STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:	CASE NO. 11,816
APPLICATION OF MARATHON OIL COMPANY FOR THE EXPANSION OF THE SOUTH DAGGER DRAW-UPPER PENNSYLVANIAN ASSOCIATED POOL AND THE CONCOMITANT CONTRACTION OF THE INDIAN BASIN-UPPER PENNSYLVANIAN GAS POOL, APPROVAL OF THREE NON-STANDARD 320-ACRE GAS PRORATION UNITS, AND AN UNORTHODOX GAS WELL LOCATION AND APPORTIONMENT OF GAS ALLOWABLES, EDDY COUNTY, NEW MEXICO	ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

July 24th, 1997

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MICHAEL E. STOGNER, Hearing Examiner, on Thursday, July 24th, 1997, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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I N D E X

July 24th, 1997
Examiner Hearing
CASE NO. 11,816

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A P P E A R A N C E S

FOR THE APPLICANT:

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Santa Fe, New Mexico 87504-2265
By: W. THOMAS KELLAHIN

* * *

WHEREUPON, the following proceedings were had at 10:20 a.m.:

EXAMINER STOGNER: Call this hearing to order, and at this time I will call Case Number 11,816, which is the Application of Marathon Oil Company for the expansion of the South Dagger Draw-Upper Pennsylvanian Associated Pool and the concomitant contraction of the Indian Basin-Upper Pennsylvanian Gas Pool, approval of three nonstandard 320-acre gas proration units -- I assume that's in the Indian Basin-Upper Pennsylvanian Gas Pool -- and an unorthodox gas well location and apportionment of gas allowables in Eddy County.

At this time I'll call for appearances.

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

EXAMINER STOGNER: Any other appearances in this matter?

Will the three witnesses please stand to be sworn?

(Thereupon, the witnesses were sworn.)

Mr. Kellahin, would you kind of give me a little run down on what we're doing --

MR. KELLAHIN: Yes, sir.

EXAMINER STOGNER: -- before we commence?

MR. KELLAHIN: I'll be happy to.

If you'll look at Exhibit 1, it's a locator map that may serve as a useful point of explanation. You can see in the center of the display Sections 3, 10 and 15. They're stacked vertically.

East of those three sections, in Sections 2, 11 and 14, you see oil wells, and those wells are in the South Dagger Draw-Upper Penn Associated Pool.

The vertical blue line is the current western boundary of South Dagger Draw, and the current eastern boundary of Indian Basin-Upper Penn Gas Pool.

The technical witnesses are here to demonstrate today that the oil production in the Canyon portion of Dagger Draw that's being produced in Sections 2, 11 and 14 is oil production that is also available in the east half of Sections 3, 10 and 15.

We're asking you to move the oil pool boundary, if you will, half a section to the west. The purpose is to allow the same pool rules to operate in the Canyon Oil Production so that Marathon may compete for and produce their share of the oil that is currently being produced by the operators in Sections 2, 11 and 14.

In order to do that, a certain set of other things may be dealt with. The fact that we have existing

640-acre gas GPU units for 3, 10 and 15 needs to be adjusted. And so to change the pool boundary we also need to approve three nonstandard gas proration units for the Indian Basin Gas Pool.

In addition, when you move the boundary and you see Section 3, that NIBU Gas Com Well 3 in Section 3 becomes unorthodox for the gas pool rules. Gas pool rules are 1650, and all is said, and we've made an unorthodox location. You -- We'll ask you to approve that.

In addition, you will see that if there ever are to be future gas wells in the west half of the sections, we have created a problem for ourselves in that virtually any location for a future well is going to be unorthodox.

Because we haven't selected where future wells may be drilled, we're going to leave that piece undone and suggest to you that the approval of the nonstandard proration unit can be done, and if future wells are added we'll simply have to file for administrative nonstandard locations. We recognize that as something that needs to be accomplished later.

And once you move the boundary and divide the spacing unit into a 320, then you've got to do something about the allowables, because Indian Basin Gas Pool is still prorated. And you'll find that for a full 640, the current daily gas allowable is 6.5 million a day.

And so part of our presentation is an accounting of how we're proposing to reallocate the production. You're going to find that for Sections 10 and 15 that's going to be easy, because those wells in 10 and 15 have been marginal, if you will, and don't have now, in this configuration or under the new configuration, the capacity to produce even half the gas allowable.

We're going to direct your attention to Section 3, though, because the gas well in the west half has some allocation issues for you to decide.

In addition, it has a request under the statewide gas prorationing rules -- and I think it's 14 B; we've got it here to look at it. But what we're asking you is to credit some underproduction to that well, and we'll show you how to balance the account so that that well's status can be established in the gas pool if anyone ever bothers to check how that gas pool prorationing is to function, if at all.

What we end up with, though, is the opportunity in the oil pool, in Section 15, where we can put a well 660 from the common line, because those are the Dagger Draw rules. And without the change, a standard well in 15 has got to be 1650 from the side boundary, and we can't compete with Santa Fe.

We've notified all the offset operators of this request. There is no opposition from any of the offsets. We've notified all the interest owners in the spacing units to be changed, and with the exception of an entry of appearance for Mr. Kerr on behalf of that trust, I've been contacted by no one.

When we talk about the allocation of production in the three spacing units, we will have testimony, either today or by affidavit, as to whether or not there is any equity adjustment required among those interest owners. We are making our best effort not to disrupt those equities.

The purpose today, though, is to present to you the technical information on the adjustment. I have two geologists and an engineer.

The first geologic expert is Denise Cox. She's going to talk about the data that's been developed to show you where our information tells us the oil pool boundary is located for Dagger Draw and to justify for you her recommendations for that change.

The second geologic witness is Mr. Dembicki. Mr. Dembicki is also an expert in geochemistry, and he has some visual illustrations of the difference in composition of the condensates produced in this area so that you can be satisfied that the adjustment of the boundary is truly an appropriate adjustment.

In addition, our last witness is Mr. Kloosterman.

He's a reservoir engineer, and he'll provide you pressure data to show you that Dagger Draw is separated from Indian Basin. He will go through the calculations of the allocations for you, and hopefully at the end you'll be convinced, as we are convinced, that this adjustment is necessary and appropriate.

EXAMINER STOGNER: Will one of these witnesses appear to discuss the land issues or any discontinuity on royalties from going from a 640-acre spacing to a nonstandard 320?

MR. KELLAHIN: Mr. Tom Lowry, who is an attorney with Marathon, resides in Midland, is here to make that presentation. During the break he and I discovered an item that we had not attended to. He's gone to the telephone to check, to make sure our representations to you are going to be accurate, and he is the witness to address that item.

EXAMINER STOGNER: I thought you said you had an engineer and two geologists.

MR. KELLAHIN: Yes, sir, and Mr. Lowry is my land expert. He's not listed on the prehearing statement. He's not in the hearing room and cannot be sworn at this time.

EXAMINER STOGNER: Oh, okay.

MR. KELLAHIN: He's gone to check his homework.

EXAMINER STOGNER: All righty. So we may have four witnesses?

MR. KELLAHIN: Yes, sir, and if Mr. Lowry and I are not able to address the land issue, then we will deal with that topic at that time and either ask you for a continuance or an opportunity to submit that information by affidavit.

We'd like to begin with the technical part.

EXAMINER STOGNER: Okay, let's do that.

MR. KELLAHIN: All right.

EXAMINER STOGNER: Thank you.

DENISE COX,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Ms. Cox, for the record, ma'am, would you please state your name and occupation?

A. My name is Denise Cox. I'm an advanced geologist for Marathon Oil Company in Midland, Texas.

Q. On prior occasions, Ms. Cox, have you testified as the geologist before the Division?

A. Yes, I have.

Q. Pursuant to your employment as a geologist, have you made a study of the geologic evidence available from which to make conclusions about the appropriateness of adjusting the boundary between Dagger Draw and the Indian

Basin Pools?

A. Yes, I have.

Q. And based upon that study, have you satisfied yourself that there is sufficient reliable geologic information upon which to reach such conclusions?

A. There is, indeed.

Q. And you have those conclusions for us?

A. And I have those conclusions right now.

MR. KELLAHIN: We tender Ms. Cox as an expert geologist.

EXAMINER STOGNER: Ms. Cox is so qualified.

THE WITNESS: Thank you.

Q. (By Mr. Kellahin) Let's move past the locator map. We've spent a few moments talking about that. Let's go to the first illustration so that we can refresh the Examiner's recollection about the reservoir environment, if you will, that you're examining when you address the issue about an appropriate boundary between what I called Indian Basin and South Dagger Draw.

First of all, describe for us where we are, and what are we looking at.

A. Exhibit 2 contains two parts that show the stratigraphy or the reservoir compartments of the South Dagger Draw field. These also apply to the Indian Basin gas cap.

We look at South Dagger Draw/Indian Basin gas cap as divided into three part: the Cisco, shaded in pink; the Canyon 1, shaded in blue; and the Canyon 2 in the darker blue.

The gray that you see between each of these are shales, and these form barriers to flow between the different horizons. So the Cisco is a separate and distinct reservoir from the Canyon 1 and Canyon 2.

The Canyon 1 is what we have been developing in the South Dagger Draw Pool. It produces predominantly oil out of the South Dagger Draw Pool.

And the Canyon 2, as we have stepped further to the west -- you can see this is a west-east cross-section -- as you move further to the west, we actually begin producing out of the Canyon 2 reservoir.

And that's why we're asking for the pool rule to be moved over, is that we have additional reservoir that we have not yet developed within the South Dagger Draw field.

If you look down at the bottom of the two diagrams here, this is what South Dagger Draw looks like, Indian Basin/South Dagger Draw looks like when placed on a structural datum. You can see here that the Canyon beneath minus 3850 is going to be the main oil producer, 3850 being our working gas-oil contact.

The Canyon 2 does have reservoir there that has not been developed until we drilled our NIBU 30 in Section 10 and realized that the Canyon 2 is going to be a significant contributor to our South Dagger Draw Pool.

Q. When you look at Indian Basin Gas Pool, that Upper Pennsylvanian gas production for Indian Basin is being produced out of which one of these intervals?

A. When you say "Indian Basin", you refer to the Indian Basin gas cap?

Q. Yes, ma'am.

A. The Indian Basin gas cap produces predominantly from the Cisco, and that is a separate and distinct gas and condensate reservoir than the oil reservoir in the Canyon.

Q. The significance of the minus 3850 datum point on the structure map is what?

A. That is our working gas-oil contact for the Canyon only. I show it extended here to the Cisco to make a point, that the Cisco nowhere in the South Dagger Draw produces oil. The Cisco is predominantly a gas and condensate -- it is only gas and condensate producer in the Indian Basin/South Dagger Draw fields.

Q. As you move above the minus 3850, in the Canyon 2 to the west, is that production oil or gas?

A. The Canyon 2 above minus 3850 is also gas and condensate.

Q. Let's take a moment and relate the stratigraphy to the structure map we're seeing for Exhibit 3. If you'll turn your attention to that display, let me have you orient us as to the basic information, and then we'll ask you questions about this exhibit.

A. Mr. Examiner, it may help if you leave that stratigraphy diagram out. I realize I'm very familiar with it, and I'll be using these Canyon 1, Canyon 2 terms freely, so hopefully I'll keep you oriented with this conveniently colored diagram.

Exhibit Number 3 is a Canyon 1 structure map. That's the lighter blue-colored stratigraphic unit. And what you can see on the Canyon 1 structure map, in the South Dagger Draw Pool as it is currently defined as shown by the blue outline, I've colored in a light shade of green everything that we know to be productive from the Canyon 1 reservoir. And you can see that that pretty much encompasses almost every well in the South Dagger Draw Pool.

We can contrast that with Exhibit Number 4, which is the Canyon 2 reservoir. That would be the darker blue on our stratigraphic chart. And you can see that that boundary of productive reservoir extends past the South Dagger Draw Pool rules, as they currently are defined, and moves to the west, into the half-sections of 3, 10 and 15. It is this Canyon 2 oil that we would like to continue to develop if we can find a spacing and allowable rules which will allow us to do that.

Q. All right. Let's go back to Exhibit 3 now, from the structure map --

A. That would be the Canyon 1 structure map.

Q. Yes, we're on Canyon 1, and we're looking at the shaded blue area. Canyon 1 is the oil production in Dagger Draw that was historically developed in this area, in Dagger Draw?

A. That's correct.

Q. The existing boundary between Dagger Draw and Indian Basin appears to have some reasonable justification when you're looking only at the Canyon 1 oil?

A. That's correct.

Q. Historically, then, that's how this was divided?

A. That's my understanding.

Q. When we go to Canyon 2, which is the oil below the Canyon 1, you've changed the shading. The same light green or light blue shading has been expanded, and you have placed a green stippled rim around that shading?

A. That's right. What I've tried to distinguish here, Mr. Examiner, is an area that should be -- that is known proven oil production shaded in a solid green color, and what I have stippled in the light green is the undeveloped Canyon 2 oil. This is placed at the minus 3850 structural boundary of the Canyon 2, and it's set up by our NIBU 30, which we had drilled last year and a well that we have drilled this past year, our NIBU 32. That is -- NIBU 32 being in Section 15.

Q. Let's look at the relationship of Section 11 and the opportunity for Canyon 2 oil that is represented in Section 10 -- No, I want to go farther down. I want to compare 14 to 15.

A. Okay.

Q. In comparing 14 to 15.

A. I'm there.

Q. Are you with me?

A. I'm there.

Q. All right. In Section 14 the operator is Santa Fe?

A. That's correct.

Q. And they have Canyon 2 oil wells in 14?

A. They have Canyon 1 and Canyon 2 in Section 14, yes.

Q. Okay. Is there an opportunity for Canyon 1 and Canyon 2 oil production in the east half of 15?

A. There's an opportunity for predominantly Canyon 2 oil production in Section 15.

Q. Does that Canyon 2 oil opportunity also exist in Sections 10 and 3?

A. Yes, it does.

Q. How have you determined -- Let me ask you: Farther upstructure, there is a transition between the oil and the gas intervals. There's a gas -- a general change from oil to gas?

A. There is -- Yes, I believe what you're asking is, if we perforated above minus 3850 we would make a gas well; that is correct --

Q. Okay. Let's look --

A. -- in the second Canyon.

Q. In the -- In Canyon 2?

A. In Canyon 2, yes.

Q. In Canyon 2, you're going to have oil production at minus 3850 or deeper?

A. That's correct.

Q. If you're above 3850, it's going to be gas production in the Canyon 2?

A. That's correct.

Q. Except the Canyon 2 gas production is isolated and separated from any of the Cisco gas production?

A. Absolutely.

Q. These containers shown on Exhibit 2 are isolated and separate reservoirs, unique unto themselves?

A. That's correct.

Q. All right. On Exhibit 4, then, as you compete for the Canyon 2 oil, do you have a recommendation as to whether the Canyon 2 oil competition ought to take place under the same set of pool rules?

A. Yes, any wells that are going to produce oil out of Section 15 should be subject to the same rules, to fairly compete for the oil with Santa Fe in Section 14.

Q. What do the rules in 14 provide an opportunity for Santa Fe to do?

A. They can produce at a GOR of 19.8 per 650, and we can only produce at a -- I mean not a GOR, a total gas allowable -- help me out here -- of 6.5 million in Section 15.

In order to produce the gas in -- Excuse me, in order to produce the oil in South Dagger Draw, you produce at very high gas rates. And so if we want to get the oil, we have to move the gas. If we want to do it economically, we have to have the same rules in 15 to fairly compete with 14.

Q. All right. In Dagger Draw you've got 320 spacing?

A. Yep.

Q. You can have multiple wells in the 320?

A. That's correct.

Q. They're not limited to simply being gas or oil wells; you can have any combination?

A. That's correct.

Q. You can locate a well anywhere within a setback of 660 around that entire side or end boundary, right?

A. Yep.

Q. And you get an oil allowable for that unit of 1400 barrels a day, right?

A. That's right.

Q. Your GOR is 7000 to 1, and the spacing unit gas allowable is going to be 9.8 million a day?

A. Right.

Q. Give or take? All right.

A. That's what I meant to say.

Q. If you're over in the gas pool for Indian Basin, you're on 640 spacing, right?

A. That's correct.

Q. Your well setbacks are 1650, and your maximum gas allowable is 6.5 million a day for a 640 GPU.

How do you propose to change the rules so that the Canyon oil production that is available in 3, 10 and 15 is under the same set of rules as the oil wells in the Canyon in Sections 2, 11 and 14?

A. We're proposing splitting 3, 10 and 15 into two standup 320s. The western half would stay under the Indian Basin gas cap rules at 6.5 million allowable, and -- I'm sorry, be cut in half, since you've gone to a 320 spacing, 320 acres, you'd be down to half the 6.5 million.

And the same thing on the east side, you'd go to 320 acres, and again you'd be at half the allowable of the 640.

Q. All right.

A. Did I state that clearly?

Q. I think so.

Let's look at Exhibit 4 and talk about the geologic data that you have developed that gives you confidence that minus 3850 is the correct elevation upon which to contour the oil-gas contact in Canyon 2. Starting up in Section 3 with the well in the northeast quarter of 3, that Comanche 1 well, describe for us what results you achieved with that well and where it is in positioning the Canyon 2.

A. The Comanche 3 Number 1 was completed in the Second Canyon. It made oil on the initial test, the first day of testing, and then went to 100-percent gas in future tests after that.

This well was completed in the second Canyon and was not a sustained oil producer. Therefore we felt the 3850 contact defined that boundary, that portion of Section 3.

We can go down to the NIBU Number 3, to the south of that. That well also is completed right to the minus-

3800 boundary, and it also has made 100 percent gas.

Q. These wells are named similar. Let's make sure we're staying straight. In the southwest quarter of 3 --

A. Yes.

Q. -- the NIBU 3 that you're talking about, it encountered the Canyon 2 where?

A. The NIBU 3 was initially -- It's a very old well; it was initially completed in the Cisco. We have recompleted it in the second Canyon, and it makes gas above minus 3800.

Q. All right. As you move down your structural control line, give us some other data points that give you confidence that the 3850, minus 3850, is the gas-oil contact in Canyon 2.

A. The NIBU 30 in the northeast quarter of Section 10 is completed in the second Canyon below minus 3850 and is an oil producer.

Q. It's going to be one of the wells we show on the cross-section?

A. That's correct, we will get to the cross-section, and that might be the easiest way to look at the oil and gas production in reference to the minus 3850 interpreted contact.

Q. Okay.

A. And then the last well that we've just recently drilled in Section 15, the northwest quarter, you can't see it very well, it's the NIBU Number 32, and that well was completed as deep as we could go in the reservoir. So we went to the very bottom of the upper Penn reservoir to see if we could make oil out of it, and we put it on production and it has only made gas, and that is right at the minus-3800 boundary.

Q. The objective, then, in changing the boundary of South Dagger Draw is so that the east half of these sections are applying the same rules for Canyon 2 oil production that is available to the other Canyon oil wells east of these half-sections?

A. That's correct.

Q. Let's turn to the cross-section now, to illustrate this relationship. If you'll take a moment and unfold Exhibit Number 5, let's talk about this.

Either Exhibit 3 or 4 could be used -- Let's use 4 as our locator.

Let's start with X and go to X'. If you'll start on the west, walk us through the cross-section.

A. Yes, this is a structural cross-section hung at minus 3850, and it is a west-to-east cross-section going from the limits of the reservoir, NIBU 34 being a well that's 100-percent limestone, not having any reservoir facies present, continuing through NIBU 3, which has been a long-standing Indian Basin gas-cap-classified well -- it was one of the initial wells drilled in the field -- and extending all the way down to the eastern extent of South Dagger Draw field, the Bone Flats 6.

What I'd like to do is walk through and look at the completions so you can see how these different stratigraphic units -- the Cisco, the Canyon 1 and the Canyon 2 -- relate to gas and oil production in the reservoir.

If you look at the NIBU Number 3, that has historically been a Cisco and Canyon 1 production. The only current producing perfs right now are Cisco, and they are gas production. The Canyon 1 production was gas and condensate and has been squeezed off. And most recently we added Canyon 2 perforations, and we've gotten -- getting gas and condensate out of that well. That is one of the key wells we've used to define this minus 3850 horizon.

We move to the next well to the east, the NIBU 30, you can see we've tested the second Canyon. And this well initially came on at 389 barrels of oil a day. This is between the NIBU 3 and the NIBU 30, we've chosen the minus-3850 contour.

And you can see I've highlighted in blue above the NIBU 30, we have proposed to move the pool-rule boundaries to the west between NIBU 3 and NIBU 30, and the current boundaries are actually between NIBU 30 and NIBU 7.

And just to summarize the rest of the cross-section to the east, NIBU 7, NIBU 19, Bone Flat 6, all of the Canyon 1 and Canyon 2 production is oil, and it's the same oil that, we'll hear testimony later, that has produced out of NIBU 30.

Q. Okay. Let me direct your attention to Exhibit 6, which is a log portion of a well that's not shown on the cross-section but was one of your control points for determining the gas-oil contact in Canyon 2. I believe it's down in Section 15 that you referred to.

A. That's correct, NIBU 32 is in the northwest quarter of Section 15. It's a well we've drilled this year. We went down to the deepest portions of the well in the Canyon 2, we opened up the entire Canyon 2 interval, and we've produced no oil from the NIBU 32.

You can see it marked on the log, the red line, minus 3850, and if you look in the depth portion of the log you can see the marking, a minus 3800, you can get a feel that we're only making gas above minus 3850.

Q. This well is in the northwest of 15?

A. That's correct.

Q. And the west half of 15 stays subject to the gas rules?

A. That's correct.

Q. All right. Let's focus on the gas cap now and have you direct your attention to Exhibit 7, and let's talk about the Indian Basin-Cisco gas cap.

A. Right.

Q. If you'll look at 7, identify and describe what we're seeing, and then let me ask you some questions.

A. This is a structure map on the top of the Cisco carbonate. On our stratigraphic chart in Exhibit 2, that was the reservoir that's shaded in pink.

What's shown on the map in Exhibit 7, shaded in the dark pink color is Cisco water-free gas production. This is what most of the operators that are present in the Indian Basin gas cap call the Indian Basin gas cap, is Cisco reservoir, and it produces water-free.

The area that is with the striped shading also produces from the Cisco, but it produces with water. This is what we'd call co-production area of the Cisco. And you can see if you look at the boundary, where that water-free gas production is. It is to the west of the area we're proposing to go to the pool rules.

I might say that, no matter how hard I try to keep my maps up to date, I'm always a step behind, and that water-free gas production is actually further west than is shown here. We are currently making water out of the Cisco in both NIBU 3 and NIBU 1, NIBU 3 being in Section 3, NIBU

1 being in Section 10.

Q. One of the decisions for Examiner Stogner is the contraction of Indian Basin, to delete the east half of each of these sections. At this point in withdrawals from the Cisco, the Cisco water-free gas production has now moved west of where we propose to move the boundary?

A. That's correct.

Q. Can you conclude, then, that it's appropriate to delete the east half of each of these sections from Indian Basin gas cap rules?

A. It would be very appropriate.

Q. Is there any opportunity in the east half of these sections to drill a water-free Cisco stand-alone Cisco well?

A. To my knowledge, that would not be possible.

Q. So if wells are drilled in the east half of these sections, they're targeting the Canyon hydrocarbons?

A. Absolutely.

Q. Summarize for us, Ms. Cox, what you see to be the opportunity that you cannot now attain under the current rules and what you're trying to accomplish with this change.

A. If we go back to Exhibit 4 -- it's easiest for me to talk off the map -- right now, the pool rules that exist under the Indian Basin gas cap in Sections 3, 10 and 15 mean that I should place my well in an orthodox location, 1650-1650 from the lease lines.

In almost every -- In every case here, by doing that, I will be outside my boundary of oil production. So if I go with an unorthodox location I'm most likely to make a gas well. So therefore, I will not produce the reserves in the Canyon 2 and effectively compete with Santa Fe and basically will not be developing reserves.

The other problem is, if we get an unorthodox location and put it in the 660-660 from the corner, to be within the South Dagger Draw, the oil -- excuse me, to be within the Canyon 2 oil zone, we'll have to take a penalty on the gas. As we stated earlier, to make the oil in South Dagger Draw, you've got to move the gas.

So to effectively compete with people that have -- across the boundary that are making gas and oil at a higher rate, we will have to have the same rules. If we're penalized, we're not going to have fair and equal treatment across the -- in the same pool.

MR. KELLAHIN: Mr. Examiner, that concludes my examination of Ms. Cox.

We move the introduction of her Exhibits 1 through 7.

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

EXAMINATION

BY EXAMINER STOGNER:

Q. Ms. Cox, in referring to Exhibit Number 7, you had mentioned that you try your best to keep this updated but the water keeps moving. What -- Do you have any idea where the initial gas-water contact was back when the Indian Basin-Upper Pennsylvanian Gas Pools --

A. Yes, the --

Q. -- first developed?

A. Excuse me. The historic gas-water contact for Indian Basin has always been considered to be minus 3770.

Q. Which would have taken it up there to what? Sections 2, 11 and 14?

A. That's correct.

Q. Roughly around there?

A. Roughly.

Q. Now, you also show a fault about that area too, don't you?

A. Yes, I do.

Q. Is there a correlation?

A. The fault that is present in the South Dagger Draw field does cut the Cisco, and I don't believe it has an effect on the contact, because we do know down to the south of the field, where there is no fault, that minus 3770 is actually where that gas-water contact was more accurately defined, the true gas-cap area.

You can see where the height of the structure is down there to the south. That would be more in Sections 4, 5 of 22-23.

Q. Now, what's the Cisco like on the east side of that fault? Is that all watered out?

A. In the South Dagger Draw field it is the same thing. You have Cisco gas with water production.

And that's very well established by our MOC Fed 1 in Section 1, in the northeast quarter. We perforated that Cisco well down below minus 3850 and produced only gas and water from that well.

Q. Referring to Exhibit Number 1 -- and that's just for reference only -- the Well Number 30 in Section 10 --

A. Yes, sir.

Q. -- how long has that well been producing?

A. One moment. That well is also on cross-section -- on Exhibit 5, the cross-section. That well was put on production in 10-96, so it's about a year and a half now. I'm sorry, half a year.

Q. Okay. Now, the Cisco was not perforated in this well, but can you tell what the water contact is or anything, just by the logs itself?

A. One of the reasons the Cisco is not perforated in this well, if you look up, the top line would be the top of the Cisco, the second line is the Canyon 1, and you can see the majority of the Cisco is actually limestone. You can see that by the overlap of the density and neutron curves. And at this point we couldn't tell where a water contact would be for the Cisco.

I might add that log analysis in a vuggy, carbonate reservoir, especially this reservoir, is very misleading. We would love to have the secret code to interpreting water saturations in Dagger Draw, but I don't think any of the operators out there have figured it out.

And it is a problem we are all faced with, especially the Dagger Draw Complex Operators Committee, facing the same problems: How do you determine water saturations, and where is the water zone?

Q. Now, you move over there on your cross-section, back toward the east, to the NIBU Number 19. Now, that one you have some perforations in the Cisco; is that correct?

A. That's correct.

Q. And what's perforations there making? Is that water or oil, gas?

A. Yes, the red shading would indicate that it is making gas. If we look down at the detail underneath the NIBU 19, at the very bottom of the log, you can see the first two completions were in the Canyon 1. That's shaded green for oil. And they were making less than -- well, the very -- Excuse me, the very first set of perfs were very low in the reservoir, and they made all water. The second set of perfs, shaded green, were making about -- were making 70 -- 69 barrels of water.

We came up and added the Cisco, we increased gas rate and we also increased water to 373 barrels of water. So NIBU 19 is making gas and water out of the Cisco and is also making water out of the Canyon 1.

Q. When I refer to Exhibit Number 2, you show -- The pink interval, as far as the Cisco goes --

A. Uh-huh.

Q. -- looks relatively the same -- I hope I'm putting this right -- the same thickness throughout, from the west to the east, at least the pink portion that you're showing. Is that somewhat interpretive as far as the -- whenever that structure was laid down during the early -- or whenever it was first formed?

A. That's very perceptive. What I didn't go into was the detail of our geologic model. Indian Basin is a carbonate margin. It's a series of prograding margins.

So what you can envision is, when you're in the shallow shelf environment, the reservoir is very flat, like the Cisco is drawn. As you move toward the margin it thickens, as you would envision a reef thickening as you go to the margin. You can see the Canyon 1 shows that beautifully. And then as you go to the basin it thins again. So your best portion of the reservoir is at the margin. What this shows here is that the Cisco margin is never reached in the South Dagger Draw field for Marathon's acreage. So we're still in a flat -- more flat-shelf environment there.

Q. So Exhibit Number 2 pretty muchly exhibits what is happening in Section 3, 10 and 11?

A. That's correct.

EXAMINER STOGNER: Okay. And the transition zone, there again, the request that they have essentially a buffer zone between the two pools that have come together.

Okay, I have no other questions of this witness.

Thank you, Ms. Cox.

THE WITNESS: Thank you.

EXAMINER STOGNER: You may be excused.

MR. KELLAHIN: Mr. Examiner, this next witness is sponsoring Exhibits 8 and 9. Mr. Harry Dembicki is a geologist with Marathon Oil Company.

HARRY DEMBICKI, JR.,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. Harry Dembicki, Jr., advanced senior geologist with Marathon Oil Company in Littleton, Colorado.

Q. Have you on prior occasions testified before the Division, Mr. Dembicki?

A. No, I haven't.

Q. Summarize for us your education.

A. I have a PhD in geology with emphasis in organic geochemistry from Indiana University. I received that in 1977.

Q. With regards to this particular project, what has been your involvement and what are you here to describe?

A. I have been requested by our Midland office to analyze a series of liquid hydrocarbons from the Indian Basin field area in South Dagger Draw to determine composition of these liquid hydrocarbons and see how they interrelate, what the composition will tell us in terms of whether or not they are related or whether or not they represent different fluids.

Q. Is this the kind of activity that you perform on a regular basis?

A. Yes, it is.

Q. Are the kinds of samples that you received taken and prepared in a way that's acceptable for people with your expertise to analyze?

A. Yes, they were.

Q. And were you able to reach certain conclusions with regards to these samples?

A. Yes, I was.

MR. KELLAHIN: We tender Mr. Dembicki as an expert geologist with special expertise in geochemical analysis.

EXAMINER STOGNER: So qualified.

Q. (By Mr. Kellahin) Let me have you take Exhibit 8, which is a spreadsheet showing various data and which has superimposed in the right margin some photographs. Let me have you help us orient the photographs to the data shown on the spreadsheet, and then let me ask you some questions.

A. Okay. The spreadsheet lists seven liquid hydrocarbon samples that we analyzed. They are grouped according to geochemical families that we ascertained they belong to based on the compositional data that we gathered during their analysis.

The top group is the Indian Basin gas cap group. It consists of the Indian Basin D Number 2 and the NIBU Number 9.

Q. What characterizes those samples and the analysis of those samples to this A1 geochemical family?

A. We went through six different geochemical analyses and were able to distinguish these samples from the others, based on these geochemical parameters.

We were also able to do a classification and separate them based on physical characteristics. The compositional characteristics that these oils or liquids exhibit also allow us -- also are manifest in the physical appearance of the liquids.

Q. Let's take a moment and look at Exhibit 9, which is the locator map, and have you show us on the locator map the wells from which these two A1 family samples were taken.

A. The A1 family samples are designated by the red squares.

Q. Those are wells within what we've characterized the Indian Basin gas cap?

A. That's correct.

Q. Having identified a category of samples that represents Indian Basin gas cap, are you able to analyze hydrocarbons from other portions of these reservoir systems and distinguish the Indian Basin gas cap samples from other samples?

A. Yes, we can.

Q. Let's go to the next family. You've identified a family identified as 1B. What does that represent?

A. 1B is another condensate. The photograph on

Exhibit 8 -- it is the second photograph from the top, the single small bottle -- if we looked at the Indian Basin gas cap condensates, they're clear, colorless, waterlike in appearance. The 1B, which is the NIBU 32, is also clear, but it's a dark yellow in color, and it did contain suspended sulfides. They subsequently settled out, and that's the dark black color at the bottom of the bottle in the photograph.

Q. Ms. Cox has concluded geologically that there is a physical barrier separating the Cisco gas cap from the Canyon 2 gas and condensate. Do your samples and your analysis verify her conclusions, or are they different?

A. Well, the two samples from the gas cap are distinct from that NIBU 32, which is in this transition zone.

Q. Let's look at the third family. It's -- Well, come back to the 1B family.

A. Okay.

Q. Show us on locator map 9 where the 1B family sample was taken.

A. 1B family, that's the gold-colored square.

Q. In Section 15?

A. In Section 15, yes.

Q. All right. Let's move up to Section 3 on Exhibit 9, and that represents the NIBU 3, and you have categorized the sample from NIBU 3 as a 1C family type?

A. That's correct.

Q. Let's go back to Exhibit 8 and have you describe for us how you distinguished 1C sample from the others we've just described.

A. 1C, again, that's another condensate sample. It had different geochemical characteristics, different compositional characteristics, that would distinguish it from the others and, in addition to that, its physical appearance. It is a clear, but this time pale yellow, condensate with no suspended particles, no precipitates.

Q. Geologically, Ms. Cox has identified the east half of each of these sections as having an opportunity for Marathon to produce condensate and oil out of the Canyon 2. Have you examined Canyon 2 samples? And if so, what conclusion did you reach about those samples?

A. Well, primarily the Canyon 2 samples that we looked at were from the South Dagger Draw group, the NIBU 30 and the NIBU 7. An additional sample out of South Dagger Draw was the Federal Number 7.

These would be more closely aligned with oils instead of condensates. They are dark brown in color, they are cloudy, they contain suspended paraffins, and they are compositionally, again, different from the condensates that we previously discussed.

Q. Again on Exhibit 9, the location of the wells from which those three samples were taken are identified by the green boxes?

A. Correct, those are the green boxes.

Q. What is your professional opinion, then, about the separation of hydrocarbons between the Canyon 2 and the Cisco?

A. We have a distinct compositional difference in the liquid hydrocarbons between the Canyon 2 and the Cisco. It demonstrates that they are from separate compartments. If they had been one compartment and in communication, there has been sufficient time that the hydrocarbons would have mixed and we would have had a more homogeneous composition, we wouldn't have these compositional differences.

Q. In your opinion, did you have sufficient data available to you to reach the conclusion that the Cisco reservoirs, in fact, are isolated and separate from the Canyon 2 reservoir?

A. I believe I have sufficient evidence.

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

We move the introduction of his Exhibits 8 and 9.

EXAMINER STOGNER: Exhibits 8 and 9 will be admitted into evidence.

EXAMINATION

BY EXAMINER STOGNER:

Q. Dr. Dembicki, whenever I'm looking at Exhibit Number 8, you've classified these out, but nowhere have I seen you talk about the API density or the -- of the liquids that you show over here and describe.

A. Uh-huh.

Q. Are they similar, or why did you not include that information?

A. One of the things that we wanted to do in terms of the analytical work was to be able to provide me with a minimal amount of data on the samples at the time I was doing the analysis so I would not be biased in my analytical work and interpretation of the data.

So at the time I was doing the work and compiling geochemical families, I did not have the API gravity information. However, I do believe that's available.

MS. COX: Yes, it is.

Q. (By Examiner Stogner) What is usually the API cutoff between condensate and oil? Or are there other things to consider?

A. Well, there are other things to consider. An API gravity cutoff is not necessarily an applicable parameter for distinguishing between oil and a condensate in some instances. Usually you'll have to look at compositional variation as well. We could get an oil that is in the high 40s in terms of its API gravity and still be a very thick, viscous oil. It all depends on paraffin content.

Q. What in this area -- what else do you look at besides the API gravity between the condensate and oils? What would you consider the difference?

A. Well, I would look at the volatility of the oil, how much of the material was in, say, the C10, C15 range, versus the lighter materials. That would be a very good descriptor for it.

Q. How about sulfur content?

A. In general, these are very high in sulfur, all of them. It just depends. It -- These oils, the sulfur compounds that are contained in there, they're just partitioned differently between the condensates and the oils.

Q. How about the con- -- Is the condensate, is that sulfuric out here?

A. It has lots of light sulfur-bearing compounds like mercaptans.

Q. How about the Cisco gas and the Canyon gas? Is there much of a sulfuric contents difference between the two gases?

A. Not that we could detect.

Q. Would this indicate a separate migration, or a particular area that the gas or oil or hydrocarbons were formed, and as it migrated into this area does it indicate there are two separate environments of a formation of the hydrocarbons?

A. Yes, it does. The condensates and the gas may have been formed at the same time, from the same source, migrating in place, whereas the oils probably came from either an earlier generation from the source or a separate source coming in a different migration path.

Q. Any indication of overlapping of the migrational -- I call it Cisco gas, in the Canyon area?

A. Some of the data that we have in the intermediate zone, we're not clear yet on exactly the source of the differences between those condensates and the gas cap, and it's difficult to say with any certainty if we do have any overlap or intermingling in that zone.

Q. As far as the samples that you chose, any particular reason, or did you just do them at random?

A. They were supplied by our Midland office.

Q. Okay. So you had no -- You had nothing to do with the choosing of the samples?

A. No. Again, that was part of the design, was to keep me blind and unbiased.

EXAMINER STOGNER: Oh, surely Marathon doesn't do that, Steve, do they?

Thank you, sir. I have no other questions.

MR. KELLAHIN: All right, John, you're up.

Mr. Examiner, John Kloosterman is a reservoir engineer. He's got two chapters in his presentation. One is to show you the reservoir pressure we have by which he has concluded there's separation. In addition, his second chapter deals with the allocation of production and how he proposes to divide that in the spacing unit among the new spacing units.

JOHN T. KLOOSTERMAN,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

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

A. My name is John Kloosterman. I'm a senior reservoir engineer with Marathon Oil serving on the Indian Basin asset team.

Q. And you reside where, sir?

A. In Midland, Texas.

Q. On prior occasions have you testified before the Division?

A. I have not testified before this Division before.

Q. Summarize for us your education.

A. I received a bachelor of science in mechanical engineering from Rose-Hulman Institute of Technology in 1982. I started employment with Marathon in 1982 in Illinois. I worked there for nine years.

While in Illinois I did serve as an expert witness in a waterflood unitization hearing in Michigan and also in a litigation in Illinois.

After Illinois I worked for three and a half years in Alaska, working on some reservoir modeling up there. And for the last two and half years I've been in the Midland office, working Permian Basin, the last year of which I've been serving as a senior reservoir engineer on the Indian Basin asset team.

Q. As part of your responsibilities in Indian Basin, have you compiled and analyzed the pressure data that's available in this area?

A. Yes, I have.

Q. In addition, have you tabulated the production information and provided displays and conclusions with regards to how you propose to reallocate the allowables among these spacing units?

A. Yes, I have.

MR. KELLAHIN: We tender Mr. Kloosterman as an expert engineer.

EXAMINER STOGNER: Mr. Kloosterman, you said you had testified in Michigan?

THE WITNESS: Yes, sir.

EXAMINER STOGNER: And when was that?

THE WITNESS: That was 1985.

EXAMINER STOGNER: And that was for a waterflood?

THE WITNESS: We were putting together a waterflood unit in West Branch, Michigan.

EXAMINER STOGNER: Mr. Kloosterman is so qualified. Did I pronounce that right?

THE WITNESS: Kloosterman.

EXAMINER STOGNER: Kloosterman. Mr. Kloosterman is so qualified.

Q. (By Mr. Kellahin) Let me have you take your first two displays, Mr. Kloosterman. Let's take 10 and 11. Let's start with 10, and give us an understanding of how you have separated your pressure data by a color code.

A. Okay. The red open circles are pressures that we have acquired historically in the Indian Basin Pool. The green open circles are pressures we've acquired in the South Dagger Draw Pool. The colored green -- the filled-in green and red circles are pressures that we've acquired in the three sections of interest, 3, 10 and 15, and they exhibit trends, in some cases more similar to South Dagger Draw and in some cases more similar to Indian Basin.

Q. Do you have sufficient pressure data to reach any conclusions concerning whether the Cisco gas cap in Indian Basin is in pressure communication with the Canyon production in South Dagger Draw?

A. Yes, I do.

Q. What is your conclusion?

A. I conclude that the Indian Basin Pool is not in communication, pressure communication, with the South Dagger Draw Pools -- Pool.

Q. Have you plotted your pressure date on another display so that we can see the level of separation in pressures upon which you base that conclusion?

A. Yes, I have. That's displayed in Exhibit Number 11.

Q. All right. There are a lot of data points on Exhibit 11. Let's take a few minutes and make sure we can recognize the differences in your coding for that pressure data.

A. Okay. The red open squares on the graph correspond to the red open circles on the locator map. Those are pressures that correspond to pressures in the Indian Basin Gas Pool.

The green open triangles are pressures that were acquired in South Dagger Draw.

The red -- or, excuse me, the green filled-in triangles are pressures taken from Section 3.

The green-colored circles are pressures taken from Section 10.

The red-colored squares are Cisco pressures from Section 15.

And the green-colored diamond are Canyon pressures in Section 15.

Q. Let's draw the comparison between the Indian Basin-Cisco pressures and the Dagger Draw-Canyon pressures that you accumulated in Sections 1, 2, 11 and 12. There's a difference in where these are positioned on the display?

A. That's correct. The -- If you notice the trend for the Indian Basin Gas Pool, the red squares all form a very nice trend, with the exception of a few scattered points there at the tail end, indicating a very constant pressure decline in the Indian Basin Gas Pool through time.

The pressure data I have available for South Dagger Draw started in 1994. That's when we started developing the Sections 1, 2, 11 and 12.

Q. Those are the open --

A. The open --

Q. -- triangles?

A. The open green triangles, yes, sir.

Q. Okay.

A. You can see the pressure at the time of initial development of South Dagger Draw was close to 1000 pounds higher than the Indian Basin Gas Pool at that time.

Q. Is that enough pressure differential to cause you to conclude that they're, in fact, separate reservoirs?

A. Yes, it is. I've corrected all the pressures to a common datum, so there's no elevation differences involved. So there is -- That's a very large pressure difference.

Q. The question is, in what pool should we place the east half of 3, 10 and 15? Based upon pressure, do you have a recommendation as to where to place those half-sections?

A. Yes, I do. I'll direct your attention to the green-colored triangles. They are taken from Section 3, either from the -- Most of the data points are from the NIBU 3 in the southwest quarter. See, those pressures are much more closely aligned with the South Dagger Draw pressures.

And the final green triangle at the far right of the exhibit, that's actually two data points there that are virtually identical. One is from the Comanche 1 and one is from the NIBU Gas Com 3, the two wells in Section 3.

Based on this data, I would conclude from a pressure standpoint that the Section 3 is more closely aligned with South Dagger Draw.

Going through the other sections, in Section 10 we have only one pressure data available from one well, the NIBU 1 in the southwest quarter. See, that pressure falls in between the South Dagger Draw pressures and the gas cap pressures.

You also notice it's on a different trend. The South Dagger Draw and Indian Basin gas cap pressures are declining more steeply than the pressure data we have from Section 10. That, to me, indicates -- The other thing is, the Section 10 pressure is a Cisco-only pressure, whereas the pressures in Section 3 are Canyon pressures.

That indicates to me that in Section 10 it's not -- I can't draw a firm conclusion whether it's the Canyon because I don't have Canyon pressure data, but the Cisco is somewhere in between the South Dagger Draw and the Indian Basin Gas Pool.

In Section 15, the Cisco data -- which is, on the locator map, the red-colored circle and on the pressure display the red-colored squares -- you can see that falls very much in line with the Indian Basin Gas Pool, whereas the pressure from NIBU 32, the green-colored circle on the map in Section 15 and the two green-colored diamonds at the far right of the pressure display, show that the Canyon pressure is in line with the South Dagger Draw Pool.

Q. In summary, then, can you support a recommendation to adjust the western boundary of South

Dagger Draw by moving it a half section west in relation to Sections 3, 10 and 15?

A. Yes, I think the pressure data confirms the previous testimony from a geologic and geochemistry standpoint that it is appropriate to move the pools a half section to the west.

Q. Let's turn to the topic of how -- of what the data shows on the allocation of production --

A. Yes, sir.

Q. -- and then finally to your recommendations as to how to readjust these allocations.

Let's start with Section 15. Describe for us how Exhibit 12 is organized, and then we can go through the conclusions.

A. Exhibit 12 has production data from the two wells in Section 15. Both wells are in the west half, so they're both colored the same. You can see there is a black line in the middle of the blue production data at the bottom of the graph that distinguishes the production from the two wells.

The blue dotted line across the graph at 100,000 per month, that would be a half-allowable line. The full-allowable line is shown as the burgundy line at 200,000, which is the 640-acre proration unit allowable at Indian Basin.

What this display is showing is that the two wells in the west -- Well, for one thing, it shows there was no production until early this year in that section. We reactivated a well in the southwest quarter of Section 15 and drilled a new well, NIBU 32, in the northwest quarter, and that production is shown on the graph.

It shows that the production has not exceeded the full allowable or even half-allowable, assuming that if we split the section in half we'd get a half-allowable for that 320-acre nonstandard proration unit.

So there is really no action required from the standpoint of reallocating production. It would be quite clean just to split the proration unit and apply a half-allowable to the west half of that section.

Q. All right, let's turn to Section 10.

A. Okay, Exhibit 13 shows production history from Section 10. Again, the blue color is from the west half. You can see production declining through time from -- that would be NIBU 1 in the southwest quarter of that section.

The burgundy color coming on in October of 1996 corresponds to gas production from NIBU 30 in the northeast quarter. Ms. Cox previously testified about the oil production of that well. This is the gas production of that well.

This display shows that these two wells combined have not exceeded the full allowable for that proration unit, and the western-half well by itself does not exceed the half-allowable for a 320-acre nonstandard proration unit.

So again in this case, there would be no allocation adjustments required.

Q. Okay, let's turn to the next display, Exhibit 14, and look at the tabulation of production for Section 3.

A. Okay, Exhibit 14 is production history for Section 3. You can see a -- back in early 1995 it was very low production; it was a marginal well. What the display does not show is that we worked on this well in November of 1995, and this would be the NIBU Number 3 in the southwest quarter, and I have some additional exhibits to enter about that --

Q. All right, let me find on the horizontal scale on 14 where the NIBU 3 in the west half was worked over.

A. Okay, it was worked over in November of 1995.

Q. Okay.

A. That's where the production goes essentially to zero.

Q. All right. And then it is apparently not produced, despite the workover, it's not produced until May of 1996?

A. That's correct. It was actually June of 196 when we --

Q. June of 1996?

A. -- reactivated that well.

Q. Did the well have the capacity to produce during this period of time, despite the fact that it was not produced?

A. Yes, the well had a substantial capacity to produce. At the time we were limited by the Indian Basin Gas Plant, which processes the gas in the area.

Because of the substantial development of South Dagger Draw and some infill development drilling in the Indian Basin Gas Pool, the inlet capacity of the gas plant was exceeded, forcing cutbacks in some production.

We chose to cut back these wells because they were not oil producers. We preferentially produced oil and associated gas from the oil producers and used these gas-only producers as swing wells. We reinstituted production in these wells once the capacity of the Indian Basin Gas Plant was expanded in October-November of 1996.

Q. When we look at the combined production for the 640 spacing unit, it has the capacity to exceed the 6.5 million a day?

A. That is correct.

Q. And so it has overproduced its allowable. Is it more than six times overproduced?

A. No, sir, it's not.
Q. So it's still being produced in compliance with the gas proration system?
A. That is correct.
Q. Let's set this exhibit aside for a moment and turn to the supporting data in Exhibit 15 to show the workover and the additional capacity added to the NIBU Number 3 well in the southwest of 3.
A. Okay, Exhibit 15 is a metering and testing production report showing hourly production from this well. I know this is a lot of numbers on there.
The important column is the third one from the right, which shows the gas rate from this well. This was after the well had been tested about three or four days. Gas rate continually built during that time.
By this time, on November 26th and 27th, you can see the gas rate was averaging about 3.4 million a day, with -- And the next column over is the bottomhole producing pressure. This well is produced via sub pump, and it was the pressure data recorded from that submersible pump. You see pressures of about 650 pounds. Reservoir pressure at the time was 1800 pounds. So we were producing 3.4 million of gas with relatively limited drawdown on that well.
Q. Let's turn to Exhibit 17 and describe for us how

you've recommended the gas production in Section 3 be reallocated.

A. Okay. Do you want to go through 16 first, which is the test sheet for the Comanche?

Q. Yes, please.

A. Okay. Exhibit 16 is a test sheet for the other well in that -- in Section 3. That well was drilled in February of 1995. You can see again the third column from the right is the gas rate. You can see by the end of the test there on February 13th we're up over 5 million cubic feet of gas a day on test, again with limited drawdown. The producing bottomhole pressure was 1465 pounds at that time.

The one thing to note is, these two wells combined, the NIBU Gas Com Number 3 and the Comanche Federal Number 1, have production capacity in excess of the allowable for the proration unit. Combined, they have a production capacity of over 8 million a day, compared to an allowable of 6.5 million a day.

Q. All right, let's turn to 17 and see how you have reconciled the allowable and the gas production and balanced between the over- and underproduction.

A. Okay, let me walk you through Exhibit 17. The first column to the right of the date is the monthly gas production, and that production corresponds to the graph shown in Exhibit 14.

The next column is the monthly allowable for a full section, a standard gas proration unit in Indian Basin, of 200,000 MCF a month.

The next column is the difference between the monthly gas production and the monthly allowable. You can see up until November of 1996 those numbers were all negative, meaning that we're not exceeding the allowable.

The next column over is how we would accumulate under- and overproduction from February of 1996, which, as I pointed out in Exhibits 15 and 16, show that in February of 19- -- excuse me, Feb- -- yes, February of 1996, that the well was capable of -- that unit was capable of producing in excess of the allowable.

I'd like to go back. On Exhibit 16, the test date shown as February 12th of 1995, that should be a 1996. That well was drilled in early 1996, not 1995. That's why I stuttered there for a second, I -- threw me off.

That is the point in time we're proposing that the well should be declared as -- the gas proration unit should be declared as nonmarginal and, as such, should start accumulating underproduction from that point in time, as being February of 1996.

As you follow down that column you see we accumulate underproduction until November of 1996 and at that point start reducing the underproduction, the accumulated underproduction, until July of 1997.

The June and July numbers, production numbers on here, are estimates based on daily production data we have to date. We don't actually have the allocated production, but they're estimates.

And you see from that we're still cumulatively underproduced 665 million cubic feet of gas.

How I propose to handle that when we split the gas proration unit in half is, allocate half of that accumulated underproduction to the west half of Section 3. So at the time an order is issued to split that, if it's so ordered, I propose that the west half of Section 3 would have an accumulated underproduction of 332 million cubic feet of gas to be worked off by subsequent overproduction.

The other two columns on there are -- were just for reference, if for some reason a decision was made not to go back to February of 1996 but start at the beginning of the April 1, 1996, proration period, how that number would work out.

And then if for some reason there was a decision made not to declare the well nonmarginal and allow us to accumulate any underproduction, where we would be at today, the gas proration unit would be at 729 million cubic feet of gas overproduced, which is about 3.3 times the allowable, so nowhere near the six times.

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

We move the introduction of his Exhibits 10 through 17.

EXAMINER STOGNER: Exhibits 10 through 17 will be admitted into evidence at this time.

EXAMINATION

BY EXAMINER STOGNER:

Q. Now, the Number 1 well, the Comanche Number 1 well, that will still produce, will it not?

A. That's correct, it will produce in the South Dagger Draw Pool.

Q. Okay. Now, what's the gas allowable for that pool?

A. The gas allowable is -- There's a GOR allowable set of 7000. There's an oil allowable for 1400 barrels of oil a day, multiplied by the 7000 GOR gives a gas allowable for a 320-acre proration unit of 9.8 million cubic feet of gas a day.

Q. And how does that Number 1 production compare or -- Yeah, how does it compare with the GOR casinghead limit for that pool?

A. The Comanche Number 1 well currently produces about 4 million cubic feet of gas a day and about 1500 barrels of water a day.

Q. So it's substantially under the --

A. That's correct.

Q. So there's really no concern on that well getting put over into the Dagger Draw Pool and chance of it -- or no chance of it overproducing its allowable; is that correct?

A. That's correct.

Q. Okay. Now, the figures you give me on Exhibit Number 17, that is the cumulative production from both wells in the Indian Basin; is that correct?

A. That is correct. That's the combined total, monthly production total from both the NIBU 3 and the Comanche 1 well.

Q. For me to make sure what -- I want to make sure that I'm reading this right.

A. Okay.

A. So you've got -- You're proposing to bring some underproduction from the both of those pools combined, that was cumulative for 640, just cut that in half and bring it into the new scheme just to be applied to the Number 3 well; is that correct?

A. That's correct, that's what I'm proposing.

Q. Are both these wells shut in, or are they producing?

A. Currently they're both active.

Q. Okay, because -- Okay, on the right-hand side of the scale it just comes down to zero.

A. Well, yeah, that's just where the end of the data -- The last data I've included was July of 1997.

Q. Okay. Did you run this kind of a scheme, Exhibit Number 17, by splitting the wells' productions out and just looking at the Number 3 production?

A. Yes. Yes, sir.

Q. And how the over- and the underage that was accumulated would have -- how it would have been affected?

A. Yes, sir, I did. I looked at the NIBU Number 3 in relationship to a half allowable, basically assuming that we'd been producing as a 320 proration unit all along.

And in that analysis I went back to December of 1995 to start accumulating underproduction since at that point, if you refer back to Exhibit 15, in late November of 1995 the well was shown to be capable of producing in excess of the half-allowable, which would be 3.25 million a day.

And accumulating that production from November or December, the accumulated underproduction to date would be 341 million cubic feet of gas a day, compared to the 332 million cubic feet under the exhibit I showed you or presented here. So very similar.

Q. Very similar. Because that's what I was -- Actually, you've done something that I was thinking about, and that would make it retroactive, essentially, back to November or December or something to that effect.

A. Right.

Q. So no gain, no advantage.

A. Right, either way you do it, it comes out essentially the same.

Q. Okay. Now, you show the monthly allowable for those pools to be what? 200,000 MCF?

A. That's correct.

Q. And that has been consistent for some time now?

A. That has been consistent at least for the last couple of proration periods. I know it had been lower previously. I know at one point it was slightly lower, like 190,000.

And then back in the -- I really don't have a good working knowledge of what the allowable was prior to 1995.

Q. I wonder if anybody does.

MR. KELLAHIN: I'm not sure it works anymore; I know the number. But we've had 200,000 a month back here for at least the last six proration periods. So it would predate 1995.

Q. (By Examiner Stogner) Which leads me up to -- On

Exhibit Number 17 you do show the monthly allowable as 200,000 all the way down. Were you able to pull that number out of old schedules and such?

A. I just knew that it was -- that number was applicable from April of 1995 forward.

Q. Okay.

A. That's been the allowable in the field from that time.

Q. So we're able to get that off of proration schedules --

A. That's correct.

MR. KELLAHIN: We pulled it off the Commission orders, Mr. Examiner.

Q. (By Examiner Stogner) Okay. When I had asked you that question about essentially going back to retroactive stuff, November, and you had given me some figures of it being around 340,000, do you have those written out or --

A. Yes, sir, I do.

EXAMINER STOGNER: Mr. Kellahin, just for comparison, can I have you submit that information as a supplement to this exhibit?

MR. KELLAHIN: Sure, we'll be happy to do that. We'll prepare it in the form of an exhibit and show you a spreadsheet like this one using the west half, and that way you'll have all the numbers.

EXAMINER STOGNER: I would appreciate that. I would just suggest you make that like, say, 14A or make it subsets to the present exhibit.

MR. KELLAHIN: All right, sir.

EXAMINER STOGNER: I have no other questions of this witness.

MR. KELLAHIN: All right, sir.

EXAMINER STOGNER: He may be excused.

MR. KELLAHIN: I need just a minute with Mr. Lowry to see if we've checked on our --

EXAMINER STOGNER: Yes.

MR. KELLAHIN: -- equities.

(Off the record)

MR. KELLAHIN: With your permission, Mr. Examiner, I'd like to call Mr. Tom Lowry for a few minutes to talk about the equities.

EXAMINER STOGNER: Okay.

MR. KELLAHIN: Mr. Lowry was out of the room when you swore the witnesses, Mr. Examiner. If we could put Mr. Lowry under oath.

EXAMINER STOGNER: Mr. Lowry, would you please stand and raise your right hand?

(Thereupon, Mr. Lowry was sworn.)

EXAMINER STOGNER: You may be seated.

Mr. Kellahin?

MR. KELLAHIN: Thank you, Mr. Examiner.

THOMAS C. LOWRY,

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

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Lowry, on prior occasions have you testified as an attorney on behalf of Marathon Oil Company before the Division?

A. Yes, I have.

Q. Pursuant to your employment in that capacity, have you become familiar with the contractual arrangements and the equities established in the three existing spacing units that we're discussing today?

A. Ye, I'm familiar with the various agreements that govern the ownership of oil produced from those sections.

Q. In addition, have you caused Marathon personnel to tabulate under your supervision the names and addresses of all equity interest owners in these three spacing units?

A. Yes, I have.

MR. KELLAHIN: We tender Mr. Lowry as an expert.

EXAMINER STOGNER: Mr. Lowry is so qualified.

Q. (By Mr. Kellahin) Let's talk about the notice requirements.

With your permission, Mr. Examiner, I need to give you a certificate. I've left it on my desk. I need to bring it to you this afternoon.

But the certificate that we prepared and compiled, Mr. Lowry, was that done under your supervision?

A. Yes, it was.

Q. And what were you attempting to do with that notification?

A. We were attempting to notify all of the owners of any interest whatsoever within Sections 3, 10 and 15 as to our Application, as well as the operators of all offsetting units.

Q. As a result of that attempt, were you able to satisfy yourself that you had accurately tabulated all those interest owners, including the offset operators to whom notice was entitled?

A. Yes, I did.

Q. And was that notice sent?

A. Yes, it was.

Q. To the best of your knowledge, is there any opposition raised by any of the parties to whom you sent notice?

A. There is none.

Q. Let's talk about the equities in Sections 3, 10 and 15.

Have you satisfied yourself concerning the equities of these three existing spacing units in terms of what happens to their equity if the pool boundary is shifted?

A. Yes, I've analyzed the various agreements involved, and in my opinion those agreements will remain in place following this change, should it be granted, and the ownership will not be affected at all by the change. In other words, every barrel of oil and every MCF of gas will continue to be owned as the production is currently owned from those sections.

Q. So despite this shift in spacing, the underlying agreements that commit all interest owners will allow those parties to continue to be paid in the same percentages, to the same people as are currently being paid for the production?

A. Yes.

Q. In your opinion, will the approval of this Application impair correlative rights?

A. No, it will not.

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

EXAMINER STOGNER: Okay, Mr. Lowry -- By the way, we'll keep the record open pending the receipt --

MR. KELLAHIN: The two exhibits, the notice and the supplemental exhibit on the west-half allocation.

EXAMINER STOGNER: Right.

Q. (By Examiner Stogner) Just by some of the exhibits that I do have -- and I'm referencing Exhibit Number 1 --

A. Uh-huh.

Q. -- especially I'm interest in Section Number 15 --

A. Okay.

Q. -- because that looks like it's split, north half being in the unit, south half being a federal com. Is that the way you --

A. Actually 3 and 15 are both split that way.

Q. Okay.

A. The unit involves all of Sections 2 and 11, 10, 9 and 16, and the south half of 3, north half of 15 and the south half of 4, up in the upper left-hand corner.

Three and 15 have their own 640-acre com agreements, which provide for the sharing on an acreage basis of production from those individual sections.

The production from those sections that's allocated to the south half in the case of Section 3 and the north half in the case of Section 15 is then shared amongst the unit owners, since those lands are within the unit.

In our discussions with the BLM regarding the treatment of the com agreements, they have indicated that even though the spacing will be changing, that they wish those com agreements to remain in place as they are, so that all production continues to be shared in the same manner as it has been for 30 years.

Q. The com agreements that are in effect for 15 and 3, are those 100-percent voluntary?

A. Yes.

Q. Okay. So there's no force-pooling?

A. No.

Q. Okay. And in Section Number 3, you're going to have a 320-acre nonstandard proration unit, standup, over on the west half. And -- Going to the Number 3 well.

The Number 1 well is going to be a standard 320 in the South Dagger Draw; is that correct?

A. That's right.

Q. Okay, they're the same percentages because you have two laydowns. The com agreement essentially takes in the two half-sections as a laydown?

A. That's right, that's right.

Q. Okay. Now, in Section 15 you're going to have two wells now in the Indian Basin and no production at this point --

A. Initially in that new -- that new South Dagger

Draw 320, that's right.

Q. So -- But as far as the percentage goes, it's not going to matter?

A. No.

Q. Okay.

A. No, the same ownership division will be used for both halves.

EXAMINER STOGNER: Okay. I don't have anything further, Mr. Lowry.

MR. KELLAHIN: All right, sir. Thank you.

EXAMINER STOGNER: Thank you.

MR. KELLAHIN: Subject to those two supplemental exhibits, Mr. Examiner, that concludes our presentation.

EXAMINER STOGNER: And I'd be more than happy to accept a rough draft order.

MR. KELLAHIN: Yes, sir, I'll be happy to prepare one.

EXAMINER STOGNER: Yeah, you're to be commended on this, Marathon, putting some sort of a buffer area in two pools that come together that are formed different and have different allowables.

This is very commendable, trying to get something out there. I wish it would be this easy in many cases where these kind of pools come together. So...

If I could, I'd rule from the bench now, but since we don't have that in place...

MR. KELLAHIN: All right, thank you, Mr. Examiner.

EXAMINER STOGNER: With that, I'll take this under advisement pending the additional information.

And let's take a ten-minute recess.

(Thereupon, these proceedings were concluded at 12:00 noon.)

* * *

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11816, heard by me on 24 July 1997.

, Examiner

Oil Conservation Division

CERTIFICATE OF REPORTER

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

I, Steven T. Brenner, Certified Court Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Division was reported by me; that I transcribed my notes; and that the foregoing is a true and accurate record of the proceedings.

I FURTHER CERTIFY that I am not a relative or employee of any of the parties or attorneys involved in this matter and that I have no personal interest in the final disposition of this matter.

WITNESS MY HAND AND SEAL July 28th, 1997.

STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998