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

18 January 1989

EXAMINER HEARING

IN THE MATTER OF:

Application of Marshall Pipe & Supply for dual completion and salt water disposal, Roosevelt County, New Mexico. CASE 9574

BEFORE: Victor T. Lyon, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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

For the Applicant:

MR. LYON: Case 9574.

MR. STOVALL: Application of Marshall Pipe & Supply for a dual completion and salt water disposal, Roosevelt County, New Mexico.

MR. PADILLA: Yes, Mr. Examiner, we request on behalf of Mr. Dickerson that you continue this case for two weeks.

MR. LYON: At the request of the applicant Case 9574 will be continued to the February 1st, 1989 Examiner hearing.

(Hearing concluded.)

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

4 January 1989

EXAMINER HEARING

IN THE MATTER OF:

Application of Marshall Pipe & Supply for dual completion and salt water disposal, Roosevelt County, New Mexico. CASE 9574

BEFORE: David R. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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

For the Applicant:

MR. CATANACH: Call Case 9574.

MR. STOVALL: Application of Marshall Pipe & Supply for dual completion and salt water disposal, Roosevelt County, New Mexico.

Applicant requests this case be continued to January 18th, 1989.

MR. CATANACH: Case 9574 is hereby continued to January 18th.

(Hearing concluded.)

C E R T I F I C A T E

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

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9574, heard by me on January 4 1989.

David R. Catanach, Examiner
Oil Conservation Division

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

1 February 1989

EXAMINER HEARING

IN THE MATTER OF:

Application of Marshall Pipe & Supply for dual completion and salt water disposal, Roosevelt County, New Mexico. CASE 9574

BEFORE: David R. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Division:

MR. CATANACH: Case 9574. Application of Marshall Pipe & Supply for dual completion and salt water disposal, Roosevelt County, New Mexico.

The applicant has requested this case be continued to February 15th.

(Hearing concluded.)

C E R T I F I C A T E

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

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9574, heard by me on February 1 1989.

David R. Catanach, Examiner
Oil Conservation Division

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

15 February 1989

EXAMINER HEARING

IN THE MATTER OF:

Application of Marshall Pipe & Supply for dual completion and salt water disposal, Roosevelt County, New Mexico. CASE 9574

BEFORE: Michael E. Stogner, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

| | |
|---|---|
| For the Division: | Robert G. Stovall<br>Attorney at Law<br>Legal Counsel to the Division<br>State Land Office Bldg.<br>Santa Fe, New Mexico |
| For Marshall Pipe & Supply: | Chad Dickerson<br>Attorney at Law<br>DICKERSON, FISK & VANDIVER<br>Seventh & Mahone/Suite E<br>Artesia, New Mexico 88210 |
| For the Objectors: | Damon C. Richards<br>Attorney at Law<br>SANDERS, BRUIN, COLL & WORLEY<br>Box 550<br>Roswell, New Mexico 88202 |

# I N D E X

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EXHIBITS

MR. STOGNER: Call next Case 9574.

MR. STOVALL: Application of Marshall Pipe & Supply for dual completion and salt water disposal, Roosevelt County, New Mexico.

MR. DICKERSON: Mr. Examiner, I'm Chad Dickerson of Artesia, New Mexico, on behalf of the applicant.

I have four witnesses to be sworn and we'll try to get by with three of them.

MR. STOGNER: Are there any other appearances in this matter?

MR. RICHARDS: Yes. I'm Damon Richards of the law firm of Sanders Bruin, Coll & Worley, representing the objectors, Wendall Best, Thelma Parker, Dooley Cooper, and Evelyn Kirby.

We may have one witness and that will be Mr. Best.

MR. STOVALL: Will all the witnesses or potential witnesses please rise and be sworn?

(Witnesses sworn.)

LESLIE BENTZ,

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

DIRECT EXAMINATION

BY MR. DICKERSON:

Q Ms. Bentz, will you state your name, your occupation, by whom you're employed and your capacity in this hearing, please?

A My name is Leslie Bentz. I'm employed by Yates Petroleum Corporation of Artesia, New Mexico, as a geologist.

Q And does Yates Petroleum -- your employer has a working interest in the well, is that what you testified, is it not?

A Yes, sir, it is.

Q And your appearing in support of and on behalf of the Applicant, Marshall Pipe & Supply Company?

A Yes, I am.

Q Ms. Bentz, will you summarize the purpose of Marshall Pipe & Supply's application in this case, please?

A We respectfully request approval for the application for dual completion and salt water disposal in the Cook Well No. 1, Section 34, Township 2 South, Range 29 East, Roosevelt County, New Mexico.

Q Ms. Bentz, you have made, have you not, a study of the available geological and hydrologic data which is available in this area?

A Yes, I have.

Q You have testified as a petroleum geologist on numerous occasions before this Division and your credentials as such are a matter of record, are they not?

A Yes, they are.

MR. DICKERSON: Is Ms. Bentz qualified, Mr. Stogner?

MR. STOGNER: Are there any objections, Mr. Richards?

MR. RICHARDS: No.

MR. STOGNER: Ms. Bentz is so qualified.

Q Ms. Bentz, will you summarize the lithology for us in the proposed injection interval, which is the subject of this application?

A The proposed injection interval in the Marshall Pipe and Supply Cook No. 1 is the Montoya formation of the Ordovician period.

Q Now, you have prepared certain exhibits. Will you refer to the exhibit which we have submitted as Applicant's Exhibit Number One and identify it for us?

A Exhibit Number One is supplemental testimony to Section VIII of the Oil Conservation Division

Form C-108.

Q Okay, describe the lithology of that proposed injection interval, please.

A As described by rotary sample cuttings the lithology of the injection interval is as follows: Dolomite, buff tan to off white in color, fine crystalline to sucrosic in texture, naturally occurring fractures are probable.

The depth to the top of the Montoya in the Cook No. 1 is 7088 feet and it's described thickness is 73 feet.

Q Refer to what we have submitted to Mr. Stogner as Exhibit Number Two and summarize the data that you've shown on that map.

A Exhibit Number Two is a map based on the subsurface structure of the Pre-Penn unconformity. The proposed injection well is immediately south of established Montoya production as defined by the Tule Field.

Q Point out the location of that injection well for us, will you, please?

A It's in the northeast quarter of Section 34.

Q The southernmost map -- or the southernmost well in the area.

A Yes, it is. Yes.

Q All right.

A The contour interval is 50 feet; datum points are noted by circles and an appropriate datum is listed. Well spots colored in red indicate Montoya producers. Well spots in blue indicate production from the Pennsylvanian formation. Well spots in red and blue denote dual completions in the Montoya and Pennsylvanian formations. Cross Section A-A' is so labeled.

The structure map shows a north-northeast, south-southwest trending horst block, which is fault bounded to the east, west and south. Throw on the bounding faults is approximately 200 feet.

Closure into the west fault provides the trapping mechanism. Gas production is limited down dip by water. The gas/water contact in the Montoya formation has been established at -2700 feet. It is defined on the map by the dashed-dot line.

The Montoya formation in the proposed injection well is below the contact as indicated by a drill stem test and by production data.

Q Okay, refer now to your cross section submitted as Exhibit Number Three, allow Mr. Stogner the opportunity to unfold his, and review that for us.

MR. STOGNER: All right, Mr. Dickerson, you may continue.

Q Okay, review that cross section for us, Ms. Bentz.

A Cross Section A-A' stretches from north to south across producing wells in the Tule Field. The well immediately on the right is the Cook No. 1, the proposed injection well.

The drill stem test performed over the Montoya interval in the Cook No. 1 is listed. Inadvertently the production test information has been left off the cross section but --

MR. DICKERSON: A later witness will further --

A -- a later witness will further describe the production testing.

As both the production test and the drill stem test indicate, the proposed injection zone is not capable of producing gas in commercial amounts.

In addition to describing the Montoya interval, the structural cross section illustrates a Pennsylvanian zone that produced also in the Tule Field. The correlation carbonate pay does exist in the Cook No. 1 and production tests indicate that with compression the zone is capable of sustaining commercial gas production.

Specific information of that production test is noted on cross section A-A'.

Q Ms. Bentz, what are the sources of fresh water in the area that we're concerned with?

A The proposed water injection well is located outside of a declared water basin. The underground source of fresh water in the area is the Quaternary alluvium. The estimated depth is 70 to 80 feet. The aquifer is behind the surface pipe and cement at the proposed injection well. There are no other known sources of fresh water overlying the proposed injection zone and no other known sources immediately underlying the injection interval.

Q Okay, in your examination of the available hydrologic and geological data in this area, have you seen any evidence of any open faults or any other hydrologic connection of any type between the proposed injection interval and any source of fresh water in the area?

A No, I have not.

Q Where are the closest windmills located in this general vicinity?

A In the section immediately to the north.

Q And those are indicated on a subsequent exhibit, are they not?

A Yes, they are.

MR. DICKERSON: Mr. Stogner, I have no further questions of Ms. Bentz.

I would move admission of Exhibits One, Two and Three at this time.

MR. STOGNER: Are there any objections?

MR. RICHARDS: No, I don't object to entry of the exhibits.

MR. STOGNER: Okay, Exhibits One, Two and Three will be admitted into evidence at this time. Thank you, Mr. Dickerson.

Mr. Richards, your witness.

CROSS EXAMINATION

BY MR. RICHARDS:

Q You indicate that your examination of the drill stem test in this Cook No. 1 Well indicates that it's not capable of production. How did you determine that?

A Well, there was some gas recovered in the drill pipe but the main recovery was 625 feet of gas cut water, and all the other tests in the area, producing wells you have gotten gas to surface on the drill stem test.

Q And were any other tests conducted other than the drill stem test that you're aware of to determine if there is production --

A Yes, they did perforate that interval and could not sustain gas flow.

Q Okay, what did you examine to determine that?

A Information that was reported by Mr. Marshall of Marshall Pipe & Supply to all the working interest owners.

Q You don't know if that was supplied to any of the royalty interest owners, then, do you?

A No, I do not know.

Q What type of gas was shown to be produced? I mean how much gas was produced? You said there wasn't any sustained production. I want to know how much --

A I don't know that I have a rate --

Q -- gas are produced.

A -- of gas. I know that they were seeing some gas shows but I'm not sure that it was a measurable rate.

Q So you have -- will you have somebody else to testify on that?

MR. DICKERSON: I have a reservoir engineer, Mr. Richards, who --

MR. RICHARDS: Okay. That's fine.

Q And then in the Pennsylvanian formation, I believe, you indicate that it is capable of production with compression. Why do you say it's capable of production with compression?

A Well, right now the flow rates are not strong enough to buck the line pressure and so the well would go off and if you could get a compressor on there, I believe that probably could stay on line. Again, I think that we have additional testimony on that point.

Q Do you know what the line pressure would be or do you have somebody else that's going to testify on that (inaudible), the line pressure?

MR. DICKERSON: We have another witness who will testify as to existing line pressure. I think it's 900 pounds.

MR. RICHARDS: Okay. I'll just ask some more questions of the other witness.

MR. STOGNER: Thank you, Mr. Richards.

Any rebuttal, Mr. Dickerson?

MR. DICKERSON: No, sir.

CROSS EXAMINATION

BY MR. STOGNER:

Q Ms. Bentz, so I can make sure I've got all the information straight in my mind, the Cook Well No. 1, the -- in looking at your Exhibit Number Three, is the cross section -- I'm sorry, is the well log to the extreme right, is that correct?

A Yes, sir.

Q And the perforated interval into the Montoya and what you propose for injection will be from 71 --

A 04, I believe --

Q 7104.

A -- to 7116.

Q 7116. Is there any particular reason why this particular portion of the Montoya was chosen for injection other than other portions of the Montoya?

A No, sir, I really don't know that, other than it has already been production tested and is already perforated and I guess it would eliminate going in an perforating again.

Q In coming up the hole there is some perforation marks already on there. What are those again?

A There -- that's Pennsylvanian.

Q And are these the present Pennsylvanian perfs?

A Yes. The lowermost set of perfs are in a Pennsylvanian channel sand and the upper set of perfs are in a carbonate.

Q Are there any other perforations in existence at this point --

A No.

Q -- besides these three sets?

A No, sir, not to my knowledge.

Q And once this well goes on line these are the two sets of perforations in the Penn in which production will be accountable, is that correct?

A Yes, sir.

Q Ms. Bentz, do you -- I'll retract that.

MR. STOGNER: I have no other questions of Ms. Bentz. She may be excused.

Continue, Mr. Dickerson.

MR. DICKERSON: Call Mr. Richard Stamets.

RICHARDS L. STAMETS,

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

DIRECT EXAMINATION

BY MR. DICKERSON:

Q Mr. Stamets, will you state your name, your occupation, and in what capacity you appear in this case?

A My name is R. L. "Dick" Stamets. I'm a consultant located here in Santa Fe and I've been employed to examine the application for the salt water disposal well in this case to determine whether or not in my opinion it -- it would comply with the standard permitting requirements for the Oil Conservation Division.

Q And you have previously testified before this Division, have you not --

A I have.

Q -- and your credentials area a matter of record?

A I have and they are.

MR. DICKERSON: Tender Mr. Stamets as our expert witness, Mr. Stogner.

MR. STOGNER: Mr. Richards, do you have any objection?

MR. RICHARDS: I have no objection to him being an expert witness. If he's going to testify as to matters of law I think that the Commission should take that into consideration. I think it's up to you all to determine what your regulations and rules say rather than for him to testify to you as to what they say.

MR. STOGNER: Thank you, Mr. Richards.

Q Mr. Stamets, have you reviewed the C-108 submitted in this case as requested?

A Yes, I have taken a look at the 108.

Q And have you formed an opinion as to whether or not the proposed disposal well meets the standard criteria for an injection well by this Division?

A As near as I could tell, the well is the type of injection well that has been approved many, many times by the Division with -- in all respects save one.

Q And what is that exception?

A In this case we have a well which is going to be a dual completion with injection into the lower horizon and gas production from an upper horizon.

Q In your opinion, Mr. Stamets, would this method of completing this well disqualify the well in any way for approval as an injection well under the standards of this Division?

A There was some concern on the part of the current UIC director about mechanically testing the well for mechanical integrity and whether or not that fit under the requirements of the EPA UIC program, and after I've examined that and some of the evidence that we have here later, I'm satisfied that the well can be tested for mechanical integrity and does fall within the requirements of the EPA program.

Q Okay, Mr. Stamets, our C-108, the application for authority to inject water for disposal, has been submitted as Exhibit Number Four. Will you identify that for us and review the data reflected on it and obtained by you in connection with your review of this instrument?

A I have taken a look at the records of the Oil Conservation Division to determine if I found any inconsistencies with the C-108, which had been submitted by Marshall Pipe & Supply and was part of the OCD records, and I didn't find anything that I considered to be any conflict, and so I'd just like to go through this.

If the Examiner would like to take a look at what's marked Exhibit Number Five, which is a more colorful schematic of the well, it might help.

The second page of 108 is just simply an indication of what tubular goods are in the well. It shows the setting of the surface casing and the intermediate, the amount of cement, the long string, the tubing, and so on. I have transferred that information onto Exhibit Number Five and it indicates that you've got surface pipe set at about 322, cemented all the way back to the surface; intermediate at 2119, which is nearly to the top of the San Andres formation, which is also cemented back to the surface, and then the long string is cemented with 225 sacks and the top of the cement by bond log, which I have not seen but I understand that it's here, indicates the top at about 6030, and the calculated top, I think, was about 6000 feet. So it seemed like a reasonable pick.

Also on Exhibit Five you can see the location of the perforations. We'll get back to that exhibit in a little bit.

The next page is -- summarizes some of the information. I think the part we might want to look at while we're right there would be Part 7, where Mr. Marshall indicates that he'll want to be disposing of 100 barrels a day or more as the production from his wells in the area increase.

The system will be closed. He's currently seeking 200 to 1000 pounds, 200 being the average, 1000 pounds maximum. With the Division's standard .2 of a pound per foot his injection pressure would be 1420 pounds, so he should be well within the standard pressure limitation.

Be re-injecting produced water from the wells that he has in the area and what he shows there as B really ought to be Number 5, and since the water is being injected into an oil and gas zone, oil or gas zone, no specific analysis of the water from the zone is required.

The only other thing we might want to look at on this page is Item 9 and he does not indicate that there will be any stimulation of the injection interval before he starts injection.

The next page is just simply the area map and it's not a very good good copy but what we're looking at are basically Mr. Marshall's wells in the area. There's an old Tidewater dry hole in the north half of Section 27; it's in the, oh, the southeast of the northeast quarter, and Mr. Marshall has a dry hole in Section 26, I believe, to the far east, and then we have the proposed injection well being on the southern end of the development in the area.

The next page is this looks like a copy of a Midland Mapping Company map, which repeats the same information. We have the half mile circle drawn around the well, the Cook injection well, and the only well which falls inside that half mile circle is the Wendall Best Well and the 105 from that well is shown on the next page. This is also a Marshall Pipe & Supply well. In that well you can see that we have a casing program which is essentially the same as the Cook Well. You have the 8-5/8ths intermediate set well below any potential fresh water in the area, and 5-1/2 cemented with a couple hundred sacks of cement, and I would assume that we have a calculated top of cement there at 6170. I checked that yesterday and I have no reason to believe that that's not a reasonable number.

The second page after that, then, is the completion report for the Cook No. 1, which is the well in question, and much of the detail is just repeated there and I don't really think that's of much significance.

Two pages later, then, is a 14-inch sheet of paper. The significant portion of that there would be about the middle of the page where it indicates that the 5-1/2 inch casing was cold water tested to 5000 pounds and a cement plug was tested to 2500 pounds, and that the tubing has been pressure tested before being run in the hole and this testing is part of the initial mechanical integrity required on any injection well.

The next page is the laboratory report from Halliburton Lab, as I recall, showing the average constituents in the disposal water in the first column and then the analysis of water from a couple of windmills in the area.

The next page is an affidavit which really isn't important any more since we Ms. Bentz testimony in this case relative to the faults in the area.

We have then the notice that was supplied through the Portales newspaper and then we have a copy of a letter to Mrs. O. A. Woodie, purported to be the surface owner in the area.

And we have a waiver, the final sheet of paper, form Nicor Exploration.

And that is all that was submitted with the 108.

Q The fresh water wells that you mentioned are shown on page -- on the map which is on Page 4, I guess, of the submittal, are they not?

A That's correct, and they are just to the north, oh, nearly half a mile from the Cook No. 1 Well.

Q It appears to be in the south half of Section 27 at the same location.

A That's correct.

Q Mr. Stamets, earlier you mentioned the concern of this Division regarding mechanical integrity testing. Your Exhibits Five and Six are directed to this. Would you refer the Examiner to those and express your opinion on the mechanical testing of this well?

A That's right, and Exhibit Five we've already looked, the schematic of the well.

Exhibit Number Six are selected pages from the EPA guidance under which the State of New Mexico, the Oil Conservation Division, obtained primacy for the underground injection control program.

Okay, we have -- the first two pages are part of the EPA guidance for doing that.

The next page is a portion of the MOA

which covers how the next pages, which are part of the primacy application, will be interpreted.

If we just start over from the beginning there we can see on the first page of Exhibit Six, there are couple of areas which are -- they look gray on this exhibit and they've been highlighted, they -- it just says up there that this is the -- establishes an alternative method for the state to obtain primary enforcement responsibility.

The next paragraph talks about this notice is intended to provide guidance for the implementation of the alternative demonstration.

And the last part says it includes the criteria that the EPA will use in approving or disapproving applications under 1425.

On the next page in the upper righthand there is an area which has been highlighted. This deals with the issue of mechanical integrity and describes what mechanical integrity is, that there'll be no leak in the casing, tubing or packer; and there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the wellbore; and it talks about how -- how this may be demonstrated through the use of pressure testing or other items including tracer surveys, noise logs, and so on.

The next page is from the Memorandum of Agreement that covers the primacy application. At the very bottom we have a paragraph that says that prior to the use of an alternative test, that is a test not listed in Section D-3 of the program description, for mechanical integrity, the State shall submit a written request to the Regional Administrator and shall obtain his or her written approval. No approval shall be required for the State to conduct experimental test programs at any time.

Now if we turn to the next page we see that's the cover sheet for the primacy application. The page after that, then, covers the D-3, which was referenced on the previous page.

And Item No. 3, deals with mechanical integrity, talks initially, the first part that's highlighted, about the initial test which has been conducted, and the lower portion of that talks about periodic tests of all injection wells are required, as discussed in section e, monitoring inspection and reporting, and then the latter part of that was talking about the testing program that was going on at that time and that testing program has been completed.

When we go to the last page we have Part e, which was reference on the previous page, we have a copy of Rule 704, which again talks about the initial testing for mechanical integrity, which has been done, and then at least once every five years thereafter injection wells shall be tested to assure the continued mechanical integrity. Tests demonstrating continuing mechanical integrity shall include the following.

And the first is the annulus pressure test, which the state's conducted on almost all the wells in the southeast yearly, and then the second part is the pressure testing of the casing/tubing annulus for those wells injecting under vacuum conditions.

The third paragraph, or the item (c), says, such other tests which are demonstrably effective and which may be approved for use by the Division.

Now, I believe that this well will be demonstrating mechanical integrity every day that it produces, every day that it's out there, because you have -- well, let me -- let me explain this first.

You see on Exhibit Five, you have water being injected down the tubing into the lower perforations. If a hole should come in this tubing, then you would see an increase in water production from the gas zone or the gas zone would be killed if there was sufficient water; the gas wouldn't be able to lift it out of there. So mechanical integrity of the tubing, and the same thing would be true of the packer, would be demonstrated in the ordinary operation of the well.

Secondly, if there were vertical channels outside the casing, that would again be reflected by water being produced out of the gas zone which lies above the injection zone. So in those two cases if you had a hole in the tubing or packer, you had vertical migration, you'd see that reflected in gas production or the killing of the gas zone.

The other area to be concerned about holes is in the production casing and you can see, looking at Exhibit Five, if the gas is contained within the 5-1/2 casing and I think it's 2-3/8ths inch tubing annulus, if there were a hole in the 5-1/2 inch casing, that would be reflected in a casing -- casing annulus pressure between the 5-1/2 and the 8-5/8ths, which would be read at the surface.

So it's my belief that the normal operation of this well will demonstrate mechanical integrity; that Division inspectors could go out and check the casing (unclear) annulus at anytime they chose and determine that the casing had integrity. Production tests could be run at any time the Division desired to demonstrate that there were no leaks in the tubing or the packer in this well.

Q It's your understanding, is it not, Mr. Stamets, that Mr. Marshall has offered also, if requested by the Division, to conduct packer leakage tests at some reasonable interval being necessary?

A All the Division has agreed to do with the EPA is to conduct these tests every five years and if -- if it just absolutely had to be done, I would suggest that the way to do it would be to wait for the full five years before doing it, but in order to unlatch from that packer and conduct this test, they'd have to kill the -- kill the gas zone and, you know, that's not desirable unless it just has to be done.

Q So I take it that your opinion is that the -- as a practical matter, the mechanical method proposed to complete this well is of itself a test, a continuing mechanical test of the integrity of the wellbore and its equipment?

A Absolutely.

Q Do you have any further testimony that you'd like to add in regard to Exhibits Four, Five or Six, Mr. Stamets?

A No.

MR. DICKERSON: I have no further questions of Mr. Stamets at this time.

I would move the admission of Applicant's Exhibits Four, Five and Six.

MR. DICKERSON: Are there any

objections to the exhibits?

MR. RICHARDS: No.

MR. STOGNER: Exhibits Four, Five and Six will be admitted into evidence at this time. Thank you, Mr. Dickerson.

Mr. Richards, your witness.

CROSS EXAMINATION

BY MR. RICHARDS:

Q What problems do you see with injecting in the same well that you're attempting to produce from?

A I think the primary problem you would be faced with is the potential of having something go wrong with that tubing before -- before you wanted it to, and having to kill the upper zone in order to pull the tubing out and repair it.

Q If there was a leak in the tubing above the packer, then you indicated that it could possibly kill the production of the producing gas, is that correct?

A If there were a big enough leak, that's correct.

Q Otherwise you said that there would be indications if there was more water coming in with the gas, is that correct?

A Yes.

Q The manner in which a normal gas well is cleaned up when there's water is that they go back in and swab it out, is that correct?

A Yes.

Q How would they do it in this case when the production is between the annulus and the tubing?

A With the set-up that they have in this well they can set a plug in the -- in the tubing and disconnect from the packer, unlatch from the packer, and pull the tubing out and they could actually, then, swab the upper zone through the tubing.

Actually -- and they also have a sliding sleeve in there which could be opened, although sometimes those things don't like to open, but it could be opened, and could be swabbed --

Q It doesn't presently have a sliding sleeve in it, then.

A My understanding it is. I believe that that's shown on this second 14-inch page of the C-108. There is an indication, oh, down toward the bottom. There's a number 5 that says, "XO sliding side door sleeve" and then looks like the depth is 6942.

Q And that's lower down than the perforations from the producing interval of 6853 to 6863?

A That's correct.

Q But it's higher up than the perforations at 7050 to 7064, is that correct?
A That is correct.
Q And you could still use that sleeve without any problem?
A You could try.
Q Okay.
A Well, we have a pretty minimal amount of distance there, what, oh, 50 feet, or so, 100 feet, or so?
Q Yeah.
A Something like that; very short distance; it might work.
Q You --
A And I really wouldn't expect to see it, you know, that much water getting in there from a leak in the tubing.
Q You indicated that -- earlier in your testimony -- that this injection well met most of the standard criteria except one; it was a little bit different in that it was a dual completion.

Are there very many dual completions in which you're injecting and at the same time you're producing from a well in New Mexico?
A I think there are some. I could not immediately bring any to mind and I haven't subsequently

brought any to mind. It is the sort of thing which the dual injectors with different, oftentimes, (not clearly understood) and I visited with Jerry Sexton out of the Hobbs office and he said there had been some oil zones but he didn't know if any of those were still operating.

So I wasn't able to come up with anything in New Mexico like that.

Q Generally when you talk about a dual completion don't you talk about running two strings of tubing into the well?

A I think that's the most common method of production but that's not altogether true. There are a lot of casing/tubing annulus gas producers around the state.

Q Has it been explained to you why the petitioners in this cause did not want to run two strings of tubing into the well?

A No. I can think of a, you know, couple of reasons; cost would be a significant one and got 5-1/2 inch casing in there, that makes it a little more difficult to maneuver.

Q In the protection of the rights of the party, the Oil Conservation Division usually takes into account the desire to produce gas wells, is that -- isn't that correct, generally?

A I'm not sure I understand your question.

Q The question is that if there is any way, shape or form or manner that this salt water -- or this injection into this well may cause a decline in the production or any probably production, then it appears to me that it would be best to not allow the injection into this well if there's going to be any decline whatsoever in production, especially from the royalty interest owners' position. And my question to you is since you've been testifying as to the rules and regulations, what you believe the position should be on that.

A I think if there was a serious, real potential to cause waste in this reservoir by the operation of this injection well, then it would be up to the Division to deny it, but I'm not of the opinion that that's going to be the case here.

Q Are you aware of any water that's being produced out of the Pennsylvanian formation in the general vicinity of this Cook well?

A I've taken a look at Mr. Marshall's C-115's and he does show water production from, I think, essentially all of his wells that are on production in this area.

Q He indicates that a bond log had been run on this well down to about 6000 feet, or how -- how deep was that run? I don't recall.

A Do you have that, Chad? I'd seen this reference earlier in the -- in the C-108, and it looks like it was run to, oh, about 7150, 60, 70, something like that.

Q 71 top --

A 6030.

Q (Unclear) drilling 6030 and 7000 --

A Yeah, it would run from about 5900 on down to a total depth, basically.

Q Okay.

MR. STOGNER: While Mr. Richards is looking over that, Mr. Stamets, could you please identify the bond log which Mr. Richards is looking at, which you referred to? Is that in our files?

A I don't know. It was not in your files here in Santa Fe. It may be in your files in Hobbs. It's a gamma ray cement bond log, (unclear) Wireline, Inc. (unclear), and this is a cement bond log run on 6-18-88.

MR. STOGNER: Mr. Dickerson, do you have an extra copy of that by chance?

MR. DICKERSON: Yes, sir, we sure do.

MR. STOGNER: Could you make that a part of the record?

MR. DICKERSON: Yes, sir.

MR. STOGNER: Or where would

you like to make that a part of the record?

MR. DICKERSON: I'd -- if Mr. Richards would like to introduce it, I have not proposed to introduce it. We certainly have no objection to doing so.

MR. STOGNER: I'd like to make this a part of Exhibit Four, the packet of the C-108.

MR. CATANACH: Okay.

MR. STOVALL: Mr. Examiner, I might suggest that in order to do that we refer to this as Exhibit Four-A. Four-A would be the bond log.

Q You also indicated earlier there'd been no stimulation in the injection interval. Do you see any problem with that?

A I didn't say there's been no stimulation. I said he wasn't planning any additional --

Q Any additional --

A -- or any further stimulation.

Q Do you know if there has been some stimulation?

A I've seen a daily drilling report or daily activity report that seemed to indicate that there had been some acid placed on this zone.

Q Okay. I believe it's in one of your exhibits, Exhibit Four, about page 4.

A Okay, let me get to that. That's that

--

Q And also on Page 5, I guess.

A Okay.

Q You've drawn a half mile circle. Circle is just showing that you've drawn a half mile circle and you've shown the location of the windmills, the water wells in the vicinity, is that correct?

A I didn't do this. This was done by Mr. Best or someone working for him, but that's what it does show. Mr. (unclear), I'm sorry.

Q Okay, and on Page 5 you've drawn another half mile circle and you show that there's another well in there. What is the reason for drawing your half mile circle?

A The half mile circle is required for the area of review in an application for an injection well before the OCD.

Q What is the reason for that?

A To determine whether the wells within that half mile circle had been completed in such a manner that they will or will not allow the injected fluid or fluid which is naturally in that same horizon to escape and perhaps threaten your SDW.

Q In this instance they'd be injecting into the Montoya formation and a well in Section 27 is closest to it, called the Wendall Best No. 1 Well, is producing out of that formation, is that correct?

A Yes.

Q Also in Section 27 there's a dry hole and it had been drilled by Tidewater?

A Correct.

Q Do you know if there's been any investigation of using that well as a salt water disposal well?

A No, I can't say there has and I haven't -- I've looked at that file and I can't -- I don't remember how the well was plugged, whether they left casing in there or whether it would be economic to (unclear) in that well.

Q You've not reviewed any reports so you can testify as to whether this well, the Cook No. 1 Well, is capable of production out of the Pennsylvanian formation, have you?

A The Pennsylvanian?

Q Yeah, whatever --

MR. DICKERSON: I have a reservoir engineer prepared to testify on that.

A I've seen a gas well test on the Pennsylvanian section.

Q Do you know if any xrays or other tests were conducted on this tubing other than the cold water pressure test?

A Pressure test? Not that I'm aware of, no.

Q You're aware that many wells, even though they have this cold water pressure test, I mean a lot of tubing, you know, has the cold water pressure test, could fail, isn't that correct?

A Anything can fail.

Q And do you know if this is new or used tubing that was placed in this well?

A I don't know. Let's see if it says. No, it does not say. I think it would be ill-advised but --

Q To use used tubing?

A Unless, you know, if it was old, old used tubing.

Q Okay. You also referred us to several documents in your Exhibit Number Six, I believe.

You've indicated that numerous tests could be conducted. Some of those tests included a tracer survey as well as the noise logs and temperature surveys.

A Yes.

Q Are you familiar with those, how they are run?

A Somewhat; not an expert but I'm familiar with them.

Q Have any of those, to your knowledge, been run on these -- on this well?

A I can't see any reason why they would be at this point because there hasn't been any injection and the noise log and tracer survey would be -- be related to the active injection.

Q Same with the temperature survey?

A Oh, yes, that would -- it would indicate that through an anomalous temperature that the injection -- injected water might be some place other than where you intended it to be. That would also be a post-injection --

Q If those things are post-injection and also in connection with monitoring the well, then 704 (a), or no, 704 (b) indicates that the well should be equipped so that the injection pressure and annular pressure may be determined at the well later.

Is it your understanding that both those could be determined at the wellhead in this instance?

A Well, I haven't been to the wellhead to know that that's out there, but those are requirements and I would expect the district office to see that those were enforced.

Q Explain to me how you take in 704 (a), small a, it says there should be a measurement of annular pressures as opposed to pressure testing of the casing-tubing annulus. In a well like this how would you conduct those tests? Is there anything special that would have to be done?

A Well, these are not all separately required tests. These are the types of tests within the (unclear). If this well were a standard injection well and you didn't have the perforations there for the Pennsylvanian producing horizons, the typical method of testing this well would be to go out while it's injecting and take a pressure test of the casing/casing annulus and the casing/tubing annulus and see if there was any indication of anomalous pressure on those. Since you have the gas zone in the casing/tubing annulus, you can't do that.

Similarly there would be no way that you could pressure test that annulus, so you have to rely upon the pressure that's naturally there in the gas zone and the -- any indication of the additional fluid production.

Q So the test couldn't be run the way that they'd be run due to this set up in this well, is that correct?

A That's correct. This would be an unusual situation.

Q Are bottom hole pressure tests also taken periodically?

A On injection wells?
Q No, no, on producing wells.
A Bottom holes, no.
Q Are there packer tests that are run?
A There's a packer leakage test, yes.
Q And that could still be run on this one, then?
A Again, it would be done a little on the unusual side, but yes, it could be run.
Q How would that be done?
A I haven't looked at a packer leakage test in a long time but I presume that you could shut the well in, both the injection side and the production side, allow the pressures to stabilize and then perhaps begin the injection for awhile to see if there was any change in pressure. Conversely, shut it in, allow it to stabilize, and produce the gas side and see if you had any change in pressure.
Q Okay.
A But again, as I said, I think this would be a little on the unusual side.
MR. RICHARDS: Thank you.
MR. STOGNER: Let's take a short recess at this time.

(Thereupon a recess was taken.)

MR. STOGNER: This hearing will resume to order.

Mr. Dickerson, do you have any redirect of this witness?

MR. DICKERSON: I just have one question, Mr. Stogner.

REDIRECT EXAMINATION

BY MR. DICKERSON:

Q Mr. Stamets, in your opinion is there any evidence here saying that the injection of water into this proposed injection zone in the Montoya formation will not be confined to that formation?

A No.

MR. DICKERSON: I have no further questions of Mr. Stamets.

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

MR. RICHARDS: No.

MR. STOGNER: I have none at this point.

Mr. Dickerson.

MR. DICKERSON: Call Mr. Gene Garnett at this time.

GENE GARNETT,

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

DIRECT EXAMINATION

BY MR. DICKERSON:

Q Mr. Garnett, will you state your name, your occupation and where you reside?

A Gene N. Garnett. I'm a petroleum engineer by occupation. I'm Vice President of Wintergreen Energy Corporation, which is a working interest owner in these properties.

Q And you are appearing here on behalf of Marshall Pipe & Supply Company in support of the application which is the subject of this hearing?

A Yes, sir.

Q You have not testified before this Division or the Oil Conservation Commission in this state, have you, Mr. Garnett?

A I did once before many years ago.

Q Will you briefly summarize for the Examiner your educational and employment history for us, now?

A I have a Bachelor of Science degree in petroleum engineering. I'm a Registered Petroleum Engineer, a registered engineer in the State of Texas. I have 40 years of involvement with Sun Oil Company as an engineer in various roles, most of which were for (unclear) completion and workover operations and operating properties.

After leaving Sun I worked for about five years as an independent petroleum engineer, working for the public. I worked for about five years with then First National Bank of Dallas in the Trust Department as a petroleum engineer, supervising work in the operations of oil and gas properties in the trusts and estates.

And more recently I've been employed by Wintergreen Energy, which is a small family company, for about 7-1/2 years.

Q Mr. Garnett, are you fairly familiar with the proposed mechanical construction of the well which is the subject of this hearing?

A Yes, sir, I am.

Q Let me refer you to Exhibit Number Four, which was previously admitted into evidence and direct your attention to that Otis Completion Guide, the schematic of the tubing string which is in the subject well, and let me ask you to go over that in a little more detail and explain for us how that well is equipped for the purpose of rebutting some of the questions that Mr. Richards asked of Mr. Stamets.

A Okay. If you'll look at the bottom piece immediately above the permanent packer you will see that it has a J-latch seal assembly and that J-latch means that it cannot come free of the packer unless it is rotated, which it will not do in the static condition. It will not. There's no danger of that happening other than when you're doing well work and, of course, then you probably are wanting to unlatch it.

The next piece is an end nipple and that is an Otis piece of equipment, which is to receive, if necessary a plug. You could, with wireline operations you could install a plug there. With further wireline operations if you wanted to, you could open that sliding sleeve and communicate the annulus with the tubing and in regards to some of the earlier discussion, by doing these two things you could at any time swab test the -- the Penn zones, which are now isolated in the annulus.

Q Just briefly for us, Mr. Richards asked what would be done in the event of a tubing leak so that disposal water was injected into the casing-tubing annulus. What would be the mechanical procedure that the operator would follow given the hook-up of this well to remedy that leak?

A Well, you say after you've already identified that there were a leak?

Q Yes.

A Well, obviously, if you had a -- if you did have a leak, which I'd prefer to think that we're not going to have one, but when you had one you would want to verify where that leak was and remedy the situation by eliminating the leak.

I believe that the procedure I would follow, I would probably first use wireline operations to set a plug in that end nipple and then with a pressure pump I would pressure up the tubing to see if it was in the tubing string itself. If I found that it was, then I would know I just needed to replace the tubing string. If there was some question, if it was not definite that it was in the tubing string, then I, after having retrieved the tubing, I would go back in the well with a retrievable packer, set above the (unclear) zone, and pressure test on the annulus to verity that there was no problem with the casing itself, and then I would lower the packer below the -- let me think this out -- probably at that stage you would again go back in with the -- another string of tubing. You would probably want to run this time a coated string of tubing and equip the well as it had been before.

Q What would be the procedure to remove the accumulated disposal water in the casing or the casing-tubing annulus?

A I would not see that as any problem at all. Of course the -- if and when you were having to retrieve the tubing string you would have to kill the well. You would have to load the well with salt water or some fluid and circulate the well to have it be in condition to be able to perform your operations.

Q Now that would be a procedure that is not peculiar to the application that we're here today. That would be the case in any gas well before you could pull the tubing string you'd have to kill that zone.

A Yes.

Q Isn't that right?

A That is correct.

Q Okay, so would you then swab that accumulated salt water through the sliding sleeve that's shown on this portion of the exhibit?

A Yes.

Q You don't foresee any problem with that being a satisfactory procedure to remove --

A No, it's very --

Q -- the water and repair the leak?

A It's a very standard procedure. It's

many times done and there was earlier discussion about the uniqueness of this casing-tubing dual. Well, it's not unique at all. In my experience there's a lot of areas where -- where it is done. It may be unique in New Mexico as far as having the combined gas producer and water injector.

Q Your experience is primarily in Texas and other areas?

A Yes, sir.

Q Okay. In the narrative part of the same exhibit that I've previously referred your attention to, there appears the statement that the 2-inch UVU or AUE tubing was cold water tested to 7000 pounds before run in hole.

What can you tell us about the quality of the tubing that is in the wellbore at this time?

A Well, I would have everyone know that I was not on location, I have never seen the tubing string. The -- the daily report that the non-operators receive from the operator did not describe the tubing as to whether it was new or used. From my conservation with Mr. Marshall I think that I know that it was used pipe but it was very good used pipe and it was pipe that had been tested before it was delivered to location to -- or perhaps it could have been tested on location, but probably before, to the 7000 pounds.

Q Mr. Garnett, do you know whether or not the applicant, if it was required by the Oil Conservation Division to plastic coat the tubing which is in the well, would the applicant be willing to do that, if required?

A If required, I'm sure he would. I mean, if it was suggested that it be necessary, I'm sure he would. Of course, one aspect we're always looking at is economy, and not expecting a problem and not -- the desire, of course, would be to initially produce the well with injection with the current tubing string.

Q Do you see anything in this proposed method of completing this well, Mr. Garnett, which would cause you any concern as a person experienced in completion engineering with the capacity of this proposed operation to protect the productive Penn zone from any problems by reason of this method of completion?

A No, I think it's -- I think it's a very adequate installation and if I felt otherwise, I would be -- I would express concern because my company has an interest in the Penn completion of this well.

Q Is there anything that you have seen or heard here today or that you see in the instrument before you that leads you to believe that this would not be a practical way completing the well so as to accommodate the competing interests of the parties here?

A Based on what we know about the -- the perforated zones now and I find it to be very adequate to begin what we would like to do, namely, start disposing water at this point right out of the tubing while I assume producing gas from the annulus at such time as compression is installed in the field, and I know that Mr. Marshall is already beginning to plan toward that eventuality and I think it's very possible that that might happen as early as this year.

Q Okay.

MR. DICKERSON: I have no further questions of Mr. Garnett.

MR. STOGNER: Thank you, Mr. Dickerson.

Mr. Richards, your witness.

Oh, I'm sorry, let me interrupt here right quick.

I don't think we accepted Mr. Garnett's credentials for a witness.

Are there any questions on his credentials, Mr. Richards?

MR. RICHARDS: I was going to question his credentials as to the type of petroleum engineer, but since he has limited his testimony to completion and workovers and he's just talking about the tangible construction of the well, I don't think I have any objection as to his testimony is limited to that extent, and so far his testimony has not got into the reserves or anything else. So as far as the limited extent of the actual mechanics of the well, I have no objection.

MR. STOGNER: Mr. Dickerson?

MR. DICKERSON: I tender Mr. Garnett as an expert completion petroleum engineer.

MR. STOGNER: Mr. Garnett will be so accepted.

Mr. Richards, your witness.

CROSS EXAMINATION

BY MR. RICHARDS:

Q What have you, what documents have you examined to come up with your testimony today? You've indicated you were not on the well site so you must have examined documents, is that correct?

A Well, my practice where we're in participation in a well is to try to get all the information for Wintergreen's file that the operator has in his own file.

Now, obviously, I don't -- I'm not successful with the ideal, but I have the daily well reports, I have everything that he has submitted to the Commission, and naturally, (unclear) and everything that pertains to evaluation of the wellbore.

Q Okay. And you can you tell me about what date the first completion process took place in the Montoya formation?

A The -- the report received from the operator for the date June the 22nd, which would be for the prior day, shows that the zone was perforated and after spotting acid, and that acid was displaced, and that's June of '88 I'm talking about, and subsequently swab tested.

Q Were both the Pennsylvanian and the Montoya formations shot at the same time --

A No, sir.

Q -- Perforated at the same time?

A No, sir.

Q Which one was perforated first?

A The lower, the Montoya.

Q And then it was -- there was (unclear) acidization on that well -- on that formation?

A I beg pardon?

Q Was it fraced and acidized?

A The tentative plan had been to frac but it was not fraced. It was only acidized with either 2-or-3000 gallons of 15 percent MCA, which is 15 percent hydrochloric acid.

Q When was the determination made to go up the hole and complete in a higher zone?

A Well, it was made shortly thereafter, after the swabbing operations failed to establish hydrocarbon production and instead recovered acid water in the formation water.

Q There was no hydrocarbons produced out of the Montoya?

A Not any measured amount.

Q Okay. And that's from reading the reports that Marshall Supply --

A Yes.

Q -- have given you. Okay.

A But I would wonder why you would qualify that because you'd want them to make the well there as bad as all the rest of us.

Q Right, so you went up the hole and completed in the Pennsylvanian, is that right?

A Yes, sir.

Q Did you pull the tubing first after the completion in the Montoya?

A Yes. The Montoya was tested with a retrievable packer, Halliburton RTPS or I forget what that stands for, a retrievable test and something tool, but anyway, it's a retrievable packer, and subsequently he set a permanent packer above the Montoya with an expendable plug in place, a plug in place, I think it was an expendable plug, to -- to isolate the Montoya while he came up the hole to test the Pennsylvanian.

Q Okay, was a new set of stringing run or tubing run?

A It was the same string of pipe basically. I mean, he may have -- he would have had to lay down a few joints of pipe because he's now working further up the hole.

Q Okay, and after the completion in the Pennsylvanian formation, did he then retrieve the tubing again and run new tubing in or different tubing or same tubing back in again?

A The one string of pipe that he brought to location was what was used.

Q Okay, when was the sliding sleeve and the end nipple put in place?

A It was -- it was run as part of the string when he began to -- when he was making perforations to test the Pennsylvanian zones. It was not necessary when he was testing the Montoya.

Are you seeking a specific date or --

Q Well, no, I just wanted to know what the point in time was. It wasn't put in there when the first completion process was done.

A No, there was no purpose at that time.

Q Right, it was only put in there after you plugged back the Montoya and you went up to the (unclear) and plugged it back and set the (unclear).

A He isolated it --

Q Right.

A -- beneath the packer.

Q Right, and he went back up to the higher formations in the Pennsylvanian.

A Yes, sir.

Q So at that time the decision had been made that you may need the sliding sleeve, is that correct?

A Yes.

Q Okay.

A Well, there were some who weren't, of course, sure but what a frac treatment might be tried on the Montoya.

Q How would this sliding sleeve help you if a frac treatment was done on the Montoya?

A Well, I believe we're at cross purposes. It would have no --

Q It would have nothing to do with that.

A I made that comment to -- as a background to the fact that we would have a well installation which would basically have perforations below a packer and perforations above a packer, and when you have that situation, it's a conventional procedure to equip the tubing string about as Mr. Marshall has equipped this string.

Q It's conventional in Chaves -- I mean in southeastern New Mexico?

A Well, it's -- it's pretty much an industry practice to do this.

It's certainly sound practice.

Q Were you thinking that there's a possibility you'd go back in and open up the Montoya formation for production at the time they -- you went back in the Pennsylvanian?

A It was a possibility that it would be tested further.

Q Has it been tested further?

A No, sir.

Q Okay. You were indicating awhile ago in response to a question by Mr. Carson about if there was a leak in the tubing, the process you'd go through and you indicated that if there was any problem with the tubing after running the wireline test, then you'd simply replace the tubing if necessary, but if that was not the problem you'd have to go in with a retrievable packer, set it up above the Pennsylvanian zone, then pressure up; you'd be pressuring up on the annulus or you'd be pressuring up inside the tubing?

A I'm not sure I -- I'm not sure I followed you. To fix the tubing you would be pressuring the tubing side.

Q But if you decided that there was not any problem, perhaps, with the tubing, there probably could be a leak somewhere else. How would you determine where that leak was?

A I suspect what would be done, of course, I'm not in the operator's role and therefore wouldn't be calling the shots, but I suspect if the tubing had no problem, then the -- the next thing you would suspicion, even though they have a fine record of performance, would be the packer itself, and probably what I would do would be, if I had any question at all about the packer, would be just simply to set a packer, a new packer, if you will, above the other one to -- to remove that possible source of leakage.

When you're completing wells, there's -- there's always variations that you can do. A lot of times it comes down to personal preference.

Q Would you -- well, you're not going to testify to that. Strike the question.

You talked about a type of string or tubing that was coated. What do you mean by coated?

A Well, I mean, I had nothing particular in mind, but a coating which would prohibit the water being in contact with the metal surface.

Q Okay.

A And therefore eliminating any possibility of corrosion.

Q What are some types of coating that you would that?

A You could plastic coat it.

Q Once again that costs a little bit more and you'd --

A Yes, sir.

Q -- rather stay away from it --

A Yes, sir.

Q -- anything that costs more.

A I dare say, I can't speak for Marshall, but in all probability next time that the tubing string would be for whatever reason pulled, that a coated string would be installed as replacement just as a preventive measure, but we, for my preference, at least, would be not to go out there far and replace the tubing string because there's always some danger of damaging your -- your gas zone completion.

Q Now you indicated that you didn't know for sure if the tubing that was used was new or used tubing but you testified that it was hearsay that you thought it may have occurred. Do you actually have any knowledge as to whether or not this tubing is new or used?

A I believe Mr. Marshall has told me that --

Q No, but do you have knowledge? Do you --

A No.

Q -- know that it's new or used?

A No, but there's nothing wrong, I might add -- may I? No problem.

Q Do you know if there was any discussion of a dual completion of this well with two strings of pipe?

A I've heard none.

Q Has there been, since this petition was filed with the State?

A There's been none that I participated in.

Q You testified that there were no hydrocarbons produced from the Montoya. Have you seen a report on the Pennsylvanian to determine whether or not there's production from it?

A Yes, I've seen the results of the 4-point test.

MR. DICKERSON: Mr. Richards,

I might save you some more time. A reservoir engineer is prepared to qualify and testify on those. I have no objection to you asking questions --

MR. RICHARDS: No, you're right, I should ask them to this other guy. That would be fine.

I have no further questions.

MR. STOGNER: Thank you, Mr. Richards.

Mr. Dickerson, any redirect?

MR. DICKERSON: I have no further questions, Mr. Stogner.

I would, since we -- it became the subject of testimony, I submitted the daily drilling reports furnished to the participating working interest owners by the nonoperators, I have marked it as the Applicant's Exhibit Four-B and I would propose that you enter that into the record of these proceedings at this time.

MR. STOVALL: Mr. Dickerson, may I suggest just for a procedural matter, would you ask your witness to lay a foundation as to the source of his information?

MR. DICKERSON: Okay.

REDIRECT EXAMINATION

BY MR. DICKERSON:

Q You, on some of the questions asked of you, Mr. Garnett, referred to a daily drilling report and you had it in front of you. Let me show you a copy of an instrument that I have in front of me. Is that the report that you were referring to?

A Yes, sir.

Q And this is purported -- appears to be a summary of the day by day operations during the completion of the well in question in this case?

A That's correct.

Q And this was furnished to your employer, Wintergreen, by the operator, Marshall Pipe & Supply --

A Yes.

Q -- in connection with keeping the working interest owners informed --

A That's correct.

Q -- on the operations of this well?

A That's correct.

Q And you reviewed that for the purpose of your testimony at this hearing today?

A Yes, sir.

MR. DICKERSON: Move admission of Exhibit Four-B, Mr. Stogner.

MR. STOGNER: Are there any objections, Mr. Richards?

MR. RICHARDS: Yes, there's no evidence as to who prepared this or if it was prepared properly. I know that he used it in his testimony and I think he's got into evidence everything that he testified from it.

MR. DICKERSON: The instrument speaks for itself, Mr. Stogner. We invite you to use it if you find it helpful. If you don't find it helpful, you can throw it in the ashcan.

MR. RICHARDS: As a point of reference, it's okay with me. I just don't think that a proper foundation was laid for its admittance. I don't mind it being in the record. I withdraw my objection.

MR. STOGNER: Thank you, Mr. Richards.

Exhibit Number Four-B will be admitted.

MR. STOVALL: I do have a couple questions I'd like to ask the witness, Mr. Examiner, if I might, just to clarify for my understanding.

CROSS EXAMINATION

BY MR. STOVALL:

Q And your capacity in this, the drilling and completion of this well is as an engineer for a non-operating working interest owner, is that correct?

A Yes, sir.

Q Have you participated at all in -- in designing the completion operation?

A No, sir.

Q And did we -- did you participate at all in approving it prior to -- prior to their being done?

A Well, in a general way we approved the AFE, Authority for Expenditure, for completing the well.

Q Did you personally have any input into the actual approval of design of completion operations?

A No, sir.

Q Okay. Thank you. No further questions.

MR. STOGNER: I have no further questions of this witness at this time.

Mr. Dickerson?

MR. DICKERSON: Call Mr. Tim Wilcox.

Mr. Stogner, Mr. Garnett did not feel comfortable speaking on behalf of Mr. Marshall but

I do feel comfortable speaking on his behalf, and if this Division requests or requires the plastic-lining of this tubing in order to complete the well in the manner requested, Mr. Marshall is certainly will to do that.

MR. STOGNER: Thank you, Mr. Dickerson.

TIM D. WILCOX,

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

DIRECT EXAMINATION

BY MR. DICKERSON:

Q Mr. Wilcox, will you state your full name, your occupation, and by whom you're employed, please?

A I'm Timothy D. Wilcox, petroleum engineer employed for Nicor Exploration Company in Denver, Colorado.

Q And what is Nicor Exploration Company's interest in the well which is the subject of this hearing?

A We are a working interest owner in this well and the other wells that Mr. Marshall operates in this area.

Q You have not previously testified before this Division, have you, Mr. Wilcox, --

A No, sir.

Q -- as a petroleum engineer?

A No, I have not.

Q Will you briefly summarize for us your educational and employment background as it relates to the profession of petroleum engineer?

A Yes. I have a Bachelor of Science degree in geological engineering. I was initially employed by Amoco Production Company as a petroleum engineer, mainly performing operations in the Production and Reservoir Engineering Branch.

I was employed by Amoco for five years in Casper, Wyoming, and Denver, Colorado, and finally to New Mexico.

Q And that was -- among other duties involved reservoir engineering and calculation of recoverable oil and gas reserves in place?

A Yes. Following my employment with Amoco I was employed by Energetics Operating Company for one year in a production engineering capacity in Denver, Colorado, and for the past three years I've been employed with Nicor Exploration in the reservoir engineering, production engineering and drilling engineering roles.

Q And is your employer, Nicor, in support of the application filed in this case by Mr. Marshall on behalf of Marshall Pipe & Supply, the operator of the subject well?

A Yes, we are.

Q Have you made a study, Mr. Wilcox, of the available engineering data for the purpose of presenting your testimony here today?

A Yes, I have.

Q And are you familiar with the operations conducted in the wells in the area that we're concerned with which are operated by Marshall Pipe & Supply and have you reviewed those for the purpose of your testimony?

A Yes, I have.

MR. DICKERSON: Tender Mr. Wilcox as an expert petroleum engineer.

MR. STOGNER: Are there any objections?

MR. RICHARDS: No objection.

MR. STOGNER: Mr. Wilcox is so qualified.

Q Mr. Wilcox, we have submitted to the Division and Mr. Richards a map that we have marked as Exhibit Number Seven. Did you prepare that map?

A Yes, I did.

Q Will you review it for us and tell us the information that you've shown on that map?

A This map is a production map of the Tule Field Area. It highlights the wells that are produced or shut in in the field at this present time, along with the well that is currently being drilled in the northeast quarter of Section 23.

What is highlighted next to each of the wells is an indication of the initial potential test from either the Penn and/or the Montoya shown as applicable to each well, and the cumulative and current production rates for each of the wells in the field at this time.

Q Okay, refer to the next exhibit submitted as Number Eight and tell us what that compilation is.

A Exhibit Eight is an economic run that I made for the Cook No. 1 Well.

Q In what zone?

A Producing from the Pennsylvanian zone. The economics are reflected from the 4-point potential test that was run on the well, indicating that the well has a capability of producing at a maximum rate of 164 MCF a day.

For the purposes of these economics I used 150 MCF a day initial production rate for the well.

Q Do you feel that's a reasonable rate to use for the purpose of your calculation?

A Yes, based on the analogies that I've done with initial potential tests of the other wells in the field and their actual production rates incurred, it's justified.

Q Okay, and for your purposes in making these calculations what price did you assume and how was that arrived at?

A The price I used for the economics was $1.24 an MCF, which is the average price that we received for these wells in the field for the last six months.

Q Do you know what the current price is --

A Currently we're receiving approximately $1.46.

Q Okay, but for the purposes of your calculations you have assumed $1.24?

A That's correct.

Q All right, continue and tell us what calculations you made.

A Using the initial rate that we have previously mentioned and an operating cost of $2890 a month, which includes the average well cost of the other wells in the Tule Field and a $1500 per month rental compressor fee to put the well on compression.

The well calculates out recoverable reserves of 352-million cubic feet of gas.

Q Tell us where that's shown on Exhibit Number Eight.

A It's the farthest right column under calculated value.

Q On the first page?

A On the first page.

Q Okay.

A Based on the operating cost, the severance taxes included in the State of New Mexico, and the $1.24 MCF for gas price, the well would yield a cumulative cash flow of $73,199.

Q And that's indicated at the lower right-hand corner of page two of your submitted exhibits?

A That's correct. And discounting that at 15 percent discount rate before Federal income taxes would be $49,387 worth of value.

Q Of profit over and above your assumed operating costs during the entire life of the well?

A Correct.

Q What under these assumptions and based on your calculations do you calculate to be the life expectancy of this well before it reached its economic limit?

A 7.8 years.

Q Now were the assumed operating costs that you used based on your review of the actual costs incurred to date in Mr. Marshall's operations in other wells in this Tule Field?

A It is the average costs of the other three wells being operated in the field; excuse me, four wells --

Q Okay, and do you --

A -- over the last six months.

Q Do you feel that that is a reasonable estimate on which to base your calculations for the operation of this well?

A Yes, I do.

Q So if I understand your testimony correctly, based on the gross recoverable reserves that you have calculated, the anticipated net return is $73,199 over and above expenses of operation?

A That's correct.

Q Let's turn -- do you have anything further you'd like to add about Exhibit Number Eight, Mr. Wilcox?

A No.

Q Let's turn now to Exhibit Number Nine and tell us what calculations you've made on that instrument.

A Exhibit Nine is an economic calculation to justify the economic investment of converting the Cook No. 1 Well to a salt water disposal well.

Currently the Tule Field is producing

170 barrels of water per day or 5100 barrels of water a month at a cost of $1.00 a barrel to truck out the water off the field is currently costing us $5100 a month in salt water disposal fees.

Q Let me ask you if the current rate of water production, has that recently increased?

A Yes. The Perry No. 1 Well, which is the furthest north/northeast producer in the field in the last month has jumped from approximately 20 barrels of water a day to about 140 barrels of water a day.

Q So if that level of water production is not yet reflected on the current reports to the Oil Conservation Division, it's simply because it was such a -- the well went on line so recently?

A It's not that the well went on line so recently. It's that the water production has just changed recently.

Q Okay. Excuse me for interrupting. Continue with telling us what you have shown on Exhibit Number Nine.

A Item number two in the exhibit shows an estimate for the cost of completing the Cook No. 1 salt water disposal well. We have an estimate of $20,000 to do the tangible work of installing pipeline and putting in a positive displacement pump in the field, and then we would have a continued monthly operating cost above and beyond the normal operating costs in the field right now of $500 a month.

Item number three, then, would be --

Q Let me interrupt you on that one. You have not included any additional cost from this point forward in equipping this well to produce. Is that because the well is already equipped to dispose of water and produce from the Pennsylvanian in the method that we've heard here today?

A Correct.

Q All right, go ahead with your number three.

A Item number three, then, would show a monthly payout, or, excuse me, a time period to pay out of the installation of $20,000 based on a reduction in salt water disposal costs for the field. As you can see, the reduction in our monthly operating costs would be $4600 a month and applying that to the $20,000 investment, we'd yield a 4.35 month payout on the investment.

Q Does that operate in any way to extend the life of the well or to enable the operator and the working interest owners to recover gas that would not otherwise be recovered under a higher rate of disposal cost?

A Yes, it does.

Q Okay, do you have anything further you'd like to add about Exhibit Number Nine?

A No, I do not.

Q We've submitted one last packet as -- marked Exhibit Number Ten, Mr. Wilcox. Review that for us, tell us what it is, and what in it is relevant to your testimony today.

A Item number ten is a drill stem test reservoir evaluation report performed by Halliburton for Marshall Pipe & Supply and the working interest owners on this well.

Q And how many separate tests were conducted and reflected in this exhibit?

A Only one test was conducted.

Q What formation was tested?

A The formation that was tested was the Montoya interval.

Q And the proposed injection interval which is the subject of this hearing?

A Yes.

Q All right. Summarize for us, if you would, and direct our attention to the appropriate part of this test which gives the information that you'll tell us about.

A On the fifth page of the report under the area captioned "Recovered" we have 2200 feet of gas, 375 feet of gas-cut mud, 625 feet of gas-cut salt water. No gas was recovered to surface, which is an important aspect that I'll get to later concerning this DST.

Under "Sampler Data" we have on the same page, we have 1.454 cubic feet of gas and 1450 cc's of water recovered in the sample chamber, which is the last fluid that is recovered during the testing period.

As was earlier testified by Leslie Bentz a productive well in this field typically has gas production to surface, and as shown on the next page of this report, there is no gas rate recorded during this drill stem test, indicating that no gas was recovered to surface.

When comparing this DST recovering information, namely, the sample chamber recovery information, it indicates a gas/water ratio of 159 standard cubic feet per barrel. As compared to other productive wells in the field out of the Montoya interval, both the Wendall Best and the JTEG well recovered no water in the sample chamber during the DST. The State well recovered some water but of a better gas/water ratio of 187 standard cubic feet per barrel.

The State well is the next lowest well in the Tule Field and currently its production reflects the marginal value of the well indicating from the indicated water recovery in the sample chamber, and it's produced only 11-million cubic feet of gas to date and is currently only making 22 MCF a day.

Q Now that well you're referring to the State well is the one shown in the south half of Section 22 in the northern part of this field on your Exhibit Number Seven?

A That is correct.

Q In further testing of this well in light of the DST information, the interval was perforated with two jet shots per foot from 7104 feet to 7116 feet. It was treated with 300,000 gallons of 15 percent hydrochloric acid and after recovering all load and acid fluids, the well was swabbing at a rate of 216 barrels of water per day with less than 50 MCF a day rates, indicating that the well is uneconomical to produce gas in sufficient quantities from the Montoya interval.

Q Is that your opinion as a reservoir engineer that that perforated interval which is the projected injection interval in this well, then, is nonproductive based on your testimony here?

A Yes.

Q Is there anything further you'd like to add about the testing of the Montoya section in this well, Mr. Wilcox?

A No.

Q Let me ask you, in your submittal as Exhibit Number Eight and your calculations of the reserves and the net profit anticipated to be recovered from the operation of the well in the proposed fashion, what does that tell you as a petroleum engineer as to whether or not the Pennsylvanian zone above the injection interval is or is not commercial?

A It indicates that the Pennsylvanian zone is commercial.

Q And that it does result in the recovery of a net profit over and above operating costs and other expenditures?

A It indicates a profit of expenditures from this day forward.

Q Okay. Mr. Wilcox, what is your opinion on the suitability of the proposed injection into the Montoya zone? Does that zone appear to be suitable for disposal of produced water to you?

A Yes, it does, since it doesn't have any commercial hydrocarbon potential.

Q And does the presence of the high water content, native water in that zone, factor into your conclusions?

A Yes, it does.

Q Have you seen any evidence in connection with your review of all the geologic -- or engineering data that you have available, Mr. Wilcox, to indicate to you as a reservoir engineer that there is any material risk of waste of any recoverable hydrocarbons in either the Penn or the Montoya sections in the subject well?

A No.

Q You heard on some earlier testimony the reference to the Wendall Best No. 1 Well, which is the only area within -- or the only other well within a half mile of the proposed injection well that is in the south half of Section 27, shown on your Exhibit Number Seven. Nicor also has an interest in that well, does it not?

A Yes, we do.

Q In your opinion as a petroleum and reservoir engineer does injection of water into the Montoya section in the Cook No. 1 Well pose any risk of any type to the operations or ultimate recovery of hydrocarbons in that well?

A No, it doesn't.

MR. DICKERSON: Move admission of Exhibits Seven, Eight, Nine and Ten at this time, Mr. Stogner, and I have no further questions of Mr. Wilcox.

MR. STOGNER: Are there any

objections?

MR. RICHARDS: No.

MR. STOGNER: Exhibits Seven, Eight, Nine and Ten will be admitted into evidence at that time. Thank you, Mr. Dickerson.

Mr. Richards, your witness.

CROSS EXAMINATION

BY MR. RICHARDS:

Q Let's look at your Exhibit Number Seven. You have some numbers on there and I'm not sure exactly what all these numbers mean.

Let's look at the Wendall Best No. 1 Well. Off to the lefthand side of it you have some calculations, 2805 MCF, 2.7 BCPD CAOF, what are those -- what's that stand for?

A That's 2.89 a day and 2.7 barrels of condensate a day, calculated absolute open flow potential, as derived from a 4-point test.

Q Okay, and underneath it you have cumulative?

A Cumulative production to -- through December is 276-million cubic feet and 3.8-thousand barrels of condensate; currently producing 906 MCF a day and 10 barrels of condensate a day.

Q Okay, now on the Marshall Pipe Cook No. 1 Well, Section 34, on the righthand side you have 164 MCFD.

A Correct. That is initial potential based on the 4-point back pressure test done.

Q That's the initial potential per day?

A Correct.

Q All right, now how does that correspond to the Wendall Best No. 1, 28005 MCF?

A Substantially lower potential.

Q But it's still, you're talking about MCF per day, correct?

A Correct.

Q On both of them, even though there's a D on the Cook No. 1?

A Yeah, Cook No. 1 --

Q Okay, so the Wendall Best came in at 2. or what did you say, 2.8 --

A 2.8-million, yeah.

Q 2.8-million and the Cook came in at 164 MCF?

A Correct.

Q That's a substantial difference, is that correct?

A Sure.

Q What, maybe 20 times, or 10 times? 20 times, difference, the difference?

And now you indicate that currently the Wendall Best is producing at 906 MCF per day, right?

A Correct.

Q And of course the Cook No. 1 is producing at what?

A It's not on line.

Q Okay, you indicate in there 7-88 under the Cook No. 1, what was that date for?

A That's for the date it was completed.

Q It was completed 7-88 but there has still been no production from it?

A Correct.

Q And what is the reason for that, that there hasn't been any production?

A As was mentioned earlier by previous witness, the well is of such a low deliverability that it's not able to produce against the line pressure in the field; therefore, we have to install a compressor in the field prior to getting any economic production off of this particular well.

Q How long does it take to get a compressor, do you know?

A Depend on whether you're buying it, purchasing, and the availability; could be a month to several months.

Q Can you rent one?

A Yes.

Q A month to several months but they still don't have one, is that correct?

A That's correct.

Q Okay, you indicated that your Exhibit Number Two, or excuse me, not Number Two, it's Number Eight, in which you calculated the reserves and economics, you used 150 MCF a day and you felt like that was reasonable because you looked at the other AOF's on the other wells in the surrounding area and felt like that their production would be commensurate with putting production of this well at 150 MCF a day, is that right?

A Correct.

Q Okay, although the Wendall Best No. 1 Well is now producing at approximately a third of it's AOF, you did not take one-third of the 164 MCF per day on the Cook No. 1 Well.

A One thing I need to clarify on that thing is the calculated absolute open flow potential is a little bit different than the other numbers that are on there. Calculated absolute open flow potential indicates what the well is capable of producing at into a vacuum or zero psi pressure, which is not obtainable in the oil industry. Okay.

Q Okay, so you're using apples and oranges to compare, is that right? Is that what you're telling me?

A The maximum open flow -- or maximum flow rate during a potential test for the Wendall Best well is 1699 MCF per day.

Q And where did you get that information from?

A From the 4-point pressure test taken on the (not clearly understood).

Q And that was given to the State?

A Yes.

Q Okay. Was that set forth on the well completion report and log that's furnished to the State?

A It should be, yes.

Q I'll hand you a copy of one and you can look at it and tell me. Do you have the well completion report there?

MR. DICKERSON: That is a part of Exhibit Number Four. Let's find that.

A Do you have a copy of the well completion report?

Q Yes, right.

A Third line from the bottom you'll see

the first item says flowing tubing pressure 1893 to 1400 pounds?

Q Is that in here?

A Fourth line. Right, you go over and it has gas MCF 2-8, 05 CAOF.

Q I think you're looking at the Best Well.

A Oh, are you looking at the Cook Well?

Q Yeah, yeah, I was looking at the Cook Well. Okay, now I see what you're talking about, go ahead.

A Okay, you have two different rates there. You have one underlined Date of Test 5-20-88, where gas ranged from 518 to 1699.

Q Okay.

A MCF per day, depending on the choke size used during the test, and then the next line is a 2.805 or 2805 calculated absolute open flow potential at zero pounds of back pressure on the well.

Q Where does it say zero pounds?

A That's by definition of calculated absolute open flow potential.

Q Okay, now let's look at the -- flip over a couple of pages and look at the Cook No. 1 and tell me what the difference is there.

A Okay. The Cook No. 1, they've written it in a little bit different but on the date of the test, 7-26-88, you have gas ranging from 118 to 157 MCF per day, based on back flow or, excuse, me, based on a choke size.

Down on the next line it still has 157 and below that it has absolute open flow 713 MCF per day, so that would be the number that would compare to the 2805 number.

Q Okay, so they're using two different standards on these tests, then.

A Yes.

Q And then you ended up using 164 MCF on the Cook rather than the 713?

MR. DICKERSON: I think --

A That's correct.

MR. DICKERSON: -- Mr. Richards is misstating. You used 150 MCF.

A That's correct.

Q Oh, it says -- oh, that's right, it says 164 on Exhibit Number Seven.

A That's the test and then I adjusted that down to 150 to use in the economics.

Q Right, so you did use 164 on the test in this Number Seven, but then on your economics on Number Eight you used 150 MCF.

A Right.

Q Okay.

A Indicating that I felt the well would flow a little bit low.

Q Okay, looking at Exhibit Number Eight, you've already indicated that you used 150 MCF a day to calculate it, whether or not that's correct, we'll go on to the next point, you indicated you used operating costs of $2,890 a month.

A Correct.

Q Correct, and $1500 of that a month was for a compressor.

A Correct.

Q None of these other wells in this area have compressors?

A That's correct.

Q So --

A Their operating cost is $1500 less than the $2890.

Q Let's start at the very top where it says 1289 on the second page and explain as you go across to me. You have 53.37.

A Okay, that is the production that would occur during the first year of 1989.

Q That's assuming that it went on production in January --

A Right.

Q -- 1st and this if February and it's still on production, right?

A Correct.

Q Okay, but going on across then, you have net production.

A That is the production that would be (unclear) to the working interest owners in the well after royalties have been paid.

Q Okay, so all that is deducted there is royalty. What did you base that royalty on?

A That's based on -- from Nicor's point, we have an 82 percent net lease in the well, so 18 percent of the revenue go to the royalty.

Q Okay. The -- you used $1.24 for the gas for the price, and then it says net operating revenues?

A That is the price times the net production.

Q 53.763 times $1.24 would give me 54.266.

A It should be the 43.763 times the $1.24.

Q Yeah, okay, and that would give me that, and then the severance, ad valorum taxes --

A No, the State of New Mexico severance taxes.

Q Okay, that's 30.780?

A Right.

Q And that's deducted from that amount?
A To get net cash flow to the operator, yes.
Q Okay, so you have net operating expenses of 34.680. What is that for? That's after deducting the 2,890 a month?
A That's after deducting the 3,000 -- oh, excuse me, that is the -- that is the 2890 times 12.
Q Okay. So the cash flow at the end of the first year over here on the right is 15.806.
A Correct.
Q Which would be $15,000 after expenses.
A And taxes.
Q And taxes.
A Severance taxes.
Q And royalties, right?
A Correct.
Q That would be what the working interest owner gets.
A Correct.
Q Okay, and you've taken everything that you feel like should be taken into consideration in preparing this.
A Correct.
Q As you prepared it did you have the 150

MCF a day declining over the 7-year time period?

A Yes, it is.

Q At what ratio is it declining?

A It's 5 percent per year.

Q How much?

A 5 percent per year.

Q Where did you come up with 5 percent per year figure?

A It's based on analogies with the other (unclear) and how they're performing in the field.

Q Is there electricity out there?

A I don't believe so.

Q Then the compressor would be run off of the natural gas that's produced through this well?

A Right.

Q How much natural gas would most compressors take of the size that you'd want for this well?

A I don't know.

Q All right, did you take into consideration that some of the gas would be used for that?

A No, I did not.

Q How much did it cost to drill the well? Since you're with Nicor you're a working interest owner and I presume you received an AFE. Do you know about what the total cost to drill was?

A I think it was $300,000, but we're not running the economics to pay out the drilling costs. We're running them to pay out our cost from today forward. Drilling costs are already sunk costs.

Q Is it Nicor's policy to not attempt to recoup the $300,000 that it initially invested?

A Well, if we were looking at the project from they have not drilled the well, we wouldn't drill it, that's correct, but since the well is already drilled and the investment was already made, it's not prudent to figure those costs into the future economics for the economic viability of the well.

Q It's not Nicor's position that they'd like to recoup the amount that they invested in the well within a certain time period in order to place it on your books as a viable well?

A Obviously whenever you drill a well you want to recoup the expenditures that you have in the well. Obviously, based on production from this well, we won't re-coup the drilling expenditures in the well, but we can minimize our losses by trying to recover whatever gas we can provided it will pay for the operating expenses for the well.

Q At this time the well is currently shut in, correct?

A That's correct.

Q Are you getting any revenue while it's shut in?

A Not that I'm aware.

Q Have you paid any lease operating expenses or any expenses since the --

A We have not paid any lease operating expenses on the (unclear).

Q Have you been billed any?

A No.

Q Has any been work been done on the well since July of 1988?

A Mechanically, no.

Q So the well's just sitting there not producing and not being operated at this time, is that correct?

A Waiting for the outcome of this hearing.

Q Why are they not producing it pending the outcome of this hearing?

A I think it was all the working interest owners' opinion to wait and see what the end result of the mechanics of the wellbore would be before going out and putting a compressor in.

Q That's -- that's been the agreement between the working interest owners including the operator and non-operators?

A Well, that's been our understanding with Marshall Pipe & Supply, who's the operator.

Q Okay. Your calculations take into account a lot of contingency, doesn't it, on Exhibit Number Eight?

A What kind of contingencies?

Q Well, that the decline is only 5 percent; that the well would actually come on line at 150 MCF; those are contingencies. It hasn't been on line yet, has it?

A That's true.

Q Also you don't know how much gas is going to be used for the compressor, correct?

A Correct.

Q You don't know what size of compressor you're going to use right now, is that correct?

A I don't. Marshall probably does.

Q Also you're not sure of the price of that compressor or whether it would be $1500 a month or you all may have to end up paying $100,000 for the compressor up front, is that correct?

A That's highly unlikely.

Q What do you -- what are the prices of compressors?

A Well, based on the amount of gas that we'd be putting down, the through the field, through the compressor and the size of compressor that we need, Marshall Pipe & Supply has estimated based on other compressors that they have looked at and made agreements with, they estimate a $1500 a month range to be prudent for the cost of the compressor.

Q If this well had been drilled at another location, that it could not be used also as an injection well, would it have been your suggestion as a production reservoir engineer or production engineer, reservoir engineer, to plug the well?

A No, not if the well was capable of sustained production to pay the operating costs, it wouldn't have been my suggestion.

Q No matter how long it would be on line, is that correct?

A I'd have to look at it as paying out whatever cost to put the well on line and if we received the rate of return on our money that means our criterion (unclear).

Q Now you indicated that the Montoya came in at 50 MCF a day with a lot of water, is that correct?

A Correct.

Q If you had gone in to recomplete it into a zone where you were not receiving -- squeezed back and recompleted and only got gas production with very little water, would it be suggested that you produce out of the Montoya while receiving 50 MCF a day?

A I think these economic results show that the economic limit in this area is 100 MCF a day, depending on gas price, so therefore the 50 MCF a day would be below the economic limit and therefore we wouldn't have produced it.

Q So if this well comes on line at less than 100 MCF a day, then you would suggest not producing it.

A That's correct, if the gas price remains at $1.24 an MCF. If we are able to negotiate a higher price, which the latest price I received is $1.46 an MCF, so that drops the economic limit down.

Q However, we won't know what the well can -- will come in at right now and that can be one reason that you have to start producing a well, is you all didn't want to know how much it would come in at each day until after this hearing, is --

MR. DICKERSON: I'm going to object to the question. It's argumentative, Mr. Stogner, and we seem to be getting far afield from the issue before us here today.

MR. RICHARDS: I don't think we're far afield from the issue. The issue is this lease is not held by production unless this is a viable well and they cannot use it for an injection well without going straight to the royalty interest and mineral owners who have been sitting over here and making arrangements with them.

It's our position that this is not a viable well and at this hearing to determine whether this can be an injection well or not evolves around them negotiating with the mineral owners and the surface owners to use it as an injection well.

We don't believe this lease is (not clearly understood).

MR. DICKERSON: Mr. Stogner, I would argue that as a matter of law the definition of commercial quantities for our present purposes is determined by the answer to the question of whether or not the well will produce enough gas to return the operating cost plus a reasonable profit. Exhibit Number Eight, testified to by Mr. Wilcox, and based on his assumptions because the well is not on production, but it's the best available at this time, returns of a net 70-some-thousand dollars over the economic life of this well over and above what would otherwise be recovered. He also testified that if that gas is not produced at this time that it will be -- the ultimate result will be the failure to recover those reserves, which under his calculations can be economically recovered under the procedure presented here.

MR. RICHARDS: As a matter of law, also, you'll find that this is all speculation and not worth the paper it's written on because the well's been sitting out there six months and nobody's even tried to produce it. They haven't tried to hook it up or do anything else. It can only be determined under the lease whether the well is capable of production by actually producing it or not producing it. At this point it hasn't produced and when it doesn't produce then I would suggest that it is a non-viable well and it's not capable of production. So I believe my question is relevant to the issue at hand.

MR. STOGNER: Mr. Dickerson, I'm going to overrule your objection and let the witness answer that question if he can; he may or may not.

A Could you restate the question?

Q Okay, I believe I was asking about if this well came in at less than 100 MCF a day, if pursuant to your calculations it would be a non-viable well and that would indicate that it should be plugged.

A That's correct.

Q And then I further asked that -- why it had not been placed on production and I asked of you if the reason it had not been placed on production for the last six months was that you could come to this hearing and use speculative figures such as 150 MCF a day rather than using the actual figures that it would be producing.

A No, I don't believe that's correct. I think you have to weigh into account that there's additional expenditures that are involved in putting the thing on production and --

Q What are those expenditures? You told me a compressor.

A A compressor.

Q And you told me it would take a month, maybe two months, to get a compressor.

Okay, what other considerations?

A The other considerations are what do we do with the water that's produced out of the wells out there. This well could obviously produce water.

Q Right, we're just talking about this well.

A Okay, this well, all of the wells in the area producing from the Penn do produce water. That would add incremental or additional operating cost to the well, and if we have a disposal facility in place already, it would enhance the value of this well since it is such a marginal well up front.

Q Did you take into consideration in preparing your Exhibit Number Eight the cost of trucking water off the location -- off of this Cook Well?

A No, we did not.

Q And you've indicated in Exhibit Number Nine that it's costing in the Tule Field approximately $5,100 a month to haul the water, correct?

A Correct as of January 1.

Q And the Tule Field is composed of four wells besides the Cook Well, is that correct?

A Yes, that's correct.

Q And that's about an additional $12 or $1300 a month that is not being calculated into your preparation of Exhibit Number Eight?

A Excuse me?

Q I'm just taking -- there's four wells and I took your figure $5100 a month on Exhibit Nine and I divided that by four, so per well it's costing about, I just took a round guess, around $1200 a month per well to truck off the water, is that correct?

A Correct, but that is from January 1 on because the incremental water --

Q Okay.

A -- production has just occurred in the last month.

Q Okay, but that has not been taken into account in that Cook Well; $11-or-1200 is not included in that Exhibit Number Eight.

A Correct.

MR. RICHARDS: I have no further questions at this time.

MR. STOGNER: Let's take about a 10 minute break.

(Thereupon a recess was taken.)

MR. STOGNER: Mr. Dickerson, any redirect?

MR. DICKERSON: Very brief, I promise.

REDIRECT EXAMINATION

BY MR. DICKERSON:

Q Mr. Wilcox, in your Exhibit Number Eight Mr. Richards pointed out that you did not separately show any cost of trucking water as one alternative away from this well. Was there a reason for that?

A Yes, a well completion report that was filed for the Penn zone in the Cook No. 1 Well doesn't indicate at this time to be any water production from the Cook.

Q And from the engineering data that you have reviewed, have you got any reason to believe that there will be any significant water production from the Cook No. 1 Well?

A There is a potential for there to be water production at some time down the road, as is evidenced by the Perry No. 1.

Q And if that turns into a fact when the well is actually on line, then that can be calculated at that time as far as if any additional cost is attributable to the operation of that well, but standing on its own?

A Yes, and depending on what the cost is for holding that water, it would be attributed to the well.

Q But your reserve calculations on your Exhibit Number Eight were limited to the recoverable reserves, which in your opinion can be recovered from the Cook No. I Well. You were not taking into account the reserves that were under some of the other wells in the pool which we have talked about today.

A Correct.

Q And is it still your opinion that the assumptions that you necessarily had to make in order to make these projections are reasonable in light of the current circumstances and that the well appears to be capable of returning operating costs plus a profit of $77,000?

A Yes.

MR. DICKERSON: I have no further questions.

MR. STOGNER: Thank you, Mr. Dickerson.

RECROSS EXAMINATION

BY MR. RICHARDS:

Q How can you say that when we just said that the gas -- gas would be needed to operate the compressor? You said you didn't take that into account. Now, how can you come back and say that, once again say that it will produce 73,000 when you've shown you haven't taken that into account?

A Do you want me to answer it? Depending on how Marshall Pipe & Supply intends to install a compressor in the field, the most likely way to install it will be to install one compressor that will be run -- be running all of the wells in the field at the same time and a rental charge appropriated out to all the wells at the same time.

Therefore gas will be used from all of the wells to run the compressor, so without dealing a lot more with detailed study, I don't know exactly what amount of gas would be attributed to the Cook No. 1 Well by itself to run that compressor.

Q And a separate gathering system would have to be run from all the other wells to the point that the compressor is placed before it goes into the purchaser's line --

A Well, it's already in effect up there right now and they're still being trunk lines going from -- I mean gathering lines going from all the wells and then connected into one sales line, in Cities gas line, so at that point would be where the compressor would be installed.

Q And the compressor would be -- there would be separate meters set on each well, correct?

A Correct.

Q So you'd be able to tell how much was pulled out of each well?

A Correct.

Q Would that necessarily delete the amount of gas that you estimated would be coming out of the Cook No. 1 Well with the compressor hooked up to four other wells, also? It would be -- let me restate my question a little bit.

You've indicated the Cook No. 1 Well

does not have enough pressure to buck the line pressure and -- but the other wells do. So if you put a compressor on, it seems like to me you'd just be pulling more gas out of the ones that are able to buck the line pressure already, rather than assisting one, a weak well, is that correct?

A No, it will assist all the wells.

Q In the same proportion?

A Probably not. I mean you have a well that's capable of producing against a certain pressure, you could lower that to a lower pressure and it's able to produce X more MCF per day. That's going to vary from well to well, depending on what the deliverability of each well is.

MR. RICHARDS: I have no further questions.

MR. DICKERSON: Nothing further.

MR. STOGNER: Pardon me, Mr. Dickerson?

MR. DICKERSON: Nothing further.

CROSS EXAMINATION

BY MR. STOGNER:

Q Mr. Wilcox, let's take a look at the completion report on the Cook Well No. 1. Was this test that was performed done through the 2-7/8ths inch tubing and which has been the subject of this hearing today?

A Yes.

Q Okay. Now let's take a look at the completion method which you're proposing for the Pennsylvanian production coming up the annulus or the back side of the tubing through the casing.

Do you foresee any problems of reservoir energy and efficiency of this type of production after you put the compressor on line?

A I don't know if I quite follow what you're asking.

Q Well, let me try to rephrase that. There's going to be a -- producing up tubing and producing up an annulus, there is going to be somewhat of a pressure difference, or flowing --

A Flowing tubing pressure.

Q -- flowing gas and flowing pressure and friction pressure.

A Right.

Q And do you foresee, after you've put the compressor on, any chance of possibly prematurely abandoning the Pennsylvanian zone because of this type of completion?

A Completion?

Q Or do you --

A The only thing I could say would be based on producing the well up the annulus versus the tubing, which I think is what you're addressing. The only way that that would be detrimental to you is that you would have a larger area to produce the gas up.

If you had significant fluids being produced from the Penn zone, you wouldn't have critical velocity needed there to raise fluid up the annulus.

Right now the well doesn't show any indication of producing water. If it did, we could potentially have a problem there of being able to flow the well up the annulus.

Q Do you see from past experience in other Pennsylvanian wells out here any gas influx later on?

A Gas?

Q I'm sorry, water influx later on?

A One Penn well is making significant quantities of gas but it's capable of flowing at a lot higher rates than this.

The other Penn wells are making in the one to two barrel a day range, or less, which is pretty insignificant.

Q If at some point that water influx into the wellbore would lead to premature shutdown of this particular well, would the completion technique be changed at that point? A small string of tubing or something like that?

A It probably would, depending on, you know, what the well was capable of producing at the time --

Q Okay.

A -- that problem occurred.

Q Well, let's look at a worst case scenario of something happening, and we have the tubing burst and flood the casing with disposed water. What -- what would have to be done with this well to alleviate that problem?

A To alleviate the problem?

Q If the casing flooded with --

A I would say it would be a position the same as if you had to kill the well for whatever reason to rework whatever zone. You'd have your Penn zone essentially killed by salt water. You'd have to go in and repair your tubing, run back in and set your packer, opening your sliding sleeve with the plug down below you, and swab off the water and try to kick the well off.

Q So in these instances there is a way to shut the water disposal down and work on your well and swab it --

A And kick it off.

Q -- and produce up the tubing.

A Right, until you get it kicked off.

Q And even to take this one step further, there is a way to shut the disposal down if the production in the annulus comes to the point where it cannot lift any fluid whether migrated or otherwise, and produce up the tubing and shut the disposal operations down?

A Yes, you --

Q Is that a possibility?

A -- could do that.

Q Okay.

MR. STOGNER: I've got a question for Ms. Bentz.

MS. BENTZ: Surely.

MR. STOGNER: Do you want to come up forward a little bit?

LESLIE BENTZ,

being recalled as a witness and remaining under oath, testified as follows, to-wit:

CROSS EXAMINATION

BY MR. STOGNER:

Q Do you see that the Pennsylvanian formation in this well or in this area is water sensitive?

A That has not been a problem that I have been aware of.

Q Okay, so if the worst case scenario comes along in which the tubing bursts and we've got a casing full of disposal water, or disposed water, flowing into the Pennsylvanian formation, you do not see where this has been a problem in the past?

A No.

MR. STOGNER: That's all the questions I have for Ms. Bentz.

And I have no other questions for Mr. Wilcox at this time.

Are there any questions of either one of these witnesses since I've brought them back up on the stand?

MR. DICKERSON: No, sir.

MR. STOGNER: Okay, both of them may be dismissed at this time.

Mr. Dickerson?

MR. DICKERSON: The applicant will rest, Mr. Stogner.

MR. STOGNER: Mr. Richards?

MR. RICHARDS: We rest, also. I will not put my witness on.

MR. STOGNER: Okay, I believe

we are ready for closing statements.

Mr. Richards, I'll let you go first and Mr. Dickerson, you may follow.

MR. RICHARDS: I've basically already stated our point, is that the primary term of this lease has expired. The royalty interest owners have not received any money from the well. The well hasn't been placed on production. The operator is claiming that the well is a producing well to hold the lease by production, but at the same time he wants to inject salt water. My clients do not mind. They do not necessarily object to the salt water as long as they'll admit that the lease is no longer valid and they compensate them as mineral owners and surface owners for the injection of salt water into their wellbore.

I believe it's the petitioner's position that the well is capable of production and therefore they can produce the well (unclear) and they can inject salt water into this well to help benefit them for wells that are off the location.

There's a dry well that's close to two or three of the other wells that have been drilled. If they want a salt water injection well they can use that well. That wellbore is held under a producing lease. This one is not held under a producing lease and we do not feel that it is at this time, and we argue that it is not held by a producing lease and we argue that since we are the mineral owners there should be no injection into the well without just compensation going to the mineral interest owners.

Our proof that the well is not capable of production follows through with the tests that have been conducted on it that when the Exhibit Number Eight was prepared it didn't take into consideration all the factors. We believe that it is not capable of production.

As far as injection of salt water, they've indicated that the Montoya zone did indicate it had 50 MCF a day. In order for a well to be an injection well, it has to be not capable of production, so you have to determine what capable of production is in that case. If it's -- if they end up only producing 50 MCF a day out of the Pennsylvanian or 100 MCF a day, which Mr. Wilcox indicated was economic limits, then the well would not be a producer. By the same token they could produce 50 MCF out of the Montoya, so they can't have their cake and eat it, too. It's got to be one way or the other; either they're both producing intervals or neither one of them is a producing interval. So we see -- we believe that there's going to be problems with doing bottom hole pressure tests.

We feel like there's going to be problems with leakage from the salt water into the producing formation. We feel like that if there needs to be any work done at all as a result of the salt water injection, if the well is determined to be a producer, then the royalty interest owners are going to be out money while the well is shut down because their well is not going to be producing while it's shut down, of course, to do work for salt water injection.

As royalty interest owners they're interested in achieving production out of the well and that means continuous production in paying quantities and so they want to be receiving their royalty checks all the time. It's not benefiting them, or they do not feel like it's benefiting them in this case for this well to be an injection well. It may be benefiting the operator or other people as they have indicated today, but it's in no way benefiting the mineral owner or the royalty owner.

So we ask that this Commission not approve the dual completion of this well and not approve this well as an injection well unless there's a stipulation that compensation be made to the mineral interest owners.

MR. STOGNER: Thank you, Mr. Richards.

Mr. Dickerson?

MR. DICKERSON: Mr. Stogner, very briefly, I would like to remind you of one thing and that is that the arguments of we lawyers is not evidence. The evidence that is presented to you today and will be contained in the evidence, or the transcript of this hearing, will consist of the testimony of the witnesses.

Admittedly, the calculations are based on assumptions. That, as a practical matter, is something that has to be because the well undisputedly is not yet on production. The District Court of Chaves County would be the proper forum, we would submit, not this Oil Conservation Commission, to decide the merits of a legal dispute over the position asserted here by Mr. Best and Mrs. Parker, to-wit: that the well is not capable of producing gas in paying quantities. That term has a very well founded legal meaning and that meaning is merely that it will return the cost of operations plus a profit, however small. It is not necessary nor is it relevant to that consideration, if this issue gets before the District Court of Chaves County, or Roosevelt County, where this well is located, to figure the drilling and completion costs of the well. The evidence is undisputed that in the opinion of the Applicant's experts, the proposed method of completing this well dually so as to dispose of water into the Montoya formation through the tubing and produce the recoverable admittedly marginal reserves in the ground in the Pennsylvanian formation will have the result of confining that disposed water into the Montoya formation, will not result in any damage or loss of otherwise recoverable reserves in the Penn formation. The testimony along those lines has been limited to the anticipated productivity of the Best Well alone, not tied to some combination of production or reserves under other wells in the field, and we submit that it is not necessary for your Division in making its ruling on this case to decide the question based on the lack of evidence from the parties appearing in opposition as to whether the well is or is not capable of producing in paying quantities. The operator believes it is. We submit that the law is that he is entitled to recover such gas as he can and pay his operating costs in doing so, plus a reasonable profit, and the proper forum to settle that dispute, if it becomes a dispute when the well is actually on line, is the District Court of the appropriate county in southeastern New Mexico.

And we respectfully would request that you take the case under advisement and give due consideration to approval of our application.

MR. STOGNER: Thank you, Mr. Dickerson.

Is there anything further in

Case Number 9574 at this time?

MR. RICHARDS: Do I have a rebuttal to that?

MR. STOGNER: Well, since we're somewhat informal, I'll let you, Mr. Richards.

MR. RICHARDS: My position is that it's important for the Commission to decide this issue and not just Chaves County, because if the lease is no good, surely the State is not going to make a determination that although this wellbore is not owned by Marshall Supply, who's the applicant here, the State is surely not going to say just go right ahead and inject all that water in there that you want without making arrangements with Mr. Best and Ms. Parker.

Surely you're not going to take their property rights away from them by doing that.

So I think it's important and it's crucial to determination in this case for there to be a determination for -- determination along those lines as to whether the well is capable of producing or not. And I'm indicating that maybe Marshall is not the proper applicant to be bringing this case before you.

MR. STOGNER: Thank you, Mr. Richards.

Mr. Dickerson, I'll give you

a chance --

MR. DICKERSON: No, sir, nothing further. I'm going to retire.

MR. STOGNER: Anything further in Case Number 9574?

This case will be taken under advisement.

(Hearing concluded.)

C E R T I F I C A T E

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

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9574 heard by me on 15 February 1989.

Michael E. Stogner, Examiner
Oil Conservation Division