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:

JOINT APPLICATION OF TEXACO EXPLORATION AND PRODUCTION, INC., AND MARATHON OIL COMPANY

CASE NO. 11,152

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: DAVID R. CATANACH, Hearing Examiner

December 1, 1994

Santa Fe, New Mexico

This matter came on for hearing before the Oil Conservation Division on Thursday, December 1, 1994, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, before Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

* * *

I N D E X

December 1st, 1994
Examiner Hearing
CASE NO. 11,152

* * *

E X H I B I T S

Texaco Exhibits	Identified	Admitted
Exhibit 1	8	20
Exhibit 2	9	20
Exhibit 3	18	20
Exhibit 4	17	20

(Continued...)

E X H I B I T S (Continued)

Marathon Exhibits	Identified	Admitted
Exhibit 1	27	57
Exhibit 2	29	57
Exhibit 3	31	57
Exhibit 4	33	57
Exhibit 5	39	57
Exhibit 6	40	57
Exhibit 7	41	57
Exhibit 8	42	57
Exhibit 9	43	57
Exhibit 10	43	57
Exhibit 11	44	57
Exhibit 12	45	57
Exhibit 13	46	57
Exhibit 14	48	57
Exhibit 15	49	57
Exhibit 16	50	57
Exhibit 17	52	57
Exhibit 18	53	57
Exhibit 19	54	57
Exhibit 20	55	57

Shell Exhibit	Identified	Admitted
Exhibit 1	68	-

* * *

APPEARANCES

FOR THE DIVISION:

RAND L. CARROLL
Attorney at Law
Legal Counsel to the Division
State Land Office Building
Santa Fe, New Mexico 87504

FOR APPLICANT TEXACO EXPLORATION AND PRODUCTION, INC.:

CAMPBELL, CARR, BERGE & SHERIDAN, P.A.
Suite 1 - 110 N. Guadalupe
P.O. Box 2208
Santa Fe, New Mexico 87504-2208
By: WILLIAM F. CARR

FOR APPLICANT MARATHON OIL COMPANY:

KELLAHIN & KELLAHIN
117 N. Guadalupe
P.O. Box 2265
Santa Fe, New Mexico 87504-2265
By: W. THOMAS KELLAHIN
and
MARATHON OIL COMPANY
P.O. Box 552
Midland, TX 79702
By: DOW CAMPBELL

FOR SHELL WESTERN E&P, INC:

HINKLE, COX, EATON, COFFIELD & HENSLEY
218 Montezuma
P.O. Box 2068
Santa Fe, New Mexico 87504-2068
By: JAMES G. BRUCE

* * *

WHEREUPON, the following proceedings were had at 9:00 a.m.:

EXAMINER CATANACH: At this time we'll call Case 11,152.

MR. CARROLL: Joint Application of Texaco Exploration and Production, Inc., and Marathon Oil Company for a pressure maintenance project, unorthodox injection well locations, and qualification for the recovered oil tax credit pursuant to the New Mexico Oil Recovery Act, Lea County, New Mexico.

EXAMINER CATANACH: Are there appearances in this case?

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe law firm Campbell, Carr, Berge and Sheridan.

We represent Texaco Exploration and Production, Inc., and I have one witness.

EXAMINER CATANACH: Additional appearances?

MR. KELLAHIN: Mr. Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin and Kellahin, appearing in association with Mr. Dow Campbell. Mr. Campbell is a Texas attorney and the house counsel for Marathon Oil Company in this matter.

We are appearing on behalf of Marathon Oil Company, and we have one witness to be sworn.

EXAMINER CATANACH: Additional appearances?

MR. BRUCE: Mr. Examiner, Jim Bruce from the Hinkle law firm in Santa Fe, representing Shell Western E&P, Inc.

We have no witnesses.

EXAMINER CATANACH: Anybody else?

Okay, will the witnesses please stand and be sworn in?

(Thereupon, the witnesses were sworn.)

KEVIN HICKEY,

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

DIRECT EXAMINATION

BY MR. CARR:

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

A. Kevin Hickey.

Q. Where do you reside?

A. I live in Midland, Texas.

Q. By whom are you employed?

A. Texaco, Incorporated.

Q. And what is your current position with Texaco?

A. I'm a reservoir engineer.

Q. Does the geographic area of your responsibility for Texaco include the portion of southeastern New Mexico which is involved in this case?

A. Yes.
Q. Have you previously testified before this Division?
A. No.
Q. Could you summarize your educational background for the Examiner, please?
A. I graduated with a bachelor of science degree in chemical engineering from the University of Pittsburgh in 1979.
Q. And since graduation, for whom have you worked?
A. I've worked exclusively for Texaco as an oil and gas production engineer.
Q. And at all times since graduation you have been employed as an engineer?
A. Correct.
Q. Are you familiar with the Application filed in this case on behalf of Texaco and Marathon?
A. Yes.
Q. Have you made a study of the portion of the Vacuum-Drinkard Pool, which is the subject of this Application?
A. Yes.
Q. And have you prepared exhibits for presentation here today?
A. Yes.

MR. CARR: Mr. Catanach, at this time we tender Mr. Hickey as an expert witness in petroleum engineering.

EXAMINER CATANACH: Mr. Hickey is so qualified.

Q. (By Mr. Carr) Mr. Hickey, could you briefly state what Texaco seeks with this Application?

A. Texaco seeks an order approving a pressure maintenance project in a portion of the Vacuum-Drinkard Pool, approving unorthodox injection well locations and qualifying this project for the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act.

Q. Now, Mr. Hickey, this project is going to be conducted on a lease basis, and you're not seeking approval of any kind of a unit agreement or unitization?

A. That's correct.

Q. What type of secondary recovery project are Texaco, Marathon and Shell proposing in this area?

A. Pressure maintenance through waterflooding.

Q. Could you refer to what has been marked for identification as Texaco Exhibit Number 1 and identify that for the Examiner, please?

A. This is a copy of Form C-108, application to inject fluid into reservoir, with supporting data showing the location of the proposed injection wells, their construction, a list of wells in the area of review, water analysis of formation and injection water, and freshwater wells in the area with their analysis.

Q. Before we go into Exhibit 1, could you identify what has been marked as Texaco Exhibit Number 2?

A. Exhibit 2 is a plat of the project area. The dashed outline on that plat shows that the project area covers approximately 1069 acres.

The legal description of it is Township 17 South, Range 34 East, Section 36, is the south half, southeast quarter, and the southeast quarter of the southwest quarter; Township 17 South, Range 35 East, the south half of the southwest quarter; Township 18 South, Range 34 East, the northeast quarter, the east half of the northwest quarter, the north half of the southeast quarter and the southeast quarter of the southeast quarter; in Township 18 South, Range 35 East, Section 6, the west half, the west half of the east half, and the northeast quarter of the northeast quarter.

Q. In the project area there are nine leases; is that correct?

A. Correct. It covers approximately 1069 acres.

Q. And all of these leases are state leases?

A. That is correct.

Q. And the operators of all leases are either Texaco, Marathon or Shell?

A. That is correct.

Q. And this waterflood pressure maintenance project will be operated pursuant to a cooperative waterflooding agreement that has yet to be executed?

A. That is correct.

Q. What is the present status of the wells that will be used for injection in the project area?

A. Two are active producing wells to be converted, and there are six wells to be drilled.

Q. Let's refer to Exhibit Number 1, and I direct your attention to pages 14 and 15.

Mr. Catanach, there are large copies of these plats for your review. They're easier to read.

But Mr. Hickey, would you refer to those pages and then just identify them and explain what they show?

A. Page 14 is -- Attachment 5 of the C-108 is a plat of the area showing all wells within a two-mile radius of the injection wells. These are outlined or should be outlined as the -- with yellow triangles. It shows the lease ownership of all the -- in this area.

And also on the second page, on page 15, which is a shot-down version of the project area, it just shows the wells that have penetrated the injection interval, and it shows a half-mile radius around those wells, indicating the wells in the area of review.

Q. On this page 15, then, the yellow triangles indicate each of the eight injectors?

A. That is correct.

Q. And the areas of review are indicated on this plat?

A. Correct.

Q. Let's go now to Exhibit 1, pages 16 through 19, and I'd ask you just to identify what is contained on those portions of this exhibit, on those pages.

A. Pages 16 through 19 give a tabular listing of all the wells in the area of review.

Basically, the first column indicates the operator, the second column is the well name and API number, the third column give the legal location, the fourth column gives the completion date, the fifth column gives the total depth. The subsequent columns indicate the construction of the well, the casing depths, the cement tops, the method of determining cement tops, the producing intervals, its current status, and any additional remarks regarding production intervals.

Q. Does Exhibit 1 also contain wellbore schematics for each well within any of the areas of review that penetrate the injection interval?

A. Yes, it does. Pages 20 through 70 are wellbore schematics of every well in the area of review. This indicates the location of the wells and the other information required by the Form C-108.

Q. Mr. Hickey, could you refer to the portion of Exhibit Number 1 which contains schematic drawings of any plugged and abandoned wells within any of these areas of review?

A. There are four wells. These are the Warn State A/C 2 Number 10, the Vacuum Grayburg San Andres Number 68, the New Mexico "R" State NCT-3 Number 15 and the New Mexico "AB" State Number 5.

There are schematic drawings showing the plugging detail located in Exhibit 1 on pages 23, 37, 56 and 62, and all have been plugged as to prevent migration from the injection interval.

Q. Let's go to pages 11 through 13 of Exhibit Number 1. I'd ask you to identify those portions of this exhibit and review the information contained thereon.

A. The attachments are wellbore schematics of the proposed injection wells. Page 11 is a schematic of the New Mexico "O" State Number 36, page 12 is a schematic of the "R" State NCT-3 Number 26.

Q. Those are the two wells you intend to convert --

A. Intend to convert.

Q. Okay. And then page 13?

A. Page 13 is a typical wellbore diagram of the proposed injection wells that we plan to drill.

Basically what -- All these wells pretty much have been completed. The two wells to be converted were completed in the past year, and basically they have been -- and all the wells out here drilled for the Drinkard -- pretty much the same type of construction.

Basically they set casing at the base of the Rustler, which is about 1500 feet, circulate cement to the surface.

The well has been drilled to a total depth through the Drinkard formation, a depth of approximately 8100 feet, and cement has been circulated to the surface, or at least up this far into the surface casing.

The wells should be then set with a packer within a hundred feet of the top perforation, and using 2 3/8 cement-lined tubing.

Q. You're proposing to inject into the Drinkard formation?

A. That is correct.

Q. In the Vacuum-Drinkard Pool?

A. That is correct.

Q. What is the approximate thickness of the formation?

A. The approximate thickness is about 500 feet.

Q. Will the next witness present an isopach map that actually shows the thickness of the formation in detail across the area?

A. That is correct.

Q. What is the source of the water proposed to inject in the subject well?

A. I propose to use the produced water from the Glorieta and produced water from the Grayburg-San Andres formations. This is coming from the Vacuum Glorieta West unit, which will basically supply the water to the three wells located on the eastern side of the project area, and the remaining wells will be supplied with water from the Vacuum Grayburg-San Andres unit.

Q. Are all of the injectors going to be operated by Texaco?

A. All except for the one on the Warn State. That will be operated by Marathon.

Q. And at this present time, Texaco is conducting waterflood operations in this general area?

A. Yes, there are several waterfloods in this area.

Q. And you'll be tying this into the existing Texaco water system that will -- how you will supply the project area; is that correct?

A. That is correct.

Q. And you'll be able to meter not only the injection but be able to regularly check water wells in the area so that you can maintain full control over the project?

A. That is correct.

Q. What volumes do you propose to inject?

A. An average volume of about 625 barrels a day per well, for a total of about 5000 barrels a day.

Q. And what will be the maximum injection rate you propose?

A. It will be about 8000 barrels a day for the whole project, roughly 1000 barrels per day per well.

Q. And this will be a closed system?

A. Yes, it will.

Q. Are you going to be injecting under pressure or by gravity?

A. We'll be injecting under pressure. We plan an average pressure of about 1400 p.s.i.

Q. And is that close to a .2 pound per foot of depth at the top of the injection interval?

A. That is correct.

Q. What do you anticipate would be your maximum injection pressure?

A. At this point, 1500 p.s.i.

Q. If you need to go above this .2-pound-per-foot-of-depth limitation, would you first propose that you establish with a step-rate test that that can be done without fracturing the confining strata?

A. That is correct.

Q. Let's go to Exhibit Number 1, and I direct your attention to pages 71 through 80. Could you identify and review those for the Examiner?

A. Pages 71 through 80 are water analyses of produced and injection fluid.

Page 71 is a sample of -- a water analysis of Drinkard water from the Warn State lease, page 72 is Drinkard water from the Texaco leases, page 73 is produced water from the Glorieta formation, page 74 is produced water from the San Andres formation.

Pages 75 through 80 were compatibility tests run using various mixes of Drinkard water and proposed injection water from the Glorieta and the San Andres. We indicated that there were no compatibility problems.

Q. Okay, are there freshwater zones in this area?

A. Yes there are, in the Ogallala.

Q. And are there any freshwater wells within a mile of any of the proposed injection wells?

A. There are several wells in the area. Two are identified on page 81.

One thing to note, that these are monitor wells with all the waterflood projects in the area, that these are routinely taken, monthly water analysis, to determine a possibility of contamination.

Q. And is an analysis of the water from each of the wells shown on 81 attached to this exhibit?

A. Yes, they are.

Q. They're the last two pages of the exhibit?

A. Pages 82 and 83.

Q. Now, there are additional freshwater wells in the area; is that not correct?

A. Yes, there are.

Q. And is Exhibit Number 4 a copy of water analyses on each of those wells that indicate the location of the well and also the most recent analysis of the water?

A. Yes, that is.

Q. Have you examined the available geologic and engineering data on this reservoir and as a result of that review, have you determined that there -- whether or not there's evidence of any open faults or other hydrologic connections between the injection interval and any underground source of drinking water?

A. Yes, I have, and there's no indication that there's any source of connections between the injection zone and underground source of drinking water.

Q. In your opinion, will approval of this Application result in the increased ultimate recovery of oil from the project area?

A. Yes.

Q. In your opinion has the project area been so depleted that it is now prudent to implement pressure maintenance operations to maximize the recovery of crude oil?

A. Yes.

Q. Has a copy of the Application been provided to all leasehold operators within any of the areas of review?

A. Yes it has. We've -- Exhibit 3 is a copy of the notice letters, and there's a copy of the certified receipts of the -- that each of the offset operators of wells and the State were notified.

Q. Mr. Hickey, those notice letters were provided --

A. Yes.

Q. -- by certified mail on October 31st, 1994?

A. Yes.

Q. A copy of the Application was provided at that time?

A. Yes.

Q. And a legal advertisement was also run in the newspaper as required by Form C-108?

A. Yes.

Q. That was run in the *Hobbs Daily News Sun* on November 3rd, 1994?

A. That is correct.

Q. Was notice also provided by certified mail to the owner of the surface of the land?

A. Yes, it was. It was sent to the State.

Q. What is the depth bracket allowable for wells in this pool?

A. 187 barrels per day.

Q. And what is the spacing for wells in the pool?

A. Forty acres.

Q. Is there a producing well on each 40-acre tract in the project area?

A. Yes.

Q. And do the Applicants request that each operator in the project area be allowed to produce the share of the project allowable attributable to its leases from the wells it operates in the project area in any proportion?

A. Yes.

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

A. Yes.

Q. Were Exhibits 1 through 4 either prepared by you or compiled at your direction and under your supervision?

A. Yes.

MR. CARR: At this time, Mr. Catanach, we move the admission of Texaco Exhibits 1 through 4.

EXAMINER CATANACH: Exhibits 1 through 4 will be admitted as evidence.

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

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Hickey, I'm a little bit unclear about this project. Do you plan on having two operators within this project?

A. There will actually be three operators. Shell will be operating their wells. Each lease holder will operate their own wells.

We will operate the seven injection wells that are on our property, and then Marathon will operate the one well that is shared on the lease line between them and Shell.

Q. I don't know that I've come across this situation before. Why was it necessary to do it that way, to not have a -- one operator operating this flood?

A. We felt that -- and I believe the next witness will explain a little bit more about the timing of the project.

We felt that it was better to try to go ahead from an economic standpoint, to prevent waste, that we try to do a lease line agreement with the wells to be shared between the operators.

Q. Do you specifically know which acreage will be operated by which company?

A. Yes.

Q. Can you go over that for me?

A. On that plat --

MR. CARR: Exhibit 2.

THE WITNESS: -- Exhibit 2, Texaco will operate the tracts marked 8, 9, 1, 2, 6 and 7. Marathon will operate tract 5, and Shell will operate tracts 3 and 4.

Q. (By Examiner Catanach) Did you say that Texaco will operate all of the injection wells?

A. We will operate all the injection wells, with the exception of the one that is on Tract 5, which is the Warn State lease. Marathon Oil will operate that well.

Q. Where is that Warn State well located?

A. That is located on Tract -- on this diagram, on tract 5.

It's actually -- It's on the lease line, if you see where tracts 3 and 4 and 5 come together. It's the northernmost well.

Q. Are these all separate state leases, all these tracts?

A. Yes.

Q. Have you consulted in any form or fashion with the Commissioner of Public Lands on this proposal?

MR. CARR: Mr. Catanach, we've provided a copy of the Application, we've confirmed that the leases are all -- all leases are common schools, except 2 and 7; they are New Mexico Military Institute.

We've received no objection from the Land Office.

EXAMINER CATANACH: Except, I'm sorry, tracts 2 and 7?

MR. CARR: 2 and 7 are New Mexico Military Institute.

EXAMINER CATANACH: Have you received any kind of approval from them?

MR. CARR: No, we haven't.

I mean, we've discussed it, and that's as far as it has gone with them.

If you'd like for me to follow that up with the Land Office, I can do that.

EXAMINER CATANACH: Yes, I would, as a matter of fact, Mr. Carr.

MR. CARR: All right.

Q. (By Examiner Catanach) Mr. Hickey, have the operators arrived at a method of allocating production on these -- in this waterflood?

A. Production will be allocated by -- to -- as they are -- as it is now, according to each individual lease.

There will be no central commingled facility.

As far as the injection wells, Texaco is supplying the injection well from our waterfloods, and it will be charged at a rate according to the lease line agreements and water that is agreeable to all parties.

Q. How many producing wells will you have within the project?

A. I think that's 27. We have, I believe, 15 on Texaco acreage. Marathon will have eight, and then Shell has two.

Q. Do you know, Mr. Hickey, what the average production is within the area?

A. Total production is about 2500 barrels a day.

Q. Total current production?

A. Right.

Q. That's from about 25 wells?

A. That's about correct, about -- probably a little bit less than a hundred barrels a day per well.

Q. Mr. Hickey, have you examined all the area-of-review wells and satisfied yourself that they're all cased and cemented adequately to confine the injected fluid?

A. Yes, I have.

Q. Is there actually a cooperative waterflood agreement document that's been signed by the various companies?

A. Not as yet.

Q. Will there be?

A. Yes.

Q. That will cover operations within the project area?

A. Yes.

EXAMINER CATANACH: That's all I have of the witness at the current time.

MR. CARR: Mr. Catanach, I would note that I have not been able to locate an exact precedent for an application like this.

I would call your attention, however, that approximately two years ago, Hanson Operating and Yates Petroleum Corporation came in with a joint or at least related applications to waterflood one pool. It was the Yates Creek AL lease, and it was a Hanson unit south of that, and it was similar in all respects.

There was a common waterflood project and each was going to produce wells on its own tract and keep that production.

I will provide those order numbers to you because, although they were two separate cases, the facts are very similar to these.

That's all we have of Mr. Hickey.

(Off the record)

EXAMINER CATANACH: Mr. Carr?

Upon conferring with Mr. Carroll here, we have determined that it probably would be best if we did provide notice of the hearing.

MR. CARR: What we will do, then, at the conclusion of the hearing is request that the case be continued to the January 5th Examiner hearing.

We will provide notice of the hearing, and then on January the 5th we will request that the matter be taken under advisement based on the record here today.

Inasmuch as we've provided the Application to each of the affected parties and have no objection, we don't anticipate there would be any need for any additional hearing at that time. It would just close the door on any subsequent notice question.

So we will do that.

EXAMINER CATANACH: Okay.

(Off the record)

EXAMINER CATANACH: You may proceed, Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Examiner.

At this time I'd like to call Mr. Craig Kent.

We have passed out to the Division and to the participants the Marathon exhibits that Mr. Kent will use in his presentation, Mr. Examiner.

CRAIG KENT,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. For the record, Mr. Kent, would you please state your name and occupation?

A. My name is Craig Kent, and I'm a reservoir engineer with Marathon Oil Company in Midland, Texas.

Q. Mr. Kent, have you testified before this agency on prior occasions and have qualified as an expert witness in the field of reservoir engineering, including special expertise in reservoir simulation?

A. Yes, I have.

Q. Are you personally involved with and familiar with the facts and circumstances surrounding this joint Application by your company and Texaco for approval of this pressure-maintenance project?

A. Yes, I am.

Q. As part of your work, have you in fact simulated the performance of the project?

A. Yes, I have.

Q. And as a result of that simulation, do you now have engineering conclusions and opinions about the feasibility of this project?

A. Yes, I do.

MR. KELLAHIN: We tender Mr. Kent as an expert reservoir engineer, with expertise in reservoir simulation.

EXAMINER CATANACH: Mr. Kent is so qualified.

Q. (By Mr. Kellahin) Let me have you turn to what you have marked as your first exhibit, and let's use that as an orientation display, Mr. Kent.

A. Okay. Exhibit 1 is the same plat that was shown as Texaco Exhibit Number 2. This shows the active wells in the Vacuum Drinkard Pool.

Outlined by the dashed line is our proposed project area.

Q. When the Examiner looks at all the black dots on the display, what is he seeing?

A. The black dots represent currently active producing wells within the Vacuum Drinkard Pool.

Q. Regardless of whether they're inside or outside the project, then, those are the Drinkard producers as they now exist for this pool?

A. That's correct.

Q. Okay. What is the area, project area, that you modeled as part of your simulation work?

A. I modeled the production of the entire Vacuum-Drinkard Pool and concentrated my review of that on the area that's marked within the dashed line.

Q. Did you satisfy yourself that you had adequate geologic basis upon which to conduct reservoir simulation?

A. Yes, I did.

Q. In addition, did you have sufficient production information where you as a reservoir engineer could select reservoir parameters by which to conduct an accurate simulation?

A. Yes, I did.

Q. And did you satisfy yourself that you had sufficient history in which to match or calibrate your simulation?

A. Yes, I did.

Q. Based upon that work, what were your conclusions?

A. My conclusions were that within the project area we should recover under primary depletion somewhere around 3 million barrels of oil and that by implementation of this secondary recovery project we would improve recovery by another 2.5 million barrels of oil.

Q. What is the current level of cumulative recovery from the project area's wells?

A. To date, we've recovered about 1.2 million barrels of oil.

Q. The remaining primary is another 1.8, and then on top of that you have estimated an additional 2.5 million incremental oil attributed to the pressure-maintenance process?

A. That's correct.

Q. All right. Let's look at the conclusionary displays that illustrate your points.

If you'll turn with me, sir, to what is marked as Exhibit 2, first identify what you've shown us and then describe your conclusions.

A. Okay, Exhibit 2 is a production plot for the project area, showing daily average oil, gas and water rates from all the wells, from October of 1992 through August of 1994.

Shown in the green line with the diamond-shaped symbols is the average daily oil rate. The red line with the square symbols represents the average daily gas rate. And the blue line with the triangle symbols represents the daily average water rate.

From -- During the period of October, 1992, through probably the middle of 1994, there was active development within the Drinkard Pool in this area. And that's shown, as you can see, by the increase in oil and gas rates.

Approximately the beginning of this year, the level of activity decreased, and the reservoir went on primary decline.

During that period, however, as reservoir pressure continued to decline, we've seen dramatic increases in GOR during that same time period, roughly from around 1000 standard cubic per stock tank barrel in January, to an average of about 1550 standard cubic feet per stock tank barrel now, and the trend is still continuing to increase.

Q. What did you determine to be the initial discovery reservoir pressure in the Drinkard?

A. The discovery pressure was slightly less than 3000 pounds.

Q. What is the bubble-point pressure in the reservoir?

A. The bubble-point pressure that we measured from a fluid sample in early 1992 was 2350 pounds.

Q. And where are we now in the pressure?

A. Based on our simulation work, we're estimating a reservoir pressure in the project area of around 1950 pounds.

Q. So we're now well below the bubble-point pressure in the reservoir?

A. That's correct, we have dropped below bubble point.

Q. When you look at the plot of oil production, the highest point of performance in the project area is -- What is that? February of 1994?

A. Correct.
Q. And then after that you're seeing a decline?
A. That's correct.
Q. What do you attribute that decline to?
A. That decline is attributable to depletion of reservoir energy, reservoir pressure.
Q. What kind of drive mechanism do you have in this reservoir?
A. This is a solution gas drive reservoir.
Q. Do you see any significant water production?
A. No, our water production averages between 100 and 200 barrels of water per day.
Q. All right, let's go to the results of the simulation, then. If you'll turn to Exhibit 3, identify and describe that for us.
A. Exhibit Number 3 is a combination of the existing production history, along with the projections from the reservoir simulation for oil, gas, water production, as well as water injection.

We're showing the oil production with the solid and dashed green lines, gas is shown by the solid and dashed red lines, water production with the solid and dashed darker blue lines, and then water injection with the lighter dashed blue line.
Q. What does it tell you?

A. What it's showing us is that -- particularly looking at the oil production, that by implementation of a secondary recovery project, that we will start to arrest the decline in the oil production and actually improve our ultimate recovery.

We also see by looking at the difference in spread between the gas and oil curves that we will achieve a reduction in overall GOR by maintaining higher reservoir pressure.

Q. As part of your duties to examine and analyze the project area to see if it is suitable for pressure maintenance, did you investigate the issue of timing of the implementation of pressure maintenance?

A. Yes, I did.

Q. And what was your conclusion?

A. One of our sensitivity analyses that we looked at was to alter the timing of the startup of the projects, and we chose to alter it by -- in six-month intervals.

And we found that each delay of six months cost us about five percent of the incremental benefit that we would receive.

Q. In terms of barrels of oil?

A. That would be -- Our total secondary was about 2.5 million barrels, so roughly 75,000 barrels of oil for every six-month delay.

Q. So there's a significant factor for your consideration as to the timing by which you maintain or arrest the pressure reduction in the reservoir?

A. That's correct.

Q. Let's turn now, sir, to look at Exhibit 4.

A. Exhibit 4 is an isopach map of the Drinkard reservoir. We're showing the same nine-section area as we've shown on Exhibit 1.

Highlighted in yellow is the proposed project area. Again, the solid black dots represent the currently active Drinkard producers. The Xs on the map represent Drinkard penetrations that were used for control.

Q. Let's talk about your engineering justification for the boundary of the project area, and let's start anywhere on that boundary you choose, and take us around the boundary and show us why it has this particular configuration.

A. Okay, if we start in the northwestern corner of the project area in Section 36 of Township 17 South, Range 34 East, and move in a counterclockwise fashion, from that point all the way around the southern portion of the project area boundary what we're looking at is the current producing limits of the Vacuum-Drinkard Pool.

That continues south into Section 1, then easterly through the southern portion of Section 1, through

Section 6 of 18 South, 35 East, and then as we start to move north along the eastern edge in Section 6 we still are controlled by the productive limits of the reservoir, until we get to the northeast quarter of the northeast quarter of Section 6.

Q. All right, let's go back and look at Section 7 to the south and look at the north half of the northwest quarter. There are two producers that are now abandoned in the Drinkard interval?

A. That's correct.

Q. Why is that acreage not included within the project area?

A. Those two wells were two of the original wells that were produced in the early 1960s. Those wells cum'd about 10,000 barrels of oil each, and they're not currently active. They're in a downdip, tight portion of the reservoir and probably would not respond to secondary recovery.

Q. All right, sir, that takes us around, then, up to the northeast corner of the project area, and we're at the corners of Section 6 and the northeast offset, Section 32?

A. Correct.

Q. Describe for us why you've chosen this boundary across this area.

A. The boundary from there on around, back to the northeast corner, is chosen on a political basis. We chose to include those leases that were operated by the three participants in the project: Shell, Marathon and Texaco. We excluded leases that were operated by Mobil, Arco and Phillips.

In our scheme as we have it set up right now, the injection wells will be paid for and maintained by the three operators that we've been discussing, and Phillips, Mobil and Arco will have no responsibility in that part.

However, based on our simulation, they do receive some benefit from the flood.

Q. All right. In order to test the feasibility of the project, where have you decided to locate the injection wells?

A. We have decided to locate the injection wells primarily along the lease lines of Marathon and Shell and Texaco common boundaries.

Q. In what portion of the reservoir are those injection wells to be located?

A. Those wells are located basically in the heart of the reservoir.

Q. Is that a good place to put them?

A. That's a very good place to put them.

Q. Do you see any correlative-rights impairment of Phillips, Mobil or Arco by not having their producers included in the cooperative pressure maintenance project area?

A. No, and as I said before, they, based on our simulation work, they actually benefit from the injection that would take place away from their acreage.

Q. All right. Having determined a project area, have you satisfied yourself that within this project area as you've modeled it, all the project area is going to benefit from pressure maintenance?

A. Yes, it will.

Q. What causes you to reach that conclusion?

A. That conclusion is based on the results of the simulation work that we've performed.

Q. In looking at your options or choices in pressure maintenance, did you look at various choices for the location of injection wells within the project area?

A. Yes, we did. We looked at not only locations but different pattern arrangements, ranging anywhere from drilling up to 25 to 30 infill injection wells to develop this thing on a 40-acre fivespot pattern, we looked at converting half the wells in the area to injection to form 80-acre fivespots, we looked at 160-acre ninespot patterns, we looked at flooding isolated leases, and we looked at this lease line arrangement.

Q. Independent of expense, what is the maximum secondary oil you think you could recover from the project area using any kind of configuration of injection pattern?

A. The maximum recovery that we saw was about 3 million barrels of incremental oil.

Q. In order to accomplish that, what would you have to do in terms of expense and drilling?

A. We would have to drill roughly 15 additional infill injection wells to achieve that.

Q. Under the proposed pattern that you're presenting to the Examiner, you've included it has the opportunity to recover 2.5 million additional oil?

A. That's correct.

Q. So you're giving up half a million barrels of oil. Why have you chosen to do that?

A. Because the expense to drill the additional 15 wells does not justify the additional half million barrels of recovery.

Q. Is your pattern of injection one in which you have determined it to be effective and efficient?

A. Yes, it is.

Q. And is it a pattern that has been agreed upon by participants in the cooperative project area?

A. Yes, it is.

Q. Let's talk about the issue of a cooperative project, as opposed to some other solution.

Why, in your opinion, does that particularly fit or work in this circumstance?

A. The primary reason is the timing issue. We felt that we could get a cooperative flood put together in a rather short period of time, as opposed to, say, unitization where we have to sit and argue about equity and determine an equity formula prior to moving forward. We felt that this would be a much more expedient method of achieving that.

Q. Do you have the unique opportunity in this project area to have each of the operators be a 100-percent working interest owner in their leases?

A. That's correct.

Q. In addition, these are all State of New Mexico leases?

A. That's also correct.

Q. Are you aware of any correlative rights issue that would be of concern within the project area as the various operators cooperate to recover the secondary oil?

A. No, there should be no correlative rights issues.

Q. Let's talk about the geologic predicates that went into your model.

If you'll turn with me, sir, to Exhibit 5, identify and describe what significance the structure map has for you.

A. Okay. Again, Exhibit 5 is the structure map on the top of the Drinkard formation.

As you can see, starting in the south, you see that the contour lines are very closely spaced. South of this portion of the field, the Drinkard drops off into the Delaware Basin, and the southern portion of the reservoir is tight and not productive.

As you move further to the north you get up into the shelf, and structure really does not play a significant part in this reservoir.

Q. We've got about 250 feet of elevation differential, if you will, in the project area?

A. That's correct.

Q. Does that matter to you as the engineer when you look at where to locate your injection wells?

A. No, it doesn't.

Q. In a pressure-maintenance project, why do you anticipate seeing the producers, which are one producer away from the injector, still benefitting from pressure maintenance?

A. Because what we're trying to do is replace some of the reservoir fluid that are being produced from the area with water injection.

That will ultimately maintain a higher reservoir pressure throughout the area and allow all the wells to produce at higher rates than they would have under a depletion scenario.

Q. For this particular reservoir, then, it's not necessary to have an injector located among each producer?

A. That's correct.

Q. You don't have to infill your injection pattern to that extent?

A. That's correct.

Q. All right. Let's look at how a type log illustrates the Tubb reservoir. If you'll look at 6 for me, what does this show?

A. Exhibit 6 is a type log showing the productive interval in the Drinkard Pool.

In the Drinkard Pool currently, there's production from the Drinkard proper, as well as some isolated carbonate stringers within the lower portion of the Tubb.

The production comes primarily from very low-porosity, low-permeability dolomites, and it exists throughout the entire vertical section of the Tubb and Drinkard.

Q. When we look at the producers on this display, what zones are the producers currently open in?

A. They're currently open in the Tubb and the Drinkard.

Q. So zones 1 through 4 are open in all these wells?
A. That's correct.
Q. And what do you propose to do with the injection wells as to these zones?
A. The injection wells will also be open in all the available intervals.
Q. Do you see containment of reservoir fluids within the flood interval?
A. Yes, we do.
Q. There are barriers to vertical flow up and down, so that injection fluids are going to remain confined to the Tubb-Drinkard injection interval for the pool?
A. That's correct.
Q. What causes that to happen?
A. There are tight portions of reservoir above us in the Tubb, as well as below us, there are some shales in the upper portion of the Abo.
Q. All right. This is not an area where we have Tubb gas wells, then?
A. No, that's correct.
Q. Okay. Let's turn now to Exhibit 7.
A. Okay. Exhibit 7 is a locator map showing all the available log control that was used in building our geologic model for the reservoir.
Shown in the white lines are two lines of section

which will be shown on the following display. And then just for location purposes, the yellow line highlights the border of the Marathon-operated lease in the west half of Section 6.

Q. How do you use this information in your simulation?

A. What this was -- This display just shows our model grid for the geologic model, the location of the wells. And shown on this with the white lines, as I said, are the locations of the section lines shown on the next display.

Q. All right, let's look at the next display.

A. Okay. Exhibit 8 again shows two lines of cross-section in three dimensions. On this particular plot, north is to the upper right portion of the display.

Looking at the north-south trending section, that runs roughly down the western portion of Section 6. The east-west trending portion of the section runs along the northern boundary of Section 6 of 18 South, 35 East.

Q. What's the color code?

A. The color code that we're showing here represents net pay or net porosity in the reservoir. We've colored everything with porosity greater than two percent in red and that with porosity less than two percent in blue.

Based on our geologic study of the reservoir, we feel that productive limits on a porosity cutoff basis are somewhere around two percent.

As I said, we're dealing with a very low porosity reservoir, somewhere between two to eight percent, with an average of around four percent.

Q. Let's go to Exhibit 9 and have you identify and describe that display.

A. Exhibit 9 is showing the same area of our geologic model grid. However, shown on here are several lines of section with the white lines. Again, for reference purposes, the Marathon-operated lease highlighted in yellow.

Q. All right, Exhibit 10?

A. Okay, Exhibit 10 is a fence diagram of those sections. In this particular display, north is to the upper left portion of the plot.

And again, what we've highlighted here is porosity greater than two percent in red and that less than two percent in blue.

You can see on here the structural element of the reservoir as you move to the south, dipping sharply off into the basin. And moving to the north, you see very little change in elevation in the reservoir.

What we also see, looking at the fence diagram, is that we have fairly good continuity of pay throughout the reservoir, and that's indicated by the abundance of the red coloration within the fence diagram.

Q. What are you trying to achieve with your injection wells located as they are, then?

A. What we're trying to achieve is to maintain reservoir pressure at its current levels at a minimum and try, if possible, to elevate that to maximize ultimate recovery from this reservoir.

Q. Geologically, do you see the opportunity for success in pressure maintenance?

A. Yes, we do.

Q. There is apparently sufficient continuity and reservoir quality to provide an opportunity for that success?

A. That's correct.

Q. Let's go to the simulation itself now, if you'll turn to Exhibit 11. You don't have to read it for us, just describe what you've shown here.

A. Exhibit 11 is a summary of some of the basic parameters of the Vacuum-Drinkard reservoir, showing bubble point, initial reservoir pressure, and the drive mechanism.

Of particular importance that we're looking at here, in our project area we had an original oil in place of about 21.5 million barrels of oil.

Q. All right. And if we continue primary recovery, the percentage of original oil in place is about 14 percent recovery?

A. Right, using decline curve analysis on the current production to determine that.

Q. All right, sir. Let's look at Exhibit 12. What are we seeing here?

A. Exhibit 12 is a decline curve of the project area, showing all the Drinkard producers that have produced within the project area.

What this -- Shown in the darker black line with the plus signs as the marker is average daily oil rate. The dashed line with the star-shaped markers is gas rate. And the solid line with the X-shaped markers is average daily oil rate.

The solid black line that moves from the upper left to lower right portion is a projected decline for the reservoir. And this decline has been determined from calculating decline rates on individual wells and then summing up those declines to determine the total decline rate, total ultimate recovery from the project area.

Q. How many current producers do we have in the project area?

A. Currently there are 27 active producers.

Q. Out of the 27 active producers, how many of those wells have established a production decline?

A. All but probably five or six. So 20 to 22 wells.
Q. You've satisfied yourself as a reservoir engineer that you have sufficient decline data from individual well performance by which to construct a project decline curve?
A. That's correct.
Q. And that's what this represents?
A. That's correct.
Q. All right, sir. Next page, Exhibit 13?
A. Exhibit 13 is a summary describing the black oil simulator that we put together to evaluate primary and secondary oil recovery from the Drinkard reservoir.
This particular model contains a model grid of 50 by 44 with 21 layers. Our grid block size is about 260 feet square.
For our model, we input porosity and thickness data from our geologic model, PVT data from a reservoir fluid study done in 1992 or early 1993, oil-water relative permeability and capillary pressure data from special core analysis, initial pressures that were measured on the wells, as well as the current and proposed well locations.
In order to achieve our match, our match parameters were oil and gas rate and producing bottomhole pressures, and we history-matched the reservoir through August of this year.
One thing I would like to mention at this time:

I do definitely appreciate the help from the other operators in the pool in providing the production data that otherwise would not have been available to me to do this simulation work.

Q. This has been a cooperative effort by the various companies?

A. Yes, not only Marathon, Shell and Texaco, but Phillips, Mobil and Arco have contributed as well.

Q. What parameters did you have to adjust as a modeling engineer in order to achieve the history match to your degree of satisfaction?

A. What we adjusted was the absolute permeability of the reservoir around each well to achieve our match on the oil rate, and then we adjusted our gas-oil relative permeability curves to match the gas production rates.

Q. Were those final adjustments still within the range of reason for those parameters?

A. Yes, they were. On permeability, we saw absolute permeabilities ranging from around a half a millidarcy up to five millidarcies.

Q. And that would be characteristic of Delaware production in this type of --

A. Drinkard.

Q. Drinkard production in this type of reservoir?

A. Yes.

Q. All right, let's turn now to Exhibit 14.

A. Exhibit 14 is a summary of the results of our study of secondary recovery. As I said earlier, we evaluated several different scenarios, ranging from full-field developments with infill injectors, to injecting internally to various isolated leases.

We chose this particular arrangement due to economics. This gives very low cost per barrel developed. It gives a very good rate of return and very little loss of production due to conversion of active producers to injection.

This serves to protect correlative rights, provides pressure support in the heart of the reservoir, as well as increases the ultimate recovery from the reservoir.

Q. You've estimated that you can increase ultimate recovery from 14 percent up to what, sir?

A. Around 26 percent.

Q. What type of secondary-to-primary ratio do you achieve?

A. This gives us a secondary-to-primary ratio of about 78 percent. This is in the range of acceptable values that we've seen from the literature on Drinkard or Lower Clear Fork reservoirs that have been flooded.

Q. Do you have engineering displays to illustrate various conclusions based upon your study?

A. Yes, I do.

Q. Do you have a cumulative oil-versus-time plot?

A. Yes, I do.

Q. Let's turn to that. It's Exhibit 15?

A. Yes.

Q. What does it show us?

A. Exhibit 15 shows us cumulative oil production versus time for a depletion scenario where we would continue under current operations, as well as a pressure maintenance scenario where we would drill the lease line injectors as we've described.

Up through mid-1994, the data shown with the black line represents actual, and in general the black line represents our depletion case. The dashed line represents our pressure maintenance case.

As we said before, under depletion we see an ultimate recovery of around 3.1 to 3.2 million barrels, with ultimate recovery after pressure maintenance of around 5.7 million barrels.

Q. When we look at cum oil versus time, how long a period of time are we extending the life of the project area wells over straight depletion?

A. The simulation that we're running shows that we could extend the period of -- the life of the field by around six years.

Q. Okay, let's look at rate. Do you have a rate-versus-time plot?

A. Yes, I do.

Q. Okay, if you'll look at Exhibit 16, let's talk about that.

A. Okay. Again, Exhibit 16 is a plot of daily average oil rate, showing the depletion case with the solid black line and the pressure maintenance case with the dashed black line.

As you can see, again, up through mid-1994 we're showing actual production and then, after that point, projected production.

Q. Let's talk about rate for a minute. Depth bracket oil allowable on 40 acres in this pool is what, sir?

A. It's 187 barrels per day.

Q. When we look at the wells in the pool, are there any top allowable wells still producing?

A. Yes, there are.

Q. What is the smallest amount of production from any well?

A. There are wells producing currently around five barrels a day.

Q. So you range from five up to 187?

A. That's correct.

Q. If the Division approves the cooperative project and you can initiate in a timely fashion pressure maintenance, do you have an estimate of what the maximum rate of any individual well would be in the project area?

A. Yes, we do.

Q. And what is that, sir?

A. We estimated, based on the simulation work, that the maximum rate would be around 206 barrels of oil per day.

Q. So slightly in excess of what currently is the 187 oil allowable?

A. That's correct.

Q. In order to provide an opportunity to the operators to go ahead and produce at that most efficient rate, where they can get the extra 30-plus barrels a day, do you have a recommendation on how to assign the allowables per operator?

A. Yes.

Q. What do you propose?

A. Our proposal is that each operator should be allowed to produce a volume of oil equal to the number of 40-acre tracts where an active injector or producer are located.

Q. Will that give anyone an unfair advantage if the Division allows that to occur?

A. No, it will not.

Q. In fact, that's the type of thing that's conventionally done in pressure maintenance projects on a unit or other basis; is it not?

A. That's correct.

Q. All right. The lease line wells, Texaco is going to operate the injection wells, with the exclusion of the injection well that's on the Marathon-Shell boundary where Tracts 3, 4 and 5 intersect?

A. That's correct.

Q. That injection well?

The Division practice is to approve that well for injection, subject to submittal to the Division of an agreed-upon lease-line injection agreement?

A. That is correct.

Q. Is that an acceptable process for you?

A. That is very acceptable.

Q. All right, sir. Let's look now at Exhibit 17. When we talk about timing, describe for us what you're showing on Exhibit 17.

A. Exhibit 17 is a summary discussing why we should implement pressure maintenance in this reservoir now.

First of all, our GOR is increasing rapidly from around 1000 standard cubic feet per barrel in early 1994 to a current level of about 1550. In particular, the

Marathon-operated tract has seen increases from around 1000 to in excess of 1700 at current levels.

Current estimated pressure has dropped to around 1950 pounds, which is below the bubble point, and we're in a solution gas drive reservoir with no natural support.

And again, as we discussed earlier, we looked at several sensitivity cases on timing and found that we lost five percent of our incremental benefit for every six-month delay in project startup.

Q. Do you have some plots that will illustrate the timing issue?

A. Yes, I do.

Q. Let's turn to the first one, which is Exhibit 18. Identify and describe that.

A. Exhibit 18 is a plot of gas-oil ratio versus time for the project area.

Again, the data shown in the black solid line is for depletion, and the black dashed line is for the pressure maintenance scenario. And prior to mid-1994 it's actual data, and after that point it's projected.

You can see that we are on a very steep incline on GOR under current operations, and we project that that will continue without implementation of a pressure maintenance project.

You can also see by looking at the dashed line that the pressure maintenance will in fact decrease the ultimate -- or the GOR of the reservoir.

Q. Timing appears to be everything when you have that risk, the 2.5 million barrels of secondary oil?

A. That's correct.

Q. And the longer you wait, the higher you are on the GOR curve?

A. That's right.

Q. And the more secondary oil you've left in the reservoir?

A. That's right.

Q. Let's see if you've plotted this a different way. Let's look at pressure and time on Exhibit 19.

A. Exhibit 19 is a plot of reservoir pressure versus time in the project area.

Again, the data shown in black is for the depletion case, the black solid line is depletion, and the dashed line the pressure maintenance case.

Q. What's the point?

A. The point is that first we have dropped below the bubble-point pressure of 2350 pounds at the current time and that without some sort of pressure maintenance project, our reservoir pressure will continue to decrease.

We can see from the dashed line, we anticipate that the pressure maintenance project will arrest the decline in reservoir pressure, and possibly if we maximize injection late in the life, we could see some repressurization.

Q. Mr. Kent, was it also your responsibility to certify and examine all the necessary details for not only filing the OCD Application but presenting testimony today for the enhanced oil recovery qualification of the project?

A. That's correct.

Q. And you're familiar with the Division Rules and Regulations on that topic?

A. Yes, I am.

Q. In compliance with those Rules and Regulations, have you submitted to the Division with the original Application your certificate as to those items?

A. Yes, I have.

Q. And is that what Exhibit 20 represents?

A. That's correct, Exhibit 20 is a step-by step listing of the data required in the procedure in the Division order for EOR certification.

Q. All right. Let's turn to the last page of that submittal and have you summarize for us the expenditures involved in the project.

A. We estimate that the capital cost of additional facilities for this flood will be about $400,000.

One thing I will point out, that number has been minimized due to the fact that we will be utilizing existing facilities in the Texaco-operated units to provide water injection.

We estimate the total project cost to be $2.8 million, the bulk of that for drilling six injection wells.

The estimated value of the total additional production, about $37 million, that's based on our 2.5-million-barrel increment, times an oil price of $15 per barrel.

Q. In your opinion, is there sufficient engineering conclusions and evidence to show that the project area in fact will be responsive to pressure maintenance?

A. Yes, not only the project area but the entire reservoir will respond to this pressure maintenance project.

Q. When we look at the information you have tabulated, do you have a display here the Division can utilize as a baseline curve to show primary depletion so that they can mark or judge a positive production response if the project is successful for subsequent certification?

A. Yes, I do.

Q. What exhibit would we use?

A. We should use the Exhibit Number 12, which is a composite decline curve analysis for the project area.

Q. Okay. Now, in order to judge or determine whether or not there has been a positive production response by using Exhibit 12, what would happen and what would we see?

A. What we would look at to judge a positive production response would be to see that after the flood was initiated, that the oil production improved above the solid black line that's shown on this plot.

Q. Do you have an opinion as to whether or not the approval of this Application will be in the best interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes, this should protect all those.

Q. In addition, in your engineering judgment and opinion, does this project qualify for the enhanced oil recovery tax credit?

A. That is correct.

MR. KELLAHIN: That concludes my examination of Mr. Kent.

We move the introduction of his Exhibits 1 through 20.

EXAMINER CATANACH: Exhibits 1 through 20 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Kent, despite the -- or -- How many producing wells are there within this pool, outside of the project area?

A. Currently there are, I believe, nine. Actually, there's ten. There's nine shown on Exhibit 1. Shell, I believe, has just completed a well in the southeast quarter of the northeast quarter of Section 31.

Q. What justification was used to not include these nine wells in this project?

A. What we did was to include the wells that were on tracts operated by the participants in the drilling of the injection wells.

Q. You've got three operators outside of the project area that were not included. Again, for what reason were they excluded?

A. As I said earlier, the way we set up this flood, those three operators do not share in the expense of drilling the six injection wells and the two conversions. And therefore, even though they receive benefit from the injection, we did not include them in the project area.

Q. Were these operators asked to participate in this project?

A. No, they were not.

Q. For what reason?

A. Because they share no common lease lines with the -- where the injection wells will be located.

Q. Could additional injection wells be drilled within an enlarged project area?

A. That is possible, and if this project proves to be successful, that is likely.

Q. You said that you've had some cooperation from the three operators excluded. Are these three operators fully aware of what you guys are doing over here?

A. Yes, they are.

Q. And to your knowledge, do any of them have any objections to it?

A. No, they do not. In fact, some have indicated possible support -- or possible interest in the future in injection in this reservoir.

Q. You said they would receive some benefit from the injection wells that you plan to drill; is that correct?

A. That's correct.

Q. Would they receive additional benefit if there were injection wells located closer to their wells?

A. It's possible, but we did not look at that particular case with this scenario.

Q. Mr. Kent, with regards to -- I believe you showed us a cross-section which -- and I believe you stated there are perforations in the Tubb formation?

A. Yes, sir.

Q. Is the Tubb included in this Vacuum-Drinkard

Pool?

A. We had discussed this at one time with the District Geologist in Hobbs, and his indications to us were, due to the uncertainty of some of the picks of tops in this part of the Vacuum Pool, he did not feel that including those portions of the lower Tubb was a problem.

There is no split in ownership between the Drinkard and Tubb, so we have no problems in correlative rights there.

Q. The District Geologist didn't feel like it was a problem that needed to be addressed in any form or fashion?

A. That's correct.

Q. And to your knowledge, are all the producing wells completed in that lower Tubb?

A. I'm not sure whether all of them are. I know that there are several that are.

Q. Do you plan to perforate that zone in the wells that are not perforated in that zone?

A. If there is sufficient porosity there to perforate, yes.

The lower portion of the Tubb makes a very small portion of the total net pay of this reservoir. The bulk of it is contained within what's labeled zones 2, 3 and 4 in the Drinkard.

Q. The injection wells will -- you will inject into that interval?

A. That's correct. If there's porosity at those locations, we'll inject into that.

Q. I believe you stated that you ran the reservoir simulation with the current scenario, with the current number of injection wells, and with a maximum of 15 additional -- 15 total injection wells?

A. Fifteen additional. What we did in that simulation run was to take every possible 40-acre fivespot pattern that you could form with the active wells in the pool, put a 20-acre infill injection well in those patterns and look at the response.

Q. It was your opinion or your conclusion that it was uneconomic or less beneficial in terms of economics to develop these with the 15 injection wells?

A. Yeah, the benefit that we would receive through those additional wells would not justify the additional expenditure required to achieve that.

Q. Did you run scenarios in between the two?

A. Yes, I did. We looked at cases where we would go in and convert wells to form 80-acre fivespots, where we would convert wells to form 160-acre ninespots.

Those cases, the 160-acre -- or the 80-acre fivespot patterns -- perform slightly less than the 40 acres. The problem there was that you lost half your oil rate in order to achieve that gain.

The 160-acre ninespots performed roughly as well as the lease line proposal that we have. But again, there was a significant loss of current oil rate that was required to achieve that end.

Q. At the current time, this is the proposed scenario. You don't -- Do you believe that in the future you'll drill any additional injection wells in this area?

A. It's possible, based on -- What we're dealing with right now is a reservoir that essentially is less than -- just about two years old. As we learn more about it, it may be possible.

But at the current time, this is our best estimate of the way we want to go.

Q. How fast do you anticipate a response to the project?

A. Based on the simulation, it's almost immediate. And what we're doing is getting water or fluid into the ground to replace that that's being lost through production and helping to maintain the pressure.

I think what we're looking at here is not a classic waterflood. We're looking at truly a pressure maintenance project here. There may be some flood fronts generated, but the primary benefit here is maintaining reservoir pressure.

Q. Will there be any changes made in the producing wells, such that you may see a response due to some of those changes and not to the waterflood itself?

A. Not that I anticipate. Most of the wells currently are on pump. There's a couple flowing wells. As I said, most of them are perforated throughout the entire Drinkard interval, so I don't see a major increase in production from additional perforations or workovers. Workovers -- these wells are -- most of them are less than two years old and wouldn't require any remedial work at this time.

Q. Which wells are top allowable?

A. To my knowledge there are three operated by Texaco: the two easternmost wells in tract number 1, in tract number 8 the well -- the easternmost well inside the project area.

There are two Marathon wells which in tract 5 are the two northernmost wells.

I believe the two Shell wells in tract 3 and 4 are top allowable, if not very close.

There is a Phillips well located in the southwest of the southeast of 31 that is also top allowable.

Q. Let's go over this one more time. You've got the two easternmost wells in tract 1.

A. Tract 1. The easternmost well inside the project

area in tract 8.
Q. Tract 8.
A. Just north of tract 1.
Q. Okay.
A. The two wells in -- The wells in tracts 3 and 4. The well immediately to the east of tract 4.
Q. That's not within the project area?
A. That's not within the project area. That's a Phillips-operated well.
Q. Okay.
A. And then the two wells just south of tracts 3 and 4.
Q. The directionally drilled wells?
A. Yes. Those were directionally drilled due to surface constraints in the area.
Q. Your allowable proposal is just to determine the number of 40-acre tracts times the normal allowable for the pool, 187?
A. That's correct.
Q. To be split in any proportion among the wells?
A. To be split in -- to be utilized by each operator --
Q. Correct.
A. -- based on the number of tracts they have inside the project area.

Q. Would any operator be restricted under that formula?

A. It's possible that there may be some restriction on the Shell wells.

But by the time we get this implemented, the way the reservoir pressure is declining, even those two may not be a top allowable at that point.

Q. Do you know what these top allowable wells are capable of producing?

A. At the current time I don't. I can tell you that on initial completion, some of these wells were capable of producing in excess of 300 barrels a day.

I do know that the most recent Shell well in the southeast of the northeast of 31 IP'd flowing in excess of 220 barrels a day.

But with the reservoir pressure dropped to the current levels, I don't think any of these wells has a capacity of much more than 200, maybe 220 barrels a day at the most.

Q. I believe your timing scenario, you have -- You said you were going to commence in April; is that right?

A. That's correct. And that's dependant on issuance of an order and execution of lease line injection agreements.

A. And then I believe I read that was with commencing injection into two wells?

A. That's correct.

Q. When will you bring the other wells on line?

A. What our plans are is to get the initial two wells drilled and completed and look at two issues.

One, since this is a very tight reservoir, make sure that we can get injectivity. Without injectivity, we don't have a project.

And two, since this is a carbonate reservoir, make sure that we don't have any channeling within the reservoir that's going to cause us to prematurely water out existing wells.

Once we've satisfied ourselves with those two issues, we plan to move ahead with the rest of the project. I would anticipate that that would occur within less than one year.

I think the timing that I've shown on the display was to commence injection in the rest of it January 1, 1996.

Q. How would you handle that in terms of the EOR tax credit? You said you would get almost immediate response if you just injected into two wells.

A. I would not anticipate that the day we saw a response that we would be up here asking for certification of the project. I would anticipate that we would wait until we had a few months of production history under our belts and make sure that what we're actually seeing is response.

By that time, I would anticipate that we would have either drilled or be very close to drilling the additional injectors, and I would not assume that we would try to get the project certified or get the response certified until after those wells were drilled.

Q. Just a couple questions about the cost.

The total project cost, including drilling the injection wells, is $2.86 million?

A. That's correct.

Q. Okay, the estimated total value, that's the additional 2.5 million barrels?

A. That's the 2.5 million barrels times an oil price of $15 per barrel.

EXAMINER CATANACH: That's all the questions I have of this witness. He may be excused

Do you gentlemen have anything further?

Oh, I'm sorry, Mr. Bruce?

MR. BRUCE: I came up here with the big boys, Mr. Examiner.

MR. KELLAHIN: You're sitting at the wrong table, Mr. Bruce. The big boys are over here.

MR. CARR: We could throw that to a vote.

MR. KELLAHIN: Shall we stand and see?

MR. CARR: I am standing.

MR. BRUCE: Mr. Examiner, as the witnesses have described, Shell owns the leases on the south half, southwest quarter of Section 1, Township 17 South, Range 35 East.

It does have two producing wells in the Drinkard that are at or near the top allowable, and it supports this Application.

The only thing Shell would like to see is some type of provision in the order regarding lease line agreements. Its wells are pretty young, so it would like a provision in the order, and I have a proposed provision which I provided to the other parties previously.

MR. KELLAHIN: Mr. Examiner, we have seen his proposed language. We believe it's consistent with the type of provisions you place in these orders, and Marathon has no objection to Mr. Bruce's suggestion of language.

EXAMINER CATANACH: Texaco?

MR. CARR: Texaco has also reviewed the proposal, and likewise we have no objection.

MR. BRUCE: That's it, Mr. Examiner.

EXAMINER CATANACH: Anything further, Mr. Carr?

MR. CARR: Nothing further, Mr. Catanach.

EXAMINER CATANACH: Mr. Kellahin?

MR. KELLAHIN: No, sir.

EXAMINER CATANACH: All right. There being nothing further in this case, we'll continue it to the --

MR. CARR: January 5th.

EXAMINER CATANACH: -- January 5th hearing for the notice issue.

And will one of you be present to present --

MR. CARR: Yes.

EXAMINER CATANACH: There being nothing further in this case, we'll just continue this case until January 5th.

We'll adjourn the hearing.

(Thereupon, these proceedings were concluded at 10:33 a.m.)

* * *

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 December 4th, 1994.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11152, heard by me on December 1994.

, Examiner
Oil Conservation Division