NEW MEXICO OIL CONSERVATION COMMISSION

STATE OF NEW MEXICO

CASE NO. 10450

IN THE MATTER OF:

The Oil Conservation Division calling a hearing on its own motion to accept nominations and other evidence and information to assist in determining April 1992 through September 1992 gas allowables for the prorated gas pools in New Mexico.

BEFORE:

WILLIAM J. LeMAY, CHAIRMAN
WILLIAM WEISS, COMMISSIONER
GARY CARLSON, COMMISSIONER

State Land Office Building
Morgan Hall
February 27, 1992

REPORTED BY:

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Certified Shorthand Reporter
for the State of New Mexico

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I N D E X

E X H I B I T S

CHAIRMAN LeMAY: This is the Oil Conservation Commission. My name is Bill LeMay, Chairman. On my left is Commissioner Bill Weiss, on my right is Commissioner Gary Carlson, representing the Commissioner of Public Lands.

To begin with, I'd like to call case 10450, Application of the Oil Conservation Division for hearing on its own motion to accept nominations and other evidence and information to assist in determining the April 1992 through September 1992 gas allowables for prorated pools in New Mexico.

At this time I'd like to call for appearances in Case 10450.

MR. STOVALL: Mr. Chairman, Robert G. Stovall of Santa Fe representing the Division.

CHAIRMAN LeMAY: Thank you, Mr. Stovall.

MR. KELLAHIN: Mr. Chairman, I'm Tom Kellahin of the Santa Fe law firm of Kellahin, Kellahin & Aubrey. I'm here today for Marathon Oil Company in association with Mr. Tom Lowery. We want to provide data and information on the Blinebry, the Indian Basin Upper Penn.

In addition, I'm here today for

Hallwood Petroleum, Inc., and we want to provide information and data on the Catclaw Draw Morrow Gas Pool.

CHAIRMAN LeMAY: Thank you, Mr. Kellahin.

Additional appearances?

MR. PEARCE: May it please the Commission, I'm W. Perry Pearce of the Santa Fe office of the law firm of Montgomery & Andrews, appearing today on behalf of Phillips Petroleum Company, to provide information relating to the Basin Dakota Gas Pool. I have one witness.

CHAIRMAN LeMAY: Thank you, Mr. Pearce.

Additional appearances?

MR. PADILLA: Mr. Chairman, my name is Ernest Padilla of Santa Fe for John H. Hendrix Corporation. We have no witnesses and merely want to read a statement into the record.

CHAIRMAN LeMAY: Thank you, Mr. Padilla.

Mr. Carr.

MR. CARR: May it please the Commission, my name is William F. Carr. I'm with the law firm of Campbell, Carr, Berge & Sheridan

of Santa Fe. In this case we represent Amoco Production Company, Union Oil Company of California, and Chevron USA, Inc.

Amoco and UNOCAL will present testimony concerning the fields in the San Juan Basin. Chevron USA, Inc., will present testimony concerning the preliminary allowable for the Indian Basin Upper Pennsylvanian Pool. I have one witness for each of those companies.

CHAIRMAN LeMAY: Thank you, Mr. Carr.

Additional appearances in the case?

At this time will those witnesses who will be giving testimony, please stand and we'll swear you at one time.

(The witnesses were duly sworn.)

Mr. Stovall.

MR. STOVALL: I call my first witness, Mr. Merrett.

RONALD H. MERRETT

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

EXAMINATION

BY MR. STOVALL:

Q. Mr. Merrett, for the record would you, please, state your name and place of residence.

A. My name is Ronald H. Merrett. I reside in Albuquerque, New Mexico.

Q. How are you employed, Mr. Merrett?

A. I'm Director of the Office of Interstate National Gas Markets for the Oil Conservation Division.

Q. And have you previously testified before this Commission with respect to general trends and gas market demand for the state of New Mexico?

A. Yes, I have.

Q. Are you prepared today to provide testimony with respect to the trends as you predict them for the next six months for markets for New Mexico gas from prorated pools?

A. I would say yes, except I qualify that by saying not specifically from prorated pools, but for all pools.

Q. So your testimony today will relate to perceived or projected demands for New Mexico gas, period?

A. That's generally correct.

Q. And you have prepared some exhibits for presentation today?

A. I've prepared exhibits. I will speak

from those exhibits, which I will project on the screen. The members of the Commission have black and white copies. And copies can be made available for members of the audience upon request.

Q. Would you go ahead and go to Exhibit 1 and start your presentation with respect to what you predict historically and how you base that historically, your predictions for the New Mexico gas market.

Because these exhibits are not marked on the screen, for the purpose of the record, so I'll ask you to identify them by the title of the exhibit so that the record will reflect which exhibit we're looking at.

A. The first exhibit is entitled, "New Mexico Gas Production History 1935 through 1990." The purpose of this exhibit is merely to show that New Mexico natural gas production in total has increased -- with one year exception -- has increased steadily from 1985 through 1991.

In 1991 our preliminary estimate is that gas production is one trillion cubic feet, approximately one trillion cubic feet a year. That is subject to adjustment.

The second exhibit is entitled, "Monthly New Mexico Natural Gas Production." The purpose of this exhibit is to show the seasonal trends in production, which presumably reflects demand during the year.

You will see from this exhibit that typically during the period April through the first of October demand is lower than it is in the period September through the end of March. This is partly because of seasonal demand caused by weather. That's the main reason for that.

It's not very clear from these set of graphs, but the peaks and troughs appear to have flattened out a little bit, particularly apparent on the green line 1990, but also on the purple line or pink line 1991. This is because in the summer months the pipelines seem to carry a fairly high frequence into storage, which they were not doing so much in earlier years.

So it's my view we will still see in the period April 1 through September 30, 1992, we'll continue to see this trend of lower demand in the summer months.

A. The next exhibit is entitled, "New Mexico Natural Gas Production." And it shows the

split between coalbed methane conventional San Juan gas and Permian conventional. It merely shows you the split in production between those three different types of gas. And the significance of that will become apparent.

The next slide is called, "Trends: New Mexico Natural Gas Production." This merely shows you that coal seam gas production continues a relatively steady rate of increase through the end of December 91. The conventional gas production shows, in the northwest, that is, shows a fairly steady decline. And the total northwest production continues to rise.

So we are seeing a continuous rise in coal seam methane production and a reasonably consistent decline in conventional gas production.

Q. This is, for those who can't read the slide in the back, this is actually just northwest gas and does not include Permian southeast gas?

A. That's correct. The next slide is called, "Coalbed Methane Producing Wells." This does not represent the total number of wells drilled, but does represent the number of wells

in production for each of the months. And as you see, there is a continuous and steady increase in the number of coal seam wells connected and producing, and we expect that trend to continue.

Before I leave that slide, perhaps I should say that it is our opinion, which is not necessarily that of the industry, but it's our opinion that coal seam natural gas wells will continue to be produced in almost any price scenario. I don't intend to talk much about price today, but the price of natural gas at the wellhead is expected to remain low during the period under review.

But, nonetheless, for various reasons, including but not exclusively the federal tax credit, the coal seam gas wells will continue in our view to be connected and produced. There is now adequate pipeline capacity to move almost any amount of coal seam gas or other gas out of the San Juan Basin since the completion of expansions to the El Paso system and the connection of a new pipeline by Transwestern linking the coal seam gas, linking the coal seam gas wells in the San Juan Basin to their mainline. So there is no restriction on pipeline capacity.

Q. If I might ask, do you see any reason to see this trend of increasing the number of wells to change within particularly the six month period we're talking about?

A. Well, the opportunity to become eligible for a federal tax credit will expire at the end of 1992 unless renewed by the Congress. We have no idea whether it will be renewed or not. You can argue it both ways.

So since there is that uncertainty, it would seem logical that holders of coal-gas leases would want to drill their wells and get some production started in order to become eligible for the tax credit. Even if they cannot monetize immediately, at least they would be eligible.

Final series of slides concerns reserves. This is a general national slide concerning reserves. We can see from this slide that New Mexico with 19.8 Tcf of proven reserves is second nationally behind only Texas, if you exclude the offshore federal and state reserves. So New Mexico's reserves have in fact increased.

I have a slide here showing New Mexico's reserves. This slide is entitled, "New

Mexico Proven Natural Gas Reserves, Estimated 1991." And, as you see, New Mexico's reserves are continuing to increase, and we expect this increase to continue for several years as the coal seam gas in the San Juan Basin is further developed and more than offsets the decline in conventional wells.

You can see this rather more clearly in this slide entitled, "Reserves Northwest Conventional Coal Seam," where the coal seam reserves show the greatest -- show the rise, show the increase, the conventional reserves for these two years, 1990 and 1991, are flat. The southeast reserves went up slightly but they are essentially flat. So the big increase is in coal seam gas reserves, and we expect that to continue.

That concludes my slides and concludes my testimony.

Q. Let me just ask you if you can reach any generalized conclusions with respect to New Mexico's ability to market its gas, its ability to meet demand for its gas, and market trends as a result of your information and knowledge?

A. I mentioned earlier the increased

pipeline capacity now available in Transwestern El Paso. In addition to that, Northwest Pipeline has expanded its capacity. And there is a great deal of flexibility for movement of gas by pipelines through the state.

There is probably a surplus of interstate pipeline capacity from the San Juan Basin to the markets at the moment. This leads me to believe that pipelines will be forced to discount their transportation rates in order to keep the pipes full.

So although the prices will be flat, low and flat, throughout the period on review, the reductions in pipeline transportation rates may offset this and encourage New Mexico producers to continue to produce.

In addition, the coal seam gas is, in my view, likely to be the last gas to be shut-in because it has relatively low production costs and has the potential of earning the tax credit, even if it cannot be monetized immediately.

So, in our view, the coal seam gas will continue to flow, and the New Mexico producers will have more than enough pipeline capacity to deliver their gas to the markets.

Q. Is there anything further you wish to add to your testimony at this time?

A. No.

MR. STOVALL: Mr. Chairman, I have marked the exhibits in the order shown by Mr. Merrett as Exhibits 1 through 8 on my copies. I don't think they've been marked on your individual copies. And I'd move the admission of those exhibits at this time.

CHAIRMAN LeMAY: Without objection, Exhibits 1 through 8 will be admitted into the record.

Are there additional questions of the witness?

Mr. Kellahin.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Merrett, a point of clarification, sir, have you as part of your duties made an assessment for this proposed -- for the reasonable market demand for any of the individual prorated pools in New Mexico for the next proration period?

A. No, we have not.

MR. KELLAHIN: Thank you.

CHAIRMAN LeMAY: Additional questions of the witness?

Commissioner Carlson.

EXAMINATION

BY COMMISSIONER CARLSON:

Q. Ron, have you looked at -- they extended that tax credit now to tight sands gas again. Have you looked at that in the same way you've looked at coal seam as far as the production from qualifying wells on tight sands?

A. No. We haven't done any detailed analysis of tight sands, no.

CHAIRMAN LeMAY: Commissioner Weiss.

EXAMINATION

BY COMMISSIONER WEISS:

Q. What is the excess capacity of the pipelines now?

A. Hard to say because they're still in a state of development. It's my feeling we probably have at the moment probably half a Bcf a day surplus out of the San Juan Basin. But as more wells come on, that would be used up. But then there's more pipeline capacity being brought in, so it's very hard to say that. But there is surface capacity in a fairly substantial amount.

COMMISSIONER WEISS: That's all. Thank you.

CHAIRMAN LeMAY: Mr. Merrett, just one question.

EXAMINATION

BY CHAIRMAN LeMAY:

Q. Do you expect any increase in demand, especially in the California market, over this proration period? EOR market, will that be an incremental market for New Mexico producers?

A. Yes, it is up to perhaps about four or five hundred million a day. There is a conversion of crude oil burning to natural gas burning in the EOR market. But part of that is taken up by supplies from Wyoming coming down the new Kern River pipeline, which has just been opened. So it's hard to tell whether that will impact New Mexico's producers, because there are other producing areas now available to the California market.

Demand in California is expected to be relatively flat this year. Of course, you can never tell what's going to happen with nuclear power plants, which have a very big impact on the production of electricity.

And also we still don't know whether the hydro-operations in California Sierras and the Northwest will be producing significant amounts of low-cost electricity. Those are always unknowns. But all the forecasters seem to predict a fairly flat market demand for this period.

CHAIRMAN LeMAY: Thank you.

Additional questions?

MR. STOVALL: Mr. Chairman, I would like to ask one follow-up to Commissioner Carlson's.

FURTHER EXAMINATION

BY MR. STOVALL:

Q. With respect to the tight sands gas, the first question is: Do you have knowledge of whether or not any of the areas which have been designated for tight sands and which are eligible for the credit are within any of the prorated gas pools?

A. I do not know that.

Q. Would you anticipate then, as a general question, that would the advantages and the conclusions you've reached with respect to the continuing production of coal seam apply to those

gases because of the economic benefits of the tax credit? Would it put it on a competitive footing with the coal-gas?

A. There may be people in the audience that are better qualified to answer that question than me. I think there are certainly some benefits to be had from the tight sands gas credit. But just how that will impact the producers, I really don't know.

MR. STOVALL: I have nothing further then.

CHAIRMAN LeMAY: Additional questions?

Thank you, Mr. Merrett. You may be excused.

Call your next witness, Mr. Stovall.

MR. STOVALL: Mr. VanRyan.

LARRY VanRYAN

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

EXAMINATION

BY MR. STOVALL:

Q. Would you, please, state your name and place of residence.

A. My name is Larry VanRyan, and I currently temporarily reside in Santa Fe. I'm

in the process of moving here.

Q. And how are you employed, Mr. VanRyan?

A. I'm employed as the Chief Petroleum Engineer for the Oil Conservation Division for the State of New Mexico.

Q. How long have you been so employed?

A. Since the first of February.

Q. And what were you -- what was your employment experience prior to that time?

A. Well, I have a petroleum engineering degree, which I obtained in 1962. And since that time I've worked for Standard Oil of California, for El Paso Natural Gas Company, for Northwest Exploration Company, Southland Royalty Company, and of recent experience, I've been a consultant in the San Juan Basin.

Q. And where has most of your experience been? Has it been in New Mexico or has it been --

A. Since 1967 the majority of my experience has been in New Mexico.

Q. And in your current capacity as Chief Engineer for the Oil Conservation Division, have you had the opportunity to become familiar with the allowable system as it is currently

implemented today?

A. Yes, I have.

Q. And are you prepared to present testimony and make preliminary recommendations with respect to allowables in the -- actually, 17 prorated gas pools in the State of New Mexico?

A. Yes.

Q. Have you prepared exhibits which present those preliminary recommendations?

A. Yes, I have.

MR. STOVALL: I move the qualifications of Mr. VanRyan as an expert petroleum engineer in gas prorationing.

CHAIRMAN LeMAY: Mr. VanRyan is so qualified.

Q. Mr. VanRyan, would you briefly just summarize the purpose of your testimony and the purpose of this hearing and what the Division is presenting and recommending today in general terms?

A. Well, in general, we're recommending the allowables that will be assigned to the prorated pools in the state, both in the northwest portion of the state and the southeast portion of the state. And we are doing this on a

six-month basis, which has been in effect now, I believe, for a short period, a relatively short period of time.

We're trying to set up an allowable on a six-month basis so that will allow people a little more flexibility in obtaining market and also in producing their wells.

What we have done to set these up is we have used past histories of production from the prorated pools. We've used the same period of time in 1991, from April through September, to establish what the pool sales were.

We've also used the marginal pool allowables during those periods of time or marginal production during the same periods of time to arrive at a value of production for the non-marginal wells, and those are the prorated wells in the prorated pools. We've done this for both the northwest and the southeast part of the state.

Q. And the period for which the order coming out of this hearing will be applicable is April 92 through September 92; is that correct?

A. That's correct. And that's the same period of time. We're trying to be consistent

with what Mr. Merrett showed as far as the periods where production is a little bit lower than it is in the winter months, sometimes substantially lower.

Q. Now, I think you've testified that you have prepared some recommendations in the form of exhibits. Is the Division advocating these as allowables to be set for the prorated pools?

A. These are just guidelines which we are trying to establish. And one of the reasons for this hearing today is if anybody else has any information to bring to light to help us to establish these allowables, that's why we're here, to obtain that information.

We don't always know what's going on in the field, as far as gas marketing, or as far as working in the pools themselves, which may increase the deliverability of the wells.

Q. Let's turn to your specific recommendations and first turn to the southeast portion of the state. Would you go to Exhibit A and summarize the manner in which the information is presented, that is, let's, for example, pick any one of the fields and just go through it line by line and explain how the exhibit gets from the

top to the bottom.

A. Okay. As I mentioned, line 1 on Exhibit A, is the average monthly sales for the pools for the period April 91 through September of 91. Next, we have a line in there for nominations, and that's one of things that we'll be taking up today.

Third is adjustments that we feel from what knowledge we have that should be added to the production from the pools. Those are added to the average production for the 91 period to give us what we're recommending as a monthly pool allowable for the 1992 period that we're discussing here.

The fifth line is the historical production for the marginal wells in these pools for the period April 91 through September 91. I might mention now, this is a little bit of a change from what we have sent out when we sent out the notice for this hearing.

We feel a little more comfortable with using the production from April 91 through September 91. What we had sent out to everybody was October through December of 91, not being quite equivalent to the seasonal demands that

we've seen earlier.

By subtracting line 5 from line 4, we come up with the production for the non-marginal wells in these pools. Line 7 is the number of non-marginal acreage factors for the pools. And line 8 is simply line 6 divided by line 7.

Q. Line 8 is really the bottom line, if you will, the allowable for an acreage factor of 1 is what you're recommending then?

A. Yes, that's correct. For an acreage factor of 1, that's what would be allowable for that proration unit.

Q. Now, if I'm not mistaken, if I look at this exhibit, all items, except for lines 2, in which there is no nominations at this time, and line 3, are actually statistically- or mathematically-derived numbers; is that correct?

A. Yes, they're past history.

Q. And line 3, then, is adjustments which the Division has proposed, and in all cases they are positive or increased adjustments to pool allowables, is that right, in the pools where there has been an adjustment?

A. Yes, that's correct.

Q. Would you characterize these

adjustments as being scientifically-derived or estimated adjustments based on some non-scientific factors, if you will?

A. They are not scientifically-derived. These are estimates of what we feel are needed in these pools to give them a fair allowable. In some cases they are to bring us in line with the acreage factor at the bottom that we have had historically or to bring us in line in certain pools where we have a minimum allowable.

Q. And you would hope today that industry will present some items to plug in to line 2 or line 3 that would help get something that's at least realistic in view of the industry?

A. Yes. This is the whole purpose of this meeting -- or one of the purposes is to have these people have some input into this to help us make our decision.

Q. Let's turn now to the northwest in Exhibit B. And that exhibit is structured slightly differently because of the calculation mechanism in the northwest; is that not correct?

A. Yes, for establishing the allowables in the northwest part of the state, deliverability is a factor, where it is not a factor in the

southeast part of the state.

Q. And where does that show up? Rather than go through the whole exhibit and restate everything line by line, where does that show up? And explain the differences, if you would.

A. Well, in line 8, we have a figure there, it's called the acreage factor times the deliverability factor. That factor then is used to calculate line 10. And line 10 is that figure which is determined by using deliverability, where we do not use deliverability in the southeast part of the state.

There's additional figures that go into these. The non-marginal production is allocated either on a 25-75 percent split or on 60-40 percent split, depending on acreage and deliverability. So it gets quite a bit more complicated in the northwest part of the state.

Q. In other words, if you look at the southeast, Exhibit A, if you take the line 8, if you've got a well with an acreage factor of 1 in its proration unit, the gas proration unit, that's essentially the allowable for that well; is that correct?

A. That it is the monthly allowable for

that well.

Q. And if it's anything less than or more than 1, you just multiply it and get that allowable for a monthly allowable?

A. That's correct.

Q. But it's not quite such a simple formula for the northwest and you have to look at the formulas and do a little bit more complex mathematical analysis to get the actual allowable for a specific proration unit in the northwest; is that correct?

A. Yes, that's correct.

Q. And it's not possible to do it because deliverability factors are different for each proration unit; is that correct?

A. That's correct.

Q. Do you have anything further you wish to add to your testimony about these exhibits or the Division's preliminary recommendations?

A. No. I believe we've covered everything.

MR. STOVALL: I have no further questions of this witness, and I move the admission of Exhibits A and B in this case.

CHAIRMAN LeMAY: Without objection,

Exhibits A and B will be admitted into the record.

Questions of the witness?

Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. VanRyan, I'm interested in the pools in southeastern New Mexico. For example, if we'll focus on the Blinebry Pool, let me ask you some questions about the analysis the Division has undertaken to derive the guidelines that are presented today.

For line 1, the average monthly pool sales, how is that number generated?

A. That was generated by summing up the monthly sales as reported by the Division for the period April through September 91.

Q. If you're going to get that number off the C-111's, the gas purchaser reports?

A. Yes, that's correct.

Q. And they would not come off the C-115, operator production reports?

A. No. They're from the C-111's.

Q. What progress has the Division made with reconciling any discrepancies between what the operator reports as production from his wells versus what is shown on the sales report?

A. In my current time in the Commission, I've not looked at that but, I know in the past in the records, there have been several people look at that. And I don't know that we have arrived at a given figure which we say is correct.

We're currently in a state of flux of trying to adjust our computer programs and to also eventually adjust what production report method we're going to use for the allowables.

Q. Do you have with you a copy of the preliminary guideline for allowables that was sent out in the docket?

A. Yes, I do.

Q. I'd like to have you help me understand some of the principal changes between the one that went out in the docket and the revised guidelines that you've presented this morning. Again, let's focus on the Blinebry quickly. There is a small change in the acreage factor for the Blinebry?

A. Yes, there is.

Q. And when you look at line 5, the monthly marginal pool allowable, does that equate to the marginal pool sales for that period?

A. Yes. For the period of April -- the Exhibit A is for the period of April 91 through September of 91. On the preliminary that we've sent out, that was for the period October of 91 through December of 91.

Q. Looking at line 5 and then changing the acreage factor the non-marginal wells in line 7, are those the two principal changes between the preliminary allowable and the revised allowable for that pool?

A. Yes, they are.

Q. Let's turn to the Catclaw Draw Morrow for me. Again, there's a change in the acreage factor. The original preliminary allowable that went out with the docket had a 2.99 acreage factor; it's been reduced to 2?

A. Yes.

Q. Have you verified the reliability of the No. 2 as the acreage factor that should be utilized?

A. Since we sent out the original, the

preliminary information, we have looked at that pool because there was a question about the actual acreage factor for the non-marginal wells. I'm not exactly sure that 2 is correct now. I feel we may only have one prorated well in that pool. We're in the process of trying to line that out and come up with the correct factor.

Q. When you look at row or line 8 for Catclaw Draw, the original schedule had 90,000 Mcf, the revised schedule drops it down to 75,000 Mcf?

A. Yes.

Q. Show me how that changed, what causes that change.

A. In the original that we had sent out, we had included an adjustment under line 3 of 242,000-plus to add up to a total of pool allowable of 421,900. In the Exhibit A, we did not add that much into the pool. And what we were trying to do in this case was to arrive at an acreage factor allowable of 75,000, which was what had been assigned to that pool in the previous proration period, the one we're under right now.

Q. There are some pools for which you have not yet assigned an adjustment factor in line 3.

A. Yes. Yes. To the best -- in those pools, we didn't have any knowledge that would make us want to make a change, but we are open for line 2 to accept recommendations or nominations from other people.

Q. And the fact that for the Catclaw Draw we see an adjustment factor in line 3, that does not preclude further adjustments in that number based upon operator evidence, do they?

A. No. That's correct.

Q. Let me turn to the Indian Basin Upper Penn Pool. Scanning through the two spreadsheets, the original versus the revised, there is obviously a substantial change in the acreage factor. How comfortable are you that the 6.49 is the correct acreage factor to apply for the non-marginal wells?

A. It's more accurate than the 3.49. That was simply an error when we sent that out.

Q. It appears to me that the other major adjustment in the Upper Penn is that you have recognized the downtime on the Marathon gas plant in coming up with the entry for the monthly

sales, I think it is?

A. Yes, that's correct. And line 1, we did not use the full six-month period because we found out that the plant was shut down for 12 days in September. So we have a footnote there that is actually for a five-month period, excluding September.

Q. So if I'm looking at the original guideline versus the revised exhibit today, the two major changes that cause line 8 to increase are the acreage factor and the recalculation of the average sales, recognizing the downtime in the Marathon gas plant?

A. Those are the major factors along with the factor that line 5 is a smaller factor also. And this is one of the reasons that we went to using the marginal pool allowable for the same period of time is to take another period of time.

MR. KELLAHIN: Okay. Thank you, sir.

CHAIRMAN LeMAY: Thank you, Mr. Kellahin.

Additional questions of the witness?

Mr. Carr.

EXAMINATION

BY MR. CARR:

Q. Mr. VanRyan, just to be sure I understand the Exhibit B as it relates to the guidelines that were attached to the notice of this hearing, if we look at the information for the pools in the San Juan Basin, if I go to column No. 6 in both of these exhibits, that is the monthly pool allowable; correct?

A. Yes, that's correct.

Q. And if we go over and look at the Blanco Mesa Verde Pool, the guideline had recommended an initial recommendation of 4.8 Bcf; is that what that number is?

A. Yes, that is correct.

Q. In the exhibit that you have offered today, that number has been increased to 6.9 Bcf?

A. Yes.

Q. So we're looking at just between the notice of this hearing and what we're looking at today of 2 Bcf increase in that pool alone?

A. That's correct.

Q. Just to be sure I'm reading this correctly.

A. Yes.

CHAIRMAN LeMAY: Mr. Pearce.

MR. PEARCE: Thank you.

EXAMINATION

BY MR. PEARCE:

Q. Mr. VanRyan, I have a couple of questions that I want to ask to make sure I understand, and then I have a philosophical question to run at you, I think. If you'd look at the today's exhibit for the pools in northwest New Mexico --

A. Uh-huh.

Q. -- for prorated pools, in the previous preliminary, there was an adjustment in the Basin Dakota Pool, was there not?

A. Yes, there was.

Q. And that was not repeated in the exhibit you're using today?

A. That's correct.

Q. If we look in this exhibit at line No. 4, monthly pool allowable April 92 through September of 92, that is the allowable that you believe should be assigned; is that correct?

A. Yes.

Q. And I notice that there is a significant difference between that number on the preliminary and the number that you're using

today. See that difference 6.9 to 5.8?

A. Yes. And that has to relate to the fact there's no adjustment in Exhibit B where there was adjustment in the preliminary.

Q. Now, we sort of get out of specific numbers. Did I understand you to say that we're really -- the number exercises really pointed at the bottom line?

A. In this particular case it's pointed at the bottom two lines for the northwest part of the state.

Q. And how did the Division decide what it believed was the appropriate numbers to put in those two lines?

A. In this particular case the preliminary, we were trying to arrive at some appropriate figures there. In the Exhibit B prepared for today, we went back and by changing what we looked at as far as the marginal production for these specific pools from April 91 through September 91, as opposed to the preliminary which had October 91 through December of 91, we came up with a more realistic figure for the marginal production in these pools.

The effect that had, then, was without

increasing the total pool allowable, we were increasing the non-marginal well allowable in these pools and coming to the same figure. We feel we're much more accurate now than we were when we were using the other figure.

The problem with using October to December, as Mr. Merrett showed you, that's the high demand months for natural gas for the San Juan Basin. And during that period of time, the line pressure is much lower so the wells produce much better, particularly the marginal wells which are the poorer wells.

So by changing the marginal pool allowable, what the wells will produce, we feel we're much more accurate now, and we don't have to make those adjustments.

Q. And the 5.41 AD factor shown on the bottom line, which had been 4.9 --

A. Yes.

Q. -- tell me again why you believe 5.41 is the appropriate number?

A. This matches the history of the pool.

Q. I'm sorry.

A. And I feel much more comfortable using natural production and a lot less adjustments if

we can to arrive at a basis for this. And that's why we went to this is to have less adjustments.

Q. Do you happen to know what the AD factor for the Basin Dakota Pool for the last six-month proration period was?

A. I don't have that figure with me. I can't recall.

Q. Similarly, you don't have the number with you of what the acreage factor was in that previous six-month period?

A. No, I don't. We've not been comparing these for the same problem that we've not been comparing April through September figures with the March -- with the other figures, the October through March figures.

Q. In both your testimony and the testimony of Mr. Merrett, you've mentioned demand during the summer season as being lower. And you mentioned earlier that there was a change in gathering line pressure, I believe, which you think accounted for, in part at least, the lower marginal production in the summer months; is that correct?

A. Yes, that's correct.

Q. Are you aware, if there is some

strategic marketing decision-making going on in the basin, of producers intentionally holding gas off of the market in the summer?

A. I have read some newspaper articles that refer to that, but do I know specifically and for a hard fact? No, I don't.

Q. Do you know if there are wells in the Basin Dakota which are presently constrained because of allowables, shut-in?

A. From the production, the proration production figures, I do know of some wells that are overproduced, so they would be restrained or could be restrained.

MR. PEARCE: All right. Thank you, sir. I don't have anything else. Thank you.

CHAIRMAN LeMAY: Additional questions of the witness?

Commissioner Carlson.

COMMISSIONER CARLSON: No questions.

CHAIRMAN LeMAY: Commissioner Weiss.

COMMISSIONER WEISS: Yes.

EXAMINATION

BY COMMISSIONER WEISS:

Q. You're probably the wrong man to ask, but how are these complexities that are seen in

the northwest proration schedule, how are they arrived at? They're different from the southeast.

A. They're quite a bit different. In the early days of the field up there, it was decided that the deliverability or the capability of the well to produce should be considered into the allowable for those wells.

Q. Who decided that?

A. It was an early rule of the Oil Conservation Division.

COMMISSIONER WEISS: No more questions. Thank you.

CHAIRMAN LeMAY: Anything else of the witness? If not, he may be excused.

Thank you, Mr. VanRyan.

Mr. Stovall, does that conclude your --

MR. STOVALL: That completes my case. I have nothing further, Mr. Chairman.

CHAIRMAN LeMAY: Mr. Kellahin.

MR. KELLAHIN: Yes, sir. Thank you.

Mr. Chairman, I'd like to deal with the Catclaw Draw Pool first. And at this time, call Mr. Kevin O'Connell, petroleum engineer with Hallwood Petroleum, Inc.

KEVIN O'CONNELL

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

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. O'Connell, would you, please, state your name and occupation.

A. My name is Kevin E. O'Connell. I'm a petroleum engineer and drilling and production supervisor for Hallwood Petroleum in the western district.

Q. Have you previously testified as an expert witness before the Oil Conservation Commission on allowable hearings?

A. Yes, sir, I have.

Q. Are you familiar with the OCD preliminary allowables for the expiration period for the Catclaw Draw Morrow Pool?

A. Yes.

Q. In addition, have you seen the Division's revised preliminary guidelines that they have submitted to the Commission this morning?

A. Yes, sir.

Q. Based upon your study of all that

information and your background familiarity with this reservoir, do you have recommendations and comments with regards to your pool and what ought to be done with establishing allowables for that pool?

A. Yes, we do.

MR. KELLAHIN: Mr. Chairman, I tender Mr. O'Connell as an expert witness.

CHAIRMAN LeMAY: His qualifications are acceptable.

Q. Let me direct your attention, first of all, to the package of exhibits. And looking at Exhibit No. 1, is a collection of displays and summaries, and if you'll turn to Exhibit 1, page 1, would you identify and describe your conclusions?

A. This is an exhibit that pertains to the Catclaw Draw Unit 1YN, No. 13 proration unit. That's a two-well proration unit with an acreage factor of 1. Going into the previous proration period, which would be the winter period, or October through March, this well was classified as a non-marginal well.

And our analysis, we feel this well should currently be reclassified as it meets all

the state requirements for reclassification to the marginal unit status.

Q. Let me interrupt you at this point. When we look at the preliminary allowable schedule the Division circulated with the docket, they had a non-marginal acreage factor of 2.99?

A. Yes, sir.

Q. What three wells in the pool composed that factor?

A. I'm not 100 percent sure which wells are in there because there's been some discrepancy on which are or aren't or should or should not be the non-marginal. But I believe it contained the Catclaw 13 and 1Y and the -- or it should have contained the Catclaw 13 and 1Y and the Catclaw Draw No. 9. Those should have been the two non-marginal units into the previous period.

There was an error on the schedule. The Catclaw 9 shows an acreage of 2.00, which is incorrect. It's a 640-acre unit, and it should be a 1.00.

Q. Going into the summer proration period, the revised schedule has dropped the acreage factor down to 2 at this point?

A. Correct.

Q. What does your study cause you to conclude should be appropriate acreage factor going into the summer proration period?

A. We think it should decrease down to 1.00. And as Mr. VanRyan pointed out, he's not so sure but maybe that is the right number, 1.00, because there has been some discrepancy over the past on what is or is not a non-marginal unit in the field.

Q. Based upon your study what would the well be? Identify the well that would be the non-marginal well.

A. It would be the Catclaw Draw No. 9 proration unit.

Q. Go ahead and continue, then, with your summary conclusions on page 1 of Exhibit 1.

A. We just went through the steps, and the well was last in a zero over-under status in April of 89. It was significantly overproduced to about a quarter of a Bcf. But since then it's worked off all of its overproduction.

This proration unit's production is now less than the assigned monthly allowable. It has not made its monthly allowable in, I believe,

it's eight months. And now the unit is currently underproduced. And a lot of this is due to the recent increases in the F1 factor in the field.

Q. Let's turn to page 2. Your display shows the OCD preliminary allowable based upon the docket, does it not?

A. Yes, sir. The preliminary?

Q. Yes, sir.

A. Yes.

Q. And as we go down the lines of the display, you might give us the number that would fit the revised schedule, and we can see the comparison between Hallwood's recommendation for allowables and the OCD revised guideline.

A. Okay.

Q. First of all, with line 1.

A. Well, this basically, I've just extracted these columns, or line 1 through 8, exactly as they are on the OCD schedule. And I've compared their preliminary numbers to our numbers.

The preliminary number was 179,000 for average monthly pool sales, 179,266. The revised number from the OCD is 187,858. We show -- and I've got some following exhibits that will

support this pretty good -- the actual production for the last summer period, April through September, was up in the 250,000-a-month range.

Again, we're getting into a problem of do we use C-111's or C-115's? Our numbers, which are the bulk of the field's production, are from C-115 data, which is reported directly to the OCD. And we are the first transporter on the majority of the wells through the gathering system we operate.

Q. What are the other principal changes in the various components that you want to subsequently address your discussion?

A. Well, the main item is line 4, the total monthly -- or the monthly pool allowable for the period. We were very encouraged, before I saw the revised numbers this morning, because the OCD had a number of 421,900, we arrived at a number of just under 429,000.

We were within 1.6 percent on the numbers, which is a pretty good accomplishment. I think we're moving in the right direction, because this field can and will produce over 400,000 a month right now.

I'm a little concerned to see the

monthly pool allowable on the revised number back down to 297,103. As I say, I don't know where this comes from exactly, but I think I can show that the production numbers should be higher.

And then the only other major problem, or part 2 of that, is whether we use 1 or 2 as the number of non-marginal acreage factors. If we go to 1, as in our numbers, then it shifts. The marginal pool production has got to rise accordingly, because if you have a couple other units that are reclassified, that will shift that production.

The other thing I want to point out, Mr. VanRyan this morning made a statement that we were currently under a 75,000 F1 factor, and that number is actually 127,000 as result of our November 14 rehearing. So the way I understand it, they were trying to stay at that 75,000, and we're actually under 127,000.

So you'll see -- you know, if you try to stay at an F1 of 127,000, where we're at now, then our number is relatively close to that, of 149,000. That's the main point there.

Q. All right. As part of your study, have you made a determination of the relationship

between the market demand for pool production, the deliverability of the wells in that pool, and the proposed allowables that you're requesting for the pool?

A. Yes, sir.

Q. Do you have a market demand that in your opinion is reasonable if the Division allows you or the Commission approves the allowable levels that you're seeking for the summer period?

A. Yes.

Q. Let's go through some of the rest of your displays and talk about the recent total field production. That's the bar graph, I think, that follows --

A. Yes. It's entitled, "Recent Total Field Production." What I did there is I looked back over the last eleven-month period, April 1991 through February 1992, with February being an estimate.

And basically that plot just shows the total field production has increased from April of 1991 of 166,000 per month to just under 400,000 a month. February will be about 387,000 Mcf per month. February is a little bit shorter month. So if February was a 31-day month, it

would easily top 400,000.

Q. Draw a comparison for us based upon the recent months of total field production and how that relates to market demand.

A. Just that we have been able to produce and have been able to sell this increase in gas that we've established out there. And we do have the market demand for it.

The other thing I'd like to point out on there, if you look at just the six-month summer period, April through September, you can see that the actual production was up around, if you average those, it is around 250,000 as opposed to 170- to 180,000 Mcf per month.

Q. Mr. Merrett testified a while ago that, based upon a study of all production in New Mexico, he saw a continuation of the seasonal swing in gas production and sales in New Mexico. Do you see a seasonal swing in production in your pool?

A. No. We're starting to see that swing disappear. We can sell gas in the summer. And I'm not so sure, it may not be too hard to get better summer prices, if we can lock up a market in advance, than what we've seen over the recent

winter.

Q. Let's turn to the pie chart that's the next display. What's the purpose of the display?

A. The main purpose I wanted to show on here, because there may be some conerns that the Catclaw No. 9, which is what we're recommending, is basically the only non-marginal unit in the pool, that it may be getting maybe its undue share of production or dominating the production from the field.

And this pie chart just shows, although it is the largest piece of the pie, it's still only 33 percent, or a third of the total pool production. There are some other substantial units out there that produce anywhere from 10 to 20 percent of the total pool production.

You know, that's the main thing I wanted to point out. You know, if this situation were reversed, I'd be a little concerned if you had one well dominating 60 to 70 percent of the pool's production. But you can clearly see that there are some substantial producers out there and that it doesn't unduly dominate the field production.

The other thing you can also arrive at

from there is that if you take this total pool production of 420- to 430,000 a month of capability and marketability and if you multiplied it times 67 percent, which would be the marginal, come up with a number in the 260- to 280,000 range, which that is useful to go back into the allowable determination, that shows that that market -- or that the non -- excuse me, the marginal production has got to increase some.

Q. If the Commission adopts Hallwood's requested allowable for the summer period, have you made a determination if you're going to have any capacity problems either in the gathering system or the distribution system for production of gas from the pool?

A. No, we don't anticipate any problems.

Q. Let's turn to the last display in the exhibit package.

A. This display is a comparison of the monthly average pool allowable, sales, and F1 factor for the four -- the four summer periods, one being the previous three, 89, 90, and 91, and then the fourth is the upcoming one.

The bulk of this data was taken right off the data that was supplied with the

preliminary well estimate. There was a comparison for these four well periods with one modification in the sales for the last summer, I increased to what we believe is the more accurate number, 254,000 Mcf a month as opposed to 179.

You know, this plot and why I wanted to present it, it's important because it illustrates that because of some of these changes that we've made out here and the success that we've had, the sales have increased substantially even in the summer periods, and sales have, starting last summer, have overtaken the allowable. And that in turn created the need for the allowable increase that we sought and had received.

The other thing that's important out here is that because we've got this need and we've increased the allowable, the F1 has got to come off this well. You know, you look back through the last three periods, and the F1 is running about 15 to 25 percent of the allowable.

And even if the Commission adopts some of the current numbers, which may seem high on an initial look, if you look at them on this plot, they're still in that same general ballpark. The F1 has got to increase in accordance with the way

the allowables and sales have increased.

And I just want to present this because this leaves you with some confidence as to that F1 has got to increase accordingly.

Q. Identify and describe for us Hallwood Exhibit 2.

A. That's just our nomination letter that we provided to the Commission with our estimated nominations for gas during the six-month period that we're upcoming. And it basically averages about 383,000 Mcf a month for Hallwood's gas.

MR. KELLAHIN: That concludes my examination of Mr. O'Connell. We would move the introduction of his Exhibits 1 and 2.

CHAIRMAN LeMAY: Without objection, Exhibits 1 and 2 will be admitted into the record.

Questions of the witness?

MR. STOVALL: If nobody else does, I have some questions.

CHAIRMAN LeMAY: Mr. Stovall.

EXAMINATION

BY MR. STOVALL:

Q. The only real statistical question I've got for you on information is you've testified

that there is a substantial difference between the C-111 volumes which the Division used and the C-115's; is that correct?

A. It appears there's a difference.

Q. I think you said Hallwood was the first transporter on how many of the wells?

A. We're first transporter on nine of our thirteen wells.

Q. And so you've filed the C-111's on those wells; right?

A. Yes. And we also nominate now for the other four wells in which gas companies --

Q. Okay. I'm not worried about the nominations at this point. I want, for the Division's benefit and in terms of doing an analysis, have you looked to see where the differences are between the C-111 and C-115 figures? Are you able to point that out so the Division can verify or determine how to get more accurate in that area?

A. No, I can't point directly to and say where the problem is. It seemed to me that C-115's are the more accurate numbers. They're reported right from the producer, and they take off lease gas usage. And the volumes sold are

right on there. And that seems to me to be the number we ought to key in on instead of who or how or where the gas is getting transported.

Q. That's a philosophical question, I guess, and the Commission will have to make some changes in the rules if they want to do that. I guess the other answer is the C-111's reflect the gas that's being moved away from the wells, so you can make that argument both ways.

But I'm more concerned, particularly since Hallwood is actually filing both reports, as to how we come up with substantial differences, and would you be willing at some point to sit down with the Division and do a preliminary analysis and advise the Division so we can make a determination.

And if we can find a systematic problem, then we can look at it if it's an individual problem, then we may have to deal specifically with Hallwood on the specific field. But would you be prepared or willing to do that kind of analysis so that we can?

A. Yeah.

Q. There shouldn't be that much discrepancy, I wouldn't think.

A. I'm a little confused on how there could be such a discrepancy, and we'll have to look at that some more.

Q. Let me ask you some questions just in terms of what Hallwood wants and the net effect of what you want. How many gas proration units are there producing from this pool? Does this reflect all of them on your exhibit?

A. Well, there's --

Q. The pie chart is one I'm looking to. Does that have -- or is that just Hallwood's?

A. We'll, we've got eight, and there's three outside operators or three other operators.

Q. So the total number of gas proration units in the pool is eleven; is that correct?

A. It's either eleven or twelve.

Q. And the number 9 you're seeing has got 10 percent of the gas proration units and 30 percent of the production, so it is a, if you will, something of a superstar in the pool; is that correct?

A. Yeah, it's a good well. It will produce nearly 5 million a day.

Q. Now, if I go back and take your mathematical calculations the way you've arrived

at the numbers on -- again, it's not real critical what the numbers are at this point; it's the methodology I'm concerned with -- is essentially what you are suggesting is that the Division should set the allowable, for all practical purposes, based upon the pool's capacity to deliver; is that correct?

A. Well, I don't know if we -- what we would like to see is the allowable set basically at or near the current allowable of 127,000.

Q. Okay. For an F1 factor of 100?

A. Correct.

Q. Does that restrict the No. 9 well, I think, the big one?

A. Yes, it will restrict it some. I mean, you know, if we wanted to, we could produce 8 to 10 million a day out of that well alone. I don't think that will be prudent, and that's not our intent, or we're not trying to get to that level. We're trying to keep, you know, at a level 127- to 140,000 Mcf a month.

Q. So, in other words, I guess the next question then I'll ask is that even if we grant the allowable that Hallwood is asking for, the superstar well in the pool is being effectively

restricted in production so that it is, in effect, it is protecting correlative rights --

A. Yes.

Q. -- and not allowing that well to produce gas from other proration units?

A. Yeah. It's not being produced wide-open at full maximum capacity. It's being produced, and that's what we're trying to maintain. We're trying to maintain a level that we feel is a reasonable and prudent level of production, which is in those ranges.

Q. Let me take you back. As I remember from your de novo hearing, Hallwood presented testimony in the last proration period that that well had some reworking done in the previous summer, I guess summer of 91; is that correct?

A. Yes.

Q. And have you seen any production trends from that well? Is production staying pretty level so far?

A. Yeah. We've only lost about 3 to 400 pounds of flowing tubing pressure, and we've produced nearly a Bcf out of it. So we've seen no real production decline out of it because it hasn't been produced, you know, at full rate

where it could get on a natural decline curve, you know. We anticipate it will probably start on a natural decline over the next year-and-a-half to two years.

Q. Have you seen any effect on the production from that well and other wells in terms of pressure drops or anything that you would attribute from the production of that well?

A. No.

Q. How long would you anticipate that that well will continue to produce, assuming we set an allowable somewhere in the range you're asking of F1 factor of 127,000? How long would it be before that well would eventually decline to where that allowable was no longer restrictive? Do you have an estimate just as an engineer?

A. I think in a year-and-a-half to two-and-a-half years it's going to get on a natural decline.

MR. STOVALL: I have no further questions.

CHAIRMAN LeMAY: Thank you, Mr. Stovall.

Additional questions of the witnesses?

COMMISSIONER CARLSON: Yes.

CHAIRMAN LeMAY: Go ahead, Commissioner Carlson.

EXAMINATION

BY COMMISSIONER CARLSON:

Q. Is the well No. 9, is that currently overproduced?

A. Yes. It's overproduced about 220,000 Mcf. But the current, the current O/P limit now for the field is 761,000, so it's not -- you know, not in any danger of being shut-in. But it does have some overproduction as a result of our testing last summer when we only had a shadow allowable of 22,000 a month.

Q. On page 2 of your first exhibit, line 5, could you explain again the discrepancy between your numbers and the Division numbers?

A. Well, I think it relates directly to the fact that -- it relates directly to the number of non-marginal units. If we shift from three, as was originally done, down to one, you've got to shift some of that formerly non-marginal production over into the marginal allowable category.

Q. Okay. So that's assuming that your unit 1Y and 13 are classified as marginal?

A. Yeah, because it would -- right there would just shift about 40,000 Mcf a month. So if you took the Commission numbers there, that would put you up around 190- to 200,000.

And then I think some of the other is just from some of the other recompletion work we've done, we've got some other wells that are doing pretty good and they're producing quite a bit. And their production may have lagged a little or not be reflected in these, because some of that work was completed halfway or two-thirds through last summer.

So it's not reflected in that period that they're using, April through September, yeah. So that's where the difference, in my opinion, comes from.

Q. Who are the other operators in the field?

A. Texaco, Barbara Fasken, and Hondo. They have four units. One is a two-well unit. All their wells are marginal. They've been marginal for several years. And their production is very steady at 45- to 50,000 a month total on a year-round basis. It doesn't fluctuate very much at all.

Q. Are they aware of what you're proposing today?

A. Yes. I don't know if they're aware of what we're proposing, but they were -- of today's we haven't provided it to them, but at the previous two hearings, they were in support and we received written support from them to increase non-marginal allowables in the pool. And all three companies were highly supportive of it because it really had no impact or bearing on their current status.

Q. Okay.

CHAIRMAN LeMAY: Commissioner Weiss.

COMMISSIONER WEISS: Yes.

EXAMINATION

BY COMMISSIONER WEISS:

Q. As I recall, the order we signed off on here said something about deprorating this pool. What's the status of that?

A. Well, that was just a -- I don't remember the exact phrase.

Q. I don't either.

A. It just said, you know, that was one avenue we may want to pursue. We really don't foresee any need to pursue that at this time.

It's --

Q. You like Santa Fe; huh?

A. Yeah. That's what I was trying to get at. It's a very manpower and time and effort, and we just don't see an immediate benefit from that at this time.

Q. From deprorating?

A. From deprorating. Judging from where the pool allowables were at and the direction we're moving on the non-marginal units, I think we're headed in the right direction. And after one or two more periods, the system is going to be taken over and working just like it's intended to where it's going to be based strictly on how much you produce a well. And it will -- I think it will be working for everybody.

COMMISSIONER WEISS: No more questions. Thank you.

EXAMINATION

BY CHAIRMAN LeMAY:

Q. To follow up Mr. Weiss' question, did you read the findings in the previous order on the rehearing?

A. Yes, sir.

Q. Do you remember the finding where it

was suggested that Hallwood look at deprorating the field?

A. Yeah. Like I say, I don't remember the exact --

Q. Well, I'd just like to raise the spectrum. If it's easy to come here for adjustment of allowables and you're satisfied with the allowables the Commission gives you for the one well, because in essence we are doing nothing more than kind of tracing that one well of yours with allowables in the field, and I think the Commission raised the issue of whether it's in the best interests to prorate only one well and chase it around with allowables because, you know, that's not the purpose of prorating, just prorate one well.

You can take -- I mean, we use the example of North Indian Basin, and I think the same could be said of that field. But when you're only prorating one well, you're really not prorating that well. We're taking nominations from you, and you're saying what the well will make or what you think is prudent for that well to make and then you're asking us to adjust allowables based on, in essence, what the MER of

that one well would be.

I raise this question because you have two answers that I understood in your testimony: One, the number 9, it will produce nearly 5 million a day?

A. Correct.

Q. Additional question, when asked, you said it would produce 8 to 10 million a day, again, referring to the number 9.

A. We're holding it at 5 million a day, which is basically in line with the current F1 of the well.

Q. Well, then, is your first question wrong; it will produce nearly 9 million a day -- I mean 5 million a day; that should be scratched from the record because your other answer is more reflective of the quality of that well. It will produce 8 to 10 million a day?

A. I guess -- let me clarify that. The well is currently producing nearly 5 million a day. It could produce 8 to 10 million a day.

Q. Fine. I think I understood you to say it -- well, that's fine. I'm just trying to clarify your answer to that question. It will produce nearly 5 million a day I think was one of

your answers. It will do more than that then?

A. Oh, yeah. We don't want to and aren't planning to produce it at that. That's the -- I guess the statement I'm trying to get across is we're not, you know, out there just producing everything wide-open.

Q. Well, "everything" meaning that one well. I assume your other wells are producing wide-open if they're marginal?

A. Yeah, basically they are.

Q. And this well, you claim, you have a market that does not fluctuate with seasonal demand. Could I ask you what that market is?

A. Well, I'm not our gas marketer for the field, and maybe I shouldn't be talking about gas marketing. But we do have a good contract with Gas Company of New Mexico, and we can market most anything we produce. I guess that's the best way to leave it.

Q. Well, is it a spot market, do you know, every 30 days, or do you have a long-term contract with the Gas Company?

A. We have a long-term contract with them through a five-month winter period. And they have an option or first call to take during other

periods.

Q. Well, now, we're setting the allowables for not the five-month winter period, but we're setting the allowables for the slack demand period. And, therefore, I guess my question would pertain to not the five-month winter period, but this upcoming period, April through September.

A. Yeah. But we can go out -- we can -- even though or it may be the slack summer period, we have the option and we can sell our gas during that period and intend to do so this summer.

Q. On the spot market; do you know?

A. Yes.

Q. So that's a 30-day market?

A. Yes, during the other seven months of the year.

Q. Is your assumption, then, that Gas Company of New Mexico would not want all of the gas that you could provide during the slack period so, therefore, your option to sell on the spot would be exercised?

A. Yes. But they do still have first call on it if they choose.

Q. Are you familiar with Gas Company of

New Mexico's market, if it's very seasonal or if it's pretty much equal year-round?

A. Down in this area it's pretty much, because my understanding is the market for a lot of this gas is not directly tied to the heating season.

Q. It's not with Gas Company of New Mexico?

A. I mean, our particular market for them.

Q. Your particular market for Gas Company is not tied to the seasonal heating?

A. A lot of it is tied to industrial use in the area. But then, again, we can go off-system. If we can get a market, we can sell the gas through the summer period, and we can sell at the rates we're currently producing at.

Q. Well, that's a big "if," isn't it? I'm trying to say that if you look at the charts that were presented up there, you look at the production and it's seasonal from New Mexico. All wells, not prorated wells, but all wells.

So collectively one would assume, wouldn't they, that there's a seasonal market, that there's less market in the summertime than

there is in the wintertime collectively?

A. Yeah. But I think in isolated cases we're starting to see that dissipate some and --

Q. In isolated cases?

A. Being small fields that, you know, can produce 5 to 10, 14 million a day.

Q. That they have a market that's different than the collective market of all wells in New Mexico?

A. I think that's possible, yes. A lot of it depends on who you market with or where you can get a contractor.

Q. It's possible?

A. Yeah. I mean --

Q. Maybe I'm getting a little out of your line here.

A. I'm not a gas marketer, as I stated, and I think maybe we are getting a little out of the range.

Q. Possibly. You're coming here and asking for, in essence, for 5 million a day, when during the peak season, I took it from your testimony, you were satisfied with 4.2 million adjusted at the last hearing, 127,000 Mcf, and that's high demand.

And you're saying yes, but we have this well, and we'd really like 149,767, which is 5 million a day, during a demand period when collectively demand is less than it was during your high demand period. You've experienced 300 to 400 pounds pressure drop over some frame of 1 Bcf, I think you testified, so there is some pressure drop. There is some depletion, I'm understanding, to the reservoir?

A. Well, there has to be some depletion.

Q. I would assume that, yes, unless you have a coal seam gas well or something that goes up. I'm trying to understand.

A. You know, I guess where maybe I should -- as I stated earlier, we're trying to keep the F1 at or near its current level, 127,000 Mcf.

Q. Without taking seasonal demand into consideration collectively?

A. Yeah.

Q. Because you can run counter to seasonal demand.

A. That's what I understand from our gas marketer, if we know in advance of how much we can produce, then he can actively try to sell

that gas, and we can find certain markets.

Q. And you have no plans to ask the Division to deprorate the pool because you assume that allowables can chase that one well around as long as it's capable of producing?

A. Yeah. I think, you know, back to your statement on the deproration or the purpose of proration, I don't recall where the proration -- whether you had one marginal unit or whether you had 500 was the purpose of proration.

We feel like there's a purpose for keeping proration, keeping spacing out there, keeping setbacks, and letting the system work like it's intended to. I think deproration would be counterproductive for this field right now.

Q. The reason why you think deproration would be counterproductive, can you explain to us why?

A. I think just the effort to do it. It would take, as shown in Burton Flats Field, that took nearly two years, I believe. And, you know, there's no cost benefit from it from our perspective. And if I understand you right, you're concerned about the Commission keeping track of one well.

Q. Well --

A. But the system will work on its own nearly automatically once we get through one or two more proration periods, because it will be tied strictly to production and past production and sales and future sales and it will work.

The other, I guess, supportive reason for not deprorating is if we happen to drill some additional wells or have some continued success out there and you wind up with some more non-marginal units potentially.

Q. Well, I guess I would ask you, from your testimony, you're saying it's too much effort and bother for Hallwood to come and try to deprorate, but it's not much bother for the Division to keep that well on the record and keep it on the proration system because the alternative would be an effort on your part or Hallwood's part to come in to present a case to be deprorated; is that what you're saying?

A. Well, I just don't see whether it would benefit either party. I don't -- I don't see where it would benefit the OCD or Hallwood.

Q. What benefit is there to chase one well with allowables? When, in essence, you're not

asking -- you're asking for an allowable that is more like an MER allowable. If this field was not prorated, would you produce it above 5 million a day?

A. Probably not.

Q. So the net effect of not having this field prorated would at the present time not have any effect on your marketing plans or production plans, would it?

A. The net effect from --

Q. If this field was not prorated today, what difference would there be in the field's history in the future for you to predict it or in the past, this proration period we're in right now? What difference would not having proration be effective in this field? What difference would that have right now if the field was not prorated?

A. From a production standpoint?

Q. Yes, production marketing standpoint.

A. It would probably have very little difference.

Q. But yet your testimony is that it's important to keep the field prorated. I can't understand that. If there's no difference in

production in marketing, why prorate? I guess you're saying, "Why deprorate?"

A. Well, exactly.

Q. I have a hard time understanding the value of proration in this field, what you're saying, Mr. O'Connell.

A. But proration was originally established by the OCD. And I don't see where the burden to deprorate falls on the operator.

Q. Would you feel differently if we gave you an allowable of a million a day for the No. 9?

A. Yeah. And that's where we were at and where we're trying not to go back to.

Q. I see. So it would make a difference if we, in our collective wisdom, if we decided to assign you an allowable of a million a day. You feel that would be necessary to deprorate the field?

A. Well, or continue with the processes. We've made some good headway, and I thought we were working cooperatively towards --

Q. Might I suggest you look at the recent order that was issued by this Commission, and don't just look at the results of the order, but

look at the findings and discuss that with your management.

A. Can I --

Q. Please comment, yes.

A. You would prefer, then, the operator, or us, you would prefer, as the Commission, to deprorate then; is that the way I'm reading it? The Commission is in favor of deprorating?

Q. I can only -- I can't collectively at this point put it in the record what we favor, but I think it's important when we issue an order to look at both the findings and the conclusions and the order itself. And I would just at this point ask you to look at the findings of that last order of the Commission.

A. Yeah.

CHAIRMAN LeMAY: That's all.

Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, I don't want to prolong the discussion on this point, but I don't think Mr. O'Connell needs to take the heat for that decision. It's my heat to take. I deprorated Burton Flat for Oxy. I know how difficult it is. I've spoken to Hallwood management about that process.

We are terribly aware of the order in the rehearing. Mr. Stovall and I, I think, have a significantly different point of view on prorationing. One of the comments he made in framing a question to Mr. O'Connell presumed that prorationing must restrict a high-capacity well.

As you know from the brief we filed in the rehearing of the Hallwood case, my personal opinion of that is that that is wrong, that it is easier for Hallwood in this particular instance to have allowables set based upon market demand and have allowables set on the greatest capacity of the well to produce.

There's an unknown here, and that is the drainage impacts. Mr. O'Connell has demonstrated to me repeatedly that this superpower well is going to be restricted. And when you have the capacity of a well restricted in order to meet market demand, you meet the fundamental criteria for prorationing.

Prorationing in New Mexico is market demand prorationing. And we only have it on a pool basis when the total pool deliverability exceeds the market demand for that pool. We tend to, I think, get confused in our thinking about

prorationing and sometimes use prorationing as a great big Band-Aid to protect against hypothetical drainage, disadvantages between recoveries of gas within a given pool.

I resisted making the burden of proof and the complicated engineering and reservoir studies necessary to demonstrate the drainage concept within the prorationing system. We had to do that for Oxy and Burton Flat. It is not easy. You simply don't file an application. Kevin and others have got to do some detailed geologic studies and some reservoir engineering recovery data to support that.

We're pursuing the notion of deprorating the pool, but based upon my legal opinion to that client, they have not undertaken that exercise because I have concluded it is very difficult. We'll take your comments today back to that company and reevaluate the position and see if we can't do something that makes everybody happy about this pool.

CHAIRMAN LeMAY: Thank you, Mr. Kellahin. I'd just like to point out, if I can, that because South Burton Flats had a shadow allowable of one-year period, that's not

necessarily a precedent-setting procedure for all pools that would be deprorated. I think there were 60-some wells that were subject to that deproration order.

I might suggest that you get together with counsel and in some way discuss the merits of implementing some of our findings in the previous order. Thank you.

MR. KELLAHIN: Thank you, Mr. Chairman.

CHAIRMAN LeMAY: Any additional questions of the witness?

Thank you, Mr. O'Connell.

Anything else on this particular field? Why don't we take a break now, if that's all right, counselor, and you can resume with your additional other witnesses.

(A recess was taken.)

CHAIRMAN LeMAY: Continue, Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman. Mr. Chairman, with your permission, I'd like to deal with my client's recommendations on the Blinebry Pool, it's Marathon Oil Company. I have two witnesses concerning that pool, a

reservoir engineer and a gas marketing expert. I'd like to first call Mr. Ron Folse. He spells his last name F-o-l-s-e. And he is the petroleum engineer.

I've already distributed our exhibit package. It addresses the Blinebry. Because we're dealing with the same case number, I have lettered Marathon's exhibits for the Blinebry, and then in the Indian Basin Upper Penn Pool, those exhibits will be numbered. We propose to utilize exhibit letters A through G for the Blinebry.

RONALD J. FOLSE

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

EXAMINATION

BY MR. KELLAHIN:

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

A. My name is Ronald J. Folse, F-o-l-s-e. I'm the Senior Reservoir Engineer with Marathon Oil in Midland.

Q. Mr. Folse, on previous occasions have you testified as an expert witness on behalf of your company concerning the Oil Commission

allowable hearings?

A. Yes, I have.

Q. What pool or pools did you previously testify about?

A. The Blinebry Pool.

Q. Are you familiar with the preliminary allowable schedule that was circulated with the docket by the Division for this hearing?

A. Yes, I am.

Q. And this morning, when you received Mr. VanRyan's revised schedule, have you examined that schedule?

A. Yes, I have.

Q. Based upon your studies and observations of the production, the allowables, and what you had been advised by your company as the market demand for production from this pool, do you have recommendations for the Commission for allowables for the Blinebry prorated gas pool?

A. Yes, I do.

MR. KELLAHIN: We tender Mr. Folse as an expert witness.

CHAIRMAN LeMAY: His qualifications are acceptable.

Q. Mr. Folse, before beginning our discussion, let me have you, sir, turn to what is marked as Exhibit A. Would you identify and describe that for me.

A. Exhibit A is the letter we, Marathon, sent out to all operators in the Blinebry Pool indicating our proposal to increase the monthly allowables to 45,000 Mcf per month for non-marginal wells.

Q. So that the Commission can understand where you and I will ultimately get with your testimony, let's take the Exhibit A that is the revised schedule, do you have that copy of that that was handed out this morning?

A. Yes, I do.

Q. Go down the Division preliminary schedule, as shown on the revised exhibit for the Blinebry and, without giving me the exact numbers, just generally describe where you recommend changes to be made so that ultimately the allowable assigned to the pool will give you an opportunity to produce a reasonable market demand for that production.

A. The line 1, the average monthly pool sales is 354,000 Mcf. I am proposing this

morning an adjustment on line 2 of 227,000 Mcf to arrive at a monthly pool allowable of 581,000. Line 5, 131,000, is the marginal pool allowable, subtracting that number from the line 4 results in a monthly non-marginal pool allowable of 450,000. And using a non-marginal acreage factor of 10 results in a line 8 of 45,000.

Q. Let's describe your allowable request level in terms of the last line entry, the 45,000 Mcf number. How does that compare to the allowable that was applied for the pool on the last proration schedule?

A. The 45,000 is the comparable to one-and-a-half million cubic feet a day --

Q. Yes.

A. -- for 1 acreage factor. And the previous request by Marathon was 50,000.

Q. Let's turn to page 2 of the exhibit, which will be Exhibit B in the package. Identify and describe for us that display.

A. This is a map of the Blinebry Pool with the marginal and non-marginal gas wells indicated. The smaller dots are for marginal gas wells. The larger dots represent the non-marginal gas wells. As in the left lower

corner, the different colors represent different gas transporters.

Q. Do you recall from memory and can you describe for us the general number of marginal wells and non-marginal wells in the pool?

A. Generally there are approximately 97 total wells in the pool of which 14 wells are non-marginal.

Q. Turn to Exhibit C. We might want to go ahead and use Exhibit C to let you edit that exhibit. Am I correct in understanding it was a demonstration of Marathon's allowable level request in the far right column as it compares to the preliminary schedule issued by the Division in the docket and does not yet reflect the revised Division allowable estimates?

A. That is correct.

Q. Help us edit this so that we understand what your allowable requests will be based upon the current revised schedule.

A. Based on my current revised schedule, to go along with the update, based on Exhibit A as proposed by the Commission today, line 1, the average monthly pool sales would require revision to 354,110. An adjustment, as we've proposed

here in the right-hand column, instead of 205,955, it needs to be revised to 227,241 for a revised monthly pool allowable of 581,351.

Based on the Exhibit A proposed today, the monthly marginal pool allowable is then 131,351. The monthly non-marginal pool allowable would then be 450,000. The number of non-marginal acreage factors would then be 10, as in Exhibit A, resulting in a monthly acreage allocation factor of 45,000.

Q. Describe for me the conclusion you reached from examining Exhibit D, which is the next display.

A. Exhibit D is the allowables, sales, and overproduction status of well Lou Worthan No. 9, one of Marathon's non-marginal wells.

Q. Why did you select this particular non-marginal well for presentation?

A. We selected this particular well. It is one of two non-marginal wells that Marathon currently has. And at the end of the period, based on the increases in allowables for the current proration period, we can see that the sales are exceeding the monthly allowable.

Q. When you look at the last months of

entry in January 92 and look at the comparison of the relationship between the allowable, which will be the blue line that's horizontal, there is a slight decline in sales. What is happening in January and what is the forecast for February and March for production from that well?

A. The production or monthly sales from this well in January is 46,320, which is a decrease from December of 50,130. With early production data in February, we have projected that production would be 45,192.

Q. Forecast of production, then, is not going to follow the decline established in January for sales in that well?

A. That's correct.

Q. In your opinion, do your two non-marginal wells have the deliverability or the capacity to produce their share of the allowable to be assigned on your proposed allowable level?

A. Yes, they do.

Q. Let's turn to the production on the other non-marginal well that you operate in the pool. Identify and describe this display.

A. This is a graph of the allowables, sales, and overproduction status of the Lou

Worthan No. 12 Marathon-operated well.

Q. This is Exhibit E?

A. Exhibit E.

Q. Okay.

A. The graph is similar to the numbered previous exhibit and indicates that the well's production is currently over the allowables of 38,125.

Q. Describe for us your forecast of sales and production from this well in relation to its allowable?

A. The production, as indicated here, in December peaked at 54,313. The January sales figure was 47,970. A projected February production will be approximately 45,000.

Q. Turn now to Exhibit F and identify and describe that display.

A. Exhibit F is the graph of all the non-marginal wells Marathon operates, which there are four, indicating in particular in the last several months that Marathon has equaled or exceeded the current allowables of over 125,000.

Q. All right. Let's turn to Exhibit G.

A. Exhibit G is the graph of the Blinebry Pool total Marathon operated wells, including

marginal and non-marginal wells, indicating sales are exceeding the total allowables of our wells.

Q. Having studied the production of your wells and the ability of those wells to produce, what is the relationship of that productivity to the anticipated reasonable market demand for production from your wells for this next proration period?

A. The market demand currently exceeds deliverability.

Q. When you look at the past proration period, what is the status of the pool on a pool basis between being overproduced or underproduced in terms of the allowables; do you know?

A. The current status of all non-marginal wells in the pool is underproduced.

Q. And when you look at the status of your wells, they are overproduced on the allowable, are they not?

A. That is correct, yes.

Q. But they are within the O/P limit for that production?

A. That's correct.

Q. From your perspective as the engineer involved in this particular pool for your

production, and not addressing the marketing issues I'll talk to the next witness about, summarize for us your conclusions about the justification for your allowable request.

A. I guess, first of all, we pool production right now. Market demand for the pool production exceeds total pool deliverability. Marathon is able to sell all its gas production, and we believe that other operators have adequate markets to sell all of their gas that they can produce.

Also, the proposed allowable for the total pool of 581,351 is not in excess of market demand and, if anything, is less than market demand.

Q. What is your ultimate conclusion, then, about the level of allowable request that you're seeking for the pool?

A. The ultimate conclusion is that we wish to be allowed to produce at the requested rates, 45,000.

MR. KELLAHIN: That concludes my examination, Mr. Chairman, of Mr. Folse.

We would move the introduction of Marathon Exhibits A through G.

CHAIRMAN LeMAY: A through G will be admitted without objection.

Questions of the witness?

Mr. Padilla.

MR. PADILLA: Let me get up here, Mr. Chairman.

EXAMINATION

BY MR. PADILLA:

Q. Mr. Folse, did I understand your testimony that the total pool allowable was underproduced?

A. That's correct, yes.

Q. Could that be a reflection that there is an adequate market for selling gas from that pool?

A. There is a possibility. Could be the possibility that producers are curtailing production also.

Q. But one may be the possibility that there is an inadequate market; therefore, there is no production; correct?

A. The possibility, I guess.

Q. Did you endeavor to find out what the total market deliverability for the pool was?

A. I believe our marketing people will

answer that question. I did not.

Q. As I understand your testimony, you're projecting a total demand for the pool based upon what Marathon's market is; isn't that correct?

A. That's correct.

Q. You did not go out and find out whether other producers had markets for sale of gas in that area?

MR. KELLAHIN: Mr. Chairman, with all due respect to Mr. Padilla, I think those questions are more appropriately addressed to the marketing expert.

CHAIRMAN LeMAY: As I understand, he'll have a marketing expert that will either provide those or be able to --

MR. PADILLA: Well, Mr. Chairman, if I may respond to that, he did testify to market demand, and I'm asking those questions in terms of what his knowledge is about market demand.

CHAIRMAN LeMAY: Counsel, do you want to address that? I did hear some comments by the witness concerning market demand.

MR. KELLAHIN: No. All questions about market demand were predicated on what his company expert had told him what market demand was for

the pool, and in relation to that, then, he has described what his wells can produce.

CHAIRMAN LeMAY: So his expertise was limited basically to the response of what the wells could produce, but the market demand was an assumption that he was given.

MR. KELLAHIN: Sure. And he gets that assumption from Mr. Hastings, who's sitting right here, eagerly willing to answer Mr. Padilla's questions.

CHAIRMAN LeMAY: Fine. Thank you.

Will that be acceptable, Mr. Padilla and Mr. Hastings?

MR. PADILLA: I'll talk to Mr. Hastings about market demand. I will continue.

Q. Let me go on to the, I believe on your Exhibit E -- and I don't have a copy of that -- you were testifying concerning the No. 12 well?

A. That's correct.

Q. Can you tell me how that well got to the state of being overproduced?

A. It arrived at the state of overproduction, as can be seen on the graph, beginning in January 1989. The graph comes in through the period of January 92. The graph

indicates the allowables, sales, and overproduction status of the well.

Q. Doesn't that show the major times that you were selling gas would be during the wintertime?

A. In previous years, these wells were being produced as per proration schedules under the production guidelines of following the proration schedules. The current production management by Marathon is, as opposed to previous years, we are producing the wells pretty much capacity at what we are allowed to produce.

Q. Now, I notice up here starting in January of 1989, it seemed like -- well, first of all, what does the red line indicate?

A. The red line is the overproduction status of that well on a cumulative basis.

Q. And starting in January through about April of 1989, it became overproduced starting back there; isn't that correct?

A. Prior to January 89, it had an overproduction status over 40,000.

Q. Then you had another peak in January of 1990 after that; isn't that also correct?

A. A peak of sales?

Q. Of production or sales. I'm not sure what that second line is.

A. The green line is sales.

Q. Okay. So your sales were essentially during these periods January through April and January through April of those years; correct, 1989, 1990?

A. That's correct, in those years.

Q. And then going into, starting in the fall of October of 1992 -- or 1991, I should say, you start another increase on sales?

A. That's correct.

Q. So is it fair to say that your sales generally occur during the winter months or on some seasonal basis?

A. That is basically what occurred in this case, was as a result of production restrictions on the lower months, in the summer months.

Q. Does this exhibit show how this well conforms the allowables during the time that you don't have those peaks?

A. Repeat the question.

Q. In other words, you have peak sales from January through April 1989 and from January 1990 through April and then, again, in the latter

part of 1991, you also have a peak increase. In terms of monthly production, between, say, July or April of 1990 and October of 1991, it seems to level off. How do allowables in production conform during that time?

A. Production was driven by allowables through those periods.

Q. This draft seems that it's pretty -- that they conform pretty well to each other during that time. How about on the -- on your Exhibit D, do we have the same scenario on that No. 9 well as we had on the No. 12 well?

A. Yes, we do.

Q. Let me go back and ask you about -- you indicated that you, Marathon, owned four non-marginal wells; is that correct?

A. That's correct, yes.

Q. On the other two non-marginal wells that Marathon owns there, do you have an overproduction problem?

A. We have no production problems. They are not producing over the current allowable.

Q. Why is that?

A. The capacity of those wells are not as great as the two wells we've presented here, the

deliverability.

Q. And those wells are not overproduced?

A. I believe they're slightly overproduced at the current time. They are overproduced at the current time.

Q. Are they out of range as far as overproduction is concerned with the -- compared to the two wells that you've shown on Exhibits D and E?

A. They are are not as much overproduced as those two are.

Q. How about, Mr. Folse, the remaining ten non-marginal wells in the field, are those wells overproduced?

A. There appears to be through the December report one well that is currently overproduced. The other wells appear to be underproduced.

Q. Essentially, it seems to me, that this is a Marathon problem as far as overproduction is concerned; isn't that correct?

A. A Marathon problem of being overproduced?

Q. Overproduced on its four wells.

MR. KELLAHIN: Object to the form of

the question. I think it's argumentative the way it's framed.

CHAIRMAN LeMAY: You probably ought to rephrase the question, Mr. Padilla, and rephrase it.

MR. KELLAHIN: The problem is equally attributable to low allowables.

CHAIRMAN LeMAY: I'll remind counsel he is incompetent to testify as a witness.

MR. KELLAHIN: Even when I'm right, Mr. Chairman.

MR. PADILLA: I don't know whether that's an objection, Mr. Chairman, or whether it's --

MR. STOVALL: I think it's banter between the Chairman and counsel.

CHAIRMAN LeMAY: Just a little bit of fun, Mr. Padilla. But you might want to rephrase the question.

MR. STOVALL: Mr. Chairman, if I might just ask the question, it is not in the form of an objection, but I've got a -- I've been listening to the questioning and trying to, as I pointed out, the Division is not really an advocate of anything at this point. It's created

a starting point.

And it would be most helpful, I've asked Mr. VanRyan if he understands what Mr. Padilla's concerns are with respect to Marathon's testimony, and he doesn't and I don't know. I don't know if the Commission does or not.

But I wouldn't mind if Mr. Padilla would mind if he would explain his concerns so that we can put his questions into the context of those concerns and evaluate the witness' testimony in response to those concerns. It's not very helpful to us at this point, from the Division's standpoint anyway, I don't know about the Commission.

MR. PADILLA: Let me explain, Mr. Chairman, there is a request before the Commission to increase the allowables to 45,000. We have in our prepared statement, and that's all the testimony -- it's not even testimony; it's merely a statement that we intend to read into the record. We provided that yesterday to Mr. Stovall and Mr. Kellahin.

MR. STOVALL: I was in meetings all day yesterday, so I apologize for not having seen that.

MR. PADILLA: Our position is contained in that. We feel that the allowables are simply going sky high. And manifested by Mr. Folse's testimony, it seems to me that Marathon intends to solve an allowable overproduction problem through increasing allowables. It's simply that.

The following question I would have of Mr. Folse is simply whether or not an increase in the allowable to 45,000 would solve Marathon's problems over the next six months.

CHAIRMAN LeMAY: I think that's a fair question.

Mr. Kellahin?

MR. KELLAHIN: I'd like to have the witness answer.

CHAIRMAN LeMAY: Fine. Thank you.

THE WITNESS: The increased allowable to 45,000 --

MR. PADILLA: Yes, sir.

THE WITNESS: -- would bring more into line Marathon's overproduction.

MR. PADILLA: I don't believe I have any further questions.

CHAIRMAN LeMAY: Thank you.

Mr. Kellahin.

MR. KELLAHIN: Mr. Chairman, I think Mr. Stovall's point is well taken. I'm a little at a disadvantage to put my witnesses on and then have Mr. Padilla read a statement on behalf of Mr. Hendrix.

I would request that that statement be distributed to the Commission now so that my witnesses can deal specifically with the concerns that Mr. Padilla's clients have, and we can stop fishing around on things that are of no consequence. I would like the statement in now so that we can comment on it.

CHAIRMAN LeMAY: That's up to Mr. Padilla. Generally statements aren't subject to cross-examination. They're strictly put in the record for the Commission's consideration. But if he cares to distribute it now, that's fine.

MR. PADILLA: I have already distributed it to the Commission this morning, Mr. Chairman. I would be happy to read it at this time if that's convenient.

CHAIRMAN LeMAY: Would that be beneficial to you, counselor?

MR. KELLAHIN: Mr. Chairman, I can

read. I've got a copy of it. I simply want the opportunity of my witnesses to comment on what's contained in the written statement. If the Commission wants to have Mr. Padilla read it to us, I guess that's within your discretion.

MR. STOVALL: Mr. Chairman, if I might make a comment on that. Just in the context of it, again, I apologize, as I say, to Mr. Padilla for not having read it yesterday, but I spent the entire day in other meetings.

I view the allowable hearing as a non-adversarial information-gathering hearing for more of a rule-making for the Commission, and I certainly think that anything that comes in, the more you understand the context in which it comes in, the better you're able to evaluate it. If we could read it, I think it would be great.

CHAIRMAN LeMAY: I don't think the Commission is stupid. If we are, we shouldn't be here. We understand you have overproduced wells. And we understand that if you want some higher allowable, to get that under. We understand Mr. Hendrix has underproduced wells for whatever reasons. I think that's obvious.

You can play around with those concepts

if you want, but I think -- I can't see where there's any ambiguity in what the positions are. I've not read the statement, but it seems fairly obvious to me where the parties are coming from.

MR. KELLAHIN: Well, the positions are clear; it's the reasonings that need to be discussed.

CHAIRMAN LeMAY: That's why we're having your witness here under cross-examination.

Please proceed, Mr. Padilla.

MR. PADILLA: Well, at this point, Mr. Chairman, let me read our statement, and then Mr. Kellahin can redirect on that basis.

CHAIRMAN LeMAY: I don't think we've had a long-standing policy that statements are not subject to cross-examination. If it would help to clarify your position, please read it. But it's not something that's subject to cross-examination, unless you have a witness who wrote the statement that you want to put on.

MR. PADILLA: I don't, Mr. Chairman.

CHAIRMAN LeMAY: Fine.

MR. PADILLA: The John Hendrix Corporation operates 66 wells covering 3,440

acres in the Blinebry Pool. The Hendrix Corporation proposes a decrease in the monthly acreage allocation factor (F1 factor) for Blinebry non-marginal wells from 24,906 Mcf per month to 21,840 Mcf per month, which was the average pool allowable for 1990 and was sufficient to economically and efficiently produce from the pool. In 1988, the allowable was 12,180 Mcf per month, and the 1989 allowable was 15,420 Mcf per month.

Our principal reasons for proposing a decrease in the allowables are, one, an increase in allowables will further flood the gas market with gas, in great part due to Canadian imports in San Juan coal seam gas. Two, the price for gas has fallen below its replacement cost.

In support of the foregoing, we call the Commission's attention to Northern Natural Gas Company's most recent spot market pricing letter, which set March prices at 90 cents per MMBtu for gas well gas and 80 cents MMBtu for casinghead gas. A copy of that letter is attached hereto as Exhibit A.

To continue to increase gas allowables and further flood the market with gas production

can only result in one thing: continued weaker gas prices. This is contrary to the interests of the state of New Mexico, as we will have to produce substantially more gas for the same or less economic term resulting in waste. Waste has been statutorily defined as production from any gas well or from any gas pool in excess of the reasonable market demand.

The simple result of any Commission action that would deliver gas to an already saturated marketplace would be a decrease in prices leading to a premature abandonment of gas wells. This would result in waste and would be violative of correlative rights of the producer, mineral owner, and the state of New Mexico.

By decreasing allowable gas, recovery will be maximized, and the waste of this precious natural resource would be prevented. Controlling the market by providing cheap gas is not in the best interests of the State of New Mexico.

CHAIRMAN LeMAY: Thank you, Mr. Padilla, for that philosophical statement. We appreciate your input. That's not subject to cross, and we'll put it in the file for consideration.

Are there any additional questions of the witness?

MR. PADILLA: I have none.

CHAIRMAN LeMAY: Thank you.

Do you have any redirect?

MR. STOVALL: I have some questions, if I might.

CHAIRMAN LeMAY: I'm sorry. Excuse me, Mr. Stovall.

EXAMINATION

BY MR. STOVALL:

Q. The first question I've got with respect to the Exhibit A, you've apparently sent this to all operators in the pool; is that correct?

A. That's correct.

Q. I assume that you're satisfied that Mr. Hendrix, at least, has answered the letter with a non-concurrence?

A. Correct.

Q. Have you heard from any other operators in the pool? Have you gotten any responses?

A. I have heard from Conoco, and I have discussed the proposed increased in allowable with Chevron. And Conoco had basically no

problem with our increase in the allowable, and Chevron at that time felt the same way.

Q. Let me ask you, looking at Exhibit B, that probably is some corporate relationships I'm not exactly clear on, and I don't want to make any assumptions. I don't see Conoco or Chevron either as operators on Exhibit B.

MR. KELLAHIN: Those are transporters.

MR. STOVALL: Oh, I'm sorry. I thought they were operators. Then I withdraw that question.

Q. Your letter also states that you would like to raise the F1 factor to allow wells to produce at their capacity; right?

A. That's correct.

Q. Now, presumed in that, we'll let your marketing expert testify as to that, but there is a presumption in that request that there is a market, notwithstanding some of the price issues that Mr. Hendrix raises, that there is a market for all of the gas which the pool is capable of producing; is that correct?

A. That's correct.

Q. Are you familiar with the New Mexico statutory scheme for proration and the

requirements for proration?

A. For the southeastern area?

Q. No. I'm talking about the statute and why proration exists and what the language of that statute is?

A. No.

Q. At the risk of opening a box of Pandora's, as we so fondly refer to it in New Mexico --

MR. KELLAHIN: Pandora left the box earlier this morning I think, Mr. Chairman, and if Mr. Stovall wants to engage in a legal discussion with my engineer, I would resist that.

CHAIRMAN LeMAY: I think -- this is an engineer, Mr. Stovall. We are opening a lot of boxes here with the philosophical comments that are coming forth and statutory comments.

Please, if you would, just direct your cross-examination to the expertise of the witness, which he's an engineer.

MR. STOVALL: I think I'll save the questions for the marketer.

CHAIRMAN LeMAY: If he's legally competent to answer, I would say that's fine.

Additional questions of the witness?

EXAMINATION

BY COMMISSIONER CARLSON:

Q. What percent -- we have the total production from the comparable period last year. Marathon operates four non-marginal wells. What percent of that total production is from Marathon's wells?

A. On the non-marginal wells?

Q. Well, let's do non-marginal and marginal, Marathon's production.

A. It would appear to be about 25 percent.

Q. And what percent of the deliverability from the field is attributable to Marathon wells; do you know?

A. Right offhand, I do not.

Q. And you said you had heard from two operators within the field, is that Conoco and --

A. And Chevron.

Q. -- and Chevron. How many non-marginal wells do each of those companies operate?

A. Conoco has at this time no -- they have all marginal wells. Chevron has five non-marginal wells.

Q. Is Chevron on those non-marginal wells,

have they overproduced or underproduced?

A. Of the five, one is overproduced through December's statement.

CHAIRMAN CARLSON: That's all I have.

CHAIRMAN LeMAY: Commissioner Weiss.

COMMISSIONER WEISS: I have no questions.

CHAIRMAN LeMAY: I have one.

EXAMINATION

BY CHAIRMAN LeMAY:

Q. I guess I'm five short. You have four. There's ten other non-marginals. Does Mr. Hendrix own the other five non-marginal producers in the field?

A. Mr. Hendrix has one non-marginal well. Mobile has one non-marginal well. Arco has one well. Exxon has one well. And the list I'm looking at is based on 10.25. And Texaco has one non-marginal well, with the revision to it of 10.0. I haven't been able to look at that statement yet.

Q. That's fine. That will be helpful. You said you had a no objection. Is that to be interpreted as neither support nor objection? Did any of the operators support your increase in

allowables?

A. In discussing with Conoco and Chevron, they basically had no objection. There were -- those were the only discussions we had, and we had no support for the increased allowable.

Q. Did you hear from Mobil, Arco, Exxon, or Texaco concerning your request for higher allowables?

A. We did not.

Q. Did you contact them?

A. We did not.

MR. KELLAHIN: You contacted them with this letter.

THE WITNESS: Yes, with the letter.

CHAIRMAN LeMAY: Thank you, counselor. Additional questions of the witness?

MR. KELLAHIN: No, sir.

CHAIRMAN LeMAY: If not, he may be excused.

Call your next witness, counselor.

MR. KELLAHIN: Mr. Chairman, I'd like to call Mr. William Hastings.

WILLIAM H. HASTINGS

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

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Hastings, would you, please, state your name and occupation.

A. My name is William H. Hastings. I am supervisor of resale and marketing in natural gas property development for the western United States, Marathon operations, as well as western Canada.

Q. Within your area of responsibility for marketing Marathon's gas, does it include production out of the Blinebry Pool?

A. Yes.

Q. Describe generally what it is that you do with the production out of the Blinebry Pool, and then we'll talk about the Blinebry Pool specifically. Just describe for me your area of responsibility.

A. Well, my area of responsibility encompasses a number of Marathon's operations besides just New Mexico: Wyoming, Alberta, Oregon, New Mexico, instate California, Oklahoma, Texas. Our primary focus in this area is to sell base load. And by base load, I mean non -- non-seasonal users of gas for industrial

purposes. And that's our primary focus.

Q. How long have you had this responsibility for your company?

A. I've been in the western United States for five years now.

Q. Prior to working for Marathon, were you working in gas marketing in the industry for another company?

A. No. I've been with Marathon for twelve years, and prior to being in natural gas trading, I was in foreign exchange trading in our Ohio office, at that time corporate office.

Q. Would it be within the scope of your expertise to know what the reasonable market demand is for production, not only from the Marathon wells, but the market demand for production out of the Blinebry Pool?

A. Absolutely. Yes.

MR. KELLAHIN: We tender Mr. Hastings as an expert witness.

CHAIRMAN LeMAY: His qualifications are acceptable.

Q. Let's talk first in some generalities about how the gas marketing system works for production out of the Blinebry. Give us a quick

lesson in how that production is taken to market.

A. Well, there's a nomination process for each pipeline transporter that is in the area. We have agreements, transportation agreements, with each of the pertinent transporters to move the gas downstream from the wellhead.

It right now can go to -- in any of three directions into Arizona and New Mexico to some copper smelting companies that we sell gas to. We are in the midst of moving a large quantity of gas into the Houston ship channel across Texas.

And then the third option is to move gas to Chicago to the distribution companies and industrial plants in the Chicago area and fertilizer plants upstream from Chicago in Kansas and Iowa.

We have long-term contracts with a number of these companies. And we generally stick to the same production area each month, although we vary production allocations to these different customers depending on what we perceive the operational problems to be in that field. But generally for Blinebry, we've flowed it to

the copper smelter.

Q. Is there a market demand for production from the Blinebry that is accurately reflected by Marathon's proposed allowable limits?

A. Yes. The market demand, because of the price situation that we have now, is actually stronger than it was when prices were higher. And as we get into it, I think I can demonstrate that.

Q. Do you perceive, if the Marathon allowable level request is approved, that there will be any discrimination between the various transporters of gas taken from this pool?

A. Well, I would propose that if the allowable is approved as we have requested and there are other partners in the area in the same pool that cannot market their gas, we would purchase the gas from them to keep them from being harmed by the potential drainage or whatever.

We have enough market to satisfy the entire pool, not just Marathon's pool, but the entire pool requests.

Q. Are you --

A. I'm sorry. That price is significantly

above what Hendrix brought before the table earlier.

Q. Are you currently aware of any distribution or gathering -- let's start with the gathering. Are you aware of any particular gathering problems among the transporters within the pool so that their wells would be impaired or their ability to get gas to market would be impaired at Marathon's allowable level request?

A. No. The gathering issue is not at issue. If it were, it would be because of higher line pressures, which would be in excess or an extra supply of gas moving into the system that wasn't anticipated. In that case, there are a number of wellhead compressors that can meet that line pressure if there is an increase.

But in speaking with Northern, as was presented six months ago by Mr. Gilbert, there is no concern that line pressure would increase.

Q. What about the distribution system, then, after the gas production is gathered? Are there any constraints or limitations within the distribution system to take the gas from this pool to market?

A. Prior to a week ago, there may have

been from time to time. But with the opening of the Transwestern San Juan lateral, the expansion of the El Paso system out of the San Juan Basin, with the opening of Kern River transmission from Wyoming to California, with the expansion of the Northwest Pipeline System from Wyoming into the San Juan Basin, there's plenty of space.

Space won't be a problem for the next ten years. I think Mr. Merrett pointed that out earlier.

Q. You've had an opportunity to review Mr. Hendrix' statement that was provided as part of the attachment to the prehearing filing, have you not, Mr. Hastings?

A. Yes, I have.

Q. Mr. Hendrix states two principal reasons why he proposes a decrease in allowable. Do you have that statement before you?

A. Yes, I do.

Q. One of the first things he addresses help with the proration system is to keep allowables low because an increase in allowables would further flood the gas market with gas, in great part due to Canadian imports in the San Juan coal seam gas. Do you concur in that

statement?

A. I absolutely disagree --

Q. Why?

A. -- completely. I have a long answer for that, somewhat long answer. We're facing a crossroads right now in the state, in this state in particular. I can tell you that because I'm selling gas in Wyoming, and we move gas from Alberta. And we move gas from the San Juan Basin, coal seam gas, unprorated.

We are facing a critical point right now. If we cannot secure some long-term markets, there are new pipelines proposed over and above the ones that have been completed already -- I'm talking about two from Canada into California -- that will completely take away the market that we've enjoyed with our New Mexico wells for all these years unless, unless we can move gas on an unrestricted, reasonably unrestricted basis for a long period of time. And that's exactly what we're trying to do right now.

If we don't do that, if we don't, if we're not able to move our gas on an unrestricted basis, the Canadian companies will secure the California markets with 15-year contracts. The

Canadian companies will move into the Houston area and secure the very markets I talked about earlier on a 15-year basis. And our New Mexico production will be relegated backwards to a pure-swing production. And that swing will become worse and worse as the base load disappears.

And I think that unless we do something right now, within six months, before the Canadian lines begin construction, we're going to be faced with a very, very severe problem with New Mexico wells.

And what will have happened will be that the Alberta production outside the United States will be imported into the United States and replace the prorated production that we have right now in southeast New Mexico.

Q. Can reduced allowables under a prorationing scheme that sets those allowables less than current market demand have a positive impact on price?

A. No. The gas that we're talking about in southeast New Mexico is an absolute drop in the bucket. To give you an idea, the new capacity from Wyoming, which is mostly -- or will

be mostly tight sands credit gas -- is 700 million a day. That wasn't there last year.

When Altamont is finished, the Kern River capacity will go to 1.5 Bcf a day. That wasn't there last year. The El Paso expansion out of the San Juan Basin will result in an incremental of 300 million a day of gas going to California and an incremental of 340 going eastward. That wasn't there last year.

And, lastly, the Transwestern lateral will result in an incremental of 340 million a day going to California and another 300 going eastward. So we're facing some very, very stiff competition, and we're facing it now. We've seen it already with the new lines opening up. And we need to be able to tell our markets that we're going to get them the gas.

Q. What will happen to the Blinebry Gas Pool production's share of the gas market if the allowables are set low and that gas stays in the reservoir? What happens to its share of the market?

A. I think if you look at the numbers with the proposed capacity of 2.3 to 2.8 Bcf a day into California, the market itself is already

served by 4.3 Bcf a day capacity. The market burns 5 Bcf a day. Seven hundred million a day is produced in the state. We have approximately 50 percent more capacity into California with all these projects than is needed right there.

Now, I don't need to tell you that in an open market, free entry and exit system, that that means price competition at the border in California. It is anticipated at current growth rates, California grows with a good growth rate at 1.5 percent year on year. It will be ten years before all of those pipelines are full.

What we're trying to do now is to capitalize on what we see as a long-term price problem and get some long-term markets at what we think are premium prices.

Q. In your opinion, as a gas marketer, is it good market strategy for Hendrix to underproduce their wells in the expectation that that might have some influence on price?

A. Well, just the opposite. If we're forced to underproduce or shut-in, if we're forced to do that, if we have to do that, what we have is an impaired investment. We've already invested the money, as has Hendrix.

Our outside auditors every year look for underproducing assets. If we're not able to produce gas, a certain amount of gas per the amount of reserves that we have on the books, then we're forced to right them down.

So I would say that if we're forced to shut them in, that would be a premature abandonment of the property because we would have to write them down as nonfunctional assets versus being able to sell the gas now and purchase whatever the other producers in the pool can't sell.

Q. Can the use of the regulatory prorationing system be one that would influence price based upon volume taken out of the pool?

A. No. I think the proration system hasn't influenced price. The proration system has prevented a certain portion of gas, the conventional gas in this state, from finding long-term markets.

The gas from Alberta, gas from Wyoming, the San Juan Basin coal seam gas all have 15-year commitments to the pipelines that were built, and they're trying to match that up with 15-year contracts in California. We cannot do that with

prorated gas.

We can do it with Wyoming gas. We can do it with San Juan coal seam gas. We have a very tough time doing it with prorated gas because of the uncertainty that the market perceives with a prorated gas flow. They can't afford to have their plant go down because the proration volume drops. They just can't afford it.

Q. The second principal reason Hendrix cites for opposing Marathon's allowable level request is the price for gas is falling below its replacement cost. Do you have any comments or observations or opinions about that?

A. I disagree with that. I think replacement cost is not defined here. I don't know what's being addressed through the term "replacement cost." I assume it's the cost of reserves, the cost to develop reserves.

Right now, at the risk of giving away confidential information, an average well to the Blinebry in Tubbs, and there are other formations, costs $600,000, $500- to $600,000.

At current prices, at the contract prices we're proposing, would generate with 1.5

million a day, which is the standard production rate from the well, will generate $789,000 a year in revenue before severance tax is paid to the state.

So we expect at prices now, with the low unit drilling costs, that the well would still pay out in one year and the state would receive severance taxes on production that wouldn't ordinarily be there.

I guess my overall point is we're sitting in this room right now and we've seen graphs from Mr. Merrett, and if you notice, Mr. Merrett did not put any data up there on Canada. And Canada is absolutely flooding the US market with gas.

We haven't seen the data. If you'd like to see the data at a later date, I can get it to you. They are coming into this country, and they are going to take our markets, our domestic production markets, with 15-year contracts.

And unless we do something now, even next year might be too late. I really think that next year we're going to lose out on some of these that we have already unless we do something

now or we're going to go back to a swing, a very sharp swing on production status.

Q. From your perspective, do you see a seasonal swing in the present or in the near term for gas production out of this prorated gas pool?

A. Well, it was mentioned early, Gas Company of New Mexico. Gas Company of New Mexico is a seasonal buyer. They are mostly serving the homeowner in Santa Fe. The industrial loads that Gas Company of New Mexico have had have been taken by producers like Marathon, like Chevron, that transport the gas downstream.

We currently sell to the Centex plant north of Albuquerque, to the University of New Mexico. We're working on Kirtland Air Force Base. We sell to a number of smaller wood products companies.

All of those used to be served by Gas Company of New Mexico. They are no longer served. That base load has gone away to long-term contracts. And so Gas Company of New Mexico itself has become a larger and larger swing buyer.

Our markets are addressing the Clean Air Act. The Clean Air Act has mandated

reformulated gasoline. And the primary reformulator is methyl tertiary butyl ether, which uses natural gas as a feedstock.

Those Mtbe units are being built right now. We're selling 8 million a day to one in Wyoming. And there's one in Houston, Texas, that we're trying to serve with this gas as a feedstock, which means that except for when the plant has a turnaround, the gas is going to flow everyday of the year.

MR. KELLAHIN: Thank you, Mr. Chairman.

CHAIRMAN LeMAY: Thank you.

Questions of the witness?

MR. PADILLA: I don't have any Mr. Chairman.

CHAIRMAN LeMAY: Thank, you Mr. Padilla.

Additional questions?

Commissioner Carlson.

EXAMINATION

BY COMMISSIONER CARLSON:

Q. Are these contracts that you're selling Blinebry gas, are they 15-year contracts?

A. The contract with Lyndel is five, five years with a rollover. And the contract with

Phelps-Dodge is five years. And the contract with Union Carbide will be ten years.

Q. Are those warranty contracts? Are they like basin-pool specific?

A. They are not warranty contracts. They are not basin-pool specific. We can get gas -- well, we try and use Marathon gas. We try not to buy gas. There's gas in Texas. There's San Juan gas that's available. But we'd rather use the Marathon gas because we've invested money to get that deliverability. But it's not basin specific.

Q. So the purchaser doesn't know if it's prorated gas or not that he's purchasing?

A. He does. The purchaser does know that it's prorated gas. We do not have the option to curtail, based on government regulatory production limits, we don't, because those production limits are not in place.

For instance, in Wyoming there is no limitation up there. No limitation rules. None in Colorado. Up until this point, there hasn't been any in Oklahoma.

And, really, New Mexico has been the one state that has prorated fairly strongly. And

as a bottom line, we don't have the right to cut them back. If they get cut back by a proration, then we've got to make up what their added cost is, if we can't come up with the gas.

Q. Right. He doesn't know if he's buying gas from a specific pool in New Mexico or buying gas from one of your other properties?

A. It used to be that they didn't, and then they wound up getting burned. And I think now, the Lyndel Petrochemical, for instance, burns 210 million cubic feet a day. It's a huge complex. There's actually two complexes.

They know what's going on. And they know -- they want to know where they're buying the gas. They don't want to be kept in the dark. If you can't tell them, then they'll find somebody else.

So the buyers are becoming very sophisticated under the new market system.

COMMISSIONER CARLSON: That's all. Thank you.

CHAIRMAN LeMAY: Commissioner Weiss.

EXAMINATION

BY COMMISSIONER WEISS:

Q. Are there others that share your views

on the threat of Canadian gas? Is that well-known?

A. I think it's well-known. If it isn't, it's going to be this month. I think, if you look at what prices were last year and the year before that and the year before that, before the Canadian gas showed up, then some people are asking how come prices are so low, and the answer is that the Canadian imports have gone up on an annual rate of 8 percent for the last four years. And they're expecting to go up at 6 percent per year for the next four or five years. That's the answer.

And I think if people don't realize that, then they're going to find out pretty quick with Kern River open and with the Pacific Gas transmission line being built. But I do think that -- I don't know if there's anyone else out here that would care to support me, but I do think that most people realize now, and the trade publications especially, that we have a real problem with excess gas coming from Canada.

EXAMINATION

BY CHAIRMAN LeMAY:

Q. You've raised so many interesting

issues. I'm not going to get into all of them, Mr. Hastings. But your responsibility is the western states; you don't buy gas from Oklahoma or Texas?

A. We buy in Oklahoma, and we buy gas in Texas.

Q. Don't you have prorated fields in both those states?

A. We do not. We do have proration rules, but the proration rules in Oklahoma are different. They are not based on -- whatever we think we can produce, we get to produce. It's not a question of limiting production versus what we think we can produce.

Q. Then with the assumption that this current law in the legislature would not go through?

A. Assuming that the current law will not go through, and we have reason to believe that the Associated Gas Distributors in the northeast are going to file a claim or an action to try and stop it. Even if, even if it gets in place, they're only proposing to cut 400 million cubic feet a day. And, again, that might sound like a lot of gas; it's a drop in the bucket, because

the Canadians are proposing 1.5 Bcf a day of added pipeline capacity.

So we have doubts and we've testified to that effect in Oklahoma City last week that those proration rules will cause big problems for the state of Oklahoma and cause big problems for some of the producers in there.

You've just got to take a look at the global picture and stand back a little bit and see what's happening to us. We've got to quit arguing amongst ourselves in these states and look at Canada a little more closely.

Q. In that regard, can I ask you a little clarification on a couple of your statements?

A. Yes.

Q. One, were you assuming that both Altamont and/or PGT would be that PGT expanded and Altamont built?

A. Yes.

Q. Is that your statement? Do you happen to know if they've gotten clearance from FERC or if they've gotten -- needed expansion?

A. PGT and Altamont have -- PGT has FERC clearance; Altamont, I'm not sure of. Both of them have issued irrevocable letters of credit to

Nova, which is to the intra-Alberta pipeline, which means that if they don't build those lines, then Nova is compensated to the tune of $400 million, I think it is, for Nova's expansion to meet the needs of Altamont and PGT.

Q. Are you familiar with the recent CPUC case in --

A. Yes.

Q. -- in San Francisco, as well as the application to expand the PG&E system --

A. Yes.

Q. -- to meet any expansion in the PGT?

A. Yes.

Q. And would it be fair to say that that's going through; do you think? Is that subjective, or are you saying since it's already approved, it's a done deal?

A. I know how the Canadian producers, as I mentioned, we have responsibility for western Canada. I've been to Calgary, and I know the producers up there. Their focus is not on any price forecast. They are not looking at a forecast. They're not trying to figure out what the market is going to do in the year 2000.

What they do is they I find out what

they can get for fifteen years or ten years with cogeneration or whoever, industrial, take that back to the wellhead, figure out what their investment cost is going to be. And if they make an acceptable rate of return, they're going to do it.

Q. But don't they have to have a pipeline to do it with? And isn't PGT completely full now?

A. PGT is full now, but the expansion, I think they're planning to start this summer.

Q. But isn't there a difference between planning and a done deal, because that's being opposed, isn't it, before the CPUC?

A. No.

Q. Aren't there contracts, they're talking about stranded demand charges and things that would have to allocate costs based on that expansion, and there is opposition to it, as I understand it?

A. Well, CPUC is opposed to -- not to expansion. The CPUC, in fact, would have ten pipelines put into the state as opposed to five, only because that gets the consumer a lower price. And their main interest is having enough

market power to wield one pipeline against another. And it's exactly what they're doing now. It's exactly why the CPUC feels it has some leverage with the minister in Alberta.

And if you'll notice, in settlement proceedings, Alberta is trying to work a way out of it because they know that if California can't get Alberta gas, they're going to gas from someplace else and not even miss Alberta.

So I think that the situation is, five years ago the producers had the leverage; now California has the leverage. California can dictate what happens.

Q. One more question. You mentioned Kern River. Are you familiar with the capacity in Kern River right now, whether it's running full or not?

A. It's not running full yet.

Q. One more question. Concerning the guarantee to the marketplace and how we could in our allowable system help out gas marketing, because we certainly want to sell New Mexico gas, are you familiar with what we've introduced as the concept of minimum allowables on certain fields?

A. I'm vaguely familiar with it, not in detail.

Q. We have two fields at least, Jalmat and Eumont, where there are minimum allowables, which serve to guarantee the marketplace that gas would be available from that field at a minimum level, so that be contracted. Would that be helpful in your -- in the Blinebry field, where you need to have a guaranteed supply of gas for a period of years, and I guess the threat of cutting those allowables below a certain level would make some of our gas noncompetitive?

A. Well, it depends what the minimum is. If you set it at 10,000, then we still have a problem I guess. If you set it where we've asked for it, then it would lessen the problem.

Q. Well, my question really was, no matter what the minimum allowable was set at, wouldn't that give you the flexibility to contract that minimum amount without marketplace fear that it would not be available, assuming your reserves were adequate to supply that market?

A. With the threat that you could drop it to the minimum?

Q. Well, it's not -- the minimum would be

more -- would take away the threat of taking away the gas supplied to the marketplace. That would be available at a minimum supply because the Commission order so dictated.

A. Yes.

Q. So that would be helpful?

A. Anything that guarantees some semblance of stability and the ability to flow what the gas wells have produced is helpful. Anything.

CHAIRMAN LeMAY: Thank you.

Additional questions of the witness?

COMMISSIONER CARLSON: I have one.

CHAIRMAN LeMAY: Yes.

FURTHER EXAMINATION

BY COMMISSIONER CARLSON:

Q. You mentioned that Alberta producers go out and negotiate a 15-year contract, take that price, and send it back to the wellhead, check the rate of return, and see if that's acceptable. How does that differ from the way any United States producer sells his gas?

A. Well, their gas up there -- their gas, our gas -- is shallower, much shallower than gas here in the United States, in the lower 48, on the whole and has much thicker pay. So their

economies of scale are tremendous.

To give you an example, Shell just announced plans to develop the Caroline field, which is northwest of Calgary 50 miles. That's a 3 Tcf field. 3 Tcf, that's a number that I haven't heard for a long, long time in the lower 48.

So when we're talking about putting a compressor on a 10 Bcf reserve well, that's a heck of a lot different than when Shell looks at putting a sweetening unit for 3 Tcf. They could sell gas at 30 cents and make money.

The only problem they have up there is the capacity out of the country. And they'll go a long way to make sure that that capacity gets put in.

Q. But they can live with a 30-cent net back at the well?

A. Well, I haven't done the numbers, and I think maybe 30 cents might be too low, but they can live with some very low prices. They already are. Their net-backs up there are horribly low. If we think we're in trouble here, they've got very low net-backs. And they're still talking about building pipelines.

It's just because their reserve base, the unit cost of development, divided by the reserves of their development is extremely low, much, much lower than what we have here in this country. And they are aided periodically by drilling credits and royalty holidays that the government puts in, which, you know, we don't have down here.

Q. But isn't their average royalty somewhat higher than the average royalty here?

A. Their royalty is higher by about 6 percent than ours. But to deal with that problem, the government will give them a royalty holiday, which means that the first gas that they produce up to a royalty value of $2 million Canadian is free of royalty.

So it effectively changes, unless they pay the project out before the royalty starts. And that's on top of a drilling credit that comes and goes periodically. Right now they've got drilling credits for oil, but not for gas.

COMMISSIONER CARLSON: That's all.

FURTHER EXAMINATION

BY CHAIRMAN LeMAY:

Q. I have to ask you one more question --

A. I'm glad to be here.

Q. -- since you raised the prospect of the Caroline field. That's been referred to as a sulfur mine with gas as a by-product?

A. That's right.

Q. Would it be beneficial if the world price of sulfur would fall and therefore --

A. Sulfur has already fallen. The sulfur market this month is absolutely horrible. The problem with sulfur is it's entwined with your gas production so that if you plan on selling gas and sometimes oil, you've got to run your sweetening unit and you've got to sell the sulfur.

And so it becomes something that some companies are willing to pay people to take away if it comes to that just to get at the oil and the gas.

Q. Well, your 30-cent price, I think that was -- the figure I heard was conditional upon sulfur being sold at a high price world price, like it was six months ago?

A. Well, 30 cents is the absolute worst case. I think now if you were to go in with a 15-year contract, you would get a premium in the

early years, if you would fix the price escalator for the next 15 years. And so they're starting at fairly high California border prices, which net-back to sums that are higher than 30 cents.

Down here -- to answer your question in detail -- down here, we don't look 15 years out because, first of all, we don't think we're going to have reserves in 15 years in some of these places. That's our first problem. They do. Canada does.

And, secondly, I think a lot of companies try and beat some sort of price forecast. We're all in the business of trying to figure out where the market is going down here. Canada is not in that business. There aren't too many guys up there that are trying to beat a price forecast.

They're just trying to make a rate of return on their investment. That's the fundamental difference between our country and their country, and that's what's really getting us right now.

Q. Just one other clarifying question to make sure that I think we all understood you. Did you say that Marathon would be interested or

would share their market with other producers in these fields?

A. Yes. If it allows us to get the allowable that we think we need, yes, we would share the market with other producers in the pool, if they -- if those producers want to do that.

Now, the net-back, some companies have this somewhat artificially high expectation for what the net-back ought to be, and we're probably not going to be able to meet that. But if their expectation is we'll get market-plus, then we're going to be able to meet that expectation.

Q. I appreciate that comment. Along with the responsibilities in OCD of regulation, the legislature also placed gas marketing responsibilities. So if you've not worked with Mr. Merrett, I would appreciate him working with you.

A. I've met with him.

CHAIRMAN LeMAY: We certainly want to sell New Mexico gas. Thank you.

Additional questions of the witness? You may be excused.

We'll take a break for lunch, and we'll

pick up, I guess, Indian Basin after lunch.

On gas marketing, I wondered if your witness was the same in the Indian Basin Field for gas marketing?

MR. KELLAHIN: Yes, sir.

CHAIRMAN LeMAY: Return at 1:15.

(The lunch recess was taken.)

CHAIRMAN LeMAY: We shall continue.

Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman. Mr. Chairman, at this time I'd like to recall Mr. Ron Folse and have the record reflect that Mr. Folse is already qualified as an expert witness and that he continues under oath.

CHAIRMAN LeMAY: He's so qualified, and he shall continue under oath.

RONALD FOLSE

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

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Folse, as part of your duties, have you analyzed the preliminary schedule of allowables the Division has circulated and studied that in relationship to the production

out of the Indian Basin Upper Penn Pool?

A. I have.

Q. As part of that study, have you, you and others with Marathon, come to a recommendation to the Commission for allowables to be applied for that production for the next proration period?

A. Yes, we have. I have.

Q. Have you and Mr. Hastings formulated a recommendation for a level of allowable that reflects the reasonable forecast of market demand for that production?

A. Yes, we have. I have.

Q. Let's turn to your exhibit package and have you identify and describe for us Exhibit No. 1.

A. Exhibit No. 1 is an operator map for Indian Basin field for current our producing properties in the Upper Penn Pool. At the top of the map is the various operator names, Marathon, Oryx, Chevron, Texaco, Apache, Amax, and MOK.

The wells that are indicated with the green dots are the non-marginal wells, and they also correspond to the acreage factor of 6.49.

Q. Let me have you at this time, Mr.

Folse, take a copy of the revised guidelines that Mr. VanRyan introduced this morning. Directing your attention to the Indian Basin, Upper Penn, so that we understand the changes that Marathon proposes, will you go through that schedule with us and indicate where we should make a change so that ultimately the column will reflect Marathon's request?

A. Yes. The first change Marathon would propose is an adjustment in line 3 of 464,019 for a revised, line 4, monthly pool allowable of 3,756,031. Using line 5, monthly marginal pool allowable --

Q. You wouldn't change that line; it stays the same?

A. I wouldn't change that line. It would remain the same. Line 6, then, would be --

Q. It's simply a subtraction of line 4 by the entry on line 5 to get line 6?

A. That's correct. And it would be 1,505,680.

Q. I'm sorry. I missed the number, one million, five hundred five thousand and --

A. -- six hundred and eight.

Q. Okay.

A. Using line 7 of 6.49 results in a monthly acreage allocation factor on line 8 of 232,000.

Q. The acreage factor has been adjusted between the original OCD forecast and this schedule. This one now shows 6.49. Does that agree with what you have?

A. That's correct, yes.

Q. And so the end result of line 5 is what number under the Marathon proposal -- line 8, I'm sorry?

A. Line 8?

Q. Yes, sir.

A. Would be 232,000.

Q. Let's go to Exhibit 2 and look at the gross gas production as you tabulated it from this pool. Summarize for us using this display the items that are of importance to you as an engineer in analyzing the allowable for the pool.

A. This Exhibit No. 2 is a graph of gross gas production at Indian Basin Field in the Upper Penn Pool. The graph is through the period January 1990 through a projection of March 1992.

Q. Have there been events that have

occurred in the Indian Basin gas production that have disrupted the production?

A. There have been three events that have resulted in lower production than normal.

Q. What's the first event?

A. The first event is in September 1991 when Marathon, as operator of the gas plant, had a plant turnaround which resulted in twelve days of plant shutdown.

Q. The Division, then, in the revised forecast has already taken into account that month; they have excluded it from the sales averages?

A. That's correct, yes.

Q. Describe for us briefly the plant turnaround. Is this an event that is going to occur on a regular basis, or is this an unusual event that we are not likely to see in the near term?

A. It is an unusual event in that the last plant turnaround was several years ago. It was required to do some plant modifications and electrical work, installation of additional command or control equipment, instrumentation, and modifications just to allow for easier

operation of the plant. And it is not the normal plant turnaround.

Q. Have all those activities been concluded so that in the next proration period we can reliably forecast on the ability of that plant to take gas from the pool?

A. That is correct, yes.

Q. When you look at November -- is it November?

A. December.

Q. I'm sorry. It's December and January the pool production has dropped?

A. That's correct.

Q. What occurred in the pool?

A. In December, December 11th, I believe, we had a six-day plant shutdown due to a fire that occurred. Again, in January, the first week of January, we had a six-day plant shutdown due to a fire.

Q. What's your opinion on whether or not plant fires are going to be a foreseeable event that you need to plan for?

A. We have, hopefully, taken all precautions and that will not occur again.

Q. When you look at Marathon's allowable

request level for the next proration period, do the gathering facilities within the Indian Basin, inclusive of the Marathon plant, have the capacity to gather and process the gas that would be generated at the Marathon allowable levels?

A. Yes. There will be -- or there will not be any problems with gathering the production based on Marathon's proposed allowables.

Q. Anything else about Exhibit No. 2 before we go on?

A. No, there is nothing.

Q. Identify and describe Exhibit 3.

A. Exhibit 3 is a letter sent out by Marathon to all the operators in the Indian Basin, Upper Penn Pool, advising them of our proposed increases in the well allowables from the preliminary schedule issued February 7 from the Commission.

Q. Again, without great detail, summarize for us the essential points of the request and help us understand how it fits into the current requested allowable.

A. The request or proposed allowables in the letter dated February 14, Exhibit 3, indicated we were proposing 205,000 Mcf per month

based on a sales figure. After further review by Marathon, we've determined that actual scheduling for the prorations is based on production at the wells, and therefore we've made some revisions.

Q. All right. The first letter was sent out before you recognized the impact the plant downtime was having on the sales volume that was used in the allowable calculations?

A. That's correct, yes.

Q. All right. After that, then, did you send a revised letter to the operators in the pool?

A. Yes, we did.

Q. How is that shown?

A. That is in Exhibit No. 4 by way of a letter to the chief engineer, Mr. VanRyan, via fax to the operators of the Indian Basin Upper Penn Pool, indicating in this letter that, based on our second review of estimates, we also -- we first mentioned the plant turnaround in September and the revisions required to more adequately reflect production from the pool.

Secondly, we mentioned the proposal for an F1 factor on line 8 to be increased to 232,000 Mcf per month based on production from the

wells.

Q. And you've described for us already how the 232,000 Mcf fits into Mr. VanRyan's revised allowable schedule?

A. Correct.

Q. Of those operators contacted, Chevron is here today, and I believe they seek an allowable level that's not as high as yours?

A. I believe that is the case.

Q. Turn now to Exhibit No. 5. Help us find that well, if you will, on Exhibit No. 1, and then tell us what you conclude from looking at the tabulation of production in relationship to the allowable for that Indian Basin D-1, 234 well?

A. Correct. Exhibit No. 5 is a graph of well production and allowables for Indian Basin D-1. It is located in the center part of Exhibit 1, the section numbered 34. The graph, or bar graph, on Exhibit No. 5 is production from the period January 1990 through a projected volume of March 1992.

As indicated in the graph during the year 1990, the well was of marginal well status and underproduced its shadow allowables. As a

result of well work and facility modification by Marathon in the early part of January, February, March of 1991, we have increased production from an average below 100,000 per month to approximately 200,000 per month.

The September plant turnaround in 1991 can also be seen as the reduced rates and also the December and January fire.

Q. When you look at the October and November rates, then, how do those compare to your forecasts of future well production?

A. The rates in October, November are rates prior to some facility modifications we've done in recent weeks.

Q. Do we have actual monthly production at this point that will reflect the additional capacity of the wells that are worked over to produce gas?

A. Yes, I do.

Q. And that forecast is represented for the blue lines in February and March?

A. That's correct, yes.

Q. Have you been able to determine what the basis is for the allowable peak in January of 19 -- what is it? 1991?

A. 1991, January.
Q. It's up over 300,000?
A. That was 325,000. That was the period of time when it was monthly adjustments. I have no explanation for that.
Q. Okay. Let me have you identify and describe Exhibit No. 6.
A. Exhibit No. 6 is an overproduced status of well, Indian Basin D-1. As of through December of 1991, it was approximately 165,000 overproduced. I might add that it was again a marginal well through September of 1991.
Q. And what happened to cause it to no longer be a marginal well?
A. It was a result of the work Marathon had done in the earlier part of the year to increase rates.
Q. In order to meet your share of the reasonable market demand, has Marathon produced its non-marginal wells in excess of the allowables?
A. Yes, we have.
Q. Are any of your wells up to the overproduction limitation?
A. No.

Q. You haven't had to shut your wells in from being overproduced?

A. We have not.

Q. Turn now to Exhibit 7 and identify and describe that for us, please.

A. Exhibit 7 is a graph of the daily rates from the well for the month of February through February 23rd. During the early part of the month, from the 1st through the 10th of February, the average rate was approximately 6-1/2 million cubic feet a day.

During February 11th through the 14th, the production facility, or at least separation equipment, were changed out and that accounts for the zero rates during that period.

During the 14th through the 19th, or really the 18th, production was brought back on-line and the facility problems were taken care of there.

From the 19th through the 23rd, that's the recent data collected, the well has produced in excess of 7.7 million cubic feet per day.

Q. Having looked at your non-marginal wells and their capacity and producing rates in relation to past assigned allowables, did you

make an examination and look at what the other operators were doing with their non-marginal wells?

A. I have looked at the current wells that are non-marginal and operated by other companies. It appears they have not done any work at this time to increase rates.

Q. When we look at the Bogle Flats Unit 2, 304 well, that's described on Exhibit A, who's the operator of that well?

A. Chevron USA.

Q. Why have you selected this well as part of your presentation?

A. It is currently one of the non-marginal wells in the field. Over recent years it has been the most, from what I can tell, the top producer in the field.

Q. What does the display show you?

A. The display here for the period January 1990 through projected March of 1992, the well production is either slightly above or slightly below allowables throughout the period. Generally the production on the well has averaged between 150- to upwards of 185,000 per month.

Q. Have you also tracked the overproduced

status of this well?

A. Yes, I have.

Q. That's Exhibit 9?

A. Yes, it is.

Q. Describe for us what that shows you.

A. Exhibit 9 shows the current overproduction, overproduced status of the Bogle Flats Unit 2 from the period, the same period, January 1990 through March of 1992. Initially, the well was overproduced over 400,000 Mcf, and through December is approximately 140,000 overproduced.

Q. What conclusions or points do you draw?

A. Conclusion is that this well generally has been capable of overproducing the allowables over that period of time.

Q. Let's turn now to a marginal well and look at what it's doing in relationship to the allowables. Do you have an example that's typical of a marginal well in the pool?

A. I do, yes.

Q. That's Exhibit 10?

A. Yes, it is.

Q. Identify the well and help us find it on Exhibit 1.

A. The Exhibit 10 is for North Indian Basin Unit No. 4. It is directly below or south of the top non-marginal well indicated in green. It is in Section 16.

Q. Is this a well that you operate, Marathon operates?

A. That's correct, yes.

Q. All right. Describe for us what this shows.

A. This is a graph of the well's production and its shadow allowable through the same period, January 1990 through projected March of 1992. During the period 1990 through -- well, through August of 1991, generally it has always been below its shadow allowable.

Marathon performed work in late September, early October on the well, which included additional well perforating and stimulation. In October the rates have been increasing and November -- have increased to over 130,000 per month.

Q. Describe for us the other operators of non-marginal wells in the pool. Who do we have?

A. The other operators are as indicated on Exhibit 1: Oryx, Chevron, Texaco, Apache, Amax,

and MOK.

Q. And among those operators, there are seven non-marginal wells?

A. That's correct, yes.

Q. All right. Who's got which ones? You don't have to describe the location of each well. Just tell us which operator has how many non-marginal wells.

A. MOK has currently one non-marginal well.

Q. Amax doesn't have anything; right?

A. That's correct. Amax has zero.

Q. Apache doesn't have anything?

A. That's correct. Texaco doesn't have any.

Q. Okay.

A. Chevron has two non-marginal wells. Oryx doesn't have any.

Q. Okay.

A. And Marathon currently has four non-marginal wells.

Q. Are any of the other operators in the pool undertaking at this point the type of workover program that Marathon undertook in the Indian Basin?

A. Yes. I'm aware of Apache doing some work similar to what we've done in terms of well work additional perforations, facility modifications on the lease to increase production.

Q. Is Marathon the operator that in the recent past is ahead of the others, if you will, in terms of this workover program?

A. I believe so, yes.

Q. Have you summarized on Exhibit 11 the magnitude of that program for adding additional deliverability to the wells in the pool?

A. Yes, I have.

Q. Describe for us what it shows.

A. The Exhibit 11 is a table that indicates the capital and expense costs Marathon has incurred since late 1990 through the current period where we have performed numerous aspects of work.

The first one is additional perforations added in the six wells. That involved adding perforations, perforated intervals, to the wells along with re-perforating existing intervals and well stimulations by acid treatments for a total of 300,245.

The second line is upgrading of five production units with the current pressure, the pressures existing in the field and in the reservoir. The facilities that were designed 26 years ago are being redesigned to minimize pressure drops that occur. And that has resulted so far in costs of $425,000.

In addition to that, we've seen some benefits in adding wellhead compressors on five additional wells. The cost of $50,000 accounts for the installation costs of the lease-rental units. The costs for the leases of the five units are approximately $30,000 per month, in addition to what's indicated here on Exhibit 11.

Q. The additional expenditures directed at the plant were how much?

A. The plant turnaround that occurred in September of this past year were performed to do several updates to the facilities and to ensure adequate capacity for production from all operators in the field. The total cost is close to $1 million.

Q. What, if anything, will the increased allowables under your proposed level of allowables do to Marathon's ability to sell gas

production and pay itself back for the cost of making these improvements?

A. Could you rephrase that?

Q. Sure. What's the relationship, if any, between the allowables you've requested and the costs you've expended for pool for production?

A. The relationship is that we're trying to recoup the investments as soon as possible.

Q. And is the allowable request one that in your opinion can be achieved without impairing other operators' ability to supply their share of market demand for pool production?

A. Yes, it is.

MR. KELLAHIN: That concludes my examination of Mr. Folse. We would move the introduction of Exhibits 1 through 11.

CHAIRMAN LeMAY: 1 through 11 will be introduced without objection.

And questions? Mr. Carr.

EXAMINATION

BY MR. CARR:

Q. MR. Folse, if I understand, you are recommending an allowable of 232,000 Mcf per month per well with an acreage factor of 1; is that correct?

A. That's correct.
Q. And during the last six months, Marathon has actually reworked two wells in this pool; is that right?
A. In the last six months?
Q. How many wells have you actually reworked recently in the pool?
A. In total, six wells.
Q. Six wells. You've presented information a few minutes ago on two wells; correct?
A. That's correct.
Q. And the well in Section 34 is the best well in the pool, is it not?
A. That's correct, yes.
Q. Will the well in Section 32 actually produce 232,000 Mcf per month?
A. Based on what I have seen in the work Marathon has done in recent months to a year-and-a-half, it should be capable of making quite a bit more than its current production level.
Q. Now, but will that well be restricted if in fact your recommendation is adopted by the Commission and the allowable of 232,000 per month

is established?

A. It will not be restricted.

Q. So that well will not be restricted. Is there any other well in the pool that could make the proposed allowable?

A. With the additional work that Marathon is contemplating at the current time, there should some more wells.

Q. But you won't know that until you undertake that work; correct?

A. We're in the process of doing work on those other wells too.

Q. At this time, though, my question is: If your recommendation is adopted, no well will have its production capability restricted; is that right?

A. That's correct.

Q. And, in fact, much of this allowable will actually just wind up as underproduction for wells in the pool; isn't that a fair statement?

A. That's correct, yes.

Q. And so when we talk about an increase in the pool allowable, we're talking about really an increase, only a small portion of which will ever actually be produced?

A. Could you rephrase that part?

Q. The increase in allowable, there's a difference between asking for an increase in allowable and an increase in production that will come as a result of that. And there's a disparity between those numbers, I believe.

Isn't it fair to say that much of the increase in allowable or requested increase in allowable will in fact never be produced?

A. If additional well work is not done on the wells, that is the case, yes.

Q. If that work doesn't dramatically increase the producing capability of those wells so in fact they're better than the best well in the pool right now; isn't that right?

A. That's right.

MR. CARR: I think that's all I have.

CHAIRMAN LeMAY: Thank you, Mr. Carr.

Additional questions of the witness?

Commissioner Carlson.

COMMISSIONER CARLSON: I have one.

EXAMINATION

BY COMMISSIONER CARLSON:

Q. You mentioned that you spent a million dollars on the plant turnaround on the Indian

Basin gas plant?

A. That's correct, yes.

Q. Was that Marathon's expenditures, or was that shared among all plant owners?

A. That was gross expenditures for the plant owners.

Q. So Chevron and everybody else contributed to that?

A. All the owners in the plant, yes.

COMMISSIONER CARLSON: Thank you.

CHAIRMAN LeMAY: Mr. Weiss?

COMMISSIONER WEISS: No.

CHAIRMAN LeMAY: I have none.

MR. KELLAHIN: Follow-up question to Mr. Carr's question.

CHAIRMAN LeMAY: I'm sorry. Mr. Kellahin.

FURTHER EXAMINATION

BY MR. KELLAHIN:

Q. If a spacing unit accumulates underproduction, does that constitute an incentive for Marathon to go out and try to rework that particular well to take advantage of that underproduction, and, if so, have you done it in your well?

A. Bogle Flats.
Q. Isn't that one of Mr. Carr's examples?
A. Yes.
Q. You're dealing with a marginal well at that point?
A. The Bogle Flats Unit 2?
Q. That's a marginal well, isn't it?
A. It is a non-marginal well.
Q. On the marginal well category, has Marathon reworked marginal wells in the pool?
A. We have, yes.
Q. And why do you rework a marginal well?
A. To increase its production capabilities.
Q. Exactly right.
A. Correct.
Q. And if a non-marginal well is accumulating underproduction, does that not constitute an incentive to examine the non-marginal well to see if you can rework that well as well?
A. Yes, it does.
CHAIRMAN LeMAY: Thank you, counselor.
I have one question.

EXAMINATION

BY CHAIRMAN LeMAY:

Q. Is Marathon, are they continuing on their desires? I thought they proposed unitizing the field and then deprorating it based on that unitization plan?

A. Yes, we are. We're currently continuing with the meetings with the other operators and working interest owners.

Q. How is that going?

A. We're set up for our next meeting with one of the operators next week. And we'll continue later in March with all the working interest owners.

CHAIRMAN LeMAY: Thank you.

Additional questions?

Thank you, Mr. Folse. You may be excused.

MR. KELLAHIN: I'd like to recall Bill Hastings.

CHAIRMAN LeMAY: California and Canadian gas expert.

MR. KELLAHIN: I hope he's an expert on the Indian Basin. That's what I brought him to do.

MR. KELLAHIN: Mr. Chairman, may the

record reflect Mr. Hastings continues under oath and he's been admitted as an expert gas marketing witness?

CHAIRMAN LeMAY: Yes.

WILLIAM HASTINGS

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

FURTHER EXAMINATION

BY KELLAHIN:

Q. Mr. Hastings, let me have you specifically identify the marketing arrangements in the Indian Basin Upper Penn Pool so that we will have a framework to continue our discussion in about market demand for production in that pool.

Can you give us a quick lesson on what's happening for the gas market for production out of that reservoir?

A. Right now we have what we call a settlement agreement. It comes from a thicker pay settlement that we executed with Natural Gas Pipeline in 1987. And the term of it extends through 1997. They take all the gas that we make available at the tailgate of the plant.

And as part of that agreement, we are

allowed to come in with long-term proposals that we think are acceptable. And Natural or Mid-Con has the right to match those agreements.

Q. Give us a quick review of the physical arrangements in the pool to take gas from the individual wells to a plant for processing and subsequent distribution of that gas. What's the arrangement in this pool?

A. Well, the plant is jointly owned, as Ron mentioned, and it's a huge gas plant. May be the largest in the state, although I don't think so. The total through-put at the inlet is in the neighborhood of 140 million cubic feet a day.

The gathering system behind the plant is owned by the plant owners, I think with the same working interest share as they have in the plant, and is operated by Marathon. And then there's a new inlet compressor that was put in two years ago, I think. And we also have tailgate re-compression to get the gas into a natural gas pipeline mainline.

Q. Are there any wells in the Indian Basin that transport their gas to market by any other means?

A. There are wells on the south end of our

field that may overlap our leases that flow into an adjacent Gas Company of New Mexico dual-plant system; it's called the Avalon system. They have separate sweet-name facilities versus fractionation facilities, separate locations, and we call that Avalon system.

We are, as a plant operator, actively competing to take those wellhead customers and bring them into the Marathon plant.

Q. And looking at the capacity of the Marathon plant, does it have the capacity to take the additional gas to satisfy the allowable level that Marathon is requesting for this pool?

A. Yes.

Q. What, if anything, has happened to pressures within the gathering system that takes the production from the wells to the plant?

A. Well, the gathering system pressure is governed by the inlet compressor at the plant site. The inlet compressor is brand new and was installed to lower the average gathering pressure, I believe, to 500 pounds, which is more than enough reduction to allow the existing wells to produce into the gathering system.

If we start to have -- if we need to

manage the gathering system pressure, we can with that inlet compressor. It gives us a lot of flexibility to produce the wells.

Q. Is the plant such that a poor producing marginal well can be assured of its opportunity for access into this plant into the system if this allowable level is approved?

A. There are wells that are so old and fairly far down the depletion curve that their average wellhead pressure is below 500 pounds. And there are cases of wellhead compression in the area where you have to put a wellhead compressor to get into the gathering system to begin with. So there are isolated cases where there are wellhead compressors.

Q. After the plant, what is the distribution of the gas from the pool?

A. Well, the plant right now has a single connection, although we've looked on several occasions at split-connecting or triple-connecting the plant.

But right now the plant has a single connection with telemetry with the entire stream that is tied into the Lombard control center in Chicago of Natural Gas Pipeline. They know

within seconds whether we're producing more than our nomination or less. All the gas flows into the Natural Gas Pipeline system for further sale downstream.

Q. As a marketing expert, in your opinion is there a reasonable market demand for the gas to be produced at the allowable level Marathon is seeking?

A. My answer to that is pretty much the same we had as with the Blinebry earlier. Yes, there is. The gas that flows through the natural system winds up at the same point in Texas as the gas that comes from the Blinebry to the Northern Natural Gas system. And so the stream can be consolidated and flowed into Houston if that's what we decide to do.

Q. Is there any seasonal variation to the market demand or the production of gas from this pool to satisfy market demand?

A. No. The gas flows every day of the year except for when we have a fire. And there is no interruption of the service. We are the anchor to the Natural Gas Pipeline system. It starts at this plant and goes all the way the to Chicago. With that large of volume, they go to

extraordinary lengths to let gas flow. It does flow.

We periodically have issues where Chevron or Oryx may lose their spot market. Their situation, their contract situation is a little different from ours. They're month to month, I think. And we have to adjust to deal with that when the partners lose. But our market flows constant. We've not had an interruption.

Q. In your opinion will the allowables you seek for Marathon for meeting market demand impair the ability of any of the other operators to market their share of the gas?

A. No, not at all. It might improve it.

Q. In summary, Mr. Hastings, what is your recommendation and opinion concerning Marathon's allowable request?

A. Again, my request is that we receive approval to flow the allowable volume that we've requested to countermand some of the issues I brought up earlier. That is still a problem for this plant. We have bigger volumes exposed, and we need to operate as we have in the past with some ability to let the market dictate how the plant operates and how it flows.

Q. Are the general marketing recommendations and strategies that you discussed earlier today on the Blinebry, are those also applicable to the Indian Basin Upper Penn?

A. Yes.

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

CHAIRMAN LeMAY: Thank you, Mr. Kellahin.

Mr. Carr.

FURTHER EXAMINATION

BY MR. CARR:

Q. Mr. Hastings, there's only one plant through which gas from this field is flowing through at this time; isn't that correct?

A. Well, I mentioned the Avalon plant. But for the interest owners in this plant, yes, that's right.

Q. You talked about this plant being able to take the additional gas that could be produced if in fact the allowable increase is granted?

A. (Witness nodded.)

Q. Have you estimated how much production that would be as opposed to allowable?

A. Well, the tailgate volume right now, we

operate on tailgate volume, which is the shrinkage -- has a shrinkage off of the inlet volume. The tailgate volume we have right now is 33 million cubic feet a day. And I would expect that the total volume could go above 40 million cubic feet a day at the tailgate of the plant for Marathon's account.

Q. You would agree with me that you're going to see substantially less production than allowable is assigned to that pool?

A. I think that the allowable gives us a reason to go out and do development work. In other cases the allowable gives us a reason to not go out there. I think there are documented cases where oil companies will not develop a property if it's expected that we have -- that we will have an allowable problem.

If the case is that the allowable is above what we think the well will produce, it will go out and spend some money, like Ron has already, for some of the wells to improve production. Our objective right now is to maximize production.

Q. Earlier today you were talking about basically what you perceived as a need for really

an unrestricted market if we're to compete with the Canadian flood of natural gas?

A. That's right.

Q. Basically what you're asking for in this case, is it not, is a deprorationing of the field?

A. Yes, sir.

Q. When you translate that into a foreseeable production volume, is it your opinion that the amount of actual production, we're talking about the increase in production from this field, would have any really significant impact on the problem we have with Canadian gas flooding American supplies?

A. Well, we're not trying to -- my answer to that is we're not trying to affect the market. What we're trying to do is protect Marathon's interest. We thought we saw this coming a couple of years ago. We've got contracts in place that are fairly substantial that give us a premium because the buyer, to put it bluntly, really didn't see it coming.

So our primary interest is to focus on protecting our assets, making the return on assets as high as we can and generate cash flow

for our capital programs, which include the expansion of some of the wells' production ability.

Q. And the way you're doing that is recommending an allowable higher than the best well in the pool?

A. Well, the allowable, I think Ron's graph on the good well, the one well, we are exceeding the allowable now. And I think the allowable would be set at the level that the well is producing now. All of those wells produce from the same formation.

If we do the same work and have the same success with acid stimulation, with re-perforation, then we'll see the same production rate. There is no difference in the formation. The only reason that you would have the well-by-well difference is if you didn't perforate the extra two feet, if your acid job didn't work as well as you hoped it would, or if, you know, you have some kind of casing problem.

There are other things besides market demand that affect wellhead production, all of which we can control ourselves with the exception of the marketplace.

Q. You indicated just a moment ago if you did the same work and had the same success, you could bring the other wells in line with this well in 34?

A. Yes.

Q. In fact, you've done the same work and you haven't had the same success in other wells, have you?

A. Well, that's the way it is in the oil business. I think you know that as well I do. Sometimes we do better than the best well and we've had that happen before. Sometimes we do worse. I'm not telling you that every single well that we work on is going to be a maximum producer; it's not. Same may exceed it; some may be below it.

MR. CARR: Thank you.

CHAIRMAN LeMAY: Additional questions of the witness?

Mr. Carlson.

FURTHER EXAMINATION

BY COMMISSIONER CARLSON:

Q. Did you say you're marketing all your Indian Basin gas to the Natural Gas Pipeline?

A. No, we're not. Right now under the

settlement, we have the right to market 33 -- or everything we produce to them. In the past we had a contract with Phelps-Dodge in New Mexico, in Tyron, in Silver City to supply their copper smelting operations. And we turned that contract net-back price in to Mid-Con to match, and they chose not to match it.

So right now we have 11 million a day flowing from Indian Basin to Phelps-Dodge, and 22 million a day being sold to Mid-Con. We have already turned in the Liondel proposal for Mid-Con to match on the rest of that volume, and they haven't made a decision on that yet.

Q. So you're free to seek other long-term contracts?

A. (Witness nodded.)

COMMISSIONER CARLSON: I see. That's all I have.

CHAIRMAN LeMAY: Commissioner Weiss.

COMMISSIONER WEISS: Yes.

FURTHER EXAMINATION

BY COMMISSIONER WEISS:

Q. Does Marathon have any experience with deprorating a gas field that you're aware of?

A. Well, not that I'm aware of. I think

Burton Flats is the only one that I've heard of. We have not been in that business. We have not done that. The market has been changing so fast that I think you may see more producers going that route. And we may yet get to that point, but we haven't been there yet.

I understand, and I'm not an expert on this, but I understand that each and every royalty owner needs to be contacted, a lot of the partners need to be contacted in an agreement. And in this day and age, it's pretty darn tough; it requires a lot of work to get that done. But that doesn't mean we won't do it; we'll give it a shot.

CHAIRMAN LeMAY: Additional questions of the witness?

You may be excused.

MR. KELLAHIN: That concludes my presentation, Mr. Chairman.

CHAIRMAN LeMAY: Thank you, Mr. Kellahin.

Mr. Carr.

MR. CARR: May it please the Commission, at this time I would like to present a witness for Chevron, who will present testimony

on the Indian Basin. At this time we would call Mr. Mark Corley.

MARK CORLEY

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

EXAMINATION

BY MR. CARR:

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

A. My name is Mark Corley. I currently reside in Midland, Texas.

Q. Mr. Corely, by whom are you employed and in what capacity?

A. I work for Chevron USA, and I'm currently a gas engineer.

Q. Have you previously testified before this Commission and had your credentials accepted and made a matter of record?

A. Yes, I have.

Q. Did you testify at the last gas allowable hearing?

A. Yes, I did.

Q. At that time were you qualified as a gas engineer?

A. Yes, I was.

Q. What does a gas engineer do?
A. My key job responsibilities are contract administration associated with casinghead gas, gas well gas for New Mexico only. I do production forecasting, keep up -- work together with our marketing group on pricing trends, market trends, monitor and get involved in regulatory affairs, such as allowable hearings, and monitoring how our wells are doing versus allowable and also equipment design associated with producing natural gas.
Q. How long have you worked in the capacity of a gas engineer for Chevron?
A. Two years.
Q. And prior to that time what were your responsibilities with the company?
A. I worked in the gas marketing group for two years.
Q. Are you responsible or familiar with the prorationing system in New Mexico?
A. Yes, I am.
Q. And have you reviewed the preliminary nominations or the preliminary allowable estimates that were provided by the OCD with the docket for the hearing today?

A. Yes, I have.

Q. Have you prepared recommendations to the Commission as to what should be the proper producing rates for this pool?

A. Yes, I have.

MR. CARR: Are the witness' qualifications acceptable?

CHAIRMAN LeMAY: They are acceptable.

MR. CARR: May it please the Commission, I would like to point out at this time that the exhibits that we will be presenting contain figures. The figures are drawn from the preliminary allowables sent out with the docket. We haven't been able to revise them to reflect the figures that were in the materials presented today by the Commission.

We are, however, focusing this presentation on what we think is an appropriate allowable rate for the pool so the bottom line ultimately does stay the same.

Q. Mr. Corley, what does Chevron seek in this case?

A. First of all, I would like to express Chevron's appreciation for involvement in the Commission hearings, and we continue to support

the six-month flexibility in being able to plan and develop our fields.

First of all, Chevron, like Marathon, felt like the preliminary allowable of 121,000 for an acreage factor of 1 was not adequate. And like Marathon, we seek an increase in the pool allowable.

Q. What allowable --

A. But not to the extent of Marathon's.

Q. What allowable rate does Chevron actually recommend?

A. Chevron proposes a monthly acreage factor 152,500. This equates to 5,000 Mcf a day per well with an acreage factor of 1. We feel this more appropriately reflects the producing capability of the pool on an average basis and it remains sensitive to market conditions, demand conditions for the summer period which we're talking about. And it also gives us flexibility in performing workovers during this time period to further determine if future increases are justified.

Q. Have you prepared certain exhibits for presentation here today?

A. Yes, I have.

Q. Would you refer to what has been marked for identification as Chevron Exhibit No. 1. Identify this and review it for the Commission.

A. Mr. Chairman, the Exhibit 1, which we prepared, is kind of an information type exhibit to give you an idea of who the key players are at Indian Basin. We are showing total production for the period April 91 through November of 91 for the Indian Basin Upper Penn Gas Pool.

You can see that the relative position of the operators is Chevron-Marathon; it equates to about 40 percent apiece. The next two players are Oryx and Amoco. Subsequent property exchange has occurred, and the Amoco wells are now owned by MW Petroleum.

Q. How many wells does Chevron actually operate in this field?

A. We have ten wells.

Q. How many does Marathon operate?

A. Thirteen by my count.

Q. Let's move to Exhibit No. 2. Would you identify this and review it, please?

A. Yes. Exhibit 2 further illustrates in more detail Chevron's producing habits, so to speak, in the Indian Basin Pool. We historically

went back from April of 90 through December of 91. The dark bars are indicating our non-marginal wells, and the light bars above indicate our marginal well performance.

What we're trying to show here is that Chevron tries to attempt to maintain a consistent level of production throughout the winter and summer months, if possible. So the main point is we don't try to shut in gas during the summer to try to build up our allowable for the winter periods. We are in a non-discretionary environment, and we feel like the production should stay on.

Q. You're not seeing the seasonal swings that may be reflected in some general production graphs?

A. No. And we might also point out the plant disruptions of September of 91, we also saw a significant drop in introduction. Historically, we have seen this plant turnaround as an annual event and have planned our testimony accordingly.

Q. Now, Mr. Corley, let's move to Chevron Exhibit No. 3. Would you identify this, please?

A. Exhibit No. 3 is designed to show a

tabular illustration of Chevron's proposed versus the OCD preliminary exhibits sent out with the docket. We feel like this exhibit is still valid. We will further develop it through further testimony.

If you'll look down the column 1, you'll see the original 121 that was proposed. We have it highlighted. The last, April through September of 91, allowable period, we had an equivalent of 134,728. Focusing upon Chevron's proposal, you see the 152,500, which equates upward. If you back-calculate it, it would require an adjustment on line 3 of 109,932.

And we decided to go ahead and use the September production as the plant turnaround was viewed as an annual event. We also feel like this 152,500 is more representative of the pool, pool production.

Q. Let's move on now to the next exhibit, Chevron Exhibit No. 4. Can you identify that? And I think on this exhibit, Mr. Corley, if you could review it column by column and explain how it is that Chevron came up with 152,500 for a recommended allowable range.

A. Turning to Exhibit 4, this is a further

breakdown of the previous exhibit that shows what the original proposed preliminary allowable would do to the non-marginal wells in the pool. So we had a little more detail to see how our wells would react to this proposal.

Column 1, these numbers were derived from the C-115 reports. We feel like they're the best source of data for comparison; it's public knowledge. Easy access shows the fuel, the fuel use, that type of thing. Column 1 shows total production from Chevron and Marathon non-marginal wells.

Column 2 puts that number on a monthly basis. It's just a division by eight. The reason we used April of 91 through November of 91 is because it gives you a feel of how we operate the wells during the six months. It tries to incorporate any activity that has happened in October and November. And we couldn't carry it any further because of lack of data available. But it does give a true picture of how we feel like you should forecast your production.

The next, column 3, is proposed 121 originally. The impact is shown in the delta column, which is column 2 minus column 3. As you

can see, the original proposals significantly restricted production on the non-marginal wells.

Column 4 is the Chevron proposed 152,500. Looking at the delta column, the curtailment or capacity that was caused by the proposed is significantly reduced.

And on Chevron's wells we have two wells that would become marginal under this scenario. We have the Bogle Flats Unit No. 2 that will remain non-marginal. And we have an additional well we have a planned workover on, the Helbing Federal, which I will explain later, that will become non-marginal.

On the Marathon side we show three wells that will remain non-marginal and one that will become non-marginal.

Q. Mr. Corley, why don't we stop at this point, and I'd ask you to go back to column 2. And using those figures, explain to the Commission how Chevron developed the 152,500 figure.

A. Going down column No. 2, you see the average per well. We wanted to see what the average non-marginal well did. It's basically those three numbers added together divided by

three.

You take the Marathon wells. It includes the anomaly. I'd like to show the Indian Basin D-1, and the big well is included in this. We feel like it's an anomaly, but we did include it in the averaging. So Marathon's average well does about 166 million, the non-marginal. Our average well does 139.

We did look into the other operators in the field, the Oryx and the Apache wells or MW Petroleum. And they would become marginal. The closest one was an Oryx well that was 110,000. If we included that in there, that would possibly skew the data.

Adding Marathon and Chevron together, we came up with an average per well of both operators of 152,900. Rounding that down to an even 5 million a day is where we came up with 152,500.

Q. Do you believe this figure accurately reflects the ability of the pool to produce at this time?

A. Yes, I do, including our further testimony on the Helbing well.

Q. Why don't we go now to Chevron Exhibit

No. 5. Would you identify and review that?

A. Exhibit No. 5 is basically a graphical illustration of what we've shown on the prior table with emphasis on Chevron's average non-marginal well. So we took and we plotted that average per well number for Chevron versus time versus the allowable to show how we operate our non-marginal wells and how the proration system has benefited Chevron.

The dark bars, going back to April of 90 again, depict the production. The slash bar indicates from January of 92 through September of 92, which is our forecast throughout the allowable period. And the top curve with the squares is the allowable. The furthest allowable forecast on the right is the original preliminary 121,000.

This graph indicates that if we operate according to our forecast, that original proposal would cause capacity and curtailment restraints to Chevron. We do have individual well plots for each of these available if someone would like to see those.

Q. If we take the Chevron recommendation of 152,500 and apply it to these non-marginal

wells, Chevron non-marginal wells still would experience some restriction; is that true?

A. Yes.

Q. Why don't we move now to Exhibit No. 6 and focus on the Helbing well.

A. This is one of the wells I was mentioning previously. It's currently a marginal well. We do have a well compressor on this well because of the age of the well, and it does not have the reservoir pressure to overcome the 600 pound current gathering pressure, the plant compressor.

This graph is a similar format as the previous. You can see in April of 92 the full effects of our workover coming into play. We estimate peak production at 168,000 per month. Again, we see a restriction from the original proposed 121,00 on our workover program.

Q. Again, this well would be somewhat restricted based on these projections with the Chevron recommendation?

A. Yes, it would.

Q. As a gas marketing engineer, are you required to stay abreast of trends in the gas market?

A. Yes, I am.

Q. Do you work with the Chevron gas marketing group in that regard?

A. Yes.

Q. Are you required to monitor market trends as part of your general responsibility as a gas engineer?

A. Yes.

Q. Could you identify what has been marked as Chevron Exhibit No. 7?

A. Yes. What we have here is a letter I requested from the marketing group summarizing what they felt like our marketing position was during the allowable period. In summary, the marketing group sees an instability in the market for Chevron's gas. We do have a diverse market. We do have some northeast contracts. We do have some California contracts.

We see a transition in the markets right now. Most importantly we see a downward price pressure on the Permian gas and likely weakened prices and on a capital program of a big magnitude that doesn't return on our investment what we think is necessary. So our workover program is somewhat restricted due to this

pressure on the gas market for Chevron.

Q. How does this translate into the context of prorationing considerations?

A. We feel like it gives a more relevant position to all the people within the pool.

Q. Does this --

A. Proration does help all of the operators to have a more equitable share and to have adequate development of the workovers.

Q. In your letter you talk about the Kern River Gas Transmission Project, Transwestern Pipeline expansion, things of that nature. Do the instabilities that come from these factors in your mind bear on the necessity for maintaining prorationing in this field?

A. Yes, they do.

Q. And what would they be?

A. The transition cause is constant, I think, is what it does. We don't know -- we need -- we're trying to determine what we should produce the field at at this time.

Q. Could you basically at this point just summarize Chevron's recommendation to the Commission?

A. In summary, the 152,500 we feel like it

represents an equitable picture of how the field should be produced considering the market conditions, the expected demand. We also feel like it's adequate for us to determine capabilities of the Helbing well and plan for a future development in the next allowable period.

Q. Mr. Corley, have you talked to other operators in the field concerning the proposed allowables for the next period?

A. Yes, we have.

Q. And what response have you received?

A. We have support from Oryx and MW Petroleum Corporation.

Q. Are copies of letters evidencing that support what has been marked as Chevron Exhibits 8 and 9?

A. Yes.

Q. In your opinion will approval of Chevron's request to set an allowable rate for this pool during the next period of 152,500 be in the interests of conservation, the prevention of waste, and the protection of correlative rights?

A. Yes, I do.

Q. Were Exhibits 1 through 9 prepared by you or compiled under your direction?

A. Yes, they were.

MR. CARR: At this time we would offer Chevron Exhibits 1 through 9.

CHAIRMAN LeMAY: Without objection, Chevron Exhibits 1 through 9 will be admitted into the record.

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

CHAIRMAN LeMAY: Thank you.

Mr. Kellahin.

MR. KELLAHIN: Thank you, Mr. Chairman.

EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Corley, I apologize to you for not mastering the names of all these non-marginal wells. If you could simply take and identify for me what Chevron considers to be its non-marginal well of greatest deliverability and tell me what the name of that well is.

A. Bogle Flats Unit No. 2.

Q. That's the same one that Mr. Folse described in his presentation earlier today, is it not?

A. That's correct.

Q. Separate and apart from allowable restrictions on that well, what would be its total deliverability on a daily or monthly basis?

A. Estimated deliverability of that well is in the 5800 Mcf per day range.

Q. Your requested allowable is one hundred fifty-two --

A. Yes.

Q. -- thousand Mcf?

A. (Witness nodded.)

Q. I've lost track of my table. I don't have my notes. That was on a monthly basis --

A. Right.

Q. -- using the F1 factor?

A. (Witness nodded.)

Q. If you take your best well and take its total deliverability and put it on a corresponding monthly number, what is that number?

A. It's in the 165,000 range.

Q. Between the 165,000 range and the 152,000 allowable level, will you have any other non-marginal wells restricted but for that Bogle Farm (sic) 2 well?

A. With the exception of the Helbing well,

no.

Q. The Helbing well is a well you also operate?

A. Yes.

Q. And what would be its unrestricted capacity?

A. We estimate the unrestricted capacity at about 168,000 per month. We don't see the full capacity coming on-stream till the later part of this allowable period. That's why we feel like the 5,000 a day is justified.

Q. Would there be any other non-marginal wells that Chevron operates that would be restricted below their full capacity under your allowable level?

A. No.

Q. If we use your allowable level, how many of Marathon's non-marginal wells are we going to restrict?

A. From my calculations we have three.

Q. I'm sorry?

A. We had three.

Q. One of theirs and two of yours?

A. No.

Q. Did I misunderstand you?

A. We had three Marathon, from Exhibit 4, We had one. We had two Chevron's, including the Helbing, and three Marathon wells.

Q. In terms of analyzing reasonable market demand for pool production, does not the pool market demand exceed the 152,000 Mcf?

A. I don't have knowledge to prove that. I know that we have a capacity to market our share of the gas and we've shown that through our marketing letter. We did not cite a lack of market. I cannot say to my knowledge that 232,000 could be marketed.

Q. You don't know one way or the other whether the 232 could be marketed?

A. I would say it most probably could be.

Q. Mr. Hastings testified a while ago it was an absolute certainty from his opinion that that level of gas production, if the wells could produce it, could in fact be marketed?

A. Uh-huh.

Q. Do you have any disagreement with Mr. Hastings on the market demand?

A. The only disagreement is the different markets. Each producer has its own market. And if Marathon wants to speak for Chevron's market,

it may not be consistent with our marketing strategies.

Q. What is your marketing strategy?

A. It's similar to Marathon. We have a sales portfolio that we are trying to establish. We are under pressure to look for a longer term contract with the markets due to the expansion projects. So we're trying to expand our sales portfolio to include more long-term agreements.

Q. It would appear from a casual observation of the number of wells in the positioning of you and Chevron and Marathon in the pool that you're in reasonably competitive positions within the reservoir, are you not?

A. Yes.

Q. Do you perceive Marathon to have any kind of advantage in the reservoir that you cannot attain for yourself?

A. Not that has been determined to date.

Q. If we increase the allowable levels so that your greatest capacity well is restricted, going up from 152 to 168, something just below 168, can you market that gas, the difference?

A. If you want to take a hit on a price. Part of our lack of the development is because of

the demand factor that we forecast for this period. We've seen two testimonies that show that prices are going to be very weak during the summer.

Q. Well, is Chevron's marketing strategy the same type of strategy we heard in the Hendrix statement in the Blinebry Pool earlier today? You were here for that, were you not?

A. No. We would not be in that category at all.

Q. That's not in your marketing strategy?

A. No.

Q. Do you plan to do what Marathon has done and go out and spend additional dollars to establish additional deliverability of your wells?

A. To a certain extent, yes.

Q. Have you quantified that extent?

A. Yes. One well.

Q. One well when?

A. This summer.

Q. And what additional capacity will that add to your deliverability for your wells; do you know? Is there any forecast for that?

A. We're approximating 168,000, as I've

previously stated.

MR. KELLAHIN: Thank you, Mr. Chairman.

CHAIRMAN LeMAY: Thank you, Mr. Kellahin.

Additional questions?

Mr. Stovall.

EXAMINATION

BY MR. STOVALL:

Q. I just want to make sure I understand how you arrive at the number. I realize your table was based on the original Division preliminary figures. And now, if I understand what you're really asking, is for it to come down from what the Division is proposing rather than go up from what the Division proposed?

A. I have seen the new revision, the 160,502. Is that what you're referring to?

Q. Right. Correct.

A. Yes. We would contend that we want to keep our case as designed.

Q. And if I understand the mathematical difference between that is that the Division didn't count September because of the plant turnaround?

A. (Witness nodded.)

Q. And you suggest that you should use the same production figures divided by six months and plan on the plant turnaround in September as being an annual event and base everything on that; is that correct?

A. Well, that in addition to column 5, which was pointed out earlier, that a different period was used for the marginal production, Chevron, in --

Q. Oh, right.

A. -- the October through December.

Q. Okay. But it's really a mechanical difference?

A. It's a mechanical difference, yes.

Q. My only other question, I'm just asking you for clarification, as I read the Oryx letter, it appears to me that they express support for Chevron's testimony, but they really want about 167,000; is that correct? That's what the letter says. I'm not asking you for Oryx' position. Is that how you read the letter?

A. Yes, that's how I read the letter.

MR. STOVALL: Okay. I have no other questions.

CHAIRMAN LeMAY: Additional questions

of the witness?

Mr. Weiss.

EXAMINATION

BY COMMISSIONER WEISS:

Q. On your Exhibit 5 --

A. Okay.

Q. -- what would that look like if the pool were not prorated?

A. If the pool were not prorated, what would our forecast be?

Q. Yes. What do you think the trends would be here? Would they be pretty level like this? What has proration done for you? You said it's been very beneficial. What would this look like so I can understand this?

A. Well, you can see the benefits in the wintertime in this particular case where the allowables went up to 6 million a day. From this plot, it was a little bit higher than the best Chevron well. But the main thing I was saying about benefits is the six-month period to where we can plan for it.

Q. What if it were not prorated at all, this pool? What would this look like?

A. I would say it would be very similar.

We may have started our activity a little bit sooner having a timing type effect. It's hard to predict what it would look like, but it would probably be similar.

The thing I need to qualify is there is some risk in doing these workovers.

Q. Oh, sure.

A. You take a gas well and you've got water on the backside, a lot of them have permanent packers in them. You dump the water on the formation. There is a risk in doing workovers on a deep gas well. You don't have 100 percent completion to where it will be successful.

And we have had a lot of skepticism in our field operations and local management to basically, if it ain't broke, don't fix it type, and there is some risk involved.

COMMISSIONER WEISS: Thank you.

EXAMINATION

BY CHAIRMAN LeMAY:

Q. Mr. Corley, in your marketing strategy for Chevron -- and feel free not to answer this if you don't want to -- but in your short-term markets, 30-day spot mainly, is there a price at

which Chevron decides to shut in production rather than selling the 30-day market?

A. We do have that price calculated as based on operating expense. And our operating expense is pretty low at Indian Basin. We call it a floor price, plus some margin that we would like to see on our investment. And that floor price is considerably lower than the market today.

Q. So is it fair to say, as you vary the field, you vary the price at which reserves are chosen to be shut in because you just don't want to sell at that price basically?

A. Right.

CHAIRMAN LeMAY: Additional questions?

You may be excused. Thank you. We're doing this on a field-by-field basis. I guess we're through on Indian Basin, are we, or is there additional testimony on the Indian Basin field?

MR. CARR: I believe there's no further testimony on Indian Basin.

CHAIRMAN LeMAY: Mr. Carr, do you want to proceed with another field?

MR. CARR: May it please the

Commission, at this time I'd like to move to San Juan Basin, and I would like --

MR. KELLAHIN: I would like to finance his move.

CHAIRMAN LeMAY: Lawyers are taking up a collection fee.

MR. CARR: Some reports I've gotten from earlier activities this week in the San Juan Basin suggest maybe both Mr. Kellahin should return to Santa Fe and I should go to the San Juan Basin.

I would like to make a presentation for Amoco at this time concerning Amoco's request for some increases in the allowables in the prorated field in San Juan Basin.

JAMES WILLIAM HAWKINS

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

EXAMINATION

BY MR. CARR:

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

A. James William Hawkins.

Q. By whom are you employed?

A. Amoco Production Company.

Q. In what capacity?
A. As a Senior Petroleum Engineering Associate responsible for regulatory affairs in New Mexico and Colorado.
Q. In that role have you become familiar with the New Mexico prorationing system?
A. Yes, I have.
Q. Have you previously testified before this Commission and had your credentials as an expert witness in petroleum engineering accepted and made a matter of record?
A. Yes.
Q. Have you reviewed the preliminary allowables that came out with the docket for today's hearing?
A. Yes, I have.
Q. Have you made a study of those allowables to determine how they relate to Amoco operated wells in the San Juan Basin?
A. Yes.
MR. CARR: Are the witness' qualifications acceptable?
CHAIRMAN LeMAY: They're acceptable.
Q. Mr. Hawkins, would you briefly state the purpose of Amoco's testimony here today?

A. Amoco is here to testify to some recommended adjustments for the allowable for pools in the San Juan Basin for the period of April 92 to September 92.

Q. Have you prepared certain exhibits for presentation at this time?

A. Yes, I have.

Q. Would you refer to what has been marked as Amoco Exhibit No. 1, identify that, and review it for the Commission?

A. Yes. Exhibit No. 1 shows the San Juan Basin gas production relative to the pipeline capacity for the time period January 89 through about the middle of 1992.

The heavy black line near the top of the graph or the middle of graph, I should say, shows that pipeline capacity currently at about 1680 million cubic feet per day. And it shows the expected increases up to about 3360 million cubic feet per day by April of 92.

Now, we realize that this increase in capacity is going to significantly lower the line pressures and affect the gas well production for wells in the San Juan Basin. We've shown what we think to be the potential increase for prorated

gas to be 550 million cubic feet per day. I'll run you through our basis for that.

The solid line that varies up and down is total gas production in the basin, again, from about January 89 through October of 1991. The latest information we got from Dwight's Energy Data. And it shows that during this period, specifically near 1990 and 91, that total gas production has basically reached pipeline capacity in many cases.

Reaching that pipeline capacity has caused increasing line pressures. And the effect of that increasing line pressure is shown on the dashed line, which is the total prorated gas in the San Juan Basin. And it shows that, in about January of 1990, those pools produced a maximum of about 1160 Mcf per day, and that's declined to 610 million cubic feet per day fairly recently.

We think that that decline or that decrease, that 550 million cubic feet per day represents a reasonable potential that we might expect to see when we add pipeline capacity and drop the pipeline pressures back down.

Admittedly, that's a rough estimate. Some of that decline may be some seasonality.

Some of that decline may be some natural decline from the wells in the pool. But the bulk of it is most likely due to increasing pipeline pressure.

Q. Now, Mr. Hawkins, let's move to Amoco's recommendation as set forth on Exhibit No. 2. I think the first thing you should do is explain the basis for this particular exhibit.

A. Right. This exhibit was prepared on the basis of the preliminary recommended adjustments or preliminary recommended allowables that were submitted by the OCD. And I can lead you through the arithmetic here a little bit. We've also made some estimates of what the new information that we received today would do to our recommended adjustments, and I'll lead you through that.

The first thing I'd like to do is say that we have viewed that 550 million cubic feet per day as the potential increase from prorated pool gas and tried to spread that among the prorated pools on the basis of marginal and non-marginal production.

If we look at the top line in our recommendation, that shows the total gas

production from the pool. And it shows -- the second line shows what percentage each of the pools contributed.

For example, the Dakota contributed about 31 percent of the total prorated gas production from the San Juan Basin during the last year's period. And the Blanco Mesaverde contributed about 63-1/2 percent. Even though the overall numbers changed, those percentages are still fairly representative of the data that we got today.

The third line shows the marginal allowable, as we were presented in the notice, at 14 Bcf. This is per month. I should say all of these volumes are in Mcf per month. And, of course, that number has changed dramatically. And we have some concern over exactly what those changes mean and how those changes are being calculated.

But our original recommendation is based on the fact that marginal allowable represented about 75 percent of the total production, and non-marginal wells contributed about 25 percent of the total production.

If you use that basis, we would take 25

percent of the 550 million cubic feet per day potential increase due to pipeline changes and attribute that to non-marginal wells. And the number you see here in line 5, it's labeled total potential for prorated increase, that is 550 million cubic feet per day changed to Mcf per month. It's 17 Bcf per month. Twenty-five percent of that number would be about 4.2 Bcf per month attributable to non-marginal wells.

And the next line down would show how we would divy that up among the four prorated pools based on percentage of sales. For example, the Dakota, having 30.9 percent of the sales, would get 30.9 percent of that recommended adjustment, or about 1.3 Bcf per month.

The biggest change that we saw from what was recommended by the OCD came in the Blanco Mesaverde Pool. And our calculations showed it should have an adjustment of about 2.6 Bcf per month as opposed to previously recommended by the OCD, 1 Bcf a month.

Recognizing that all this arithmetic is a little bit out of date now, we still believe that these are reasonably valid adjustments to look at for the pools on the basis of expected

increased capacity of the pipelines.

If, and the assumption is that the new calculations are as presented today are reasonably right, the marginal, or excuse me, non-marginal production now represents about 50 percent total allowable. And, therefore, our adjustments would basically double if we were to use the same methodology.

And the concern we've got there is that that appears to be such a large increase in adjustment for the allowables that it could cause wells to not be prorated at all. I think the OCD's charge here is to recognize there is some expected increase in capacity and that will have an upward adjustment on the gas production in the basin. It's a very complex situation, difficult to identify.

Our analysis is based on a lot of simplifying assumptions. But we would recommend that you take our original recommendation, 1.3 Bcf adjustment for the Dakota, 2.6 Bcf per month adjustment for the Blanco Mesaverde, and make those adjustments into the new arithmetic.

I'm afraid our proposed F1 and F2 would no longer be valid. That will have to be

recalculated. If that does not appear to be large enough in the course of the six-month period, then the OCD has the authority to make some further adjustments under their proration order.

And I think we would probably recommend that doubling this adjustment would be the maximum that we would recommend going to. So I'm giving you a range of what we are recommending, that it needs to go upward. I'd caution you not to overreact and set allowables so high that none of the wells in the pools are being prorated at all.

Q. So what you've got here is a table that is based on the information that came out with the allowable schedule?

A. That's correct.

Q. Today when the percent of allowable assigned non-marginal wells was substantially increased, that would naturally trigger a change in the recommendation?

A. That's right. And it would basically, if you look at the line entitled, "Recommended Adjustment," which would be an insert into the OCD's format where it says, "Adjustments" --

Q. Basically it would double that recommendation?

A. It would double that recommendation.

Q. And then you are recommending that to assure that in essence all wells in these pools don't wind up underproduced, that the OCD continue to monitor this and reopen the matter if at this time with the new capacity available out of the San Juan Basin there appears to be unanticipated results from the prorationing schedule?

A. Well, I do. I think our recommendation is to go ahead and use the line as it's shown here but recognize that doubling that, if you follow the methodology, would represent probably an upward limit of the type of adjustment you would need. Somewhere in that range is what Amoco would recommend. And it's a very complex situation.

I think to be on the safe side, we would recommend the lower adjustment first. And then, if the OCD sees a need to increase that, either through operator requests or through their own monitoring capabilities, that that could be adjusted upward again during the course of the

six months. But I caution you not to set the allowables so high that no wells are being prorated.

Q. Do you have anything further to add to your testimony?

A. That's it.

Q. Were Exhibits 1 and 2 prepared by you?

A. Yes, they were.

MR. CARR: At this time we would offer into evidence Exhibits 1 and 2 of Amoco Production Company.

CHAIRMAN LeMAY: Without objection Exhibits 1 and 2 would be admitted into the record.

MR. CARR: Thank you. That concludes my examination of Mr. Hawkins.

CHAIRMAN LeMAY: Thank you, Mr. Carr.

Questions of the witness?

Mr. Stovall.

EXAMINATION

BY MR. STOVALL:

Q. I just want to make sure that I understand you, Mr. Hawkins.

A. Okay.

Q. And I realize that a lot of my

confusion is caused by the fact that you were operating on a different set of numbers than I am now.

A. Correct.

Q. One of the problems I've got, let me make sure that I understand what you said first.

A. All right.

Q. Your line, third from the bottom on 2, that's the only one I want to look at is your Amoco recommendation.

A. That's right. The rest of the lines really were based on obviously out-of-date arithmetic.

Q. But you are suggesting that, for example, that the Dakota the adjustment should now be about 2.4. Am I hearing you correctly? Just tell me if that's what I heard you say.

A. I hope I didn't say that. I am recommending that you accept this adjustment. 1.3 Bcf, 1.295953 --

Q. That's right.

A. -- Bcf per month, which appears to be more reasonable to me than if I redo all this arithmetic using the latest figures that you've given us and basically double that. That's what

the new arithmetic would be.

The new arithmetic from what we've seen today would take roughly 50 percent of the potential increase, because of pipeline capacity, and apply it to non-marginal wells. And I am not totally comfortable that that may be such a dramatic increase that there would be no wells that would be prorated as a result of that.

Q. Let me go back and see, then, I think Mr. VanRyan testified this morning that in terms of where adjustments were made in the pools, kind of what the process that was, was to look at what the prior period sales were, find out what kind of F factors that gave, F1 and F2 in the case of the northwest, and then say this isn't in line with what that should be. What adjustments do we have to make to get them to where they ought to approximately be?

A. Uh-huh.

Q. Would it be safe -- would your position, having seen the revised figures on the Exhibit B that was presented this morning, would you be comfortable with making adjustments that kept the F1 and F2 factors for the respective pools consistent now with about what Amoco is

recommending?

I mean, isn't that the bottom line, to make the adjustments to get to the F1 and F2 factors? Or are you more concerned with getting the arithmetic and then ending up with a derived F1 and F2?

A. I think that's the way I'm more comfortable. And the reason I say that, if the F1 and F2 shakes out a lot with how many acreage factors are there participating in this arithmetic, and we know that non-marginal acreage factors are apparently going up from what we originally looked at, what that tells me is that there are a number of marginal wells that are now being reclassified as non-marginal.

I'm not sure on what basis that is. Are they going through a shadow allowable of reclassification, or what? A lot of this has happened so quickly it's hard for me to piece all of it together. That's why I say it's real difficult to say, well, here's what F1 and F2 ought to be, take the adjustment that's necessary.

I think you need to look at there is an additional amount of capacity available in the

basin. This is going to have what we think -- we've tried to quantify what type of increase in production that should result in. And then you have to split that out between the non-marginal and the marginal wells. And I'm not totally sure whether it should be 25 percent or 50 percent to the non-marginal wells.

Q. When we're talking about the non-marginal allowable -- let me back up and ask you the first question I've got in mind. What you're suggesting, then, is that the focus of the concern of the Division in this should be on the pool allowable; that's the number that you need to arrive at -- you're saying take previous history, add an adjustment for additional capacity based upon the proportions that you've set here and based upon some information on Exhibit 1 --

A. Uh-huh.

Q. -- and arrive at a pool allowable; is that correct?

A. That's right.

Q. And then, of course, the non-marginal allowable -- or excuse me. The marginal allowable is simply the marginal production for

the prior like period, subtracted from the pool allowable to get the non-marginal allowable?

A. It's going to be the wells that are classified "marginal."

Q. Correct, right.

A. Okay.

Q. The allowable or the production from the wells that are now classified marginal --

A. That's correct.

Q. -- subtract and then you end up with your number of non-marginal acreage factors?

A. That's right. And it is a complex problem to try to resolve. I think the only thing I can say is that we recognize there's going to be some increases. I'm just not totally comfortable after half a day of looking at this that if I run this arithmetic again and double the previously recommended adjustment that that's not an overshoot, that that's not overreaction.

Q. I guess I'm not quite sure where you get the doubling, I'm sorry. I guess that's the thing that is confusing me.

A. The simplest thing to say is that what our recommendation is based on is to take the 550 million cubic feet a day that I identified on

Exhibit 1 as potential increase, convert that to Mcf per month, and that is what's shown on line 5, 17,024,000 Mcf per month.

Q. Got you.

A. Okay. Now, we would take a certain percentage of that as a recommended adjustment for non-marginal wells that participate in the F1 and F2 arithmetic.

Q. Okay.

A. We chose 25 percent of that originally because that's what portion of total production last year the non-marginal wells contributed, based on the information we received from the OCD.

What we saw today basically changed that by a factor of 2. And it said that now the marginal production was way down, and the non-marginal share would have been roughly 50 percent of the total production.

Q. Okay. I follow you. I see where you get that.

A. If I apply 50 percent, I'm going to call it allocation, for this recommended adjustment, it basically would double the amount we would adjust on each of these pools. And I

have run through an F1 and F2 calculation with some help from Denver, and the numbers appear to be so large that I'm afraid they may be overreacting.

Q. At least I understand how you got there now and what your philosophy is in getting there, and it makes some sense to me.

The only other question I've really got is on the Tapacito Pool. It appears that most of your other recommendations are based on where you were and where you came from. And the current, your recommendation is you're not recommending any truly dramatic -- well, the Blanco Mesaverde has got a significant increase, and the Basin Dakota is reasonably close?

A. Right. Well, the reason for that, the Blanco Mesaverde increase is it currently represents about 63 percent of the production, prorated production, out of the San Juan Basin. And when you see increases due to changing pipeline pressure, I think you're going to see a lion share of that pipeline capacity go to the Blanco Mesaverde.

Q. Now, the Blanco Pictured Cliffs, you've actually gone down on both factors from both the

previous recommendation and from the current one. I'm not quite sure how you got there. I'm kind of looking at the numbers. But it appears to me you had to have given more to the marginal than the Division did; is that correct?

A. That's what I think. It must be a change.

Q. Either the number of factors or the allocation?

A. That's right. And that's why I'm saying it's very difficult to come to the hearing today and make modifications that you're totally comfortable with recommending. I feel very comfortable that we have quantified the potential increase in production from the prorated pools due to pipeline capacity.

And I feel reasonably comfortable with the methodology of sharing it among the prorated pools at 30 percent to the Dakota and 60 percent to the Mesaverde and 5 and 1 percent to the PC and the Tapacito.

The part that I'm beginning to get a little uncomfortable with is exactly how do you distribute it between the marginal and non-marginal wells? And, frankly, it's because

that calculation appeared to change pretty dramatically just this morning.

And I think we need a little time to understand what that means and how we got there. If it's a result of wells moving non-marginal because they have exceeded the shadow allowable, then I think that's probably a valid way to do it. If it's not that, if it's just a reset, kind of an arbitrary adjustment of marginal wells going back in to non-marginal, then I'm not sure what effect that has on our pool arithmetic.

Q. And the one thing that's missing from your recommendation from your Exhibit 2 is that you don't have the number of acreage factors in here so we can't make a comparison to see where there's a difference.

A. Well, the acreage factors are in --

Q. Did you use the ones --

A. We used the ones from both of the -- from what was presented to us by the OCD.

I think you'd have to say on the Tapacito, Amoco is not overly concerned with -- this is a relatively small amount of production out of the basin. Admittedly, you would want to try to set the allowable appropriately for it.

I think our primary concern is with the Dakota and the Blanco Mesaverde because they represent 95 percent of the production from the basin.

Q. I want to make sure when we look at your recommendations, I can see if you used the Division's number of acreage factors and number of AD factors. And with your adjustments they seem to make some sense, although your acreage allocation factor went up and your AD factor went down in the Basin Dakota, and it went up in the Mesaverde. I'm not exactly sure how that happened.

A. I think what I'm recommending is you recalculate the F1 and F2 based on this recommended adjustment. It's going to be slightly different, but I think it's going to accommodate increased production, increased allowable for that pool on the basis of the pipeline capacity increases.

Q. Looking at your Exhibit 1, it appears on your pipeline capacity graph line --

A. Yes.

Q. -- that you have already got an increase in pipeline capacity in the basin?

A. Well, my understanding is that Transwestern has actually increased capacity to about 500,000 MM Btu's per day, and we've converted that into an Mcf estimate, Mcf per day.

Q. I understand.

A. I'm not sure that we've actually seen any dramatic increases -- or excuse me, decreases in pipeline pressure yet as a result of that, but there are increases in production.

But what we're trying to show is that, yes, there is a dramatic increase in pipeline capacity expected to occur between basically February and April of 92. And part of that is implemented we believe now, and the rest of it will be implemented in early April. And that's the best information we have.

Q. Looking still looking at that exhibit, the difference between the total gas and the prorated gas --

A. Yes.

Q. -- do you have an opinion about how much of that is Fruitland coal gas and how much of it is other unprorated gas?

A. I don't. I know the bulk of it is Fruitland coal gas, but I don't have an exact

figure for you.

Q. Were you here for Mr. Merrett's presentation?

A. Yes.

Q. Would you concur that those are probably reasonable numbers on that?

A. Yes, I would.

Q. Now with respect, then, to any increase to give us, say, an opportunity to observe the impact of the increased capacity --

A. Uh-huh.

Q. -- would the overproduction limits in the northwest, which are currently at 12 times overproduced, although I think that's subject to rehearing, does that give some latitude to examine and see what can happen? Does that allow you to produce at a little higher rate to see what would happen? Or does that give you enough latitude where you're already more comfortable with an adjustment?

A. I think we would recommend the adjustment. And the reason for that, we recognize there's going to be a lot of wells coming back on line that are currently probably loaded up with water, can't buck line pressure,

and other wells that are capable of producing that are going to start showing some increases in production.

As far as the overproduction limits, you know, I'm not really prepared to discuss that in any great detail today. I know we're going to have to do a lot of work to get ready for a future hearing on that.

Q. I think we understand what you are recommending, then, and you're saying we can't rely on your F1-F2 factors on your exhibit --

A. Right.

Q. -- that we need to look at the adjustment figures?

A. That's right. And I just would say that I think this is a very complex problem that you're going to see some surprises as we get into this proration period. And the OCD may need to watch very closely and listen to operators and may very well need to make a mid-course correction in allowables. And I know there's authority to do that under our proration order.

So we recommend that you monitor and possibly implement that correction if necessary.

MR. STOVALL: I have no further

questions of the witness, Mr. Chairman.

CHAIRMAN LeMAY: Thank you, Mr. Stovall.

Additional questions of the witness?

Commissioner Carlson?

COMMISSIONER CARLSON: Yes.

EXAMINATION

BY COMMISSIONER CARLSON:

Q. I don't know if I understand what's going on here. Your 550 million on your Exhibit 1 is the difference between the peak prorated gas production, and I guess that's January of 90, and the minimum in -- what is that? July of 91; is that correct?

A. That's correct.

Q. And you attribute that reduction to pipeline pressure?

A. I think it's because of a number of things, and I stated it could be some influence on seasonality, and it could be some influence in natural decline in the reservoirs. But we believe the 550, that number represents the maximum potential for increase when you lower the line pressures back down. You probably won't see more than that. That's a reasonable estimate of

the potential for increase from the prorated pools when you lower the line pressure.

Q. Why would increased line pressure affect prorated gas and not non-prorated gas?

A. It will affect both. That's why -- oh, I'm sorry. It will affect that as well. What we've looked at is trying to identify the prorated gas, because that's a subject of our hearing, as to what is the effect of the lowered line pressures on just the prorated gas.

Q. But is it safe to assume that there's a lot of non-prorated gas, i.e. coal seam, I guess, shut-in right now because of line pressure also?

A. There may be some changes in production in coal seam gas as well. I did not attempt to quantify what that might be. I think what you've got and the way to put it in perspective is this: You've got an additional 1.6 Bcf per day capacity, and we're telling you that probably about a third of that is what you're going to use with the prorated gas production.

Q. I see.

A. The rest of it is going to be available for other sources.

Q. The difference between the numbers,

your calculations, I guess, based on the preliminary allowable estimates and then the ones that you would do under Exhibit B that was handed out by the Division this morning --

A. Yes.

Q. -- is basically the difference in the marginal allowables; right?

A. That's right. And I can try to put that in better perspective. I made a rough attempt at redoing this exhibit with the new -- with the information we got today.

And what happens, just the big change, would be that that marginal allowable would not be 14,072,304 -- this is line 3 on our Exhibit 2 -- it would change to 9,541,431. That's just a sum of the marginal pool allowables for each of the four pools. And the average sales -- there were some adjustments in the average sales apparently too. They would have gone up to 19,104,969.

So if you look at what percent is the marginal allowable of the total sales or average sales, it would say, well, it represents about 50 percent, and therefore there would be about 50 percent available for the non-marginal wells.

Q. But you caution us against doing that?

A. Well, the reason is that when I finished the rest of the calculations, my adjustment comes out very high. My F1 factor, let's just say for the Dakota, calculates to be 6,778, and my F2 calculates to be 8.6.

Well, those are significantly larger than what's recommended by the OCD or what we've seen, and I'm not totally comfortable that that might not move most of your wells even worse into the marginal category.

So, yes, I would caution you to maybe try the 25 percent of the capacity first. And if that does not appear to be sufficient as this capacity opens up, if industry and the OCD recognize that we need to increase the allowable and make a mid-course correction somewhere and increase it again, but I certainly wouldn't go more than double this recommended number. That's based on the 50 percent figure that I had looked at today.

Q. Is Amoco experiencing well shifting to the marginal category from the non-marginal?

A. We have seen the bulk of our wells go from non-marginal to marginal over the last two

years. I couldn't really tell you. In fact, we don't have any way to identify which wells are changing from marginal back to non-marginal with this new information that we received today. Our people back in Denver who are tracking that can't identify which of those wells there are. But I would say that, yes, the bulk of our wells are in the marginal category right now.

Now, they may, as pipeline capacity opens up and pressures drop, we're going to see, probably see, increases in production from both marginal and non-marginal wells. And there is a methodology in place for a marginal well to move back into non-marginal. And that's through its shadow allowable and comparison of that number with its actual production. And that may be what happens, and that's not totally bad.

CHAIRMAN LeMAY: Commissioner Weiss.

COMMISSIONER WEISS: I have no questions. Thank you.

CHAIRMAN LeMAY: I have one.

EXAMINATION

BY CHAIRMAN LeMAY:

Q. It's just an assumption, I think, that you're making, Mr. Hawkins, assuming that all

that is due to line pressure, the 550 million that would be available now because of the increased capacity along the lines, that you're assuming that would also find a market?

A. Yes, I'm making that assumption that that would be available for market. Now, I'm not in our marketing department, and I don't try to pass myself off as an expert in that area. But I think the main thing is that this production would be available for market, and I believe, you know, would probably find its way to market.

Q. Some of your other comments indicate or at least implied to me that the increased capacity was always reflective of increased market demand or at least marketing of the San Juan Basin gas?

A. I think you have to look at the increased capacity was financed by people who expected to be able to market additional gas.

Q. I think they're hoping that. Did you hear Mr. Merrett's presentation with over a Bcf per day into California presently that is in excess of their demand --

A. I heard the earlier --

Q. -- of their consumption. In other

words, we've got surplus capacity and we can't -- you really can't fill up all the pipes because there's nothing on the other end to take it is the point that I think he's trying to make.

A. Well, again, I'm not an expert in this field. I really can't answer all the questions along that line.

CHAIRMAN LeMAY: Additional questions of the witness?

FURTHER EXAMINATION

BY COMMISSIONER CARLSON:

Q. Following up on that, your pipeline capacity numbers, then, you're assuming that those pipelines would be at full capacity flowing with New Mexico gas, New Mexico produced gas out of the San Juan Basin. You're not taking into account, for example, Colorado gas, Utah gas, gas coming in on Northwest Pipe?

A. I don't think I've tried to identify what the sources of gas are other than there is room to move an additional 1.6 Bcf a day.

Q. Right.

A. And we believe that about 550 Mmcf per day is reasonable to expect to come from the prorated gas pools.

COMMISSIONER CARLSON: Thank you.

CHAIRMAN LeMAY: Additional questions of the witness?

If not, he may be excused. Thank you.

Mr. Carr, is there anything else Amoco wishes?

MR. CARR: Nothing further of this witness.

CHAIRMAN LeMAY: Do you want to continue? We have the Basin Dakota left.

MR. CARR: I have a presentation for UNOCAL on the Basin Dakota and Mesaverde and --

CHAIRMAN LeMAY: All three? Why don't we take a 15-minute break, and then we'll come back.

(A recess was taken.)

CHAIRMAN LeMAY: We shall continue.

Mr. Carr.

MR. CARR: At this time, may it please the Commission, I would call Paul West with Union Oil Company of California to present testimony concerning the prorated fields of northwest New Mexico.

Again, Mr. LeMay and members of the Commission, certain of the figures that will be

set forth in the Union exhibits were based on the allowables that were set forth with the docket. We will note those as we go forward with the presentation.

PAUL WEST

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

EXAMINATION

BY MR. CARR:

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

A. Paul West.

Q. By whom are you employed?

A. Union Oil Company of California, doing business as UNOCAL.

Q. What position do you hold with UNOCAL?

A. District Production Manager, Farmington District.

Q. Have you previously testified before this Commission?

A. Yes, I have.

Q. At the time of that testimony, were your credentials accepted and made a matter of record?

A. Yes, they were.

Q. Were you qualified as an expert witness in petroleum engineering at that time?

A. Yes, I was.

Q. Do your duties as District Production Manager include responsibility for monitoring the allowables that are set for the prorated pools in the San Juan Basin?

A. Yes.

Q. Are you familiar with the allowable system?

A. Yes.

Q. Have you reviewed the preliminary allowable estimates for the prorated fields in that region for the next proration period?

A. Yes, I have.

MR. CARR: Are the witness' qualifications acceptable?

CHAIRMAN LeMAY: They're acceptable.

Q. Mr. West, when you reviewed these preliminary estimates, basically what did you find?

A. I found that the Basin Dakota preliminary estimates were providing this approximately 5 percent less calculated allocation than what we had for the similar

period of last year on a typical good Dakota well.

I observed that the preliminary estimate for the Blanco Mesaverde is about 5 percent more than the calculated allocation for the previous year, there again, on a typical good well. And also that the 91 allocations and the 92 estimates for each of those pools is less than what we were granted back in 1990 before we got into the six-month allocation periods.

Q. Now, based on this review, what conclusions have you reached?

A. Well, first, that the transportation pipeline expansions from the basin, which will give us a lot more capacity, will require much more allocation than we had previously to prevent any undue restrictions on our production, especially in the non-marginal wells.

The more important item, I think, is that the preliminary estimate levels will continue to discourage UNOCAL and in fact prevent us from being able to develop each of these pools as far as drilling wells goes and also to install compression to deplete the prorated pools.

And this is a particular problem in the

Blanco Mesaverde Pool due to the fact that the calculation procedure for deliverability leaves us with much less deliverability than the capacity of the well, which is not really a subject of this hearing, but we do have a real problem with that as we draw a well down.

Q. Mr. West, have you prepared certain exhibits for presentation to the Commission today?

A. Yes. Could I address the change of the preliminary estimates?

Q. Before we get into the exhibits?

A. Yes.

Q. If you would review that.

A. I have looked at the final estimates or the ones that were provided to me today, and I do want to commend Mr. VanRyan and his efforts on making this change, particularly on changing the subtraction of the marginal production for the time frame in the last four months and changing that to the time frame that's consistent with the sales figures that's on here. I think that that gives us a lot better basis to determine where allocation should be.

Unfortunately, the change also made all

the numbers on the exhibits that we're fixing to enter wrong, so that's a little bit of a glitch. But the magnitude of the changes are such that I think all of it we'll be entering is not presenting a different picture than what we prepared the exhibits on.

Q. Let's go now to Exhibit No. 1. Would you identify that, please?

A. This is looking at Union Oil Company's allocation impacts in the Basin Dakota and in the Blanco Mesaverde Pools. And what I have shown here is the loss of deliverable gas for the time period for the next six-month allocation period.

Also, in the middle of that column, there shows curtailed proration units. And I will try to point out on this, I know in the past in discussing allocation here at the Commission with others, it is normally an easy thing to do to go to the basin-wide pool allocation numbers and try to get a basis for what is going on.

And we continually are getting into trouble with our better wells in the pools, and it's a dilemma that is not easy to understand when looking at total numbers.

In this particular case on the Basin

Dakota, we say that in this year, the next six-month period, that we will lose 275,000 Mcf deliverable gas in the Basin Dakota. But all of that loss comes from 5 of 78 proration units. That 78 proration units includes both marginal and non-marginal.

This represents a reduction of a third of our production capacity from those 5 proration units but represents 14 percent of our total deliverability from the field.

In the Mesaverde, the number is 194,000 Mcf in loss from 6 proration units. This represents 21 percent of the production from those units and 12 percent of the total pool.

Q. Now, on the bottom of this exhibit, what does that show?

A. This is carrying forward the allocation percentages or F1's-F2's that were given this year, and assuming that those were carried forward, so that we get in the winter this year the same allocations that we got last winter and the same thing next summer that the preliminary estimates showed for this summer.

And the reason for showing this next time period is to illustrate what is happening to

us with the estimates that are being provided to this point.

As you can see, in the Basin Dakota our loss of allowable gas for that year climbs to 700,000 Mcf, which represents 51 percent of the affected proration units' deliverability and 37 percent of the total gas from the pool that we operate.

Blanco Mesaverde, 934,000 Mcf and 55 percent of both the affected pools and the total removable gas. The reason for the second year impact is probably due to a couple of items. The basic one is that we just came out of a period of approximately a year where we've been severely pipeline restricted. We have incurred some constraints in production.

In our prorated pools it's hit us about 17 percent. We've had to shut in 17 percent of last year's production because of pipeline constraints. And the other thing that probably enters into that partially is that in 1990 we did have higher allocations. So our status of overproduction was not quite as bad coming in to 1991.

Q. Let's move now to UNOCAL Exhibit No.

2. Would you first identify what this table shows?

A. This next series of tables is looking at some well-by-well cases. I do apologize for the level of detail that we have here. But the only way to really understand what happens to us on these better wells and we try to manage the allocation that we've given.

The first column of that table is the capability of production is not the deliverability of the "D." It's what the well will actually produce, which as I mentioned there a while ago when talking about the Mesaverde compression issue, that's not always the same.

The second column is the allocation, and this is using the same factors that we had last winter, the last six-month period, and what is proposed for the next six months. Then the third column will be the monthly over- or under-capability.

And then next, the overproduction limit, the over-under -- an overage is described by negative and under is a positive, just to be consistent with the way the proration schedules read.

The next column there is planned production that we would have given the allocations that are suggested and then the cumulative over or under as a result of that plan level. And then finally, the loss of deliverability at the end of each proration year due to the allocation system.

The months of 1991 up-to-date, up through February, are actual numbers so that the capability and the production is all just depicting the actuals.

Q. And beyond that you have used just estimates; is that correct?

A. That's correct.

Q. Now, what does this exhibit actually show you about the Rincon Unit Wells 192 and 192-E?

A. 192-E is a well we just drilled. This is the second Dakota and a proration unit. The 192 marginal well. The reason why you see the small numbers to date, this particular well illustrates what happens to the best well, which is basically a 600-Mcf-a-day well.

We have talked to the Commission about this well before in looking at some minimal

allowable situations, but basically it was felt in that effort that we'd be able to utilize our 12 times over-allowance to help us out early on in the well's stage.

The end of the first proration year there, you see that we have built up to 46,000 Mcf overproduced. And because we, at the end of the proration year, we have to in the ensuing year balance that overproduction by having the number of months that sum up to equal that amount of overproduction, we do have to shut that well in or at least get down below our allowable allocation. We will choose to do that when the prices are probably low, which will be starting in April and going through the summer.

To balance it we have to shut it in for six months. And then put it back on when the prices start getting better. And we wind up at the end of this year with 43,000 overproduced again. That sequence happens to us again where we shut-in for five months in 93 and wind up the end of that year 53,000 overproduced, and the dilemma continues.

Like I say, this is a new well. The total loss from that well for this time period,

which would be a little over two years, the well's life, we have been curtailed by 236,000 Mcf, which dramatically impacts our ability to do the work.

Q. That's actual deliverability that is lost because of the prorationing system that applies to this unit?

A. That's correct.

Q. Let's go to the next page. This is basically the same sort of approach for another well in the Rincon Unit; correct?

A. That's correct. This is a typical good well just picked as an example. It's a well that, as you can see at the end of the first year, is 16,000 overproduced. It's not terribly overproduced. We still have to shut it in for a short period of time. And we realize that 35,000 Mcf loss at the tail end of this proration year.

But, more importantly what happens to us in this next year, again, we'll wind up at the end of this proration year at 46,000 overproduced, have to shut the well in for seven months in order to balance. And so our loss for this next year will be 93,000 Mcf.

Q. On the next page?

A. Next page is another example. In this case this is a well that lost its overproduction cum because of our pipeline constraints and was not able to make its allowable from the period October there on through a number of months.

But the end result is that this well starts out with absolutely no overproduction going into this year and no overproduction -- or no loss of deliverability in the next year, so everything looks real good there. But by winding up at 45,000 overproduced at the end of this year, we again have to shut in seven months the next year in order to balance.

Q. Now, we go to the next page, which is the Rincon Unit No. 80.

A. This is a Mesaverde well. And here, again, is one of our better wells in the pool, starting out kind of like one of the Basin Dakota examples there, where we are relatively close to being in balance in the tail end of this proration year.

We'll have a slight loss of deliverability of 6,000 Mcf for the next year, but we'll wind up 43,000 overproduced and have to shut in six months to balance in 1993. And that

year we'd lose 74,000 Mcf.

Q. Now, the last page on this exhibit.

A. Another Mesaverde proration unit, one of the better ones. And pretty much the same example as the previous one where we are slightly overproduced, and we see 15,000 Mcf of deliverability this year and another 29,000 next year.

Q. Basically is it fair to say that because of the allowable system on these better units, you're consistently losing deliverability?

A. That's correct.

Q. Are you ready to go to Exhibit No. 3?

A. Yes.

Q. Would you identify that, please?

A. This is a suggested revision that we're putting forth to the space preliminary estimates. And these, of course, are much altered because of the final estimates being changed by the state.

The first column appears on the State's publication of the preliminary estimates where on the Basin Dakota, they have suggested 1.2 Bcf administrative adjustment, which would give us the F1's and F2's that are indicated. Our

suggestion on that exhibit was to increase the administrative adjustment to 3.2 Bcf, giving us the F1's and F2's that are indicated.

Since we got the new numbers here, we have looked at that, and the F1's and F2's are obviously what determines allocation we will receive. We've looked at the new estimate, which indicates no adjustment to achieve the same F1-F2 range and principally the same allocation that will provide. We would recommend 2 Bcf of an adjustment on the Basin Dakota Pool.

Q. Now, what about the Blanco Mesaverde?

A. Blanco Mesaverde, we had recommended 4.2 Bcf of an adjustment as compared to 1 Bcf indicating the F1's and F2's shown. With the revised estimates, rather than no adjustment, we would recommend a 3.5 Bcf adjustment to give us the same F1 and F2 type allocations that's indicated on our exhibit.

Q. Let's go now to Exhibit No. 4, and I'd ask you to -- this is basically the same format utilizing Exhibit 1, is it not?

A. Yes, it is.

Q. And then you have integrated into this the UNOCAL recommendation?

A. That's correct.

Q. Would you review this for the Commission, please?

A. The bold-faced numbers appear on the first exhibit showing, starting with the Basin Dakota, the loss of deliverability, the number of proration units impacted, and the percentage of loss of production that we see in our operated part of the pool.

With the administrative adjustment that we suggested, which as I mentioned, would be very, very close to the one that the alternate of 2 Bcf that we just suggested on the revised numbers, our loss of deliverability would fall from 275 to 112.

There was a question a while ago on the previous testimony about what happens to marginal, non-marginal proration units with regard to increases. This is what happens to ours. We lose one proration unit out of five that are impacted by the allocation at that point.

This would be -- when I say it's not, it's not impacted. It may go marginal or it may not, depending on whether it will not make its

allowable for a consistent number of months to fall marginal or whether this is just a non-marginal well that will be run on the borderline and not be impacted. The reduction in the curtailed production will fall to 6 percent of the pool, 16 percent of those that are impacted.

The better well -- the best well, like the new well we're looking at, would be more like 20 percent curtailed. And this is kind of the way we had derived the figure. We felt like a new well shouldn't be impacted any more than 20 percent to be reasonable or what we're looking at in the proration system.

On the Blanco Mesaverde, going through the same exercise with the administrative adjustment being 3.5 Bcf, what's shown here, we cut the loss of deliverable gas in about half. The proration units fall from 6 that are impacted to 2. And, there again, we're losing about 6 percent of the pools that we operate production due to the allocation system.

And, once again, the next year's numbers are more dramatic even with these administrative adjustments that we have

suggested. We would lose 8 percent of the pool's production next year, and we'd probably be better than 25 percent of our best well that would be restricted. And then the Mesaverde, the number is 22 percent of the pool and about a third of the production from the best wells.

Q. Even with your recommendation, production from both Basin Dakota and Blanco Mesaverde will continue to be restricted?

A. That's correct.

Q. Have you reviewed estimates for the Blanco Pictured Cliffs Field?

A. Yes, but not in the level of detail that we have here.

Q. What sort of conclusions could you reach from that review?

A. The conclusion would be that with the suggested -- here, I'll just go straight to the revised estimate that the State provided today. A good PC well, which I say would be about a 100 Mcf a day well, this allocation would give us about a third restriction. And we feel like that is excessive for a 100-Mcf-a-day PC well.

We would suggest an adjustment of 100,000 on the administrative adjustments, which

would equate to a restriction to more like 15 or 20 percent on a 100-Mcf-a-day well.

Q. If your recommendations are adopted, do you believe it would result in a more effective way of producing the reserves from the prorated fields in northwest New Mexico?

A. Yes, I do.

Q. Were Exhibits 1 through 4 prepared by you?

A. They were prepared under my direction.

Q. Do you have anything further to add to your testimony?

A. No, I do not.

MR. CARR: At this time we would move the admission of UNOCAL Exhibits 1 through 4.

CHAIRMAN LeMAY: Without objection, 1 through 4 will be admitted into the record.

MR. CARR: That concludes my direct examination of this witness.

CHAIRMAN LeMAY: Thank you, Mr. Carr.

Questions of the witness?

EXAMINATION

BY CHAIRMAN LeMAY:

Q. Your testimony has been generally confined to the impact on UNOCAL's wells. Do you

happen to know how other operators in the field feel about your requested increases in allowables in this field or all these fields?

A. Well, the Amoco -- Amoco and Phillips I don't have any idea on as far as what they think about a large increase.

Q. But none of the other operators in the field have either received your recommendations or have indicated to you whether they support or object to or are noncommittal about your recommendations?

A. No.

CHAIRMAN LeMAY: Thank you.

Additional questions of the witness?

Okay. Thank you. You may be seated.

Any additional?

MR. CARR: Nothing further from me.

CHAIRMAN LeMAY: Thank you, Mr. Carr.

Mr. Pearce.

MR. PEARCE: Thank you, Mr. Chairman.

CURT CZIRR

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

EXAMINATION

BY MR. PEARCE:

Q. For the record, sir, would you, please, state your name and your place of residence.

A. My name is Curt Czirr. I currently reside in Farmington, New Mexico.

Q. Mr. Czirr, for the record, would you, please, spell your last name?

A. C-z-i-r-r.

Q. Mr. Czirr, by whom are you employed?

A. Phillips Petroleum Company.

Q. And in what capacity?

A. I'm the Field Development Supervisor of the San Juan Basin.

Q. Mr. Czirr, have you previously appeared before the New Mexico Oil Conservation Commission or Division and had your credentials accepted and made a matter of record?

A. No, sir, I have not.

Q. In view of that, would you previously describe your educational background as it relates to petroleum engineering?

A. Okay. I have an electrical engineering degree from Colorado State in 1980. I've worked for over eleven years with Phillips Petroleum Company in the capacity as a reservoir engineer. And currently I'm the reservoir engineering

supervisor.

Q. How long have you had some responsibility for gas pools in northwest New Mexico?

A. I've been looking at this for around two years.

Q. As part of your responsibilities and as part of the reason for your being here today, have you made a study relating to allowables and production figures in the Basin Dakota Gas Pool?

A. Yes, sir, I have.

Q. And are you prepared at this time to make some recommendations to the Commission with regard to the allowables for that pool?

A. Yes, I am.

MR. PEARCE: Mr. Chairman, at this time I would request that Mr. Czirr be recognized as an expert in the field of petroleum engineering.

CHAIRMAN LeMAY: His qualifications are acceptable.

MR. PEARCE: Thank you.

Q. Mr. Czirr, as a preface, briefly describe what Phillips seeks this afternoon, please.

A. First of all, we're keenly interested

in the Basin Dakota Pool allowables. We're seeking pool allowables which prorate the Basin Dakota Pool equitably when compared to other pools in the San Juan Basin.

And we're seeking allowables that do not penalize producers who choose to produce year-round and supply a steady supply of gas. And we hope to obtain allowables that are sufficient to encourage additional development in the Basin Dakota Pool, whether it be by delta drilling, re-stimulations, et cetera, aimed at maximizing production.

Q. In regard to that, Mr. Czirr, does Phillips have a suggestion for the increase in the Basin Dakota Pool allowable?

A. Yes, sir, we do.

Q. I ask you to tell me what that is and specify whether you're addressing that increase to the preliminary or the exhibit used this morning.

A. Based on the exhibit used this morning, Phillips would recommend a 3-Bcf-a-month increase for adjustment.

Q. All right, sir, do you have -- I don't think you do -- a copy of Exhibit B that the

Division used this morning?

A. No, I don't.

Q. Let me hand you that. And as I understand it, we're suggesting that a 3 Bcf adjustment be put in line 3 under the Basin Dakota Pool; is that correct?

A. Yes, sir.

Q. Let's turn our attention, please, to what we have marked as Exhibit No. 1 to this proceeding. And, Mr. Czirr, I'd ask you to highlight the pertinent information on that exhibit for the members of the Commission and those in attendance.

A. Okay. First of all, as you're aware, historically there's been a significant difference in pool allowables during the six months' summer period versus the winter period. We wanted to take a look at that and investigate why that was. Of course, we found out that one thing was that the production was much less in the summertime.

We looked at all the Basin Dakota production using Dwight's database and determined that there were approximately 3800 active Basin Dakota wells right now. Out of that 3800,

approximately 38-1/2 percent or 1462 wells had a winter production at least twice as great as the summer production.

And I might further clarify that by saying we do not have access to the current winter production that we're in right now. We didn't have access to that data. So we were comparing November, December, and January -- November and December 1990, January of 91, and calling that representative of winter production, comparing that to May, June, and July of 1991, comparing that as summer production.

And, as I said, there were 1462 wells that had a winter-to-summer production ratio of at least 2 to 1. What this means is that, you know, certainly the winter production is much more representative of the actual pool's deliverability.

With the large number of wells that are producing swing during the winter versus summer, the bulk of this has to be attributed to elective curtailment amongst the producers according to their own gas marketing strategy. And we don't feel that looking at summer production gives you a fair indicator of the pool's deliverability.

Q. Let me interrupt you for a moment. Were you in the hearing this morning when Mr. VanRyan expressed the opinion that part of the lower summer production might be attributable to higher gathering system pressures?

A. Yes, I was here.

Q. And have you seen that effect in your study of particularly Phillips wells?

A. I have not observed that, no.

Q. And based on your review and your understanding, as I understand what you said, you formed the opinion that the decrease in summer production may be largely a function of strategic behavior rather than market; is that correct?

A. Yes, sir.

Q. All right. Continue, please.

A. That has a negative impact on companies such as Phillips that elect to try to produce year-round in that theoretically, if you were to take every person in this room and make them an operator of wells in the Basin Dakota Pool and if everybody in this room elected not to produce during the summertime and yet Phillips elected to produce during the summertime, the overall pool allowable during the summertime would be near

zero and Phillips would be penalized because of that.

And you're penalized even on an annual basis because companies electing to shut-in during the summertime, there's no way they can make that much gas up during the winter production period. And the result is lower overall annual pool production. And companies such as Phillips that choose to produce year-round, we get penalized because of somebody else's marketing strategy.

Q. With regard to marketing strategy, is it your position, understanding, and opinion that there is in fact a year-round market for more gas than current Basin Dakota allowables will allow Phillips to produce?

A. Yes, sir. Again, not being a gas marketing person, I do know that we have not encountered difficulty marketing any of our gas at all.

Q. And do you currently have proration units which are shut-in because of overproduction?

A. Yes, sir, we do.

Q. Do you also have some proration units

which are approaching the 12 times overproduced limit?

A. Yes, sir, we do.

Q. Let's look, if you would, please, at what we've marked as Exhibit No. 2 to this proceeding.

A. Okay.

Q. A lot of numbers on that page. Could you walk us through an example and explain to the Commission what this exhibit shows?

A. Yes. First of all, what we're trying to do with this Exhibit No. 2 is provide a comparison for the non-marginal pool allowable assuming that -- first of all, this was prepared using the old numbers that we had received in the mail in terms of non-marginal acre factors and AD factors.

But assuming that those non-marginal acreage and AD factors had remained unchanged, and this exhibit shows the effect of higher F1 and F2 factors on the allowable that various deliverability Gpu's could obtain.

If we start off on the far-left column of numbers, the top part of that represents the non-marginal pool allowable, non-marginal acreage

factors, F1 and F2 that had been previously proposed by the OCD in their mailings for the Basin Dakota Pool.

If we use those numbers and continue down in that column, for a Gpu deliverability of 200 Mcf a day, then the ratio, the allowable then would be approximately 88 percent of the deliverability.

If we continue on down for a 500-Mcf-a-day deliverability Gpu, then the proposed factors in the OCD mailing would give us only a 45 percent -- an allowable that's 45 percent of deliverability.

And this situation continues to get worse and worse as you go down into higher productivity Gpu's. For 750 Mcf a day, you'd be at 35 percent. And for 1.5 million a day, you'd be at 26 percent.

And the columns to the right represent the exact same comparison if you were to change the F1 and F2 factors. If you were to increase the F1 and F2 factors, then it has calculations showing what percent your allowable would be for a given deliverability for those changes.

Phillips has recently drilled several

infill wells, a second well on 320-acre gas proration unit, in the 31-6 Unit. And one of those Gpu's has a combined deliverability of the two wells. And that Gpu is approximately a million a day, and the other Gpu has a combined deliverability of approximately one-and-a-half million a day.

And those sound very good, and technically we were very excited about our ability to make such nice wells. When we start looking at what kind of allowables we'll receive, we find out that we're going to receive between 25 and 30 percent of that as an allowable. That means our production is going to be insufficient to justify those wells.

Those wells were technically very successful, but they're economic failures under the current prorationing system.

Q. Is it fair to say that problem may impact future management decisions on whether or not to do further infill development in the Basin Dakota?

A. Yes, sir. We have a number of wells within that 31-6 Unit and within one or two other units that we would certainly desire to be able

to drill. And under the current proposals or anything close to them, the economics won't be there because no matter how good a job we do on our end, technically the allowable won't be there.

As an additional statement, in that same 31-6 Unit, there's a total of 23 wells -- prior to these 3 infill wells, there were 23 wells, so now there's 26. We currently have 6 of them shut-in due to being 12 times overproduced, and we have 3 more on the way.

Q. Ready to turn to Exhibit 3?

A. Yes. I guess the only other thing I would say is, again, looking at Dwight's production data, we found that over the last three years, 1989, 1990, and 1991, there's been an average of only 15 Basin Dakota wells drilled per year.

That's an extremely small number when you're talking about over 3600 wells in the basin. And we think that the proration has a significant impact on that.

Q. All right, sir, let's direct your attention, please, to Exhibit No. 3.

A. Exhibit No. 3 basically shows

graphically the numbers that we just went through in Exhibit No. 2. Again, what we're comparing on the vertical axis here would be the non-marginal pool allowable in million cubic feet per month. And on the horizontal axis, we're comparing the Gpu allowable as a percent of its deliverability.

And we've got a family of four curves here representing Gpu's with 200 Mcf a day deliverability, 500 Mcf a day, 750 Mcf a day, and 1500 Mcf a day. The 200 Mcf a day Gpu deliverability is represented by the line to the far right. And what that shows you is that again for 200 Mcf a day Gpu, you're going to be allowed to produce around 90-plus percent of what your deliverability is.

As you move left on the chart, all the way over to the 1500 Mcf a day Gpu, which is the far left line, the bottom point on that line, which represents a non-marginal pool allowable of approximately 1.9 Bcf a month, that represented the non-marginal pool allowable as proposed in the mailing, the Basin Dakota.

And assuming that the acreage factor and AD factors remained unchanged, then this is a

graph showing that even if you allowed a significantly higher non-marginal pool allowable, 3.1 Bcf a month, you'd still be at just over 40 percent, an allowable of only 40 percent of your deliverability. And that would still be borderline between an economical well to drill.

Q. Mr. Czirr, you mentioned earlier in your testimony that Phillips was seeking some adjustment for equity reasons between various pools in the basin. I'd ask you to direct your attention, please, to Exhibit No. 4. And could you describe the information and calculations shown there for us?

A. Yes. Certainly the Basin Dakota Pool and Blanco Mesaverde, as well as other pools, they have different formulas for determining an allowable. For example, in the Dakota, it's been decided that you would base 60 percent of your allowable for a non-marginal well on acreage and 40 percent on acreage times deliverability.

Whereas, for Mesaverde, you'd base 75 percent of your allowable on deliverability and only 25 percent on acres. So we recognize that there's differences in the formation in the various pool proration formulas.

However, we feel that overall if you look at the Basin Dakota Pool as a conglomerate pool and you compare that to other pools, primarily say Blanco Mesaverde since it's the largest, if there's curtailment between any of the pools, the curtailment should be spread equitably.

And this exhibit attempts to show that, again, based on the F1 and F2 factors submitted in the mailing by the OCD, that equity wasn't there between the Basin Dakota and the Blanco Mesaverde.

To go through it, if you look at F1 factor comparison, if you take the proposed F1 factor for the Dakota of 4357 Mcf per month and divide that by .6, then you come up with a non-marginal pool allowable divided by the sum of the acreage factors of 7262.

If you do the same thing for the Blanco Mesaverde and you take the F1 factor that was proposed of 2815 and you divide it by .25, then you come up with a non-marginal pool allowable divided by the sum of non-marginal acreage factors of 11,260.

And the F1 factor for Basin Dakota

would have to be, instead of 4357, it would have to be 6756 in order for those two factors, those two products to be the same.

And if you look at the F2 factor comparison, the proposed F2 factor for Basin Dakota of 4.94 divided by .4 gives you a non-marginal pool allowable divided by the sum of the non-marginal AD factors of 12.34.

For the Blanco Mesaverde, the proposed F2 factor of 12.81 divided by .75 gives you a product of 17.8. And, again, the Basin Dakota F2 factor would have to be 6.83 in order to yield the same product.

And what you conclude by this, and we will show in Exhibit 5, is that inequities between the F1 and F2 factors result in the Basin Dakota Pool being curtailed via proration to a greater extent than the Blanco Mesaverde.

Again, if we use the AD factors that were submitted by the OCD in the mailing, those showed an average Basin Dakota Gpu having a deliverability of 588 Mcf a day for a non-marginal Gpu and a Mesaverde average deliverability of 659. Those are-- in the mailing those were very close, not much

difference between the two.

I'd like to go ahead and go to Exhibit 5.

Q. Go to 5, please.

A. Exhibit 5 shows graphically what we just talked about in Exhibit 4. On the vertical axis, I've got your Gpu allowable as a percent of deliverability. So anything over 100 would represent an allowable that's greater than its deliverability, and so therefore it would drop over into a marginal status anyway.

On the horizontal axis, I have the actual Gpu deliverability ranging from zero to 1600 Mcf a day. The thin solid line connected by dark dots represents the allowable that you would get as a percent of deliverability based on the F1 and F2 factors in the OCD mailing.

The dashed line connected by asterisks represents for the basin -- or for the Mesaverde represents the allowable as a percent of deliverability. And you'll see that those two cross over at somewhere around a Gpu deliverability of about 200 Mcf a day.

And that's not far from -- and at that point you're about almost 90 percent allowable,

being about 90 percent of deliverability. So you're almost dropped over into the marginal well status where those cross over.

Since in the mailing it showed that the average Dakota well Gpu and the average Mesaverde well Gpu deliverabilities were almost identical at roughly 600 Mcf a day than if you were prorating the Basin Dakota equitably with the Blanco Mesaverde, those two lines should cross over at about 600 Mcf a day.

And if referred to the thick solid line that I show here, this gives you a Dakota allowable as a percent of deliverability using the F1 and F2 factors that I've said on Exhibit 4 that you would need to use to be equitable, and you'll see that it indeed crosses the Mesaverde line in the vicinity of 600 Mcf a day.

And what that's telling you is if you achieve that, then your proration formulas are doing what you've designed them to do. You've designed your proration formulas to allow low deliverability Dakota wells to receive a higher allowable than a similar deliverability Mesaverde well.

You've also designed your formulas to

allow a high deliverability Dakota well to receive a slightly less allowable than a high deliverability Mesaverde well.

So what Phillips is saying is, first of all, we believe that the Blanco Mesaverde Pool allowable should be increased over and above what's currently being proposed by the OCD for using the similar logic that we shouldn't be penalized for producing year-round when other operators are shutting in in the summer.

But all we're saying is we think the Basin Dakota should be increased even more as a percentage. The F1-F2 factors should be increased dramatically in order to get proration for Basin Dakota on an equitable basis with the other major pool in the San Juan Basin, which is the Mesaverde.

Q. After conducting your study, let's summarize the conclusions you've come to, please, sir.

A. Okay. First of all, we feel that the proposed -- that the OCD proposed F1 and F2 factors for the Basin Dakota Pool are inadequate in that they penalize too much the non-marginal well and don't allow for development, development

drilling, recompletions, re-stimulations.

We feel that, as a whole, the Basin Dakota Pool should be prorated equitably with other pools. That doesn't -- knowing full well that for any given Gpu deliverability, the formulas are set up for them to have different allowables, but on a pool-wide basis, it should have equity in it.

We feel that the true Basin Dakota deliverability is something more approximating 10 Bcf a month. Historically if you look back at Basin Dakota Pool production, you'll find that in the winter months it's consistently been able to produce at least 10 Bcf a month during the main winter months.

A very small amount of that could be due to flush production from having been shut-in in the summer, but we feel that is a very minor component of it.

Currently less than 10 percent of the Gpu's in the Basin Dakota Pool are designated as non-marginal. The vast majority of Basin Dakota Pool is producing at whatever amount it wants to and using whatever production strategy it wants to.

And the proration that's currently in place is only hurting those few Basin Dakota Gpu's that have moderate deliverability. We've been hearing about some of the southeast New Mexico pools with deliverabilities of 5, 6 million a day, and we can only dream of that. We're talking about 4- and 500 Mcf a day wells here and 700 Mcf a day wells. And we think the proration should be relaxed.

We feel that correlative rights, at least in terms of off-lease drainage from higher allowables, is not an issue. You've got over one-third of the Basin Dakota wells currently being operated on a swing basis, shut-in during the summer or produce at very low volumes and then produce at full capacity in the winter.

There's no way on an annual basis that they can produce as much gas that way as they could if they were producing year-round. And if operators were concerned about off-lease drainage, we don't think that they would have adopted that type of swing production philosophy.

In conclusion, again being consistent with what we think the true deliverability of the

Basin Dakota is and realizing that we need to have equity in proration, we are recommending a 3 Bcf a month adjustment.

Q. And that 3 Bcf a month adjustment will raise the monthly pool allowable to approximately 10 Bcf; is that correct?

A. Yes, sir.

Q. Were you in the room this morning when Mr. Hastings was on the witness stand for Marathon discussing the marketing situation?

A. Yes, sir.

Q. Are you in general agreement that there is a necessity for operators to be able to produce quantities of gas year-round without suffering the summer reduction in order to capture market?

A. Yes, sir. In fact, I agreed with every point that he made. And Phillips may be a little bit behind Marathon, but we are trying to also adopt similar marketing strategies looking for long-term contracts at attractive prices that are certainly at a premium to the current prices today.

Those long-term contracts require a steady volume of gas, whether it's 20 million a

day for that contract or 50 million a day for that contract. It's flat for that 10 or 15 years. And that's another reason why Phillips again has the need to produce year-round.

Q. Mr. Czirr, when we began, you indicated to the Commission that you were primarily a reservoir engineer. And I want to address your attention to the reservoir for a few moments.

You've indicated that increased allowables are necessary in order to enable producers to further develop the Basin Dakota Pool. In the absence of those increased allowables and the increased development, do you believe the loss of ultimate recovery from the Basin Dakota Pool will result?

A. Without a doubt. The three infill wells that I mentioned earlier that we drilled in the 31-6 Unit, we drilled them last December. We took bottom-hole pressures in two out of those three wells, and they showed near original bottom-hole pressure.

We're clearly drilling in areas that are currently not drainable by existing offset producers. And if we don't get the allowables to make it economical to drill, those reserves will

sit in the ground.

Q. Mr. Czirr, based on that discussion, do you believe that the request of Phillips for an increased allowable in the Basin Dakota Pool to 10 Bcf per month is in the best interests of the prevention of waste of New Mexico's natural resources?

A. Absolutely.

Q. And do you believe that granting that increase in pool allowable will not adversely affect correlative rights of operators in the Basin Dakota Pool?

A. Absolutely.

Q. Mr. Czirr, did you prepare or did you have prepared under your direction and supervision Phillips Exhibits 1 through 5 to this proceeding?

A. Yes, sir.

Q. Do you have anything else you'd like to address to the Commission?

A. No.

MR. PEARCE: Mr. Chairman, I move the admission of Phillips Exhibits 1 through 5. And I tender the witness for questioning.

CHAIRMAN LeMAY: Thank you, Mr.

Pearce. Without objection, Exhibits 1 through 5 will be admitted into the record.

Questions of the witness?

MR. STOVALL: Just a couple quick ones. Mr. Carr, do you have any?

MR. CARR: No questions.

EXAMINATION

BY MR. STOVALL:

Q. I just want to make sure I understand your recommendation, Mr. Czirr. At one point you made a statement you recommend an adjustment of 3 billion?

A. Yes, sir.

Q. On which schedule are you basing that recommendation, the one sent out with the docket or the one that was presented today?

A. Today.

Q. I wanted to clarify that. You've talked about getting to a pool level of 10, and that really only gets you to a pool level of about 9. Where do you want to be on that? Let's make sure we're getting a number you're happy with as far as your testimony is concerned. Do you follow what I'm saying?

A. Are you saying --

Q. If you look at the Exhibit B, Basin Dakota is 5.8. If you add 3 to it, you get about 8.8?

A. Yes.

Q. Is that number okay with you?

A. Yes. The 3 Bcf, we're looking at a total adjustment, initially looking at the old OCD mailings, and that did correlate to 10 Bcf a month. The current OCD mailings, if you add the 3 Bcf adjustment, that gets you, as you said, only to about a little less than 9 Bcf total for the pool.

But the OCD has taken that into consideration by down-scaling the marginal pool allowable using previous summer rates instead of winter. So I think we're talking about the same thing --

Q. Okay.

A. -- at least in terms of how it affects the non-marginal wells.

Q. I just wanted to clarify that. And just, if you know, is your reason for suggesting equality between the two pools based on your sense that it should be equal, or is there a regulatory basis for that that you know of?

A. No. It's based on my sense that --
Q. Okay.
A. -- you shouldn't prorate one pool without prorating -- if you have proration, if you already have proration set up for a pool, then that proration is set up to protect correlative rights.

And if owners in one formation are denied access to market more so than owners in another formation because of the proration system, then I don't think you have correlative rights protection.

MR. STOVALL: I have no further questions.

CHAIRMAN LeMAY: Additional questions of the witness?

COMMISSIONER CARLSON: Not for a minute, no.

COMMISSIONER WEISS: Yes.

EXAMINATION

BY COMMISSIONER WEISS:

Q. I was surprised in your comment on the near-virgin pressures when you cut an infill well on a dry gas reservoir. How does that happen?

A. Well, first of all, the 31-6 Unit that

I was quoting probably has some of the best Dakota production in the pool. Having said that, though, it is extremely tight formation, particularly when you compare it to other pools.

When we drill a good well, we're talking about in general maybe a 700 Mcf a day well is an excellent well for us. We have just not seen -- we've just not seen that the existing 320-acre spaced wells are capable of draining that 320 acres.

And so when we drill an infill well on 160-acre spacing, certainly we see some moderate depletion, but it's not much at all. Original bottom-hole pressure in the 31-6 Unit was around 3300 pounds.

When we did bottom-hole pressure tests in two out of those three infill wells, we tested the most permeable formation where all the offset wells had already been completed, and that's where they had produced most of their reserves, and we found between 2900 and 3,000 PSI reservoir pressure with downhole gauges.

And I think that just falls in line with OCD orders allowing for 160-acre spacing in that they've recognized that wells can't drain

320 acres.

Q. You ought to talk to Fichivich about that sometime. I don't think he'd agree with you at all.

A. Maybe if you talk about Hugoton he might not.

COMMISSIONER WEISS: That's all.

CHAIRMAN LeMAY: I have one question.

EXAMINATION

BY CHAIRMAN LeMAY:

Q. Is it you personally or do you think Phillips wants the OCD to create equity between prorated pools? That's a different concept than we've ever operated under. Texas operates under that, but you compared to one pool.

I think, by expanding that concept you'd have to say other pools, and maybe even bringing southeast New Mexico, who produces in the same California market as northwest pools, then you'd be trying to equate Indian Basin equity with Basin Dakota.

Are you sure that kind of position is something advocated by your company?

A. I can say that that's a position advocated by our Farmington office. And whether

that reflects the position of our corporate office, I couldn't say.

Certainly the Basin Dakota and the Blanco Mesaverde, they're in the same basin and very much tied to each other.

Q. You'd like to see us create equity between just certain fields and not all fields?

MR. PEARCE: I'll jump in, Mr. Chairman.

CHAIRMAN LeMAY: Mr. Pearce.

MR. PEARCE: The witness has made what I think is a valid fairness argument with regard to the restrictions suffered by Basin Dakota versus Mesaverde competing for the same market, two prorated pools in northwest New Mexico with gas trying to get in to the same market.

I think the other states who have approached the argument that you are suggesting have viewed the world as a much more finite place than Phillips does or that any company witness who's been on the stand today has.

Phillips is not in this proceeding and, as far as I know, has not ever suggested that you take an allowable that you believe can be produced out of the Blanco Mesaverde and move

that allowable to the Basin Dakota. That hadn't been suggested here today, isn't being suggested now, and I suspect won't be suggested in the future.

What we are suggesting is that we believe the market is much larger than the Division's numbers make us think that they believe it is. We think we should not therefore suffer an undue restriction on our ability to produce because Phillips believes they can go out and find markets and move gas and sell gas.

They're not trying to choke back any other pool in the State of New Mexico, and they are not, I don't think, suggesting any statewide prorationing system which chokes back one pool because another one gets more. Phillips wants to produce more gas. They don't think it's necessary to have somebody else produce less.

CHAIRMAN LeMAY: Thank you, Mr. Pearce. Just one more question.

Q. (BY CHAIRMAN LeMAY) Have you contacted other operators in the field, and do they feel the same way you do about the allowable situation with the additional 3 Bcf recommendation?

A. I guess the best way to express it is

we've contacted every operator in the Basin Dakota Pool about deprorating the Basin Dakota. And we've had several companies, in fact, that have testified in front of you today, UNOCAL and Marathon, who not only said they agreed, but said they would support us in a hearing.

The bulk of the operators have said that they do not object to removing proration. I think out of a total of approximately say 3800 wells -- 3600, 3800 wells, operators representing approximately 100 wells have shown concern. So that's their attitude towards totally removing proration.

What we're asking really is a step towards that direction where you have less proration.

Q. In terms of your specific recommendation to the Commission today, have you circulated that among operators in the field, and have you got any reaction to that recommendation?

A. Only to the extent that we've had discussions with UNOCAL.

Q. The other operators didn't know of your adjustment or have not commented on it, either pro or con?

A. That's correct.

CHAIRMAN LeMAY: Thank you.

Additional questions of the witness?

If not, you'll be excused. Thank you.

Anything additional, Mr. Pearce?

MR. PEARCE: Nothing.

CHAIRMAN LeMAY: Anyone else have anything?

Yes, sir.

MR. JONES: Mr. Chairman, Lewis Jones, Meridian Oil Company. I'm the production manager out of Farmington, New Mexico. You've asked how some of the other companies feel. I'd like to make a few suggestions, if I could. I haven't done my homework, like a few of the others earlier, but I have stayed all day, so give me a little bit of credit for that.

The different systems that were talked about in the San Juan Basin as far as conventional -- well, excuse me, line pressures were discussed as far as conventional and coal seam. For the most part the bulk of the coal seam production is segregated from the conventional system.

And, to my knowledge, there's no other

gathering system in the United States that has higher gathering system pressures now than they did 20 years ago. And that's on the conventional gathering system. So when Amoco says that they feel like we have over a Bcf of capacity, I think they're being extremely conservative. I think it's much more than that.

As far as the recommendations that have been made today and Meridian's recommendation, the Dakota adjustments and that's off the most recent, today's OCD Exhibit B, Amoco had recommended 1.3 Bcf; UNOCAL, 2.0 Bcf; and Phillips, 3.0 Bcf. In the Mesaverde, Amoco had recommended adjustments of 2.6 Bcf; UNOCAL, 3.5 Bcf; and I think Phillips just suggested an increase.

One other comment about Curt's -- your presentation, an excellent job; however, do not sell the Blanco Mesaverde short because the Blanco Mesaverde is much more sensitive to lower line pressures. And that's going to occur with the greater capacity coming out of the basin. These pipelines want to fill their pipeline capacity, and they're going to lower gathering pressures.

As far as our recommendation, we would probably lean toward the UNOCAL recommendation of 2.0 Bcf adjustment in the Dakota and the 3.5 Bcf adjustment in the Mesaverde.

Thank you for the opportunity, Mr. Chairman.

CHAIRMAN LeMAY: Thank you.

Any other statements or comments concerning the case? We will leave the record open ten days for additional comments based, of course, on the fact that we did hit you with a new Exhibit A and B today that a lot of you prepared exhibits on what was mailed, and that's understandable. So if you want to add to the record, we will certainly leave it open ten days.

Additional comments or statements?

We'll take the case under advisement. Thank you very much, ladies and gentlemen.

(The proceedings were adjourned.)

CERTIFICATE OF REPORTER

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

I, Debbie Vestal, Certified Shorthand Reporter and Notary Public, HEREBY CERTIFY that the foregoing transcript of proceedings before the Oil Conservation Commission 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 March 11, 1992.

Debbie Vestal

DEBBIE VESTAL, RPR
NEW MEXICO CSR NO. 3