STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO

9 November 1988

EXAMINER HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Company for the amendment of Division Order No. R-6469, as amended, Rio Arriba County, New Mexico. New Mexico.	CASE 9525

BEFORE: David R. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division: Robert G. Stovall
Attorney at Law
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico

For the Applicant:

MR. STOGNER: Call next Case Number 9525.

MR. STOVALL: Application of Benson-Montin-Greer Drilling Corporation for the amendment of Division Order No. R-6469, as amended, Rio Arriba and San Juan Counties, New Mexico.

MR. STOGNER: The applicant has requested that this case be continued to the Examiner Hearing scheduled for December 7th, 1988.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C. S. R. DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9505, heard by me on November 9 1988.

David R. Catanach, Examiner,
Oil Conservation Division

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO

7 December 1988

EXAMINER HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer for the amendment of Division Order No. R-6469, as amended, Rio Arriba County, New Mexico.	CASE 9525

BEFORE: David R. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division: Robert G. Stovall
Attorney at Law
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico

For the Applicant:

MR. CATANACH: Call next Case 9525.

MR. STOVALL: Application of Benson-Montin-Greer Drilling Corp. for an amendment to Division Order No. R-6469, as amended, Rio Arriba County, New Mexico.

Applicant requests this case be continued to January 4th, 1989.

MR. CATANACH: Case 9525 will be continued to January 4th, 1989.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C. S. R. DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9525, heard by me on December 7, 1981.

David R. Catanach, Examiner
Oil Conservation Division

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO

4 January 1989

EXAMINER HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corp. for the amendment of Division Order No. R-6469, as amended, Rio Arriba County, New Mexico. CASE 9525

BEFORE: David R. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division: Robert G. Stovall
Attorney at Law
Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico

For the Applicant:

MR. CATANACH: Call next Case 9525.

MR. STOVALL: Application of Benson-Montin-Greer Drilling Corporation for an amendment to Division Order No. R-6469, as amended, Rio Arriba County, New Mexico.

This case is shown as being continued to January 18th but applicant requests the case be continued to February 1st, 1989.

MR. CATANACH: Case 9525 will hereby be continued to February 1st, 1989 hearing.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C. S. R. DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9525, heard by me on January 4 1989.

David R. Catanach, Examiner
Oil Conservation Division

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO

1 February 1989

EXAMINER HEARING

IN THE MATTER OF:

Application of Benson-Montin-Greer Drilling Corporation for the amendment of Division Order No. R-6469, as amended, Rio Arriba County, New Mexico.	CASE 9525

BEFORE: David R. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division:

For Benson-Montin-Greer Drilling Corporation:	William F. Carr Attorney at Law CAMPBELL and BLACK, P. A. P. O. Box 2208 Santa Fe, New Mexico 87501
For Mobil Producing Texas and New Mexico, Inc.:	W. Perry Pearce Attorney at Law MONTGOMERY & ANDREWS P. O. Box 2307 Santa Fe, New Mexico 87504

I N D E X

E X H I B I T S

MR. CATANACH: We'll call Case 9525.

The application of Benson-Montin-Greer Drilling Corporation for the amendment of Division Order No. R-6469, as amended, Rio Arriba County, New Mexico.

Are there appearances in this case?

MR. CARR: May it please the Examiner, my name if William F. Carr with the law firm Campbell & Black, P. A., of Santa Fe.

We represent Benson-Montin-Greer Drilling Corporation and I have one witness.

MR. CATANACH: Any other appearances?

MR. PEARCE: May it please the Examiner, I am W. Perry Pearce from the law firm of Montgomery and Andrews, appearing in this matter on behalf of Mobil Producing Texas and New Mexico, Inc.

I do not have a witness.

MR. CATANACH: Any other appearances?

MR. HAWKINS: Mr. Examiner, my name is Bill Hawkins. I am an employee of Amoco Production Company.

I understand a letter requesting entry of appearance in this case will be forthcoming and I'd like to enter that into the record.

MR. CATANACH: Okay. Any other appearances?

Will the witness please stand to be sworn in?

(Witness sworn.)

MR. CARR: May it please the Examiner, I have a brief opening statement, if I could make that at this time.

MR. CATANACH: You may proceed.

MR. CARR: Benson-Montin-Greer is before you today seeking an order that would amend a prior commission order, Order R-6469, which was entered in September of 1980.

This order, among other things, created certain nonstandard spacing units in the Canada Ojitos Unit, which is operated by Benson-Montin-Greer Drilling Corporation.

We're here today to seek termination of certain of these units and we're going to show

you that now termination of these units is required by prudent operating practices.

In making our presentation today we are first going to address fluid movement across the southern boundary of the Canada Ojitos Unit. As the Examiner may be aware, there was a presentation last August by McHugh in a case concerning expansion of the West Puerto Chiquito Pool and at that time certain other companies appeared and presented testimony which suggested that this fluid migration across the southern boundary was simply not occurring.

For our application to make any sense, abolishing these units on the southern boundary, it is necessary that we come in here and show you that we have evidence, we believe, which establishes that this migration is in fact occurring.

Originally regional migration occurred to the north along the southern boundary into the unit. In 1968 gas injection commenced and this fluid migration was virtually stabilized.

In 1985, however, with development from the Schmitz anticline and other production in the area, drainage started occurring away from the unit. To mitigate this drainage Benson-Montin-Greer as operator of the unit now must drill certain wells along the southern

boundary, but in doing this, it is essential that we drill no unnecessary wells and it requires that 640-acre spacing be preserved along that southern boundary. If these non-standard units remain, and they are long, skinny units that consist of the south half of two adjoining sections, we believe they are going to result in additional wells having to be drilled, unnecessary wells, along the southern border and for that reason we request -- are requesting that they be terminated.

So we're going to present testimony that's going to show that drainage has occurred along the southern boundary; that it is now occurring away from the unit; that the economics involved simply show that unnecessary wells will be marginal and ill-advised, and would be drilled at an economic loss and that wells are now going to have to be drilled but it is essential that they be drilled on 640-acre spacing units, and that the nonstandard units previously created must therefor be terminated.

ALBERT R. GREER,

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. CARR:

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

A Albert R. Greer.

Q Mr. Greer, where do you reside?

A Farmington.

Q And what is your relationship with Benson-Montin-Greer Drilling Corporation?

A I'm an officer and an engineer.

Q And Benson-Montin-Greer is the operator of the Canada Ojitos Unit?

A Yes, sir.

Q Have you previously testified before this Division and had your credentials as an expert petroleum engineer accepted and made a matter of record?

A Yes, sir.

Q You are the applicant in this case?

A Yes, sir.

MR. CARR: Are the witness' qualifications acceptable?

MR. CATANACH: They are.

Q Mr. Greer, would you refer to what has been marked for identification as Benson-Montin-Greer Exhibit Number One, and I would initially ask you to refer and just identify the documents that are contained behind the tab identified Table of Contents, and Tabs 1 and 2 of

this exhibit, or A and B.

MR. PEARCE: Mr. Carr, may I break in at this point? I apologize for interrupting your presentation.

Mr. Examiner, at this time on behalf of Mobil Producing Texas and New Mexico, Inc., I'd like to state for the record an objection to the exhibit which is about to be discussed by this witness.

Mobil was provided with a copy of this exhibit by Benson-Montin-Greer yesterday afternoon. We have spent the time that was available to us reviewing that exhibit. We believe that the contents of that exhibit are largely irrelevant to the subject under consideration, which is the re-orientation of two 640-acre spacing units.

We believe that the information which the exhibit contains and the testimony which we assume Mr. Greer will offer on that exhibit is not properly part of the record in this case, nor do we believe that parties who are vitally concerned with what that information may be had any reason to have any knowledge that that information would be presented or discussed.

There has been in the past some use of parties failure to object to statements which they believe are incorrect being used against them as their agreement with that information. Mobil does not wish to be

put in that position on the basis of this case today.

Mobil disagrees with the conclusions which can be drawn from the exhibit. We do not believe the information contained in that exhibit leads to proper conclusions, nor do we believe it is complete, and we need for this record to reflect our objection to the use of the exhibit and the discussion of the materials contained therein.

MR. CARR: May it please the Examiner, in response to Mr. Pearce's objection to the evidence on relevance grounds, as I indicated in my opening statement, we have a question before you which involves recreating 640-acre spacing units.

Arguments have previously been presented to the Commission. In fact, Commissioner Brostuen on occasion has stated that where areas are not in communication they in fact should be in separate pools. It therefore is essential that we address the questions that were raised in the August 3rd, 1988 hearing by Mobil and others as Case 9451, that in fact this migration could not occur because while Mr. Pearce wants the record to clearly reflect Mobil's position, we think it's essential that the record address the entire question and we do not just ignore prior testimony that raises the question as to whether or not in fact this communication can exist.

640-acre drainage across that boundary is one issue. Another thing we're addressing is 640-acre spacing and in communications formally and informally with Mobil and others there has been agreement that that is appropriate here, but just because that agreement has been made, does not affect the record and the data that is on file with this commission, and it is therefore essential that we be in a position to present a full case and address all the issues, not just the ultimate issue in this case and that is that the existence of these nonstandard units is appropriate, is going to result in the drilling of unnecessary wells and is going to cause waste.

But that ultimate question rests on some other things that must be addressed; i.e. drainage across that boundary and the appropriateness of the spacing units and the economics of the wells that will be drilled down there and to make a full presentation we must address it all.

Mr. Pearce has made his objection but I want the record to also show that Benson-Montin-Greer is absolutely convinced that unless we can present the whole hearing, that only part of the whole matter is going to be before you when the time comes to reach a decision.

MR. CATANACH: Mr. Pearce, if

I may, what is Mobil's interest in the case or in the acreage involved?

MR. PEARCE; Mobil is one of the parties which holds acreage to the south of the Canada Ojitos Unit boundary. Information contained in this exhibit attempts to demonstrate communication between some acreage in which Mobil has an interest and the Canada Ojitos Unit, and that is not restricted to the proration units in question. It is some rather extensive information and Mobil's concern is that the information does not go to the proration unit orientation, which is a 640-acre question.

Our position on whether or not the proration units ought to be re-oriented might or might not be different. Our objection is to information entering this record without adequate notice to parties who are vitally affected by this information knowing about it; that we're going to get crosswise ultimately.

MR. CATANACH: So your objection is that you didn't have enough time to evaluate the evidence?

MR. PEARCE: Our objection is that based upon the case as it is called, which is the re-orientation of spacing units, that no party with interests that are going to be discussed had any knowledge that

those interests would be addressed. They had no reason to be in attendance at this hearing. They had no reason to prepare conflicting information, if such exists. It is a surprise to everyone with interests beyond the two proration units in question that this material is being presented and there are a number of parties who are vitally interested in the area and we are concerned that it will be discussed when those parties had no reason to appear and participate in the discussion of interests which are important to them.

MR. CATANACH: Mr. Carr?

MR. CARR: As to the timeliness of this, I would like to state for the Examiner's information that this particular question has been pending for, well, for almost a year, since last April, and we've deferred action repeatedly while we conducted seismic work and did other things.

So I think surprise is a false complaint. I think it's also a false issue for a party who is in attendance, who's been involved in active negotiations and running seismic work and delaying the application for some time to come in and try and say there may be somebody out there who might want to know some of this information. I don't think they've got standing to raise that.

I think that what we need to

recognize is, one, there's only one issue for you to decide, and that is whether or not these proration units should be terminated, but beyond -- and that's the only decision you're going to reach in this case because it's the only thing in the scope of the ad that's before you. But I think it would be ill advised to in the future say that in a compulsory pooling case, if you're going to squabble about the penalty, we better give notice we're going to talk about drainage to the tract to the north, because it becomes absurd.

The question is the abolishment of these units and we are to make a full presentation about a number of points that get you to the ultimate question, and they're all relevant. Is there -- if there is no drainage occurring, Mr. Catanach, there's no reason to change the proration units. It's an essential precondition. It's an essential issue that you must address, and to come in here and say, well, Mr. Greer ought to come in like some of our clients do with one little plat that says we've already done it and this is what we've done and we'd like your seal of approval, we're not doing that. We're coming in explaining to you, one, what we need, and why it is we think we need it, and also what the underlying facts are that make -- cause this to be a sensible and prudent decision for the operator.

MR. CATANACH: We'll proceed with the case, Mr. Pearce. Your objection will be noted, however we'll proceed with the case and if at the end of the case I determine that additional notice or additional time needs to be given to any other interest owner we'll do that at that time.

MR. PEARCE: Thank you, Mr. Examiner.

MR. CATANACH: You may proceed, Mr. Carr.

Q Mr. Greer, would you just identify what is contained behind Tab A in Exhibit Number One?

A Yes, sir, this is a copy of our application in this case.

Q And this application simply addresses termination of certain nonstandard proration units in the Canada Ojitos Unit?

A Yes, sir.

Q Would you go --

A And adjoining land just outside the Canada Ojitos Unit.

Q Right. Would you now turn to Tab B and just to get this hearing back on track, state for the Examiner what is your purpose in bringing this application to the Division?

A We show under Tab B the purpose in the first paragraph, which is simply to modify the well spacing regulations to eliminate certain nonstandard proration units to permit orderly development of wells within the unit and those on the south boundary and to provide drainage protection on the south boundary while at the same time avoiding the drilling of unnecessary wells.

Q Now, Mr. Greer, that's the only thing you're seeking in this application --

A Yes.

Q -- isn't that correct?

A Yes, sir, that's right.

Q Would you now turn to Tab C, identify the plat contained behind that tab and review the information contained on that exhibit?

A The plat is an orientation plat and we show shaded on this plat the nonstandard units that will be affected by -- if the application is approved, to eliminate these nonstandard units.

Starting at the top, there are four nonstandard units in 26 North, 1 West. On one of them is a well, the Canada Ojitos Unit F-20, which we've been testing in the Dakota, and it will be the subject of another application for commingling later on today.

Another one, we have an injection well,

the G-1, 24 North, 1 West, and then two nonstandard proration units in 24 North, 1 West, Sections 23 and 24.

And we will be discussing the south part of Township 24 North, 1 West, those proration units, the injection well just north of it there, the A-14, and wells producing to the south of it in Section 25, 26, 35, 36, and then one well in the township south of that in Section 2.

Q Mr. Greer, we're going to focusing the presentation on the wells on the southern -- or the units on the southern end of the Canada Ojitos Unit.

You're also seeking to abolish some nonstandard units elsewhere within Canada Ojitos. What is the reasoning for that, those that are completely interior?

A Well, it's just to make the development more orderly. Those interior to the unit now were at one time on the boundary, the same as the others. When the unit was expanded then they became internal units and there's just no purpose at all having (unclear.)

Q Now, I'd like to direct your testimony now primarily to the units on the southern end of the Canada Ojitos and would ask you to refer to the information behind Tab D and explain to Mr. Catanach your reason for seeking elimination of those nonstandard units.

A Yes, sir. If we'll look at the tan colored page under Tab D, we show here the situation that

could develop. The nonstandard units are a half mile north/south and two miles long east/west, and I show in the upper frame, for instance, the low capacity well is the first well drilled in Section 24 on that long, nonstandard proration unit, and then if, for instance, we would drill another well in Section 23 and it turned out to be a high capacity well, then the owners of the south proration unit would want to drill another well in the south half of 23 and we would then have an unnecessary well if such were allowed, and there's a good possibility it would be allowed.

On the other hand, if we look at the bottom frame, if the first well is drilled in the same location as indicated above, the proration units are square, then there's no problem of -- of drainage and equal sharing of the production from those wells both north and south of the boundary.

The high capacity well, then, would be drilled on Section 23. Half of the production would go to the unit, half to the land south of the unit and here again there is an exact division of the production with no -- no possibility of offset -- unequal offset drainage, and so this would permit the drilling of wells on 640-acre and eliminate the hazard of drilling unnecessary wells for those (unclear).

Now when we look at the gray sheets on the righthand side, we have another example of the first well drilled in the southwest of 23 and it's offset directly by a unit well to the north. The result, then, is two long proration units, 2 miles east/west, and the issue could be raised that those are too, too great a distance for a well to drain and protect its land, and that would open the door, then, to 320-acre spacing.

We eliminate that by the manner shown on the lower frame. The first well drilled in Section 23, the southwest part of it, a square proration unit; the second well in either the north or the south part of Section 24, and here again in both instances the production from each well is shared exactly the same both north and south of the unit boundary, and you then have protection of the unit from drainage and eliminated the risk of drilling unnecessary wells.

Q Mr. Greer, you're familiar with the testimony presented last August in the McHugh case, are you not?

A Yes, sir, I've read the transcript.

Q Have you made a study of regional migration in this area?

A Yes, sir.

Q And are your conclusions summarized in

the material behind Tab E?

A Yes, sir.

Q Would you refer to that material, please, and first generally summarize the conclusions you've reached concerning regional migration?

A Yes, sir. I was concerned about the testimony in -- or some of the testimony in the August hearing. It indicated no -- no communication north and south in this area, and we have studied the area for many years and found the relation of virgin pressures to depth of the reservoirs and found that they are equal; over geologic time the pressure is equalized.

Q Now is that information set out on the blue pages following Tab E?

A Yes, sir.

Q Would you refer to that and review it, please?

A On the lefthand page we show schematically the same situation as is found with a water sand with outcrops that with depth its pressure will be greater and be greater by the density of the water. In this instance the pressure, the virgin pressures of the fields are -- show an oil gradient and it can be calculated from about a +6100 foot elevation to the depth of the pools when they were first drilled and when pressures were unaffected by

production during man's lifetime.

Q It's shown more exactly on the graph on the righthand side of the different pools which were drilled at a time when pressures were virgin in the area and they all fall within a band of roughly 50 pounds.

If a well is drilled anywhere in the east side of the basin around West Puerto Chiquito, or East Puerto Chiquito, or Boulder, that has an initial pressure of less than indicated by this -- this graph, this slope, we can be assured that the well has suffered by migration, or the area around the well has suffered migration to a producing well.

Q I'd like you now to direct your attention to the southern portion of Canada Ojitos Unit and would direct you more specifically to the structure map, the brown sheet behind Tab F, and ask you to explain what that shows.

A This is one interpretation of the structure in the area and we note here that original migration has occurred north and south across the unit's south boundary. I believe there's a typographical error on the lower page, second line. Regional migration first was from the south during the 20-year period of initial development of the unit. Then after development took place south in the unit, then migration turned around and went in the other

direction.

Q And would you review the pressure information on the subsequent sheets that confirm this?

A The two -- two yellow sheets following that show some statistics of pressures of the nearby wells; the pressures in the gas cap area in the unit and pressure of the CC State Well that was drilled in February -- or completed in February, 1988.

There was testimony in the August hearing that the pressures were substantially different and therefore the -- there was no communication between the two areas.

It's my analysis of this that the pressures are very -- when the CC State Well was drilled, were practically equalized. The pressure at 6687 feet in the Amoco CC State at a depth of +617, a datum depth, which is in the C zone, the CC State at that time was completed only in the C zone, was 1460 pounds.

The bottom hole pressure in the Canada Ojitos Unit A-14 Well in the last two years has varied within about 50 pounds of that. We show here pressures taken and reported to the Commission during the November, 1987, field-wide survey and the February field-wide survey. Those pressures are very close to the pressure in the CC State.

Now, in the unit the formation is gas saturated and has a different pressure gradient than the oil area south of the -- south of the border, and we recognize that in the next graphs, the gray pages.

On the lower of the gray pages we show graphically the initial pressure of Amoco CC State and how that pressure varies with depth, and we've taken the different datums as high as 1000 feet. The reason for that is the A zone in the Schmitt Anticline Well, which is the highest well in the area, is about +1000. We know that all of the zones, A, B and C zones in the area have shown to be in communication someway or another. In individual wells vertically they show perhaps no communication, but reservoir wide they all show that they have a tendency to equalize.

So, we compare the -- the pressures at the different depths, in the gas cap to the north and the oil area to the south, and we see by the dashed line that the -- for this variation in reservoir datum, that the pressure of the Amoco CC State falls right in the band of pressures of the nearest injection well in the Canada Ojitos Unit.

Q In your opinion does this confirm your feelings that there is migration of fluids in the southeastern part of the unit?

A Yes, sir. The significance here is 300 to 350 pounds lower pressure than virgin pressure. There's no reason for the pressure in the Amoco CC State to be down 350 pounds from virgin pressure unless it's been depleted by production.

Q Would you now identify the information on the gray sheets behind Tab G in Exhibit Number One?

A Yes, sir. In the August hearing there was testimony to the effect that the areas were not in communication because the gas/oil ratio of the Schmitz Anticline Well, a high well in this area, was low and if it was in direct communication with the pressure maintenance project of the Canada Ojitos Unit that it would necessarily have to have a high gas/oil ratio.

That presumption comes from assuming that what we term "attic oil" would be displaced by a lower down dip gas injection well and we just note in here the description of "attic oil" in the first three gray pages in from the technical literature.

And then we show with the colored map following that how communication can exist without the gas/oil ratio of the Schmitz Anticline being initially increased by the -- by the pressure maintenance project.

Q Could you explain what the various color coding on this exhibit is intended to show?

A Yes, sir. We show in the brown colored area the lands that we think could be underlain by commercially productive oil zones in the Niobrara.

The yellow colored area is the gas invaded area. We show it schematically and by the red arrows we show generally the path and the directions of force and pressure that the gas injection exhibits.

The gray shaded area is area that generally is a steep dip, uniform dip, and for the most part it is nonproductive and actually we used the gray shaded area in initially establishing the east boundary of the West Puerto Chiquito Pool to lie within that gray shaded area.

Q Are you now --

A Excuse me, the green, the green coloring is the barren zone which we noted earlier in the little sketch of pressures versus depths.

Q Are you now ready to discuss gas drive in this reservoir?

A Yes, sir. I'd like to point that -- to the formation that we think is too tight between the two areas, we think there's a high capacity system to the south, there's a high capacity system to the north. The two areas are joined by a tighter, tighter rock. The gas can force its way slowly into the tight rock to the south and its initial movement will be not by a solution gas

drive, which is expansion of gas, moving oil by expansion. There is no expansion, the pressures are constant, by a gas drive; gas forcing oil by piston movement ahead of it until it breaks through. That's how the pressures can be maintained and they were maintained on the Schmitz Anticline Well; didn't take much volume to do it. It only produced about 80 barrels a day, so it didn't take much movement to hold the pressures up on the Schmitz Anticline.

Q All right, would you now go to the information behind Tab H and review the evidence of gas drive in this reservoir?

A We have here some evidence of gas drive as a consequence of the pressure maintenance project.

Principally we injected pressure and maintained pressure in this unit in order to augment the gravity drainage process and realize the relatively high recovery of the oil in place.

All of the gas injection wells are drilled on the up-dip side, or completed on the up-dip side of the reservoir and they're all in very tight rock. The highest capacity well, as I recall, of the current injectors, made about 4 or 5 barrels of oil per day; very tight rock, and yet it will accept gas for gas injection and it's because of the nature in the reservoir, the fracture system and fracture blocks and the ability of the gas once it gets

into the high capacity fracture system to move throughout the reservoir.

But in the course of that, when the tight blocks in which the wells are completed and the injection wells receive gas, they actually move the gas ahead of them by gas drive, they move gas and then oil, and as a consequence, for instance in this A-14, when it was completed it would have been a noncommercial oil well that we have injected gas in and moved the oil out of that block and then produced that oil that otherwise would have been unrecoverable.

This testing that we did to determine the action, the gas drive action, is through a repeated or successive pressure fall-off test on the injection well, the nearest injection well, the A-14. We show here tests in 1978, 1980, 1987 and 1989, and you'll note that in each instance the pressures move to the left on this graph. From the amount of gas injected and the slope of the line, we can determine permeability to gas of the tight block in which the well is injecting.

We show in the schedule on the upper green sheet for July '78, transmissibility, kh/u of 71 darcy feet and permeability to gas, kgh .0012.

Over the approximate 10-year period that gas was injected, the permeability, the transmissibility,

to increase to kh/mu to .88 and kgh, .015.

Now these are just approximate. We arrived at these by working through a simple analysis of the slope of the line on the semilog graph, a method of analysis often used in determining permeability.

Well, this closed system happens to be the kind that's determined or referred to as concentration at the boundary. These figures that we get will be a little bit off because of that and we show a more -- a more precise calculation later but the difference is relatively small. But it does confirm that the permeability did increase.

Now, the only way the permeability can increase is for the gas saturation to increase and gas saturation can increase only if oil is displaced, so it's very clear the gas drive has moved oil through the reservoir and has increased the permeability to gas, and that's a hazard that we face on the south boundary although initially we may be pushing just a small volume of oil across the boundary, once the gas gets there then a significantly larger volume can move across. If it were only the amount of gas that we moved initially, we would not have a serious problem to worry about, but knowing this, this history of what's happened, of gas moving through the reservoir, it's just essential that we drill protective wells on the south

boundary.

Q Now, would you go to the pink sheets behind Tab H and review -- explain first what the graph on the Unit Well A-14 shows and then review the summary below.

A The pink sheets, the graph shows the amount of gas injected over the time that -- since we started in 1974. The injectivity has increased as would be presumed from the fall off tests and we've calculated the transmissibility

We've injected now at rates as high as 3000 reservoir barrels per day, which is a very substantial injection volume and recognized that we injected this volume of gas in a tight block in the reservoir which would produce probably less than 5 barrels of oil a day when it was initially completed.

Q Now I'd like you to go to Tab I and start with the first sheet behind that and provide us with a brief summary of the geometry of this particular reservoir.

A Well, we've found that this reservoir comprises tight fracture blocks surrounded by a high capacity fracture system and the flow, the flow through the reservoir is primarily through the high capacity fracture system and then if there's a well in a tight block it charges the tight block the oil is produced on.

Because of this it's possible for wells with good connection to the high capacity fracture system to drain the tracts of wells completed in tight blocks better than the wells themselves can do it. We've found that in West Puerto Chiquito and we now have an example in the area south of West Puerto Chiquito in which the same thing is occurring.

Q Okay, will you now go to the yellow sheets?

A Here we look at the same test that we looked at earlier, which we had on the green sheets, the pressure fall-off test of the A-14 Well. We show here by the lower red cross the time that it takes for a pressure to stabilize. In the 1978 test it took about 60 days. By the time of the 1987 test, the points showed with the solid dots, it only took about 5 days to reach steady state condition. And here again is the -- this is an exact flow regime of concentration at the boundary. Gas is injected in concentration and the reservoir is in concentration.

We can from -- from this make an estimate of the size of that block that the well is injecting into and we show that on the green -- green pages. The analysis on the right is just a simple solution of the diffusivity equation for the -- for the characteristics in reservoir rock as we measured and the only assumption we

have to make is the foregoing in terms of barrels per acre of pore space.

For the different values of that then we can calculate the different sizes of the fracture blocks.

We show it in the table form in the upper green sheet and tabular or graphic from on the lower. It runs from roughly 1000 to nearly 3000 feet would be the size of the outside edge of the fracture block as we determined from this method.

Q All right, would you go to the tan sheets that follow and explain how you estimate the barrels per acre in the tight block?

A The tan sheets show the relation of oil in place per acre as a function of capacity of the formation, kh, or transmissibility with the viscosity of one.

We first presented this to the Commission in Case 3455, December, 1969. I've seen nothing since then to give us a better idea of what the relation would be.

From this we can enter this graph with the transmissibility or the kh as we estimated from transmissibility, and how we come up with 200 to 500 barrels per acre would be the probably pore space of the tight block of the A-14 Well, and then from that we can go to the next white sheet in which we pick out the part of the graph that

is probably the range of this outside edge of the fractured block. It shows running from roughly 1500 to 2800, a difference for the two different tests. Of course if everything were perfect, if we had exact measurements in the 1978, the exact measurements in the 1987 test the two lines should fall together, but since we don't there is just that much difference in our analysis.

Q Okay, let's to to the last plat behind this tab and explain how you derived the size of the fracture block around the A-14 Well.

A It's impossible, of course, to know exactly the shape of these fracture blocks. The fact that the pressures to be leveled off on the pressure fall-off tests seem to follow a fairly uniform curve implies that the fracture block is fairly uniform; that is, not exceptionally long compared to its width; doesn't make much difference if it's a square or a circle, it's going to be about the same.

Generally what the information shows is the distance to the nearest side of the fracture block and so if we take those minimum distances and if, for instance, the oil in place is about 250 barrels an acre, it would be 2800 feet to the nearest side, or 5600 feet across the block and we show that schematically as a right angle to the dashed lines. The dashed lines are drawn around a

circle with a diameter of 2800 feet, it's my thinking that the blocks are more like parallelograms than they would be squares, and if so, then the edge of the fracture block could extend a significant distance away from the well and the important thing here is that although the well may be a mile and a half from the boundary, the point of injection of the gas into the high capacity fracture system may be nearly to the south boundary line. We can think of the injection of the A-14 Well, begin to think of it in terms of 3000 barrels of reservoir space a day that it injects being replaced by a series of smaller injectors around the periphery of that block.

So it was noted in the August hearing that the A-14 injection well was over two miles away from the wells to the south and that it's too far for there to be any -- any communication. Well, that's just not the case in this instance, so it's possible the effective point of injection is much closer than just the wellbores.

Q All right, let's go to Tab J and address now the -- your calculations on the size of the fractures.

A Well, since this is an exact -- a flow regime of constant pressure at the boundary, it's possible by type curves and recognizing its constant pressure at the boundary, we can calculate the size of the fracture block; not only the size of the fracture block but the length of

the fracture of the well, the induced fracture caused when we fraced the well initially.

Now, all of these fracture blocks act to a certain extent by constant pressure from the boundary because the transmissibility of the fracture system is so much higher than that of the fracture block, and so within the Unit, where pressure is maintained, and it is an absolutely constant pressure as to the boundary flow system.

In the other areas it's very nearly that because there is such a high transmissibility here.

I've shown by the circles the match that we get by analyzing this with type curves and it's a very good, good match. The upper horizontal dots, where the pressure stabilized, shows the relative length of the -- a measurement of the side, the analysis called the X_b and the fracture half length, X_f, X_f is a half length, and that shows to be a ratio of about 2.2. That means that the length of the side is 2.2 times the length of the fracture.

Now, while we're looking at the little square and the schematic diagram of the whole system, it shows the well to be in the center of the fracture. Well, of course there's no way of knowing whether it's the center of the fracture or not and it really doesn't make a lot of difference. The fracture is so much higher transmissibility than that of the rock around it, it doesn't make any

difference if it's from one end, the center, or the other, the results will be very nearly the same.

What is significant is that the curve that fits best is the one calculated as a uniform plus fracture. This is opposed to a fracture of infinite conductivity and what that means is there's a pressure drop within the fracture and that simply confirms what the service companies tell us all the time, that to get better frac treatments we need heavier gel and bigger, wider fractures and I think that's true.

Q All right. Please go to the green sheets and review your calculations on the pressure fall-off test.

A Okay. We have here a schedule of the data used to make the test and the analyses at the bottom is summarized in a little box at the bottom righthand side for the different assumed values of pore space in terms of barrels per acre, we could determine the fracture half length. Now that's X_f, that's the center of the -- of the figures in the little box.

For instance, if it's 500 barrels per acre the fracture half length is 316 feet or if it's 250 barrels per acre it's 446 feet. That means the fracture length. Now this is the induced fracture caused when we fraced the well would be from 600 feet to 900 feet.

Now, we asked the service company that fraced the well what their computer shows should be the length of the induced fracture according to the size of the frac treatment, the pressure, the injection pressure while we were fracing it.

They show that if there was a frac height of 150 feet the frac length would be 750 feet. If it was a 50-foot height it would be 1100 feet. It's my feeling that the frac height was probably not over 50 feet but their range of 750 feet to 1100 feet fits rather close with our calculated figures of 600 to 900 feet.

Q Would you just identify the pink sheets that follow?

A The pink sheets are to minimize the error of analyzing the -- the pressure behavior during the pressure fall-off test, and the fact that in a gas system both the viscosities and the deviation from (not clearly understood) vary within the closed system from the outer boundary to the well. We take that into account by recognizing this difference through psuedo pressures and of course the most accurate way is to integrate the relation of the psuedo pressures and the square of the psuedo pressures and these graphs just show those figures reduced graphically so that it's easy to read.

Q Now, Mr. Greer, behind Tab K is some

information on the Schmitz Anticline. Before we go into that, I'd ask you to refer to your mobility analyses that are contained in Section O in Exhibit Number One.

A Yes, sir. If you'll turn to Exhibit O, the first two green sheets, we've summarized on the upper green sheet the slope of the build-up curve by a Horner plot in terms of pounds per cycle, we used logarithm cycles to find both the first and the second slopes. The second slope projects out to on the Horner P*, 1254 pounds.

I'd like to move to the yellow sheets to -- to show the interesting part of this pressure build-up.

The first slope is 40.5 pounds per log cycle and the second is 25.8 pounds per log cycle.

And I've expanded the 25.8 pounds per log cycle on the lower of the yellow graphs in order to see how we have analyzed it. It's very important to know if or if not that slope is a straight line. Unfortunately, when Amoco ran this test they did not use a sensitive pressure bomb and it's necessary then to estimate as best we can from this. I think it's most unfortunate that just the fact that Amoco did not use the pressure -- a sensitive pressure bomb indicates that the Amoco engineers are not analyzing the rate/time part of the pressure curve. I think it's most unfortunate because in this reservoir that is everything. The rate/time portion is everything and the

only way it can be analyzed is with -- exactly, is with very careful pressure measurement.

But I think here that we've taken as best we can the information available and can draw a reasonable conclusion from it.

Now what I've done is to take the pressures, and this graph the vertical scale covers about 30 pounds, the pressures cover roughly 20, it's only possible with this type of pressure gauge to read pressures within certain limits and so what's happened is the scanner has read one pressure for four or five readings and probbably the average time and average pressure would be where I've drawn the crosses, and for instance, the very -- the lowest cross is four points, it's pretty clear that the average point would be at the center of the crosses.

As we come up to the next to last cross where there's six points on one side of the cross and one point on the other, that's where the scanner changed from readings of one point an hour to six hours between points. Has it been read all the way across, then there would be another four or five points there, which would make it appear a little more uniform than just looking at it here. I interpret that to be a straight line. I think it's correct. Now the significance of that is the drainage radius recedes in this Amoco Schmitz Anticline Well on production

and chains on shut-ins that that drainage radius reached a fracture or a fault of very high capacity. Now if the fault had infinite capacity, the slope would have changed from 40.5 pounds to 20.2 pounds, but then it changed to 25.8 pounds. Now that's as accurate as we can tell but it is enough to know that it is a very high capacity, straight line fracture or fault, and this is important in our analysis of what's happening in this area.

Q All right, why don't you now go back to the plat in Subsection G and relate this information to the plat.

A This is the colored plat about four or five pages into the section.

I'd like to call attention now to the faults on the lower righthand side that are evident from the surface geology. We think there's no question that in this area those faults extend, or if not those faults, similar faults extend into the subsurface in the producing area. We don't know how Amoco located its CC State and Schmitz Anticline Wells, but if they had information on faulting in the area it's to be presumed they would locate them close to the faults because they'd have more fracturing there and productivity.

And, as a matter of fact, Mobil, in asking for a continuance of this hearing, wanted to run a

line northeast from Section 27 across the unit boundary into Section 13, across Section 23, looking for some of these faults, we presume. We joined them in the survey. The very first analysis is there is a fault in the south half of 23 and the presumption is that it's an extension of a fault from -- from the southeast, mostly east.

We think it's a very good possibility that there is a fault near the Amoco CC State and if so, the same directional trend of the fault would place that same fault close to the Schmitz Anticline.

Now, what that means is when we looked at the evidence of fault of the Schmitz Anticline, that high capacity fault, the flow system is that the well produces oil out of the tight block; the tight block is recharged continually by that high capacity fracture. If the flow from that high capacity fracture is cut off, then it will affect the productivity of the well in the tight block.

And that's what happened at the Schmitz Anticline when the CC State was drilled.

Q All right, would you now move to Tab K and review the production information on the first graph behind that tab, on the only graph behind that tab?

A Well, we can see here that the production from the Schmitz Anticline Well was for all practical

purposes flat for two years after first completion. There's no way that the well, aside from mechanical problems of some kind, or whatever, will produce level, unless, number one, it's in an exceptionally large reservoir, or number two, it's got pressure support from some place.

Well, when the CC State and Wishing Well were drilled and completed and started producing in the spring of 1988, the production from the Schmitz Anticline fell off, as would be expected from the analysis of the fracture system, and that then means that it was not a large reservoir that held the pressure up, so there's only one other thing that can hold the pressure up and that's support from the pressure maintenance project.

So, during this time with the Schmitz Anticline producing only 80 barrels a day it was receiving enough pressure support to hold its pressure level. Once the other wells were completed and the pressure fell off, the pressure maintenance support is not enough to hold it up, so all we know, all we can tell for certain is that the pressure maintenance support is somewhere between 80 barrels a day and 1000 barrels a day.

Now 80 barrels a day is no problem. 1000 barrels a day is, could be a problem. So again we're back to the need to drill protection wells for the unit on the south boundary.

Q All right, would you identify the material contained behind Tab L in Exhibit One?

A Under L we show analysis -- simplified analyses that show simply the slope so that we can project the pressure out to the Horner P* pressure and transmissibility, and here for the Wishing Well in May it shows about one darcy feet per centipoise for transmissibility, and we show on the second of the yellow sheets on a standard scale the projection of its pressure out to the Horner P* pressure, which would be about 1436 pounds at the depth at which the bomb was run and then reducing it back to the datum of +617, and I use that +617 because that's the datum of the first pressure in the Amoco CC State, why, we get there 1457 pounds.

The following sheets are simply the statistics of the pressure survey, the pressure survey data itself.

Q All right, now, behind Tab M would you just identify those exhibits, please?

A Okay, here is an analysis of the Wishing Well in September.

Now, in September I plotted -- it's important to realize in the analyses that follow that when the first test was run on the Wishing Well in May, the build-up test, that the CC State was shut in and so we

think that there should have been little interference of that test at that time.

Now, in September all the wells in the area were shut in for presumably for a frac pulse test when Amoco fraced its well in the northwest quarter of Section 36. Unfortunately the well was in the gray zone and probably would have no -- no communication with the West Puerto Chiquito reservoir.

We've not seen a completion test on that so we don't know about that, but the fact is that all the wells were shut in so we had another good -- another point in which we might contain fairly good pressures to try to make an estimate of the size of the reservoir on the south, the south boundary.

Here we have about the same mobility, total mobility, a little less than one and we show again on an expanded graph on the yellow sheet the calculation of the P* pressure.

And then again we have the same statistical information as before.

Q Now if we go to Tab N we also have some additional analysis of mobility on the Laguna Colorado 2 No. 6 Well.

A Yes, sir.

Q Will you review that?

A Yes, sir. Now this, this well is a small well, makes about 11 barrels a day. It produced for a month or so, was shut in for I think over a month, then produced again. It's a real tight well; would have a long time to reach steady state conditions. It's build-up test is kind of late. We just didn't have time to go back and try to analyze the effect of the shut-in and the producing and the shut-in on its test, but I have an idea that that has something to do with the wavy nature of the curve.

The -- we took the last projection, of course, as we have with the others, and projected it out to a P* pressure. We show that calculation on the yellow sheet following it.

Q And the remainder of the documents behind this tab are supporting information?

A Yes, sir.

Q We have previously discussed Tab O. Are you ready to go to Tab P?

A Yes, sir.

Q Would you identify the first documents behind that tab and explain what they are and what they show?

A These show the -- schematically the build-up test by Horner plots that we looked at before for the three wells when they were shut-in in September, and

the thing that I'd like to point out here is, first, the big difference in pressure from the virgin pressure.

The next thing is the P* pressures are very, very nearly the same and what is really important here, I feel, is that the different wells, although they project out to about the same pressures, have very different cumulative production.

The Schmitz Anticline, 85,000 barrels; the Wishing Well 57; and the Laguna Colorado only 1,000 barrels, and yet its pressure is somewhere on the order of the others.

Now, a true reservoir pressure is going to be something less for the Schmitz Anticline and the Wishing Well than the P* pressures and my estimate is that's 1250 pounds.

Now the Laguna Colorado is different. It's drilled a tight block. It's taken a long time to reach steady state conditions. It's P* pressure would probably be pretty close to these pressures. It's just possible that their pressures are all within about 25-30 pounds of each other. Now that would be the pressure in the high capacity fracture system, and what that means is here is another example of wells, the closest well to the Laguna Colorado is a mile away. These other wells have drained that well's tight block, as tight as it is, and

it's been able to do that because the high capacity system surrounds the block and the flow system from oil out of the tight block into the fracture system is so much greater than the reverse where the flow streams are concentrated where a well produces in the -- within a tight block.

And so this again confirms the -- what I think is a high capacity system within the south area.

Q Mr. Greer, have you an opinion as to whether or not wells in the southern portion of Canada Ojitos can in fact drain 640 acres?

A Yes, sir, I've made a study of that.

Q And have you prepared certain information to support that conclusion?

A Yes, sir.

Q Is that contained behind Tab Q in Exhibit Number One?

A Yes, sir.

Q Would you refer to the first pink sheet and identify that and then review the information contained in this section?

A Yes, sir. In order to analyze this I took the tightest, the indication of the tightest rock around each of these -- of the smallest wells, the Schmitz Anticline and the Laguna Colorado.

Now in this reservoir the bulk of the

production is going to come from the high capacity fracture system and given the opportunity of gravity drainage within that, but I have eliminated that from this analysis and taken simply the indication of the tight rock itself, assumed that there was nothing there except just the tight rock, that you had a reservoir of only that characteristic and how long would it take for a well on 640 acres to reach steady state conditions and how long then it would take at the current rate of production and given a constant percentage decline, which most wells seem to exhibit in this area, how long would it take to drain the blocks.

The first one is shown on the second sheet, the Schmitz Anticline, it would take about 70 days to reach steady state conditions. It has a production rate now of 70 barrels a day, was initially -- well, I say now, in September, but I would imagine it's less now, and project that to a rate of 3 -- an estimated economic limit of 3 barrels a day, the decline rate would be 98 percent a year and it would completely deplete that tight block in about 3 years. It would only be about 25,000 barrels recoverable limit.

Q Would you compare the information on the next sheet.

A Same thing for the Laguna Colorado. It would take a longer time; I have nearly 200 days to reach

steady state conditions but it doesn't have as much oil in place and as much recoverable oil. It would deplete 5640 acres in about 7 years.

No question that the wells, even without the high capacity fracture system that helps them, would drain 640 acres and we're looking at the very tightest rock in the area.

Q Now, Mr. Greer, have you also looked at anticipated recoveries in the southeastern portion of this pool?

A Yes, sir, from the pressure decline, and of course it's only a 4-month period from May to September, but still it appears that the information is good enough that we can make an estimate of -- of production decline versus pressure. I've shown this here schematically on the second of the green sheets.

Q That's behind Tab R.

A That's behind Tab R. The virgin pressure was around 1800, 1850 pounds in 1965. I show it dropping down as the pressure in the unit dropped down until 1985 when the Schmitz Anticline Well was drilled. Note that from 1985 till 1988 the pressure didn't change very much. We show there the February, '88 pressure; the May, '88 pressure; and the September, '88 pressure. The dotted line shows a straight line extrapolation of that and the

dashed line, the curved line, shows the track that the pressure probably will take if there's no support from the pressure maintenance project.

That line might extend a little farther to the right depending upon how much gravity drainage the wells are allowed to produce. There is enough structure in the area for some gravity drainage and I believe there's enough high capacity fracture system to do it. Now, we don't have an interference test to confirm that but -- but it would be somewhere in that -- in that range, not very far. It would not vary much from where that is.

Q Mr. Greer, if you'll now go to the tan sheets that are the next part of Tab R, review the information, and particularly would you compare the information from May, '88 and September, '88 that's on the top of the bottom sheet?

A All right. I'd like to look at the bottom sheet first to show the -- that I have arrived here from the pressure drop from May to September in the Wishing Well. You'll note that the Wishing Well and the other wells are pretty well equalized in September. I noted in May that the CC State was shut in and the build-up test there was probably pretty good.

I compared the pressures for the different methods we might use. I'd like to note that in May

compared to September for the Wishing Well, the 24-hour shut- in pressure dropped 170 pounds, and the 48-hour pressures dropped 175 pounds. A modified Muskat average pressure dropped 180 pounds. Then a Miller, Dyes and Hutchinson method for the assumed distances to the outer boundary with 1000 feet and 1500 feet, we show 154 pounds to 151 pounds.

Now, we don't have any idea as to the distance to the boundaries of these fracture blocks with the information we now have, but the important thing here is not that we know it exactly but if it's 1000 feet what would be the pressure drop; if it were 1500 feet what would be the pressure drop. It's roughly the same in both instances and so we can feel like the pressure drop is reasonably accurate. The Horner P* difference is 151 pounds. I've used for my analysis 150 pounds, which we show on the upper tan sheet down toward the middle, if there is 157,000 barrels, reservoir barrels produced, which is what we estimate here, 150 pounds, that's a coefficient of 1050 reservoir barrels per pound, and divide that by the system compressibility and we come up with a total reservoir volume of 2600 thousand, 2-1/2 million barrels, approximately.

Then we make a further analysis, assuming it is 2-1/2 million barrels, then on the pink sheets following we come up with the area that would be involved,

depending on how many barrels per acre. It runs from 2000 barrels an acre, it would be about 1250 acres indicated; for 500 barrels an acre, about 5000.

On the lower of the pink sheets we show diffusivity constant and the area which would be brought into a steady state condition given the transmissibility of the Wishing Well type log and we calculate that here and we show that 500 barrels an acre could be up to 6000 acres but 2000 barrels an acre it's only 1450.

Then we plot those on the next blue sheets and the lower curve on the blue sheet shows the relations of reservoir area to pore space in stock tank barrels an acre. If we had an interference test in the area there we might be able to tell something about what the pore volume is. We don't have one and so we've drawn it for the different possibilities.

The next line above shows the area that would be possible for steady state conditions to develop in the 120 days of the test. That's roughly that much -- many days initially before the May test and that many, then, to September test.

If there is a high capacity fracture system, which I firmly believe there is by all indications up there, and the indications are of a high capacity fracture system, we note those on the bottom of the upper blue

sheet. Number one is the equalizied pressures. Number two is the two slopes of the Schmitz Anticline build-up, and the interference from the State CC and the Wishing Well when they came on. The immediate interference between the Wishing Well and the CC State and that's recorded in the transcript of Case 9451, and then the P* pressure of the Laguna Colorado. Those things added together tell me there is a nigh capacity fracture system in this area.

So when we add those things together what it means is that the area of the reservoir that could be brought into steady state conditions could be 10, 15, 20, 30,000 acres. Now the indication is from the oil in place that it's only like 2 to 5000 acres, so what that means to me is this -- this area, the high capacity fracture system is not very big and wells drilled within that area and have the depleted pressure will have to share in the production that's already developed. Those that are drilled outside that and have higher pressures, then, will be in tighter formations than what is exhibited here.

And what that means, then, is that the wells generally are going to drain on an average only their spacing units and that's not very much at solution gas drive.

Now, we point out that in West Puerto Chiquito and in Gavilan, that initial wells with capacities

of 5-to-600 barrels a day, in West Puerto Chiquito have produced as much as 2-million barrels; in Gavilan they've produced several hundred thousand barrels. That's not going to happen here. The only way that can happen is for the wells to drain large areas and you can see by this blue graph that that can't happen.

So, again our concern for spacing, that the wells just absolutely must be drilled on no closer than 640 acres.

Q Would you now go to the information contained behind Tab S in Exhibit Number One and review the economics involved in development of this southern portion of Canada Ojitos?

A We show here some economics of oil value and total gross -- total net income to wells depending on whether -- what the spacing is.

On the lefthand sheet we show the figures for 100 barrel per acre recovery and on the righthand sheet, 150 barrels per acre.

I have three columns. One is for the value of oil at $10.00 a barrel, one at $15.00, and one at $20. We assume the value of gas at roughly 1/8th of the value of the oil; that is, 1/8th of dollars per barrel would give dollars per mcf of gas, and then I've assumed about 5.6 mcf per barrel might be realized. We add the two

together to come up with a total value of gas and oil based on oil barrels, and then we assumed lease burdens, taxes, and so on, gives a net value then of about 75 percent of the gross and then after operating expense, $2.50 a barrel, which I think is probably conservative, then we show a net value then of $10.00 oil is $10.30; $15.00 oil, $16.70; and $20.00 oil, $22.00.

Then for the various spacings and gross income, or net income, we arrive at the economics, which I think are more readily absorbed by looking at the graphs on the green sheets that follow.

On the upper green sheet we show, for instance, that it's for 100 barrels per acre recovery, and which "Below B. P." means below the bubble point. All of this area is going to be below the bubble point, that there would be a loss for anything less than 320 acres per well; zero ratio of profit to investments for anything less than about $16.00 a barrel, and even at $20.00 a barrel, the -- the profit probably would not cover interest on investment. I've not figured interest and I've not figured rate of return. These are just simple profit-to-investment ratios.

On 640 acre spacing at $100.00 per barrel -- I mean 100 barrels per acre, there's an opportunity in the range of $15.00 to $20.00 a barrel to show a minimum profit.

At 150 barrels an acre profit ratios as high as 2-to-1 can be realized if we can get up to $17.00 to $18.00 a barrel. Right now it's about $16.00; just what it will be, no one knows. I think it's a little bit difficult to forecast.

But at 320 acres per well, even at $20.00 a barrel, the profit-to-investment ratio is less than one and just is not enough to warrant the drilling of these risky wells.

Q And you conclude from this that you need 640-acre spacing in the area?

A Yes, sir, we can conclude we need 640 acres and we can conclude that the wells will drain 640 acres.

Q Now, Mr. Greer, behind Tab T in Exhibit One is just some statistical information on the wells in the southern portion of this pool, is that correct?

A Yes, sir, uh-huh.

Q Is Exhibit Number Two a copy of the affidavit of notice letter given to Mobil providing them with notice of today's hearing?

A Yes, sir.

Q Mr. Greer, is Mobil the only other interest owner in the proration units that would be reestablished as a result of your application in this case?

A Yes, sir.

Q Based on your study of the area and your experience with this particular field, is it your professional opinion that fluid is migrating at this time from the Canada Ojitos to wells that are producing south of the unit boundary?

A Yes, sir.

Q As unit operator is it your opinion that you have an obligation to protect the unit from this fluid migration?

A Yes, sir.

Q In your opinion will wells have to be drilled if you're to fully carry out that responsibility?

A Yes, sir.

Q In developing this pool is it your opinion that 640-acre spacing is appropriate both geologically and economically for the development of this area?

A Yes, sir.

Q If the nonstandard proration units that are the subject of this hearing are abolished, will that enable you to protect the unit in a responsible and prudent manner?

A Yes, sir.

Q In your opinion will granting this application be in the best interest of conservation, the

prevention of waste, and the protection of correlative rights?

A Yes, sir.

Q Were Exhibits One and Two prepared by you or compiled at your direction?

A Yes, sir.

MR. CARR: At this time, Mr. Catanach, I move the admission of Benson-Montin-Greer Drilling Corporation Exhibits One and Two.

MR. CATANACH: Exhibits One and Two will be admitted as evidence.

Let's take a short break at this point, ten minutes.

(Thereupon a recess was taken.)

MR. CATANACH: We'll call the hearing back to order and turn it over to Mr. Pearce at this time.

MR. PEARCE: Thank you, Mr. Examiner.

CROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Greer, if you would, please, turn

with me to Tab C, which is the orientation plat of the area, and we are interested in the two nonstandard proration units at the southern end of the Canada Ojitos Unit. Do you see the two units I'm talking about?

A Yes, sir.

Q How were those two nonstandard proration units formed?

A When the Canada Ojitos Unit was originally put together it covered a little bit larger area than now shown in Township 14 North, 1 West.

After drilling the A-14 injection well, the USGS at that time wanted the unit contracted and we had just an arbitrary final agreement, we wanted to include all of 23 and 24; they wanted to take out as much as we would agree to, and we just finally settled arbitrarily on cutting 23, 24, and then the east 19 and 20, in half.

Q And you filed an application with the Division to form those nonstandard units, is that correct?

A No, sir. Then in 1980 -- and at that time the spacing was 320 acres a well. Then in 1980 under one of our applications the spacing in West Puerto Chiquito went to 640 acres a well. So at that time the west boundary and the north part of 26, 1 and the south boundary, then, in 24, 1, cut through half sections, and the engineer at that time, Dan Nutter, said, well, he'd feel more com-

fortable if we just separated the unit acreage from the non-unit acreage and make some long, nonstandard proration units.

At that time we had seen no arguments in this area for spacing closer than 640 acres and so I had no objection to doing whatever they wanted to do at that time and felt like if and when the time came to drill them, why, we could always take another look at them, and so that's how they came to be and that's -- the time to look at them is now.

Q Okay, so they currently do have 640 acres each.

A Yes, sir.

Q And under the proposal they will have 640 acres each.

A Yes, sir.

Q So we're not proposing to change the amount of acreage --

A Per well.

Q -- per well.

A No, sir.

Q All of this acreage is in a 640-acre spaced pool at this time, is that right?

A Yes, sir.

Q And unless somebody showed something

different the assumption before this Division is that a well drilled on that acreage would drain 640 acres, is that correct?

A Yes, sir.

Q Okay. Thank you.

A Mr. Examiner, if I might, that's my feeling, too, that it will drain more than 640 acres.

Q And you -- okay, you mentioned that the A-14 injection well was drilled. When was that well drilled?

A Well, we started injecting in 1974. I believe it was completed and maybe a well was drilled a year or two earlier than that, I believe.

Q Was it drilled intending for that to be an injection well?

A No, we just drilled it as another well.

Q And it was nonproductive.

A It did not make a commercial oil well.

Q Non-commercial.

A And my analysis was in view of what we had found with the other wells in tight blocks, that it just might possibly make a good injector, so we started injecting gas in it and then made our first confirmation in that test shown in 1978 that in fact it -- it was a good injector because as we determined at that time that

pressure in that well was the same as the gas cap pressure in the rest of them, although we had injected quite a bit of gas for four years. That meant that there -- we were not in a sense stacking up gas around the well, it was getting into the reservoir. That was the main purpose of that first test in 1978, to confirm that.

Q Okay. Now, based upon the results of drilling and A-14 Well, the BLM indicated -- or its predecessor agency, I guess, not the BLM, the predecessor agency indicated to you that the boundary should be contracted.

A Yes, sir.

Q And that unit boundary be negotiation was moved up to the middle of 23 and 24.

A Yes, that's correct.

Q Mr. Greer, I apologize, maybe you can tell me the tab. On one of the tabs you had a graphical representation of injection into the A-14?

A Okay.

Q I'm sorry, I turned to it and I believe it's H.

I notice that beginning in perhaps mid-19 -- late -- I apologize, early 1986, it seems that injection rates in the A-14 Well have been increased --

A Yes, sir.

Q -- rather dramatically?

A Yes, sir.

Q Do you have any plans to further increase the injection rate of wells in the Canada Ojitos Unit?

A Well, we're thinking about it. One of our problems is that the G-1, which is completed only in the C zone, was not taking as much gas as I thought we should be able to get into it, so a couple of years ago we fraced the A and B zone and initially when we fraced it was with oil and it made a reasonably good injector.

Since that time fairly good results in the area have been obtained by fracing with water. We took the risk of fracing in that tight zone with water and in the course of drilling it we did not increase the capacity of the A and B zones and in fact the frac apparently extended into the C zone and rather than helping the well, we hurt it, so in order to get more gas in the southern part of the unit, then, we have injected more gas in the A-14 than otherwise we would have.

So that's the reason why we injected more gas. And then what we'll do in the future is just going to depend on all of the things that's happened. Right now it really makes little difference where we inject the gas. We can maintain pressure on the unit while injecting in any one of the injection wells if they'll take

the gas.

Q All right, Mr. Greer, looking -- I'm now looking at the colored representation behind Tab G, which shows your interpretation of the gas zone.

A The gas invaded area, yes, sir.

Q It appears that operations to date have just about swept all of the oil in your opinion out of the southern part of the Canada Ojitos Unit.

A Well, of course, this is schematically. There is undoubtedly tight rocks there that the gas is going around; we don't know just where they are; some of it will be swept out and some of it will not, but the gas is not yet channeled to the L-3 in the upper lefthand side, so again this is just schematically I think a fair representation of what's taking place.

Q All right, sir, looking at this exhibit, we're looking at the proration and spacing unit in Section 23 and 24. You're suggesting two standard, standardly oriented 640-acre spacing and proration units.

A Yes, sir.

Q If those two spacing units are approved and wells are drilled on those spacing units, do you believe that that is adequate protection to the southern boundary of the Canada Ojitos Unit?

A Well, it's just going to depend on the

capacities of the wells. We won't know that until they're drilled. My firm hope is that that's -- that those two wells will be enough. We may have to drill another one but I would hope not.

Q Where would you put another one if you felt it was necessary?

A Well, we might come over into 19 and maybe into 15.

Q Looking at pressure data in this area, particularly on the Amoco State CC-1 --

A Okay.

Q -- what's the latest pressure information you have on that and if you could get me to a tab in your exhibit, --

A Okay.

Q -- I would appreciate it.

A Let's see, would like the summary or the build-up or --

Q The State CC-1, you've got the build-up and then we'll look at the summary.

A Oh. Okay, the CC State, all we have is what was recorded by -- by Amoco in the August hearing and what they furnished to the conservation commission, so that's only a summary. We don't have a build-up. I think Amoco took a build-up in September. We asked them for it

but they felt they could not release it.

Q Okay. Can you refer me to the summary?

A It would probably be I'd say in Section P. No, this is September and we didn't have it.

Okay, it would be with the initial pressures in the area, which would be under Tab F, the two yellow sheets. Okay, the CC State on the righthand side of the center of the page, February 15th, '88, at a depth of 6687, which is +617, was 1460 pounds.

Q Okay.

A The -- that pressure was given to the Oil Conservation Division; also was recorded in Case 9451 in August by Mr. Jones. Mr. Jones was the witness and he said he made a rough adjustment to a datum of +750 for his exhibit. So he used a +750 for his exhibits and his rough adjustment I think was pretty rough, all right, because that doesn't check out very good, but the C zone pressure was at 6687 and that was just about the center of the C zone. The C zone was the only zone open at that time and so I think there's very little doubt as to the depth and the pressure.

Q Okay, but you don't have the build-up data available to you on that?

A No, sir, Amoco would not release that to us.

Q All right. Let's flip back, if we can, to Tab C, the map, again, please, sir.

The well in Section 26, which well is that?

A I believe that's the CC State.

Q And the well in Section 35 immediately south of that?

A That's the Wishing Well.

Q And the well to the south of 35 in 2?

A That's the Laguna Colorado.

Q The well in 25?

A Is the Schmitz Anticline.

Q And I notice there's a well in 36. Do you know what that well is?

A The north -- the southeast of 36 is a well of Southern Union's which we consider is out of the West Puerto Chiquito Pool. They asked that it be removed 8 or 10 years ago and we had no objection since it's in the gray zone, and then the well in the northwest of 36 is one drilled by Amoco just recently and we've not seen a completion on it but the fact that it's bottomed in the C zone -- I mean in the gray zone leads me to believe it probably is not in the reservoir, not in the West Puerto Chiquito reservoir.

Q All right, sir, looking at the progres-

sion from the Canada Ojitos Unit down through the State CC, down to the Wishing Well, down to the Laguna Well --

A Okay.

Q -- if that area is receiving pressure support from the Canada Ojitos Unit, what impact would you -- what differences would you expect to see in GOR's between those wells?

A Initially there'd be no impact, as I indicated before. The action is going to be a piston action pushing oil ahead of it, ahead of the gas, until the gas breaks through and it, if anything, will tend to reduce the gas/oil ratio.

Q Okay, and so that --

A And then once the gas breaks through, then, of course, it will tend to increase it.

Q Mr. Greer, in looking over these materials, Mobil has come up with some data requests which I'll simply state for the record and I don't expect that it's things that you have available to you, but I want you to know what they'd like to see if you can provide it, and certainly you and Mr. Carr can discuss that.

With regard to the A-14 injection well we'd like to see the injection pressures by month, '84 through '89.

A Okay, we have that. I don't have it

with me but we can supply it.

Q Now the note I have in front of me says, "Raw fall off pressure data".

A Okay.

Q It says '78, '80, '87, '89, and '89, the most recent data.

A Yeah, we --

MR. CARR: '78, '80 --

MR. PEARCE: '87, '89.

Q Injection rates by month, which I think you've graphically shown but if you've got a sheet that just sets that forth.

A Okay.

Q Item raw meter reading injection rate data for January of '86 through January of '89, including operating conditions.

A January which?

Q '86, January of '89.

A That's a three year period?

Q Yes. They would like initial bottom hole pressure data, whatever you have available on the A-14 and the COU L-3.

A Okay, we don't have any on the L-3. The A-14, the bottom hole pressures have been calculated from the static pressures of the -- of the surface pressures, so

--

Q You didn't take a bottom hole when you initially drilled that well?

A I think not.

Q Okay. Have you done any bottom hole pressure build-ups on the L-3 in the last five years?

A We've never, never done any on the L-3.

Q Okay. Do you have separate production data on the L-3 not aggregated with the rest of the unit?

A Yes, sir.

Q Gas and oil?

A Yes, sir.

Q We'd like to see that, please. Let me pause for one moment.

Thank you, Mr. Greer.

MR. PEARCE: Mr. Examiner, I have nothing further of Mr. Greer.

MR. CATANACH: Mr. Carr, will your -- Mr. Greer have any opposition to supplying that information to Mobil?

MR. GREER: No, I have no objection. The pressure fall-off data was taken, let's see, the one back in '78, 10 years ago, I think that we can dig up the charts on it. I know the one since then, that we have them, and it's very simple, we have the well so

equipped that when we shut it in, we shut it in up-stream of the meter run and that means that the instant that the well was shut in we have both the flowing pressure and the fall-off pressure immediately takes place. The only estimates that have to be made is the amount of friction between the flowing pressures and the static pressure and so I can send a copy of the charts and Mobil's engineers can analyze them just like I do.

CROSS EXAMINATION

BY MR. CATANACH:

Q Mr. Greer, most of the testimony today has been with the units in Section 23 and 24 but you also want to rescind units within the Canada Ojitos Unit. Do you see any adverse affect on any interest owners by this?

A No, sir, I see no adverse affect on anyone. Those within the unit are just a practical matter of kind of cleaning up the records.

Q There are wells currently drilled on three of those units, is that correct?

A Well, there's a well drilled on -- the F-20 is being tested in the Dakota. The A-8 has just been staked. It's not yet been drilled.

Q I see. And the well in Section 1 is --

A A-1 is an injection well.

Q -- an injection well.

A The reason for that was I think there was, oh, 10 or 15 acres in the south part of Section 1 that people didn't want to lease their land, they didn't want to fool with leasing it, and so that was taken care of with the statutory unitization two years ago, so we have no longer a need for that.

Q Mr. Greer, what is the -- what is the ownership of the south half of Sections 23 and 24?

A I believe the south half of 23 is all Mobil and the south half of 24, as I recall, Mobil has I believe it's 120 acres.

The rest of 24 is owned by the unit owners who were unit owners prior to 1980.

Q And how do you plan to develop those two sections --

A Well, our discussions with Mobil have tentatively been that the well in 23 would be located in the southwest of 23. Mobil would operate it.

The one in 24 is still indefinite. Mobil wants to look at some more seismic work before they come to a conclusion on it, so if we drill 24 the chances are that the unit would operate it.

MR. CATANACH: That's all I have at this time.

Are there other questions of Mr. Greer? Mr. Chavez?

QUESTIONS BY MR. CHAVEZ:

Q Mr. Greer, is it significant that Section 19 is not included in this, or wasn't included in the original order in this case?

A Oh.

Q It's also cut in half like 23 and 24 but doesn't appear that there was a nonstandard proration unit assigned for that.

A Yeah, we probably should have included it. The -- I think all the acreage, my recollection is all the acreage in Section 19 is unit acreage, both inside and out, owned by unit owners, and we felt like there's be no problem with that but of course we probably should have included it.

Q Do you mean that here is -- there is --

A I wonder if it's too late.

MR. CARR: Yes, I think it is.

Q You mean that there is or that there isn't a nonstandard proration unit already?

A Well, there is a nonstandard proration unit, my recollection is.

Q Okay.\

A Oh, yeah, I remember now what the problem was. It covers the south half, I believe, of 19 and the southwest of 20, so it's nonstandard not only as to the shape of it but I think it's only 480 acres and it would seem to be like most of that acreage is owned, if not all of it, by the unit and so I believe I decided, well, we'll just address that when the time comes to drill it.

Q Okay. Is there any significance to the well that's already been drilled and plugged and abandoned in Section 24?

A My recollection is that that was a well drilled by Reading & Bates maybe in the 1950's before we ever drilled any wells in the unit and we've used it for a point for mapping and that's about all.

The Mancos, my recollection is that they did not test the Mancos. I think the well went to the Dakota.

Q Mr. Greer, when you're talking about attic oil under Section G, the reference that you've used talks about attic oil that appears to have been displaced by a water drive in a water drive reservoir. Is that -- are you drawing an analogy or is there --

A Well, they, in water drive reservoirs you can sweep most of the oil but you won't get the so-called attic, might not get the so-called attic oil, and

you can then inject gas even down in the water zone, let the gas migrate up above where any wells are drilled and the gas will force the oil back down into the lower -- wells that are structurally lower, and that's the type of attic oil that we're talking about here.

Q How would you relate that attic oil in the -- that you're referring to in the Schmitz Anticline Well where there has not been a water --

A Hasn't been a water drive? The analogy is the same. The gas is injected below the oil. The oil is up-dip from the injector and so it's in a sense attic oil with respect to -- to the injector, and if there's highly communicative area between the injector, in the Schmitz Anticline, for instance, then it would displace the oil out of the Schmitz Anticline area and it would have a high gas/oil ratio as Amoco suggested in the August hearing.

Q Thank you. That's all.

MR. CATANACH: Are there any other questions of the witness?

MR. PEARCE: Just very briefly.

RECROSS EXAMINATION

BY MR. PEARCE:

Q Mr. Greer, I think I understood your position to be that if these proration units, spacing units, are re-oriented having half of them in the unit and half of them out of the unit will represent no problem.

A Yes, sir, I see no problem at all with that. In fact, I think it's the ideal way to drill wells on the boundary.

Q It's an accounting -- thank you; just wanted to confirm my understanding. Thank you.

MR. CATANACH: Anything further?

MR. CARR: Nothing further.

MR. PEARCE: I'd like to make a brief closing, if I might, Mr. Examiner.

MR. CATANACH: Certainly. You may proceed.

MR. PEARCE: Thank you. Mr. Examiner, it seems to me that -- that the problem is obvious.

If we just look at the two nonstandard spacing units presently existing in Section 23 and 24, the problem is there is not adequate information to determine what the orientation of those proration units

ought to be.

Mr. Greer had a hand in creating those nonstandard proration units in 1980. We're now back in 1989 and we're seeking to undo what we did.

Mobil has earlier expressed an objection to Mr. Greer's exhibit and his testimony as irrelevant. Since 1980 Section 23 and 24 have been subject to 640-acre spacing. They are subject to it now and in the absence of someone putting on a nonstandard proration unit case to show that the proper spacing for those wells should be something else, those two sections will continue to be subject to 640-acre spacing.

The Exhibit One, which was presented and discussed at length in this hearing had something to do with 640-acre spacing and the propriety of that spacing. Mobil began the case expressing its concern that we were going to have a discussion of irrelevant information because that evidence is not relevant in an area that is already subject to 640-acre spacing. After listening to the testimony and reviewing the exhibit in the hearing today, Mobil's position is that the application is still premature. We still have no idea what the appropriate orientation for 640-acre spacing units in Section 23 and 24 is. Until wells are drilled and technical information is developed I don't think we will have any idea. I don't think

the information presented in Exhibit One is helpful to that case. We still have an objection to the admission of that information.

This is a 640-acre spacing, has been and will be a 640-acre spacing unit and information which is put into this record on the pretense that it is supporting 640-acre spacing is irrelevant. Our concerns remain.

Mobil therefore requests that in view of the admission of the exhibit that this record remain open for a period of thirty days to allow Mobil to submit written comments and a written response. We began by discussing other parties with interests in the area south of the Canada Ojitos Unit who might be concerned about the evidence which has been presented to the Division. I do not know what to suggest to the Division to do about those parties. Amoco has indicated on the record that they expect to file an entry of appearance in this case. We don't know whether there are other parties who are interested or not.

We remain concerned. We think the application is premature and we think wells should be drilled before the decision is made.

Thank you.

MR. CATANACH: Mr. Carr.

MR. CARR: I had really not planned to give a closing but I'm going to respond to certain things that Mr. Pearce has said.

First of all, as to the false issue of other parties, and he doesn't know how that should be handled. I would suggest to you that what the Examiner ought to do is rule on the application. We're here seeking one thing, creation of standard 640-acre spacing units on the southern border of the Canada Ojitos Unit so development can take place in a prudent fashion.

Now perhaps Mobil has some broader scheme or some other plan for what's going on here today but all we would like is to get some obstacles out of the way so we can do what the unit operator has been trying to do for a year now and that is drill necessary protection wells along the southern boundary.

It's premature Mr. Pearce says, maybe we should wait till the wells are drilled. Well, that is absolutely the flip side of what we're talking about. We think the administrative obstacles ought to be removed so we can put these wells in an efficient, prudent location and that we can avoid drilling unnecessary wasteful wells which will cause economic waste and impair the rights of the interest owners in this area.

We talk about irrelevant evi-

dence. I wonder if he was here for the hearing. He employed the same tactic he employed earlier when we were talking about the admission of the exhibits.

Certainly it's relevant to tell you we need to have standard units because there is migration in the area, and we can tell you there is.

Certainly it's relevant to show you that 640-acre standard spacing units are appropriate and we have shown you that they are.

Certainly it's relevant for us to come in here and tell you that we've been standing around for a year waiting for people to make up their mind that the time has come now to get on with carrying out our obligations as unit operator and protect the southern portion of this unit and we've shown you not only what we need but why we need it. We've given notice to everyone who's entitled to it, they're here today, and it seems to me that they should have put their case on today and not sit back and ask to submit written comments thirty days after the hearing.

We've been waiting for a year now. We think it's time to get this matter resolved and we ask you to enter an order granting the application.

If Mobil wants to take this case and run off and try and do something else with it,

well, they can try that later and we'll come in and object.

But we've made a complete record. Everything that we've presented is relevant. It's consistent with our application and the time has come to take the case under advisement and enter an order so we can continue to carry out our duties as unit operator in a responsible fashion.

MR. CATANACH: Mr. Pearce, I'm going to -- I'm going to allow ten days for written comments to be submitted by Mobil and then we'll close the record in this case.

At that time we'll take the case under advisement.

(Hearing concluded.)

C E R T I F I C A T E

I, SALLY W. BOYD, C. S. R. DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division (Commission) was reported by me; that the said transcript is a full, true and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9525, heard by me on February 1 1989,

David R. Catanach, Examiner
Oil Conservation Division