STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

CASES 10341 and 10342 (Consolidated)

EXAMINER HEARING

IN THE MATTER OF:

Application of Marathon Oil Company for Statutory Unitization, Eddy County, New Mexico.

Application of Marathon Oil Company for Pressure Maintenance Project, Eddy County, New Mexico

TRANSCRIPT OF PROCEEDINGS

BEFORE: MICHAEL E. STOGNER, EXAMINER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

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ORIGINAL

A P P E A R A N C E S

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I N D E X

E X H I B I T S

APPLICANT'S EXHIBITS:

EXAMINER STOGNER: At this time I'll call both Cases 10341 and 10342, both to be consolidated.

MR. STOVALL: 10341 is the application of Marathon Oil Company for statutory unitization, Eddy County, New Mexico.

10342 is the application of Marathon Oil Company for pressure maintenance project, Eddy County, New Mexico.

EXAMINER STOGNER: Call for appearances in both these matters at this time.

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

EXAMINER STOGNER: If there are no other appearances, will the witnesses please stand to be sworn.

[Thereupon, the witnesses were sworn.]

EXAMINER STOGNER: Mr. Kellahin?

DANIEL D. TAIMUTY

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

EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Daniel D. Taimuty, and I'm an engineer for Marathon Oil Company.

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

A. No, sir.

Q. Summarize for us your education.

A. I received a Bachelor of Science from the University of Pittsburgh, Pennsylvania, in chemical engineering in 1980. I received a Master of Science in petroleum engineering from the University of Pittsburgh in 1982, and I'm also a registered professional engineer in the State of Pennsylvania.

Q. Summarize for us your employment experience as a petroleum engineer.

A. I have worked for Marathon Oil Company since 1982 in Midland, Texas. I've spent four years in the reservoir department, one year in special projects, two years in the operations group, and in June of 1989 I was transferred back into the reservoir group, and I've been there ever since.

Q. Marathon has requested approval under the statutory unitization procedures of a pressure maintenance project called the Tamano Bone Springs Second Carbonate Unit. They've abbreviated that, but it's the Tamano Unit?

A. Yes, sir.

Q. What did you do for that project?

A. I did most of the reservoir evaluation to determine if secondary reserves existed in the Bone Springs Second Carbonate, and if they could be commercially recovered.

Q. Have you finished that reserve study and that engineering evaluation?

A. Yes, sir, I have.

Q. Based upon that study, do you have conclusions about the feasibility of this pressure maintenance project for this particular portion of the Tamano Bone Springs Pool?

A. Yes, sir.

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

EXAMINER STOGNER: Mr. Taimuty is so qualified. And I must say, this must be a record number of Pennsylvania people we've had today at this hearing. Mr. Kellahin?

MR. KELLAHIN: We have an index map, Mr. Examiner, that is also in the exhibit book, but it serves as an easy reference. Let me hand you one of those now.

Q. Before we talk about the specific conclusions that you personally have made and that have subsequently been adopted by your company for this project, let's talk in general terms about what you were trying to study.

A. Okay.

Q. Tell us a little something about this Bone Springs reservoir.

A. As far as the geologic aspects?

Q. Some of the geologic aspects of it, and give us some of the engineering characteristics that you're finding in the Tamano Bone Springs Pool.

A. The Bone Springs Second Carbonate is part of the Bone Springs formation recognized by the State of New Mexico. The productive portion of the Second Carbonate is located at approximately 8,000 feet.

It had an initial reservoir pressure of 3,000 pounds and estimated bubble point pressure of 2,500 pounds. We've determined it to be a solution gas drive reservoir with some bottom water, but I would hesitate to refer to it as an aquifer because we do not believe it's lending any pressure support to the reservoir.

Q. What is the current spacing applied by the Oil Conservation Division to the production from the

Tamano Bone Springs?

A. It's 40 acres per well.

Q. What is the maximum daily oil producing rate that the Division allows for production from the pool?

A. 460 barrels per day, per well.

Q. You're seeking the approval of a pressure maintenance project?

A. Yes, sir.

Q. Pursuant to that request, have you been involved in preparing the C-108 documents to justify the integrity of the water injection procedures to be utilized for the project?

A. Yes, sir.

Q. Let's look at the handout, which is simply a locator map, if you will. What's the significance of the red dashed line Mr. Taimuty?

A. That is the proposed unit area or the unit boundary for the unit.

Q. When we look at the circled numbers, what does that represent?

A. Those are our proposed tract designations.

Q. The wells identified on this display are only the Bone Springs penetrations?

A. The black circles indicate Bone Springs

Second Carbonate producers, and the X's indicate wells that have penetrated the Bone Springs Second Carbonate that are not productive.

Q. When we look at the current status of development of the pool at this time, what is that status? Has it been fully developed on 40 acres?

A. Yes, sir, we believe it has been fully developed.

Q. You have a couple of open locations, however, within the proposed boundary of the unit when you look at the south half of Tract 3?

A. Right.

Q. Those with that exception is the only tract not fully developed on 40 acres?

A. That's right. Well, in Tract 1 there's a 40-acre location on Tract 1 also.

Q. As part of the unitization process, you and the other working interest owners have resolved what to do with the undeveloped tracts that would be within the unit, have you not, sir?

A. Yes, sir.

Q. Give us a short summary of what your major conclusions are that you have reached. And perhaps the easiest way to do that is to direct the Examiner's attention to the second book, which is marked as

Marathon Exhibit 2. Do you have that?

A. Yes, sir.

Q. This engineering study is, in fact, authored by you, is it not?

A. Yes.

Q. Before we get to your conclusions--

MR. KELLAHIN: Mr. Examiner, Exhibit 2 is the package of documents that we will spend most of our time with Mr. Taimuty on.

Q. Before we talk about the conclusions, let's turn behind the cover sheet and look at the table of contents. Summarize how you have organized your study for presentation?

A. We have initially included or at the beginning included a list of all the tables and figures that we have used to refer to in the report.

Following that, we have listed our conclusions that we've drawn from our evaluation of the Bone Springs Second Carbonate reservoir, and recommendations based on those conclusions.

We have then provided a history of the Bone Springs Second Carbonate Pool. We've described the unitized interval in a vertical sense, and have supplied some geology that pertained to that unitized interval. We've then addressed the proposed unitized area and discussed its primary performance.

We used a computer model to help us in our evaluation of secondary recovery, so the next section supplies most of the data that we used to construct our computer model. And also a discussion of the history match, showing that we believe the model is doing a very good job of describing the reservoir behavior.

We then went into a discussion of the enhanced recovery evaluation, using the model and using our available data. We have summarized our results and then we have listed the tables and the figures at the end of the report.

Q. If the Examiner desired to do so, he could take the figures and tables along with the written narrative in the engineering study book and have a reference, then, that will track your oral testimony today?

A. Yes, sir.

Q. Let's talk about some of the general conclusions you have reached with regards to studying this project, and turn then to page 3. And without having you read them to us, Mr. Taimuty, give us the general sense of your major conclusions with regards to the feasibility of this project.

A. The first conclusion is that we have reasonably delineated the Bone Springs Second Carbonate reservoir. After we have delineated it, we determined that the original oil in place was 15 million barrels of oil, and the gross primary recovery would be 2,167,000 barrels of oil, which represents 14.4 percent of the oil in place.

Based on our evaluation, we believe that a peripheral waterflood yields the maximum incremental recovery due to a secondary project, and that these reserves can be developed economically. Also, that if the waterflood project is deferred, there may be a loss of reserves.

Q. When you characterize this as a waterflood project, I'm going to use, interchangeably with that, the phrase pressure maintenance. If I ask you about pressure maintenance I'm asking you about this waterflood project. So don't let that confuse you. I intend to mean it the same thing.

A. Okay.

Q. When we look at the first conclusion, you've talked about the reservoir being reasonably delineated?

A. Yes, sir.

Q. Let's talk about how the reservoir was delineated and then how you have determined the reasonable vertical, as well as horizontal boundaries for the unit itself.

A. Okay.

Q. To do that, let me direct your attention to Figure No. 1, which corresponds to the same handout we just gave the Examiner. Have you found that?

A. Yes.

Q. Let's relate that now to the type log, Mr. Taimuty, and that's easiest to find as Figure No. 3?

A. Yes, sir.

Q. So that we can understand the proposed vertical interval for the unit as well as what is being developed as the Second Bone Springs Carbonate, will you take the type log, tell us what well it's taken from, and then describe for us the vertical interval that you want to unitize?

A. Okay. The type log is taken from the Johnson "B" Federal Well #4 by Marathon Oil Company. For practical purposes, we consider this to be the discovery well in the Bone Springs Second Carbonate of the Tamano Field.

The type log we have listed there has a gamma ray curve on the first tract, then a depth tract. The second tract contains density and neutron porosity estimates, and the fourth tract contains the resistivity profile.

The interval we're proposing to unitize is located, in Johnson "B" Federal #4, is from approximately 7,905 feet to 8,190 feet. It is a dolomitized carbonate interval that is overlain by the Bone Springs 1st Sand and underlain by the Bone Springs 2nd Sand.

If you look on the far right track or the fourth track of that type log, you'll notice that the resistivity is off scale throughout most of the upper portion, approximately 150 feet of that interval. This is a hard dolomite or tight dolomite. It's general unproductive throughout the interval, although there are some porosity streaks that are productive.

The main pay interval which is at approximately 8,050 feet, is indicated by the fact that the resistivity comes back on scale, suggesting better effective porosity and permeability, and this is the interval that we concentrated our efforts on, and that is the most prolific and productive portion of the Bone Springs Second Carbonate.

Q. When you, as a reservoir engineer, evaluate the feasibility of this Second Bone Springs Carbonate to determine the integrity vertically, so that you could see if you can flood that zone in a feasible fashion, what did you find?

A. Actually that we could flood this zone and recover our oil and do it commercially.

Q. Let's talk now about the horizontal boundaries of the container, and let's do the Figure 4 following the type log, and have you take that schematic and give us a general view of the geology and the characteristics of the reservoir.

A. Okay. What Figure 4 shows, and it's easier to understand if you turn it sideways, this is a characterization of the Bone Springs Second Carbonate. It is a debris flow and it's located at the bottom of the shelf margin. Geologists just refer to that as toe-of-slope. It is not a single-debris flow but a series of debris flows.

If you turn to the next page, which is Figure 5, this is a structure map on top of the main pay interval. The shelf margin is approximately one mile north of here, and coincidentally runs across the 31 East range line, so the Tamano Bone Springs field is approximately one mile from the shelf margin and what I indicated as the toe-of-slope.

Q. Let me have you go to the cross-section up on the wall, Mr. Taimuty. That would be found as an appendix in the feasibility study, as the last display in the plastic folder at the end?

A. What we would like to show from the cross-section, this is the top of the Bone Springs Second Carbonate interval, and we have indicated the top of the main pay. Within the main pay our geologists have defined 11 layers that seem to be correlatable across the field. They have their own types of characteristics.

The important point here is that, of the 11 layers, we refer to the odd numbered layers as low-flow units and the layers here in purple as the high-flow units. The significance of that is that the high-flow units most likely occur during violent, geologic times where larger debris flows, such as clasts, were dumped over the shelf edge and deposited in this nature.

In between, there were long periods of dormant times where just mud stones were deposited over. The mud stones have very low permeability and are very fine grain, more difficult for the fluids to move through the reservoir. Most of the production occurs in the high-flow units or the purple units, and they just happen to be numbered as all the even numbered intervals.

Q. Can you use the cross-section to help us understand the concept by which you're going to introduce water into the reservoir to help you maintain pressure of the reservoir?

A. I'm not sure I--

Q. We have 11 zones potentially in this Second Bone Springs Carbonate. How are you going to do it?

A. Actually, we're just going to go in and we may have to add some perfs at some intervals, but we're going to perforate and try to introduce water into the entire main pay interval on the peripheral of the reservoir, and hope to flood it that way.

Q. What's the concept behind opening up all 11 zones or however many zones you can find in each of the wells, and for those wells selected for injectivity, use those for maintaining pressure of the reservoir?

A. Well, we hope to maximize our sweep efficiency in a vertical sense by injecting into the entire main pay interval.

Q. Does it make any sense to try to isolate individual stringers within the Second Bone Springs Carbonate to use for injectivity?

A. No, we don't believe so. Actually, that would hurt your vertical efficiency.

Q. Okay. Let me have you return to your seat.

Having identified the structural relationship of these wells in the area of the unit, having examined the cross-section, what then did you and the geologists do in order to determine the horizontal boundaries to be suitable for the unit purposes?

A. I would like to refer to Figure 6 which may help understand what we've done. Figure 6 is a map of porosity, a map of the product of porosity, permeability to oil, and thickness. The way we have constructed this map was to determine permeability to oil through transient testing data and then determine porosity values from log analysis.

We have mapped the product of those three parameters, and the result was Figure 6. As it shows, the greatest porosity permeability thickness exists within the west half of the south half of Section 11 and it extends into Section 10. We have a zero line there that well defines our proposed unit boundary, whereas you reach the limits of the reservoir you lose your porosity and permeability.

Q. When we look at the display and find the letters NA next to a well dot, what does that tell you?

A. It indicates that we didn't have transient test data on those wells and were unable to determine an exact porosity value.

Q. Let's turn now to Figure No. 7. Having constructed your porosity/permeability ranges in values and contouring it on Figure 6, what then did you do on Figure 7?

A. Figure 7 was just actually a test of Figure 6, to see if it made sense. The wells circled in red on Figure 7 were wells that flowed when they were initially completed. The wells circled in yellow on Figure 7 were wells that pumped initially.

What we have contoured there is the initial potential of each well. As you can see, Figure 7 agrees quite well with Figure 6, as far as the most productive portions of the reservoir. So basically what we've done is just put an oil production number to the phi-K-H value and we have quite good agreement between the two figures.

Q. What does that help tell you as a reservoir engineer about the logic of the unit boundaries that you're imposing upon this portion of the pool?

A. We feel that the entire productive portion of the Bone Springs Second Carbonate is contained within the proposed unit boundary.

Q. If the Examiner approves the unitization of this configuration of acreage for the unit, will that give Marathon, as the operator, effective and efficient control of the reservoir to maximize the opportunity for enhanced oil recovery through the pressure maintenance project?

A. Yes, it will.

Q. Before we leave Figure 7, give us a quick summary around the boundary, let's start with the north boundary, and give us a little sense of the available data that's caused you to conclude that the northern boundary has got a good, justifiable, engineering basis.

A. Okay. If you look at Figure 7, you'll see along the top row, and from west to east, Wells #10 and #3, and Well #3 on the Heyco lease, and Well #5, those are all marginal producers. Gross recovery to date is something less than 30,000 barrels per well, and in most cases less than 10,000 barrels. As opposed to the well circled in red that have exceeded 100,000 barrels and some in cases 200,000 barrels of recovery.

As you move north, into Section 2, there have been some tests of the Bone Springs Second

Carbonate, and none of them were productive, so we feel that our boundary clearly defines the productive portion of the Bone Springs Second Carbonate to the north.

As you move to the east side, we can use the same argument. The wells along the eastern row, as indicated by the yellow circles are all pump, whereas the central portion of the reservoir the well's plugged, or are just reservoir properties. There are two dry holes in Section 12, and those are numbered 5 in the north and to the south, right along the unit boundary there.

A point I would like to make at this time is that those wells had zero effective porosity. They were not water productive and therefore uncommercial. They actually did not have any porosity that would contribute fluid at all. That emphasizes the stratigraphic nature of the Bone Springs Second Carbonate reservoir.

Another point I would like to make is that the #1 AJ well and our #8 well--our #8 well is located in Tract 5, and the AJ-1 is in Tract 2--those wells produce most of the water in the field. That goes back to my earlier testimony which we believe there's bottom water there, but that we've not observed any pressure support from those wells.

Moving along the south border, two wells drilled in Section 14, both indicated by a 1 and the X's, more Bone Springs Second Carbonate tests, as with the wells in Section 12. Those wells in Section 14 had no effective porosity. One was plugged back and completed in the Grayburg, and the other has been abandoned since it was attempted to test the well.

Moving to the west, we feel that we have the western boundary defined by the fact that the #2 well has been a poor producer to date, indicating a pinch out of the porosity and permeability. Although #3 flowed, the porosity and permeability values on the #3 well were not as great as those in the central portion of the reservoir, the well treated at a higher pressure and the pressure behavior in that well has declined rapidly in the last three months, which suggests that that's an edge well. So we really believe we have a good definition of the Bone Springs Second Carbonate on all four sides.

Q. When we look at the property on the outside of the proposed unit, immediately adjacent to that outer boundary, do you see any engineering justification for the inclusion of any more acreage or any additional wells within the unit, in order to give you effective and efficient control of this portion of the reservoir for unitization purposes?

A. No, sir, nothing outside the proposed unit area.

Q. Correspondingly, do you see any wells or acreage inclusive of the proposed unit boundary that, in your opinion, ought to be excluded?

A. No, sir. Everything we've included in here we feel should be in here, for effective flooding of the zone.

Q. Let's turn to Figure 27. Before we talk about the details of Figure 27, let me have you lay the foundation for how we got to the point of having the computer generate this concept of the reservoir.

Go back and tell us why you thought it necessary to simulate the performance of individual wells and then to model that in terms of designing a program for enhanced recovery.

A. We felt that by using the computer model it would be the most powerful way of trying to describe what has happened in the reservoir and what would happen by going to some secondary type project. The Bone Springs Second Carbonate is very stratified, as I've indicated with the 11 zones on the cross-section; therefore, conventional volumetric or material balance calculations really don't hold well individually, but some combination of material balance and volumetrics would be the most powerful way and the best way to describe the reservoir, and by using the model we felt we could accomplish this.

Q. Were you able to use the model to help you select the type of waterflood project that gave you the greatest potential secondary oil recovery?

A. Actually it goes beyond even just water injection. We also evaluated emissible gas injection as a possible secondary project, and we varied the amount of gas injected and we also varied the waterflood pattern in an attempt to find the optimum recovery.

Q. Did the model aid you, as a reservoir engineer, then, in selecting this peripheral waterflood pattern to maximize the oil recovery?

A. Yes, it did.

Q. In addition, the model helped you predict the performance of the existing wells?

A. That's right. The first thing we did with the model was to try and determine remaining primary recovery.

Q. Why could you not do that without the assistance of the simulation of the reservoir, the individual well performance model?

A. Some wells had an established decline and we could use conventional decline analysis to try and determine remaining performance on primary recovery. However, other wells were either very new or had produced at the top allowable rate for their entire life; therefore, there was no production history that would assist us in conventional decline analysis.

Q. With the assistance of the reservoir simulation by computer modeling, you were able to quantify, within a certain range, your anticipated secondary oil recovery from the waterflood project?

A. Yes, sir.

Q. And it also aided you in determining what would be the primary oil production by well or by tract, without the waterflood operation?

A. That's right.

Q. Anything else in a major conclusion that the model was used for?

A. If I could summarize, we used the model for primary depletion and then to evaluate both emissible gas injection and various waterflood patterns, and that's it.

Q. From those conclusions, then, you were also able to assign values to each individual tracts?

A. In terms of--

Q. Relative value for each tract by which, then, participation parameters can be selected for participation and production from the unit?

A. Right. We did use the model to some extent for that, to estimate reserves for our tracts where we did not have established decline. So we did.

Q. Let's go back and build the model. What model did you use? what software program?

A. The software name is Eclipse.

Q. How many phases in this software program to model this reservoir?

A. There are three fluid phases, oil, gas and water.

Q. Was this a single porosity model or dual porosity model?

A. It's a single porosity model.

Q. Why did you select a single porosity model?

A. We've looked at a single and a dual porosity model. In a fractured reservoir, which is what we believe the Bone Springs Carbonate to be, you would normally use a dual porosity model. However, through our evaluation we've determine that most, if not all of the storage capacity and the flow capability of the reservoir is contained within the vugs and fractures of the reservoir. Therefore, even though it may be a dual porosity model, by normal convention it behaved as a single porosity model because the vugs or fractures were so dominated. We went ahead and ran both types of models and found that we got almost identical results with both a single porosity model and a dual porosity model, and obviously a single porosity model was more efficient in describing the reservoir. So we opted for the single porosity model.

Q. How many layers did you integrate into the model?

A. All 11 geologic layers that we described by the cross-section.

Q. When we look at the horizontal pattern or the grid size for the model, what was the grid size?

A. The grid size was 264 feet on the side in Section 11 and 528 feet by 264 feet in Section 10.

Q. Were you satisfied that you got reliable results from reservoir simulation with a grid size of that configuration?

A. Yes, I am.

Q. At this point, then, you have to select reservoir parameters or values to input into the computer, do you not?

A. That's right.

Q. Do we have a reference sheet or some way to tell the Examiner what the input was into the model, in terms of that data?

A. Not necessarily one reference sheet, but there's an entire chapter in the report, and everything that we used within the model is described within that section.

Q. The Examiner will find it, starting on page 16, running all the way through page 23?

A. That's right.

Q. Having input all the reservoir data that you are satisfied, as an engineer, would give you an accurate reservoir description, what then did you do?

A. Okay. We first history-matched the model to determine the accuracy or the comfort level the model was giving us as far as predicting reservoir behavior.

Q. You're doing that on an individual well basis or for a selected number of wells?

A. We did it for every well.

Q. What are you history-matching against?

A. Four things; oil production, gas production, water production and reservoir pressure.

Q. Can you direct our attention to those portions of the engineering book that will give us your history matches, first of all, on oil?

A. That would be, Figure 37 would be the oil history match.

Q. Figure 37 represents an oil history match for what wells?

A. Actually for all of the wells that are to be included in the unit, all 19 wells.

Q. What do you find when you examine the match?

A. The model predictions are indicated by the solid line and the actual production are indicated by the plus signs, and they overlay identically. They're exact.

Q. In order to get a history match on oil, what reservoir parameters did you have to adjust or fine-tune in order to get the history match?

A. Probably the parameter we adjusted the most was permeability. I don't mean to mislead you by saying "the most," because there were just basically some minor adjustments in permeability to get a match that we were comfortable with.

Q. Where is the base data derived from that gives you your permeability value?

A. Okay. I would have to refer to the

technical report.

Q. Is that from core information?

A. Oh, yes, sir. We plotted the core data, core porosity versus core permeability, and we were able to derive three correlations that we used to determine permeability. One were all of the low-flow units seemed to have the same characteristics. In addition, our high-flow Unit No. 2 had the same flow characteristics. So there was one correlation for those zones.

Zones 4, 6 and 8 had another set of data that seemed to fit quite nicely together, and we generated a second permeability/porosity correlation from that data, and Zone 10 stood alone. It had its own correlation.

So, after determining porosity from logs, we then assigned a permeability value based on the three sets of correlations.

Q. From the analysis of the core information on permeability for the various zones, does that give you a range of permeability, or is it an absolute value based upon that core?

A. We found a range of permeabilities.

Q. Can you approximate for us, based upon your recollection, what is the range of permeability derived from the core analysis?

A. Less than one hundredths of a millidarcy to a thousand millidarcies.

Q. In order to adjust the history match of the reservoir simulation to the actual oil producing rates shown in the wells, to what degree did you have to adjust the permeability?

A. Most of it was just minor. If the zone was 10 millidarcies, I may have increased it to 20 millidarcies to get a better match on the production. So I guess, maybe, in that case, that would be doubled. But again, it was on a millidarcy basis, and maybe 10 to 20 millidarcies on any particular layer to get a good match.

Q. Were you satisfied, as a reservoir engineer, that you were adjusting the permeability so that it stayed within the reasonable range of permeabilities derived from the core data?

A. Yes, sir.

Q. Let's go and see what the history match is on the gas production. That's Figure 38?

A. Yes, the very next figure. Again, as you can see, the solid line would be the gas direction determined from the model, and the plus sign would be the actual gas production. We were very happy with the fit. They track each other very well.

Q. Let's go to Figure 39. That's the history match on the water production?

A. Yes, sir. Again it's the same convention, the solid being the model prediction and the pluses being the actual. The match here doesn't look as good as the oil or gas, but we do believe we have a good match on the water.

Q. The history match is not as close here. Have you examined why it has occurred, and is there an explanation that satisfies you about this occurrence?

A. Yes, there is.

Q. What is the answer?

A. One reason that the match may not agree as closely is that, if you'll notice, there's only 100,000 barrels maximum on the axis, so that's not a large volume of water. Therefore spin acid water from our treatments would tend to skew the curve, and the actual data would be somewhat greater than the model predictions because of the spin acid.

Another reason is that some of the wells are commingled in the Bone Springs Second Sand, and there's water production associated with the Second Sand that our the model wouldn't be predicting. Our model is confined solely to the Second Carbonate. So, for those two reasons, the actual production is somewhat higher than model predictions.

Q. The actual water production is not exclusively confined to the Second Bone Springs Carbonate to formation waters?

A. That's right.

Q. Have you attempted to exclude the elements of air and reported water production to see what current formation water rates are and how they compare to what the model has predicted?

A. That's what gives us our confidence level because the current projected water production for the model matches quite well with the actual production. The Bone Springs Second Sand is producing a minimal amount of water at this time, and we feel like we've recovered most of the spin acid. So our current rates and our production model are quite close.

Q. Let's go to Figure 40 and have you describe that.

A. Figure 40 is a plot of the reservoir pressure. The solid line is average reservoir pressure thoughout the Bone Springs Second Carbonate as determined from the computer, and the pluses are actual data points. I would like to point out at this time that although some of the pluses fall below the average reservoir pressure for the entire unit, that's not alarming because those pluses represent reservoir pressure from any one individual well and are not representative of the entire pressure, which is what the model is plotting.

Q. When we turn to Figure 41, what are we looking at with this figure?

A. Figure 41 was really the first test of the model. Most of the model was built in January of this year when we were doing our history match. We completed this Stedco 10 #3 in January of 1991. After measuring the reservoir pressure in that well, we plotted the reservoir pressure of just that well in the model. As you can see, we had an excellent agreement between the estimated pressure from the model and actual pressure observed in the well.

Q. At this point, then, you were satisfied, as a reservoir engineer, that you have a good, reliable working simulation of the performance of the reservoir and these wells?

A. Yes, sir.

Q. Did you use the model, then, to help you construct the optimum waterflood configuration to get you the greatest amount of oil recovery?

A. Yes, we did.

Q. Turn your attention to Figure 42. Tell us how you to read that display.

A. This is a plot of four different types of secondary recovery projects that we evaluated, and a dip curve that is just straight primary depletion. The primary depletion curve is in black and it would level off at somewhere around two million barrels of oil, something greater than two million barrels of oil.

The four color plots, then, are the four scenarios that we've evaluated; those being a downdip waterflood, a peripheral waterflood and gas injection, both at 10 million cubic feet a day of methane, and 20 million cubic feet a day of methane. And these are the projected ultimate recoveries inclusive of primarily for all four scenarios.

Q. In each instance the pressure maintenance waterflood projects exceed depletion without secondary recovery?

A. Yes, sir, all four do.

Q. The best one is the peripheral waterflood that you've ultimately adopted and proposed to the Examiner?

A. That's correct.

Q. Having determined that the peripheral waterflood is the best or the optimum configuration of the project, did you make a study to determine what is the optimum time in which to commence the project?

A. Yes, we did.

Q. Is that shown on Figure 44?

A. Figure 44 are the results of what we are proposing today. Water injection would begin on January 1, 1992. We plot oil, gas and water production, oil being indicated by the curve with the squares, gas production by the triangles, and water by the circles.

As you can see, we're projecting a decline in production through about 1994, at which point we start seeing the benefits of our waterflood project. The production peaks at around 900 barrels per day, and then goes on an ultimate decline.

Q. What is your recommendation for an actual commencement date of water injection for pressure maintenance purposes into the project?

A. January 1, 1992.

Q. Have you examined the possibility of delaying the initiation of injection until the working interest owners in the three 40-acre tracts that yet do not have Bone Springs wells on them, until those wells are drilled, completed and produced, and then initiating waterflood?

A. Yes, we've done that evaluation.

Q. What did you find out?

A. If I could refer you to Figure 46, what we found out is that if we delay water production for two years, until January 1, 1994, the estimated secondary recovery is somewhat less than if we begin injection in January 1, 1992.

Q. How did you resolve or attempt to resolve, then, the fact that you've got undrilled tracts in the unit, in terms of how you handle those and the timing of the project?

A. I'm not sure I understand the question.

Q. You've got three undrilled tracts.

A. Right.

Q. Those tracts are going to be committed to the unit?

A. Yes, sir.

Q. Have you satisfied yourself that under the participation formula those tracts are not going to receive more than their contributing value from participation in the unit?

A. Yes, we've satisfied ourselves that it's been handled equitably.

Q. So you have overcome any obstacles in your mind about having any undrilled tracts in your waterflood?

A. Yes, sir.

Q. Summarize for us the secondary recovery potential that you've assigned, then, to the waterflood project.

A. The amount of reserves we believe we can recover are 2,261,000 barrels through our peripheral waterflood.

Q. Let's go and have you give us the economics, then, for the investment, and the schedule of investment for the working interest owners in the project.

A. If I may refer to Table 8, Table 8 summarizes our projected investments.

Q. It's on page 44 of your engineering book?

A. Yes, sir. The field is relatively new. Discovery occurred in 1987, so most of the equipment we have on hand is in very good shape and we can use this equipment for the waterflood.

Most of the initial investments will be for consolidation of a main battery and for our injection facilities. We're also proposing the conversion of five wells initially to water injection, and we have two wells in the proposed unit area that are currently commingled in the Bone Springs Second Carbonate and Bone Springs Second Sand.

We'll set cast-iron bridge plugs between the two zones and dump cement on top of the bridge plugs, which should effectively isolate the two zones. The total cost as outlined in Table 8, is 1,125,000 gross to the working interest partners.

Beyond that, we are proposing the conversion of two additional wells to injection in 1994, at an incremental cost of $140,000. Also, based on our estimation, we'll require larger lift equipment beyond the existing broad pumps. We need to acquire three submersible pumps, one in 1997, one in 1998 and one in the year 2002, for a total investment in the waterflood of $1,511,000.

Q. Turn now to Table 10 on page 46 and summarize that for me.

A. These are the key economic parameters that suggest how the waterflood project will work. We have our initial investments of $1,125,000, and future anticipated investments of $386,000. What this is a summary of are our incremental economics, or economics above and beyond what we would realize through just straight primary depletion. We'll pay the investment out in roughly three and a half years, at an annual rate of return of 60 percent.

The net present value of the secondary project is roughly $9.4 million, using a discount factor of 15 percent. Incremental net profit would be $26,284,000, and as you can see, suggested incremental reserves net to the working interest owners, would be $1,979,000, and the difference would go to the royalty owners, the difference between that number and the total of 2,261,000 barrels that we've estimated.

We feel these are very good economic parameters and the flood should be very successful.

Q. Let's go back to the chronology of the efforts to complete the study, and then to share it with the other working interest owners in the proposed unit. In that regard, identify for me what is marked as Exhibit 1?

A. This is the feasibility study that we put together between January of 1991 and March of 1991. When we had that completed, we called for a meeting of all the working interest owners in the proposed unit area, at which time we submitted the feasibility study to them and discussed it.

Q. Give us a quick summary of the major differences, if any, between the March 91 feasibility study and the engineering book you've discussed, which is dated June of 1991?

A. The technical report dated June of 1991 is a more complete report from a geologic and engineering standpoint. The feasibility study was designed to just hit the highlights of the results of our evaluation, and to let the partners know what our conclusions were, and to discuss with them any merits or how to proceed about unitizing this area. So the feasibility study may be more geared toward the economics and what Marathon was proposing, whereas the technical report would supply most of the actual factual data.

Q. When we compare the June 1991 engineering report to the March 1991 feasibility study, are there any major conclusions or recommendations in the March 91 report that should be changed?

A. No.

Q. Who are the major working interest owners? You don't have to name them all, but give us a general idea of the major companies or individuals that you were dealing with on a voluntary basis to formulate this unit.

A. Actually there are, I believe, eight major partners. In addition to Marathon Oil Company there was Hudson and Hudson, the Harvey E. Yates Company, or

Heyco, Yates Energy, Pennzoil, Winoco, Arco, and Kerr McGee.

Q. Were there various meetings called by your company, as the initiator of this proposed unit, to meet with the working interest owners and give them an opportunity to hear your presentation and then to comment on the feasibilily of the project?

A. Actually, we had three working interest owner meetings to discuss the merits of the project. In addition to the three meetings, we had several individual meetings. Several companies came in to review our data, our logs, and the model runs.

In addition, we traveled to both Hudson and Hudson and Heyco to discuss the data. So several meetings, I guess three formal.

Q. Ultimately, did the working interest owners vote on an equity participation formula for unit production?

A. Yes, they did.

Q. Describe for us the parameters that they had to select from.

A. We tried to review all possible parameters. We used various rate parameters, and we were focusing on an average six-month oil rate. Surface acres, wellbores, cumulative production, remaining primary production and ultimate production.

Q. Did the working interest owners finally vote on and adopt a final participation formula to share production in the unit?

A. Yes, we did.

Q. Do you have a reference by which we can see that participation formula?

A. Actually, I don't have one handy.

Q. Will we find that in the Unit Agreement?

A. Yeah, it's in the Unit Agreement,.

Q. Let's take a moment and find that.

MR. KELLAHIN: Mr. Examiner, if I can direct your attention to Exhibit 44, that will be the Unit Agreement.

Q. If you'll turn to page 14 of that agreement, describe for us the participation formula that was ultimately selected by the majority of the working interest owners.

A. It's based five percent on number of service acres contributed by any one working interest owner, compared to the total acreage in the unit, six percent on wellbores, 56 percent on a six-month average oil rate, and 33 percent on the remaining primary recovery from April 1, 1991.

Q. This acreage is, in fact, all federal BLM acreage, is it not?

A. Yes, it is.

Q. Has the BLM giving you preliminary approval for this unit, including this participation formula?

A. Yes, they have.

Q. Have a majority of the working interest owners adopted and approved this participation formula?

A. Yes, they have.

Q. In your opinion, as a reservoir engineer, is this final participation formula one that is fair and equitable to each of the interest owners in each of the tracts?

A. Yes, sir.

Q. Can you think of another participation formula that is better than this one?

A. None come to mind.

Q. Have you concluded, as a reservoir engineer, Mr. Taimuty, that the unitized management and operation, development of this unit, in fact, is feasible?

A. Yes.

Q. Have you determined that it will result in a reasonable profit to the working interest owners that have to contribute the investment required to obtain the additional oil recovery?

A. Yes, sir.

Q. In your opinion, is the participation formula fair and reasonable?

A. Yes, sir.

Q. Have you also determined and satisfied in your own judgment that the procedures for allocating units expenses to the various separately owned tracts, is fair, reasonable and equitable?

A. Yes, sir.

Q. Will this project, if approved by the Commission, benefit each of the working interest owners and the royalty owners in the affected unit?

A. Yes, sir.

Q. And under the unit operations and with this proposed participation formula, does each tract receive its relative value when compared to its contributing value?

A. Yes, sir.

Q. In your opinion, will the granting of this application prevent waste?

A. Yes.

Q. Afford you an opportunity, as a company, on the behalf of all these interest owners, to recover additional oil that might not otherwise be recovered?

A. That's right.

Q. In your opinion, will it protect the correlative rights of all the interest owners involved?

A. Yes, it will.

Q. In your opinion, is the unitized management and operation development of this portion of the Tamano Bone Springs Pool, necessary in order to carry on the pressure maintenance or to implement pressure maintenance in order to increase ultimate oil recovery?

A. Yes.

Q. Will the estimated additional cost of this operation exceed the estimated value of the additional oil?

A. No.

Q. It, in fact, will recover a reasonable profit for the working interest owners?

A. Yes, sir.

MR. KELLAHIN: That concludes our portion of this part of the presentation, Mr. Examiner. Mr. Taimuty needs to talk to us about the C-108 procedures. There is a request in the application for an increase surface injection pressure that exceeds the .2 PSI guideline.

If we need a five-minute break, this is a convenient place. If you would like us to continue, we're prepared to go on.

EXAMINER STOGNER: How much longer with this witness?

MR. KELLAHIN: It will probably take at least another 30 minutes or so.

EXAMINER STOGNER: Let's take about a five-minute break right now.

(Thereupon, a recess was taken.)

EXAMINER STOGNER: Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

EXAMINATION RESUMED

BY MR. KELLAHIN:

Q. Mr. Taimuty, the last item before we leave your Exhibit No. 2 is to direct your attention to page 33, Table 1. For benefit of the interest owners as well as for reference by the Examiner, what have you shown on that page?

A. Table 1 includes estimated remaining primary reserves as of April 1, 1991, and secondary reserves that would be attributed to each tract based on the equity formula.

In addition to that, we've provided economics or the net present value of the remaining primary reserves--

EXAMINER STOGNER: Where are you at?

MR. KELLAHIN: Table 1.

EXAMINER STOGNER: Thank you, Mr. Kellahin.

Q. What have you summarized on this table, Mr. Taimuty?

A. Remaining primary reserves as of April 1, 1991, and secondary reserves attributed to each tract based on the equity formula, the net present value of both remaining reserves, and incremental secondary remaining reserves and then the total secondary net present value.

Q. And on a tract-by-tract basis, then, what do you conclude about each tract receiving secondary credit?

A. That each tract would indeed benefit from implementation of the peripheral waterflood, and that it would be done in an economic fashion.

Q. Is there an explanation as to what assumptions went into price in order to get the dollar amount of the value of secondary reserves?

A. There's a summary-- With regard to price, yes, there is, on Table 11 on page 47. There's a total summary of the incremental economics, and it lists reserves, operating revenue, operating expense and investment. It also lists various parameters that we've already discussed in Table 10, and in the bottom left-hand corner it gives initial product prices. $20.96 per barrel of oil, $2.01 per Mcf of gas. We included no inflation factors in our economics. We were going to leave that to the individual working interest owners.

Q. Let's turn now, Mr. Taimuty, to the C-108 package of documents. Are you familiar with the C-108 procedures?

A. Yes, sir.

Q. Attached to the end of Exhibit No. 3 is an area map, if you will. Do you have a copy of that?

A. Yes.

Q. Have you complied, to the best of your ability, with the requirements of the C-108 filings by the Oil Conservation Division?

A. Yes, sir.

Q. When we look at the half-mile area of review around each of the proposed injection wells, how have you identified that area on your area map?

A. With a solid dashed line.

Q. You simply squared off what would otherwise have been circles around these injection wells?

A. Actually we've gone maybe a little further than a half mile. We extended it one-half mile beyond the unit boundaries in all directions.

Q. Have you inventoried, within that half-mile radius, all the wellbore data for individual wells, whether producing or plugged and abandoned, that penetrate to or through the Second Bone Springs Carbonate?

A. Yes, we have.

Q. When we go through all the data you've assimilated, do you, as a reservoir engineer, find any plugged and abandoned wells that can be characterized as problem wells?

A. No, none.

Q. Are all the plugged and abandoned wells within this area of review, properly plugged and abandoned so that the Second Bone Springs interval is isolated out from any other interval?

A. Yes, sir.

Q. Did you have any plugged and abandoned wells?

A. Yes, we did. We had a few.

Q. When we look at producing wells, other than those you'll utilize for production here, do we have deeper wells that penetrate through this Second Bone Springs Carbonate?

A. Yes, we do.

Q. You find that each of those is completed in such a way to isolate out the Second Bone Springs Carbonate so it will not be intrusive onto the casing or the tubing of those wells?

A. Yes, sir.

Q. No problem wells?

A. No problem wells.

Q. The source of water to inject into the Second Bone Springs comes from where?

A. Three sources we propose to use. One will be actual produced water from the Bone Springs Second Carbonate. That's only approximately 100 barrels per day right now, so it will not fill all of our needs.

We also proposed to use City of Carlsbad water, which I believe they acquire from the Ogallala, and also local Grayburg production in and around the area. It is Marathon's intent to inject as much salt water as we can or as much produced water from the Grayburg and the Bone Springs Second Carbonate, and minimize, if not eliminate, all the fresh water or any fresh water requirements from the City of Carlsbad.

Q. Have you provided any compatibility tests thus far with regards to the types of waters that might be introduced into the Bone Springs?

A. Actually, attached to the C-108 are all of the compatibility tests of the various combinations I just discussed. Both the fresh water with the Grayburg, and the Bone Springs produced water.

Q. We have fresh water, Grayburg and Bone Springs. Any other potential combinations of waters from other zones at this point?

A. No. We reviewed the entire area and found that there's just no other feasible source of water to inject.

Q. What are the results of the compatibility tests, integrating those three sources of water into the Bone Springs?

A. There's a mild tendency to form calcium carbonate scale, but it's very mild and easily treatable, so we're not anticipating any problems at all.

Q. Do you find sources of fresh water in this immediate vicinity?

A. There are no sources of fresh water.

Q. How have you made that determination?

A. We visited with Ken Fresquez from the State Engineer's Office, and he had given us some insight into what we might review. And in conversations with him, and our best known analysis, we found no other possible sources.

Q. Has there been field inspections of the surface to see if there was any undocumented windmills or fresh water sources that were not of record with the State Engineer's Office?

A. We reviewed the area, and we didn't find any.

Q. What is the range of anticipated volumes that you think you'll need for this project in terms of barrels of water per day?

A. Initially we will inject 3,500 barrels, is what we're estimating, with a maximum of 5,000 barrels once we have all seven conversions to injection.

Q. In providing the data for the Examiner, do you have schematics of the injection wells, either for each one or by type or example?

A. Yes, we have them all included.

Q. Give me a general summary of how you propose to complete these wells for injection.

A. It would just be, we would use plastic-coated tubing and inject under a packer, put such packer above all Bone Springs Second Carbonate first, and inject with a coated tubing.

Q. Is the annular space between the tubing and the casing filled with some type of fluid?

A. I'm sure we'll use KCL inhibitors.

Q. And is there some way to monitor the annular space, between the casing and tubing, to see if you've got any tubing leaks or other failures that might require action on the part of the operator?

A. Yes, sir. We'll been able to tie into the casing and pressure up to determine if there are any leaks.

Q. The request in the application is for a maximum surface injection pressure up to 2,300 pounds surface?

A. Yes, sir.

Q. That will be greater than the Division guidelines of .2 PSI per foot of depth to the top perforation?

A. Yes, sir.

Q. If you applied the .2 guidelines, what pressure surface limitation will that be?

A. Approximately 1,600 pounds.

Q. So you want an additional 700-pound flexibility?

A. Yes, sir.

Q. Let's turn to the package of exhibits that are identified with the No. 4. If you'll find all those, Mr. Taimuty, they're identified as Exhibit 4(a) and they run through 4(f).

I marked, as Marathon Exhibit 4(a), a step rate test?

A. Yes, sir.

Q. On what well is that taken?

A. Marathon Shugart "B" No. 1.

Q. I have to go back to my index. The Shugart "B" No. 1?

A. It's located in tract 6. It's the southern well in tract 6.

Q. What was the purpose of the step rate test?

A. To determine the parting pressure of the Bone Springs Second Carbonate.

Q. What does this test show you?

A. That the Bone Springs Second Carbonate will part at a pressure of 5,371 pounds bottom-hole. Actually, the pressures there are not mid-perf pressures, they're somewhat higher. The corrected bottom-hole pressure would be 5,474 pounds.

Q. What is the parting pressure within the formation, then? This is a surface pressure?

A. No, sir, these are bottom-hole pressures.

Q. On this well, the "B" 1 well, the bottom-hole pressure is what? The parting pressure within the formation breaks over at what pressure point?

A. 5,474 pounds.

Q. Translate that to surface pressure for me.

A. That's indicated on the very next page or exhibit, around 2,150 pounds, approximately.

Q. Do you have any other step rate tests other than the Shugart "B" 1?

A. Yes, sir. We ran one also on the Johnson "B" Federal No. 10. That's the No. 10 indicated on tract 4.

Q. You have a step rate test on the north side and a step rate test on the south side. When I look at the Johnson "B" Federal 10, what is my surface pressure at the breakover point?

A. 1,928 pounds.

Q. If we're increasing pressure above the .2 gradiant, which is 1,600 surface pounds, we can find that we can do that without fracturing the Bone Springs Carbonate up to a range of between 1,928 and 2,147 pounds?

A. Yes, sir.

Q. What does that tell you, as an engineer?

A. That we're able to inject at higher than the 1,600 pounds indicated by the .2 gradiant, and still not fracture the reservoir.

Q. Your request, however, is to go up to 2,300 pounds?

A. That's right.

Q. Knowing that we've fractured a formation at a certain step rate test, what then have you done to derive data to give you confidence that the fractures you're now propagating in the Second Bone Springs are going to remain confined to the Second Bone Springs Carbonate?

A. We reviewed the unit area to try and determine the fracture gradiant properties, to see how consistent they were, and we evaluated a frachite log and after-frac survey and two injectivity profiles, to see where the fluids were going.

Q. Let me have you turn your attention now to Exhibit 4(b). Identify and describe that.

A. These are the wells within the unit area that Marathon operates. What we have listed there are the estimated frac gradiants as determined from acid treatments. That would be taking the hydrostatic pressure and the initial shut-in pressure, following acid stimulation, and then dividing by the mid-perf depth.

What we hope to illustrate by this are that the frac gradiants are all around the .72 average we indicate at the bottom, and that we have good rock properties that we can correlate across the unit area.

Q. Can you take 2,300 pounds at the surface and convert that into a frac gradiant?

A. Actually with the hydrostatic, that would be .72.

Q. I would direct your attention to 4(c). That's a frachite log. I have it on the Johnson "B" Federal A/C 1 No. 7 well?

A. Yes, sir.

Q. Give us your conclusion about the frachite log and then support your conclusion.

A. Okay. The conclusion from the frachite log is that if we do initiate any fracture in the Bone Springs Second Carbonate, it will remain totally confined within that interval and we will not go out of zone with it.

We base that conclusion on the Delta pressure tract, which is really the fifth tract over from the left of depth. Beyond depth the first three tracts are just reservoir properties. The Delta pressure tract, what it suggests is it ranges from zero to a thousand pounds, and this tract shows you what interval will begin to fracture initially when the external pressure is applied.

If you look at that, the depth of 8,062 to -64, that has the lowest Delta pressure, and we would expect that to frac first. The line, then, as it increases to roughly 100 pounds, as your surface injection pressure increases by 100 pounds over the pressure that's required to frac the formation, that zone will also fracture. As that line gets greater, to 500 pounds, then you would have to increase your reservoir pressure or your injection pressure by 500 pounds to propagate a fracture in that interval.

If you'll notice, at the top and the bottom of the Bone Springs Second Carbonate, it would require a thousand pounds over the surface pressure to propagate a fracture above or below the Bone Springs Second Carbonate. Because, as you've indicated already, our surface pressures range from 1,928 pounds to 2,147 pounds before you even begin a fracture, and we would have to increase our surface injection pressure to over 3,000 pounds, therefore, to frac out a zone.

So I feel our request of 2,300 pounds will keep any fracture confined within the Bone Springs Second Carbonate.

Q. You use the "B" 1 well step rate test at 1,928, add a thousand pounds to that step rate test, that will give you close to 3,000 pounds in that well?

A. Yes, sir.

Q. At that point is the first point you're going to begin to run the risk of propagating fractures outside either the top or the bottom of the Second Bone Springs Carbonate?

A. That's right.

Q. And your request, then, is at 2,300 pounds?

A. Right.

Q. Some 700 pounds less than that maximum amount?

A. Yes, sir.

Q. Let's go to 4(d) and have you identify and describe that exhibit.

A. This is our after frac survey. What we did to stimulate the Stetco "10" Federal No. 2 was to sand frac the well. We tagged the sand with a radioactive material that we could follow through the reservoir with a gamma ray to determine where our frac went.

As you observe on the log, we have a gamma ray baseline above and below the main pay interval. Our treating pressures reached 5,000 pounds, and as the after frac survey indicates, all of the high gamma ray activity, which would indicate where this sand went, is confined within the main pay interval.

We have a minor fracture growth upward to approximately 7,950 feet, but there's still a good 50-foot barrier above that before we got out of the Bone Springs Second Carbonate.

So, the after frac survey supports the frachite conclusions that even at very high surface treating pressures, that any fracture propagated is confined within the Bone Springs Second Carbonate.

Q. Let's go to Exhibit 4(e). This is the same well?

A. Yes, sir.

Q. What are we looking at here?

A. This is an injection profile, to determine if we had any fluid movement up or down from the perforated interval. What they do, they inject the radioactive material again, and then they try and trace it with a gamma ray.

What the top portion of this exhibit shows is as you go down, as the intensity of the gamma ray reading decreases, suggesting that you're losing more and more of your radioactivity into the perforations. Once you get below the indicated perforations, you have absolutely no radioactive material present and the gamma ray goes back to the baseline that has been established. This suggests that there's no movement of any fluids downward, or there have been no fractures created beneath the Bone Springs Second Carbonate.

If you go to the bottom portion, where it says "Upward Channel Checks," they inject the radioactive material, and then they try and trace it. Their sensors are pulled above the perforations to see if there's any radioactive material moving upward, and as indicated on the log, no channels upward were found.

So this, in addition to the frachite log and the after frac survey, indicates that we've confined our injection totally to within the main pay interval.

Q. You have a similar display for Exhibit 4(f) on another well?

A. Yes, sir. This is the Marathon Shugart "B" 1. We ran this injection profile after we ran our step rate test to determine where our injected water was going, and exactly like with the Stetco 10 No. 2, we have found there were no channels either downward or upward. Everything stays confined within the perforated interval.

Q. The Division, on occasion, requires some resolution of injection wells that might be characterized as being lease line injection wells. On occasion you'll see that in waterflood projects. There are a couple of your proposed injector wells that while they're not right on the lease line, they're on the outer boundary.

Do you see any necessity to have any contractual arrangements with the offsetting operators with regards to what might be characterized as lease line injection wells?

A. No, sir.

Q. Why not?

A. There's no productive Bone Springs Second Carbonate outside the proposed unit area.

Q. In those instances, that has been verified with actual wellbore data offsetting you, is that right?

A. Yes, sir.

Q. Those wells have either been depleted or have shown no opportunity for production?

A. I won't even say depleted. Just no opportunity for production.

MR. KELLAHIN: That concludes my examination of Mr. Taimuty, Mr. Examiner. We would move the introduction of his Exhibits 1 through 4.

EXAMINER STOGNER: Exhibits 1 through 4

will be admitted into evidence.

EXAMINATION

BY EXAMINER STOGNER:

Q. In referring to your description of your unitized interval, and to Figure 3 on Exhibit 1--

A. Yes, sir.

Q. --I would like to get the heading on this log, or is it a composite of several logs?

A. It's a composite of several logs. I could provide all the headings. I don't have them with me.

Q. I take it the one on the far right is of a separate log and the two combined is of one log; so we, essentially, have two logs?

A. Yes, sir. It would be a density neutron log and a resistivity log.

Q. If you could give me a heading on that and with the date shown and the pertinent information, I would appreciate that.

A. Okay.

Q. In looking at your Figure 7 in Exhibit 1, and with the remarks made before the end of the testimony, and I'll also refer back to, I believe, page 14 of the Unit Agreement.

EXAMINER STOGNER: Mr. Kellahin, that's the participation formula?

MR. KELLAHIN: Participation formula?

EXAMINER STOGNER: Mr. Kellahin, help me out. One of your last questions was about lease line injection?

MR. KELLAHIN: Uh-huh.

Q. And, if I remember right, Mr. Taimuty, you said that there was absolutely no flow outside the unit area, is that correct?

A. Well, we don't believe there would be any flow, sir.

Q. Maybe I'm not seeing that on Figure 7. How do you explain the far right-hand corner?

A. Figure 7 is kind of difficult. It's an initial potential well, so there's a zero line that extrapolates outward but, as you can see, the wells outside the line are dry-hole wells, and I think the way things are mapped it would be difficult to put contour lines on top of each other so we map it that way. Figure 7 is more to verify Figure 6. Figure 6 is what is defining the productive portion and where the fluid movement would occur, and Figure 7 is more of just a support. It's difficult. Obviously we have edge wells that are producing a minimum amount of oil, but they would have something other than zero, so that would require us to draw a zero line outside that range.

Q. There are three 40-acre proration units which essentially have no well on them, never had a well on them, and your zero line on your Figure 6, especially the, what is that, the southwest quarter of the northeast quarter? but you still have it in the unit. Has that been discussed, about taking that out, and why didn't the BLM, perhaps, take it out?

A. Our reasons for keeping those in there are that we're offsetting top allowable wells. We don't feel that these wells are necessary for any primary production, but it's possible that future evaluation would suggest that we would need those to improve the sweep efficiency of our flood.

We visited with our working interest partners and with the BLM, to discuss that matter with them.

Q. Did that have any bearing, with only five percent being dedicated to the acres of the tract?

A. The BLM actually had given us some guidelines on what they would consider acceptable as far as surface acres, and that five percent is within their guidelines and agreeable to all the working interest partners.

EXAMINER STOGNER: Mr. Kellahin, help me

out on this one. In the beginning, this being a pressure maintenance project and the current allowable is 460 barrels of oil per day, I believe that was established?

MR. KELLAHIN: Yes, sir. We had a special hearing in which we got a special depth bracket allowable for the Tamano Bone Springs, and it increased it up to the 460 a day as a maximum.

EXAMINER STOGNER: Do you have an order number on that?

MR. KELLAHIN: I do, and I'll have to look it up and give it to you. It escapes me at the moment.

EXAMINER STOGNER: Okay, if you will do that. And as far as this particular pressure maintenance project, would that allowable still be sufficient or is there any request to amend that or establish a new one just for the unit area? It wasn't advertised, and that's the reason I'm bringing it up.

MR. KELLAHIN: I think the initial thought was the maximum allowable under the rules would be translated into a unit allowable that could then be produced out of any combination of the producing wells. But we're not asking for a waiver at this point of the maximum 460 a day.

EXAMINER STOGNER: That's what I was asking. I apologize.

MR. KELLAHIN: We'll stick with that until we can determine that it's justifiable to ask that that be withdrawn.

EXAMINER STOGNER: Okay. There's a lot of information to digest here, and there's a need to move on, so I have no further questions at this time.

MR. KELLAHIN: Mr. Examiner, that special depth bracket oil allowable is by Order No. R-9354, Case 10115. The order is dated November 7, 1990. I'll give you a copy of that for your reference.

EXAMINER STOGNER: Thank you Mr. Kellahin.

GREGORY A. WILSON

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

EXAMINATION

BY MR. KELLAHIN:

Q. Would you please state your name and occupation.

A. My name is Gregory A. Wilson. I am employed by Marathon Oil Company as a geologist.

Q. Mr. Wilson, on prior occasions have you testified as a petroleum geologist?

A. Yes, I have.

Q. You reside in Midland, Texas?
A. That's correct.
Q. Summarize for us, Mr. Wilson, what has been your involvement as a geologist in studying the Tamano Bone Springs, and in participating in the feasibility studies that Mr. Taimuty has just described.
A. I wasn't involved in the drilling and development of the well. The geologist, Patty Phillips, that was the geologist working on the project, left Marathon Oil Company and moved to Dallas, Texas, so I was taking over the project.
Subsequent to her leaving, I did some additional examination of the cores, familiarized myself with the previous core studies, and had done some additional mapping in the area. I had also done some thin section studies of samples in the area.
Q. Have you reviewed the Marathon feasibility study that's dated March of 1981, as well as Mr. Taimuty's engineering report of June of 1991, insofar as it has geologic components to it?
A. Yes, I have.
Q. Based upon those studies, do you have certain geologic conclusions about the feasibility of this project?
A. Yes.

Q. I don't ask you for the conclusions now, but did you have conclusions?

A. Yes, I did.

MR. KELLAHIN: We tender Mr. Wilson as an expert petroleum geologist.

EXAMINER STOGNER: Mr. Wilson is so qualified.

Q. Without trying to repeat what Mr. Taimuty has testified, let me have you summarize your geologic conclusions. First of all, in looking at the feasibility of taking the Second Bone Springs Carbonate, isolating that vertically and seeing whether, as a geologist, you find it to be sufficiently continuous that it may serve a suitable environment in which you may introduce water and recover additional oil, have you examined that topic?

A. Yes, I have. As to vertically containing a waterflood within the carbonate, overlying the Second Bone Sprins Carbonate is the First Bone Springs Sand, which is predominantly a fine-grain sand and siltstone with some dolomite stringers. It's a clay-rich sand, where there is sand developed as opposed to siltstone, and tends to be very low permeability and somewhat water sensitive. In this area there are no productive First Bone Springs Sand wells.

The base of the Second Bone Springs Carbonate would be the Second Bone Springs Sand, which is very similar, virtually identical in lithologic properties. It's a quartz sand, very clay-rich, with some stringers of dolomite. Again very low permeability, very fine-grain and owing to the clays within the matrix of the sand, usually some are water sensitive. It would be very difficult, if not impossible, to put a significant amount of water into the Second Bone Springs Sand or First Bone Springs Sand.

Q. Geologically, then, are you satisfied the Second Bone Springs Carbonate can be isolated?

A. Yes.

Q. From the interval above and below that carbonate?

A. Yes, I am.

Q. Let's talk about the horizontal extent. Does this provide well-to-well continuity, if you will, of the Second Bone Springs that you can map it geologically?

A. Yes. As shown on the cross-section, which was previously brought in evidence, there are specific porosity intervals within the Second Bone Springs Carbonate that can be correlated. In addition to that, the top of what we call the main pay interval is very correlatable through the area, and I don't think there's really any question that what we are mapping as the main pay interval is continuous across this area.

Q. You can find, by mapping the log information from each of the wells, that the Second Bone Springs Carbonate can be correlated among all the wells?

A. Yes.

Q. Within that zone, though, there are individual lenses that may come and go within the Second Bone Springs Carbonate?

A. Yes. The lenses, or the high-flow units, as they've been called, were originally identified using core data, looking at the porosity and permeability to rock, and also using some of the production logs which determine where the greatest amount of fluid was coming into the wellbore, and applying that to the neutron density logs where that information was available, and correlating those high-flow units in the wells where the core information was available, to the wells where there was no core information. And the correlations are always open to some interpretation, but these are very high degree of probability correlations.

Q. Justify geologically the conclusions about the boundary of the unit. Is it a logical and reasonable boundary, from a geologist's point of view?

A. Because of the nature of these debris flows, they tend to be somewhat limited in size in one event. They're basically a cohesive mud flow which will pick up and carry larger clasts and grain stones, usually shelf-dried material, and they're basically going to be a pile of mud at the base of the slope, where you have a steeper slope that grades to a less sleep slope and you lose sufficient slope for the mud to continue to flow.

They tend to be either elongate, parallel to the shelf edge, or somewhat round in shape. As you move away from the debris flow, you start going from the shelf drive, a nice clean carbonate, into the slope drive, a more clay-rich, deep water deposited muds, therefore losing any original porosity and permeability. So the configuration and size of the field is consistent with the depositional model.

Q. As a geologist, do you see any need to include additional acreage that is not already included in the proposed unit?

A. No. The surrounding well data which shows no porosity and permeability, there are some wells with porosity but very poorly developed permeability, which is related to the postdepositional digenesis in the rock, the well data, I think, very clearly defines where the limits of the effective porosity in the reservoir are.

Q. When we get to the western side, there are three tracts, if you will, 40-acre tracts, that do not yet have wells?

A. That's correct.

Q. They are in an area where there is some well control?

A. Uh-huh.

Q. Give us your geologic opinions about the reliability of that boundary of the unit in terms of what acreage has been included or excluded?

A. As far as what has been excluded, which would be the acreage west of the Stetco 10 #3 well, I think that's reasonable because the amount of porosity found in the formation was greatly decreased, the thickness of the formation was decreasing, which suggested that we're moving towards the edge of the reservoir.

The acreage that was included, as can be seen in--let's see, it would be Figure 6 of Exhibit 2, and Figure 7, it can very abruptly go from a porous, permeable reservoir to a very impermeable portion of the formation, or if you can't tail out to where you'll have a marginal well before finding an impermeable, nonproductive section. So there's really no way of determining whether one location away from a top allowable well you may have a productive location or not.

So, I think including the additional undrilled acreage is reasonable, as was stated earlier, for possibly increasing the efficiency of the sweep. There may be porous, permeable rock in those locations.

Q. From a geologic aspect, though, can you reach a geologic conclusion that the proposed boundary for this unit is reasonable and fair?

A. Yes, I think it is.

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

EXAMINATION

BY EXAMINER STOGNER:

Q. Several quick and basic questions. I'm referring to Figure 6. Are there any Bone Springs sand producing intervals anywhere within the map area? I'm looking at the nine-section area.

A. Yes. On Figure 7, the map of the initial potential, there are two wells in which the initial potential reflect a production from both the second sand and the second carbonate. They were perforated and treated separately, but the initial potential was put together, so we didn't have figures broken out individually for the two zones.

Those are the two numbers that are in parenthesis. It would be Well #3 in the northeast of the northwest quarter, and Well #3 in the northwest of the northeast quarter. In addition, the five wells in Section 2 on the Mesquite Unit are Second Bone Springs Sand producers.

Q. So is it really reflecting some Bone Springs sand production, or is it just reflecting that the sand was open?

A. You mean, the initial potential, or--

Q. Yes.

A. In the case of the Heyco #3 in the northwest of the northeast, that was believed to be, on the initial potential, primarily Second Bone Springs Sand production. That well is not on the cross-section. That well falls between the 50 and 0 barrels of oil per day lines. The initial potential is about 248 barrels per day. That's only an estimate. We know that the quality of the reservoir, from log data in the second carbonate, did not look very good. In looking at the surrounding wells, we assumed it was one of the four wells from the carbonate, and they did have a very good second sand section. So, that is an estimate as far as where that well falls within the contour lines.

Q. I assume all of these intervals, wells that will be taken over that have perforated intervals into the sand, will be plugged back?

A. Yes. I think Mr. Taimuty mentioned that there will be a cast-iron bridge plug set between the perfs in the Second Bone Springs Sand and second carbonate, with cement on top of the plug to effectively separate them.

Q. And as Mr. Taimuty said, and I'm sure you will probably agree, even the injection into those wells or near those wells will not spread into the sand zone?

A. I couldn't address the fracture properties of the Bone Springs carbonates, but the sands, where they are well developed, tend to be very low permeability. The low from some sidewalk core studies that we've done at Marathon and from studies I've read done by Heyco, below a porosity of eight percent, there is effectively all microporosity in the clay matrix. There is no effective porosity that could contain oil or move fluid.

Even where there's greater than eight porosity developed, there can be very low permeability. And due to the movement of fines, the clays within the core spaces, it's very difficult to move water through those sands. So, because of the very low permeability of the sands and water sensitivity of the clays within the matrix, I can't imagine that a significant amount of water, if any, could be put into the second sand.

Q. And the information you reviewed or worked was included in the Unit Agreement?

A. It was included in the Exhibit 2, the engineering study.

Q. How about the geologic information in the Unit Agreement?

A. Yes, I believe that was the same information that was taken from the study.

Q. And you reviewed it?

A. I did not review the agreement myself, but I believe the same exhibits were used from the engineering study.

EXAMINER STOGNER: I have no further

questions of Mr. Wilson, Mr. Kellahin.

MR. KELLAHIN: Thank you. Mr. Wilson?

RANDAL PAUL WILSON

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

EXAMINATION

BY MR. KELLAHIN:

Q. Sir, could you please state your name and occupation.

A. My name is Randal, R-A-N-D-A-L, Paul Wilson. I'm a landman with Marathon Oil Company in Midland, Texas.

Q. Mr. Wilson, on prior occasions, have you testified as a petroleum landman before the Division?

A. No, I haven't.

Q. Summarize your educational and employment experience that qualifies you to be a petroleum landman.

A. I graduated from the University of Texas at Austin in 1981 and worked for one year in Abilene, Texas, as a landman, before being hired by Marathon in May of 82. I have been with Marathon since that time, and have recently completed certain requirements, successfully completed certain requirements so I can be considered as a certified professional landman in my field.

Q. Describe the kinds of activities you've performed with regards to the Tamano Bone Springs unit?

A. I compiled the list of owners, overriding royalty interest owners, a search of their records and titles, to determine what where there's federal or state acreage, prepared the initial documents, came up with the address lists and so forth.

Q. Do you also maintain, as part of your duties in the land department, the correspondence files that deal with the unitization efforts of your company in dealing with others?

A. For those unitization efforts that I'm involved in, yes.

Q. Does that include this Tamano Bone Springs?

A. Yes, it does.

Q. Have you satisfied yourself that to the best of your ability you have an accurate list of the working interest owners by tract, and you know what you believe to be the percentage in which they have the interest for those tracts?

A. Yes, I do.

Q. Have you performed the same function with regards to the royalty or overriding royalty owners?

A. Yes, I have.

Q. And, to the best of your ability, do you have a reliable list of the names and addresses of those parties or individuals?

A. Yes, I do.

MR. KELLAHIN: We tender Mr. Wilson as an expert petroleum landman.

EXAMINER STOGNER: Mr. Wilson is so qualified also.

Q. Let's go through the correspondence file here rather briefly, Mr. Wilson, and then we'll get down to the ultimate status of your efforts to obtain voluntary participation in your unit. Let's look first of all, so we can identify them for the record.

Have you had a chance to review the chronology shown as Exhibit No. 5 to determine whether it lists, in chronological fashion the major items of interest in your efforts to obtain voluntarily participation?

A. Yes, I have.

Q. I don't ask you to read the list, but it's simply a compilation taken from your files of those major events, in chronological order?

A. That's correct.

Q. When we look at the correspondence package, starting with Exhibit No. 6, do we find individual copies of letters and correspondence that can be matched with the chronology, so that if the Examiner desired to do so, he can see individual pieces of communication?

A. That's correct.

Q. Let me ask you to turn your attention to Exhibit No. 42, if you'll find that in the package of documents. What is Exhibit 42?

A. That's the letter from the BLM basically accepting our application to unitize the field.

Q. This was after a series of conferences, discussions with the BLM, on the topic of acreage and participation formulas?

A. That's correct.

Q. Ultimately you have received in your files, this letter, Exhibit No. 42, giving you a preliminary approval on behalf of the BLM for this project?

A. Yes.

Q. Did they attach any conditions or qualifications to their preliminary letter of approval?

A. Yes, sir, they had certain changes they wanted to make within the, I believe that's the unit.

Q. Have those proposed conditions and

contingencies been circulated and approved by Marathon for inclusion?

A. Yes, sir.

Q. And have you shared those with the other working interest owners?

A. Yes.

Q. Go back and find Exhibit 38.

A. Okay.

Q. What is Exhibit 38?

A. That is a letter written by Tom Lowry, an attorney, to the lessees of records, overriding royalty interest owners and owners of royalty, notifying them of the hearing.

Q. Have you compiled, in response to that letter, the green return receipt cards for notification purposes?

A. Yes, sir.

Q. Are they appended to that letter?

A. Yes, they are.

Q. So the best of your knowledge, information and belief, did you attempt to notify all the working interest owners that might be affected by this project?

A. Yes, we did.

Q. In addition, did Marathon undertake to notify the offsetting operators within the half-mile area of review, that might be affected by any of these injection wells?

A. We did.

Q. And did you also attempt to notify the BLM, as the owner of the surface of each of these injection wells?

A. We did.

Q. Let's turn now to Exhibit 44. What is that Mr. Wilson?

A. That is a copy of the Unit Agreement.

Q. Is that Unit Agreement on a form that's approved by the Bureau of Land Management for unitization of production such as this?

A. Yes, sir.

Q. Have you circulated that Unit Agreement to all the proposed working interest owners?

A. Yes, sir.

Q. In addition, have you prepared an Operating Agreement?

A. Yes, we have.

Q. Has that also been circulated to the potential working interest owners?

A. It has.

Q. I am going to direct your attention to what is marked as Exhibit 47, and I'm going to share with you, Mr. Examiner, a substitute copy of both 47 and 48. They have been color-coded to assist you in understanding what the status is of participation in both categories of interest owners.

If we start off with 47, first of all, Mr. Wilson, the color codes I've shown to the Examiner represent what, in terms of the participation of the working interest owners in the unit?

A. I did that a couple of days ago. The fluorescent yellow colors are the signature pages that I had received in the office at that time. The pink would represent companies that had indicated that they were mailing it back. The day before we left I received two more in, so I circled those in yellow. I believe the only one that has indicated they would send it back, but has not, is Yates Energy.

Q. With the assumption that Yates will be sending you the signed ratifications to the unit, what percentage of working interest owner participation is now committed to the unit?

A. Excluding Yates right now, it's 75.01322 percent. Including Yates--

Q. I think you wrote that on the bottom of one of the displays?

A. It is on the bottom--I don't have a copy with me--but it would approach over 76 percent.

Q. How have you tabulated the responses from the overriding royalty interest owners?

A. I used a copy of Exhibit B of the Unit Operating Agreement that has the listing by tracts of all royalty owners.

Q. If I asked the Examiner to compare it to Exhibit No. 48, appended to the back of that series of correspondence, then you have highlighted in yellow what?

A. Actually, I put red check marks by the parties that I have actually received the ratification and joinders from. At the time I started this, I highlighted in yellow the parties that indicated they would be mailing them in. You might have a check mark and a yellow highlight by a same name.

At the time I believe there's only two parties that have indicated that they would be mailing in, that I have not received.

Q. Do you have an estimate for us of the percentage of royalty participation that you have at this point in the unit, including both the federal royalty and then the overriding royalties into that category?

A. Yes, sir. It's approaching 86 percent. It's 85.7 percent.

Q. Ask you to go back and identify some of the components of the Operating Agreement and the Unit Agreement, to see where we can reference those documents and find the corresponding requirements out of the Statutory Unitization Act. Have you accomplished that review?

A. Yes, sir.

Q. Let me ask you, is there a provision in the Unit Agreement where the operating expenses and capital investments have been allocated to the various separately owned tracts?

A. Yes, sir. It's Article 11 of the Unit Operating Agreement. It's on page 15.

Q. It's on page what?

A. 15.

Q. Of the--

A. Unit Operating Agreement. And, of course, the COPAS also deals with accounting procedures. That's Exhibit D.

Q. The COPAS attachment in Exhibit D, is it?

A. Yes, sir.

Q. From your perspective, is the language used to accomplish those provisions, can that be characterized or considered to be a fair allocation of cost between the parties that have to bear those expenses?

A. Yes, sir. The parties will receive revenue based on the same percentage as they will be billed, so I believe that's a fair and equitable situation.

Q. Is there a procedure in the Unit Agreement for taking care of credits and charges for equipment, machinery or anything contributed to the unit?

A. Yes, sir, it's Article 10 of the Unit Operating Agreement.

Q. Okay. How is that to be accomplished?

A. Article 10 provides that we will have an inventory committee, and if we can't decide on a committee, there will be an independent authority that will propose the inventory to the working interest owners.

Charges and credits will be given to each working interest owner. If charges exceed credits, they will receive a bill. If credits exceed charges, then they will receive a check in payment from the operator.

Q. Are there provisions made in the agreements in the event a working interest owner does not pay his share of unit expenses?

A. Yes, sir. That's also in Article 11 of the Unit Operating Agreement. The COPAS provides that you can charge interest after 30 days if you've not received payment. Article 11 provides that after 60 days, the nondefaulting working interest owners can't pay their proportionate share of the defaulted payment, at that time the operator can pay them back with the interest attributable to the defaulting party.

Q. Do the agreements provide for a risk factor penalty to be assessed against any nonconsenting working interest owner?

A. No, sir.

Q. Is there a procedure provided for in the Agreements for the designation of successor operator or procedure for removing of a current operator?

A. Yes, sir. Section 6 and 7 of the Unit Agreement and Article 6 of the Operating Agreement provide for the resignation and designation of operator; Marathon Oil Company being designated as the initial unit operator.

Q. Does the agreement provide for a method of voting on unit matters?

A. Yes, sir. That's Article 4 of the Unit Operating Agreement, and that provides for voting procedures, I believe 80 percent and three parties.

Q. Does the agreement provide for a method in which to implement the unit, a starting time as well as a procedure for termination of the unit?

A. Yes, sir. The effective date of the unit is either going to be the latter of January 1, 1992, or the first day of the next month succeeding approval of the unit by the State, BLM and the working interest owners. As far as termination, they can terminate on January 1st of 93 if it hasn't been approved by that date. That date can be extended by a vote of 75 percent or more of the working interest owners. And the term, the unit will say in effect for as long as there's unitized substitutes being produced from the unit area.

Q. Are there provisions in the Agreement to effectively describe the unitized interval and the unitized substance?

A. That's in the definition portion of the Unit Agreement. I believe it's subparagraph W on page 5.

Q. Are you satisfied, Mr. Wilson, as a petroleum landman, that you have the appropriate contractual documentation approved by the various parties and the agencies involved, would give Marathon as the unit operator, effective and efficient control over this portion of the Tamano Bone Springs Pool?

A. Yes, sir.

Q. Were Exhibits 5 through 48 either compiled with your assistance or under your direction, or copies of documents taken out of Marathon's file derived in the ordinary course of doing business on this project?

A. Yes.

MR. KELLAHIN: Mr. Examiner, we tender Exhibits 5 through 48.

EXAMINER STOGNER: Exhibits 5 through 48 will be admitted into evidence at this time.

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

EXAMINATION

BY MR. STOVALL:

Q. Mostly as a point of clarification, looking at Section 11, and I've just only skimmed through it--

MR. KELLAHIN: Of the Operating Agreement?

MR. STOVALL: Yes.

Q. --that is what you referred to in response to Mr. Kellahin as a method for allocating costs and charges, is that correct?

A. Yes, sir, I believe that's correct.

Q. Would it be more accurate to say that the Unit Agreement itself, and it appears just looking at the Table of Contents, it talks about, I believe, Sections 13 and 14 establish the formula?

A. Yes.

Q. And then the Section 11 that you're talking about says, what do you do with that formula now that you've got it?

A. That's correct. 11 deals with costs, and the articles you're talking about are the tract participation formula.

Q. And then Exhibit C, then, I assume, to the Operating Agreement, is the working interest tract participation, is that correct?

A. Yes, sir. That's the summary of the working interest owners' interest.

Q. As it stands now, at this point in time, based upon the formula you've used and the interest held by the other parties?

A. That's correct.

Q. And the statute, Mr. Kellahin was tracking you through the statute there to make sure your agreement addressed all the issues, has a specific provision which allows for treatment of nonconsent interests? It appears you don't really have anything which you would call nonconsent, it's just failure to pay your share when due?

A. That's correct.

Q. You're not really treating anybody as a nonconsent with a nonconsent penalty attached to it?

A. No, sir, not planning to.

EXAMINER STOGNER: What did he say?

MR. STOVALL: He said "no."

Q. You talked about joinder, and your 86 percent royalty was all of the noncost-bearing interest. When you refer to royalty, you're referring to the combination of basic royalty and overriding royalties?

A. That's right. There are some owners that own overrides that are also working interest owners. When you add those parties in, it increases that by a minimal--about one and a half percent.

Q. In doing your calculation, did you separate those parties? Did you put them--you know, Mr. Jones is in the working interest column and here's how his interest is there, and here it is?

A. Yes. Right now we have 85.7 percent of the royalty committed, and that's not including any of the working interest owners own overrides.

Q. I think I understand what you said, but I don't think it matters because you're in excess of the statutory requirement. But your working interest calculation is based upon 100 percent of the working interest?

A. That's correct.

MR. STOVALL: I don't think I have any other questions.

EXAMINER STOGNER: Neither do I.

MR. STOVALL: You did get him to state that all those numerous exhibits regarding correspondence, you've verified their authenticity as either being to or from Marathon?

THE WITNESS: Yes, sir.

MR. STOVALL: Okay. That's it. Now I'm through.

EXAMINER STOGNER: Thank you, Mr. Stovall. Thank you, Mr. Wilson. Mr. Kellahin, anything further?

MR. KELLAHIN: No, sir.

EXAMINER STOGNER: Does anybody else have anything further in either of these two cases?

If not, Case Nos. 10341 and 10342 will be taken under advisement.

CERTIFICATE OF REPORTER

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

I, Carla Diane Rodriguez, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I caused my notes to be transcribed under my personal supervision; 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 July 3, 1991.

Carla Diane Rodriguez
CARLA DIANE RODRIGUEZ
CSR No. 91

My commission expires: May 25, 1995

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case Nos. 10341 + 10342 heard by me on 27 June 1991.

_______________, Examiner
Oil Conservation Division