NEW MEXICO OIL CONSERVATION DIVISION

STATE LAND OFFICE BUILDING

STATE OF NEW MEXICO

CASE NO. 10570

IN THE MATTER OF:

The Application of Marathon Oil Company to Qualify a Portion of the South Eunice Seven Rivers Queen Unit Waterflood Project for the Recovered Oil Tax Rate Pursuant to the "New Mexico Enhanced Oil Recovery Act," Lea County, New Mexico.

BEFORE:

DAVID R. CATANACH

Hearing Examiner

State Land Office Building

October 15, 1992

REPORTED BY:

CARLA DIANE RODRIGUEZ
Certified Court Reporter
for the State of New Mexico

ORIGINAL

A P P E A R A N C E S

FOR THE APPLICANT:

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BY: **W. THOMAS KELLAHIN, ESQ.**

I N D E X

E X H I B I T S

EXAMINER CATANACH: At this time we'll call Case 10570, the application of Marathon Oil Company to qualify a portion of the South Eunice Seven Rivers Queen Unit waterflood project for the recovered oil tax rate pursuant to the New Mexico Enhanced Oil Recovery Act, Lea County, New Mexico.

Are there appearances in this case?

MR. KELLAHIN: May it please the Examiner, I'm Tom Kellahin of the Santa Fe law firm of Kellahin & Kellahin appearing on behalf of the Applicant, and I have two witnesses to be sworn.

EXAMINER CATANACH: Are there any other appearances in this case?

Will the two witnesses please stand to be sworn in.

[The witnesses were duly sworn.]

MR. KELLAHIN: Mr. Examiner, Marathon is seeking approval of a portion of its South Eunice Seven Rivers Queen Unit waterflood project for the New Mexico Enhanced Oil Recovery Act recovered oil credit.

I'll provide you a copy of the Act so that you can specifically see what we're looking to accomplish. It's found in 7-29 A-2. It's subsection D, and then it follows over on the second page. I've highlighted in yellow the specific portion of the Act that we seek to qualify this project with.

The southern end of the waterflood project has an area we've designated as the project area. After exhausting efforts to improve primary recovery as well as waterflood secondary recovery on an 80-acre pattern, the Applicant has conducted geologic and engineering studies to demonstrate that by reducing that pattern to a 40-acre pattern, it will substantially increase the secondary oil recovery.

We believe it qualifies and should be approved under the Enhanced Oil Recovery Act of New Mexico, and that's what we'll focus in on.

We'll call two witnesses. Mr. Eric Carlson is a geologist and he's the first witness. Mr. Michael Wiskofske is the engineering witness. He spells his name W-I-S-K-O-F-S-K-E.

At this time, I would like to call Mr. Carlson.

ERIC D. CARLSON

Having been first duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Eric D. Carlson. I am a petroleum geologist.

Q. Mr. Carlson, on prior occasions have you testified as a petroleum geologist before the Oil Conservation Division?

A. Yes, sir.

Q. What has been your activity with regards to the waterflood project described as the South Eunice Seven Rivers Queen Unit Waterflood Project?

A. For the past three years I've been the geologist assigned to this project, this area.

MR. KELLAHIN: Mr. Examiner, we tender Mr. Carlson as an expert petroleum geologist.

EXAMINER CATANACH: He is so qualified.

MR. KELLAHIN: Before we commence Mr. Carlson's geologic displays, I would like to share with you the Administrative Order that approved the conversion of certain producers to injectors within what we propose to qualify as the project area. It's Administrative Order WFX-629 entered effective as of April 9, 1992.

Q. All right, Mr. Carlson, let's turn to your first display. Identify for us the map.

A. Exhibit No. 1 is a summed net sand map for five stringers that are in the Queen formation. We exclude the Penrose because it's not productive. The sand really doesn't develop here. We're talking about just the Queen formation as part of the pool here.

Q. What is the purpose of the yellow outline?

A. The yellow outline is the unit boundary for the Seven Rivers Queen Unit here.

Q. Within the unit boundary, you've identified a well with an orange dot or an orange circle around the well location?

A. Yes. That well is Unit Well 439. That is the type well that I will show you some core information very shortly. Frankly, what I'm doing with this map is to give you a general shape, first of all, where the sands are in this unit. You can note that in the northeast portion of this unit we have a thick area. In the southeast portion we have a relatively thick area. Those are the best parts of the unit.

If you look in the north-central part of the unit, you can see the sand quality is very poor and there isn't much sand at all.

Q. As a point of reference, Mr. Carlson, let me ask you to turn to Mr. Wiskofske's engineering exhibits, and if you'll look at Exhibits 8 and 9--and, Mr. Examiner, if you would also pull out those plats, I think they'll serve as a guide so you can see the proposed project area that we want to qualify for the oil credit.

Do you have those displays before you, Mr. Carlson?

A. Yes, I do.

Q. On Exhibit No. 8, there's an area stippled or shaded in gray. What does that represent?

A. That's the pattern reduction project area.

Q. Let's take that area and have you help me understand geologically why that area is suitable for the reduced pattern project?

A. Sure. First of all, I'll point out the reduced pattern area. On Exhibit No. 1, we see that it is in the southern portion of the unit. What we found is that basically this map is the state of our knowledge in 1989, before I was asked to come in and look at this unit, late in its life. Can we find some more opportunities for drilling or other recovery methods that might perhaps extend the life of this unit, keep it economical longer?

So I was hired in, brought in, rather, to this project as a geologist with the new concepts of the late 80s and early 90s, if you will. The previous geologic work had been through the 70s. What I had to do at this point was to take this relatively general map and attempt to explain the production anomalies we saw in the secondary recovery.

As we had been waterflooding for a long time by then, we saw that almost all the new waterflood or almost all the recovery from the waterflood were from the northeast portion and the south-central portions of the unit. We saw very uneven recoveries. And we had drilled some wells in the 80s, starting from about 434 or so and 435. Most of the wells, 435 through 440 are infills, if you will, on tighter spacing in the pattern area.

Q. In order to establish a reference in terms of the development of the unit, in 1989, were there infill wells yet drilled in what we've defined as our pattern reduction project area?

A. Yes. All the wells were drilled by 1989. So, I had all this data and we had cored the wells 435 through 440 as well, so I was able to take a look. What I found out is that this examination, this look here of net sand, this is on a particular scale that people often look at to drill wells, but what I had to do was to look at a finer scale, at the various individual stringers of this formation, to actually diagnose what had happened in this waterflood.

So that how I'm going to take you through this geologic argument is to go to a scale that we don't usually look at. It's late in the life, we have a lot of information, and we had to look at the scale to diagnose why we had so many production anomalies.

Q. Before we go through the specific details of that geologic evaluation, let me have you summarize the geologic conclusions that are applicable to the application today, and why you, as a geologist, can now conclude that there is a geologic explanation to the ability to improve secondary oil recovery for a project defined within this pattern reduction project area.

A. What we found is that these individual stringers within the reservoir are very discontinuous. To use some words that many people often do, we found that this is a very heterogeneous reservoir system rather than homogeneous, and that we had to take a look and we saw that variations from well to well on the increased density were still very great. We still saw a lot of differences even from, say, 40 acres away. There were great variations and, in fact, unless you drill tight enough you won't really be able to flood from one stringer to another.

As a result of this, in fact, as an aside, when we went to flood Section 16 in the next year or so after I looked here, we realized to begin with we had to be on tighter spacing, so we put this application to use here and also northwest, five miles away.

Q. Was the existing 80-acre flood pattern in place at the point in time when you're commencing your geologic examination of this area?

A. Yes. All the wells were already drilled and the patterns were already on 80-acre flood. Those wells that were injectors at the time that are outside the pattern area are obvious in the north part of the unit particularly. You can see all the injectors that were already set up on an 80-acre flood.

Q. What is your conclusion, geologically, about the 80-acre flood pattern for the southern portion of the unit?

A. The 80-acre flood pattern in the Queen is insufficient to waterflood properly. You leave too much oil in the ground on an 80-acre flood.

Q. What is your recommendation, then, with regards to a flood pattern?

A. You need to tighten that flood pattern up to a 40-acre pattern.

Q. Having realized the conclusion that you've reached from your study, let's go back and touch on some of the pieces for the Examiner so he can see how you've gone through your thought process to reach that conclusion. Let's go to what you've called the type log.

A. Okay. I would like to direct your attention, Mr. Catanach, to Exhibit No. 2, the type log. Once again, the general picture that I showed you in Exhibit No. 1 was not specific enough to address the problems that we saw, so we went back to the beginning, we took a look at the core data and compared it to the log data.

Now, this example is Well 439. It's the orange dot on your geologic map. There's a lot of information on here. We did have a great amount of data, and I'm going to take you kind of slowly through it to help you kind of visualize what's going on.

Very quickly, first of all I would like you to note the scale is five inches to 100 feet, just like a standard detail log that you would see. We have, from the left, a gamma ray caliper log, then we have some resistivity logs, some neutron density logs with a PE curve. We have a core time and core gamma for correlation purposes, and then the rest of the information from Bell Petroleum Services' core analysis, porosity, permeability, water and oil saturations and, of course, your grain density. So we have a lot of information.

Q. What portion of the pool are you examining with the data shown on this display?

A. Okay. We are examining that portion of the pool that's from the top of the Queen formation, which you see marked in your resistivity log track, down through the Queen sands that are productive in this pool.

Q. Are there any other producing members of the pool--

A. No, sir.

Q. --other than this Queen?

A. This represents the entire productive portion of the pool in this unit area.

Q. And the names that you've placed within these individual stringers of the Queen are names that Marathon uses internally?

A. Yes, sir. These are simply designations for the stringers. I just happened to choose the alphabet and started with A, and later on I realized there was a stringer I had to map above that, hence the "Z," but basically they're in alphabetical order.

Q. Without describing all the details on the display, give us a summary of the key components to the display and the conclusions you've reached.

A. The key components are the lithological analysis, the porosity analysis, especially the comparison of log to core, and that allows us to establish a pay cutoff, a minimum porosity for pay cutoff. And also just to mention, we do see also some saturation information which is helpful in describing the seals. And that's the main portions of this log.

In sum detail, very quickly, the purple is dolomite in the left track and left depth track; the purple is dolomite and the yellow is sand. Those are the two components of this system.

Q. Does the dolomite produce oil from the reservoir?

A. No. The dolomite contains oil but it is extremely tight and it will not produce oil. The oil is all being produced from the sands. And as we go to the neutron density log, we see, for instance, a PE curve which I've highlighted in color as well. Once again, dolomite is that portion of the PE curve to the right, increasing greater than 2.75 on the PE, and then the sands are the yellow highlighted less than 2.75. So I have a PE to really help the lithology determination here.

We did a lot of work with core-to-log porosity to really try and understand this thing, and what we find is the sand is pretty fine-grained but where you don't have impurities in the sand, it's really a pretty good producer. So, as you look, I've indicated with a slanted red line in the neutron density track there and also a slanted red line in the porosity track.

As you see around 22 percent log, neutron density plus porosity, it's about 20 percent core porosity. So, when the sand is very porous it's very clean and almost all the porosity, Mr. Catanach, is effective porosity.

As your log porosity towards the top of that slanted line gets down to 14 percent, you'll see the core porosity is now reading approximately eight percent. What that means is that as the pay quality diminishes, you start getting clays into that sand that effectively are read as nonporosity, read as formation by the core porosity, which is just the connected porosity.

We look at our permeability associated with these, and we see in the Klinkenberg permeability, which is a permeability calculated back to reservoir temperature and pressure, that in fact the 20-percent porosity stuff is looking at 100 millidarcies. It's a really good permeability ride. If you look at 15 percent, you're down around 10 millidarcies. If you want to establish a pay cutoff, I've circled the zone at the top of the neutron density log, and that zone is approximately eight percent density neutron plus porosity. And you'll see it's about one millidarcy permeability.

That left basically our pay cutoff, eight percent. You'll see that the dolomites have permeabilities around .1 millidarcy. They're tight. They're not productive.

So, those are the points I want to show you, again, the relationship of the various sand stringers, the great variation in porosity and permeability that we see and how it compares to the core, and it established the minimum porosity cutoff in the sands of eight percent. It shows the dolomite is seal facies, and the sands, that's the pay facies.

Q. Mr. Carlson, have you prepared a cross-section that illustrates your conclusion about the discontinuity of the sands in the reservoir through the project area?

A. Yes, sir. Exhibit No. 3 is a print of a cross-section that I did in 1989 as part of this work. Once again, the type well is on this section. You can see on the right-hand display there, the unit boundary again in yellow, the cross-section runs west to east from the left to the right, from A to A'. We have eight wells on the cross-section.

I would also like to point out, Mr. Examiner, the vertical scale below the map which shows you, once again, that there's 30 feet in almost an inch of vertical scale there. Once again we're looking at detail logs on this display.

Q. If we look back at Mr. Wiskofske's Exhibit No. 8 to give us the project area, find the producer in the southeast corner of the project area, it's Well 439?

A. Yes.

Q. That corresponds to your Well No. 6 on the cross-section and that's your type log well?

A. Yes. Once again, this is the same density neutron log you've just seen on Exhibit No. 2.

Q. Let's start with Well No. 6 which is Unit Well 439, and have you describe for us the reservoir thickness of this sand on that log, and demonstrate for us what happens to that sand as we move both east and west of that location.

A. What we've found is that Well 439 saw one particular stringer, which I've highlighted in yellow on this display, that stringer is in the Able sand. And it was quite thick, 28-feet net, I believe, in that interval.

We see, as you go west from Well 439 to Well 435, just one 40-acre location away, we can see that the overwhelming majority of this sand is just not present. We can also see if we go just a little further, one 40-acre spacing away to Well 701, that this sand is absent for all intents and purposes. We see that with an 80-acre distance it's completely gone, and within 40-acres' distance it's very nearly gone.

If we go eastward to Well 414 or

actually southeastward, we'll see that Well 414 does see this sand, and it's also quite well-developed, and in fact we have found that Well 414, being an injector, has pushed movable oil to Well 439, and it's been a very good recovery.

In fact, also Well 413, which is located northwest of 439, has also been able to move oil. So that explained this anomalous high production in Well 439. Just happened to have a single stringer that was well-connected, and we were on a tight enough pattern there to flood oil from the injectors 413 and 414, into 439.

As you look, if you go just east from 414 again to 417, once again the 40-acre pattern, you're out of it. Again, you have no well sand to speak of in Well 417 to the east. If you look at this shape and cross-section, you'll see it has sort of a beach sand profile and when we make an environmental determination for all these sands, we see they're just about right on the edge of the ocean. And I would submit to you that this Able sand is like a Galveston beach example. I'll show you a map of it in a minute, but this shape, this airplane wing-type shape is indicative of a beach sand here.

Q. I want to ask you a question with regards to the pattern and then we'll go into having you give us a demonstration of your isopachs of these various sands.

A. Sure.

Q. Let's take Exhibit No. 9 at this point. When you look at Exhibit No. 9, the six diamond shapes are the producing wells to be converted to injector?

A. That's correct.

Q. And that is what we're talking about when we say we're taking the flood pattern from 80s to 40s?

A. That's correct.

Q. Describe for us now, using your type log, what do we achieve geologically by converting all these producers to injectors? What's going to happen?

A. What will happen is that these individual stringers will see more than just the one well. They'll see a second well. And so that second well can be used to flood mobile oil into the producer. As long as you're on a tight enough pattern, you can actually have conductivity, connectedness, between two wells.

We can actually--you have to get two wells, two straws in the same stringer before you can effectively waterflood. These stringers are so discontinuous, the reservoir system is so heterogeneous, that if you don't have two straws, you'll just be putting water over here and you'll never recover the good, fat sands oil over here because it won't have had any pressure support, so that's what we're doing.

I would like to point out one other thing if I could, Mr. Catanach, from this, because it's indicative of the Queen in general and it's an important point and explains why I hung this cross-section the way I did. The dolomites are relatively deposited over a wide area, but the sands are very local. We find that we can hang the stratigraphic datums on dolomite.

What I've done, there's a nice dolomite at the base of the Able sand, I've called it the Beta dolomite here. It's fairly regional in extent and it extends up into Section 16 where it separates the Upper from the Lower Queen sands in our flood there. It's easily extendable. It can be traced for at least two townships around here. It's a good stratigraphic time line. What we find is that a lot of the confusion we've had in the Queen pools over the years, if you look and hang it on a time line, you'll see there's an unconformity at the top of the Queen.

I've also hung another good time line above that unconformity, which is a lower Seven Rivers A sand which we've discussed in testimony earlier with the Commission here, and that's another good time line. It extends all the way up into Section 16 as well. What we see is about a 30-foot unconformity which has generated a lot of the confusion over the years over just exactly where the top of the Queen is. It was resolving this unconformity factor which allowed me to go in and do a better job of actually mapping these stringers than what people could previously do.

The modern geologic concept of rises and falls and sea level help us to explain this unconformity. At the top of the Queen it's a formation boundary and there was a sea level fall there and a sea level rise again, and we were able to deposit some of these Seven Rivers sands above the Queen. That was a very big help to us in understanding the extremely heterogeneous nature of the Queen pays here.

Q. To further illustrate that point, Mr. Carlson, let me have you take the composite isopach, Exhibit 1, and let's use that as our base map and then compare each of a number of isopachs to that base map. Let's start now with Exhibit No. 4.

A. Exhibit No. 4 is an isopach map of net thickness for the Able sand. This Able sand is the sand I just highlighted for you, Mr. Catanach, in yellow, on the cross-section.

You're looking at this beach sand, and you'll see that it's found exclusively, really, in the east and central portions but particularly in the southeast portion of the unit. Because we're right on the coast line here, Mr. Catanach, geologically when we look at the environment of deposition, we have two major influences on the shape of these sand bodies. One is the wave energy that tends to make a nice long beach. This is the end member. This one looks the most like a beach, this Able sand, of all the stringers.

We also have a tidal energy which will

tend to act and elongate things in a southwest and northeast fashion. I have for you Exhibit No. 5, which is really complementary to Exhibit 4 if I could pull it out, please--

Q. Before we leave Exhibit 4, you call it a net thickness. What have you used for a porosity cutoff?

A. Eight percent.

Q. Have you used eight percent on all the maps?

A. Yes.

Q. Let's compare Exhibit 5 to 4, as you build a geologic picture of the Queen interval for us.

A. Remember, Exhibit 4 is a sand in which we see a lot of wave energy. It's a beach sand. If you look at Exhibit 5, you'll see the influence is much more tidal. There's much more tidal influence, so we see a geometry running southwest and northeast. You still see a thickness running roughly parallel to the sand in Exhibit 4. You see the Charlie sand is roughly parallel to the Able sand, if you will, but the exaggeration of the lobes in the Charlie sand is due to stronger tidal influence at that very time than in the Able sand where the lobes are very subdued.

So, these are end member sets of what these sands actually look like when you pin them down and start looking at the 5 and the 4 and the 10-foot interval thickness. In fact, I've mapped the other sands and I'm not going to burden you with all these details, but these are the end member sets of what these sands look like. They kind of are all distributed in the unit in different places.

Q. Let's turn to Exhibit No. 6 and have you identify and describe that exhibit.

A. Exhibit No. 6 is a structure map on the top of the Queen formation. Like the previous geological map exhibits, you'll see it still has the yellow border around the unit boundary. It still has the type log, No. 439 in the pattern area indicated with the orange circle.

Q. What is the impact of structure on the unit?

A. The impact of structure is that the sands in general tend to be cleanest and thickest on structural highs. I'll make a point here, make a case to demonstrate to you, Mr. Examiner, that in fact the theory of synchronous highs, which you're probably familiar with, the notion that your best sands occur on the tops of small structures, that that theory applies very well in looking at the general picture of Queen sand distribution from Section 1. But when you actually look at the little, thin stringers, you have to take into account much more seriously the local geological factors and local depositional environment factors.

So, in general, when we take a look at Section 6, we note, first of all, in the very northeast portion of the map, we have a fairly steep gradiant for this area. This represents the structure of the formation as it comes off the arrowhead platform. So, there's a buried fault that runs northwest/southeast in the very northeast corner of this map. It's the major structure. Everything else is variations on flat in this map. You'll see we only have a 20-foot contour interval.

What we see is that in general there's a low area southwest of this major structural feature, and then that low area basically tends northwest/southeast, and across that area is a little subdued arch that runs southwest/northeast from Section 34 in the southwest, through Section 26, and into Section 25. Those are the major structural factors.

Now, if you look at this to set up the theory of synchronous highs, I'll show you another structure map below it and show you that what was once high, is later high.

Q. Let's turn now to Exhibit No. 7, and this is a structure map on top of the lowest sand member that is productive in the Queen?

A. That's correct. This map in Exhibit 7 is a structure map on top of the easy sand, the lowestmost member. You'll see, once again, this is only 150-feet deeper so there isn't much difference between these two maps.

Once again, the extreme structure we see associated with the fault is on the northeast corner of the map. It's draped over a buried fault, if you will. Again you see a low area running northwest to southeast, from Section 23 down to the southeast of the unit. We again see the arch running across from, this time, the southwest corner of Section 35 into Section 25's northwest corner area.

So the structure isn't very much different. The theory of synchronous high says that your current bathymetry, which will affect your sand deposition, your current bathymetry is related to deep structure because of differential compaction, which is the word that's used, but basically your compaction is such that your buried structure is reflected in a very minor way in the local sea floor bathymetry.

If you have a structural high buried maybe 150-feet deep, you'll see a slight bathymetric effect. What will happen is, wave energy across that slight high, that shallowing of water, if you will, over that deep, buried high, will clean up the sands and allow you to then have productive sand and not dirty, gritty stuff.

In general, the reason this unit is productive in the Queen is because if you go north into Section 23, or east into the next township there, you lose the structural advantage that helps you window and clean out those sands.

Q. Go back to Exhibit 8. We've used this as a locator plat, if you will. The stippled area in gray, which is our project area of discussion in this application, give us a geologic summary to show us the justification for the project area, in terms of its geology.

A. The project area is one of the best areas for development in this pool. It's much structurally higher than the north/central area of the unit, for example, Section 26.

As a result, the sands are generally cleaner, but even though they're cleaner, the individual stringers are very, very discontinuous. So, because the individual stringers are very, very discontinuous, you need to tighten up your pattern so that effectively you can see a single stringer with both a producer and an injector.

Q. Does this represent the portion of the unit that is Marathon's best opportunity to improve secondary oil recovery by some enhanced oil recovery technique or procedure?

A. Yes, it does. Of course, after doing all this detailed geologic work it would have been great if I could have found eight new locations to drill. Unfortunately, this late in the life of the reservoir, we find that with today's economics and prices, we can't justify drilling. We can't justify a lot of new capital expenditure because of prices being what they are and because we're so late in the life of the reservoir.

It looked like about the only thing we could do to extend the life of this field, to increase ultimate recovery, if you will, would be to tighten the pattern and flood and, of course, once again as an aside, we took this knowledge and applied it immediately to the McDonald State waterflood in Section 16. There was a benefit of doing this work elsewhere, where we saw that the Queen, in general, has to be tightly flooded in order to really maximize your recovery. So we convert some wells. That's what we recommend to do. That's the best we can do out here.

MR. KELLAHIN: That concludes my examination of Mr. Carlson, Mr. Examiner. We move the introduction of his Exhibits 1 through 7.

EXAMINER CATANACH: Exhibits 1 through 7 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Carlson, is this the only area

within the unit that this will work in?

A. Well, in a sense, yes, and in a sense, no, Mr. Examiner. First of all, I believe that you could probably do some infill drilling in Section 25 in the northeast corner. There's the easy sand there. The lowest sand is quite thick there. In fact, you could probably get more oil.

The question is, can you do it profitably. At this time, the only place where you can tighten the pattern profitably is where the wells already are, so you have to do a conversion. And in that sense, the south portion of the unit is the only place we can do it profitably now.

Q. Within the proposed project area, what is the main producing sand?

A. I would say the best producer in the project area to date has been the sand we see in Well 39, the Able sand. And that's almost perhaps been coincidental because of the way they set up the 80-acre pattern originally, where the injectors 413 and 414 happened to line up nicely in that sand with 439.

I believe there's additional recovery

potentials particularly in the Baker sand, and those are going to be more seen, and obviously the Charlie sand if you look is much more developed over in the pattern surrounding Wells 440 or 436.

So really, it was one of those things where you couldn't just generalize. You had to go in here and root through all of these details and the sand quality for all the individual sands varies that much.

Q. Within the pattern reduction area, have you found all the sands to be discontinuous?

A. Yes. As a matter of fact, even the wet sands above the top of the Queen, even those Seven Rivers sands, the sand quality varies. There's no producing sand out here that's producible across the entire project area.

Q. It is your opinion that recovery from all the sands will benefit from reduction in spacing?

A. Yes. You know, originally this thing was set up, once again this scale they were looking at, Mr. Catanach, originally they just perf'd every sand, everything that was an excursion of the gamma ray to the right they perforated, and there wasn't a whole lot of science put into the original flood or the original production.

We're still left with the fact that when we do our testing for these wells, it's hard to isolate zones individually. Fortunately, for us, if you're moving oil through a zone and you're producing it out of another well, you create a pressure sink for that zone and not allow the waters that you're injecting to preferentially find that zone and help you produce whatever stringer in the adjacent well.

Q. When did waterflood operations commence in this unit?

A. I want to say it was in the mid-70s but my associate, Mr. Wiskofske, has memorized all those dates for you.

EXAMINER CATANACH: Okay. I believe that's all I have at this time.

MR. KELLAHIN: One follow-up question.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Am I correct in understanding your response to Mr. Catanach's question, all the producing wells in the project reduction area have been fully and completed perforated in any of the possible producing sands?

A. Yes.

Q. We don't have any behind the pipe primary potential in any of those wells?

A. Unfortunately, no. We did a little work above the top of the Queen in the Lower Seven Rivers. We tried to open up a zone there in the Lower Seven Rivers A and found, unfortunately, that that was wet, that that Lower Seven Rivers A is wet.

The rest of them, however, we found they've already been opened. We've already seen some flooding effect. It's just a matter of maximizing waterflood recovery with this pattern tightening.

MR. KELLAHIN: Okay.

FURTHER EXAMINATION

BY EXAMINER CATANACH:

Q. Mr. Carlson, is the Seven Rivers also being injected into?

A. No, sir.

Q. It's just this portion of the Queen?

A. We attempted to see if there were primary reserves in the Seven Rivers. In the area of--well, we were even thinking of drilling a well down in 701 and 702 to see if we could support a well, and I had just enough sand thickness from five or six stringers there that if they had been oil, we would have had a viable economic project.

What we did was, we recompleted a well just northwest of there first, a little thin one, to see if there was any oil, and it came back wet so we couldn't do anything more with the Seven Rivers.

Q. So, the sands you've identified in your exhibit, those are the only sands being produced in the unit?

A. Yes, sir. Those are the only oil productive sands in the unit.

EXAMINER CATANACH: Okay. Nothing further.

M. T. WISKOFSKE

Having been first duly sworn upon his oath, was examined and testified as follows:

EXAMINATION

BY MR. KELLAHIN:

Q. All right, sir, would you please state your name and occupation.

A. My name is Mike Wiskofske and I'm a reservoir engineer.

Q. Mr. Wiskofske, on prior occasions have you testified as a reservoir engineer before the Division?

A. No, I have not.

Q. Summarize for us your education.

A. I graduated from Marietta College in 1987 with a bachelor of science degree in petroleum engineering.

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

A. As a reservoir engineer, I've worked for Marathon for about a year and a half in the reservoir department. Four years prior to that I was in production/operations in Iraan, Texas.

Since I've been working as a reservoir engineer, pretty much the South Eunice is the field I work on.

Q. How long have you devoted your attention to the engineering aspects of the South Eunice Queen waterflood project?

A. Approximately a year now.

Q. Are you currently familiar with the operations of all those wells and the unit in general?

A. Yes, I am.

Q. Have you done engineering analysis and calculations on your production and on your reservoir data?

A. Yes.

MR. KELLAHIN: We tender Mr. Wiskofske as an expert reservoir engineer.

EXAMINER CATANACH: He is so qualified.

Q. Let's start with Exhibits 8 and 9. We've talked about them, but for the purpose of the record would you identify them?

A. Both Exhibits 8 and 9 are well location plats showing the pattern reduction project area. Exhibit No. 8, in the gray, is the project area while Exhibit No. 9 shows the individual patterns of this project area.

Q. Let's look at the conversion of producers to injectors. Those wells on Exhibit 9 identified by the diamonds, there's one of the wells, 416. Describe for us the status of that well?

A. Well 416 is currently a producer. Under the original Administrative Order, I guess was WFX-629, we only applied for five wells to be converted to injection wells. However, for our 1993 budget, Marathon Oil also proposed to convert Well No. 416.

Q. When we look at the Administrative Order I referenced the Examiner to, that approves the injector wells, the conversion of producers to injectors, for all but 416?

A. Correct.

Q. You will go ahead and apply for administrative approval to add 416 as an injector?

A. Correct.

Q. Give us a short history of the unit in terms of its development and production under the primary phase, then move us in through secondary recovery.

A. Okay. The majority of the wells in this unit were drilled between 1958 and 1961. The unit was formed in 1971 for the purpose of waterflooding this area. At the time the waterflood was installed, primary recovery was on an average of about 10 percent in the unit.

We originally started with a pilot area in the northeast portion of the unit in November of 1972. By June 1975, this waterflood injection had expanded to cover the entire unit, and the patterns which it expanded to were 80-acre five-spot injection patterns.

In 1984, we drilled six infill wells on 20-acre spacing. Wells 434, -35, -36, -37, -38, -39 and -40, with five of them being in the southern end or the pattern reduction project area.

December 1991, we converted five wells to injection wells; however, at the present time, these wells--injection has not been initiated in these wells.

Q. What do you see as a reservoir engineer to be the advantage of reducing the flood pattern from 80-acre spots to the 40-acre spot?

A. Well, really two advantages. First of all, you're going to improve your aerial sweep efficiency in the area, and secondly you're going to help pressure maintenance in the area.

Q. Let me ask you to turn to what is marked as Exhibit No. 10. Would you identify that for us?

A. Yes, that is a production and injection plot of daily production injection of the unit.

Q. Describe for us the color-code and what is plotted on the display?

A. Daily oil production is in green; gas production is in red; water production is in purple; in orange is injection per day. As you can see from the graph, unitization was in 1971, which is what the graph starts, through the present time.

Injection was initiated in November of 72, and then field-wide in 75. As you can see, peak production was obtained in 1976. We went on pretty much of an established decline until 1984 when the infill wells were drilled and we peaked again, and then from that time we again have come on to an established decline until December of 91, when we shut in the producers or converted them to injection service.

Q. Let's now take your production information and have you demonstrate what that production shows you for what we've described as the pattern reduction project area. Have you plotted that information?

A. Yes, I have. It should be in Exhibit No. 11.

Q. Let's turn to that and have you describe that display.

A. Again, this is a production plot of daily production oil, gas, water, and daily injection. This is for the pattern reduction project area. Again, oil's in green, gas is in red, water's in blue and injection is in purple.

From this graph you can see that the injection began in the southern end in 1975 and also, from the oil production plot, you can see that we took a kick in 1977 from the flood response and then we again established a decline. And then, in 1984, we took a production kick from the infill wells and from there we've also gone on an established decline again.

Q. As a reservoir engineer, do you find any other viable alternative to improving secondary oil recovery, other than reducing the flood pattern?

A. At the present time, no.

Q. Let me ask you to turn to Exhibit No. 12. In trying to quantify the opportunity for additional secondary oil recovery, have you gone through conventional engineering calculations and methodology to try to determine the approximate additional barrels of oil that might be recovered from the unit if you reduce your flood pattern?

A. Yes, I have.

Q. Is that what's demonstrated on Exhibit No. 12?

A. Yes, it is.

Q. Give us a summary of what you've done here and describe the conclusions.

A. Okay. The main points would be the original oil in place, the developed primary, the developed secondary, the ultimate recovery, and then the incremental secondary recovery. Those columns.

What I did was, I took from Eric's net sand maps, his individual net sand maps, we planimetered each individual sand stringer. We added up the total volume and then, taking average porosity, water saturation values, we determined what the original oil in place of each individual pattern should be.

Knowing the developed primary and the developed secondary for the area, we were able to determine so far what percentage of the original oil in place we were able to recover.

Now, in 1985 we had done some core work on the infill wells that were drilled and, from this data, we got fractional flow curves and also we did some core flooding. We were able to determine that we should be able to recover 30 percent of the original oil in place.

That is basically what the theoretical ultimate would be. The difference between what we developed and what we theoretically should develop is the incremental secondary which you see in the following.

Q. When you get to the last column on the spreadsheet, the one on the right, it's captioned "Incremental Secondary," what does that mean?

A. That is the amount of reserves we should be able to recover by reducing everything to 40-acre spacing in that pattern reduction area.

Q. An estimated 366,000 barrels of additional oil?

A. Yes.

Q. All right. In order to exercise that opportunity for the additional secondary oil, you propose to convert current producers to injectors. That conversion is going to defer or postpone the recovery of a certain portion of this secondary oil, is it not?

A. Right.

Q. Have you been able to estimate or to quantify the time interval in which that secondary oil is going to be deferred, and give us a sense of the volume of oil that you're going to have to postpone recovery?

A. Yes, I have, and that's under Exhibit 13.

Q. All right. Let's turn to Exhibit 13. Before you give us the conclusions, tell us how to understand the display.

A. Okay. This display is basically just a graph of incremental production per day per month. What we're looking at is when a project was initiated in December of 91, we were averaging approximately a little over 13 barrels a day from the wells that were shut in.

As you can see, we go on a decline, an established decline from all the wells, and then, in February of 93, we shut in Well No. 416 which is what we were shooting for our budget.

Now, after February of 93, again we go on an established decline until Well No. 416 becomes uneconomical, which the well would have been shut in anyway.

Again, then we go on a decline, and

Well No. 14 would have been uneconomical, Well No. 409 uneconomical, and so on, as all the wells decline.

It was estimated that the total deferred production would be 22,000 barrels. It is important to note that when I did the reserves for the area, I included these reserves on my total secondary developed. Those numbers are included in there. I didn't shortchange and keep those out knowing that, all right, we'll catch those on this project. No. Based on those declines, those reserves are in that developed secondary.

Q. So we are not attempting to take credit for this deferred oil when we get down to our incremental secondary oil that should qualify for the tax credit under the Act?

A. No, we're not.

Q. Let's turn now to the subject of the cost. Have you provided itemized, detailed information, with regards to the capital investments of the project area? And what I'm talking about here is the pattern reduction project area.

A. Yes, I have.

Q. Let's turn to Exhibits 14 and 15 and have you identify and describe those displays.

A. Exhibit No. 14 is the total capital investments for the project. We replaced some facilities and injection lines. That was $553,000, and then itemized for each of the conversion and the workovers which we performed for this project. The total cost is about $1.5 million.

Exhibit No. 15, on the other hand, is the itemized breakout of just the facilities and the injection line investments. Again, this total was $553,000.

Q. Within the pattern reduction area, have you provided the Examiner with individual well production plots?

A. Yes, I have.

Q. How were those shown in the exhibits?

A. Exhibits 16(a) through 16(l) are the individual--they're on a monthly basis and they're the individual production plots for those wells. They would be for each of the conversion wells, and then also the existing producers right now.

Q. In addition to tabulating or plotting individual well production within the project area, have you also prepared production decline plots and forecasted ultimate recoveries for the individual wells within the project area?

A. Yes, I have. They are shown in Exhibits 17(a) through 17(j).

Q. Let's take 17(a) as an example, and have you demonstrate for us what you've done.

A. We've taken the daily production--well, it's monthly production--from each of the individual wells. From the data we try to make the best fit line reflecting the decline of each individual well. On Well 406's case, we used an economic limit of 60 barrels a month or approximately two barrels a day. We drew our best fit line and we calculated the remaining recoverable reserves.

Q. Are there any of these decline curves for which you've forecasted ultimate recoveries that you want to comment on, or are they all within a certain pattern? Do you see anything unusual about any of these plats?

A. I think the most important thing to point out is that other than Wells 439, 440 and 406, the majority of the wells in this area are pretty much at their economic limit, two, three years of economic life left. That's pretty much typical of the entire unit in general.

Q. Let me have you go back to Exhibit No. 8 at this point. The project area is described as that area that's stippled in gray?

A. Yes.

Q. Describe for us the wells that will be in that project area and how you have determined what portion of production from those producing wells in the project area ought to qualify for the tax credit.

A. Okay. Of the wells included in the area, you have five complete 40-acre five-spot injection patterns with the four injection wells surrounding, with one producer in the middle. You also have a partial pattern 438 which only is surrounded by three wells.

Q. When we look at the five wells, excluding 438, is it your engineering recommendation that all of their incremental secondary oil recovery should be attributable to the tax credit?

A. On wells-- Pardon? I didn't understand.

Q. When you look at Well 440 for example, on the eastern edge of the project area, that is fully enclosed by the 40-acre reduced waterflood injection wells?

A. Yes, sir.

Q. What have you concluded in terms of what percentage of the oil produced from 440 ought to be applied towards the tax credit?

A. 100 percent above the incremental.

Q. Okay. Is that the same conclusion you reach for each of the other producers, with the exception of 438?

A. Yes. Yes, it is.

Q. What do you propose to do with 438?

A. 438 again it's pretty much 100 percent of the the incremental. The only difference is, 438 compared to 439, 437 and 435, is that once 416 is converted, just the oil that we're going to be able to recover is just going to be a smaller amount. I don't believe we'll be able to recover all 30 percent of the original oil in place with only the three injection wheels. We feel another injection well would help us and we would be able to recover 30 percent.

Q. Let's go to your last display, Exhibit

No. 18. Have you provided the Examiner, in Exhibit 18, a baseline production plot by which you can then quantify the additional incremental oil that will be produced from the producer wells in the project area, that is directly attributable to the reduced pattern or this enhanced oil recovery procedure change?

A. Yes, I have.

Q. Describe for us how you've done that.

A. I've taken again, similar to the decline curves which were shown earlier, I added up the production for each of the wells in the area clear back to when unitization occurred in 1971.

From this data, I was able to graph it, and from this data I was able to obtain a fit between 1987 and 1991 which I felt was the best fit line through this data.

As you can see, in 1991 you see the drop off in production and that is basically because of the deferred production which we shut in.

Q. Later on, when we're attempting to certify the volume of additional oil above--I think it's characterized as a positive production response, can we use this baseline plot shown on Exhibit 18 by which to determine the positive production response?

A. Yes, we can.

Q. For the project area, then, when the additional producing wells show a response from the reduced waterflood pattern, there will be a change above this decline curve shown on Exhibit 18?

A. Yes, there will, as evidenced from some of the other--as the response we've seen elsewhere in the unit. Back in 75 you see the big production spike. We should be able to see similar results from that.

Q. You will be able to tell us, in terms of barrels of oil, what that positive production response is?

A. Since I have a base decline set up, yes, I will be able to tell that.

Q. In your opinion, is the baseline production curve you've shown for the project area an accurate and reliable means upon which to determine a positive production response?

A. Yes.

Q. Were Exhibits 8 through 18 prepared by you or compiled under your direction and supervision?

A. The majority of the ones I did myself. The production plots that were Exhibits 16(a) through 16(l) were done under my supervision.

Q. You've examined that information, and to the best of your knowledge, information and belief, it's true and accurate?

A. Yes, I have.

MR. KELLAHIN: That concludes my examination of this witness, and we move the introduction of his exhibits 8 through 18.

EXAMINER CATANACH: Exhibits 8 through 18 will be admitted as evidence.

EXAMINATION

BY EXAMINER CATANACH:

Q. Within the pattern reduction area, I count six injection wells and 12 producing wells, is that correct?

A. At the present time, not including any conversions?

Q. No, that would--let's see.

A. If we include the conversions, we should only have, at the present time--we should end up with six producers and the rest injection.

Q. 12 injectors, is that right?

A. Correct.

Q. Now, if I understand your Exhibit No. 12, the 366,000 barrels is what you would recover as a result of pattern reduction?

A. Yes. If we can eliminate the aerial, say, unconformities, we should be able to recover approximately 30 percent. And to do this it would be to decrease the pattern sizes.

Q. Have you calculated what would have been recovered if the pattern reduction would not have taken place in this area?

A. If we would never have infill drilled?

Q. Right.

A. I believe it should have been around--well, it's going to vary through each of the individual patterns. Of course, Well 439, which is the best well in the field at the present time, has recovered more oil. I don't have the numbers in hard copy, no. I can give you a rough estimate of what they would have been, probably between 17--well, 15 to 17.

Q. 15 to 17?

A. 15 to 17 prior to infill drilling. Now we've gone up in percent recoveries to 15 percent, so actually five to 10 percent.

Q. You don't have a number in terms of barrels which may have been recovered?

A. Yes, I do. Approximately 100,000 barrels; 100 to 120.

Q. Now, does the 366,000 include that 100,000 barrels?

A. No.

Q. It does not?

A. That 366,000 barrels would be taking, if you look at this table under developed secondary, what I did was, I took each of the wells and I declined them out under primary and secondary conditions.

Under the secondary conditions for each of these wells, I included what that well should recover at an economic limit. I also did that for the injection wells that we converted over, and those numbers are included under developed secondary. The remaining number is the incremental secondary number based on a 30-percent recovery factor.

Q. So the 366,000 barrels are additional recovery that will occur directly as a result of pattern reduction?

A. Yes, it is.

Q. How long do you think it would take to get a response to your positive production response?

A. I think you'll be looking at approximately a year.

Q. Is it your intent that Exhibit No. 18 would be used to demonstrate when that production response would occur that would be the basis for us to use?

A. Yes, I felt that was a better fit line through the points I took rather than those end points through the deferred production.

Q. The end points represent what, now?

A. The end points at the very end, where we had that second decline coming down, that's after we shut in the injection wells--I'm sorry, the producers which we converted to injection service.

Q. Okay.

A. So really, any oil production made from these wells would be accounted for, that these wells were already making that was swept over into the new wells, are accounted into the production decline curve.

Q. Has the conversion work already been done on the wells?
A. Yes, it has.
Q. Has the facility work been done out there?
A. It's completed.
Q. The figures you gave me for capital investments, those are accurate, as far as what you have spent out there?
A. Yes. Correct. The only numbers--the only difference would be for Well 416, Well 438 and Well 437. Work has not been done on those three wells yet. That is just an estimated cost.
Q. Okay. Other than the pattern reduction, is there anything else that you're going to change in terms of injection or physically carrying out the waterflood project? Anything you're going to change as opposed to what you've done in the past?
A. Not from what base case production is, no.
Q. The infill drilling occurred in 1985, did you say?
A. End of 84. 84 and 85.
Q. How long will the pattern reduction

extend the life of the wells in terms of producing the remaining incremental reserves?

A. I think you'll be looking at 15 to 20 years, depending on, you know, which pattern has most reserves and which one has less.

Q. 15 to 20 additional years after the wells were--

A. Yeah, I believe we had until, I believe, to the year 2015, so that's about 20 years.

Q. Is the 30-percent recovery factor going to vary in these producing wells?

A. Not knowing really what the heterogeneities that will go into effect, 30 percent is a good number. When they did their fractional flow curve, they were able to get recovery factors of 51 percent. That being just on a core, though, and knowing that each of the sands come in, pinch in and pinch out, we cut that down to 30 percent, which is pretty similar to what they got on some disk flood work they did, which I believe the results were 29 percent recovery factor.

Q. So that number may vary well to well?

A. Right. It could go 35 on some wells

and 25 on others. It's a number that, at the present time, no, that's not set in stone.

Q. That could increase or decrease your incremental secondary?

A. Correct. But just from the available data we had, we felt that 30 percent was a pretty viable number to use.

EXAMINER CATANACH: I think that's all I have of the witness.

MR. KELLAHIN: That concludes our presentation, Mr. Examiner.

EXAMINER CATANACH: There being nothing further in this case, Case 10570 will be taken under advisement.

(And the proceedings concluded.)

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 10570, heard by me on October 15 1992.

David R. Catanach, Examiner
Oil Conservation Division

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 November 3, 1992.

Carla Diane Rodriguez

CARLA DIANE RODRIGUEZ, RPR
CSR No. 4