So how many -- initially, how many injection and producing wells will there be?

A. Under Phase I we'll have 13 injectors and 17 producers. And by the time we finish, if the plan is borne out, we'll have 18 injectors and 12 producers.

Q. Now you mentioned toward the south that -- this transition zone, and then the reservoir to the south and west. One thing in unitizing this particular acreage, no new wells will have to be drilled; is that correct?

A. That's correct.

Q. When you're looking toward the south, that has not been fully developed yet; is that correct?

A. No, it doesn't -- again, you get into a situation, there's really no reservoir to the south of

Section 11, so you've got -- you really don't have any way to encircle that or create a very efficient flood pattern in the south half of Section 11.

If we included the south half of Section 11 from a cost standpoint, our contention was, you would have to drill several wells in there in order to create some patterns to flood that. And our aim is to do this efficiently. And cost, drilling cost, is very high today, so if we can keep from drilling wells -- We've had very good success in flooding these wells basically on 40s. We're a little closer than 40s on most of this, so the only thing we have to do is re-enter one well right now. So we're trying to keep our costs down.

Q. Now how many additional barrels of oil do you anticipate recovering as a result of the waterflood project?

A. We expect 734,000 barrels, which is equal to primary. That's the ultimate primary recovery, and we feel like we should be able to get a one-to-one secondary-to-primary ratio.

Q. And that --

A. The calculation sheet also showed 765,000.

Q. Yeah, that's what I was going to ask you. On Exhibit 19 you had a theoretical recovery of 765,000, but you're using the more conservative figure?

A. Yes, that's just to check and see if we're in agreement and balance, and it does.

Q. Okay. And maybe at this point you might want to refer back to Exhibit 18, but describe just briefly again how you calculated the reserves to be recovered by the waterflood project.

A. Again, our primary -- our experience in Queen, these Queen floods come in pretty fast and go out pretty fast. It's a very -- we're flooding a very high-perm streak in a little bit tighter rock. There's not a lot of net pay, and I think that's the reflection of the 15-percent cutoff. The pay that is flooded is high-perm, there's a lot of rock that probably does not get flooded. The primary is drained out of those high-perm intervals.

And so primary and secondary are almost universally related in the Queen that we've had experience -- If the Queen is all developed at a similar time, you'll see a peak response in the Queen. It will come off 25 or 30 percent or a hyperbolic decline, and then when you put a flood in, if you do it all at one time, it will go up to about the same peak as the primary, almost, and then go out at 20 percent.

And the flood generally lasts about 10 years, and that's been our experience in looking at floods. We've looked at these -- all the floods on Exhibit 18, and the ones where we have current production history, where we can see that actual performance where we have development peak on primary and the same on secondary.

What we've got here is a secondary-to-primary ratio for all of these units, and you can see that they average .99-to-1 for all of the units on this. There are a few units that are -- included other zones, but almost all of these units include some member of the Shattuck, and there are quite a few of these units that are Shattuck-only floods. And --

Q. Are any of these of particular interest?

A. The ones that we're really -- that we've really taken a hard look at, of course, is -- in order to convince ourselves that this could be flooded was the Turkey Track-Queen unit.

I think everybody in the area thought this couldn't be flooded because that flood wasn't successful. But we started going back into the hearing records in 1960, and they put a Shattuck-member Queen flood in that was only Shattuck-Queen in 1960. They used fresh water to flood it, and we've gone back and -- They kind of did a pilot flood and staged it on in, so it's kind of stretched out a little bit. But you can see the primary performance and project that off of what we know Queen performs now.

And if you do that and look at the total recovery out of the Queen, before they started perforating these other zones and cut it off at that point, you have a one-to-one secondary-to-primary ratio in that unit just to the west of us.

We also have looked closely at the Taylor unit and the Culwin unit. The Culwin-Queen had about a .8-to-1 secondary-to-primary ratio, and the Taylor unit had a 1.45-to-1 secondary-to-primary ratio. So we feel comfortable with the one-to-one as a reasonable estimate of secondary reserves. And of course we've done some volumetrics and ϕh's to kind of confirm that too, so...

Q. What is Exhibit 23?

A. Exhibit 23 is a -- basically a cost estimate or AFE of what we think it will cost to install this unit. We installed the West High Lonesome unit, which was a 27-well unit, in 2002, so we have direct experience. The pressures that we're going to be dealing with are very similar here. The infrastructure is almost identical. We have the same number of wells, we have almost the same number of injectors, so it's a very close analogy for facilities to this particular -- And that's been a successful flood.

And based on the increase in costs that we've seen in the last few years, that well -- that unit cost about $1.1 million to put in. And we've experienced about 2 1/2 times increase since that time, and I think we've got a fairly close estimate on what we think it will cost. It always changes a little bit when you get into it, but I think we're pretty close on our estimate here.

Q. Will the project be economic?

A. Yes, it will. The Exhibit Number 24 is our economic runs for the unit, and as just a brief -- the front one is a full waterflood case, and we expect it to generate revenues of about $38.5 million. The cost, taxes, direct operating expense and investment, is probably going to be around $14 to $15 million, which will net a profit of about $24 million. Should have about 77-percent rate of return and should pay out in about two and a half years, and that's based on $60 flat oil.

Q. Is the portion of the pool being unitized suitable for waterflooding?

A. Yes, it is.

Q. And is the project area so depleted that it's prudent to apply an enhanced recovery program at this time?

A. Yes, I think it is.

Q. Is the waterflood project technically and economically feasible at this time?

A. We feel definitely that it is.

Q. Will the value of the oil and gas recovered by unit operations exceed the unit cost plus a reasonable profit?

A. Yes, we've demonstrated that with the economics.

Q. Will waterflood operations result in the recovery of substantially more hydrocarbons from the pool than will otherwise be recovered?

A. Yes, it will.

Q. And will unitization and secondary recovery benefit the working interest and royalty interest owners in the unit?

A. It definitely will.

Q. Is unitized management and operation of this portion of the Queen reservoir reasonably necessary to effectively carry out waterflood operations?

A. Yes, it is.

Q. And because of the estimated additional production, do the wells in the unit qualify for the recovered oil tax rate?

A. Yes, they will.

Q. At whatever the price may be in that --

A. Right, yes.

Q. Now let's discuss -- and the Hearing Examiner asked about this before -- the tract allocation formula as set forth in the unit agreement. Could you refer to Exhibit 25 and discuss this briefly?

A. Yes, Exhibit 25 is a reproduction of Exhibit C to the unit agreement, and basically what we've done here is projected Queen or Shattuck-member Queen reserves only. There are some wells that are perforated in the Seven Rivers, and there are Seven Rivers reserves. These are fairly large leases, and individual well performance is somewhat difficult to discern. We have gone through those lease curves because they're the most accurate curves of projections.

And with the GOR difference we see about a 2000 GOR in the Seven Rivers, and you can see when these wells were perforated and when they came on, you can see the gas kicks when you perforate a Seven Rivers zone.

So we've got several leases that are pure Shattuck-member Queen, so you can see Queen performance, you know what the GOR is doing and how the wells decline. The leases that are combined Seven Rivers and Queen, I went through and picked out, you know, when they perf'd.

We usually have a period of time where it's Queen only before that Seven Rivers was perf'd, so we have a starting point for those, you know, typical declines to calculate Queen reserves, Shattuck-member Queen. So I went through and segregated what middle-Queen was there, very little, and I segregated out the Seven Rivers. So the reserves on this page represent the Shattuck member of the Queen reserves only.

The cums, we have one well in the State HL lease that had perforated the Shattuck member of the Queen, and then they went up to the Seven Rivers and had a bridge plug on it. We did a typical decline on that short period of time that it produced to come up with that 11,000 proved developed non-producing reserves.

Other than that, you can see we've got a cum of 660,000 barrels there with a remaining of 63,000, so it's pretty much advanced depletion. And our ultimate primary is 734,000.

With our knowledge about Queen and all the other units being one to one, we see no better indication of secondary performance than primary, and so that's our only participation factor, is ultimate primary recovery, what each well has contributed, or each lease or tract has contributed to ultimate primary.

Q. In your opinion, does this formula allocate produced and saved hydrocarbons to each tract on a fair, reasonable and equitable basis?

A. Yes, I feel it does.

Q. Mr. Rose, let's move on to the injection operations. Would you identify Exhibit 26 for the Examiner?

A. 26 is the C-108 application.

Q. Would you describe first how the injection wells will be completed? And --

A. The injection wells --

Q. And I was going to say, and in going through this, since there's so much paper here, if you're referring to any of the attachments please go slowly so the Hearing Examiner can find them.

A. If you go back to the sixth page from the front there is a list of 18 wells within the unit area there. And what follows behind that list is 18 wellbore sketches, and those are the proposed injection wells.

I will characterize those in general for you. In general, to give you an idea about the age of these wells, there are only two wells that were drilled in the '60s, and those were actually plugged. And one of them was re-entered in the '80s and the other one was re-entered in the '90s, and they brought it up to snuff as far as cement and surface casing at that point in time.

Three wells were drilled and completed in the '79 to '85 time-frame, 11 of them were in '86 to '90, and one of them was done in '99, so...

All these wells are typically 8-5/8-inch casing, generally. There are some exceptions, but generally 8-5/8 casing set between 300 and 400 feet, cemented to surface. Hardly anything circulates to surface out here. They get up to about 50 feet, and then they almost all of them are topped off with Redi-Mix, per OCD guidelines. But they all have cement at surface. There are a few that actually circulated on the surface, but very few.

Typically the water zones are at about 230 here, so generally, even if you don't get up to -- if you get up to 100 feet or 80 feet, you've probably got fresh water protected. There's nothing that shallow that we've seen.

Generally, the production casing is 4-1/2 or 5-1/2 set to TD and cemented to surface, so you've got two strings of cement casing and cemented to surface on most of these wells. And they're very recent, so...

Mechanically it's very clean, as far as a flood goes.

At this time I have a question for you all from the standpoint of -- we were talking about pools earlier. Jim, if you feel like that's appropriate to bring up at this point in time?

MR. BRUCE: (Nods)

THE WITNESS: We have -- within the unit area we have probably eight Seven Rivers completions in these wellbores. Almost all these wellbores were drilled to the Shattuck, and they've penetrated the Shattuck. Some of them have penetrated a little lower into the Penrose and a couple of them into the Grayburg. But for the most part, they don't get completely through the pooled interval all the way down to the San Andres.

There are eight wells, producers and injectors, within the unit area that have Seven Rivers completions in them, so they're shot in the Queen and the Seven Rivers, the Shattuck member of the Queen.

Our first thought in going into this -- and of course, we're interested in the Shattuck only, as far as a Queen flood for an efficiency, and we just feel like it makes more sense just to plug the Queen.

The Seven Rivers and the northern portion of this, up in Eastland's acreage, MYCO in Section 11, they have their wells perforated in the Seven Rivers, and those wells did quite a bit better than Eastland's wells in the Seven Rivers. So we don't feel like the Seven Rivers is very continuous. And as I say, there's only seven wells out of the 29 -- or eight wells out of the 29 that are perforated. So the Seven Rivers really isn't a continuous interval across the flood -- proposed flood area.

There are a couple of -- I think we have four middle-Queen intervals that are perforated, that we would probably need to go in and set a cast-iron bridge plug above, to isolate.

Our assumption going into this is that we will squeeze off in the injectors, squeeze off the Seven Rivers, and go back down, drill that out, test it. Typically, our injectors are going to be set through -- what we've used is just 2-3/8 J tubing, and we line that with dual lined 10, which is a PVC liner, and then we put it on a lined 81 tension packer, put it within 50 feet of the perfs, and that's how we inject. The back side would have Seven Rivers on it, and that would be squeezed. If there's any perforations below, in the middle Queen, we will set a cast-iron bridge plug with cement on top of that. And so we only want to put water in the Shattuck member of the Queen.

We're going to have several producing wells that would have Seven Rivers open on the backside. Our assumption going into this is that we would squeeze the Seven Rivers in those producing wells and just produce out of the Shattuck member of the Queen.

When you get into that, though, you start getting into a pretty big cost factor, and I don't know what's -- regulatorywise, what's possible. But if it's all possible, what we'd like to do is not squeeze the Seven Rivers. We've got eight squeeze jobs on Seven Rivers. At roughly $40,000 to $50,000 apiece, you're talking $400,000 to squeeze off the Seven Rivers in all of these wells.

We've got a -- we'll probably still have to drill out some cast-iron bridge plugs and set a couple, so we're not going to save any there, but the Seven Rivers is going to cost us about $400,000 to eliminate. I don't know whether it's feasible for an injection well.

Our thought on the producing well is, it's the same pool. When we talked about pool issues earlier, our exhibit of our multiple floods that go out to the east, I'm sure we've had situations there where the Shattuck member was not the only member in the pool that has been flooded. So I'm relatively certain that that's been handled before.

My concept of how the Shattuck would be handled regulatorywise is, our Queen flood is in the pool, it will be reported as a portion of the pool, and when we get done, if they go to another member, that will still be in the pool. So it will just be a pool reporting, because all we're doing is flooding a particular interval within the pool. And I would imagine that's been done in some of those floods to the east of us.

The question we have is, since the Seven Rivers is in the pool, is it necessary for us to squeeze the Seven Rivers to accomplish this flood?

From an injection standpoint, we still want to only put water in the Queen. And if we did an injection well without squeezing the Seven Rivers, we would just run a packer in the hole with our plastic-coated tubing and set it above the Shattuck member and inject in the Shattuck. We wouldn't be injecting into the Seven Rivers.

The only problem I see with that is, injection control does MIT or casing integrity tests, and with the Seven Rivers open on the back side, you're not going to get an integrity test.

From a producing-well standpoint, the ownership is basically common between the Seven Rivers and the Queen in these wells. So if we allow ourselves to produce Queen and Seven Rivers, you know, I see no mechanical difficulties there.

So that's a question we have. You know, the thought was, we're going to squeeze all this stuff, and we can definitely do that. But the question arises.

EXAMINER JONES: Okay, I've got several questions related to that. And David would have to chime in here. He's probably going to have --

EXAMINER BROOKS: I'm going to have a couple questions also, but go ahead.

EXAMINER JONES: Okay. First of all, feasibilitywise on your producing wells, how are they produced right now, the Queen and the -- under primary operations? Are they tubing set below the perfs in the Queen?

Let's say you've got a Seven Rivers and a Queen opened up --

THE WITNESS: Uh-huh.

EXAMINER JONES: -- in a producing well. How is that configured?

THE WITNESS: Typically, they have tubing down to the Queen and a pump.

EXAMINER JONES: And a pump.

THE WITNESS: They're all pumped.

EXAMINER JONES: So you've got --

THE WITNESS: -- rods and tubing.

EXAMINER JONES: -- 4-1/2 or 5-1/2 casing and 2-7/8 --

THE WITNESS: -- 2-3/8.

EXAMINER JONES: -- or 2-3/8 tubing.

THE WITNESS: And generally 3/4-inch rods are, you know, seven -- 3/4 and one inch, maybe. Seven-eighths and 3/4.

EXAMINER JONES: Okay. So you would keep the well pumped off?

THE WITNESS: Yes.

EXAMINER JONES: In other words, the waters that -- the high-pressure waters that are coming through in the Shattuck member of the Queen, as far as going up and into the Seven Rivers, you're not worried about that?

THE WITNESS: I wouldn't be worried about it because, like you say, we need to pump off the wells. In any flood, you know, your injection-withdrawal ratio is critical, and you want to withdraw whatever you can out of that wellbore and keep them pumped off.

In our other floods we do fluid levels routinely to determine whether we're getting everything, and we either speed the pumps up, get bigger pumps or get bigger pumping units if we don't have them pumped off.

EXAMINER JONES: Yeah. Is there any difference in the fluids that could be -- you could tell what production is coming from the Seven Rivers versus the Queen? In other words, let's say this waterflood goes ahead and you don't squeeze off the Seven Rivers after any kind of legalities happen. How would you allocate production between the Seven Rivers and the Queen?

THE WITNESS: That would be difficult. I don't know -- You know, I haven't been out there to take a sample of, you know, how many Seven Rivers-only wells we've got to sample and -- I mean, some oils are a little bit different color and stuff like that, but once you commingle them you're not going to be able to tell that.

An allocation would probably be based on remaining primary for the Seven Rivers --

EXAMINER JONES: So --

THE WITNESS: We have a separate projection, and --

EXAMINER JONES: So subtraction method?

THE WITNESS: Right, we would probably allocate a certain amount of production based on primary Seven Rivers and assign that to Seven Rivers, and anything over that would be the Shattuck-Queen.

EXAMINER JONES: Okay. What about the waste issue? Is there Seven Rivers that would be wasted by squeezing the Seven Rivers off? How much, and would it be significant or...

THE WITNESS: The reserves in the Seven Rivers -- and I need to refer to some of my notes.

EXAMINER JONES: You say it's pretty gassy, but that's not these gas wells that are here, is it?

THE WITNESS: No, no, those are deeper, Atoka-Morrow. None of the Seven Rivers are classified as gas wells at this point in time.

EXAMINER JONES: Would you damage it by squeezing it off and then harvesting it again ten years later? Would you lose --

THE WITNESS: I don't think you're going to damage it. The question always, in a later -- is going back later in a depleted zone and trying to get it back. That's realistically an issue. But technically, if you squeeze it off after the flood's done, you want to come back in and open it back up again and treat it and get it producing again, theoretically you ought to recover your additional primary reserves.

EXAMINER JONES: And you can't produce it under the Queen under a packer, that's not a good way to do that?

THE WITNESS: No, not in a pumping situation. Probably it wouldn't hurt in the long run, but early on you're going to have some gas coming through here. We do sell gas on this Eastland Queen, and we'll continue to do that. So gas-locking underneath a packer is not a situation you want to have.

EXAMINER JONES: Okay, what about the State Land Office? Did they say anything about this --

THE WITNESS: I don't think we really addressed that with them. We didn't talk about the -- This is an idea that has evolved. We basically came with the idea that we'd squeeze it off and, you know, I've had some of these thoughts along the way. And I assume, since you've got holes in your casing on your injection wells that they wouldn't let you do it, the OCD wouldn't let you do it from an injection standpoint. But -- and we're prepared to do whichever, but it would save considerable money.

The only other mechanical consideration that I think you might have on injection wells is, you've got a producing Seven Rivers zone above your packer in your injection well, drop out from that production on top of your packer, you might stick a packer. That would be your only other mechanical concern that I can see.

And most of these wells are -- almost all these wells are tied to surface on both strings. So, you know, how critical is a mechanical integrity test? Well, it depends on how the State views it, I think.

But as far as Seven Rivers reserves in these tracts, in the north half of Section 11, in MYCO's leases, there are four wells there. The Queen ultimate is 120,000 barrels of oil and Seven Rivers is 64,000. The remaining is only 29,000.

The north half of Section 11 for Eastland's properties, those other four wells in that north half, basically we have no Seven Rivers there. We've got about 109,000 barrels there.

Then in the PJA lease you have about 10,400 barrels of middle Queen and the rest, 482,000, is Shattuck-member Queen, and you've got a little Seven Rivers.

So you know, you're talking about 72,000 -- 130,000 out of 800,000 barrels as Seven Rivers, and it's already pretty depleted. So the Seven Rivers complement of reserves for this unit area is pretty minor. Compared to the benefit of getting 734,000 barrels, you're probably talking -- the remaining Seven Rivers, I think I've got another exhibit, but -- you know, if you need more number confirmation I can give it to you, but --

EXAMINER JONES: No, that's -- I just -- you know, you've got your issue of the injection wells, which would have to be squeezed off, so you're going to lose those reserves, at least until the well --

THE WITNESS: Yeah.

EXAMINER JONES: -- quits being used as an injector --

THE WITNESS: Right.

EXAMINER JONES: -- in the Seven Rivers. And then you've got the producing wells, which may or may not through some downhole commingle get produced or squeezed off, so you've got an issue there, so...

THE WITNESS: Uh-huh.

EXAMINER JONES: Anyway, I'd better turn this over to David, because I think he's got a lot of ideas on the subject.

EXAMINER BROOKS: Well, I really don't have a lot of ideas. I do have some questions and I want to understand this a little bit better.

The Seven Rivers is above the injection interval?

THE WITNESS: Yes, it is.

EXAMINER BROOKS: It's above the Queen?

THE WITNESS: Yes, significantly above it.

EXAMINER BROOKS: Now did you say that you had non-Shattuck-member Queen production in some of these wells?

THE WITNESS: Yes, we have some middle Queen, and I think there are -- let me see if I've got -- We've got two middle Queen sets of perforations, one in the BBOC Number 3 which is a MYCO well, and the BBOC Number 2. Those are perforated in the -- those two wells are perforated in the Seven Rivers, and that's probably up around 1700, 1800 feet. The Shattuck member is probably on the order of 2300 to 2400 feet, and the middle Queen is probably another hundred feet below that.

And those two wells are the only ones -- well -- yes, I think so. The HL 1 Number 2 is perforated in one of the lower Queen members too. So we've got two or three wells that have some middle Queen perforations, in addition to the Shattuck member, and then we have eight wells that are perforated in the Seven Rivers in addition to the Shattuck.

EXAMINER BROOKS: And you haven't been accounting for these separately. You adjusted the numbers, as you explained for your allocation count?

THE WITNESS: Yes, they're all reported, and it's one pool, and it's --

EXAMINER BROOKS: Right.

THE WITNESS: -- they're -- where they are commingling, there are some Seven Rivers-only production here, not very much. But most of them are commingled between the Shattuck-Queen and the Seven Rivers.

EXAMINER BROOKS: You explained why you thought you could properly segregate out the Seven Rivers production.

THE WITNESS: Uh-huh.

EXAMINER BROOKS: What about the lower production? Do you have a handle on how much that is?

THE WITNESS: It's about 10,000 barrels out of the whole thing.

EXAMINER BROOKS: So it's a pretty small --

THE WITNESS: And that well -- the middle Queen that we separated out was basically a middle Queen by itself. It's still got Shattuck, but it's not perforated. So that was how I was able to segregate the --

EXAMINER BROOKS: Okay, so -- Your discussion was about the Seven Rivers, so --

THE WITNESS: Uh-huh.

EXAMINER BROOKS: -- do you have wells that produce from both the middle Queen and the Shattuck?

THE WITNESS: Let me look. The BBOC wells and -- let me look at that.

EXAMINER JONES: I assume that as part of the notice for these cases that the Seven Rivers owners were not specifically told, but they were -- they probably could guess that their production may be either squeezed off or isolated for years because of this waterflood.

THE WITNESS: That will only happen within the unit area, and the unit owners have been notified of that, yes.

EXAMINER JONES: They -- Specifically, they've been notified that this -- because you heard --

THE WITNESS: We've had --

EXAMINER JONES: -- me questioning how we would handle --

THE WITNESS: We've had working interest owner meetings, we've had that discussion with them.

EXAMINER JONES: Okay.

THE WITNESS: Yeah, that has been -- definitely with all the working interest owners, that's been discussed and it's out in the open that we're going to squeeze off the Seven Rivers.

The BBOC State Number 3 has Shattuck-member-Queen perfs and some middle-Queen perfs. The Number 2 BBOC has Seven Rivers perfs, Shattuck-member perfs and some middle-Queen perfs.

EXAMINER BROOKS: And did I understand you correctly to say that in those that have lower perforations that you're going to set a cast-iron bridge plug and --

THE WITNESS: That's --

EXAMINER BROOKS: -- seal off those lower --

THE WITNESS: That's correct.

EXAMINER BROOKS: So the only issue then is the Seven Rivers?

THE WITNESS: Yes, that's right.

EXAMINER BROOKS: Now the Seven Rivers, of course, is not in the unitized interval, right?

THE WITNESS: Not -- no --

EXAMINER BROOKS: So --

THE WITNESS: -- not by our definition, no.

EXAMINER BROOKS: So --

THE WITNESS: The ownership is common, but the -- it would not be in the unitized interval.

EXAMINER BROOKS: Well, the tract ownership is common --

THE WITNESS: Yes.

EXAMINER BROOKS: -- but the ownership of production is not going to be common, because the ownership of production in the unitized interval is going to be allocated according to the unit agreement?

MR. BRUCE: Yeah, and then the Yates -- or the Seven Rivers, it would on a leasehold basis.

EXAMINER BROOKS: Right.

THE WITNESS: Yeah, that's true.

EXAMINER BROOKS: Now is this -- You went through the construction of the well, but I didn't follow all of it. Is this -- if you left the Seven Rivers perforations open, would that oil be downhole commingled?

THE WITNESS: In the producing wells it would be.

EXAMINER BROOKS: Yeah, it would be -- it would not come to the surface through a separate channel?

THE WITNESS: No, that's correct.

EXAMINER BROOKS: Okay. And that would be a downhole commingling without --

THE WITNESS: -- diverse --

EXAMINER BROOKS: -- it would not -- yeah, with diverse ownership, that's what I'm --

THE WITNESS: Yeah.

EXAMINER BROOKS: Okay.

EXAMINER JONES: Which we do administratively, but if we're talking about doing it over the whole unit, maybe we should have another little uniform notice and then a little hearing that provides notice of that --

EXAMINER BROOKS: It would seem that --

EXAMINER JONES: -- intention.

EXAMINER BROOKS: Yeah, it would seem that would provide -- it would require separate notice. I don't know that it would require separate hearing, but it would seem to require a separate --

EXAMINER JONES: Okay.

EXAMINER BROOKS: -- notice --

EXAMINER JONES: Okay.

EXAMINER BROOKS: -- if they were going to go that way.

I guess that's -- Oh, yeah, I had one other area I wanted to touch on.

This stuff down in the south half of Section 11 --

THE WITNESS: Yes.

EXAMINER BROOKS: -- you explained that -- as I understood it, at least one of your reasons for not including that in the unit is that you would have to drill additional injection wells?

THE WITNESS: Yes.

EXAMINER BROOKS: Now the people who own in the south half of Section 11, they're all within one half mile so they've all been notified, right?

THE WITNESS: They are MYCO and Devon.

EXAMINER BROOKS: Okay. Well, that probably alleviates my concern, because they probably would have continued their opposition if this had been a concern.

But my question basically is, is there any obstacle to -- does the fact that we're putting the north half of 11 in one unit and the south half of 11 is excluded from that unit, does that -- is that going to provide any obstacle to a subsequent waterflood in that portion down in the south half of Section 11?

THE WITNESS: It should not.

EXAMINER BROOKS: Okay, well --

MR. BRUCE: I think if you'd look at the geology, I think, you know, the reservoir in the south half of 11 continues over into Section 10, and --

EXAMINER BROOKS: Yeah, that's the way their isopach is drawn.

MR. BRUCE: Uh-huh.

EXAMINER BROOKS: So -- Well, I don't know that OCD should be concerned about that if MYCO and Devon are not, so...

THE WITNESS: We've had discussions with MYCO and agreements concerning frac pressures and -- that we won't exceed frac pressure. Of course, we can't exceed frac pressure anyway. And we have our own money in this unit, and our contention is that we don't want to frac these wells.

When these wells are completed they have to be frac'd to get the Queen to move. It's kind of an anachronism, and I don't know why it's that case, because you've got -- typically this stuff is 25, 30 feet thick in the gross pay, and by the time you get down to what you're really flooding it's probably four or five feet, and that four or five feet might be 50, 100, 150 millidarcy.

And when we produce this primarily it comes out of those high-perm streaks, and when we flood it we flood that high-perm streak and we don't flood the tighter stuff. It's just never going to get there, unless you can do some kind of, you know, diversion within the reservoir to get that tighter stuff flooded.

So that's why your secondary and primary are almost identical, because you're sweeping out that four- or five-foot-high perm streak. And that's why we see that 15-percent cutoff being -- or comparative to our performance. And so, you know, it just flushes out very quick. And what we're concerned about in that south portion there is, it seems to be a segregated reservoir, and I think they can go in there and flood that anytime that they want.

When we complete these things they have to be frac'd, even though you're talking about these high-perm streaks. You'd think with that kind of high permeability they'd come in naturally, but they don't.

And with the fracs that we put on them, all these wells are completed with about 20,000 gallons, about 15,000 to 20,000 gallons and about 30,000 pounds of sand. They're very small fracs, they don't go very far, but they get the well started and create an effective larger wellbore radius.

There's no concern on my part, and we haven't seen any damage from initial completion fracs that affect the floodability where we've got a well that fracs over to an injection well, even on fairly close spacing.

Most of this is high frac gradient. Queens frac, generally, almost at a 1-p.s.i.-per-foot, which is almost overburden. That's our experience. And I think when you frac these things you actually horizontally frac a lot of them.

And we've discovered that, and we will not go over frac pressure because if you go over frac pressure and do a horizontal frac, you're going to create an avenue straight -- especially in injection. Injection, when you continue to put volumes of fluid in there, if you start frac'ing with injection fluid you just keep frac'ing, and you can go straight to another well. And we have no vested interest in going over frac pressure from an economic standpoint, so...

We've talked to MYCO about these issues, and their concern is us frac'ing into their wells in the south and watering them out. And you know, other than OCD Regulations and our assurance that we won't do it, we've got some agreements on our -- that we have and -- that we're working on right now, concerning frac pressures.

EXAMINER BROOKS: Okay, that's all my questions.

EXAMINER JONES: Before we leave the issue of the downhole commingle either being in this order or as a separate individual well case, you know, no matter which way we did it I think we would need a projected decline for each Seven Rivers well. How would you -- How would you know that, if you're already producing -- already downhole commingled? They're in the same pool now, so there's no downhole commingle permit required, but --

THE WITNESS: What we do -- what I did when I segregated these out -- and I don't have an exhibit that I can give you. I have my projections and how I split this out on curves, and -- but basically with these GOR differences -- and going month by month when these wells were drilled and when they came on, all these leases that are involved in the unit had Queen-only initial period, at least a year, almost.

So we see how they came in and where they started. And we have tracts in this area that are pure Queen, and we know what that performance is and what the GOR looks like for the entire history of the well.

So we took that initial one-year, Queen-only -- later it's commingled with Seven Rivers -- that Queen-only performance, and put a hyperbolic that's similar to the -- you know, we modeled that same decline --

EXAMINER JONES: Right.

THE WITNESS: -- and that's our Seven -- that's our first pass at Queen versus Seven Rivers.

And when you look at that, you can see when the Seven Rivers wells come on the GOR just -- for the lease, goes bananas.

EXAMINER JONES: Yeah.

THE WITNESS: And so you can see where that's happening.

And some Seven Rivers wells aren't very good, they come in strong, the GOR goes away, and you get back to a Queen decline.

EXAMINER JONES: Yeah.

THE WITNESS: But it's pretty -- I think it's pretty succinct. It's as good as -- You're never going to be able to segregate it out.

And there are -- you know, other than well tests and how accurate the well tests are -- individual well performance is even an issue, to try and -- really, I did this segregation based on the lease curve, because I know on a lease basis -- that oil was measured on a lease.

EXAMINER JONES: So it sounds like you would use some decline curve methods, but --

THE WITNESS: Yes.

EXAMINER JONES: -- you can almost use some volumetrics also to -- Sometimes we like the downhole commingle permit allocations to be based on reserves that the operator estimates are being downhole commingled.

THE WITNESS: Uh-huh.

EXAMINER JONES: Of course the time -- value and money, it means you -- it's nice to have those -- with the subtraction method you can change that as you go. But -- So are you saying you can use the subtraction method?

THE WITNESS: I would think you -- I would feel comfortable using it as a reasonable allocation. Nothing is going to be 100-percent accurate. But as far as the most accurate, I would think that would be -- We've got a pretty good handle, I think, on Seven Rivers contribution in this area. We've studied it pretty hard, and there's not much doubt in my mind how much is -- Seven Rivers can contrib- -- You know, if somebody was contesting us they might have a different opinion and, you know, there might be other issues involved, but I -- I think -- engineeringwise, I think it's a pretty good split.

EXAMINER JONES: Okay. On the downhole commingle app., if it's diverse interests it requires notice to every person that gets a check --

MR. BRUCE: Correct.

EXAMINER JONES: -- so that would -- the State Land Office, all within the -- I guess the lease that's going to get Seven Rivers --

MR. BRUCE: And I don't think -- for the State it probably wouldn't matter, because this is all state land with a uniform 1/8 royalty, so it would be more the working interest owners and the overriding royalty owners.

EXAMINER JONES: Okay.

THE WITNESS: And the other -- the other overall consideration on this -- and there are two points that I'd like to make, is that we do have some timelines here and -- on contracts that we're trying to work. If, you know, this commingling issue becomes burdensome and, you know, we need to move forward too, so if that slows the process down -- if it could be addressed separately and continue with unitization, that would be advantageous for us, almost essential, really. We might have to forget the commingling and go ahead and squeeze them off.

The other issue is, how many of these are producers and how many of them are injectors? Out of the eight Seven Rivers squeeze jobs we're talking about, five of them are injectors. So if we have to squeeze the injectors we'll probably go ahead and squeeze the producers.

EXAMINER JONES: Well, but I think you do -- will have to squeeze the injectors.

THE WITNESS: Okay, if that's -- if that's the point, we're not going to save enough money, probably, to try and commingle the Seven Rivers --

EXAMINER JONES: In the producers?

THE WITNESS: Uh-huh.

EXAMINER JONES: So you --

THE WITNESS: We only have three producers.

EXAMINER JONES: Oh, I thought you said there were seven.

THE WITNESS: There are eight that are perforated --

EXAMINER JONES: Oh.

THE WITNESS: -- in the Seven Rivers, but five of those are injection wells --

EXAMINER JONES: Oh.

THE WITNESS: -- three of them are producers. So you know, we're starting to lose the -- I'm going to have to squeeze five of them anyway, so five times 50, that's $250,000. So if we're going to do that in the injectors -- the only way we can save a significant amount of money is not squeeze them in any well.

EXAMINER JONES: Yeah. We routinely require MITs --

THE WITNESS: Uh-huh.

EXAMINER JONES: -- which means backside, internal and external MITs of injection wells, so -- and that wouldn't -- they wouldn't -- but of course there's always exceptions.

THE WITNESS: That's the question. You know --

EXAMINER JONES: Yeah, maybe David and I can talk about that.

EXAMINER BROOKS: Yeah, I think so. I'm not sure that's authorized, but you probably know those regulations better than I do.

EXAMINER JONES: Well, we've got the EPA requiring that and -- okay, so --

THE WITNESS: I think the situation -- you know, the reason -- the only reason we're asking is that these wells are tied up with two strings of casing all the way to surface in cement, so --

EXAMINER JONES: That's a good situation.

THE WITNESS: It's kind of an unusual situation for a flood. Usually you have stuff that's not, you know, tied up quite as tight and --

EXAMINER JONES: Yeah.

THE WITNESS: -- it's pretty good mechanical -- We'd just like you to consider it, you know. And I think my take -- and I don't speak for everybody, but I feel like if we can't squeeze the injectors we'd probably just go ahead and squeeze everything. I mean, if we can't --

EXAMINER JONES: Okay. Well, you guys can always talk about it, and you can always cement -- downhole commingle on each individual producing well --

THE WITNESS: Okay.

EXAMINER JONES: -- and you would -- at that time you would have to project your Seven Rivers --

THE WITNESS: Uh-huh.

EXAMINER JONES: -- decline and send it out as an exhibit with the notice, and all it takes is 20-day notice --

THE WITNESS: Okay.

EXAMINER JONES: -- to all the owners in the two zones, the owners in the unit, the owners in the Seven Rivers.

THE WITNESS: Okay.

EXAMINER JONES: But you've got to satisfy yourself as a reservoir --

THE WITNESS: Right --

EXAMINER JONES: -- that --

THE WITNESS: -- I understand.

EXAMINER JONES: -- you're not worried about any of the Seven Rivers bothering your --

THE WITNESS: The Queen.

EXAMINER JONES: -- the Queen flood.

Now there's another -- As long as you guys keep the wells pumped off, because otherwise we have to really do an AOR look up a little higher there in that are, you know, so...

Okay, I'd better ask some quick questions here and --

MR. BRUCE: Mr. Examiner, we do have a few more areas to --

EXAMINER JONES: Okay, go ahead.

MR. BRUCE: Two main areas.

Q. (By Mr. Bruce) Mr. Rose, how many wells are in the area of review?

A. In the one-half-mile area of review around the injectors we have 46 wells within a half mile of the area of review.

Q. Okay.

A. Seventeen of those are P-and-A'd, and 29 of them are producing wells. And from the -- I've got to get some more information.

Of the 29 producing wells, four of those wells did not penetrate the Shattuck member of the Queen. They only go down to the Seven Rivers or shallower. Sixteen have casing and cement across the Shattuck member of the Queen but are not perforated, and there are nine wells in which casing and cement are set through the Shattuck member of the Queen, and they are open in addition to other zones. We've got three wells by Jim Pierce. One of those is a -- in addition to the Shattuck member of the Queen being open it has a -- one of them is perforated in the Queen-

Grayburg-San Andres. The other one is in the middle Queen only, and the other one is on a lower Seven Rivers Sand.

MYCO has three wells in the south half of Section 11 that have Seven Rivers open. And then Parrish in Section 12 has two wells. One is just perforated in the Shattuck member of the Queen, so that's not really a concern at all.

And then we have -- Snow operating has a well up in Section 36, Unit M, and they're open in the Seven Rivers, Queen, Grayburg and San Andres.

Our feeling on most of these wells -- producing wells that offset us, if they're perforated in the Queen, most of them are on the limits of the edge of our field, and we feel like most of them are tight. They're probably not going to see anything from the flood. If they do see something from the flood out of the Shattuck member, they're probably going to get oil first and it's probably going to benefit them.

Almost all these wells in this area are in an advanced stage of depletion. I did -- You asked the question if I had talked to Dan Snow, Snow Operating, and I had because he expressed some concerns about watering his well out. And I -- he has four wells, and on the north boundary of Section 1 only one of those is perforated in the Shattuck member of the Queen, the one I just referred to. His comment was, he was concerned about us frac'ing into his wellbore and watering it out. He also told me that these wells were, you know, barely making it now, and if we had to dispose of anymore water at two dollars a barrel, probably -- to truck it off, that he would probably have to walk away from it.

I told him that I felt like his zone was too tight to probably be a concern and that if there is some communication with their injectors, he's probably going to see oil production. That's our experience in offset Shattuck members, Queen, that -- maybe not be very good, but if you see any response you're going to see oil first.

And we have some -- a flood -- one of these floods -- oh, I guess that was an East Shugart flood. In fact, Yates declined to go into that unit, and they were intermixed with that, and they recovered an additional 120,000 barrels that they wouldn't have recovered, and they didn't participate in the unit.

So we've had responses from other -- Morexco has stated that they're glad we're putting a unit in, because if anything happens to them it's probably going to be good. So I really don't feel like these offset wells are that big of a concern.

Snow did express concern. He asked if we would take his water if we got water. I said I'd take your water, but I'll also take your oil, so -- You know, he's trying to sell those wells, and they're very marginal right now, is my discussion with him.

Q. Of the wells in the area of review, are there any questionable wells, wells that could potentially have problems?

A. As far as P-and-A wells?

Q. Correct.

A. We have 17 P-and-A wells in the area of review. Of those 17, five did not even penetrate the Shattuck member of the Queen. We have three out of the 17 that are questionable in our mind about plugging and/or communication. In the C-108 we have all 17 wells, whether they penetrated or not, with wellbore sketches showing how they're tied back and where they're perforated, so...

But there's only three that we feel like are maybe questionable.

Q. Will you identify those specifically by name and location for the Examiner?

A. Yeah, if we -- if you go into the C-108 --

MR. BRUCE: About midway through, Mr. Examiner, there's --

THE WITNESS: Yeah, it takes a little while to find --

MR. BRUCE: -- roughly midway through, there's a list of the 17 P-and-A'd wells.

EXAMINER JONES: Okay. I saw the list earlier of the three that were kind of a concern on the supplemental application.

THE WITNESS: Yes. Actually, those are not.

EXAMINER JONES: Those are not.

THE WITNESS: One of them didn't --

EXAMINER JONES: One of them didn't even complete --

THE WITNESS: Yes.

EXAMINER JONES: -- go through the --

THE WITNESS: And the other one has an order. It was properly plugged by the OCD. The OCD issued an order saying that it was properly plugged, so...

We had some problems with some records on a few wells --

EXAMINER JONES: Okay.

THE WITNESS: -- and I think that particular well was plugged by Ledbetter, and there was a question about whether it had been plugged. They made Pierce go -- or OCD made Pierce go back in and drill out plugs, and they got partway down and were running into plugs about where they were supposed to be --

EXAMINER JONES: Yeah.

THE WITNESS: -- and so they replugged it back out and issued an order saying that it had been plugged properly.

The two that we're referring -- the other ones that we're referring to, I'll go ahead and identify those. They are in Section -- the first one is -- was drilled by Roach and Shepherd. It's the Elliott Number 1, and it's in 18 South, 30 East, which is northeast of Section 1. It's -- I don't know what exhibit you're looking at, but it's 330 from the south line and 330 from the west line of Section 31 in 18-30. It would be a direct northeast offset to the 7A, which is the most northeastern corner of our flood.

That well, we had no records in the State, no records in Santa Fe, no records in Artesia. We were able -- Elliott Oil Company had the leasehold on that well, and they were able to go down in their archives and find some plugging records, so we did come up with some plugging records.

The well was drilled and abandoned in 1950, and there is a description and a sundry notice, and that was October 30th of 1950 showing how it was plugged. And then there was a Department of the Interior saying that your subsequent report of abandonment was accepted. Those are the only records we have.

But what we have mechanically in that wellbore is, the TD was 4280, which is well through our Shattuck member of the Queen. There's a 10-sack plug at the base of the salt at 1168. It's an open hole, and it's probably a 7-7/8-inch hole. We're not positive for sure. We think the surface hole was a 10-inch hole. There was 8-5/8-inch casing set at 355 feet and cemented with 50 sacks of cement, which is pretty minimal.

They later pulled 160 feet of casing. I would assume, based on that, that probably the cement came up to about 160 feet, if they -- They probably tried to pull everything they could out of that well. So you've probably got 8-5/8 cemented from 355 back up to 160.

The put a 10-sack plug at the base of that surface casing, and then they put a surface plug -- they mudded it to surface and spotted a cement plug and a marker, and it doesn't say how much cement was used.

So you've got pretty minimal plugs there. I guess my contention on this well is, it was drilled and abandoned. The well is outside of our area. We don't -- that 7A is kind of a tight well in our mind, and this was drilled and abandoned. We feel like that well is probably a tight well, and there's probably some concern about that. That's questionable in our mind. We're afraid not to plug it, because it's going to cost money to plug it. And being tight and drilled and abandoned, we're probably not going to affect the problem. I don't see any way to monitor these wells, other than watching them. They've got a dryhole marker and a cement plug at the surface, so there's no way to monitor them.

EXAMINER JONES: Is there any withdrawal from the Seven Rivers and the Queen in this area around that well?

THE WITNESS: No, all you've got is plugged wells. You've got a well to the northwest, which was a MYCO well, that was plugged. You've got a well to the northeast which is plugged. The only withdrawal you've got is from the Eastland P.J. State 7A to the southwest of it. And that 7A -- 7A is only perforated in the Queen, Shattuck member of the Queen.

The --

Q. (By Mr. Bruce) What's the next --

A. The other well that is somewhat questionable is in Section 6, which is east of Section 1. It's the Leonard Oil Company Keohane Number 2. It's in Unit 6K, 1650 from the south and 1650 from the west. That particular well -- We do have plugging records on it. Again, this well was drilled and abandoned. It's southeast of our strike, downdip. It's obviously a tight well because they drilled it and abandoned it.

They do have a little more plugging in here. They've got a 20-sack plug at 2250 to 2350. The Shattuck member is down at about 2458 in this, and we're going downdip so...

EXAMINER JONES: No casing?

THE WITNESS: No casing, it's an open hole, an 8-inch hole. There's a 30-sack open-hole plug at the base of the salt at 1250 to 1350.

EXAMINER JONES: The first plug was below the Seven Rivers?

THE WITNESS: Below the Seven Rivers, yes, below the Yates and the Seven Rivers and above the Shattuck member of the Queen.

So we've got a 20-sack plug above the Queen. We've got a 30-sack open-hole plug at the base of the salt, we've got a 10-sack plug at the base of the 8-5/8. And the 8-5/8 was set at 284 feet and cemented with 50 sacks. I estimate with a 50 percent excess that it might have come up to about 50 feet. That's never been pulled, the 8-5/8. They have a five-sack surface plug with a marker in it.

I think that well is probably -- We couldn't find any other information on that well. That one -- in today's -- today's plugging regulations, those are weak plugs.

The downhole plugs are not too bad. You've got a 30-sack plug at the base of the salt, and you've got a fair number of plugs in between the Queen interval and your surface casing, so... It's not plugged according to what we would do these days, but I feel pretty good about that one.

The only other well that we're concerned about is in Section 2, and that's the Leonard Oil Company State B 7717 Number 1. It's in Unit I, which is 1980 from the south and 660 from the east. You'll see that gas well on the east side. It's the dryhole just immediately above the gas well.

EXAMINER JONES: Deep gas?

THE WITNESS: Yes, that's a deep gas well, and it's -- all the deep wells in this area have got casing. They have surface casing circulated to surface, and then they have an intermediate string at about 3300 feet through all this stuff, and that's cemented to surface.

So all the Atoka-Morrow wells are all cemented well within -- you know, they've -- are circulated to surface, 8-5/8 down at 3300 feet. So we don't have any issues with any of the deeper wells.

This particular well was plugged -- Let me find that. And again, this information is in the C-108, but it's hard to -- I was going to number these so we could find them easier, but we didn't get that far.

This well was drilled in 1948 by Leonard Oil Company, and it was drilled to a total depth of 4112 feet. 8-5/8-inch casing, 24-pound was set at 303 feet and cemented with 50 sacks in a 10-inch hole. With calculations in excess, I'm figuring the top of cement is probably 50 feet. I don't have any idea of whether they filled that up from the top or not.

There was an open-hole completion at 3987, and that was in February of '48. They tried to complete it in May of '52, and in May of '53 Leonard Oil Company plugged the well. They put a 30-sack plug in the bottom of the hole, mudded it to surface and put an P-and-A marker at the top.

That well was found by an Eastman employee to be leaking one day, and the State investigated the well, tried to find Leonard Oil Company, could not find Leonard, and the State plugged this well.

The only concern and what I need to bring to your attention is, the top of cement -- there was 5-1/2 -- 7-inch and 5-1/2 casing run down to 3987. They only cemented it with 130 sacks, and with a 50-percent excess in the hole size and casing, I figured the top of cement behind that casing is about 3400 feet.

So you've got 7-inch and 5-1/2-inch casing, a combination string, with backside open all the way to surface through our intervals.

The State contracted this to be plugged, they perf'd at 2750 and tried to squeeze and weren't able to squeeze. They couldn't pump into it, so they set a 30-sack plug inside the casing at that point in time.

And then according to the records -- and I can't find anything to the contrary -- they proceeded to set plugs inside the casing at -- they set a 25-sack plug at 2250, no perforations; a 25-sack plug at 1650, no perforations; a 25-sack plug at 1000 feet, the base of the salt, and no perforations. And then when they got to the bottom of the 8-5/8 they perforated at 425 feet and squeezed 100 sacks. So they got a real big, good squeeze plug at the base of the 8-5/8. And then they had a 10-sack surface plug, so --

EXAMINER JONES: What year was that?

THE WITNESS: That was in '96.

EXAMINER JONES: Why do you think they couldn't get it squeezed on that?

THE WITNESS: You know, they may have had fill down to 2750. I'm surprised they didn't -- and it may -- you know, maybe they did try and perforate them and they couldn't squeeze them. But as far as I can tell from the wellbore sketch, the casing -- Obviously there's a restriction at 2750 that they couldn't pump into, so there's something sealing off something at 2750. But 2750 up to the surface, the base of the surface casing plug, there was no perf and squeeze that I can tell, outside. So you've got that backside open from, you know --

EXAMINER JONES: A hundred percent --

THE WITNESS: -- 425 feet --

EXAMINER JONES: I'm sorry, if you did a hundred percent cement, how high would the cement top go? Or 80 percent, on your calculation?

THE WITNESS: You mean 80-percent excess?

EXAMINER JONES: Yeah. Well, no, no, not excess, 20-percent --

THE WITNESS: No excess.

EXAMINER JONES: Yeah -- Yeah, no excess.

THE WITNESS: No excess, just -- and if it was a gauge hole?

EXAMINER JONES: Yeah.

THE WITNESS: Well, yeah, to see if it will come up to 2750. I don't know whether I have -- I don't have my --

EXAMINER JONES: That's all right --

THE WITNESS: -- book with me right now.

EXAMINER JONES: -- I can do that.

THE WITNESS: Well, 50-percent excess, let me -- I can probably do that, just a second.

That's about 552 feet, and that's one-point -- you'd probably divide that by 1.5. Multiply it times 1.5. It would be 828 feet, subtract -- 3160 maybe, somewhere around there.

EXAMINER JONES: And your injection zone is --

THE WITNESS: Injection in this well is at -- probably be at 22- -- 2240.

EXAMINER JONES: Okay. So basically --

THE WITNESS: And there's a plug at 2250 inside the casing.

EXAMINER JONES: Yeah.

THE WITNESS: Unless there's, you know, additional evidence, you know, that I -- but looking on the website and looking at the plugging procedures and C-103s that were filed, I don't see that they were perf'd. I think Mayo-Marrs was contracted, but the State, you know, deemed it plugged. But that was my only -- that was the only other one I had a concern on.

Q. (By Mr. Bruce) All the other wells are properly completed? I should say, all the other P-and-A'd wells are properly plugged and abandoned, according to your records?

A. Yes, and I looked at them from a surface casing standpoint, whether they were circulated on surface or not, and also the downhole plugs. And yes, the rest of them seem to be well plugged.

Q. And they will prevent the movement of fluids to other zones?

A. Yes.

Q. A couple more areas to cover. Let's talk about your proposed injection operations. What rates and injection pressures are you looking at?

A. We would like to probably have about 1250 pounds. Generally, you're talking about 2400 feet. In our other Queen flood north of Loco Hills that's at 1750. We've done step-rate tests on almost all our wells, and they -- the lowest frac gradient is about a .75. The highest frac gradient is 1.05. So they vary well to well.

And we typically do step-rate tests and monitor those wells with Hall plots to see if we're frac'ing them as we continue to inject.

We've got an authority to go to 1100 pounds on that flood. Almost all these flood out here have -- if you stay with .2 p.s.i. per foot, which is the standard, we're not going to get any water in the ground. We're going to have to have probably at least 1250 pounds. And that -- 1250 pounds at the surface would translate to about a .96 gradient, as far as frac gradient, with the hydraul- -- I mean, you've got --

EXAMINER JONES: Oh, are you talking about bottomhole pressure?

THE WITNESS: Yeah, yeah.

EXAMINER JONES: But surface --

THE WITNESS: Surface pressure would be 1250 --

EXAMINER JONES: -- .5 or so?

THE WITNESS: Right. But a surface pressure of 1250 would give you a bottomhole frac pressure on the order of 2300 pounds or so, which is pretty close to 1 p.s.i. per foot, which is our experience in this area.

What we've found is that when we did our West High Lonesome flood with this peripheral flood, we were expecting a peak response a lot earlier, like a year. And injecting around the edges of these sweet spots, our wells tend to be tighter. And so that's one of the reasons we have so many injectors around the sweet spots, because if we can't get enough water in one well, we'll convert another well, and...

But we had to take our time in West High Lonesome and back off and say, you know, we can't frac it, we can't put it in faster, we just need to be patient. And it took two and a half years to get to our peak rate.

And that's kind of what we're seeing here, and we felt like, you know, economically and mechanically that's the only option we've really got, so...

EXAMINER JONES: Okay.

Q. (By Mr. Bruce) What are the -- What will be the injection rates in your injectors?

A. We target about 200 barrels a day. We've got only one well in our West High Lonesome flood that will make -- put in more than 200 barrels a day. They probably average close to 100 barrels of water a day. And on my calculation sheet on the fill-up time, that's really what we've estimated. So 100 is probably realistic. We'd like to get 150 a well, if I could, and we'll just have to see how it goes when we get into it.

Q. Now there is fresh water in this area, but are there any freshwater wells within a mile of the injectors?

A. There are no freshwater wells within a mile of our injectors, our proposed injectors, and so we don't have any water samples of any nearby wells.

Q. And is a freshwater sample included in the C-108?

A. No, it's not, because we don't have any freshwater wells within a mile. We do have freshwater sample from our proposed water source.

Q. Let's move on to your final exhibit, Exhibit 27. What will be your source of injection water?

A. What we're planning to use for makeup water, we're going to -- initially there's very little water production out here, so we're not going to have enough to flood with. We're going to have to have a significant amount of makeup water initially. As we go along probably over the life of the flood, it will probably be about a 50-50 makeup water versus produced water.

We've done a search over a four-township area, and what we're -- this exhibit is kind of a summary of what we found within a four-township area. We've looked at disposal wells, and the numbers under the black circles are disposal wells, and that is how many barrels of water per day they are disposing of. We need approximately 2100 barrels a day, realistically, to effectively complete this flood.

You can see there's only two disposal wells to the west of us. They do 67 and 60 barrels, which is woefully insufficient. And then we've got one about eight miles northeast that does 14. So disposal wells are really not an option around us.

There are several injection wells that put a fair amount of water. There's seven injection wells within the four-township area, and together they probably do about 4300 barrels a month. And we need probably about 63,000 a month, so...

And we've contacted all those people to see if they would give us water. They're all using them for pressure maintenance and won't release any of it for our use.

We also -- there are seven floods around us. We called all the operators of those floods to see if they had any water that we could use, and they said they were all using everything they could and wouldn't -- wouldn't be able to give us any.

Also, those seven floods around us have all used fresh water for makeup, generally Carlsbad, some of them have used water wells within the area.

Our proposal, we've located two wells in Section 3, and they're in the Turkey Track unit, the two squares, the black squares, and those wells are in the Capitan Basin. And one well is capable -- has been tested at 75 gallons a minute, which is about 2100 -- or actually about 2500 barrels a day.

We do have a water analysis on that well, and that water analysis is included in the C-108, as well as a compatibility test with the PJ State A lease, Queen-Shattuck water. It's compatible, very little issue.

The only treatment that's going to be required for that water would be some oxygen scavenger initially. Later on in the well, the life of the flood, as we mix them we'll probably have to do some scale prevention and some corrosion on the -- in producing wells. But generally that's the only thing we've experienced.

Our West High Lonesome flood to the north used Double Eagle fresh water, and that's what we've experienced up there.

These two wells are dedicated. One well was drilled in 1956, the one that can deliver 75 gallons a minute. I don't know for sure that it was used for the Turkey Track unit, because there were two wells of a similar depth that were used north -- and that unit injected about 1.5 million barrels, probably. Actually 3 million, but I'm figuring 1.5 was makeup water.

So during the '60s that water -- water is at about 230 out there for all these wells, so I'm sure they were drawn from the same sand. So they've used probably 2 1/4 million barrels since the early '60s out of these wells. This well is still capable of delivering 75 gallons a minute, so I think we've got sufficient quantity.

We have approval from the State Land Office to use those two wells. Those two wells were tested in 1985 for a year, and they delivered 98 acre-feet of water in a year, which is 750,000 barrels in a year, which is well within our usage. And that 98 acre-feet is dedicated to the use of oilfield development. So we've gotten that approval.

And that's one of our contract issues with those two wells. We're trying to sign a contract before the end of the year on those two wells.

Q. And the State Land Office does ordinarily scrutinize use of fresh water for injection purposes?

A. Yes.

Q. And so you have submitted this to the State Land

Office, and they have no objection?

A. Yes, they've given us preliminary approval, and we've given them all the information on these wells.

Q. In your opinion, is the granting of these Applications in the interest of conservation and the prevention of waste?

A. Yes.

Q. And were Exhibits 18 through 27 prepared by you or under your supervision?

A. Yes, they were.

MR. BRUCE: Mr. Examiner, I'd move the admission of Exhibits 18 through 27.

EXAMINER JONES: Exhibits 18 through 27 will be admitted.

EXAMINATION

BY EXAMINER JONES:

Q. I'll try to make this mercifully short here, so... The -- But I've got to ask you, on this Phase II where you're going to convert some more wells --

A. Yes.

Q. -- do you guys want to wait and submit that as a waterflood expansion in the future? In other words --

MR. BRUCE: Well, it's not really an expansion, Mr. Examiner, because all the lands will be in the unit. It's just a conversion of some producers to injection.

Q. (By Examiner Jones) Okay. But you want to submit the C-108s in the future for those, or do you --

A. We --

Q. -- you've already done it now?

A. In our West High Lonesome unit we did the same thing, because we -- as soon as -- if you see that pattern on the edge of the sweet spots, we alternate injectors and producers, and as soon as that next one waters out we want to convert it to injection to keep water going to the middle.

And we applied for all those wells with West High Lonesome, and -- in the original C-108, and the OCD has allowed us to convert those wells without additional approval, other than C-103, notification subsequent. And we've still got one well that we haven't converted there, we're probably not going to, but --

Q. But your owners in your tracts know this is going to happen as the wells water out or as you --

A. Yes.

Q. -- deem it necessary?

A. We've had working interest owners' meetings and discussed the patterns and the injection wells and --

Q. So -- done it once here.

A. We would prefer to.

Q. Yeah, okay. Okay, the -- So basically on these

Queen floods, we've had a lot of people come back and ask for additional pressure increases --

A. Yeah.

Q. -- on their injection. And you know, it just seems like it's awfully tight. And so you want to start out at the 12- --

A. 1250.

Q. -- 1250. And the reasoning for that is, it would be less than the frac -- the analogy frac gradient that you've seen on other --

A. Yes.

Q. -- floods? You don't have any injection tests so far, though?

A. No. Our operational plan, of course -- our whole concept in this flood is to see if we can get it approved and move forward. And once we get that approval, then we're going to start, you know, signing contracts and doing stuff.

First thing that we'll probably do is run step rate tests on the injection wells. We want to know ourselves where these wells frac. We have a list of surface frac pressures on our other flood, and myself and the pumper talk routinely and he sends me daily reports in. And if we're -- if he's going over that pressure we tell him, you know, you need to back off of that thing, and we watched those with Hall plots.

So our plan is to do step rate tests. And, you know, if it requires administrative approval we can do step rate tests and file those and -- We had a range of frac pressures, and some of them are over 1 p.s.i. per foot, which --

Q. But you're talking bottomhole frac pressures?

A. Yes, bottomhole frac pressures.

Q. Gradient, okay.

A. And the 1250, again, corresponds to about a .96 bottomhole frac gradient. But we want to know that also. So we can -- you know, we'd like to have the privilege to go to 1250. We're not planning on going over frac pressure either, but I understand your concerns. And if you can't grant us 1250 what we would request is that we administratively approve that based on submission of step rate tests at a later date.

Q. Would you like some -- like a uniform pressure limit across the whole field?

A. Yes, we have 1100 at West High Lonesome, and some other wells frac at 900 pounds, but some of them frac at 1400 pounds. So we've got to kind of have a -- you know, other than approving it on a well-by-well basis.

We -- the other problem we had with our West High Lonesome, and the reason we'd like to get this administrative approval or some easier way of doing it, when we started the flood we got authority to do an administrative approval of a higher pressure because we knew we were going to have to have it -- I think that was during the time you all were scanning documents.

Q. Oh.

A. We never could get administrative approval for six months.

Q. Oh, really.

A. And we had to back off on our pressure, and we actually had to call a hearing to get -- and so we actually started getting a response, we had to back off on our pressure, and we started losing our response and we went to a hearing and got approval, and it didn't really affect us too bad but, you know, I'd prefer not to do that if we can --

Q. I hear that a lot.

Okay, the frac jobs that you have to do initially -- are you going to have to do any more fracs on these wells?

A. Completions, typically what we see in most of these wells, we've tried acid and xylene when we clean out an injector, getting ready to convert it. And the acid doesn't do anything. Most of this is silicate sand with anhydrite and salt, and we just don't see much with acid.

The xylene, because of the long-term production of oil and oil residue, seems to do pretty well. And so our plan would be to do a xylene treatment on these wells, no additional fracs.

The one well that we're going to re-enter, that plugged well, we'll run casing and cement it, perforate it and frac it --

Q. Okay.

A. -- in order to get it started as an injector. But there are no other dramatic treatments.

In our other wells we have some calcium sulfate scale that occurs occasionally. We usually do dump jobs, conversions, with a little acid afterwards, and that usually takes care of calcium sulfate scale when we have an issue. Other than that, xylene has been our best treatment.

Q. Okay. And you think oxygen scavenger -- or oxygen -- chemicals to remove oxygen on your fresh water will be fine, instead of a tower to --

A. Yes.

Q. -- knock out the oxygen?

A. We've -- What we do currently in our facilities that we used at West High Lonesome are working real well. We're going to use an identical facility construction here. We inject oxygen scavenger -- We bring fresh water from three miles east of us by gravity feed. About a quarter mile east of our tanks we inject oxygen scavenger to give it time to scavenge any oxygen before we get it into our freshwater tank.

We've got three tanks. One's a produced tank and it comes out of a 750 gunbarrel, it's a settling tank. It overflows on the top into a second combination tank. We've got a freshwater tank in that combination tank, and that's where we suck for our suction for our injection pump --

Q. Okay.

A. -- so we've got fresh water and produced water being mixed there. And we treat for scale in that water, and we also treat for scale out at the wells to get that in the water coming in, as we produce more water.

Q. Okay. I didn't ask previously from Sandy Beach about the directional permeability out here, but I hear a lot about this microseismic -- being able to monitor your frac jobs. That's one reason I ask about the frac job, that you can kind of tell the orientation of a frac, and --

A. Uh-huh.

Q. -- and that's kind of -- Of course, I know you're committed to a peripheral flood here, but at least it -- You know, what do you think about that? Have you ever --

A. I think in this particular area what we see in these Queen floods is a permeability orientation that tends to be northeast-southwest --

Q. Okay.

A. -- especially when you have this going on. And our peripheral flood segregates these sweet spots northeast and southwest with injectors between them.

Q. Okay.

A. So we're trying to, you know, catch the good rock in between the sweet spots and then put water around the tight spots.

Q. Okay.

A. Fracturing -- and the small frac jobs that we put on them, I don't think it makes a difference where they go. And in some cases they're probably -- I would say probably in 70 percent of these cases, these are horizontal fracs. I think they just -- Overburden is 1 p.s.i. per foot, and we're approaching overburden. So when we frac these things I think we're just opening them up horizontally in most cases --

Q. Okay --

A. -- and maybe some --

Q. -- northwest I've seen horizontal-type gradients up around 1000 feet, but you're talking about 2300 feet here.

A. Yeah. And we haven't done the step rate tests here, yet, to confirm that. And that's, you know, one of the processes we're going to go through, is, we're going to go through -- and maybe these wells do frac at .7 p.s.i. per foot in their vertical fractures, in which case we still want to stay under frac pressure. There's no -- I think any fracturing from an injection standpoint is going to harm us.

Q. Okay. What about initial reservoir pressure or current reservoir pressure estimates?

A. I don't have a good handle on that. I'm sure it's probably 300, 400 pounds, 500 pounds. I'm sure this was underpressured to begin with. Most Queen floods were, and Queen reservoirs have been underpressured that we've come in contact with.

Q. And I saw you used like .35, I think, for your water saturation, or was --

A. Yes.

Q. -- it .4 or something?

A. There were some saturation calculations done and -- early on. Some of the other floods in this area have used 35 percent. A 1.05 B_o for a current B_o. If you look at correlations, that's consistent with about a 400-, 500-pound bottomhole pressure.

Q. Okay.

A. So we don't have a lot of hard data. We have had -- our experience with the Queen in Texas, which really looks very similar to this, we cored every well we had there, and we had some core history there.

And we've had some cores taken north of Loco Hills. We drilled a couple of subsequent wells and took some cores, and it's what I'm describing to you. We've got 25 foot of pay, 15 feet of net pay, and then you've got about four or five feet that you're really producing and flooding --

Q. Okay.

A. -- high-perm streaks.

Q. Okay. So your initial -- your increased pressure will actually cause it to flood a --

A. Yes.

Q. -- little bit more interval?

A. Give you a little more lateral and vertical within the zone.

EXAMINER JONES: Okay, that's -- I better shut up here and turn it over to David.

EXAMINER BROOKS: Well, I think I've asked all the questions I have, so I don't think I have any more questions.

EXAMINER JONES: Thank you. Have you guys -- do you have anything else? Got some --

MR. BRUCE: Don't have anything else.

EXAMINER JONES: Okay. Lisa, right?

MS. GRAY: May I approach?

My client is Snow Oil and Gas in this. Mr. Rose pointed out he spoke with him. I believe your conversation took place on Tuesday. And there was no prehearing letter submitted on our part because we do not know whether we're protesting or not. We haven't been privy to any of the exhibits that were presented to you. Mr. Bruce is going to allow me to have a copy of that.

But as Mr. Rose's testimony pointed out, Mr. Snow does have concerns. He operates in that area.

Mr. Beach's presentation noted that there is high levels of porosity in this area which are probably horizontal. If -- if it proves to be the case as the -- your analysis of the reservoir. And Mr. Snow's property is actually on the western side of this and to the south of most of this, and these are -- it's an unusual flood pattern, and so -- with that peripheral injection well pointed right at Mr. Snow's property.

The other thing that we hadn't discussed that is another concern is the Seven Rivers presentation. And it's not a matter of objecting to it or not objecting to it, it's simply a matter of not knowing what that situation is, relative to his --

MR. ROSE: Right.

MS. GRAY: -- wells.

Now it is my understanding and my client's understanding that time is of the essence here, and we certainly appreciate the need to act quickly on contracts in situations.

However, it would be prudent on Mr. Snow's part to examine the materials as far as it affects his particular interest in all of these intervals. And, you know, some accommodation as MYCO and Devon apparently are negotiating with -- to the south in Section 11, or the south half of 11 -- could certainly be a potential.

But those are my statements and concerns. And certainly we would like to work with all the parties concerned here to get a swift resolution to any concerns that might be -- that might be forthcoming.

EXAMINER JONES: Okay, Mr. Bruce?

MR. BRUCE: And I think Mr. Rose addressed the issues about, you know, Snow's well, which is the fact that it is very tight, and any benefit would probably be -- or any effect would probably be beneficial.

But the fact of the matter is, we're not going to expand the unit at this point. You know, the matter has been heard and we think it's ready to be taken under advisement.

MS. GRAY: May I make one additional comment?

And then -- Mr. Snow isn't asking to be included in the unit, he's simply asking that he review the materials to see how it'll affect his interest and the interests of his participating with the interest owners.

MR. BRUCE: And he does -- I mean, you know, he's entered an appearance, or his company has entered an appearance, so they have the right to appeal.

EXAMINER JONES: Okay.

EXAMINER BROOKS: If they should choose to move to reopen before the order is entered they can do that, but at this time you're not proposing to present any evidence, correct?

MS. GRAY: That's right. Well, we've not received the materials.

EXAMINER BROOKS: Yeah.

MR. BRUCE: Well, they've been given the materials that were required to be given as part of the offset notification.

EXAMINER BROOKS: You received the C-108, right?

MS. GRAY: (Nods)

EXAMINER BROOKS: That's all I have.

EXAMINER JONES: Okay. Thanks, Mr. Rose --

MR. ROSE: Thank you.

EXAMINER JONES: -- and Mr. Hinson, Mr. Beach, Mr. Bruce.

MR. BRUCE: That's it for today.

EXAMINER JONES: Okay. With that, we'll take Cases 13,972 and Cases 13,973 under advisement.

And this hearing is adjourned.

EXAMINER BROOKS: Very good. Thank you for your time.

(Thereupon, these proceedings were concluded at 11:25 a.m.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. ______ heard by me on ______

______, 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 October 26th, 2007.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 16th, 2010