

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

18 February 1987

EXAMINER HEARING

IN THE MATTER OF:

Application of Conoco, Inc., for hard- CASE  
hardship gas well classification, 9079, 9080,  
Eddy County, New Mexico. 9081

BEFORE: David R. Catanach, Examiner

TRANSCRIPT OF HEARING

A P P E A R A N C E S

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## BECKY BARNES

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MR. CATANACH: Call next Case  
Number 9079.

4

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6

MR. TAYLOR: The application of  
Conoco, Incorporated, for hardship gas well classification,  
Eddy County, New Mexico.

7

8

MR. CATANACH: Are there ap-  
pearances in this case?

9

10

11

MR. KELLAHIN: If the Examiner  
please, I'm Tom Kellahin of Santa Fe, New Mexico, appearing  
on behalf of the applicant.

12

13

14

We'd request, Mr. Examiner,  
that you consolidate for hearing purposes Cases 9079, 9080,  
and 9081.

15

16

MR. CATANACH: Okay, at this  
time we'll call Cases 9080 and 9081.

17

18

19

MR. TAYLOR: Case 9080 is the  
application of Conoco, Incorporated, for a hardship gas well  
classification, Eddy County, New Mexico.

20

21

22

Case 9081, the application of  
Conoco, Incorporated, for hardship gas well classification,  
also in Eddy County, New Mexico.

23

24

MR. CATANACH: Are there any  
other appearances in these cases?

25

MR. KELLAHIN: Mr. Examiner, I

1 have one witness to be sworn.

2 MR. CATANACH: Will the witness  
3 please stand and be sworn?

4

5 (Witness sworn.)

6

7 MR. KELLAHIN: Mr. Examiner, I  
8 hand you our set of proposed exhibits for each of the three  
9 cases.

10 We would like to organize our  
11 presentation so that we discuss the Federal 34-2 Well first;  
12 then the Federal 34-1 Well second; and then lastly, the  
13 Levers Federal 1.

14 MR. CATANACH: Okay.

15

16 REBECCA BARNES,  
17 being called as a witness and being duly sworn upon her  
18 oath, testified as follows, to-wit:

19

20 DIRECT EXAMINATION

21 BY MR. KELLAHIN:

22 Q Ms. Barnes, for the record would you  
23 please state your name and occupation?

24 A Rebecca Barnes. I'm a petroleum engineer  
25 with Conoco.

1 Q Have you testified before as a petroleum  
2 engineer before the Oil Conservation Division?

3 A No, I have not.

4 Q Would you describe for the Examiner when  
5 and where you obtained your degree?

6 A I have a Bachelor of Science in petroleum  
7 engineering from New Mexico Institute of Mining and Techno-  
8 logy in Socorro, New Mexico.

9 Q In what year did you obtain that degree?

10 A May, 1986.

11 Q Subsequent to graduation have you been  
12 employed as a petroleum engineer?

13 A Yes, I have, with Conoco.

14 Q Would you describe for us what your gen-  
15 eral duties are for Conoco?

16 A Currently, right now, I'm working in our  
17 Acquisitions Group and also handling what we consider our  
18 Dagger Draw Area. We have a regular engineer in that area  
19 and I've been helping him out.

20 Q Where is the reservoir that's the subject  
21 matter of the three hardship well applications before the  
22 Examiner today?

23 A Where is --

24 Q Where is it located?

25 A It's located about fifteen miles north of

1 Carlsbad, New Mexico.

2 Q And this is in Eddy County?

3 A Yes, it is.

4 Q Has the reservoir been assigned a pool  
5 name?

6 A The reservoir is the Upper Pennsylvanian,  
7 or Upper Springs Gas Pool.

8 Q The docket describes it as the Spring-Up-  
9 per Pennsylvanian Gas Pool in Eddy County, New Mexico?

10 A Yes, that's correct.

11 Q Pursuant to the application that Conoco  
12 has filed in each of those cases, have you made yourself  
13 aware of the requirements of the Division with regards to  
14 the filing of an application for a hardship gas well case?

15 A Yes, I have.

16 Q And did you prepare the exhibits and the  
17 proposed testimony for the presentation of each of those  
18 cases?

19 A Yes, I did.

20 MR. KELLAHIN: Mr. Examiner, we  
21 tender Ms. Barnes as an expert petroleum engineer.

22 MR. CATANACH: Ms. Barnes is  
23 considered qualified.

24 Q Ms. Barnes, let me direct your attention  
25 to the package of exhibits for Case 9081 for the Federal 34

1 No. 2 Well, and ask you to turn to Exhibit Number Two of  
2 that package on which we have the well located.

3 First of all, will you take a moment and  
4 identify for the Examiner what well is indicated by the red  
5 arrow on that exhibit?

6 A Okay. The red arrow indicates the Fed-  
7 eral 34 No. 2 Well.

8 The area outlined in red ink is the pro-  
9 ration unit for that well. The area outlined in the blue is  
10 the limits of the Federal 34 lease.

11 Q So the Examiner will know the location of  
12 the other two wells in relation to this well, would you also  
13 use this exhibit and find for us the location of the Levers  
14 Federal No. 1 Well?

15 A The Levers Federal No. 1 Well is located  
16 in Section 2, which is just south of Section 34. It's lo-  
17 cated in Unit E.

18 Q And where will we find the location of  
19 the Federal 34 No. 1 Well?

20 A It's located in the -- in Section 34,  
21 south of the No. 2 Well. It's in Unit N.

22 Q Would you describe generally what caused  
23 you to conclude that these wells were eligible for a hard-  
24 ship gas priority classification?

25 A In 1986 we were shut-in for approximately

1 five months out there. In the past it cost Conoco large  
2 sums of money to bring these wells back on, but due to the  
3 extensive shut-in this year, it was a lot more expensive.

4 The Federal 34 No. 2 Well, we spent  
5 \$70,000 on, restored production temporarily and lost the  
6 well again due to the large amounts of water which accumu-  
7 lated.

8 Due to the extent of the circumstances  
9 and the pay out of the jobs to unload these wells is in ex-  
10 cess of what we anticipated to be (unclear) might occur  
11 again. We would like to investigate the possibility of  
12 classifying these wells as hardship so we could continue to  
13 operate out there.

14 Q Were all three wells shut-in in 1986?

15 A Yes, they were shut-in the first of June  
16 and we were -- we began to bring them back the first of Nov-  
17 ember, 1986.

18 Q When the wells were shut-in in June of  
19 '86, would you give us the approximate producing rates in  
20 terms of water production and gas production on a daily  
21 basis?

22 A Okay. The Levers Federal No. 1 averaged  
23 about 600 MCF per day and around 2400 to 2500 barrels of  
24 water per day.

25 The Federal 34 No. 1 makes about -- made

1 about 400 to 450 MCF per day and approximately 1200 barrels  
2 of water per day.

3 The Federal 34 No. 2 averaged approxi-  
4 mately 450 to 500 MCF per day and ranged from approximately  
5 2000 to 2200 barrels of water per day.

6 Q Based upon your studies, Ms. Barnes, do  
7 you have a recommendation to the Examiner as to what the  
8 minimum producing rate is for each of the wells for which  
9 you would recommend the Examiner make approval of the wells?

10 A Yes, I do.

11 Q And what are those rates?

12 A For the Levers Federal No. 1 we seek a  
13 minimum sustainable rate of 350 MCF per day.

14 For Federal 34 No. 2 we seek 350, also.

15 And for the Federal 34 No. 1 we seek 300  
16 MCF per day.

17 Q All right, using the package of exhibits  
18 for the Federal 34 No. 2 Well, would you turn now to Exhibit  
19 Number Three of that package and identify that exhibit?

20 A Okay. Exhibit Number Three is certified  
21 mail receipts of notification of the offset operators out  
22 there.

23 I will bring your attention to the certi-  
24 fied receipt for NAPCO. The receipt was stamped for date of  
25 delivery but there was no signature. We sent a copy to two

1 different addresses for them.

2 Q All right, let's turn to the wellbore  
3 schematic for the subject well and have you describe that  
4 exhibit.

5 A Okay. This is the wellbore schematic for  
6 the Federal 34 No. 2. It exhibits the casing, casing sizes  
7 and completion and also the tubing size which is in the  
8 hole.

9 The well was originally drilled to a  
10 depth of 10,388 feet and the Cisco formation was tested and  
11 perforated from 8,013 to 8,036 feet.

12 Currently we have 3-1/2 inch tubing in  
13 the hole, set with a packer at 7950.

14 Q The requirements of the hardship applica-  
15 tion require you to make an investigation to determine  
16 whether or not there is anything mechanical that you could  
17 do to the well to alleviate the volume of water produced and  
18 flowing into the wellbore.

19 Have you made such an investigation?

20 A Well, the water which is made is made  
21 from the producing interval, so we could not cut off or eli-  
22 minate the water production without eliminating your gas and  
23 oil production; however, originally this well was run with  
24 2-7/8ths inch tubing and we -- and to eliminate the effects  
25 of the large water, we ran 3-1/2 inch tubing to reduce the

1 friction factors and allow us to be able to flow a larger  
2 quantity of water.

3 Q Is that true of each of the three wells?

4 A Yes, it is. They all originally were run  
5 with 2-7/8ths inch tubing and have since the original com-  
6 pletion that has been replaced with 3-1/2 inch tubing.

7 Q And in your opinion, for each of those  
8 three wells, the 3-1/2 inch -- 3-1/2 inch tubing size is the  
9 optimum size to minimize the water problem and the friction  
10 involved in lifting this volume of water?

11 A Yes, it is. If you go with even a larger  
12 size tubing, you encounter the effects of increasing the  
13 diameter of the -- the column of fluid makes it heavier and  
14 then the well will not be able to flow. So there's an opti-  
15 mum region of friction factors and when your tubing size  
16 gets too large and the column is too heavy, so you need to  
17 find that optimum crossover where that occurs.

18 Q With regards to the perforations in each  
19 of the wells, do you have an opinion as to whether the per-  
20 forations could be relocated in the wellbore at a point that  
21 would minimize the water flow?

22 A I have not investigated where the perfor-  
23 ations are. All of the wells which have been perforated in  
24 the Cisco formation have all -- they've all produced large  
25 quantities of water.

1 Q All right, so it doesn't appear to be  
2 possible to simply isolate the water by perforating higher  
3 into the reservoir.

4 A No.

5 Q Is there anything else that you could  
6 think of that you might do to minimize or eliminate the  
7 volume of produced water?

8 A No, not out in this formation to elimi-  
9 nate the volume. The only way you could do that would be to  
10 try to isolate where the water was coming from, but the  
11 water is coming from the same zone as the oil and gas.

12 Q Let's turn to Exhibit Number Five and  
13 have you explain what this exhibit shows.

14 A Exhibit Number Five is a decline curve  
15 production history of the Federal 34 No. 2. This decline  
16 curve was generated on a computer which we have at Conoco.

17 The shut-in periods have been indicated  
18 on the decline curve. The majority of shut-ins you will ex-  
19 hibit a zero production. Some of the shut-ins were only for  
20 a short period of time or a partial month, so you can see a  
21 drop in production but not a zero production.

22 The -- well, I don't have colors on here  
23 -- I believe it's the red solid line is oil. The red/green  
24 line is oil. The red dashed line is gas, and the blue  
25 hatched line is the water production for the well.

1           Q           Using Exhibit Number Five, would you show  
2 the Examiner the shut-in periods and identify for us, if you  
3 can, what impact those shut-ins have had on the subsequent  
4 ability of this well to restore itself to the original rates  
5 prior to the shut-in periods.

6           A           Okay. Going back to 1984 a shut-in  
7 period was exhibited from about April through September of  
8 that year. Looking at the production after there, you can  
9 see that the first month the well is on the production has  
10 dropped and that is due to it usually takes a couple of  
11 weeks for the well to get back up to its original rate prior  
12 to shut-in; however, as you can see, the rate never quite  
13 recovers to the -- to the amount it was making before. This  
14 could be attributed to the shut-in or it could be attributed  
15 to just the normal decline of the well.

16                       Going to 1985, we were shut-in twice out  
17 there. We were shut-in for approximately a month in the  
18 middle of the year and came on and the first month after  
19 that our production was lower due to giving the well time to  
20 recover.

21                       The production came up and then we were  
22 shut-in again for approximately two to three weeks, just at  
23 about the time that the well was trying to recover.

24                       That second shut-in in 1985 is shown by  
25 the dip in production. It's in about the month of Septem-

1 ber. As you can see, the well was slower to recover; each  
2 month it made a little bit more, and reached a rate that was  
3 somewhat similar to what it was making before it was shut-  
4 in, which still might be considered to normal decline.

5 In the shut-in in 1986 we were shut-in  
6 for an extended time, five months. We were notified by the  
7 gas company at the end of October that we could come on with  
8 these wells.

9 We did not get on location to the Federal  
10 34 No. 2 till toward the end of the first week in November.  
11 We were on location for approximately three to four days  
12 jetting nitrogen continuously and got the well to flow on  
13 its own. The well flowed for approximately 13 days and then  
14 loaded up and died again and we have not done any more at-  
15 tempts to restore production in this well.

16 Q Would you describe the method Conoco has  
17 selected to attempt to restore production in each of the  
18 wells?

19 A Okay. In order to restore production you  
20 must lift the accumulated water which has encroached to-  
21 wards the wellbore. We use coiled copper tubing and nit-  
22 rogen gas. Coiled tubing is run down the hole and nitrogen  
23 is injected at a rate of 350 to 450 cubic feet per minute.  
24 You will continue to inject nitrogen until you've unloaded  
25 enough of the water that the gas will be able to enter the

1 wellbore and begin to flow.

2 Q What is the approximate cost per well to  
3 attempt to lift the water production with the -- a nitrogen  
4 lift?

5 A It varies on each well. On this Federal  
6 34 No. 2, in November when we restored production we spent  
7 \$68,000.

8 Q Looking at the information from this well,  
9 do you have an opinion as to whether the decreased produc-  
10 tion is a permanent effect in this well?

11 A It's hard to determine in this well be-  
12 cause the well was not on long enough to see if it was --  
13 would stabilize.

14 In some of the other wells the recovery  
15 of the well has been so slow, particularly in the Levers  
16 Federal No. 1, that it appears that it will never come back  
17 up to the rate it was, but this well was not on long enough  
18 to determine that or not.

19 Q What do you believe is the cause in the  
20 decreased productivity of the well?

21 A When the wells are shut-in water  
22 encroaches towards the wellbore and this in turn decreases  
23 your relative amount of gas permeability at the wellbore.  
24 When the wells are brought back on, you must reduce this  
25 water saturation to allow the gas to come into the wellbore

1 and flow.

2                   With a large -- the amount of time that  
3 the wells were shut-in, the large amount of water  
4 encroached, and with the nitrogen job we tried to decrease  
5 saturation around that wellbore as much as we could, but in  
6 actuality what we did was just reduce it in the immediate  
7 area; when the well began to flow it came on at a rate real  
8 close to its minimum sustainable flowing rate and therefore  
9 the well kind of slugged (sic) along and in turn water satu-  
10 ration continued to increase and again the well died after  
11 two or three days.

12                   Q           You've indicated for us the approximate  
13 cost for restoring production in the well. Can you now tell  
14 us the period of time it will take you to recover out of  
15 production the cost necessary to nitrogen lift the water?

16                   A           In this Federal 34 No. 2, basing the pay-  
17 out on the rate at which the well came back on, which is  
18 approximately 300 MCF, if the well would have continued to  
19 flow, the payout on that \$68,000 would have been in excess  
20 of one year.

21                   Q           Apart from the economic impact of having  
22 to spend additional monies to restore production after shut-  
23 in periods, what are the other concerns that Conoco has  
24 about the water encroachment on the wellbores?

25                   A           Well, Conoco would like to continue to

1 operate in this area. Our main concern right now is the  
2 possibility if we get shut-in that we might permanently lose  
3 the Levers Federal No. 1 and the Federal 34 No. 2 -- or No.  
4 1.

5 On the Federal 34 No. 2 we're in the po-  
6 sition where we can't justify any more work to bring back  
7 production unless we can be guaranteed a continual stream of  
8 revenue.

9 Conoco would not like to abandon this  
10 well but in our situation now and with the gas market, we  
11 can't justify spending more money since the payout is al-  
12 ready in excess of one year.

13 Q Under normal operating procedures with  
14 the additional benefit of having a hardship gas well classi-  
15 fication, can you project for us what the remaining life is  
16 of the well?

17 A Based on just the average decline of this  
18 well and declining from the rate which was before the shut-  
19 in, this well will reach the minimum sustainable flow in ap-  
20 proximately two and a half years, on the Federal 34 No. 2.

21 Q In addition to estimating the economic  
22 life of the well have you also calculated the remaining re-  
23 coverable gas reserves in the well in the event the hardship  
24 gas well classification is granted?

25 A Yes. Based on decline curve analysis

1 again, the estimated reserves for the Federal 34 No. 2 is  
2 approximately 350 or 360-million cubic feet of gas.

3 Q In the absence of a hardship gas well  
4 classification, to you have an opinion as to whether or not  
5 that is recoverable gas reserves that are going to be lost?

6 A In the Federal 34 No. 2, if hardship  
7 classification is not granted, Conoco will probably opt to  
8 abandon this well; so therefore the recoverable reserves  
9 will be lost.

10 Q For this well you have requested a mini-  
11 mum sustainable producing rate of 350 MCF a day?

12 A Yes, that's correct.

13 Q Would you explain to us upon what basis  
14 that you have reached that conclusion?

15 A Okay. We base this on a -- well, it's  
16 typical of the production history that we saw in 1986, and  
17 by using a Hagedorn-Brown pressure analysis for vertical gas  
18 flowing wells to anticipate necessary pressures and require-  
19 ments to flow this well.

20 Exhibit Number Six or I believe it's Ex-  
21 hibit Number Seven, is a curve which is data which was gen-  
22 erated from Hagedorn-Brown. Hagedorn-Brown is the most  
23 widely accepted calculations for vertical pressure losses in  
24 flowing wells. Hagedorn-Brown is usually used for wells  
25 which the primary production is a liquid and this -- in



1 your friction factor decreases and your gas will lighten up  
2 the fluid and allow it to flow at a lower pressure.

3 As you come down and you reach the point  
4 at which the turnaround is, this point indicates that at  
5 that point your friction factor is no longer effective. At  
6 that rate your gas rate is low that what you really have is  
7 a water well; you don't have enough gas to lighten that  
8 fluid, the column of fluid, to lift it, so therefore, in  
9 turn you start needing more energy again to lift that water.

10 This turnaround point, or the bottom  
11 point, is your minimum flowing rate. That would be your ab-  
12 solute. That's where -- that's the least amount of energy  
13 is required to ever flow this well.

14 Q The exhibit shows 150 and it says GLR, is  
15 that the --

16 A That's gas liquid ratio, 150. That will  
17 correlate looking at a certain water production, say, of  
18 2000 barrels of water, that correlates a 300 MCF gas rate  
19 based on that GLR. Each water rate has a gas rate. These,  
20 you will see the bottom peak is at about 140 barrels of  
21 water per day, 100 -- and right around in there, which cor-  
22 relates, or it's -- it's actually 930. The hatched line  
23 there is 1000, and that correlates with approximately 140  
24 MCF, but what you need to do is, you need to come up and  
25 look at this curve a little bit away from the peak.

1 Q All right, let me make sure, at the bot-  
2 tom of the trough just --

3 A Yes.

4 Q -- just a little less than 1000 barrels  
5 of water a day.

6 A Yes, it's about 930.

7 Q All right, at 930 convert that to me into  
8 an MCF of gas a day.

9 A That's 140; that would correlate to 140.

10 Q All right. Now, you have indicated that  
11 is the calculated absolute minimum rate.

12 A Correct.

13 Q In terms of the calculation, I assume  
14 that you factor in some safety margin in order to have a  
15 rate at which you have eliminated the problem of having the  
16 well log off with water.

17 A Yes.

18 Q All right.

19 A As you move to the right you will notice  
20 as your curve, as the slope of the curve between your points  
21 is varying and it changes. If you look on Exhibit Seven-B I  
22 blew up that area which is in the square and you can see how  
23 -- how your slope and conduct of this curve is changing.  
24 What this means or what this is interpreted as is that the  
25 well is what Hagedorn-Brown calls bubble flow. Many people

1 call it critical flow. What it actually interprets is that  
2 the well is not really flowing, it's more or less burping.  
3 It bubbles along with gas coming up and burping water, and  
4 you want to eliminate any of that type of situation because  
5 in a bubble or burp flow the well may continue to flow with  
6 that rate for a couple of days but what's happening is gas  
7 is burping up and it's leaving some liquid behind and the  
8 well is not really at a continuous flow.

9 If you look at your curve up at your  
10 higher water rate and your higher gas rate, you'll see that  
11 the line is pretty much a straight relationship. This indi-  
12 cates that it's in a somewhat continual flow.

13 So alleviating any of this bubble flow  
14 region you come up and your bubble flow region ends at ap-  
15 proximately, oh, looking on the curve it's at about 1900  
16 barrels of water, which correlates to about 280 or 300 MCF  
17 of gas.

18 So in other words, to eliminate bubble  
19 flow or critical flow, we need to have a rate that exceeds  
20 300 MCF of gas; therefore to allow for a safety factor, Con-  
21 oco has asked for 350 to eliminate the possibility of get-  
22 ting too close to that minimum rate.

23 Q Are you confident, Ms. Barnes, that the  
24 method by which you have calculated and determined the mini-  
25 mum sustained flowing rate for this well is one that's fair

1 and reasonable?

2           A           We, once we did the computer analysis of  
3 this and generated the data, we compared it to the produc-  
4 tion which occurred on this -- this Federal 34 No. 2 Well in  
5 November.

6                       Exhibit, go back to Exhibit Six, is a re-  
7 cord or just a reproduction of some of the daily production  
8 reports that well exhibited during that period after the  
9 nitrogen job and before it loaded up.

10                      As you can see, the well originally came  
11 on at a rate of just a little over 300, which is real close  
12 to that critical bubble flow.

13                      The well dropped to 270, continued to  
14 flow at that rate for about thirteen days but in actuality  
15 what the well was doing was kind of burping along and plug-  
16 ging along and the well was just slowly loading itself up,  
17 and then eventually died thirteen days afterwards.

18                      Well, this correlates very well to the  
19 predictions of Hagedorn-Brown, which indicates that anything  
20 around below 300 you're going to be in that critical bubble  
21 flow and the possibility of loading up that well is very  
22 strong, and that correlates very well to what happened out  
23 there. So I feel secure that what we generated here is ac-  
24 curate data for the conditions in the reservoir that we have  
25 out there.

1                   Q                   Do you have an opinion as to whether or  
2 not an actual log off test ought to be conducted on any of  
3 these wells?

4                   A                   Well, the reason Conoco has not has been  
5 due to the fact that if we lose the well during the log off  
6 we're looking at having to spend anywhere from \$40-to-70,000  
7 to unload this well.

8                                   The other problem with a log off test is  
9 if you do not do an extensive log off test, if you did, say,  
10 a 24-hour log off test to see if the well would flow with  
11 that rate, if you had taken the Federal 34 No. 2 Well and  
12 cut it back to 270 MCF, that well probably would have flowed  
13 at that for a day but it was really not flowing. It's in  
14 that bubble flow.

15                                   A well may flow in a bubble or critical  
16 type flow for a week or two weeks, maybe only a day, so to  
17 do an accurate log off test it would have to be an extensive  
18 test to make sure that that rate is a permanent sustainable  
19 rate.

20                                   This well will probably, oh, you know,  
21 sustain a rate maybe of as low as 200 for a day, maybe, but  
22 it would not sustain that rate permanently, so therefore  
23 having to do a log off test, then you have to determine at  
24 what point is the well actually flowing or is it just bur-  
25 ping in that bubble type flow, and unless you do an exten-

1 sive log off test, you know, in a month, cutting back, let-  
2 ting the well flow at a certain rate for, say, two weeks, to  
3 make sure that well will continue to flow at that rate and  
4 not only temporarily.

5                   Therefore it would be very hard, I think,  
6 to get an accurate log off test on these wells due to the  
7 fact that they really are not flowing gas wells, you know,  
8 they're really more of a liquid well because of the large  
9 extent of water that they make.

10                   Q               In your opinion is the Hagedorn-Brown  
11 calculation or correlation a more accurate method by which  
12 to set a minimum producing rate for these three wells?

13                   A               It is in this case. All that the Hage-  
14 dorn-Brown correlation does, it calculates the pressure los-  
15 ses in your flow stream. Hagedorn-Brown is the most widely  
16 accepted correlation for which you would consider a liquid  
17 well; Gray is the most accepted for a gas well, but this is  
18 really not a gas well. You would want to correlate it more  
19 on liquid, and they have done, Hagedorn-Brown, they've done  
20 some modifications to this and the program which Conoco has,  
21 has incorporated those correlations.

22                   Q               And you have, as I understand your testi-  
23 mony, you have taken the Hagedorn-Brown calculation and you  
24 have matched or compared it to the producing reports on the  
25 Federal 34 No. 2 Well?

1 A That's correct.

2 Q The information available from the actual  
3 reports on that well closely matches the curve, then, for  
4 the Hagedorn-Brown calculation?

5 A Yes, it does.

6 Q Okay. Who is the gas purchaser for the  
7 gas from this well, do you know.

8 A Gas Company of New Mexico.

9 Q And is that true of the other wells?

10 A Yes, it is.

11 Q Has Gas Company of New Mexico been noti-  
12 fied of the hardship application?

13 A Yes. They were sent copies of the emer-  
14 gency hardship classification that were obtained for these  
15 wells, plus the application for a hearing for the hardship  
16 gas well classification.

17 Q Do you have an opinion, Ms. Barnes, as to  
18 whether approval of this application would be in the best  
19 interest of conservation, the prevention of waste, and the  
20 protection of correlative rights?

21 A Yes, I think it would be.

22 Q Let's go now to the exhibits for the next  
23 well, which is the -- I believe we were going to talk about  
24 the Federal 34 No. 1 Well?

25 A Yes, that's correct.

1           Q           All right. Did you also prepare the  
2 exhibits and make the study for the information that's  
3 available to us on your proposed exhibits for the Federal 31  
4 -- 34 No. 1 Well?

5           A           Yes, I did.

6           Q           All right. Let's turn to that exhibit  
7 package, which is labeled for Case 9080. Again let's look  
8 at Exhibit Number Two and have you locate the well for us.

9           A           Okay. The Federal 34 No. 1 Well is  
10 located in Section 34, Township 20 South, Range 26 East, in  
11 Unit N, and is designated by the red arrow on this map.

12          Q           And again have you sent certified mail  
13 receipt notification to the offset operators?

14          A           Yes, we have. Exhibit Three is a copy of  
15 the certified mail receipts.

16          Q           Exhibit Four is the schematic of the  
17 wellbore?

18          A           Yes. This well was originally drilled to  
19 a depth of 10,595 feet. The Morrow, this well was  
20 originally drilled this deep to test the Morrow. The Morrow  
21 was tested and was perfed and was produced for approximately  
22 a year and a half or two years.

23                        In 1981 the Morrow formation became une-  
24 conomical. The well was plugged back and perfed in the  
25 Cisco formation from 8,045 to 8,055 feet.

1                   The completion on this well was similar  
2 to the Federal 34 No. 2. 3-1/2 inch tubing with a packer  
3 set at 7,905 feet, and the casing is similar.

4                   Q            Okay, and also you've adjusted the  
5 tubing size to be the optimum tubing size --

6                   A            Yes.

7                   Q            -- to lift this volume of water?

8                   A            Yes, 3-1/2 inch tubing.

9                   Q            All right. Let's turn now to the  
10 information shown on Exhibit Number Five and have you show  
11 the gas/liquid production versus time plot.

12                  A            Okay. This is the decline curve  
13 generated. The green solid line again is oil. The red  
14 dashed line is gas, and the blue hatched line is your water.

15                                The shut-in periods have been noted again  
16 on this exhibit. I'm looking at the various shut-ins. You  
17 can see that this well has a tendency to recover to a rate  
18 equal to that prior to shut-in a little bit quicker than the  
19 other well has; however, if you look at the 1986 drop in  
20 production you can -- as you can see this was a lot lower  
21 drop and seems to not be along the lines of the normal de-  
22 cline of this well.

23                  Q            After repeated shut-ins, then, the latest  
24 shut-in periods have affected the well insofar as it is un-  
25 able, apparently, to restore itself to the original produc-

1 ing rates?

2           A           It was been extremely slow in restoring  
3 itself when compared to the other times; however, in this  
4 well it has over a period of, say, a month or a month and a  
5 half, it has exhibited characteristics that this well may  
6 return to a rate similar to it, but it is taking a longer  
7 time to do it than it has in the past.

8           Q           What is the volume of -- what is the  
9 amount of money or the sum of money Conoco has spent with  
10 regards to restoring production in this well?

11          A           In November, 1986, Conoco spent  
12 approximately \$54,000 to restore production in this well,  
13 using the same method, the nitrogen gas and coiled tubing it  
14 has in the other well.

15          Q           Is there a relationship in terms of the  
16 shut-in period that the well is shut-in, a relationship  
17 between the shut-in period and the effort you must expend to  
18 restore production --

19          A           During --

20          Q           -- in terms of time and money?

21          A           During extended shut-ins it appears that  
22 it costs you a little bit more, need more nitrogen and of  
23 course you have to be on location longer. This is mainly  
24 due to it's more -- more water has encroached towards the  
25 wellbore and your water saturation has increased in a larger

1 radius around the wellbore.

2 Then in the past, some of the short shut-  
3 ins we've had, a month or so, we've only spent, say, around  
4 \$20,000 to unload these wells.

5 So it appears that the longer the extent  
6 of the shut-in, the harder it is to bring these wells back  
7 on production.

8 Q With a shut-in period of two weeks or  
9 less are you subject to having to expend money for the  
10 nitrogen lift?

11 A Yes. We had -- I believe it was back in  
12 1984, '83, we had a compressor fail and we were shut-in.  
13 The well went down for only a couple of days and we still  
14 had to get nitrogen and coiled tubing.

15 Of course the cost of the nitrogen and  
16 coiled tubing was a lot less, but even for the short period  
17 it is still expensive to unload, but not as large, of  
18 course, as the extended shut-in.

19 Q Would you identify for us Exhibit Number  
20 Six?

21 A Exhibit Number Six is just a short record  
22 of some of the daily production reports for this well just  
23 to exhibit how slow the well has come back.

24 The well was at a rate of approximately  
25 450 to 500 MCF per day before it was shut-in. Usually in

1 the past this well would recover in about one to two weeks  
2 to a rate, but as you can see, it has taken almost two  
3 months, really, for it to slowly come back up to the rate  
4 similar to what it was making before shut-in.

5 Q Have you made a decline curve analysis of  
6 the production of this well to determine the remaining eco-  
7 nomic life for this well?

8 A Yes, approximately 2.1 to 2.3 years.

9 Q And what do you calculate to be the re-  
10 maining recoverable gas reserves in the event a hardship gas  
11 well classification is approved?

12 A Approximately 250-million cubic feet of  
13 gas.

14 Q Have you also determined what you believe  
15 to be the minimum sustained flowing rate for the well?

16 A Yes, I have.

17 Q And what is that rate?

18 A The minimum sustainable flowing rate for  
19 this well is 300 MCF of gas per day.

20 Q And did you do a similar Hagedorn-Brown  
21 calculation --

22 A Yes, I did.

23 Q -- or analysis?

24 A Yes, I did. Exhibit Seven is again a  
25 graph interpretation of the data obtained from Hagedorn-Brown

1 vertical pressure drops in a flowing well.

2                   Again you've got reservoir energy or re-  
3 quired pressures to flow the well at a certain rate on your  
4 Y axis.

5                   Your X axis is water production. This  
6 water production correlates to a specific gas rate based on  
7 a gas/liquid ratio of 320. Through historical data that's  
8 what this well averages to exhibit. Just to give you an ex-  
9 ample, at 1000 barrels of water per day the gas rate would  
10 be 350 MCF per day.

11                   Q                   The dashed line at 800 barrels a day?

12                   A                   800 barrels a day is approximately 250  
13 MCF per day. That's the upper range of that bubble flow and  
14 that's the -- that's the flow that you want to avoid, so we  
15 have asked for 300 to allow for, you know, safety factors  
16 not to encroach too close to that 250 number.

17                   This well will flow at a slightly lower  
18 rate than the other two wells because it only makes 1200  
19 barrels of water per day; not the 2000 or 2500 a day.

20                   Q                   Okay. let's turn to Exhibit Number Eight  
21 and have you identify that exhibit.

22                   A                   Okay. Each of the wells I've included  
23 just a copy of the data obtained from the computer program.  
24 All this is is just a copy of the data that generated these  
25 curves, such water rate, and then the required reservoir

1 pressure rate for each well.

2 I ran it for 100 to 800 in one case and  
3 then broke it down to get some intermediate points so that  
4 we could get an accurate graph in that critical range.

5 And Exhibit Nine is just a monthly pro-  
6 duction report. This is actually the amount of gas per  
7 month, not per day as the exhibit says, and this just exhi-  
8 bits -- gives you monthly gas rates and monthly water rates,  
9 monthly oil rate, and then a calculated gas/liquid ratio.  
10 This is a monthly average, just to exhibit where that 320  
11 figure was obtained for the Hagedorn-Brown correlation.

12 Q Do your opinions about the Hagedorn-Brown  
13 calculation that you gave us on the 34 No. 2 Well, that it  
14 was the most effective method to calculate the minimum flow,  
15 do those same opinions apply to this well?

16 A Yes, they do.

17 Q Ms. Barnes, let's go to the last set of  
18 exhibits for Case 9079 --

19 A Okay.

20 Q -- and have you identify for us Exhibit  
21 Number Two concerning the Lever Federal No. 1 Well.

22 A Okay. Again this is a plat showing --  
23 the blue outline indicates the Levers Federal lease, which  
24 is -- includes the entire Section 2, Township 21 South, Ran-  
25 ge 25 East.

1                   The red outlined area shows the proration  
2 unit for the Levers Federal No. 1 and the arrow designates  
3 the well.

4                   As you can see, these are not standard.  
5 This is not a standard section. It contains 912 acres and  
6 the proration unit is also nonstandard and it contains 296  
7 acres.

8                   Q            Okay. And have you provided notice to  
9 the offset operators for this well?

10                  A            Yes, we have.

11                  Q            And that's Exhibit Number Three?

12                  A            Uh-huh.

13                  Q            All right.

14                  A            The certified notices.

15                  Q            All right, let's look at Exhibit Number  
16 Four.

17                  A            Okay. Number Four is a wellbore schem-  
18 atic of the Levers Federal No. 1. This well was drilled to  
19 a total depth of 10,362 feet. It was drilled to this depth  
20 to test the Upper Morrow formation. The well was tested in  
21 that formation and proved to be noncommercial.  
22 The well was plugged back to 9390 feet and was perforated in  
23 the Cisco formation. The perforations extend from 8,088  
24 feet to 8,104 feet.

25                                The completion of this well is similar to

1 the others. It has 3-1/2 inch tubing and the packer is set  
2 at 7,805 feet.

3 Q As with the other two wells, in your  
4 opinion has Conoco done all it can reasonably and economic-  
5 ally do to eliminate or prevent the water problem?

6 A Yes, it has.

7 Q Let's turn to the tabulation of produc-  
8 tion on Exhibit Number Five --

9 A Okay.

10 Q -- and have you describe that exhibit.

11 A Okay. Again this is a decline curve for  
12 the production history for the Levers Federal No. 1.

13 Again the oil is a solid green line; the  
14 gas is a solid -- or the dashed red line; and the water is  
15 the hatched blue line.

16 Again I've tried to designate the shut-in  
17 periods on this well. We experienced one shut-in in 1984,  
18 two in '85, and one in '86.

19 In looking at these shut-in periods, if  
20 you look at the production immediately after the shut-in you  
21 can see that it is a lower production, but the well was then  
22 increased to a rate which could be considered probably nor-  
23 mal decline of the well.

24 However, if you look at the 1986 shut-in  
25 period, you look and you see that the well came on at a

1 lower rate and recovered slightly but the rate is still well  
2 below the normal decline of this well.

3 Q As with the other wells, do you have an  
4 opinion as to whether the current decline in production is  
5 anticipated to be permanent?

6 A In this well, in the past the well has  
7 recovered -- or the drops in production have only been tem-  
8 porary; however, Exhibit Six, I have included some produc-  
9 tion reports extending two months past the shut-in and the  
10 well still has not recovered to a rate of approximately 600,  
11 which is what it was making before; therefore in this well I  
12 feel that it will never recover to the rate similar to what  
13 it was making before shut-in.

14 So I think the decline of production this  
15 time is permanent.

16 Q Have you made a calculation to determine  
17 the remaining economic life of the well if the hardship ap-  
18 plication is approved?

19 A This well will produce for a little over  
20 two years and calculated remaining reserves are approximate-  
21 ly 418-million cubic feet of gas, and these were calculated  
22 off a decline curve analysis, declining it down to the mini-  
23 mum sustainable rate.

24 Q For this well what is your recommendation  
25 for the minimum sustainable producing rate?

1           A           We would like -- we seek the minimum sus-  
2 tainable rate of 250 MCF per day.

3           Q           Let me direct your attention to Exhibit  
4 Number Seven-A and have you identify that exhibit.

5           A           Okay. Again this is a graph interpreta-  
6 tion of the data obtained from Hagedorn-Brown's correlation  
7 of pressure drop in a vertical flowing well.

8                       The Y axis represents the required reser-  
9 voir energy or required pressure to flow this well at cer-  
10 tain production rates. Again the water production rates  
11 correlate to a gas rate. This well exhibits a gas/liquid  
12 ratio of approximately 200; therefore, looking at a water  
13 production rate of 2000 barrels of water per day, this would  
14 correlate to approximately 400 MCF per day.

15                      Again the -- starting at the top as you  
16 come down, as you make less water the friction factor and  
17 the pressure drops caused by the water decreases; therefore,  
18 the rate, the well will exhibit a lower rate when you get  
19 down to your peak, therefore your gas rate becomes so low  
20 that the primary function of how much pressure it takes is  
21 the fact that you don't have enough gas in a column to  
22 lighten it so that it will lift.

23                      The area which -- which exhibits that  
24 bubble flow is indicated with a dashed line; however, look-  
25 ing at Exhibit Seven-B, which is a blow-up of that square

1 area, this well, you will see that the inflection on the  
2 curve changes. It's a little more difficult to see in this  
3 well because the extent is not so great, but if you take a  
4 ruler or a straight line and lay it along that line you can  
5 really see that the inflection is changing.

6 Therefore, to avoid this bubble flow, we  
7 need to stay at a rate no less than 300, so we've asked for  
8 a minimum sustainable rate of 350 to allow for a safety fac-  
9 tor.

10 Q On the chart where will that put you in  
11 terms of barrels of produced water a day?

12 A 350, it would be approximately 1750, so  
13 it will be between that hatched line and the 2000 hatched  
14 line, is where your 350 MCF of gas is.

15 Q 1750 --

16 A Barrels of water per day. 300 MCF corre-  
17 lates with 1500 barrels of water per day.

18 Q Okay.

19 A That's where that dashed line is coming  
20 down. That's the area we want to avoid. That's about crit-  
21 ical bubble flow that you don't want to get well into.

22 Q The Exhibits Eight and Nine again are  
23 what?

24 A Exhibit Eight is a computer printout of  
25 the results from Conoco's Program GC-260, which is the well

1 flowing analysis. These are the numbers which generated the  
2 curves that I presented.

3 And Exhibit Nine is just the monthly pro-  
4 duction and with a calculated average monthly GLR. That's  
5 just to indicate where the GLR factor came from that was  
6 used for the Hagedorn-Brown correlation.

7 Q Were Exhibits One through Nine in each of  
8 the three cases prepared by you or compiled under your  
9 direction and supervision?

10 A Yes, they were.

11 MR. KELLAHIN: That concludes  
12 our direct examination of Ms. Barnes.

13 We move the introduction of Ex-  
14 hibits One through Nine in Cases 9080, 9079, and 9081.

15 MR. CATANACH: Exhibits One  
16 through Nine in Case 9079 are hereby admitted.

17 Exhibits One through Nine in  
18 Case 9080 are admitted into evidence.

19 And Case -- Exhibits One  
20 through Nine in Case 9081 are admitted into evidence.

21

22 CROSS EXAMINATION

23 BY MR. CATANACH:

24 Q Ms. Barnes, do you know of any -- have  
25 you done any comparisons between your log off, actual log

1 off tests and the type of equation that you used to deter-  
2 mine this? Do you know how that correlates?

3 A I compared the results of the Federal 34  
4 No. 2 log off, where the equations predicted it would log  
5 off, to the actual data that we had in November, 1986, and  
6 those correlated fairly well. It predicted that -- the  
7 equation predicted that anywhere between a range of 200 and  
8 300 you were risking the possibility of losing that well to  
9 log off, and that well logged off at about 270 MCF.

10 That's the only actual log off test I  
11 have for those wells. We have never actually executed log  
12 off tests for any of those wells out there, due to the ex-  
13 treme amount of cost of bringing the wells back on.

14 Q Assuming that they died?

15 A Yes.

16 Q The wells aren't experiencing any forma-  
17 tion damage, though, it's just the water encroachment that's  
18 occurring.

19 A From what I can tell, yes. It's just  
20 that by letting the water encroach toward the well you in-  
21 crease your water saturation at the wellbore which in turn  
22 decreases your relative permeability of gas; therefore you  
23 don't have that required amount of gas to, you know, around  
24 the wellbore to lift that amount of water.

25 I would like to add on the Federal 34 No.

1 1, the payout on that nitrogen job, the well is still produ-  
2 cing. The payout on that job is six months; therefore as  
3 long as we're not curtailed before that six month period we  
4 will pay out that job; however, with the current gas situa-  
5 tion, there's a strong possibility we'll be shut in before  
6 we ever pay out that job.

7 Q Okay, let me see if I have this right.  
8 On the 34 No. 2 you spent \$70,000, is that correct?

9 A Yes, approximately; it was actually  
10 \$68,000.

11 Q That was for the shut-in period for 1986.

12 A Yeah, that was the restore production in  
13 November of 1986.

14 Q The 34 No. 1 Well you spent \$54,000?

15 A Yeah, between \$54 and \$56, actually.

16 Q That was for that same shut-in period?

17 A Yes. We -- it was the first week in No-  
18 vember we were restoring production.

19 Q How long was that well shut-in for?

20 A They were all shut-in for approximately  
21 five months.

22 Q Five months.

23 A Since the first of June, 1986.

24 Q Okay, on the last well you haven't had to  
25 spend any money --

1           A           We -- it was shut-in in June with the  
2 rest and we spent \$34,000 to restore production on that  
3 well.

4                       We were not on location quite as long on  
5 that well. That well makes a little bit more gas; therefore  
6 it was easier to reduce the water saturation to such a rate  
7 that the well could flow on its own.

8           Q           Okay, are you saying that if you had to,  
9 if the wells died again and you had to spend as much to re-  
10 pair them, you might not opt to repair them, or Conoco might  
11 not?

12           A           Of course the Federal 34 No. 2 is shut-  
13 in. We will not do any additional work on it unless we can  
14 be assured of a continual generation of revenue.

15                       The payout on the \$68,000 job is already  
16 in excess of one year and you can't justify spending any  
17 more money unless you think you're going on for that.

18                       The Federal 34 No. 1 with the payout on  
19 it being six months, if we're shut-in for an extended amount  
20 of time, we believe that it's going to cost us \$55,000 to  
21 lift it, we may opt not to bring it on if we don't think  
22 we're going to be on at least six months or for a year;  
23 therefore a hardship classification would help us out on the  
24 fact that we would know we would be on so we would be wil-  
25 ling to spend the money if we knew we could bring the well

1 back on, or if we brought it back on, you know, that we  
2 would pay out the job that we spent money on.

3 Of course the main concerns that we have  
4 on the Levers Federal No. 1 and the Federal 34 No. 1 is that  
5 we lose the wells altogether like we did No. 2, and we're  
6 afraid with another extended shut-in that they may exhibit  
7 characteristics similar to the No. 2 and it may be extremely  
8 difficult to bring them back on.

9 We would like to try to avoid losing  
10 those two wells as well.

11 Q So this is all due to economic reasons?

12 A Somewhat. Of course, the main concern  
13 Cononco has right now is losing the reserves in the Levers  
14 Federal No. 1 and the Federal 34 No. 1. If we're shut in  
15 again we may have the difficulty we did with No. 2, and may  
16 have to abandon those wells, you know, as we might the No.  
17 2.

18 We're trying to avoid -- you know, in the  
19 past the wells have recovered, you know, fairly quickly,  
20 like in two weeks, but this time the Levers Federal didn't  
21 exhibit that recovery rate, and so we're afraid that if it  
22 gets shut-in again it may be more of a situation like the  
23 Federal 34 No. 2 and it may not recover at all.

24 The Federal 34-2 makes the least amount  
25 of gas and that is why I believe that that well died on us

1 first before the other two.

2 We would like to avoid, you know, we  
3 would like to continue to operate out there and avoid having  
4 to abandon those wells before those reserves are recovered.

5 Q Are these the only three wells that you  
6 operate in that area?

7 A Yes. They are the only three wells that  
8 also produce from that pool in that formation.

9 We, well, we operate six to eight wells  
10 in the Dagger Draw area which is approximately -- must be  
11 about five miles from there, but that's in a different pool;  
12 that's in an oil pool.

13 Other than that those are the only wells  
14 that Conoco operates in the Carlsbad area.

15 Q This isn't a prorated gas pool, is it?

16 A No, it's not.

17 MR. CATANACH: I have no  
18 further questions of the witness.

19 She may be excused.

20 Is there anything further in  
21 Case 9079, 9080, or 9081?

22 If not, they will be taken  
23 under advisement.

24

25

(Hearing concluded.)

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C E R T I F I C A T E

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

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 9079-80,81 heard by me on February 18 1987.

David L. Paton, Examiner  
Oil Conservation Division