STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 11,757

APPLICATION OF AMOCO PRODUCTION COMPANY FOR PERMANENT EXEMPTION FROM OIL CONSERVATION DIVISION RULES 402, 406 AND 1125 RELATING TO SHUT-IN PRESSURE TESTS FOR THE BRAVO DOME CARBON DIOXIDE GAS UNIT, UNION, HARDING AND QUAY COUNTIES, NEW MEXICO

ORIGINAL

REPORTER'S TRANSCRIPT OF PROCEEDINGS

EXAMINER HEARING

BEFORE: MICHAEL E. STOGNER, Hearing Examiner

April 3rd, 1997

Santa Fe, New Mexico

This matter came on for hearing before the New Mexico Oil Conservation Division, MICHAEL E. STOGNER, Hearing Examiner, on Thursday, April 3rd, 1997, at the New Mexico Energy, Minerals and Natural Resources Department, Porter Hall, 2040 South Pacheco, Santa Fe, New Mexico, Steven T. Brenner, Certified Court Reporter No. 7 for the State of New Mexico.

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April 3rd, 1997
Examiner Hearing
CASE NO. 11,757



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EXHIBITS



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WHEREUPON, the following proceedings were had at 11:28 a.m.:

EXAMINER STOGNER: Hearing will come to order. We'll call Case Number 11,757.

MR. CARROLL: Application of Amoco Production Company for permanent exemption from Oil Conservation Division Rules 402, 406 and 1125, relating to shut-in pressure tests for the Bravo Dome Carbon Dioxide Gas Unit, Union, Harding and Quay Counties, New Mexico.

EXAMINER STOGNER: Call for appearances.

MR. CARR: May it please the Examiner, my name is William F. Carr with the Santa Fe law firm Campbell, Carr, Berge and Sheridan.

We represent Amoco Production Company in this matter, and I have one witness.

EXAMINER STOGNER: Any other appearances?

MR. BRUCE: Mr. Examiner, Jim Bruce representing Amerada Hess Corporation.

I have no witnesses.

EXAMINER STOGNER: Will the witness please stand to be sworn?

(Thereupon, the witness was sworn.)

MR. CARR: At this time we call Perry Jarrell, J-a-r-r-e-l-l.

PERRY JARRELL,

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

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state our name for the record, please?
A. Perry Malcolm Jarrell.
Q. And where do you reside?
A. Houston, Texas.
Q. By whom are you employed?
A. Amoco Production.
Q. Mr. Jarrell, what is your current position with Amoco?
A. I'm a senior staff petroleum engineer.
Q. Have you previously testified before the New Mexico Oil Conservation Division?
A. No, I have not.
Q. Could you briefly review your educational background for Mr. Stogner?
A. I received a bachelor of science degree in petroleum engineering from Texas Tech University in 1980.
Q. Since graduation in 1980, for whom have you worked?
A. I've worked for Amoco production.
Q. And during that time with Amoco, have you worked

in engineering or managerial positions?

A. I have.

Q. What are your current responsibilities in regard to the Bravo Dome Carbon Dioxide Gas Unit?

A. I'm responsible for developing business opportunities for Bravo Dome.

Q. Are you familiar with the Application that has been filed on behalf of Amoco in this case?

A. I am.

MR. CARR: Mr. Stogner, at this time we would tender Mr. Jarrell as an expert witness in petroleum engineering.

EXAMINER STOGNER: What do you mean by "business opportunities"?

THE WITNESS: Business development opportunities, other than conventional infill drilling or drilling opportunities, which is held by other engineers in the group.

Basically anything outside the existing gathering system. I look after, for instance, the west-side development of Bravo Dome, situations such as this, external issues with, say, other working interest owners and royalty owners, those things.

EXAMINER STOGNER: Okay, so qualified.

Q. (By Mr. Carr) Mr. Jarrell, could you briefly summarize what Amoco seeks with this case?

A. First of all, I want to clarify what we are seeking and what we're not seeking.

We're not proposing to do away with all pressure testing in the Bravo Dome unit. What we're seeking is an amendment to Rule 402, which requires every well to be tested every year with a shut-in pressure test for a minimum of a 24-hour period.

What we'd like to propose is an amendment which will achieve a couple of things. One is better data, and reduction in costs and revenues -- I'm sorry, reduction in costs, and cash flow to the State and the working interest owners.

That's primarily what we're here for.

Q. If your proposal is accepted by the Division, it will, in fact, result in certain economic savings, will it not?

A. That's correct.

Q. At the same time, is it going to be your testimony that you will not undercut the database that is available and used by you in managing this unit?

A. No, that is not our intention, to withhold data, no.

Q. And is it also going to be your testimony that the data that you have will be made available to the State and others who have interests in this area so they can also make informed decisions on matters relating to Bravo Dome?

A. The pressure data, that's correct.

Q. What are Rules 402, 406 and 1125?

A. My general understanding of Rule 402, as I said earlier, is the requirement for natural gas well operators to perform annual shut-in pressure tests on each well each year, a minimum of 24 hours per test, and this is a surface-pressure test.

Q. 406 is just a rule that extends the rules that apply to natural gas to carbon dioxide?

A. That's correct.

Q. So we're not asking for anything in addition by referencing Rule 406; it just is related to the base request for a change in the shut-in pressure testing requirement?

A. That's correct.

Q. And Rule 1125 simply requires that the results be filed on form C-125; is that not right?

A. That's correct. So in essence, we're really asking for an amendment to Rule 402 and not any changes to the other rules.

Q. And you're seeking just an exception that will not require -- that will enable you or exempt you from annual testing of every well in the unit?

A. That's correct.

Q. Have you prepared exhibits for presentation in this hearing?

A. I have.

Q. Let's go to what has been marked for identification as Amoco Exhibit Number 1, and would you just identify this, please?

A. This is merely a location map to draw bearings to the location of Bravo Dome within the northeastern corner of New Mexico.

Q. Let's go to Exhibit Number 2. Would you first identify this, and then if you could review the information on this exhibit for the Examiner.

A. Okay. I realize there's a lot of information on this map, and it's here for qualitative purposes.

What you're looking at is a unit map of Bravo Dome, with the black line showing the unit boundary. This is a contour map of $\phi h$, or the volumetrics, as we currently interpret them for Bravo Dome unit, contoured at, I believe, around 5 $\phi h$ intervals.

What you're also seeing red lines within the unit are the interpretations of faults within the unit.

I have two or three key points I want to make with this exhibit. One of them is to show the variability in the storage capacity of the unit.

The very bright yellows there in the center that I've characterized as the area north of the fault is our highest porosity and transmissibility portion of the field and, of course, was the area that we developed first.

The area south of the fault -- and if you can see it, there's a red line indicating a fault there -- is somewhat less porosity feet.

And then the Leg 8 area has its different $\phi h$ characteristics, and Leg 9 has its different $\phi h$ characteristics.

So I'm trying to show the different porosity characteristics with this visual.

Q. And so we basically have four distinct areas that have different reservoir characteristics; is that right?

A. It's all one reservoir, I don't want to -- That's correct, I'm not trying to show that these are four distinct pools. It is certainly all one pool.

But for speaking purposes today, these areas are different, not only in their porosity but also in a couple other distinctions, and those are that they were developed at different times.

So the area in the center of the field there was developed first, as I mentioned, that's characterized as north of the fault. The south-of-the-fault area was developed after that, around the 1983-84 time frame.

The Leg 8 area was drilled in 1993, very recent drilling and gathering system installation development. And Leg 9, 1980 -- I'm sorry, 1993. Did I say 1983? 1993 for Leg 8 and 1995 for Leg 9.

Q. Basically what we have here is a relationship. The extent of the depletion obviously relates to the amount of time the area has actually been on production; is that right?

A. That's correct.

Q. And what do the general color codes show here, Mr. Jarrell?

Q. Well, the very bright yellow is the highest porosity-feet. And it shades ever so slightly into duller shades of yellow. For instance, the very outlining tan pieces of the $\phi h$ over in the west Bravo Dome unit is lower $\phi h$ than, say, the bright yellow.

And the very lowest is the very light blue within the unit boundary, terminating at the zero net isopachous line, that's a dotted line which delineates the unit boundary on the southern and eastern side of the unit.

Q. How many wells is Amoco now proposing to drill in each of these four areas?

A. Proposing to drill?

Q. Or, I'm sorry, proposing to test?

A. We currently test every well, which is around 360 wells. And what we'd like to propose is testing a statistical sample of these four areas of about three wells per area, which would be around 12 wells per year.

And these tests would not be just surface-pressure tests; they would be bottomhole pressure tests with a bottomhole bomb, over about a 72-hour period, which for engineering needs would be more accurate data for determining reservoir pressure.

Q. Currently you're using a 24-hour test?

A. That's correct.

Q. Will test information from three wells in each of these areas provide an adequate statistical sampling in each area for you to continue to properly manage the reservoir?

A. Yes, it will. And what I have to say here is, why that is so is because we have a reservoir model that we have a high degree of confidence in that predicts what the reservoir pressures, deliverability and recoveries will be in the future, and they match very well with what those actual pieces of data are today.

So we would use this data to continue to make our model as rigorous and as accurate as it could be, by checking the model's predicted pressures versus the actual pressures we sample in each of these different drainage areas.

Q. Let's go to what has been marked Amoco Exhibit Number 3. Would you identify and review that, please?

A. Yes, Exhibit Number 3 is showing six curves of pressure data, surface pressure data, versus time, from 1987 till 1996.

And what these are, are linear best fits of all the pressure data that was taken on very well in each of the townships and sections noticed in the legend.

For instance, the red line at the top on the right-hand side of the Exhibit says "Linear 1835". That's Township and Range 18-35, and so forth.

These six townships represent a good sampling of a lot of data that we've collected through the longest period of time, and that is the areas characterized in the previous exhibit as areas north and south -- north of the fault and south of the fault. These have been on production for a good 12 years.

Q. What does this now show us?

A. The intent of this exhibit is to illustrate that there's a similar rate of depletion in each of these township and ranges, as far as pressure depletion. And so I think if you look at them visually you can come to that conclusion.

What it also shows is, if you use an abandonment pressure that we're currently expecting the unit to be at, which is around 100 and -- well, for p.s.i.g. purposes, it would be about 95 p.s.i.g. The units of pressure depletion is about half right now, it's about 50-percent depleted.

So we have a good amount of data here that shows a pretty good fit of the information that we've collected from all the wells so far. So the data has been useful, and it's been good.

Q. Does this data suggest continuity throughout the reservoir?

A. I believe it does, because of the similar rates of depletion of pressure.

Q. What is Amoco Exhibit Number 4?

A. Exhibit Number 4 is -- is just an exhibit to attempt to further make the point made in Exhibit 3. This is a blow-up of the area that I characterize as north of the fault and south of the fault, and I show the approximate fault line here in red.

And what this is showing is what the initial pressure was north of the fault, around 390 p.s.i.a., and what the initial pressure south of the fault was, which is about 460 p.s.i. So it's showing when the reservoir was initially discovered and developed, there was a pressure difference.

What I'm also showing is the 1996 calculated bottomhole pressure from the surface pressures that we collect, which is an average of all the wells. So in the north of the fault area it's around 246, and the south of the fault area it's 301 p.s.i.a.

Q. This information basically supports the information presented on the preceding curve, does it not?

A. It supports that the reservoir is a -- from a pressure standpoint is about 50-percent depleted, from initial bottomhole pressure to the current bottomhole pressure, keeping in mind that our abandonment pressure would be around 95 p.s.i.g. or about 124 p.s.i.a. bottomhole pressure.

Q. And the difference between the two areas is attributable to the fault that runs through there, correct?

A. That's correct.

Q. Let's go to Exhibit Number 5, the P/Z curve, and have you review this for Mr. Stogner.

A. Okay. This is your fundamental reservoir engineering tool for a dry gas reservoir to approximate ultimate recovery. What I'm showing is pressure over a Z factor or compressibility factor, plotted versus cumulative production.

And the green diamonds are the actual data points from 1985 through 1996, using the 24-hour or the surface pressure data that we've collected in every well that we're finding, and these points are the average of each of those pressure points for the whole unit, not just the north-of-the-fault and south-of-the-fault area, but the whole current developed unit area.

Q. How good a fit have you actually gotten with this data?

A. What I show here with this dashed green is a linear best fit through those data points, which is a pretty good fit.

Q. And what is the equation in the lower right-hand portion of the exhibit?

A. That is the linear equation of that best-fit line, which states y equals -- et cetera. The $R^2$ factor is a number used in the -- plotting package I used here was an Xcel spreadsheet that describes the goodness of the fit.

My understanding, anything better than a .7 is pretty good; this is a .96 fit through the data, showing the data points determine a pretty good estimation of what the ultimate recovery would be through this unit using this data and not collecting any more data.

The fit is a pretty good amount of data and approximates what we think the ultimate recovery will be with the current developed area.

Q. And what is that recovery with the current developed area?

A. It's around 3 TCF where it crosses the abandonment P/Z line of 130, that red dotted line.

Q. What sort of recovery factors do you have in the unit?

A. This total unit recovery factory is -- I'm sorry, factor, is around 65 percent, which to my understanding is a pretty reasonable recovery factor for a dry gas reservoir.

Q. Now, Mr. Jarrell, since the model that Amoco is using predicts rates, reserves and pressures, do you need the amount of data on a point-forward basis that you have needed in the past to make informed decisions about reservoir performance?

A. No, we don't think we do. The data we've collected was useful in putting together the reservoir model we have. The reservoir model, point-forward, I think, just needs to be fine-tuned with a quality selection points of wells to corroborate its predictions of bottomhole pressures.

We have other things to corroborate the model, of course, is production, which we obviously will continue to get a measurement of production rates and volumes. And with those pieces of data I think we can still improve the model's ability to predict and our confidence in that model.

Q. Is what you're requesting, in effect, the optimum level of additional data needed to continue to manage this reservoir?

A. That's correct. It's a matter of cost versus benefit. You know, obviously it costs us and the State money to take this amount of data, and we're looking for that compromise.

Q. When you run these tests on 12 wells, as we're proposing, and you see deviation from this P/Z curve, what would happen in that circumstance, should that occur?

A. My -- My expectation is that as we sample these 12 key wells each year and took the 72-hour pressure buildup tests, we would compare those to what the model says those individual well pressures should be. And if those deviated significantly, then we would have reason to think the model needed to be fine-tuned.

If that continued to be a pattern, we would want to take more data in more wells. So we're not being steadfast to the recommendation today forever and for -- and not to be flexible. We're going to be flexible with what data we need.

Q. And that data would be reported to the Oil Conservation Division?

A. Absolutely.

Q. And the Division, under your proposal, would still have the requirements -- or the authority that it always has, to require additional testing under Rule 402, should the information that is reported to them be inconsistent for what you're predicting on this particular P/Z curve; is that right?

A. That's correct.

Q. And Amoco is not opposed here today to doing any testing that's needed to properly monitor this reservoir or make informed decisions. It is just asking for an exemption from what has become unnecessary testing within the Bravo Dome unit?

A. That's correct.

Q. And we're here today making this recommendation, but we're flexible in terms of the number of tests that need to be run if, in fact, as the data comes in it appears that these wells are, in fact, deviating from the curve that we've presented here; is that right?

A. That's right.

Q. Will other owners in the unit be able to use the information from this model?

A. Yeah, we would make available the pressure predictions.

Q. The results would be made available to anyone who needed them?

A. Yes. To me, that --

Q. You can't release --

A. I'm sorry. To me, that --

Q. You can't release the model, but you would give them the results?

A. That's correct, because in our estimation it would be a fair representation of what the bottomhole pressures actually would be over time because of our confidence in the model's ability to predict.

Q. Let's go to Exhibit Number 6. What is this?

A. Exhibit Number 6 is a production decline, a production plot of Bravo Dome unit, the entire unit, using actual data from 1984 through 1996, with projected data point-forward.

What this exhibit illustrates is, if I were to do a decline curve analysis on this reservoir to get the same 3 TCF the P/Z plot provides, you would have to back into an exponential decline rate, and this one is about 8.5 percent.

Q. And this is the same decline utilized in the model?

A. Right. The -- That decline rate is the same one that the model predicts. So I'm trying to show the accurateness and the confidence we have in the model, so that it shows the same kind of rates, reserves and pressures that we've been measuring and that we expect to get in the future.

Q. Let's go to Exhibit Number 7. Could you explain what this exhibit is and what it's designed to show?

A. Yeah, I can. Before I do that, I'd like to make a comment about the past -- the past two or three exhibits.

All this recovery and decline is just using point forward production in existing wells. This isn't a prediction that we don't have other further development plans for the unit, because we do. So I just want to make sure that's not a misconception or interpretation of these exhibits. It's just taking --

Q. Now, when we talk about 3 TCF, we're talking about what is currently developed --

A. That's correct.

Q. -- within the unit?

A. Correct.

Q. All right. Let's go to Exhibit Number 7.

A. Exhibit Number 7 is pressure data output from our model. I've picked a time reference here, when we had this data last produced, August of 1995.

It's produced on a grid. If you look at it, it looks similar to a layout of Bravo Dome unit in the developed area. Okay, so you're seeing those areas that I characterized as north of the fault, south of the fault and Leg 8. Leg 9 is missing because it wasn't developed at the time we put this together.

What this is showing is the pressure deviations of what the model predicted at this -- on this very day, versus what we've actually measured on that day for the wells. And it's showing that well over 85 percent of the wells sampled there were within plus or minus 5-percent -- I'm sorry -- that's right, plus or minus 5-percent pressure of what the actual pressure reading was.

It's to exhibit our confidence in the model's ability to be fairly accurate on a regional-wide basis.

Q. And so basically this just confirms that the data you get from the model is consistent with -- in most areas, within 5 percent of what you get by actually going out there and testing; isn't that correct?

A. That's correct.

Q. In fact, some of the variances may be a result of testing, not the model; isn't that right?

A. That's true.

Q. Let's look at Exhibit Number 8. Can you explain what this is?

A. Yes, Exhibit Number 8 is the fiscal results of our current testing process, first of all, we're proposing.

If I could draw your attention to the top star there where it says the current testing process, which is annual on every well, as I stated....

Before we focus on the numbers, I just want to point out, we sell every MCF of gas we can. The market's there, we're producing at near production capacity. We're in a market where selling every MCF we can is very important. We don't have any wells shut in -- or really don't think we can afford the luxury of having wells shut in any time that we absolutely don't need to have them shut in.

So the current testing process of having every well shut in every year is equivalent to having one well shut in for the entire year. So it's like losing a well.

So the numbers I've generated here is showing the result of having one well's production lost for the entire year, which is about a million cubic feet per day, just on average.

Obviously, that production produces state tax and royalty, and I'm showing in the year 1997, if we could take a test in every well, that's a lost revenue to the State of about $14,000. And over to the right, that's a lost revenue to the unit working interest owners of about $62,000.

And then I go on to show what that loss is over the next ten years. That's approximately $104,000 to the state and around $437,000 to the working interest owners, due all to losing that production --

Q. All right --

A. -- of the one well.
Q. -- and then if we look at the economics on the proposed testing process, what do they show?
A. It shows some reduction in the impact on the state and the working interest owners, because we're proposing we test fewer wells.
However, we're also proposing -- There would be added cost to the way we would like to take tests, and that with a bottomhole pressure bomb. So that would be added to the cost, to the deferred production cash flow cost.
So the bottom line there at the bottom is that the savings generated to the State, to the working interest owners, is around $94,000 over the next ten years to the State and around $214,000 to the working interest owners in the unit.
Q. Mr. Jarrell, isn't one of the questions we're dealing with here today whether or not the data received from the tests is actually worth the cost being incurred?
A. That's correct, it's a cost-benefit analysis. You've got to ask yourself, if you're Joe Blow Oil Company and you'd like to -- and you have to pay $62,000 a year to collect pressure data, and do you use those data for any significant value, you've got to weigh those difference.
Q. Is it your opinion that not only will savings be affected by approval of this recommendation but, in fact,

the information obtained will be as good or not better?

A. That's correct.

Q. What conclusions generally have you reached from your review of the Division's shut-in well testing requirements as these requirements relate to Bravo Dome?

A. In general, I believe they're, for our purposes of prudently operating the unit, we think they're excessive in the regard that it's more data than we think we need to adequately understand how these wells deplete and how to further develop the unit.

We do agree there's data we do need to continue to collect, bottomhole pressure data, and we want to do that. But we're also -- realize that there are some cost savings to be derived by changing the process as well, and that benefits the State and the working interest owners.

Q. Are there other operators in the are who would be affected by this recommendation?

A. Yes. To my knowledge, the only operator in this pool was Amerada Hess.

Q. And have you reviewed this proposal with representatives of Amerada Hess?

A. Yes, I have.

Q. Is Exhibit Number 9 a copy of a letter received from Amerada Hess in which they waive their objection to the current proposal?

A. It is.

Q. Now, Mr. Jarrell, if this proposal is approved by the Division, how do you, in fact, recommend that it actually be implemented?

A. We'd be glad to write an amendment to the current rule to the effect it exempts Amoco from requiring every well -- requiring Amoco to take surface pressure tests on every well every year.

We prefer some language that states that Amoco should take 72-hour bottomhole pressure tests at about 12 key wells each year in the current developed area of the unit and that we would make that data available to the State, of course, to the similar forms in which we report data to the State, and that we would -- I also wanted to point out that we've already taken five tests this year and that, you know, as we continue to develop wells and work over wells and have wells down for various reasons, and with those wells are down or -- you know, we prefer to take the data because it's -- we're not saying the data is useless. We'll take it if it's, quote, unquote, free, if the well's already down for some reason. We'll take those wells' tests and submit them to the State as well.

So it will be more than 12 wells in a practical sense of how much surface data and bottomhole pressure data that we'd be collecting and sending to the State.

Q. Would Amoco be willing to, early each year, by a set date, provide a list of the wells to the Division, wells in which they plan to conduct the 72-hour shut-in pressure tests?

A. Yeah, we'd be glad to let the State take a look at the wells we're proposing to test. I don't expect that they would change each year, but if they did we'd provide that to the State for their approval.

Q. So that they could then approve them, so that if they felt there was -- additional wells or other wells that ought to be tested, that they would be engaged in that dialogue with Amoco before the testing commenced during any one-year period of time?

A. That's correct.

Q. And the results of all these tests will be reported to the Division as they are now on Form C-125 under your proposal; is that right?

A. That's correct.

Q. Mr. Jarrell, in your opinion, will approval of this Application be in the best interests of conservation, the prevention of waste and the protection of correlative rights?

A. Yes.

Q. Were Amoco Exhibits 1 through 9 either prepared by you or compiled under your direction?

A. They were.

MR. CARR: Mr. Stogner, at this time we would move the admission into evidence of Amoco Exhibits 1 through 9.

EXAMINER STOGNER: Exhibits 1 through 9 will be admitted into evidence.

MR. CARR: And that concludes my direct examination of Mr. Jarrell.

EXAMINER STOGNER: Mr. Bruce?

MR. BRUCE: I just have one thing, Mr. Examiner.

EXAMINATION

BY MR. BRUCE:

Q. I'd like to hand Mr. Jarrell what's been marked Amerada Exhibit 1. I think it's probably similar forms to his Exhibit 9.

Mr. Jarrell, this letter from Amerada says it doesn't object to your request, provided it only applies to the currently drilled and producing wells in the Amoco-operated Bravo Dome unit.

Does Amoco have an objection to that stipulation in the order?

A. I just want to be clear before I answer that. It's our hope and expectation that any further wells that are developed within the current developed area, such as infill wells, we're not expecting to take annual 24-hour shut-in pressure tests on those wells.

Outside the current developed area, we're open to those wells still following within the current rules guidelines.

Q. Okay, I just wanted to clarify. I think that's a little different than what the letter says.

A. It is a little different, and that's why I wanted to clarify.

MR. BRUCE: I don't have anything further at this time, Mr. Examiner.

EXAMINER STOGNER: Mr. Bruce.

MR. CARROLL: Mr. Bruce?

MR. BRUCE: Yes.

MR. CARROLL: What's Mr. Mendenhall's title with Amerada Hess?

MR. BRUCE: He is an engineer, I believe, an engineering representative, and I am getting the original of this, and I will submit it to you today.

I have nothing further.

EXAMINER STOGNER: Thank you, Mr. Bruce.

I believe Mr. Roy Johnson, District 4 Supervisor, has some questions at this time.

EXAMINATION

BY MR. JOHNSON:

Q. Mr. Jarrell, have the working interest owners of the unit been apprised of this Application?

A. Not all of them, no.

Q. Okay. Are you obligated to do so by the unit or the operating agreements?

A. I'm not sure I know the answer to that.

Q. Okay. Could you please explain to the Examiner how Amoco takes their annual shut-in pressure tests, wellhead configurations --

A. Yeah.

Q. -- all the way down?

A. I sure will. Our annual pressure tests are taken with the equipment that's currently on the well's automation system.

There is a pressure sensor at the wellhead, and these wells are shut in through a remote shut-in device that closes off the well's production capability downstream of the wellhead, and the automation system starts the clock at the time it shuts it in and counts a 24-hour period and measures that pressure point with that remote wellhead sensor at that time, and that is the pressure that we collect and report on the forms to the state.

Q. Okay. So basically all this can be done within a room that has the computer linked to all the wells; is that correct?

A. That's correct.

Q. Okay. What are the manpower requirements on this?

A. Very minimal.

Q. Yeah.

A. I don't think we've stated there's been any significant costs associated with taking the tests other than just the lost production.

Q. Okay, so basically what you're referring here in your lost cash flow, lost production, these numbers just relate to the lost production as far as going through the sales meter of the plant?

A. Yes, sir, that's correct.

Q. Has Amoco looked at an eight-hour test versus a 24-hour test? If so, what are the substantial differences between the two?

A. It depends on what your intent of the data is. I've looked at an eight-hour test and I get pressure readings, but I couldn't tell you if they're meaningful if you're trying to estimate bottomhole pressure from that data, if that's what you're asking.

Q. Well, that's -- I don't believe the intent of the Rule 402 is for a bottomhole pressure. It's for shut-in tubing pressure, but not...

A. Well, it clearly states that's where you take the pressure; I'm just not clearly -- I'm not clear what the intent of the use of that data is for. I assume it's to understand what the bottomhole pressure is. The State's rule doesn't say why it wants the data; it just says collect it.

So I'm trying to understand, if I can answer your question correctly about the eight-hour pressure data.

Q. Well, let me rephrase the question. Is an eight-hour test within a certain parameter, say ten pounds, of a 24-hour pressure test?

A. It varies from well to well, obviously, because they have the different deliverabilities and different pressures.

I did scan a few wells to look at whether that would be a reasonable way to collect pressure data, again assuming that I'm using it to try and estimate bottomhole pressure.

The wells that I saw had a -- it was about a 50-percent difference, almost linear, from the existing flowing pressure to the shut-in wellhead pressure of 24 hours.

So if I was to shut it in four 12 hours, for instance, the data I saw roughly was about half the pressure difference.

Q. About half?

A. Yes, sir. Again, it varies from well to well.

Some wells, if they're very transmissible, you know, they will meet stabilized wellhead pressure very quickly. If they're not very transmissible it takes a while for that wellhead pressure to stabilize at a pressure -- It could take three days, four days.

Q. Okay. Have you reviewed all the bottomhole pressure data for the entire unit and areas even outside of the unit?

A. I have not reviewed the data outside the unit, now.

Q. How about within the unit?

A. Within the gathering system area, I've looked at all of the surface pressure data that we collect. I haven't reviewed all the bottomhole pressure data that's been collected.

Q. So you wouldn't know if this reservoir was in equilibrium where the pressure on one side in a producing area is going to be equivalent to what it is over on the -- say the west side of the unit?

A. If you're talking about the far west side versus the current developed area, no, I haven't performed that study, I don't know what the pressure differences are. I know what they were when the reservoir was initially developed and there were wide differences in initial bottomhole pressure.

Q. Okay. Are you familiar with Amoco's endeavor last year on their Bueyeros Com Number 1 well?

A. Yes.

Q. Are you familiar with the geologic concept of it?

A. Yes, I am.

Q. Is it possible for you to tell the Examiner of this?

A. It is. I'd rather not, because it's proprietary and we're -- It's rather tight. If you can elaborate on how it has bearing on this, I'll be glad to give you what data --

Q. Well, basically, the bearing is that when you move to the west side of the unit the pressures are nowhere near what they are in the producing area.

A. I agree.

Q. You also run into not only a different unit agreement, but you start running into a rather large, substantial lease out there that separates the two units and also several ranches that the royalty interest owner is not in the Bravo Dome unit.

And as a mechanism for reservoir engineering, these pressure datas, whether it be tubing or bottomhole pressure, are very, very important as far as correlative rights are concerned.

A. Agreed.

Q. And what -- By the way your Application reads, you want this exemption to be over the entire unit, over 900,000 acres, is the way I read it, where when you start getting off to the peripheries of the unit, the pressures start changing, the royalties start changing, and correlative rights are an issue. And to have a complete, total exemption on shut-in pressure tests, we will be starting to forego our integrity on our data. Would you agree with that?

A. I think I said earlier, our intent is to get this exemption within the current developed gathering system of the unit, per Amerada Hess's question about getting clarification on where we're trying to get exemption.

I'm not seeking to exempt wells outside the current gathering area that we plan to drill further. At this time we don't produce any wells, nor have plans to produce any wells, outside the current developed area within the unitized interval.

Q. You have two wells on the western side of Bravo Dome currently now that are --

A. I'm sorry, except for those two wells. I'm sorry, that's correct.

Q. To get back to this Bueyeros Com Number 1 of yours, if -- First let me say I think that's an outstanding, gutsy move on Amoco's part, to do what they did out there. But if that geologic model proves true, then those pressure tests all along that fault are going to be highly critical.

A. I agree. Our interpretation of that is not within the unit, so that would not fall within the --

MR. JOHNSON: I believe there's some argument to that from some of the other working interest owners, but...

Mr. Examiner, that's all I have.

EXAMINER STOGNER: Mr. Carr?

MR. CARR: That concludes our presentation.

EXAMINATION

BY EXAMINER STOGNER:

Q. What would -- What do you propose the criteria to be on these -- I believe these 12 test wells, or would they change?

A. We think it would be wise to use the same wells, just so you'd reduce the amount of variables that could change from one well to the other on collecting data.

The criteria would be -- As I said earlier, what we shoot for is about three wells in each of these four regions of the unit, which are -- have different porosity and development time-frame period.

So factors would be the range of porosity these units, these wells, would have, when they were developed, you know, whether it's an early-life well or a late-life well, and whether it's north or south of the fault. That covers the criteria being in each of these different areas.

Other than that, I think we're going to be pretty flexible. We obviously want to have some wells that penetrate all the horizon, that don't make water, so we can maintain the integrity of the bottomhole pressure data and not be complicated with water buildup in the wellbore. That would be another criteria.

Q. Should any other criteria be utilized?

A. I can't think of any at this time.

Q. You've essentially stated more of an engineering type of criteria, and even the ones you've told me seem to be somewhat enhancing the information.

Those that didn't produce water, would they give me some other indications, perhaps? Would they give me a false reading if I took an average, just wells that didn't produce water?

A. I'm not sure if I understand your question. You're saying if I took these tests in wells that produced water, would that compromise --

Q. Yeah, would the water production have any bearing on these pressure tests?

A. I think they would, yeah. I'd have to -- I'd just have to account for it. You know, we have to know how much water head built up in the reservoir and factor that in to trying to understand what the interpretation would be that we're after, and that is, what is the average reservoir pressure, and the bottomhole stabilized pressure for each well.

Q. You've got to forgive me, here. I mean, I'm used to dealing with micro-type stuff. I think you were here at the last hearing where bottomhole pressure had everything to do with the case --

A. Yeah.

Q. -- on a small, individual type of basis. And trying to shift to a macro type of thinking is a little bit difficult for me here.

And that does concern me, what Mr. Johnson had brought up, correlative rights issue. If pressures were varied between wells, even in one of these little areas where there was some discrepancies in the proration unit, whether it was 100 percent in the unit or there was some variances outside of it, how would you account for that, or should that be some criteria in there also that would account for those?

A. You're speaking about areas outside the unit. If you're trying to --

Q. No, I'm speaking about areas inside of the unit. Are you telling me you've got 100-percent participation and ratification in the whole unit?

A. No, we don't, there are some unratified --

Q. Okay, now, you know what a proration unit is then?

A. Yes.

Q. Okay. And these -- How are these interest owners handled in a proration unit that haven't ratified the unit? Are they kept separately just for that proration unit?

A. I believe units that haven't been ratified get paid on the amount of production that's metered off each well.

Q. Okay. So there again, we're talking about metered well data --

A. Correct.

Q. -- or -- volumes and everything. Would it be prudent not to also have information pertinent to that well to meet the criteria for rules and regulations for that particular well that's handled different than what all unit wells are?

A. It gets into exactly what data you need to make that decision, and I think you're asking, is pressure data also required and prudent to collect to do the right thing for all parties included for drainage purposes?

That's where we feel like our reservoir model adequately understands and predicts what the pressures and rates of recoveries will be on every well, not just the entire unit. So I would rely on that model for that kind of information.

It's my understanding currently, you know, what our obligation is, is to prudently and effectively drain this reservoir, and that we don't offend any parties in doing that. So the ones that are not ratified, what we do right now, of course, is meter the production that is on their lease, and that's how they're paid.

Q. These figures on Exhibit Number 8 represent the loss of revenues for these tests.

Do you have any similar type of figures that represent actual loss of -- whenever, say, systems or wells are down or shut in for mechanical problems? Do you have any percentage of what kind of production or what kind of figures are lost due to that kind of a shut-in, a mechanical shut-in?

A. Yes, we've looked at wells that were shut in -- and it would be shut in for the same reasons, the same way, the well's down and not producing any rate out of it whatsoever, whether we shut it in at the surface or it's down for, as you say, mechanical reasons. For instance, say, a compressor goes down. We may go shut in all the wells feeding those compressors.

We've looked at the production rate from those wells, and what we've seen is that wells that have been down, say, for instance, for a whole day, an entire 24-hour period, when we bring them back on production, there's a slight increase in production the next day, but it falls off very quickly and does not come close to making up for the rate lost the day it was down, primarily because of backpressure considerations in the gathering system. We just can't physically move that entire volume of rate lost that date through the system the next day or the day after that.

Q. Does it happen a lot out there?

A. Wells going down, does that happen a lot?

Q. Yes.

A. I wouldn't say a lot, no.

Q. But it does happen?

A. Primarily when we get power interruptions or customer demand goes down.

It's very rare that the wells go down for a mechanical reason in and of themselves, because they're practically mechanical-free; you're just flowing gas wells.

FURTHER EXAMINATION

BY MR. JOHNSON:

Q. How often does your gathering system go down? The legs, the nine separate legs?

A. Well, we get leaks in gathering systems from time, primarily in the spring and fall when the soil starts to settle and shift a little bit.

I don't know that I can quote you a number. But as far as number of days operated, our run time for the whole unit, including all the compressor down time, legs being down, wells being down, is about 98 percent. We run 98 percent of the time.

EXAMINER STOGNER: Do you ever make arrangements when a well is down to go ahead and do a shut-in pressure test on it?

THE WITNESS: We do. That's the time we try to take advantage of our current obligation to take that pressure test.

Q. (By Mr. Johnson) That's why I was referring to the eight-hour shut-in pressure test, because usually when the gathering line goes down it takes eight to ten hours to go ahead and replace them.

A. That's right.

Q. And at least that data is better than no data.

A. I would agree because it's just basically free data, right. The well's down, all we've got to do is tell the computer system to collect it, and we've got it.

Q. When the system does go down, and because of your contracts for your $CO_2$, do you have to replace that $CO_2$ from some other source down in west Texas --

A. We do.

Q. -- to fulfill your contract?

A. We do.

Q. And that number is reflected in this sheet?

A. No, I did not calculate added costs to working interest owners' needs to make up contractual obligations. No, that's not in here.

Q. So basically, the whole scenario is, with 362 wells averaging a million a day, you are having to purchase 362 million cubic feet a day, the way our rules are written, to go ahead and fulfill your contracts in west Texas? Roughly?

A. Close to what you said is right. It's equivalent, again, for one well being down all year. So it's a million cubic feet a day. For the whole year it would be 360 million cubic feet.

FURTHER EXAMINATION

BY EXAMINER STOGNER:

Q. I'm going to go back to some sentence in criteria, because with what you're proposing I don't believe -- Well, I don't know, let me ask you: Has this been done in any other units than Amoco-operated? I know Amoco has a lot of large gas units over in northwest New Mexico. Has a similar request been granted in those areas?

A. The only request that I know is that they have gotten exemption -- an exemption in the northwest area on a similar rule, but for a different reason. I believe they're now collecting data on every well every three years, as opposed to every year, for this particular rule. But I don't think they proposed key wells being set. I think they do every well every three years, as opposed to every year.

Other than that, I'm not familiar, I haven't researched whether Amoco does this anywhere else.

Q. Okay. If I open the floodgate, if you will, allowing this, and then others come in, what should I look at as far as the criteria goes for a large unit or a large area, maybe even a poolwide basis?

A. I think you have to consider how much data has been collected, and that's what I've tried to show with some of these exhibits. We've got 12 years' worth of data collected, and I think you could use that to produce a P/Z plot.

You need to see how much have they collected so far, and does it give a fair representation of what the recovery should be from that well or from that unit. If you have confidence in that character of the decline nature, the P/Z plot, I'd consider that.

If they haven't, if you don't have a good understanding, or an outsider won't have a good understanding through the State's data, what the ultimate recovery would be from the well, I would look at whether they have other ways of estimating recoveries and pressures and rates like our reservoir model that we have that's combined with the gathering system.

That, in effect, takes the place of actually measuring the data, but it's integrated and complicated enough and -- that it can predict that rather accurately, and it can make that pressure data available on top of the production data that's already reported to the State. Any outsider could develop recovery plots that they'd probably want to see to look at what kind of pressure depletion is happening, what kind of recoveries would you be getting from each well and/or unit.

So I don't think it's a good idea to wholesale do away with the rule because, as we stated, I think the data has been meaningful that we've captured so far. But we're far enough in maturity of the life of the unit that's losing its value.

Q. How about other issues? I mean, you talked about engineering issues. How about --

A. Yeah.

Q. -- some of these other units? Would I have ownership differences? What other criteria can you think of I would need to look at?

A. I'm not very familiar with other units, I'm sorry to say, throughout New Mexico. I've been working just Bravo Dome.

Obviously, some issues that were brought up earlier as far as drainage, if there's a concern that there is -- that offset operators aren't seeing eye to eye on what the recoveries are on their individual wells or leases and that's a point of contention, I think both parties probably would want to have as much and as accurate data as possible to make their case.

And I think having shut-in bottomhole pressures would be adequate and necessary information to try to understand drainage implications. And of course that affects royalty owners as well as the less -- the people who take the least, the operators. I think you have to consider that.

And I think what we're proposing is that we feel like we can address those issues within, again, the current developed part of the unit.

But if we had some reason to think that there was an issue of what we were draining off another lease from an offset operator or someone else that's been using this data to build a case against us or to state their understanding of their well's recovery, I'd certainly want to make sure we all had the data we need to make the right decisions.

But that's the only other criteria I can think of, of course, is correlative rights and royalty owner rights.

Q. Referring again to Exhibit Number 8, you show in one of the columns State's savings, tax and royalty.

A. Yes, sir.

Q. How does the State collect the royalty on the $CO_2$ in the Bravo Dome?

A. The State is a royalty owner in Bravo Dome. I think you own about 26 percent of the acreage.

Q. Is that paid out on a volume basis unitwide?

A. If I understand your question right, yeah, you -- All royalty owners are paid based on total unit volume, averaged across what the average tailgate price of $CO_2$ is at the time it's sold, and you get paid that way, like -- but -- similar to the federal government. They have acreage in the unit as well.

Q. So it's a cost per MCF or a rate per MCF to the State, paid to the State?

A. That's right. So for instance, assuming the average royalty burden throughout the unit is an eighth and the State owns 20 percent of the royalty, you'd factor that times the amount of production that's produced, times the eighth, times the $CO_2$ price at the time, and that's how I come up with part of that value. The rest of it is the tax that you collect on that production, severance tax.

Q. Is that a standard one-eighth, unitwide, for the state tax, based on the percentage of state lands in the unit?

A. I don't know what the exact number is. It's close to an eight.

FURTHER EXAMINATION

BY MR. JOHNSON:

Q. Amoco has experienced quite a bit of litigation on this Bravo Dome unit. Has any of this litigation been on correlative-rights issues?

A. I believe it has. Explain correlative rights for me exactly. You're talking about royalty owners having issues?

Q. No, not the royalty owners. I'm basically concerned with drainage.

A. I don't know that there's ever been a case for other operators having a --

Q. How about the working interest owners, as far as engineering practices?

A. Not to my knowledge, no.

FURTHER EXAMINATION

BY EXAMINER STOGNER:

Q. I'm still a little vague on which wells would be chosen. Have you got a list of them that you would choose, or how -- or would you just submit them, or how would that be included in the order if an order is issued?

A. What we propose to do is to pick those wells or show the criteria and submit them for your approval. And our -- Again, our expectations, it would be the same 12 years again, for continuity of the data, minimizing other variables in collecting the data from well to well.

And those would be wells, again, as I stated, a statistical sampling within each of those four areas, three in each.

So I don't have the well numbers today, but I'd be glad to provide them to you.

Q. Would the data that you presently have installed in all of the wells that provides that information from a control area, would that be taken out also as a cost savings?

A. I've factored that into our proposed cost numbers, the fact that we still expect to have production lost from those wells, but we think that's a price worth paying for the data that we collect.

Is that your question?

Q. So those wells, other than the 12 chosen wells, would not be -- have the capacity, other than shutting them in and doing a deadweight test, or something to that effect, should a pressure -- should a bottomhole pressure be necessary on wells on a -- for whatever reason, you would not have that convenience anymore to get a computer readout, as you described?

A. The wells would still be capable of taking that information.

Q. Well, that's what I was asking. So that hardware, or whatever is in that well that does that, will not be taken out?

A. No, sir, we'll still have the capability of taking surface pressure readings on each well. That's part of our automation system, we need that to operate the units. It will still be there.

That monitors flowing tubing pressure. I mean, it's just the same equipment that monitors our flowing tubing pressure as it does if we shut the well in at the wellhead.

Q. Why wouldn't you go ahead and take it off if you're not required to have it anymore for reporting purposes?

A. We installed it for our own purposes of monitoring flowing tubing pressure and wellhead pressure, with rates. That's meaningful data for our model as well.

Q. So you're going to collect this data anyway?

A. Not the shut-in pressure data. I may not be answering your question correctly.

What I'm trying to say is that the equipment that's on the wells now, we're not proposing to do away with. They monitor pressure at the wellhead whether the well is shut in or whether it's flowing. And of course, obviously as the well is flowing, we're collecting that pressure data.

What we're not proposing to do is shut in each well for a 24-hour period every year and collect these shut-in pressure tests at the surface. It's the same equipment that reports that pressure as it does the flowing tubing pressure, as the well's producing.

Q. So there would be an ability out there to either do an abbreviated Reader's Digest version of a shut-in test --

A. Correct.

Q. -- or some other mechanism, perhaps, a 24-hour shut-in test on a third of the wells every year. That way all of them would be tested over a period of three years. Of course, that's not a 9-percent savings, as you're proposing, but a 70-percent savings on a -- or a 66-percent saving over that year. So that ability would still be there?

A. That ability is there. I guess what one has to ask is, what do you use the data for and what's the value of it?

Again, my understanding is that what's really meaningful is what is the bottomhole or average reservoir pressure, and that's what you need for correlative rights and other issues regarding drainage and production. Surface pressure is a way to estimate that number and calculate that number.

Q. Uh-huh.

A. That's -- I'm just trying to make sure that we're giving the State what it needs. If an eight-hour test is what you need, we will still have the capability to provide that. If we -- If the State requires a third of the wells be tested every year, we'll still have the capability of doing that.

We're just telling you, we're not using that data very much from an engineering perspective.

Q. Well, who else would be using that information? You kept referring to the State. I think -- I always like to say that you're probably referring to the State Land Office, which I do not represent. I'm having to worry about correlative rights with everybody, federal, fee, everybody.

So now that we've got that clear, who else would use this information?

A. Well, I'd have to speculate again for the current wells that we're producing, why -- what others would use that information for.

Anybody that's interested in the bottomhole or average reservoir pressure depletion on every well in this unit would want to have access to that data. Anybody that's planning to develop offset the unit or anyone that's got their own lease and they want to drill a well and they're trying to understand how the reservoir behaves, they would probably want to have access to that information.

The case we're trying to make is that we think the amount of data that's been collected already gives you a pretty good tool to estimate what the recoveries are in every well. I mean, you can develop a P/Z plot for every well out there with all the data we've recovered, and that shouldn't substantially change, point-forward.

Q. It shouldn't, but it does a lot. I mean --

A. Yeah, it can.

Q. -- the preceding case is a good example that I have to deal with all the time. There again, forgive me, I'm used to dealing with a micro- --

A. I understand.

Q. -- management of an area that has a problem.

A. We're talking about a pool that's pretty well defined, and we've had testimony provided to this agency before that delineates in detail the geologic deposition of this pool and this unit, and we've submitted where the zero net pay is.

And, again, trying to think, anybody who'd want to abut the unit and try to develop -- The testimony we've provided in previous hearings shows that the west side of the unit is all that's left, as far as trying to do something outside the unit area.

To the south, to the east, I think if you'll look on Exhibit --

Q. -- 2.

A. -- 2, in our estimation, there's just no gas there. So we don't feel like we're taking away any opportunities for further development of this pool on those sides.

On the west side, I think we've already agreed that we're not expecting to do away with pressure testing over there, because it is different. You know, that's an area that's a little more less understood, it has opportunity for development, and I think everybody should share in whatever data they can get their hands on to prudently develop that area.

But it's these four areas I'm speaking of that I don't feel like we're compromising about that, anything we need.

Q. Okay, when I look at Exhibit Number 2, you've got these areas defined. There's other wells outside those little four areas. Are you proposing that we do a 24-hour test on each one of those? I mean, do you -- With what you give me here, I --

A. Right, I realize it's tough to see the specifics --

Q. No, it's not -- Well, yeah, it is tough, but you've got a bunch of wells -- it looks like there's a certain amount of percentage that's outside of those four podded areas, and I guess -- What's to be done with those wells?

A. Well, my understanding is that the rules for active wells -- I don't know what --

Q. The wells that are shown outside the blue areas are not active?

A. Outside the blue area?

Q. Yeah. When I say "the blue area", you've got a --

A. I've got a light --

Q. -- you've got circles, four circles, Leg 9 --

A. Oh, I see, yeah.

Q. -- the area north of fault, area south of fault and Leg 8 area. Now, there's a bunch of wells in between those areas.

A. Okay. Yeah, again, the intent was a qualitative understanding of the areas. You're right, there are wells outside those circles. My intent is, those wells will be part of this exemption, the existing producing wells that are in the gathering system, and that's those 300-and-some-odd wells we've referred to.

For instance, in the blue circle that says area north of the fault --

Q. Yeah.

A. -- you see some green lines. That's the gathering system of Leg 3. And you see some red dots. Those wells are also part of what I am referring to as the current developed unit.

The only producing wells outside the current gathering system are two that Mr. Johnson referred to, to the far west that aren't tied into our current gathering system. There are no other unit producing wells.

Q. I was just trying to figure out what geographical area I would utilize to say this area would represent -- or these three wells would represent this particular geographical area.

A. Oh, I'm with you.

Q. I'm unclear of the definition of it, of which wells would be included in that area. I mean, this is a pretty rough -- rough type of an item, and any kind of an order that allows something like that needs some sort of --

A. Well --

MR. CARR: Mr. Stogner, we'd have to provide you with not only an areal description but an identification of the wells, obviously.

THE WITNESS: Yes, we would do that.

EXAMINER STOGNER: For some reason, I see a floodgate coming through, and I've seen durn near everything. It even, then, surprises me what I see on a day-to-day basis, on what information is needed to properly evaluate different pools, when you think it was a homogeneous pool, but yet something happened like infill drilling, perhaps, comes in and affects a unit area. And then all the things that occur, see differences between the factions that review a unit operating area, federal, state, us of course, and then you've got somebody in there that objects to the unit operations, and then they bring something here. I'm involved in that right now too.

So I'm -- There's a lot of things involved in this that is still unclear, and it's those other areas that I'm very concerned about.

THE WITNESS: Which other areas are those, exactly --

EXAMINER STOGNER: Correlative rights.

THE WITNESS: -- if I might ask? Okay, correlative rights.

EXAMINER STOGNER: Protection of correlative rights. And yeah, reservoir is an area. There again, my macro-management is the whole state, and any exemption we give usually starts with the first one somewhere down the line.

So this is not only just what you're asking for in the Bravo Dome; I foresee how this is going to affect all the others that will come in subsequent to that, with the, to be quite honest with you, appears to be an application out of convenience by Amoco, which I had one, I think, several months ago that we worked with in the surface commingling side. In fact, there was a finding in that order that talked about requests out of convenience and how we proceed with those.

Well, with that, if there's no other questions of this witness, I'd ask that you provide me a rough draft order, Mr. Carr.

MR. CARR: Yes, sir, I will. I knew you would.

EXAMINER STOGNER: With that, this case, 11,757, will be taken under advisement.

Let's take a lunch recess and reconvene at 1:45.

(Thereupon, these proceedings were concluded at 12:40 p.m.)

* * *

CERTIFICATE OF REPORTER

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

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

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

WITNESS MY HAND AND SEAL April 9th, 1997.

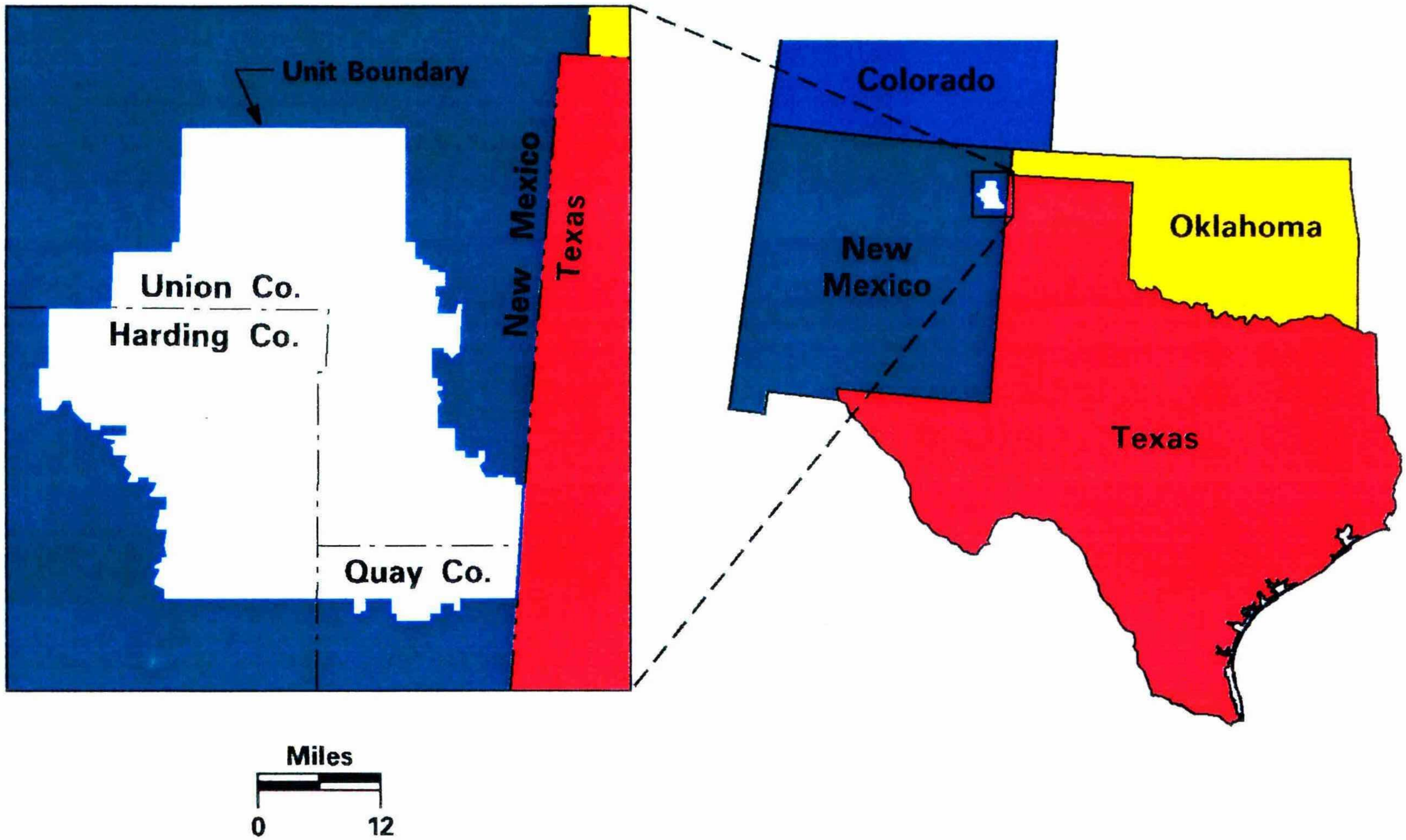
STEVEN T. BRENNER
CCR No. 7

My commission expires: October 14, 1998

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 11752, heard by me on 3 April 1997.

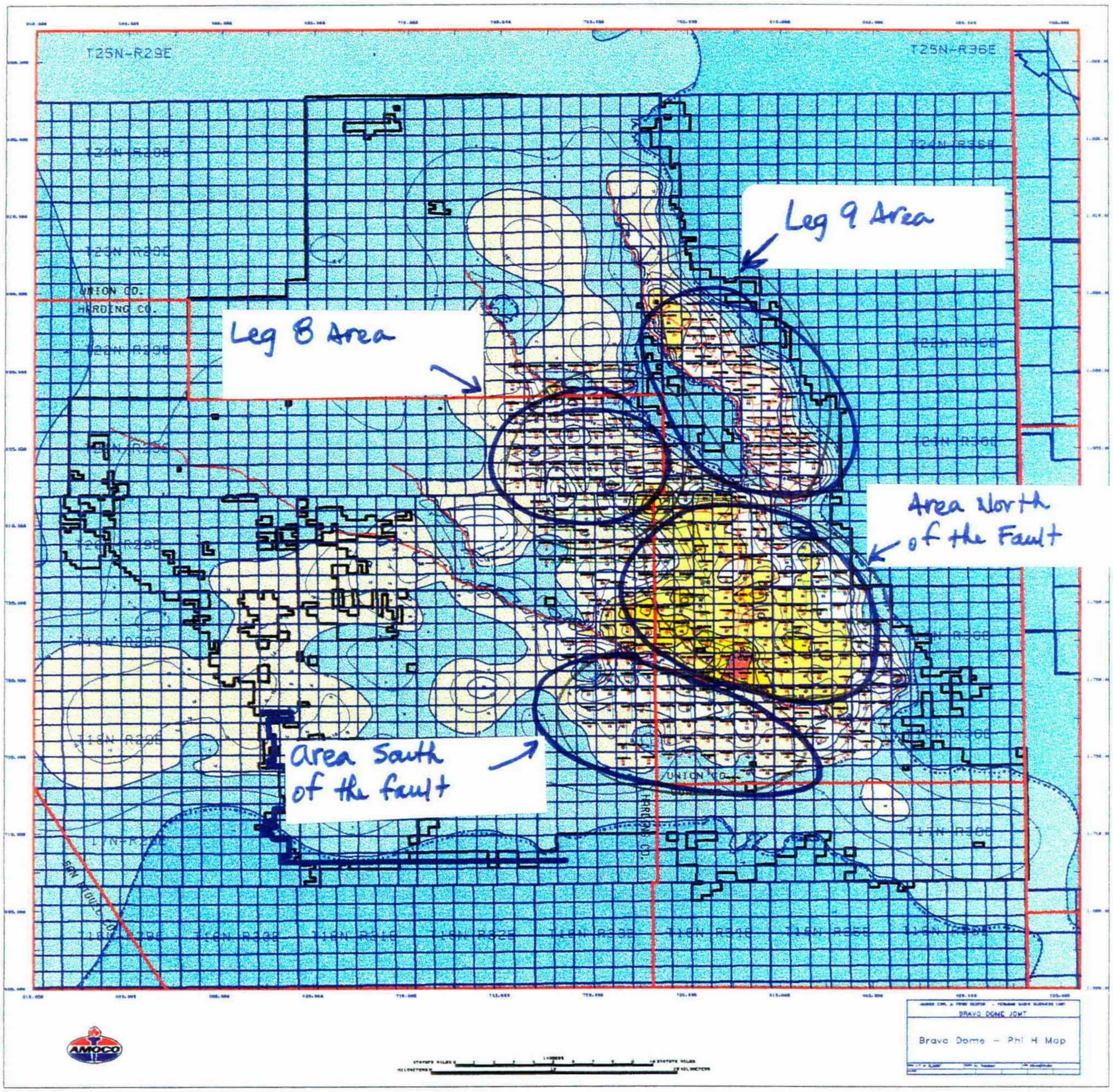
_______________, Examiner
Oil Conservation Division

# Bravo Dome Carbon Dioxide Gas Unit



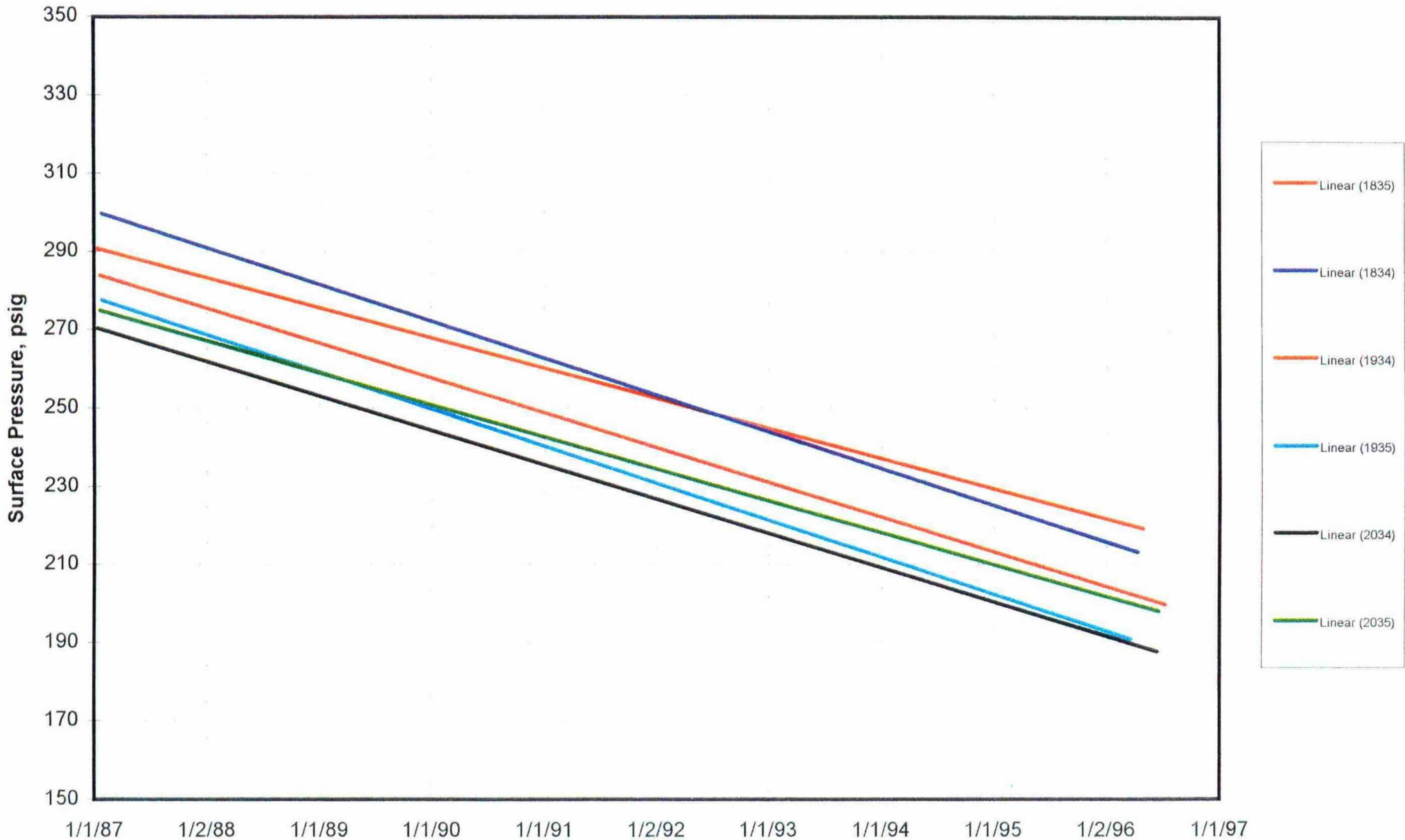

BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
CASE NO. 11757 , EXHIBIT NO. 1
SUBMITTED BY: AMOCO PRODUCTION CO.
HEARING DATE: APRIL 3, 1997

# Bravo Dome Carbon Dioxide Gas Unit
## PHI-H Map

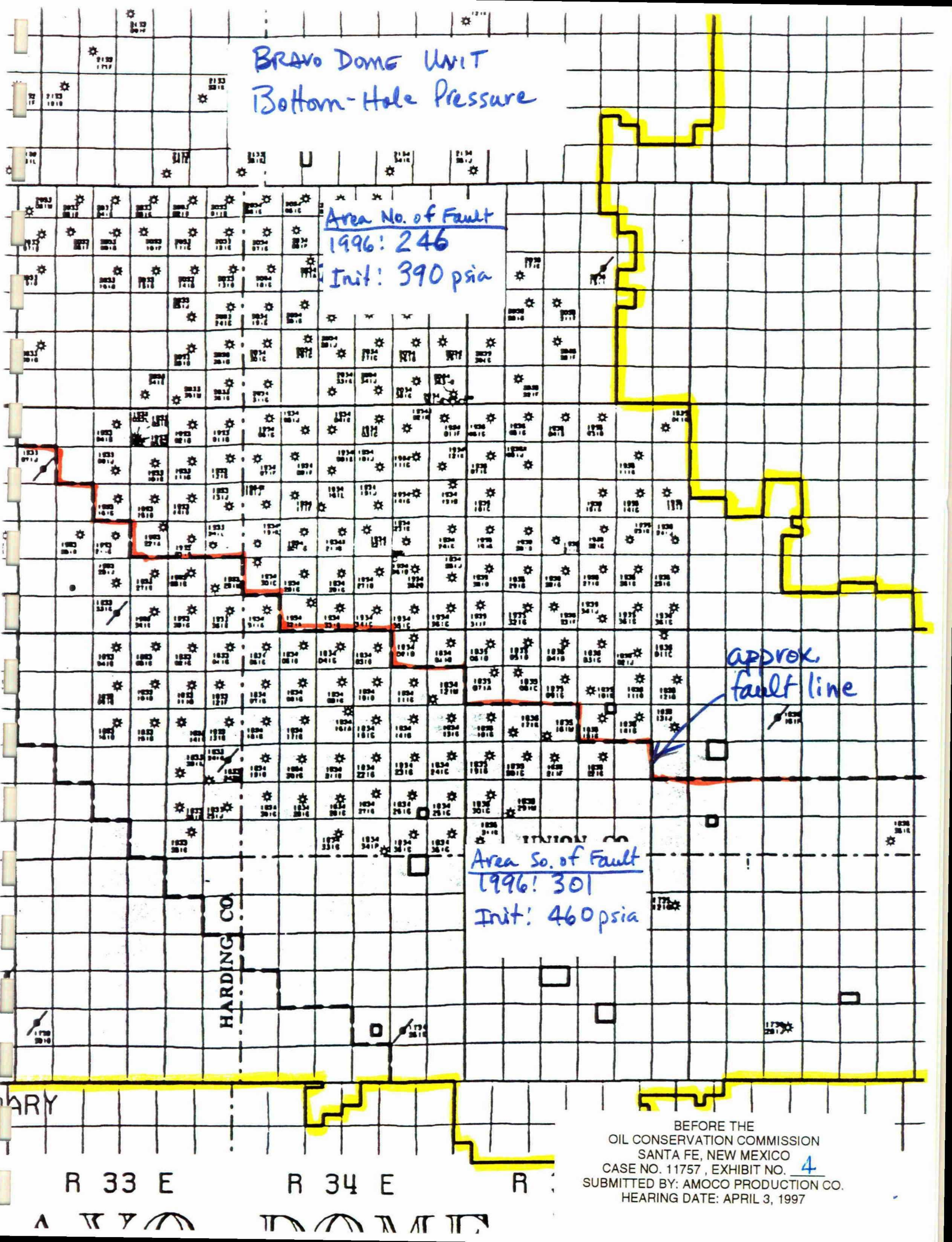



BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
CASE NO. 11757 , EXHIBIT NO. 2
SUBMITTED BY: AMOCO PRODUCTION CO.
HEARING DATE: APRIL 3, 1997

## Bravo Dome 24-Hour Shut-In Surface Pressure, psig

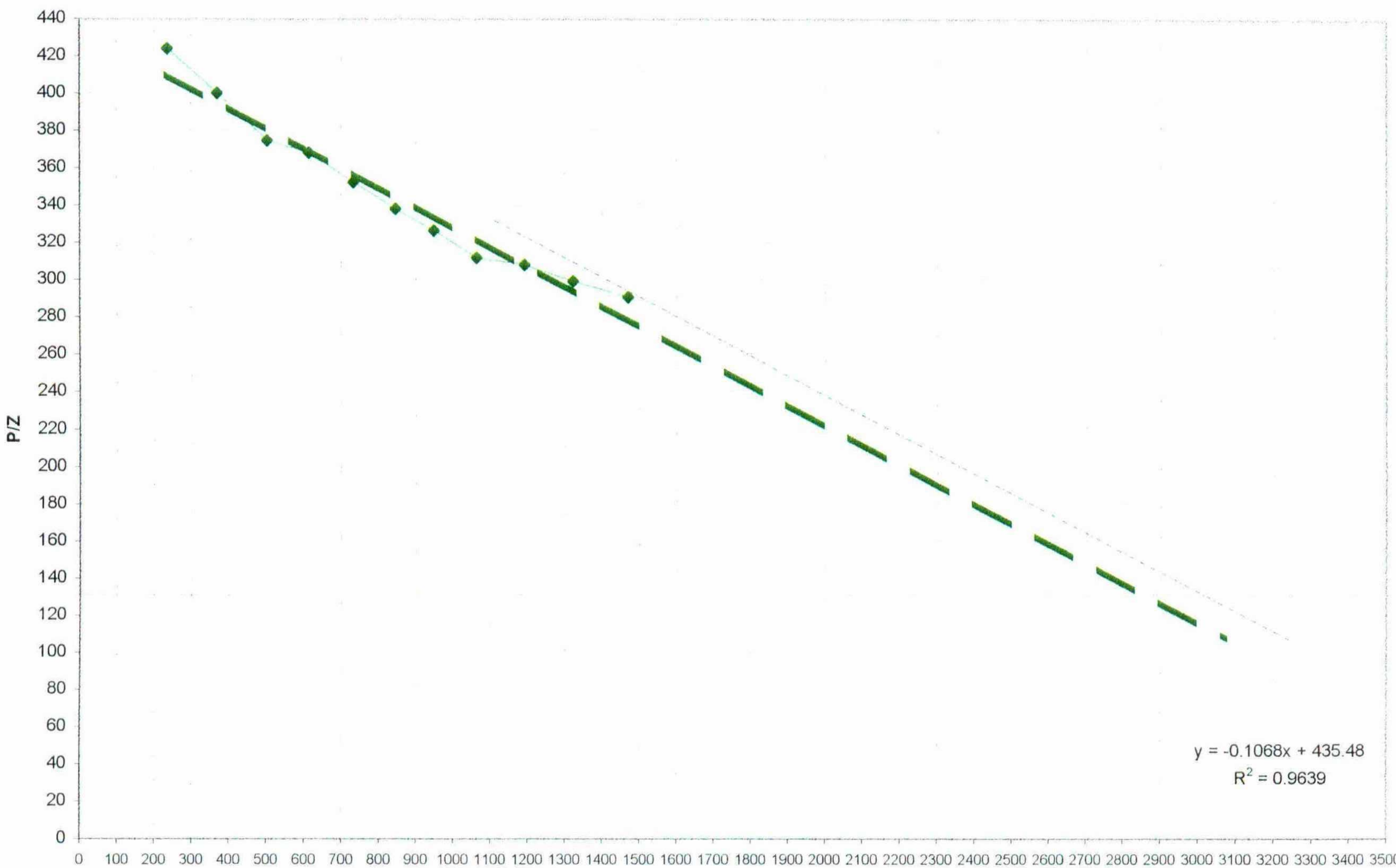



BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
CASE NO. 11757 , EXHIBIT NO. 3
SUBMITTED BY: AMOCO PRODUCTION CO.
HEARING DATE: APRIL 3, 1997




BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
CASE NO. 11757 , EXHIBIT NO. 4
SUBMITTED BY: AMOCO PRODUCTION CO.
HEARING DATE: APRIL 3, 1997

Bravo Dome P/Z Plot from 24-hr SI Pressure data

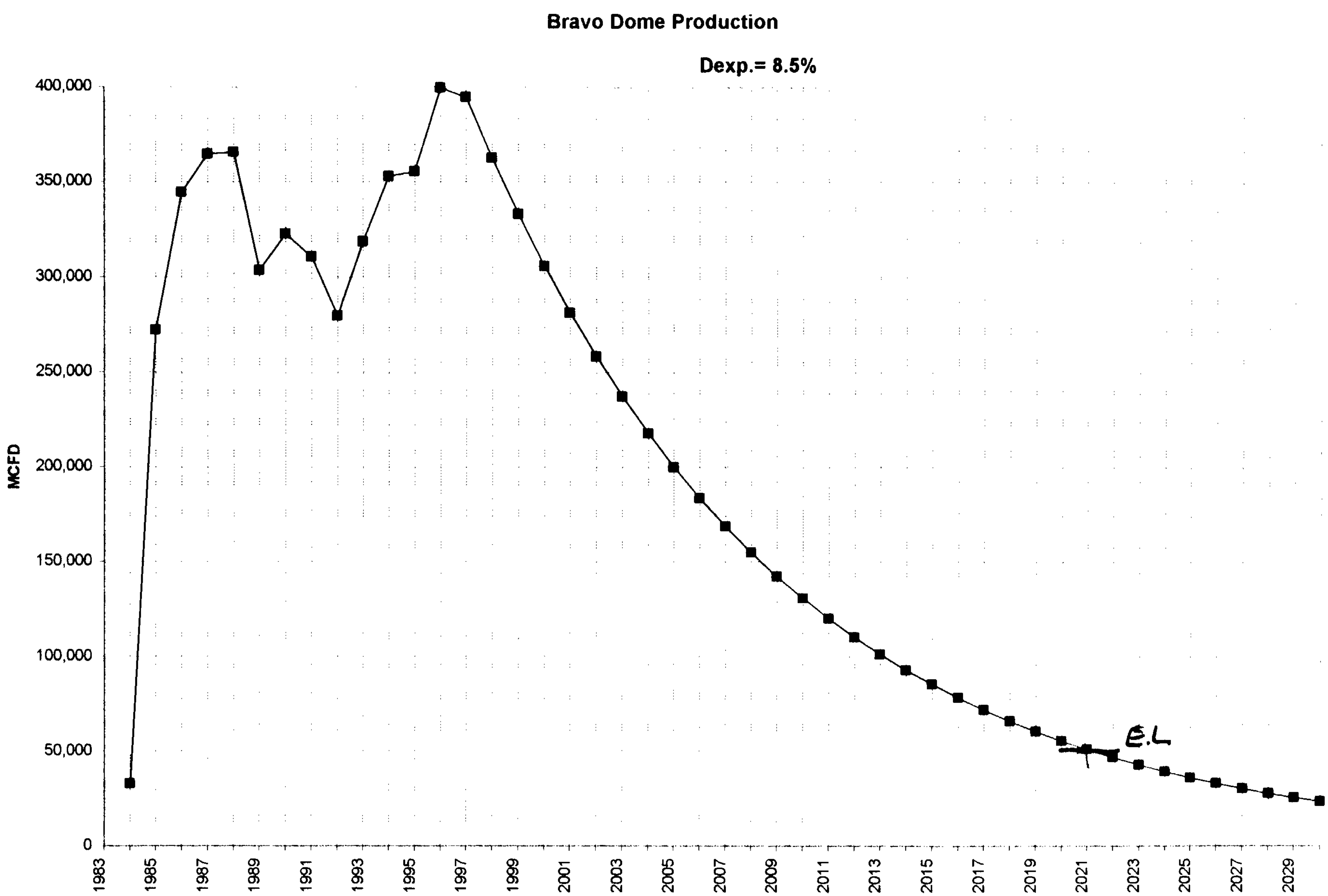



Cumulative CO2 Production, BCF

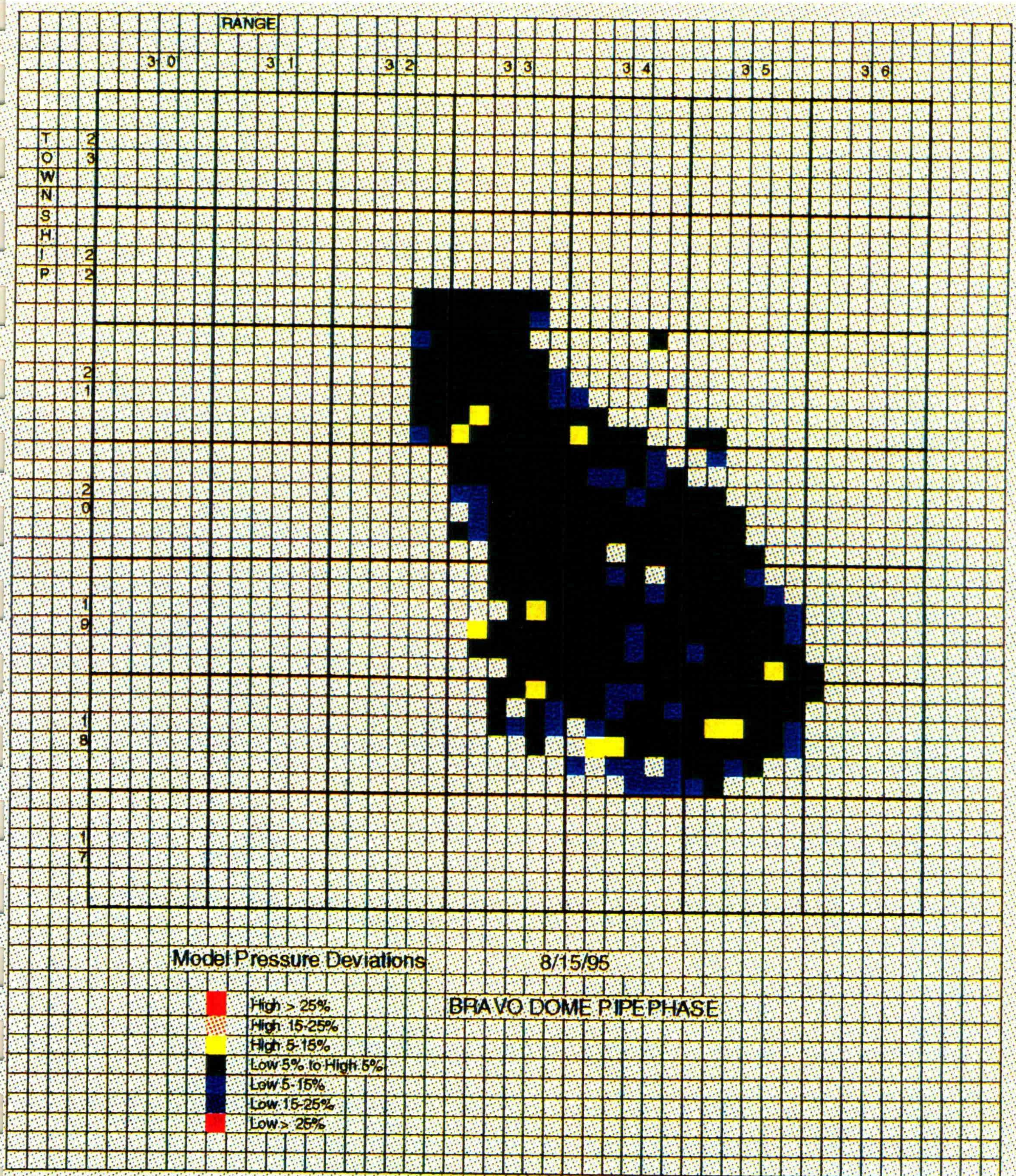


BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
CASE NO. 11757 , EXHIBIT NO. 5
SUBMITTED BY: AMOCO PRODUCTION CO.
HEARING DATE: APRIL 3, 1997

Data Chart 21




BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
CASE NO. 11757 , EXHIBIT NO. 6
SUBMITTED BY: AMOCO PRODUCTION CO.
HEARING DATE: APRIL 3, 1997




BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
CASE NO. 11757 , EXHIBIT NO. 7
SUBMITTED BY: AMOCO PRODUCTION CO.
HEARING DATE: APRIL 3, 1997

# Bravo Dome Carbon Dioxide Unit
## Shut-In Pressure Tests

### *LOST CASHFLOW FROM LOST PRODUCTION*

* CURRENT TESTING PROCESS(Annual on every well)

| | State (tax & royalty) | Unit |
|---|---|---|
| 1997 | $ 14,000 | $ 62,000 |
| Next Ten years | $104,000 | $437,000 |

* PROPOSED TESTING PROCESS

| | State (tax & royalty) | Unit |
|---|---|---|
| 1997 | $ 1,000 | $ 24,000 |
| Next Ten years | $10,000 | $233,000 |

| | | |
|---|---|---|
| * SAVINGS: | $94,000 | $214,000 |

BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
CASE NO. 11757 , EXHIBIT NO. 8
SUBMITTED BY: AMOCO PRODUCTION CO.
HEARING DATE: APRIL 3, 1997

# AMERADA HESS CORPORATION

500 DALLAS
HOUSTON, TEXAS 77002
Phone 713 609-5000
Fax 713 609-5984

April 2, 1997

**VIA FACSIMILE**
**& FEDERAL EXPRESS**

Amoco Production Company
501 Westlake Park Boulevard
Houston, Texas 77210
Attention: Perry Jarrell

RE: Case 11757; Exception to New Mexico State Rule 402, Bravo Dome Unit.

Gentlemen:

You have advised that Amoco Production Company ("Amoco") seeks an exception to Division Rule 402 with respect to the Bravo Dome Unit as currently developed as of the date hereof in order to permit Amoco to conduct bottom hole pressure tests on one well per township each year, rather than the current requirement of a test on each well per section each year.

Pursuant to your request, please be advised that as operator of West Bravo Dome Carbon Dioxide Unit, Amerada Hess Corporation ("AHC") has no objection to Amoco's request for such an exception *to the extent and only to the extent* that the exception to Rule 402 shall apply only to Amoco's testing obligations with respect to the currently drilled and producing wells in the Bravo Dome Unit. AHC expressly reserves the right to object to any request for such an exception to Rule 402 to the extent it may apply to any wells drilled and/or producing after the date hereof either within or without the boundaries of the Bravo Dome Unit, including, without limitation, any wells which may be drilled and/or producing after the date hereof as a result of development of West Bravo Dome or the west area of Bravo Dome Unit.

Very truly yours,

Steven B. Mendenhall

cc: R. L. Cawood

s:\jfr\letters\amoco.402

BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO
CASE NO. 11757 , EXHIBIT NO. 9
SUBMITTED BY: AMOCO PRODUCTION CO.
HEARING DATE: APRIL 3, 1997

AMERADA HESS CORPORATION

500 DALLAS
HOUSTON, TEXAS 77002
Phone 713 609-5000
Fax 713 609-5984

April 2, 1997

**VIA FACSIMILE**
**& FEDERAL EXPRESS**

Oil Conservation Division
for the State of New Mexico
2040 South Pacheco
Santa Fe, New Mexico 87505

RE: Case 11757; Application of Amoco Production Company for an exception to Division Rule 402, Bravo Dome Unit.

Gentlemen:

We have been advised that Amoco Production Company ("Amoco") seeks an exception to Division Rule 402 with respect to the Bravo Dome Unit as currently developed as of the date hereof in order to permit Amoco to conduct bottom hole pressure tests on one well per township each year, rather than the current requirement of a test on each well per section each year.

Please be advised that as operator of West Bravo Dome Carbon Dioxide Unit, Amerada Hess Corporation ("AHC") has no objection to Amoco's request for such an exception *to the extent and only to the extent* that the exception to Rule 402 shall apply only to Amoco's testing obligations with respect to the currently drilled and producing wells in the Bravo Dome Unit. AHC expressly reserves the right to object to any request for such an exception to Rule 402 to the extent it may apply to any wells drilled and/or producing after the date hereof either within or without the boundaries of the Bravo Dome Unit, including, without limitation, any wells which may be drilled and/or producing after the date hereof as a result of development of West Bravo Dome or the west area of Bravo Dome Unit.

Very truly yours,

Steven B. Mendenhall

cc: R. L. Cawood

s:\jfr\letters\ocdc.nm

NEW MEXICO
OIL CONSERVATION DIVISION
Amerada EXHIBIT 1
CASE NO. 11757