STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING)
CALLED BY THE OIL CONSERVATION)
DIVISION FOR THE PURPOSE OF)
CONSIDERING:) CASE NO. 10647
CASE NO. 10648

APPLICATIONS OF SEELY OIL COMPANY

REPORTER'S TRANSCRIPT OF PROCEEDINGS

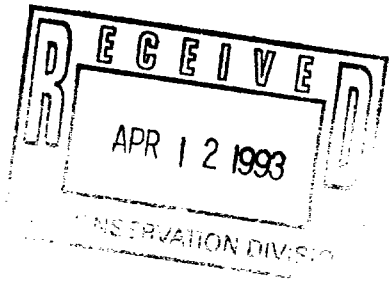
EXAMINER HEARING

BEFORE: Michael E. Stogner, Hearing Examiner

March 18, 1993

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Division on March 18, 1993, at the Oil Conservation Division Conference Room, State Land Office Building, 310 Old Santa Fe Trail, Santa Fe, New Mexico, before Deborah O'Bine, RPR, Certified Court Reporter No. 63, for the State of New Mexico.



I N D E X

March 18, 1993
Examiner Hearing
CASE NOS. 10647 and 10648

E X H I B I T S

A P P E A R A N C E S

FOR THE DIVISION: ROBERT G. STOVALL, ESQ.
General Counsel
Oil Conservation Commission
State Land Office Building
310 Old Santa Fe Trail
Santa Fe, New Mexico 87501

FOR THE APPLICANT: CAMPBELL, CARR, BERGE & SHERIDAN
P.O. Box 2208
Santa Fe, New Mexico 87504
BY: WILLIAM F. CARR, ESQ.

EXAMINER STOGNER: This hearing will come to order. Call next case, No. 10647.

MR. STOVALL: Application of Seely Oil Company for statutory unitization, Lea County, New Mexico.

EXAMINER STOGNER: Call for appearances.

MR. CARR: May it please the examiner, my name is William F. Carr with the Santa Fe Law Firm, Campbell, Carr, Berge & Sheridan. We represent Seely Oil Company, and I would request that this case be consolidated with the following case in which Seely is seeking approval of a waterflood project for this unit.

EXAMINER STOGNER: Are there any other appearances in case 10647? In that case we'll call Case 10648.

MR. STOVALL: Application of Seely Oil Company for approval of a waterflood project and qualifications for the recovered oil tax rate, Lea County, New Mexico.

EXAMINER STOGNER: For the record, are there any appearances for 648?

There being none, Mr. Carr?

MR. CARR: May it please the Examiner, these cases were originally filed in early December

1992. At that time, as you will recall, we drew opposition from Ray Westall, BTA, Marathon, and we also had questions raised about the application by Santa Fe Exploration Company. Since that time, we have been able to resolve our differences with each of these interest owners. Part of the arrangement was concluded, oh, approximately two weeks ago, a little over two weeks ago, and we've agreed to adjust the unit boundary. But I can stand before you today saying that we anticipate that we will have 100 percent of the working interest and royalty interest voluntary joining in this unit, and we would therefore request that we be permitted to present an application for approval of a voluntary unit in lieu of presenting a case for statutory unitization.

EXAMINER STOGNER: Thank you, Mr. Carr.

MR. CARR: At this time we would call Clarence Stumhoffer.

(Witnesses sworn.)

CLARENCE STUMHOFFER,

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

EXAMINATION

BY MR. CARR:

Q. Will you state your name and place of

residence?

A. I'm Clarence Stumhoffer. I live in Fort Worth, Texas.

Q. By whom are you employed?

A. Seely Oil Company.

Q. And in what capacity?

A. Consulting petroleum engineer.

Q. Mr. Stumhoffer, have you previously testified before this Division?

A. Yes, I have, but it was back in the 1960's and early 1970's.

Q. Would you summarize your educational background and work experience for the examiner?

A. I have a Bachelor of Science Degree in petroleum engineering from the University of Texas in Austin, 1953. And I have 40 years of experience in the oil industry working for various companies. And during the 60's and '70's, I worked with Newmont Oil Company and Anadarko Petroleum Company, doing secondary recovery projects in the southeastern part of the state.

Q. Are you familiar with the applications filed by Seely in this case seeking approval of the Central EK Queen Unit Agreement, and also a waterflood project for that unit?

A. Yes, I am.

Q. Are you familiar with the status of the lands in the unit area and the technical considerations that were involved in deciding to go forward with this project?

A. Yes.

MR. CARR: Are Mr. Stumhoffer's qualifications as a petroleum engineer acceptable?

EXAMINER STOGNER: They are.

Q. (BY MR. CARR) Could you briefly state what Seely Oil Company seeks with these applications?

A. Seely Oil Company seeks the approval of the Central EK Queen Unit as a voluntary secondary recovery project.

Q. And how many acres are now included within the proposed unit boundaries?

A. 988.4 acres of state land.

Q. Does Seely also request approval for a waterflood project in the unit area?

A. Yes.

Q. Have you prepared certain exhibits for presentation in this case?

A. Yes, I have.

Q. Could you identify and review what has been marked as Seely Exhibit No. 1?

A. Exhibit No. 1 is a Unit Agreement of the proposed unit, prepared on the form that's approved by the State of New Mexico Land Commissioner Office.

Q. Does this form provide for a waterflood operations in the unit?

A. Yes, it does, under Section 11.

Q. Does Exhibit C to this Unit Agreement set out the tract participation factors for each of the tracts in the unit area?

A. Yes, it does.

Q. And could you now review Seely Exhibit No. 2 and basically review for the examiner the basis for unit participation?

A. The basis for unit participation is a single phase formula composed of 90 percent primary recovery as of January 1, 1991, from the Queen Sand and it includes a 5,000-barrel credit for each usable well in the unit area. This usable well credit is to adjust for the large number of plugged and abandoned wells that will be redrilled on this project. And plus in addition it has a 10 percent factor for acreage.

Q. Let's now refer to Seely Exhibit No. 3, and I would ask you to identify that and review it for the examiner?

A. Exhibit No. 3 is -- there are two pages. The first page is a map of the -- is Exhibit A to the Unit Agreement, and it shows the revised unit area as it is today. The second page was the unit area as it was originally set out.

Q. Mr. Stumhoffer, the proposed unit now consists of nine leases and 13 tracts; is that correct?

A. That's correct.

Q. And to get this unit into a voluntary posture, Seely deleted certain tracts from the original proposed unit area?

A. Yes.

Q. Has that deletion had any material impact on the waterflood project that is being proposed?

A. No, it has not.

Q. When those tracts were originally included, what was their real value?

A. Their value was the fact that they had usable well bores on the tracts that we could use for water injection wells.

Q. And now with those tracts out, is Seely prepared to drill new injection wells to replace the well bores that are no longer available?

A. Yes. Three new injection wells are

necessary now by the deletion of these tracts at a cost of approximately $600,000.

Q. So the actual physical aspects of the project haven't changed, but the costs have been substantially increased?

A. That's correct.

Q. Does Exhibit No. 3 also show the lessee of record for each of the tracts within the unit area?

A. Yes, it shows lessee of record.

Q. Have you reviewed this agreement with the New Mexico State Land Office?

A. Yes, I have.

Q. Could you identify what is marked as Seely Exhibit No. 4?

A. Exhibit No. 4 is a letter from the Commissioner of Public Lands Office dated March 17, giving Seely Oil Company preliminary approval of the proposed unit.

Q. And in the negotiations with the Commissioner of Public Lands, has Seely reviewed with the Commissioner staff the need to use fresh water as a make-up water source for injection in this unit area?

A. Yes, we have.

Q. Do we now stand with approval to go forward

with that plan from the Land Office?

A. Yes.

Q. Could you go to what has been marked Seely Exhibit No. 5, identify that, and review it, please.

A. Exhibit No. 5 is the Exhibit B to the Unit Agreement in which we set out the working interest and royalty interest ownership.

Q. It shows the ownership by tract, does it not?

A. It shows the ownership by tract.

Q. What working interests have been committed to the unit?

A. 100 percent.

Q. Does Seely desire to be designated the operator of this unit?

A. Yes.

Q. Does this agreement provide for the periodic filing of plans of development with the State Land Office?

A. Yes, it does.

Q. Will these plans also be filed with the Oil Conservation Division at the time it's filed with the Land Office?

A. Yes.

Q. Could you identify what has been marked for

identification as Seely Exhibit No. 6?

A. Exhibit No. 6 is the proposed Unit Operating Agreement, which is on a standard form.

Q. And this agreement has been or will be voluntarily executed by all the working interests in the unit area?

A. That's right.

Q. Could you identify Exhibit No. 7, please.

A. Exhibit No. 7 is an Affidavit of the mailing of the notice of the formation of the unit and the waterflood development.

Q. To whom was notice of this application originally given?

A. The waterflood unitization notice was mailed to all the owners of any economic interest in the unit. The waterflood development -- waterflood development plan notice was mailed to all the operators within a two-mile radius of the unit.

Q. And has the C-108, the actual application itself, been provided to all leasehold operators within a half mile of any injection well?

A. Yes, it has.

Q. And has a copy of the C-108 also been provided to the owner of the surface of the land on which any injection well is located?

A. Yes.

Q. Are those interest owners identified in the Affidavit attached to Seely Exhibit No. 7?

A. Yes, they are.

Q. Following the final negotiations with BTA and Ray Westall and the agreement to adjust the unit boundary, were the interest owners in the waterflood project advised of the change in the boundary and the need to drill additional injection wells?

A. Yes, they were.

Q. Was a letter advising them of this also provided to them March the 5th, 1991?

A. That's correct.

Q. Were Exhibits 1 through 7 prepared by you?

A. Yes.

Q. Or under your direction?

A. Yes.

MR. CARR: At this time, Mr. Stogner, we would move the admission of Seely Exhibits 1 through 7.

EXAMINER STOGNER: Exhibits 1 through 7 will be admitted into evidence at this time.

Q. (BY MR. CARR) Mr. Stumhoffer, will Seely also call two additional engineering witnesses, one to review the technical aspects of the project, and

another to review the C-108 waterflood application?

A. Yes.

MR. CARR: That concludes my direct examination of Mr. Stumhoffer.

EXAMINER STOGNER: Any questions, Mr. Stovall?

MR. STOVALL: No.

EXAMINER STOGNER: I have no questions of Mr. Stumhoffer at this time.

MR. CARR: At this time I WOULD call Mr. Charles Seely.

CHARLES SEELY,

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

EXAMINATION

BY MR. CARR:

Q. Will your state your name for the record, please.

A. Charles Seely.

Q. Where do you reside?

A. Fort Worth, Texas.

Q. By whom are you employed?

A. Seely Oil Company.

Q. And in what capacity?

A. Owner and President.

Q. Mr. Seely, have you previously testified before the Oil Conservation Division?

A. It sounds like a broken record, but a long time ago, 1963 and 4.

Q. In that case, could you summarize your educational background and review your work experience for Mr. Stogner.

A. B.S., petroleum engineering, from Texas A&M in 1955. Seven years with Mobil as a petroleum engineer. Three years with Newmont as a reservoir and chief engineer. Ten years with Armour Oil Company, production manager and president. Seventeen years as president and owner of Seely Oil Company, 37 years total.

Q. You are familiar with the applications filed on behalf of Seely in this case?

A. Yes.

Q. In fact, you are responsible and have prepared the technical study upon which the decisions were made to go forward with this project?

A. That's correct.

MR. CARR: Are the witness's qualifications acceptable?

EXAMINER STOGNER: Oh, they are, and they're most welcome. It's good to see people with

experience back in here.

Q. (BY MR. CARR) Mr. Seely, could you identify first what has been marked as Seely Exhibit No. 8?

A. That is the report that was prepared in determining whether or not this was a feasible waterflood prospect, which includes 12 exhibits, 12 figures, and 5 tables.

Q. What we have is a text on the right-hand side of the exhibit with some tables, and the figures are in the pouch; is that correct?

A. The figures are in the pouch. The tables are attached in the middle at the back.

Q. Let's go first to what is marked Figure 1 to Exhibit 8, and I would ask you first to identify this and then review it for the examiner.

A. Okay. Figure 1 is a structure map contoured on top of the Queen in the central portion of the EK Queen field.

A little background of the Queen Sand in this area, which is located about 25 miles west of Hobbs. It's in an area of extremely good flood performance for Queen Sand waterfloods. The Queen Sand that we're talking about is in the upper part of the Queen, which is about a total interval of about 50

feet. It is part of the Guadalupean series of Permian age.

The oil-producing portion of that 50 feet is a grade of fine to medium grain friable quarts sandstone. It's probably either a wedge or a bar sand deposit. It is -- this oil-producing portion is some 30 to 35 feet below the top of the Queen formation itself. The structure, as you can see, dips to the south and at the rate of about 100 to 125 feet per mile.

The reservoir itself is bounded at least for the entire EK Queen field to the north and the west basically with permeability pinchouts, to the south and east with a water table.

The reservoir is a solution gas-drive. It has had no effect from water-drive either from natural causes or from two previously installed and plugged-out floods that have been part of this EK Queen field.

Q. At this time, why don't we move to Figure No. 2?

A. Okay.

Q. If you could, review the primary oil production history of the area for the examiner.

A. Let me say, there are two figures that I'll probably refer back to. This is one of them, and the

other one is Figure 5, which is the isocum map. But this is a production history of the wells located inside the Central EK Queen area.

In addition, it shows the primary production which shows it peaks out at about 10,000 barrels per month and declined in a solution gas-drive manner. Also, I show the number of producing wells.

At the bottom of this, which is important, I show the active time that the Mobil -- there are two units that have actually operated in the field. One to the south was the Mobil EK Queen Unit, and the other one is the Murphy Baxter to the north.

I think what might be important here is the fact that you see when there was water injection into the reservoir, there were only like three or four producing wells in this unit, and they were off to the side.

Q. The number of producing wells is indicated by this sort of solid line that steps up and down through the center of the exhibit?

A. Yes, it is, that's correct.

Q. And when you compare that to the periods when the offsets were injected, you can see that there really were only about three wells in the unit producing?

A. That's right.

Q. Anything else to show with this exhibit?

A. Not at this time.

Q. Let's to go Exhibit No. 3. Could you identify then review that for Mr. Stogner -- or Figure 3?

A. Okay. Let me refer to the isocum map on the wall, which is Exhibit No. 5, which it shows the entire EK Queen field, and it shows that there was a flood up to the north portion, which was done by Murphy Baxter. Then there was a flood done to the south by Mobil. Then you see the outline of our proposed unit, which is in the central portion there.

Then back to the curve here of Figure No. 3. It's simply a response curve of the Mobil unit. As you can see, they've got a very fast response in less than a year, declined at a very rapid rate, indicative of the type of pattern that was used, which is a five spot. It peaked out at about 60,000 barrels per month.

The flood was initiated in 1966, and most of the injection was stopped in 1978; so that by about 1983, there were only maybe 6 producing wells and just a few injection wells left that were used mainly for saltwater disposal.

Q. If we could go now to Exhibit No. 4, could you identify and review that, please, and again I mean Figure No. 4.

A. Yes. Figure No. 4 is the primary and secondary history of the Murphy Baxter North EK Queen Unit, again showing the prime -- well, not again, well similar to our Central EK Queen Unit. The primary production comes down at a very fast clip, indicative, there again, of a solution gas-drive. And then water injection was started like in about the latter part of '70 and you can see a very strong response in 1971, which was something less than a year.

What's interesting about this one is that you don't see the same type response as you did with a five spot. This is a peripheral-type pattern, and only nine injection wells were used, but it was a very effective one, also.

What you see is instead of a large, tall peak, and extended increased production time period with the amount of oil, maximum amount of oil reaching about 10,000 barrels a month.

Q. And this is a similar injection pattern in fact to what you were proposing to implement in the proposed --

A. Yes, it is.

Q. Are you ready to go to Figure No. 5?

A. Well, we've kind of been on No. 5. I'd like, as I said, I've got a little problem with these things. I almost need to go back a little bit on that Central EK Queen Unit itself, Figure No. 2, which is the -- there were or there are are 25, 40-acre locations in this proposed unit. There's productive acreage of about 951 out of 988. Sixteen of the 40 tracts had Queen Sand production. Thirteen of the wells that were originally drilled of the 13 that were originally drilled -- and you don't really ever see 13 up here because one was plugged out very quickly. Ten of the 13 wells were plugged out at a very early time, in most cases, about 10 or 11 years.

I'd also like to refer to Table 1, which is in the back, back here. And what I've tried to indicate here is that there is a substantial amount of primary oil that was never recovered from this reservoir due to the premature plugging of several of these wells, these ten wells.

The three wells that have produced continually, as you look all the way over to the right, you can see that they've averaged 29,000 barrels a well over and above what the ten that were plugged out made.

In addition to indicate that there's still primary oil left, four wells were redrilled, and they're shown on this curve at different times under the general operating, Amoco State General Operating, Santa Fe State 1, General Operating State AJ No. 1, and the Santa Fe State No. 2. And those four wells have averaged anywhere from 5 to 17,000 barrels, and have averaged 10,000 barrels a well.

The total primary recovery from this reservoir is 444,562 barrels as of 1-1-91, and that's only like maybe 65 barrels per acre foot, if you take all of the productive acreage, which is only like 11 percent of the oil in place. If you take the full developed area or just the developed area only, that increases to about 93 barrels per acre foot or 16 percent of the oil in place, which seems to be a little bit more logical.

There were also in this area three locations that have since been proved up that were not drilled by some deeper wells that had been drilled in there.

I think maybe now we might want to go to -- back up to Figure 5 and also to the two cross-sections.

Q. Those your your Figures 6 and 7?

A. That's correct.

Q. All right.

A. What we're really trying to do here is to show the proximity of the Central EK Queen Unit to the other two floods, and to show -- and we've got a cross-section that runs north and south and one which is B-B', and one that goes east and west. And you can see the tie lines on the two cross-sections, and you can see that there is a portion of porosity about 30 or 35 feet below the top of the Queen that correlates continually through the Murphy Baxter flood, through the Central EK Queen Unit area, down to the Mobil flood. And you can also see that in the one going from west to east, that you can also correlate all the way across it.

The two floods themselves were studied, and there was excellent recoveries, and on that isocum map, I show the performance of both floods. The Murphy Baxter north unit had 702,000 barrels of secondary recovery for a primary recovery of 513 or a secondary primary of 1.37.

The Mobil unit had a primary recovery of 1,737,000 barrels and a secondary recovery of 2,140,000 for a secondary to primary of 1.23.

Basically what we're trying to do is to

show that we've got the same type reservoir characteristics as the other two. And I guess the things that certainly are common to the central and the others is that you can certainly correlate an oil productive porosity zone in from one to the other and all the way across it. All of them had similar initial potentials. There was little or no water production in any of the field. All of the three areas have a solution gas-drive. And also on Figure 8, which is a structure map of the entire field, you can see that basically they're all the same type structure with a dip to the south.

There's further evidence of the floodability of the central area. Well No. 601, which is also Tract No. -- Well, 6 well No. 1, was used as a saltwater disposal well in the Queen Sand for the period of around 1987 to 1989.

Our State BC lease, Tract No. 2, which is located in the south half, southeast quarter of Section 8, responded significantly to the injection in that saltwater disposal well. This could be seen, if we go back to this Figure 2, the primary decline curve for the unit, and about in '89, you can see that production went up for some reason, and there was not anything caused that other than the fact that it

responded to this water injection.

Then in 1989, the production ceased, and the increase in production from Tract No. 2 was lost. I think we --

Q. Are you ready to go to the isopach map?

A. Yes.

Q. Figure No. 9?

A. Right.

Q. Just identify and explain to the examiner what this shows.

A. Okay. Figure No. 9 is an isopachus map in the Central EK Queen area. Just to tell you the information that I had to prepare this, I did have two detailed cores plus a summary of average core data that had been presented in a report, in a report done for Mobil back in the 50's. So I actually had core data on seven wells in the unit area.

In addition, to make comparisons, I had a summary of core data on 24 wells in the Mobil unit. And, incidentally, the porosity for the central unit averages 13.4, for the Mobil unit 13.3. Permeability is 35 millidarcies for the central unit and 33 for the Mobil unit. So from that point you can see it's very similar.

In addition to the cores, I had

radioactivity logs on all the other wells. This would have been the time of about 1956 through around '58. But in addition to that, there were two wells that were drilled over to the east there in Section 9 that were drilled later that had modern logs. These four wells that were redrilled in -- let me just say, in Section 8 and Section 17, well, plus the Santa Fe State No. 2 in Section 18, all of these wells have modern logs. So we were able to get good porosity figures and water saturation figures.

In addition to that, there was a Bone Spring or there is a Bone Springs plate. Going back to Figure 5 over there on the wall, you can see there's triangles just to the west of the unit itself. All of those are deeper wells, and you can see some of those come into the unit itself. We were able to use those logs, which are modern, density neutron plus dual lateral logs, in coming up with net pay.

So we feel like we've had a fairly good -- we think that there may be a connection with the old Mobil flood with this central flood. You can see we show zero contours. However, there's one, two, three dry holes -- four dry holes in one direction and a couple down offsetting the Mobil flood. It's our

opinion that it's probably not completely separated, but that it probably does have some pressure communication between the two.

Q. If we look at the isopach map, Mr. Seely, is the dark-hatched line that comes across kind of the southwest corner of this exhibit, that's the boundary of the old Mobil flood?

A. Yes, it is.

Q. Then we have the Murphy Baxter flood -- where did it actually come in the reservoir?

A. I don't have it shown on there, but that's interesting to show. We're actually using two of the old Murphy Baxter injection wells for our injection wells. One of them, which is Tract 13, Well 1301, the other one is in Tract 4, Well 401. The Murphy Baxter unit came down just south of those two wells. It's been dissolved; so we were able to come up with these two wells.

Q. And the boundaries of this proposed unit actually conformed to the area that you've isopached, that's productive in the area?

A. That's right.

Q. Are you ready to go to your Figures 10 and 11?

A. I think maybe we need to do maybe a little

bit of talking about how we came up with secondary reserves. We did it by two approaches. One was volumetric, and the other was offset production. We took the acre-feet from the isopachus map and multiplied by recovery factor to come up with the secondary reserves. That calculated to be 130 barrels per acre foot. Calculations are shown in Tables 2 and 3.

To back up that 130 barrels per acre foot figure, another approach was taken. I had all the core data from the Mobil flood, and Mobil had done some statistical studies concerning permeability capacity distribution, and with relative permeability of water to oil, they were able to come up with recovery versus percent water saturation. And they estimated from this core data that at 1340 barrels per acre foot, the water percentage would be 96.5, which would probably be pretty close to the economic limit of this flood.

When you figure the reserves based on offset production, we've already talked about the isocum map and the location of it, and we've gone over the amount of production that each unit and the ratios of secondary to primary. We feel that the ratio of this 1.26 is a very good figure. The only thing that

we think is probably not quite right is the fact that we do have primary oil left in the reservoir because there were ten wells that were plugged out early, and there were three proved locations that have never been drilled.

And we've estimated that from this ten wells and the three new locations, that there would probably have been another 175 to 200,000 barrels of additional primary oil, had the wells been drilled and had the other ten wells not been plugged earlier.

Q. This production cannot, though, now be recovered by primary operations?

A. Oh, no.

Q. Reservoir energy no longer exists?

A. No, there is no energy there. By using Mobil's primary recovery factor of -- you take the 1,737,000 barrels that they produced in their unit, and take that over the acre-footage, that's about 90.5 barrels per acre foot.

If you use this recovery factor in with the acre-footage that's going to be swept, that would increase from this 444,000 to 617. Then if you use the combined flood performance of the two floods of 1.26, the secondary would be 777,000 barrels, which is in good agreement with the figure we came up with

volumetrically, and also by the permeability, relative permeability relationships.

This would be secondary recovery of 130 barrels per acre feet foot or about 22 percent of the oil in place. This results in an ultimate recovery of 1,230,000 barrels or 180 barrels per acre foot or about 31 percent of the oil in place, which I would think would be a very reasonable figure in this case.

Figures --

Q. Are you ready to go --

A. We didn't really talk about -- I talked about it, but I didn't refer to it -- Figures 10 and 11 were the basic data that Mobil had presented to come up with the water-cut relationship versus recovery.

Q. All right. Now we have Exhibit No. 12. It is a waterflood development map for the unit copied below the isocum plat?

A. That's right.

Q. Could you just generally review the plan for the examiner?

A. Okay. This plan, as you can see, if you follow, the injection wells are in triangles. They're colored as to when we think we'll probably put them all in. Since we are having to drill a number of

wells, we're staggering when we're converting and drilling the wells over a period of about three years.

As you can see, the yellow wells will be done in 1993, and the others in '94, '95, and '96. This total thing is going to require drilling six new water injection wells and four new producers.

We will also have to reenter and complete two old water ejection wells, the wells that I mentioned earlier with the Murphy Baxter unit. We will start up the injection again in the saltwater disposal well over there that we had received response earlier from.

We will -- there's a Well 301, which is now a Yates sand producer, which we will recomplete and make it an injection well. And we will be converting one producer to water injection. In addition, we have seven existing producing wells. We think the total number of wells will be 11 injection wells and 11 producers.

Q. Mr. Seely, part of our negotiations with BTA resulted in the contraction of the unit boundary to exclude three, 40-acre tracts on the western end of the unit area?

A. That's correct.

Q. Because of that, there were wellbores no longer available to Seely to convert to injection?

A. That's right.

Q. And you have proposed two injection wells that are just 50 feet inside the boundaries of the unit on the western perimeter?

A. That's correct.

Q. Could you explain to the examiner why those wells are located that close to the unit boundary?

A. We do not feel that there is very much significant reservoir in Section 12 in that 120 acres that we have proposed for the unit. There are two wells there that show as dry holes.

Q. Those are in Section 12?

A. In Section 12. One is in the northeast of the southeast quarter. The other one is in the northwest of the northeast quarter. The first one that I talked about, actually they set pipe on it, frac'd it, did not make a well. The other well, they cored and didn't get a show and didn't set pipe on it.

Since that time, there have been some deeper wells drilled, and there appears to be a small amount of reservoir that exists fairly close to the line there but not really a significant amount. So

our maybe purpose was to put that 120 acres in to save $400,000. We think that since they really wanted to use these wellbores for deeper wells, and I understand that, that -- and we've talked to both BTA and OXY, and they do not have an objection for us putting these wells in.

Q. If the injection wells sweep production to the west, is there any producing well out there, or do you foresee one that would recover that production?

A. Not only is there not one there, but there has never been any Queen Sand production on that lease.

Q. So is it fair to say that by placing the wells where we're proposing, that the production in the Queen formation that we will be sweeping will in fact be swept toward wells that can produce those reserves?

A. That's correct.

Q. And we have discussed this with both BTA and OXY, the owners in those 40-acre tracts, and by deleting the tracts and placing the wells here, they've expressed no objection?

A. That's correct.

Q. Is there anything else that you would like to review with the examiner in terms of the figures or

the tables contained in your technical report marked Exhibit No. 8?

A. I don't know if I referred to Table 2 or not, but that's just a summary of basic data. It gives all the productive acres, the acre-footage, the total acre-foot, the acre-footage within the pattern that we've proposed to flood. It gives the residual oil in place and the expected secondary, ultimate primary.

Table 3 is a calculation of the oil in place and also the calculation of the secondary reserves. Using a flooding efficiency of 50 percent, which I think is probably certainly within line of what we think we might get, residual oil saturation of 23.5, based on water, water-based mud core analyses, and a water saturation of 30 percent which was obtained from about four recent electric logs.

Table 4 is nothing more than what was presented earlier. This was the basis for coming up with the unit. It just shows how the participation factors were developed.

Table 5 shows a plan of development and cost figures with a total cost of about $2,375,000 being the development cost to put in the flood.

In addition to that, we estimate the

operating cost over a period of about 14, 15 years to be about $3.6 million, with a total development and operating cost of about $6 million.

Q. From the study alone, I'd like to in a minute have you look at those portions of your testimony that relate to qualifying the project for the enhanced oil recovery incentive tax rate. Could you just summarize the conclusions that you have been able to reach as a result of this technical study?

A. There have been two previous waterfloods in the EK Queen field, the Mobil EK Queen Unit and the Murphy Baxter unit, and they've both been very successful. There has been little or no secondary oil produced from the Central EK Queen area. The ultimate recovery from the Upper Queen can be increased significantly by waterflooding.

Using a peripheral water injection pattern and by drilling six new injection wells and four new producers, we think reserves can be increased by 786,000 barrels. Capital expenditures over 3-1/2 year period is $2,375,000. And for the waterflood operations to be efficient, it's absolutely necessary that we unitize this Upper Queen formation.

Q. Seely is requesting that this project be certified for the incentive oil tax rate?

A. Yes, we are.

Q. You have indicated that the estimated capital cost for these additional facilities will be $2,375,000; is that correct?

A. Yes.

Q. Have you estimated the total project cost?

A. Yes. That's at $6 million.

Q. Will the proposed waterflood in this reservoir, in your opinion, result in an increase in the amount of crude oil that ultimately will be recovered from the Queen formation in this area?

A. Yes.

Q. And you've indicated that the additional recovery will be 786,000 barrels?

A. Right.

Q. What would be the estimated total value of this additional production?

A. About $15.7 million.

Q. What price per barrel are you using to estimate this figure?

A. $20 a barrel.

Q. In your opinion, is this area so depleted that it is now prudent to apply enhanced recovery techniques to maximize recovery from this area?

A. Yes.

Q. When do you anticipate that you could start the commencement of the actual injection into the unit area?

A. After approval, within six months.

Q. Will you advise the Division prior to the commencement of any injection?

A. Yes.

Q. Were you present this morning when Mr. Stovall discussed the requirements of this agency --

A. Yes.

Q. -- for projects of this nature? And you understand that you will have to keep them advised as to when you experience a positive production response?

A. Right.

Q. Does the proposed waterflood project, in your opinion, appear to be technically and economically reasonable?

A. Yes.

Q. And it isn't premature to begin an operation of this nature, is it?

A. No.

Q. In your opinion, would approval of this application be in the best interest of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes.

Q. Mr. Seely, was Exhibit 8 prepared by you?

A. Yes.

MR. CARR: At this time, Mr. Stogner, we would move the admission of Seely Exhibit No. 8.

EXAMINER STOGNER: Exhibit 8 will be admitted into evidence.

MR. CARR: And that concludes my direct examination of Mr. Seely.

EXAMINER STOGNER: Mr. Stovall, do you have any questions?

EXAMINATION

BY MR. STOVALL:

Q. Let's just touch on the EOR tax rate here. You heard the discussion about the relationship between the time of certification and the time required to get to file the positive production response?

A. Five years, I believe, isn't it?

Q. Yes. And you're talking about injection within six months after the order?

A. Um-hm.

Q. Inasmuch as you are doing a phased development of this, do you have any requests that we delay the certification until you start injection, or

would you want that certification issued with the order?

A. I don't think it really matters because I really feel the reservoir is just almost full due to the other two floods, and I think response is going to be a lot quicker than it normally would. I don't think you'll have to wait two years or a year and a half or even a year to see a response. I think once injection starts, I think you'll see it almost instantaneously.

Q. It appears that what you're doing is, you're kind OF starting in the northwest and working around the south to the central part of the unit and then the east side of the unit with your injection development; is that correct?

A. Yeah. Actually, we're starting to the north and to the west and to the south, and then we're moving over to the east side, and we're pushing it like this, and then waiting to the last to drill those green wells there which are more in the center of -- which would not have gotten response at that time.

Q. Is there a problem with this being a -- do you anticipate getting a positive production response throughout the unit area within the five years so you don't have to phase the --

A. If you mean every well --

Q. I don't mean every well.

A. But can we really see a response? Oh, yeah.

Q. Where I'm coming from is, under the rules as we have interpreted them, you only get a credit for essentially what you get a response for.

A. Um-hm.

Q. And you can't certify an entire area and then only initiate a flood in part of it and only get a response in part of it but then get a credit for the entire area. And we want to make sure we do this in such a way that -- assuming in fact that you do do the development of the entire project area, that you get a flood -- or that you get the credit for it, my question is whether it should be a phased -- to whether we should certify it in phases in accordance with the way you're developing it.

A. That seems to make sense, but it also -- I really think that we'll have response to the whole thing before the end of five years.

Q. That's fine. I'm asking you, I'm not telling you what to do.

A. Right, I know.

Q. And, again, it's not -- the purpose of it

is to, of course, make sure that you have a full project development and response. What I would think, my example would be that, say, if you did it on that eastern portion first -- if you go into the western portion in 1995, that really does, and you get a response within a year or two, that still gives you plenty of time. And the central part is just sort of filling it out. That shouldn't be a problem then?

A. That's right.

Q. It appears then that we could certify the whole project --

A. I really think we can.

Q. -- immediately?

I have no other questions.

EXAMINER STOGNER: Mr. Carr, is your next witness --

MR. CARR: The next witness, Mr. Stogner, will review the C-108 application and considerations related to that part of the waterflood.

EXAMINER STOGNER: And the actual locations of the injector wells and stuff?

MR. CARR: Yes.

EXAMINATION

BY EXAMINER STOGNER:

Q. Mr. Seely, you did mention that there was

an old saltwater disposal well in this area. Which one was that one?

A. It's in the northwest of the southwest of Section 9. It's 601, Tract 6. It's all the way over to the east.

Q. And that is no longer a saltwater disposal well?

A. We actually bought the well. The only thing that happened to it is that water was stopped being injected, but the packer, the plastic-coated tubing, everything that was in the well is still there. So it's still available for putting water in almost instantaneously. We know it's going into the right place because we got response.

Q. That injected into the Queen, I assume?

A. Yes, it did.

Q. What kind of water did it inject?

A. Bone Springs.

Q. Produced water?

A. Produced water.

Q. But yet you're going to be injecting fresh water out here?

A. Yes, that's correct. The Bone Springs well is no longer there. And we didn't own the Bone Springs well, another operator.

Q. If you got a response with produced water, how come you have to use fresh water?

A. Well, this was another company that had the Bone Springs well. It was only one well. We now own that well, and we own the disposal well, which was also a deep well. And during the time they were producing their Bone Springs well, they used 601 as an injection well.

Q. Into the Queen?

A. Into the Queen. And why it went into the Queen, I don't know, because they didn't own anything else in there, and they certainly didn't -- well, I don't know why.

Q. That's not what I'm asking. You saw response from that well in the Queen formation, and it utilized old saltwater or produced water, and now you have to use fresh water to get a response.

MR. CARR: Mr. Stogner, the fresh water is only to be used as a makeup or a fill-in.

THE WITNESS: That's right.

MR. CARR: We're going to be reinjecting all the produced water we can get, but it was just a question of availability, and we're only using that as makeup over and above what we can locate having been professional produced. And in our C-108 portion of

that, we can show you which wells, and we have a separate exhibit which identifies not only the existing source wells for produced well but where we will be drilling fresh water wells to use as a makeup.

EXAMINER STOGNER:

Q. Okay. I appreciate you straightening me up on that one. So within the unit area, the 601, the 401, and the 1301 are the only wells that had any kind of Queen injection or disposal or whatever; is that correct?

A. That's correct. There was a lot of water that was put in 401 and 1301.

EXAMINER STOGNER: Mr. Carr, it will probably be necessary to dig out those old authorizations and supersede them at this point.

MR. CARR: Okay.

EXAMINER STOGNER: With that, I have no other questions of Mr. Seely.

MR. CARR: Mr. Stogner, would you like me to locate those old authorizations for you?

EXAMINER STOGNER: We should have one on record. I may --

MR. CARR: I'll check with you on that.

At this time I'd like to call David L. Henderson.

DAVID L. HENDERSON,

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

EXAMINATION

BY MR. CARR:

Q. Will you state your name and place of residence?

A. David. Henderson, Fort Worth, Texas.

Q. By whom are you employed and in what capacity?

A. Seely Oil Company as Vice President.

Q. Mr. Henderson, have you previously testified before this Division?

A. No.

Q. Could you briefly review for Mr. Stogner your educational background and then summarize your work experience?

A. I have a B.S. in civil engineering from Texas A&M University. I have been with Seely Oil Company for 12-1/2 years. I'm a member of the Society of Petroleum Engineers.

Q. And your work with Seely is as a petroleum engineer?

A. That is correct.

Q. Are you familiar with the application filed

in this case for approval of a waterflood project?

A. Yes.

Q. Are you the individual who was responsible for and in fact did prepare the C-108 and its attachments?

A. Yes.

MR. CARR: Are the witness's credentials acceptable?

EXAMINER STOGNER: They are.

Q. (BY MR. CARR) Could you refer to what has been marked Seely Exhibit No. 9 and identify this and explain what it shows?

A. Seely Exhibit No. 9 is a completed Form C-108 with all the attachments.

Q. And this is for a new project?

A. That is correct.

Q. This C-108 is not identical to the one that was filed with the Division in November of 1992; is that correct?

A. That's correct. The data has not changed per such, but we've had to delete wells that are no longer going to be used for injection or are in the area of review.

Q. So basically what you have done is, for wells in the east half of the east half of Section 12,

those wells have simply been deleted from this exhibit?

A. That's exactly right.

Q. And you are using the sample diagrammatic sketch for an injection well for the new wells, and that was also included in the original filing?

A. That's exactly right.

Q. So, in essence, we haven't put any additional information in this exhibit; we have deleted some because the boundaries have been contracted?

A. That is correct.

Q. Let's go to pages 12 and 13 of this exhibit, and could you initially just identify those for the examiner?

A. Page 12 is an area map showing ownership within two miles of all injection wells.

Q. And then on page 13, that's a similar plat, but what have you done to that?

A. Page 13 shows the area of review in a circle, one-half mile radius, within each proposed injection well.

Q. Now, I think at this point, it would be helpful again to simply define the areas that are now excluded from the unit area that were included when

the application was originally filed.

A. Okay. We have deleted the east half of the southeast quarter and the southeast of the northeast quarter of Section 12, 18 South, 33 East, and the northwest quarter of the northwest quarter of Section 16, Township 18 South, Range 34 East.

Q. So we've deleted 40 acres in the extreme southeast corner?

A. That's correct.

Q. And we've taken 120 acres off the west edge of the unit?

A. That's right.

Q. Because of that, you're going to have to drill three additional injection wells?

A. That's correct.

Q. What are the locations of those wells?

A. Section 7, 50 feet from the south and 50 feet from the west line. Again in Section 7, 1370 feet from the south line and 50 feet from the west line. And in Section 17, 900 feet from the north line and 330 feet from the east line.

MR. CARR: Mr. Stogner, when we reached agreement with BTA, at that time we were within the 20-day notice period preceding this hearing date. On March the 5th by certified mail, I advised all

interest owners or all owners who were entitled to notice in accordance with Form C-108. That's all the leasehold operators within a half mile of an injection well and all surface owners, one, of the change in unit boundary, and, two, we advised them of the location of each of the new injection wells, told them that we would go forward to hearing at this date.

We recognize that the time period, the statutory 20 day-time period for notice has not run, and for that reason we would request that the case be readvertised with these well locations in it so that at your next hearing, it could be taken under advisement.

We have talked to the affected parties, we anticipate no opposition, but we would prefer to have all the loose ends tied up before we start going with injection wells, locations 50 feet from the outer boundary of the unit.

EXAMINER STOGNER: Okay, Mr. Carr. I'm sure you will provide me a --

MR. CARR: I will do that.

EXAMINER STOGNER: In writing, with those locations?

MR. CARR: Yes, sir, I will.

EXAMINER STOGNER: Okay.

Q. (BY MR. CARR) Mr. Henderson, let's go to Exhibit No. 9. I direct your attention to pages 28 through 116. I'd like you just to, in a generic way, identify what we're talking about.

A. Okay. This is data sheets on all the wells that are within the area of review which penetrate the injection zone. They're organized by section and then by unit letter within each section.

Q. What we have in this portion of the C-108 is a diagrammatic or a well data sheet for each of these wells?

A. That is correct.

Q. And it contains on these sheets all the information required, well by well, for each well within an area of review?

A. That's correct.

Q. Are the plugged and abandoned wells also included in these diagrammatic sketches?

A. That is correct.

Q. How many plugged wells are we talking about within the proposed unit area, approximately?

A. About 32, I believe.

Q. We have diagrammatic sketches in this material for each of those plugged and abandoned wells showing the location of all plugs?

A. That's correct.

Q. And it shows casing strings or anything else unique in any of the wells that have been plugged and abandoned?

A. That is also correct.

Q. Did you prepare these sketches?

A. That is correct.

Q. Have you reviewed the plugging detail on each of these?

A. Yes, I did.

Q. In your opinion, are there any wells that could become, because of the way they're plugged, a vehicle for migration of injection fluids out of zone?

A. No.

Q. Has this material been provided to the Hobbs District Office of the Oil Conservation Division?

A. A copy of the C-108 has been provided to the district office. As late as this week there has been no -- in a conversation, there was no indication of any problems.

Q. And this-week contact was made with Mr. Sexton to confirm there were no problems?

A. That is correct.

Q. If anything is discovered where it appears

there needs to be additional work or that a well might become a problem, are you prepared to work with either the Santa Fe or the district office to address that problem?

A. Yes.

Q. Let's go to what has been marked in this exhibit pages 14 through 27. Could you identify those for Mr. Stogner?

A. Those are well data sheets and schematics on all injection wells that we're proposing, both the current construction and the proposed construction.

Q. And so you will have a proposed construction sheet, and then you will also show the current construction on each of these wells?

A. That is correct.

Q. And this gives the current location of each well that you intend to use for injection in the new unit?

A. Yes, along with a typical well diagram.

Q. And that typical well diagram is set out on page 28 of this exhibit?

A. That is correct.

Q. Now, the formation into which we're proposing to inject or flood was defined by Mr. Seely, was it not?

A. That's correct.

Q. Could you identify the source of the water that you propose to inject into this waterflood project?

A. We will inject produced water from all producing wells within the unit along with fresh water which will be used for makeup water.

Q. Has the Commissioner of Public Lands approved the use of fresh water for makeup in the unit area?

A. Yes.

Q. Have the fresh water wells been drilled at this time?

A. No, they have not.

Q. Have you obtained permits or filed permits with the State Engineer's Office?

A. Yes.

Q. And you have the water rights to drill these wells?

A. That is correct.

Q. Can you tell us the general location of the water supply wells that will be drilled as part of this project?

A. Yes. There will be two of them. One will be in the southwest quarter of the southwest quarter

of Section 8. The other will be in the northeast quarter of the northwest quarter of Section 17.

Q. What volumes are you initially proposing to inject?

A. Two hundred barrels of water injected per day per well.

Q. And what maximum daily injection rate might you have to achieve for an effective flood?

A. Two hundred barrels per day per injection well.

Q. And you're going to have an open or a closed system?

A. It will be a closed system.

Q. Will it be necessary to inject under pressure?

A. Yes.

Q. Would a pressure limitation of .2 pound per foot of depth to the top of the injection interval be satisfactory for your purposes?

A. No.

Q. What would be the maximum injection pressure you anticipate you might need?

A. Approximately 2,000 psi.

Q. Would it be satisfactory to Seely to establish an injection pressure in excess of .2 pound

per foot of depth?

A. Yes.

Q. Do that by having Division-witness separate tests conducted on the injection wells?

A. Yes.

Q. And then in conjunction with the district office of the Division, you could establish a safe and appropriate injection pressure for this project?

A. Yes.

Q. Let's go to what has been marked as Exhibit No. 10. Could you identify that for Mr. Stogner?

A. Exhibit No. 10 is a water analysis of two injection fluids, both produced water from the eight producing wells that are currently producing in the unit plus makeup water, which is fresh water.

Q. So by looking at these analyses, you can not only obtain an understanding of the characteristics of the water, but you can also identify the water sources you intend to use?

A. That is correct.

Q. The fresh water samples, their locations are indicated. You, of course, will be using fresh water from the supply wells?

A. That's correct.

Q. And into what formation will you be

drilling these supply wells?

A. The fresh water will come from the Ogallala at a depth of approximately 250 feet.

Q. Are there any other fresh water zones in the area other than the Ogallala?

A. No.

Q. Are there any fresh water wells within a mile of the injection wells?

A. There are none in the State Engineer's records.

Q. Are the logs of the proposed injection wells -- of the wells which you will be converting to injection on file with the Division?

A. Yes.

Q. Have you examined the available geologic and engineering data on the area?

A. Yes.

Q. As a result of that examination, have you found any evidence of open faults or any other hydrologic connections between the injection zone and any underground source of drinking water?

A. No.

Q. Were Exhibits 8 and 9 prepared by you or compiled under your direction?

A. Yes.

MR. CARR: At this time, Mr. Stogner, we would move the introduction of Seely Exhibits -- I'm sorry, Exhibits 9 and 10 are the two we're talking about.

Q. They were prepared by you?

A. Yes.

MR. CARR: We would move the admission of Seely Exhibits 9 and 10.

EXAMINER STOGNER: Exhibits 9 and 10 will be admitted into evidence.

MR. CARR: And that concludes my direct examination of Mr. Henderson.

EXAMINATION

BY EXAMINER STOGNER:

Q. Your C-108 represents how many schematics and information on how many wells within the area of review?

A. Total number of wells within the area of review is somewhere around 60, I believe. I'm not exactly sure.

Q. You have tops of cement shown on all those 60 wells?

A. Yes, I have. The schematics are drawn on the plugged-out wells plus the injection wells. The other I just have data sheets that show tops of

cements.

Q. And that either showed whether they were calculated or had actual tops of cements verified by temperature surveys?

A. Temperature surveys or by logs, that's correct.

Q. Of these 60 wells, 60 plus or minus odd wells, how many wells penetrated the injection interval?

A. All of them.

Q. And how many are P & A'd of these 60 wells?

A. Around 30.

Q. And how many of these wells are, say, producing wells but are deeper than the proposed injection interval? Do you have any deep gas wells, anything like that?

A. Of the plugged?

Q. No, of the -- let me rephrase it. Of these 60-odd wells, are there any that are producing from a deeper horizon than this Queen interval?

A. Yes, a substantial number of them.

Q. Give or take?

A. Twenty.

Q. And how many of these wells will be utilized or are now being utilized as EK producing

wells?

A. There's eight producers in the unit area at this time.

Q. You're ultimately seeking the maximum of 2,000 psi injection interval; right?

A. That's correct.

Q. Or have any of the previous two floods had a higher pressure, do you know?

A. I do not know, I do not know if it was higher than 2,000.

Q. Do you know if it was higher than the .2 psi per foot?

A. I feel certain that it's above that.

Q. You feel that's going to contribute to your need of going up to 2,000 psi?

A. Yes.

Q. On your review of the old plugged and abandoned wells, about what era or what time period were they plugged and abandoned?

A. There were a substantial number in the '60's. Most of them were in the '60's and early '70's.

Q. Do you think the plugging techniques utilized back then on those wells are going to be able to withstand 2,000 psi?

A. Yes. There's standard commission plugs in all of them, 2556, whatever was required, and it's basically the same that's required now.

Q. What makes you feel that they are adequate to withstand 2,000 psi?

A. Because there's plugs above and below wherever there should be porosity. And most of the wells that are plugged just went to this interval, in fact, the old wells inside the unit. And also, in addition, most of the deep wells have 8-5/8 set through this interval in several cases.

Q. I guess I'm concerned, on some of those P & A'd wells, is the production string still through that interval?

A. Yes.

Q. Are there a bunch that are open-holed through there or had the 5-1/2-inch casing pulled?

A. No. Oh, like I say, most of these wells were drilled before that formation, and the pipe was left.

Q. So there are none of them out there that are without 5-1/2-inch production casing?

A. There are some that have had the casing cut and pulled from 2,800 to 1,800 feet, something like that.

Q. Are there any out there absent the production casing?

A. Dry holes?

Q. Yes, or old P & A'd, for that matter.

A. Maybe a couple. I'm not exactly sure.

Q. Let's talk about one. Let's turn to page 77.

A. Okay.

Q. What can you tell me about that old well?

A. Okay. That well was drilled -- that was drilled by Zia Petroleum. That's a recently drilled well, drilled in the '80's, and was a dry hole with no porosity in the Queen, which is our injection interval. You've got 25 sacks plugged above, which is about half above and half below the Queen interval, at around 4,350, 25 sacks at 3,150, which is above the Yates, and 25 sacks at the bottom of your surface pipe, 10 sacks surface plugged.

Q. So there's no casing in that well at the injection interval?

A. That's correct.

Q. But there is a 25-sack plug?

A. Right above -- directly -- it's across the Queen interval. Some of the plug is above, and some of it will be below.

Q. And that's going to seal off 2,000 psi?

A. There's no porosity in the well in the Queen.

Q. So you don't feel it will get over there in the first place?

A. No, I do not.

Q. So Exhibit No. 5 is questionable. Okay.

On page 99, what's the corresponding injection interval in this well?

A. It is around 44 -- it's on there, around 4,400 feet. It's a little bit deeper, 4,450, something like that. It should correspond to some of the wells down in the EK Queen unit.

Q. Has this one got porosity in that interval?

A. Let me see. Southwest, northwest of 17. No, it does not. It was a well drilled for the Queen which was unsuccessful.

Q. Now, as opposed to going through all 60 wells tonight -- of course, at this point we -- never mind.

Is there anything further, Mr. Carr?

MR. CARR: Nothing further, Mr. Stogner.

EXAMINER STOGNER: Would you give me some of the sack locations so I can re- --

MR. CARR: I will. I will prepare a

proposed advertisement and bring that to you tomorrow, if you're going to be in tomorrow.

EXAMINER STOGNER: No, I won't be. Will Monday be sufficient?

MR. CARR: Monday will be better for me.

EXAMINER STOGNER: And that will be for the April 22?

MR. CARR: Yes, sir.

EXAMINER STOGNER: With that, do you have anything further?

MR. CARR: Nothing further.

EXAMINER STOGNER: Do you have anything further, Mr. Stovall?

Does anybody else have anything further in this case?

With that, we can take Case No. 10647 under advisement; is that correct?

MR. CARR: That will be --

EXAMINER STOGNER: That's the Unit Agreement.

MR. CARR: Yes, sir.

EXAMINER STOGNER: Okay. So we'll just need to readvertise 10648.

MR. CARR: Correct.

EXAMINER STOGNER: With that, I'll take

Case 10647 under advisement, and Case 10648 will be continued and readvertised for the hearing scheduled for April 22.

With that, hearing adjourned.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case Nos. 10647 and 10648 heard by me on March 1993.

, Examiner
Oil Conservation Division

CERTIFICATE OF REPORTER

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

I, Deborah O'Bine, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that I caused my notes to be transcribed under my personal supervision, and that the foregoing transcript is a true and accurate record of the proceedings of said hearing.

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, March 30, 1993.

Deborah O'Bine

DEBORAH O'BINE
CCR No. 63