STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO

7 August 1986

COMMISSION HEARING

IN THE MATTER OF:

Application of Northwest Pipeline Corporation for Hardship Gas Well Classification, Rio Arriba County, New Mexico.

CASE 8890

BEFORE: Richard L. Stamets, Chairman
Ed Kelley, Commissioner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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I N D E X

E X H I B I T S

E X H I B I T S CONT'D

MR. STAMETS: Call Case 8890.

MR. TAYLOR: Application of Northwest Pipeline Corporation for Hardship Gas Well Classification, Rio Arriba County, New Mexico.

MR. STAMETS: Call for appearances.

MR. COOTER: Paul Cooter with the Rodel Law Firm in Santa Fe, appearing on behalf of Northwest Pipeline Corporation.

We have one witness.

MR. STAMETS: Any other appearances?

I'd like to have the witness stand and be --

MR. COOTER: We have one other appearance.

MR. WILSON: Richard Wilson, Bureau of Land Management.

MR. STAMETS: Thank you. I'd like to have anybody who's going ot be a witness in this case stand and be sworn at this time, please.

(Witness sworn.)

MR. COOTER: Just a primary statement, Mr. Stamets. I'm handing you a packet of fifteen exhibits, some of which, one or two of which are the same as were offered at the Examiner's Hearing. Others are similar but have been updated and some are new exhibits, and rather than create confusion by going back and looking and all, we just prepared a packet of all the exhibits that will be offered today, and for convenience sake, as you'll note on the first page, while we do start with No. 1, I've designated it A-1.

MR. STAMETS: Thank you, Mr. Cooter.

PAUL C. THOMPSON,

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

DIRECT EXAMINATION

BY MR. COOTER:

Q State your name for the record, please, sir.

A My name is Paul Thompson.

Q And by whom are you employed, Mr. Thompson?

A By Northwest Pipeline Corporation in Farmington.

Q And what is your position with the company?

A I'm the Manager of Production and Drilling.

Q Relate briefly, if you would for the Commission, your education and professional experience.

A I graduated from New Mexico State University with a Bachelor's in chemical engineering in 1976.

I worked for Philips Petroleum Company for three years in Bartlesville, Oklahoma before I started work for Northwest as a drilling engineer in 1979.

I was promoted to Manager of Drilling and Production in 1984.

Q And have continued in that position to this date?

A Yeah, that's correct.

Q You have in front of you a packet of some fifteen exhibits. Let me ask you to turn to that -- well, before you do, what does Northwest Pipeline seek by its application in this case?

A Well, we're requesting that a hardship classification be granted for our San Juan 29-5 Unit No. 91.

Q What leads you to believe that under-ground waste would occur if the well is shut-in or production be curtailed?

A This well was shut in for overproduction for three months in 1984 and after this extended shut-in period the well required swabbing to return it to production.

After the production was re-established the well's delivery potential showed a marked decrease. Our studies also indicate that irreversible formation damage has occurred resulting in the loss of recoverable reserves.

We believe that this formation damage is caused by an increase in the water saturation around the wellbore which permanently lowers the formation's relative permeability to gas.

Q Mr. Thompson, without this hardship classification do you have a reason to believe that a similar result or results would occur with other shut-ins of extended periods, say three months or more?

A Yes, I don't think three months would be required to log the well off.

Q All right. Now let's go to those exhibits, if you would, and first identify the well in question on Exhibit One.

A Exhibit One is just a map of the area. The San Juan 29-5 No. 91 is located in the northeast quarter of Section 35. The east half of this section is dedicated to this well.

Q What is the well's significance?

A I'm sorry?

Q We're referring to the 91 Well that is the subject matter of this application but does it have some significance with the offsetting wells?

A Yes. I'll be referring to the No. 90 Well, located in the southwest quarter of this same section, as well as the two wells in Section 34, the 88 and 89, and also the San Juan 29-5 No. 70, which is located in the northeast quarter section of Section 28.

Q All right. Let's go to Exhibit Number Two in that packet of exhibits and discuss the well's history briefly, if you would.

A This well was drilled and completed in July of 1980. Late in 1980 a water test was performed on the well that indicated the well was producing around 19-22 barrels of water per day.

A water analysis taken at this time indicated that the water was Dakota formation water.

We installed a stopcock in May of 1981 to control this water production. It took us several settings to settle on two hours on and ten hours on as being the -- we found that to maximize gas production while limiting water production to less than 5 barrels of water per day.

During our application for administrative approval Mr. Chavez from the Aztec Office questioned as to why no water had been reported from this well, so I asked the Salt Lake office who filled our our Form C-115 and they said that they had talked to a Mr. Eppie Martinez several years ago and he said that our filings with the BLM on our NTL-2B exemptions were sufficient for the state; howewver, after we inquired, Mr. Harold Garcia requested that we start supplying the water information on Form C-115, and it's my understanding that data has been supplied retroactive to January, 1985.

This well produced at the two off/ten on setting until it was shut-in for overproduction on September 19th, 1984.

When the well ws scheduled to return to production in December of '84, we found the well was logged. We made several attempts during the next year to unload the well by blowing it, soaping the tubing, equalizing the tubing/casing pressures. All these were unsuccessful.

We started our swabbing operations on October 16th, 1985, and swabbed the well from the 16th through the 29th. Since we had encountered scale problems in this area before, we performed a nitrofied acid job on this well and the three offsets, 88, 89, and 90 Wells in an attempt to remove any carbonate deposits on the tubing, the perforations, and the area immediately adjacent to the wellbore.

Q Let me interrupt you right there, and have you -- those other wells to which you referred to the west, 88, 89, and 90, had those wells been shut-in and were they logged?

A Yes, yes, they both were. They were all shut-in for different reasons and they were all logged.

We were trying to -- our original plan was to swab in all four of these wells at one time and to apply for a hardship application on all four wells. Well, what we were trying to do was to re-establish production, run the logoff test, and then have enough data to apply for the hardship application.

After we had spent about $15,000 on each well only the 91, the well in question here, could sustain production. We even had attempted plungers in two of the wells, the 88 and 89, and even tried to swab those with the plungers in place and that was unsuccessful.

So I felt like since Northwest does not have any wells under hardship, we'd be better off to temporarily abandon our attempts on the other three offsets and try to see if we could get o hardship on the 91.

But while we were swabbing the 91 we were continually moving the rig back and forth between all four of these wells

So the well was swabbed again from October 31st to November the 2nd and we finally got it to produce to the atmosphere continually.

We attempted to put the well back on line with a stopcock setting of five hours off and one hour on on November 11th, 1985. We found the well had logged off the next day.

The well was swabbed again on November 20th and returned to the production to the pipeline with a stopcock setting of seven hours off, one hour on, and at this setting the well had a longer period of time for the gas to recharge around the wellbore and then to lift liquids when it was scheduled to come on. That's why I think we were more successful with the seven off and one on setting than we were at the five off/one on setting.

The total swabbing costs are estimated at around $13,700.

Q Are those itemized on Exhibit Number Three?

A That's correct. Exhibit Three just outlines the rig time, our technician's time and mileage charges, and miscellaneous and engineering costs.

Q All right, let's turn to Exhibit Number Four, if you would, and explain that.

A Well, if I could back up just a second.

Q Okay.

A We had notified the office in Aztec of our intention to try to apply for a hardship application and they instructed us how to take the logoff test

We started a logoff test December 16th and completed it the 20th; however, the results from this logoff test were inconclusive, so we tried it again starting on January 7th through the 17th. It was determined that a stopcock setting of 11-3/4 hours off, 1/4 hour on, was not sufficient to unload the wellbore liquids.

We reconfirmed this by a third logoff test run between January 22nd and the 25th, and after exper- imenting with several stopcock settings the well appears to produce best with a stopcock setting of seven hours off and one hour on, at an average rate of 140 Mcf per day and 4-1/2 barrels of water per day.

Q So that is in excess of the amount you seek in your application.

A That's correct. The -- part of the log- off test we had the stopcock set at 11-1/2 hours off and 1/2 hour on, so that during a 24 hour period we'd get one hour of production, and at that stopcock setting the well pro- duced 28 Mcf per day; however, with the longer flow period you're going to get more gas after the initial (unclear) is over, so that's why 140 divided by 3 is more than the 28.

But if the pipeline were to ask us to minimize our production, we could still produce at this 11-1/2 hours off and 1/2 hour on to keep the well from logging off.

Q Now, are you ready to go to Exhibit Four?
A Yes, fine.
Q Okay.
A The procedure for running a logoff test on a well without a stopcock is just to choke the well back to the point where there's not a sufficient volume of gas to lift liquids. On a well with a stopcock you decrease the flow time to the point where the well cannot lift liquids.

Exhibit Four shows a graph of the casing pressure versus time. The No. 91 is being produced without a packer so that there should be free communication between the casing annulus and the tubing. What we'd expect to see is that every time you produce gas up the tubing you see a drop in the casing pressure, and if there was free communication between the casing and the tubing, you'd get the same casing pressure drop for every flow period.

If for some reason the well starts logging up, you start to lose this communication between the casing annulus and the tubing and you get smaller and smaller casing pressure drops as you flow the well up the tubing, until at some point when you open the tubing you won't see any casing pressure drop at all. All you will do is produce the gas up the tubing and then the well will be logged; won't flow at all.

You can see from this graph that for every fifteen minute period that the well was on, the casing pressure drops were getting progressively smaller so that the well was logging off at this flow rate.

We didn't allow the log to completely log off so we opened it up to the atmosphere there at the end of the chart.

And as I mentioned before, we had run this same type of test with the stopcock set at 11-1/2 hours off and 1/2 hour on and the well did not log off. It showed equal casing pressure drop for each flow period.

Q Turn next to Exhibit Six, if you would -- Five, pardon me, the wellbore diagram.

A Exhibit Five just shows the mechanical configuration of the well. This is the standard format for the procedure we've used on several hundred Dakota wells in the San Juan Basin. We set 9-5/8th surface casing and cement that to surface.

We drill with mud and set a 7-inch intermediate string into the Lewis Shale and cement that above the Ojo Alamo top.

We then drill from the bottom of the 7-inch to TD with gas and set a 4-1/2 inch long string. We cement the production casing, bring the top of cement up into the 7-inch pipe.

This well was then perforated and fraced with 50,000 pounds of 40/60 sand and slick water. The well produces up 2-3/8ths tubing.

What I should point out at this point is that only one, the top zone of the Dakota is open in this well so that the water that is being produced is coming from the same formation, the same zone as the gas, so that eliminates any possibility of setting a cement retainer downhole and squeezing off some of the water zones.

The water zone and the gas zone are the same.

Q Explain, if you would, what Northwest Pipeline has done to rectify the wells problems.

A Well, first let me say that the well has a problem in that it logs off after it's shut in.

The well does not have a problem logging off while it's being produced.

Therefore the possible solutions are involved with preventing or removing the head of water which accumulates during the shut-in period either by swabbing or by pumping the water off.

The solution is not to help remove liquids while the well is producing, like with stopcocks or plunger lift systems or small ID tubing.

The obvious thing to do would be to prevent the water from coming into the wellbore but as I menioned previously, that's impossible, since to shut off the water you'd also shut off the gas.

On Exhibit Number Six is listed some of the possible alternatives under optimum lift systems. This graph was taken from a petroleum production course taught at the Colorado School of Mines by Dr. John Wright.

This exhibit takes the initial installation cost, the operating costs, and the performance of the equipment into account when recommending the optimum system for different liquid production rates and well depth.

As can be seen from the graph, really only rod pumping systems would be practical to run on the 91, which is approximately 9000 feet deep and initially will produce anywhere from 50 to 100 barrels of water.

Gas lift systems work best at shallower depths and in higher volumes of gas than what we have available.

Also based on our experience with scale problems in the area we would anticipate a lot of problems getting the gas lift valves to open and close properly.

Electric submersible pumps are better suited, as can be seen on the graph, to extremely high flow rates.

Another drawback of electric submersible pumps is that if they should pull the well dry, which is not out of the realm of possibility at the speed that they pump, they -- they transmit their heat into the produced fluid and if there's no fluid there the pump would burn itself up in a short matter.

Surface hydraulic pumps, their efficiency dropped to almost zero at the typical gas to liquid ratio that we have in the 91 of approximately 10,000 cubic feet to one barrel.

We considered a compressor; however most field compressors have a typical suction pressure of around 50 pounds and the well, if he well can't produce to the atmosphere, a compressor is not really going to do them any good here, either.

That leaves us, then, with rod pumping systems. They also don't work very well with high GOR wells so they would require a downhole separator to separate the liquids from the gas, so it would only pump what was essentially gas free liquid and with the scale problems we would anticipate several workovers caused by the scale.

However, assuming that the rod pumping

system would work, I've compared the economics of producing the well continually, as we've requested in this application, with swabbing and with rod pumping systems in Exhibit Number A-7.

What I've tried to show here are the break even costs with each of these types of production scenarios.

What I've assumed is that the well will be sold at current market out gas price effective August 1st of '86; that our normal production costs will remain the same.

If the well is allowed to produce continually the break even production required is 11 Mcf per day, and using the normal exponential decline analysis, the reserves that would be left in the ground at this abandonment rate are only 14.6-million cubic feet.

If the well required swabbing and the well required five days of swabbing each time it's shut in, assuming it's shut in three times per year if the production is curtailed 50 percent due to pipeline demand, the break even production requirements are 98 Mcf per day, the reserves which are to be lost at this abandoment rate are 127.8-million cubic feet.

If a rod pumping system is installed, assuming that the well has an average 7-1/2- year remaining, the break even production cost -- break even production required is 84 Mcf per day and the reserves which would be lost at this abandonment rate are 109.5-million cubic feet.

As I've mentioned before, probably swabbing would be chosen over a pumping system due to the high capital expense of the rod pumping system and some of the mechanical constraints that we have talked about earlier.

Q Before you leave that, Mr. Thompson, when you're talking about swabbing costs and swabbing the well after prolonged periods of shut in, at that point there would be reserves lost or left in the ground of 127.8-million.

A That's correct.

Q You are assuming that your swabbing efforts would always be successful.

A That's correct.

Q And there is certainly some possibility if not a stronger possibility or probability that somewhere along the line that those swabbing costs would not -- or swabbing efforts would not be successful.

A Well, that's correct. Based on the three offset wells where we gave them, again, about three or four opportunities for five days apiece to return to the production and we were unsuccessful in all three of those wells, again I guess I'd say the probability is pretty high.

Q And if those swabbing efforts were not successful, then the reserves left in the ground and forever lost would be an amount in excess of that 127.8-million.

A That is correct.

Q Okay, continue, if you would.

A Okay. Some of the other things that should be considered at this time are stopcock, plunger lifting, and small bore tubing. They're all methods for lifting liquids while the well is producing. If the well is allowed to log off, none of these systems will help the well regain production.

Small bore tubing actually -- it will be easier to log the well off if small bore tubing was installed and the well allowed to shut in. If you'll look at Exhibit Number A-8, please, these refer to small bore tubing effects. What I've shown here is the condition of the well as we found it 10-16-85 and this is in its logged off position; with the 2-3/8ths tubing 22.2 barrels of water were required to give the hydrostatic head sufficient to equal the formation pressure and log the well off.

If we had inch and a half tubind installed in this well, only 14.4 barrels of water would be required to log the well off.

And if inch and a quarter tubing was installed, only 10.6 barrels of water would be required to log the well off.

Some of the other drawbacks of small bore tubing, that you can't run a plunger lift system in tubing smaller than 2-3/8ths and it is a lot more difficult to swab and a lot less effective to swab in smaller ID tubing.

If the hardship classification was approved for this well, we would consider running small bore tubing in this well because the velocity of the tubing then would be greater.

Another way of saying that, I guess, is that as the well declines and you have a smaller volume of gas, you'd get a higher velocity and still be able to lift liquids in smaller ID tubing.

This would have to be weighed against the possibility of increased scale problems in smaller diameter tubing, but without the hardship it's really not very prudent to set smaller ID tubing at this point.

We did install plunger lift systems on two of the offset wells. Unfortunately, on these wells there did not appear to be enough gas to run the pistons and the well would log off during the shut-in period of the stopcocks.

We swabbed these wells several times with the plungers in place but we were never able to sustain production for longer than two or three cycles.

A plunger was not needed on the No. 91

because the well was adequately removing the wellbore liquids with only a stopcock at a setting of 7 hours off and 1 hour on.

Stopcocks are very effective ways to produce low permeability gas wells and we operate several hundred wells in the San Juan Basin through the use of stopcocks.

In tight gas sands wells with low permeability, it takes a while for the gas to flow from the outer reaches of the reservoir to the wellbore and by using a stopcock the well is shut in after a predetermined flow period, gives the well a chance to kind of recharge around the wellbore and it does take different amounts of time for different wells, so the stopcock settings are usually determined through a trial and error method.

Now the 91 was originally fitted with a stopcock to control water production, less than 5 barrels of water per day required by NTL-2B; however, we've found now that the stopcock is required to retain production.

We feel, after examining all the possibilities, that the most efficient way to produce this well would be to prevent the well from logging off in the first place, and to do that we would require at least twice a day to blow the well for fifteen minutes each after we -- or for thirty minutes each, and that's what we've requested in this hardship classification.

All the other alternatives, in our opinion, would cause formation damage and result in premature abandonment.

Q Let me direct your attention next to Exhibits 9, 10, and 11. Explain those exhibits, if you would.

A Okay. Exhibit 9 is the production graph for the San Juan 29-5 No. 91. The units are in Mcf per month and the years. I need to point out that we installed the stopcock late -- or actually in May of '81, but settled on the stopcock setting of 2 hours off and 10 hours on late in the year, late '81 or the first part of 1982, and you can see that the production increased during 1982 due to that stopcock setting.

The well was shut in for overproduction in September of 1984 at approximately 7500 Mcf per month

After swabbing and acidizing the well we re-established production at approximately 4500 Mcf per month in 1986.

What we would have expected if the well had not been damaged was that the production immediately following the shut-in period should have been significantly higher than it was when we shut it in, due to this flush production. The fact that the gas had built up around the wellbore and then was unloaded, and obviously that's not occurring in the No. 91. Because of the small amount of production data, I'd like to refer you to Exhibit Number A-10, which is the production from the offset well, the 29-5 No. 90.

This well was shut in in the middle of 1982 for about a year and it's obvious from this production graph that the well's deliverability potential never achieved what it was before the well was shut in. After several attempts at swabbing this well late in '85 and the first part of this year we've been unable to regain production on this well.

As an example of what we'd expect from a well that does not show signs of damage, I'd like you to refer to Exhibit A-11, which is the production graph of the 29-5 Unit Com No. 70 Well.

This well was shut in in mid-1982 for several months. You'll notice that right after it came back on production the production was significantly higher than it was when it was shut in, indicating this flush production.

The well then declined to approximately the same level as it was before the shut in period and then followed approximately the same decline rate.

Q What does -- does Northwest Pipeline have any other information that indicates that damage has occurred to the formation in the No. 91 Well?

A Yes. We took -- the initial gas to liquid ratio run in November of 1980 indicated that the ratio was approximately 39,700 cubic feet of gas per barrel of water. The current ratio is now only -- is down to only 7700 cubic feet per barrel, which indicates that the area around the wellbore is increasing in water saturation and reducing the relative permeabiity to gas.

Another way to demonstrate the damage that this well suffered is by examining the plots of cumulative production versus the square root of time, as indicated on Exhibit Number A-12.

This data is the same information collected from the normal production charts, which is flow, cumulative flow versus time. It's just presented in a little different manner. This technique is becoming increasingly popular in the gas industry for low permeability gas wells becaue it clearly shows the effects of damage and/or flush production on the wells.

It's been observed for anundamaged well that the slope of this cumulative production versus time is a linear function and should remain on the same slope until the well becomes depleted, at which time, then, the slope goes horizontal or to zero very rapidly.

If the slope should decrease, that's an

indication that the well's been damaged.

I need to point out the beneficial effects of the stopcock as we set it there about the time, the square root of time equals around 23. You can see a little bit of increased rate there, and then the increased slope between slope one and slope two shows the beneficial effects of the stopcock.

Even after a relatively short shut in time, around the square root of time equal to 28 and 35, you can see that it had a detrimental effect on the slope, as in slopes 3 and 4, and then obviously, after a prolonged shutin perid, slope 5 is significantly lower than it had been before the shutin period.

What I should note also is that there seems to be no negative effect, and actually a positive effect, on the slope after the stopcock was originally installed, which indicates that the stopcock had no adverse affect on the well's deliverability potential, so our attempts to curtail the water production really helpd the well's gas delivery; didn't hinder it at all.

So this well's production problems are not related to the stopcock installation.

Again, a well that was undamaged, you'd expect to see some increased slope immediately after a shutin period due to flush production. That's not obvious as for any of these shutin periods on the 91.

To confirm this, the same data plotted for the No. 90, given on Exhibit A-13, this well originally stabilized at a slope of 15.7. We feel that the lower slope initially in the well is probably due to formation damage caused during the fract job. It just took that long for the well to clean itself up and then stabilize at this rate.

You'll notice after a prolonged shut-in period the slope has decreased now to 8.8 but it is the linear function, so this is not just a one time deal. It's obvious that the well stabilized at this rate and that this is a true indication of the well's production capacity.

From -- for an example of what we would have expected from an undamaged well, I'd like you to refer to Exhibit A-14, which is the same data, cumulative production versus the square root of time, for the 29-5 No. 70.

In this well you'll note the flush production after the shutin period of approximately the square root of time equals around 44. So you'll see that the slope of the line comes a little bit above the normal trend line there, indicating that there is some flush production being produced at this point, and that the slope of the line before and after the shutin periods are almost the same, indicating that there is no difference in the well.

We see this on a lot of wells after a

well's being shut in for awhile. They get some increased production which would have occurred if the well had been flowing. Then the well settles right back down to the same slope as it had been producing before.

Q Has Northwest Pipeline calculated the gas reserves that have been lost, and may be lost in the future if this hardship application be not approved?

A Yes. The reserve calculations are listed on Exhibit A-15.

For this exhibit we assumed an exponential or constanct rate of decline. This type of analysis tends to give conservative figures for low permeability gas wells. It's normally observed, and back on the data of the 70, that the decline tends to stabilize at some -- tends to flatten out during the life of the well, but because the exponential decline gives conservative figures, we used it for this analysis.

Northwest Pipeline actually uses the log of the cumulative production versus the log of time to estimate reserves. We don't use bottom hole pressure versus cum production.

However, this well experiences a 28 percent decline from its initial production until it was shut in. Using this 28 percent decline analysis we estimated that there were 319-million cubic feet of reserves left at the time that the well was shut in in September of 1984.

After we re-established production for the pipeline at only 146 Mcf per day, using the same decline analysis, we estimate that the remaining reserves are now only 190-million cubic feet, so that we assume that the other 129-million cubic feet have been permenantly lost due to formation damage.

We would anticipate that with each subsequent shutin that additional reserves would be lost.

We also estimated that at the current market out gas price of $1.35 per Mcf, that the well would be uneconomical to swab if the production rate averages less than 49 Mcf per day.

Using this production rate and the same 28 percent decline analysis, it's estimated that the reserves which would be left in the ground at abandonment would be 64-million cubic feet.

Q Why does Northwest Pipeline seek this hardship classification for this well?

A Northwest is asking for a hardship classification as the operator of this well because we've been given the charge to economically maximize production while protecting the working interest owners' investment.

We believe that we've considered every possible alternative to try and solve this well's problems mechanically and that the circumstances of this case dictate that a prudent operator would petition for a hardship gas well classification.

Northwest Pipeline, by the way, does not have any working interest in the Dakota formation in this unit so that we do not stand to gain financially if a hardship application is granted.

El Paso is the purchaser of this gas and their subsidiary Meridian owns approximately 40 percent of the Dakota participating area of this unit.

The state and federal governments will benefit from keeping this well on since they, too, receive royalties from this unit.

The gas from this well is currently being sold on the spot market at a very low price, which indicates that the working interest owners of this well are willing to work with the purchaser to minimize any hardship that they should incur by having to keep this well on.

Q Would approval of the application encourage further expenditures for the Wells 88, 89, and 90?

A Yes, it would. As I mentioned before, it was our original plan to bring all four wells on production and apply for a hardship classification. If we were confident that the wells could be produced uninterrupted, we'd be more willing to risk spending the extra money to try to get the wells back on production.

If this application is unsuccessful, then I would imagine that these wells would remain in a temporarily abandoned status until they are permanently plugged.

Q Mr. Thompson, were Exhibits Numbers 1 through 15, with the exception of Exhibit A-6, prepared by you or under your direction and supervision?

Exhibit 6 is the diagram from Dr. Wright.

A Yes, they were.

Q And is Exhibit Number 6 that diagram that you testified was prepared by Dr. Wright a true and correct copy of that document?

A Yes, it is.

MR. COOTER: We would offer Exhibits A-1 through A-15 at this time and that concludes my direct testimony.

MR. STAMETS: The exhibits will be admitted.

Are there questions of the witness?

MR. LYON: Do you have a set of exhibits I could see?

MR. COOTER: Sure.

CROSS EXAMINATION

BY MR. STAMETS:

Q While Mr. Lyon is taking a look at those, let me ask you about Exhibit Number Nine.

A Okay.

Q The production decline that we see from 1982 running through 1984, was that indicative of the well's ability to produce?

A It seems to have stabilized based on those cumulative production versus square root of time plots at about that 28 percent decline.

Q So if I draw a line through that decline rate or along the top of that, it seems as though that line passes through the -- some of the rates that we see, then, in 1986.

A That's what you would expect if the well had been producing all the time from the end of '84 through the end of '85; however, that well wasn't producing at that point, so that volume of gas that should have been produced, you know, during that decline slope, the area under that line that you've drawn should have been produced and never was.

Q That gas is gone and you're never going to get it.

A That's correct. If you were to slide that production in '86 up against the production there in September of '84, then you'd see a marked decrease in production.

Q Okay.

MR. STAMETS: Any other questions of the witness?

QUESTIONS BY MR. LYON:

Q Mr. Thompson, I'm Vic Lyon, Chief Petroleum Engineer.

You have had an emergency hardship classification, haven't you, for some time granted by the District Office?

A That's correct. When we first applied for this case administratively we received a temporary.

Q And how long have you been operating under that emergency classification?

A I don't remember. Seems like it was since March, or I can't remember exactly when we first applied for that. It originally went through July, I know, and then was extended until this hearing.

Q Have you noticed any change in the performance of the well during the period that you've had that classification?

A Well, we've -- we experimented with several stopcock settings and finally settled on 7 hours off and 1 hours on. They told me just a couple days ago that it appears that the well's starting to even log up at this rate. They've had to blow the well once to, you know, unload the liquids to the atmosphere before they put it back on line, but it seems like it's fairly stable at that stopcock setting.

Q The reason I was inquiring, oftentimes when a well is produced and the water saturation around a wellbore is reduced, the flow characteristics will improve. I think Mr. Chavez alluded to that in his letter granting you the emergency classification.

I was just inquiring to see whether or not that might have been experienced in your case.

A We haven't seen it yet and based on the offset production data I gave on the No. 90, where it produced for almost two years, it's obvious that it did never come back to where it was.

Q Now, let's see, which exhibit was it that you -- is it your Exhibit 12 and 13 where you plotted the cumulative produciton against the square root of time?

A Yes.

Q I'm having trouble identifying these exhibits.

A They are numbered down in the lower righthand corner.

Q Your time is in calendar days.

A That's correct, that's why it shows the shut-in period as being a horizontal line.

Q What kind of impact does curtailment of the pipeline, reduced takes, and that sort of thing have on your well?

A On a well such as this it would be very detrimental. We've shown any kind of a shut-in period could potentially log the well off and with subsequent loss of reserve.

Q Well, it appears to me it would be difficult to draw conclusions from a curve like this if you went from a period of unrestricted production to a period of curtailment.

A I'm not sure I understand. The wells -- the wells when they're on, are on as much as they can produce. The wells are never choked back. The curtailment is controlled by the master valve; either it's on or it's off.

Q Yeah, but if the well produces 100 percent of the time for a period of several years and then goes into a period where it's produced only 25 percent of the time (unclear to the reporter.)

A Actually it should not. When the well

comes on you'll show -- the slope of the line won't change. When it's on it should have the same slope as it had before and what you'll see is a bunch of little stairsteps. When the well's on it should have the same slope before the shut-in period, then a horizontal line when the well is shut in.

Actually, you should see a little increase in slope if the shut-in periods are small and you get some flush production advances.

The data on the No. 90, Exhibit 13, you know, like from the square root of time from 33 to 43, or from 33 to, say, 40, they're showing that there's no -- there were no shutins during that period and that well was producing its maximum rate all the time.

You look at the data on the 91, you see those little horizontal blips as the well was shut in for a month here and a month there.

Q Well, I see that this Exhibit 13 that goes from three days, on your horizontal scale, it goes from three days to 48 days, isn't that right?

A Yes, that's right. That's the square root of days.

Q So this -- you're not talking about the cumulative production from the inception of the well's production.

A Yes, sir.

Q You mean that well has only produced 48 days?

A That's 48 squared.

Q 48 squared.

A The wells were all drilled and completed in, like, 1980, 1979.

So, like, 3 squared is 9 days after it originally was produced.

MR. LYON: I think that's all the questions I have.

MR. STAMETS: Are there any other questions of this witness?

He may be excused.

Mr. Wilson, are you going to testify in support of this application?

MR. WILSON: Yes, I am.

MR. STAMETS: Just sit there a minute.

MR. WILSON: All right.

MR. STAMETS: The application is for 28 Mcf a day?

MR. COOTER: Yes, sir. That's correct.

MR. STAMETS: Although Mr. Wilson is certainly always welcome in these chambers, the Commission sees no need for him to testify since we are convinced by the evidence which has already been presented, and we will grant the application for hardship classification and would ask Mr. Cooter to supply us with a draft order to that effect, which we will sign as soon thereafter as we can.

With that, Case 8890 is concluded.

MR. COOTER: Thank you.

(Hearing concluded.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY 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 this portion of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR