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MASSIVE HYDRAULIC FRACTURING WELL FEDERAL NO. 498-4-1 RIO BLANCO COUNTY, COLORADO

Final Report

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ABSTRACT

This project is an MHF of a previously untreated Mesaverde interval in a well in northwest Colorado. The rocks involved may have been deposited during a marine invasion of long-continued, swamp environments. If so, they would have possessed superior primary reservoir properties. The logging program, identical to those used in the nearby Rio Blanco Nuclear and MHF Project wells, supplied contradictory information. The frac could furnish better understanding of the log suite, better parameters for pre-frac judgments of productive potential and further proof of the commercial capabilities of the formation. The frac job was performed as designed. A total of 775,000 lbs of sand in a total of 276,000 gallons of gelled water (YF4PSD) were injected. The injection pressures ranged from 2,000 to 1,300 psig at rates from 37 to 10 BPM. During the post-frac clean up, 30% of the frac fluid flowed back in 36 hours. Following eight days of swabbing and a total fluid recovery of 46%, the well began continuous flow, which within an additional three days brought total fluid recovery to 70%. Then gas flow increased from gas-cut water to 800 MSCF/D and declined to about 200 MSCF/D within 22 days. After over four months of production and cumulative frac fluid recovery of 82%, the gas rate appears to stabilize at around 130 MSCF/D with about 7 BF/D which contain over 50% oil. The post-frac to pre-frac production ratio is 2:1.

From the performance of this project thus far, the following conclusions can be made:

1. Revision of interpretive methods and/or logging programs is required if consistency in selecting zones most productive of gas and most receptive to stimulation is to be achieved.

2. Injecting large volumes into short vertical intervals appears presently economically unattractive in this area.

3. Properly designed moderate volume multiple fracs may achieve commercial deliverability.

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MASSIVE HYDRAULIC FRACTURING WELL FEDERAL NO. 498-4-1

INTRODUCTION

The Rio Blanco Natural Gas Company Project involves three wells, Federal No. 498-4-1, Government No. 397-19-1 and Government No. 298-22-1, which are located in the Piceance Creek Basin in Northwestern Colorado. The Project involves six phases and numerous zones. Each phase was designed to provide answers to some of the problems encountered in stimulating the tight gas reservoirs in the area.

Phase I involves the application of massive hydraulic fracturing of a Mesaverde Section in well Federal No. 498-4-1. This Phase is the subject of this report and is covered under the Rio Blanco Natural Gas Company-U.S. ERDA Contract #EY-76-C-08-0677.

The purpose of this report is to discuss the activities performed under the subject contract. The report discusses the planning and design of the massive hydraulic fracturing treatment, the logic used to arrive at this design and the pre- and post-fracturing tests and analyses. The report also relates the costs and results of this particular treatment and previous ones to the overall stimulation approach in the tight gas reservoirs of the area.

The work under the Contract consisted of preparing an existing well in the northern Piceance Basin (Federal No. 498-4-1) for the MHF treatment by first perforating in the interval 6,185 feet to 6,320 feet and production testing the well, conducting a breakdown in the perforated interval and a second production test and then shutting in the well for pressure buildup measurements. The MHF design utilized approximately 280,000 gallons of gelled water and approximately 770,000 pounds of sand. Production testing and logging were used to help determine the results of the MHF treatment.

The Federal No. 498-4-1 is located 3,490 feet from the north line and 2,710 feet from the east line Section 4, T4S, R98W, Rio Blanco County, Colorado. It was drilled and cased to a total depth of 6,963 feet in March 1975. The Mesaverde Formation had been stimulated in two separate treatments:

1. The first was in the interval of 6,850 to 6,928 feet, which was treated with 50,000 gallons of gelled KCl water and 133,000 pounds of sand. This first zone produced at a rate of approximately 225 MSCF/D.

2. The second zone, 6,594 to 6,742 feet, was treated with 67,000 gallons polyemulsion fluid and 154,000 pounds of sand and production rate was not improved appreciably. With both previously treated zones open to production, the well produced at a rate of approximately 280 MSCF/D.

RESULTS

1. The pre-MHF tests indicated that calculated minimum capacity (kh) of 0.5 md-ft was unquestionably present and that due to the multi-layer character of the reservoir, the calculated kh value is a minimum, with an actual kh of approximately 1.0 md-ft. After the perforations were broken down, the flow rate ranged from 72 to 52 MSCF/D with an average of about 58 MSCF/D.

2. The massive hydraulic fracturing treatment was performed as designed. A temperature log run after the treatment shows fairly uniform coverage of the entire perforated section.

3. During the post-frac flow, 30% of the fluid flowed back in the first 36 hours after which the well died. Following eight days of swabbing and a total fluid recovery of 46%, the zone began continuous flow, which within an additional three days brought total fluid recovery to 70%. Then gas flow increased from gas-cut water to 800 MSCF/D. Within 22 days the gas flow declined to approximately 200 MSCF/D, with average fluid production of 3.5 barrels of water and 3.5 barrels of oil per day. This production rate appears to reach a stable rate of 130 MSCF/D after 4 months of production. Low temperatures during the last two months have resulted in mechanical difficulties at the well site; i.e., mainly equipment malfunctioning due to freezing. The well was shut in on February 28, 1977.

   If this rate continues, the stimulation ratio for this frac job would be about 2 to 1.

CONCLUSIONS

1. With presently available technology, the task of planning, designing and performing a massive hydraulic fracturing treatment in these tight gas reservoirs does not present a problem in itself. All necessary parameters and practical precautions were considered in designing the treatment on this well and the treatment was performed as designed without any difficulty.

2. Means of selecting the zone or zones for the treatment in these massive gas-bearing sections need further investigation. This may be achieved by:

a. Revision of the interpretive methods and/or logging programs to determine zones most productive of gas and most receptive to stimulation. The geologic implications of the testing and stimulation work in the area need further delineation. Also, the results of the work performed so far indicate that the gas may not be coming from the best looking sections of the logs.

b. More research in the area of rock mechanics, especially those areas that may help determine what acts as a barrier to vertical fracture growth. This will require numerous core studies, as well as in-place testing on location.

3. Current economics do not justify injecting large volumes into short vertical intervals. We need to treat as many of these zones as possible at one time without sacrificing efficiency. Properly designed, moderate volume, multiple fracs may achieve commercial deliverability in this area.

RECOMMENDATIONS

1. In order to make full utilization of the data from past projects in the area, a multiple-staged stimulation of the thick (1,000+ feet) Mesaverde-Fort Union should be performed.

2. Changes on future work:

   a. Need to be able to start the temperature survey work sooner. This would allow several runs to be made thirty to forty-five minutes apart. A differential should also be run in conjunction. The decay time and the differential would give a better quantitative profile.

   b. It is recommended that a reactive fluid (3% to 7 1/2% acid) be used to breakdown perforations and clean up the wellbore area. This fluid should be conditioned with iron stabilizers, silt suspenders and the proper surfactants. Whenever possible, laboratory testing of the effect of chemicals on core samples should be performed to evaluate compatibility.

   c. Ball sealers should be continued, but a minimum of 500 gallons should be considered between each ball to obtain maximum cleaning for testing and pre-frac conditioning. The well should be backflowed or swabbed immediately after job completion.

3. The small amount of evidence from the temperature survey indicates the importance of good cementing practices. The survey also tends to verify the importance of proper perforations planning and placement; including the relationship between hole size, injection rate, differential pressure and individual zone thickness.

4. Operators need to spend more time in planning pipe size, as it relates to hole size and cementing. Cement with expanding properties should be used and the pipe properly centralized. The technology for better cementing is available today. This area of well completion can use much improvement.

GEOLOGY

Regional Setting

Figure 1 shows the regional position of the Basin in northwestern Colorado where Nuclear Stimulation Project Rio Blanco was performed and the conventional MHF Project is progressing. Figure 2 shows the location of the Rio Blanco Unit in the Basin about 15 miles equidistant from two major north-south trending regional structural features--the Grand Hogback Overthrust on the east and the Douglas Creek Arch on the west. The nuclear and conventional stimulation wells are in the south-central part of the unit. Mesaverde outcrops are stippled. Figure 3 shows the position of the Nuclear and MHF Project wells in relation to three wells drilled by Rio Blanco Natural Gas Company to correlative stratigraphic depths. The southerly well, Rio Blanco Federal No. 498-4-1, is five miles south of the Nuclear Project.

Structure

Figure 4 shows well control in the general area and structural contours on a phantom Upper Mesaverde time line. The contour interval is 500 feet. Two western structural noses are separated from the Piceance Creek anticline by a northwest-southeast trending syncline. Some 20 wells have made variable penetrations of the Mesaverde. The Federal No. 498-4-1, located in the southwest part of the map, is structurally 1,500 feet high to the Nuclear well. It is 3,000 feet high to a planned massive hydraulic fracture location on the crest of the Piceance Creek Structure. Seismic fault traces shown are at the overlying Wasatch level. The faulting is high angle normal with maximum indicated displacements of less than 200 feet.

Stratigraphy

The Rio Blanco Natural Gas Company Federal No. 498-4-1 was drilled with careful attention to recovering good representative drill cuttings from the formations of interest. The use of button bits reduced the number of trips made during the drilling operation to a minimum. The KCl mud system was designed so that up-hole lost circulation zones were essentially sealed off by the time the Mesaverde rocks were reached. Interpretation of drill cuttings from most of the older wells is difficult due to poor sample quality.

The 4,000-foot interval of Upper Cretaceous rocks here exhibits a wide range of variations in the shale-siltstone-sandstone range.

A review of the available geologic literature indicated that a stratigraphic analysis of the depositional history of the area might be useful in selecting zones from this thick rock sequence which would make preferable completion targets.

Subsurface control in the area showed that a well on the Piceance Creek structure seven miles northeast of the Nuclear well could serve as a location common to a series of electric log cross-section studies for this purpose. This is 54-13 Unit near the north end of the Piceance Creek closure seen in Figure 4. It is well No. 4 in Figure 5 which is a north-south cross section from Craig on the right to Grand Junction on the left, a distance of 110 miles. The Trout Creek Sandstone is used as a datum. This time line is the first continuous horizontal band shown midway in Figure 5. The sequence above the Trout Creek includes the rocks of interest in the various projects at Rio Blanco. The position of the Rio Blanco Unit is immediately to the left of well No. 4. The phantom Upper Mesaverde time line lies about 3,000 feet above the top of the Trout Creek. This is the surface on which the structural interpretation in Figure 4 is mapped. Shales below the phantom Upper Mesaverde time line are predominately dark grey to black and carbonaceous, while those above are lighter shades of grey with included varicolored shales.

Well No. 4 is seen to occupy a position in which the northern marine Lewis Shale on the right interfingers southward with an extensive swamp facies. Southwest of well No. 4 the swamp facies interfingers with a long continued flood plain sequence. Southward transgressions of the Lewis Sea resulted in deposition of thin tongues of shallow water nearshore marine sediments in the area of well No. 4.

Figure 6 is an east-west cross section from near Rangely Field, intersecting with the north-south cross section at well D, which is No. 4 in Figure 5. Present structure on the west flank of the Piceance Basin is approximated by using the Paleocene Ohio Creek Conglomerate as a datum. The Ohio Creek-Mesaverde contact is seen in the upper part of wells C and D. The Trout Creek Sandstone is the continuous band reaching from near surface on the west to a depth of 11,500 feet in well D. Rio Blanco Unit occupies an area between wells C and D. Stratigraphic traps of marine sandstone tongues in the swamp facies are shown, as is the westward intertonguing of swamp with flood plain rocks.

In more intensively drilled Mesaverde producing areas, such as the San Juan Basin, it has been found that although the entire marine-swamp complex is hydrocarbon generating, the best deliverabilities are usually obtained from nearshore marine sandstones associated with marine-swamp depositional interfaces. Deliverabilities are also enhanced near faults.

As noted, the opportunity for shallow water-marine deposition in the Rio Blanco area was best during the Trout Creek to phantom time-line period.

Detailed electric log correlation work and lithologic analysis indicates a 1,000-foot interval in Federal No. 498-4-1 should contain these preferable rocks. The dual induction log of the interval is shown in Figure 7. Electric logs for correlative depths in the MHF and Nuclear wells and in two wells (No. 12 and No. 13) at Piceance Creek Field are included. The Contract Zone labeled Phase I in Federal No. 498-4-1 is the massive frac target zone. Triple horizontal circles on the logs denote sandstones which are medium to coarse grained. The occurrence of these coarser-grained rocks was an important factor in making the correlations as shown. The correlation shows that Phase I sandstones are approximately correlative to the zone in well No. 12, which recovered gas at the rate of 2 MMSCF/D on drill-stem test.

Figure 8 is a composite of the mud log and Saraband log for the Phase I Zone. Gas shows in the drilling mud, which were minor above Phase I, gradually increased becoming moderate throughout the lower unit. Saraband illustrates 9 individual sandstone units with gross thickness of 71 feet in the 130-foot thick zone. The Saraband indicates porosities within individual units are not uniform. Saraband shows a total of 14 feet to have 10%+ porosity. The drilling time log shows 8 individual units totaling 60 feet in thickness to have been drilled at less than 12 minutes per foot. Lithologic analysis indicates the presence of 3 sandstone units: (1) an upper unit, 48 feet in thickness, which is fine-grained and tightly cemented at the top, becoming medium- to coarse-grained, friable at the base, (2) a middle unit, 11 feet in thickness, which is fine- to medium-grained, tightly cemented, and (3) a lower 40-foot unit which is medium- to coarse-grained and friable, becoming very fine-grained at the base. All units are variably calcareous and clay filled. The shales separating the units are variably light grey, dark grey, dark grey-brown and grey-green. They contain fossil fragments.

At this time, without benefit of cores which might furnish information regarding cross bedding and other depositional features indicative of rock genesis and lacking micropaleontological data which might be a key determinate as to the depositional history of the rocks, their specific origin is unknown. Without cores, the amount of clay filling and the degree of calcite cementation is unknown.

The lower unit becomes coarser upward, which may indicate a regressive origin. The upper unit becomes coarser downward, which may indicate a transgressive origin. The presence of fossil fragments in the intervening shales and their predominately dark grey-grey-brown color are not in themselves definitive.

Thus the designation of the Phase I Zone as a favorable geologic target was primarily based on inference, keyed to comparatively coarse-grained lithologies and comparatively good gas shows in a zone which appears to be correlative with similar conditions in nearby wells.

MHF TREATMENT

Design Parameters

1. Planning of the design of the massive hydraulic fracturing treatment started in March 1976. Rio Blanco Natural Gas Company, U.S. ERDA, Dowell and H. K. van Poollen and Associates, Inc., were involved in designing the treatment.

   The treatment consisted of the following:

   a. Mobilization.

   b. Perforating, testing, breaking down perforations and testing. Evaluation of pre-frac tests.

   c. Performing a massive hydraulic fracturing treatment.

   d. Flow back, clean up and test. Evaluation of post-frac tests.

2. The section to be stimulated was picked from geologic data and the fact that the section may be correlated to other wells in the area. The final gross section picked for stimulation was 6,140 feet to 6,320 feet (180 feet). This section showed only four very small gas shows during drilling. These shows were at 6,140 feet, 6,180 feet, 6,265 feet and 6,310 feet. There were 10 zones in the 180-foot section that calculated hydrocarbon on the Saraband log. The net sand thickness within the interval is 95 feet.

3. The bond log on this section indicates inadequate bonding for stimulation confinement; therefore, it was decided to block squeeze at the top and bottom of the section. This would not insure confinement to the ten individual zones, but it would help restrict the treatment to the total section. Individual zone confinement would have required numerous cement squeezes.

4. It was decided to perforate the section of interest with 17 holes of approximately 0.40-inch diameter. Individual perforation location was chosen from the frac gradient log in conjunction with data from the Saraband. Fracturing fluid injection rate was determined by balancing fluid required per zone with the differential pressure required (per frac gradient log) across the perforations. This technique should insure uniform fluid entry within the zones.

5. A flow and bottom-hole shutoff buildup were planned to evaluate the interval's pre-frac capacity. The result of the pre-frac test's evaluation was a decision point under the subject Contract.

6. Prior to the fracturing operation, perforation breakdown with 2% KCl water, surfactant, nitrogen and ball sealers was planned. KCl water, surfactants and nitrogen were used to minimize formation

damage and promote rapid cleanup with maximum fluid recovery. Ball sealers were used to insure that all holes were open for testing and treating.

7. The detailed fracturing procedure is shown in Appendix A. The following relates to the important parameters of fracturing fluids, additives and procedure:

   a. The volume of fluid and sand was derived from computer calculations of fracture geometry. A total of 276,000 gallons of fluid (YF4PSD) was designed for the treatment, of which 12,000 gallons were to be used as pad. The remaining fluid carried a total of 775,000 pounds of sand of the following size:

225,000 lbs	100 Mesh (FLA 100)
434,000 lbs	20-40 Mesh
116,000 lbs	10-20 Mesa

   b. Forty pounds of a refined gel per 1,000 gallons of water were used as the fracturing fluid. The gel was crosslinked to enhance fracturing fluid properties. This fluid was picked because of excellent cleanup experience, stability and the ability to transport large volumes of sand within the fracture. The gelling agent selected (PSD) hydrates at a lower temperature eliminating the necessity of maintaining the water temperature at 70° F. PSD is also cleaner than guar; i.e., it contains approximately 2% solids as opposed to 10% in the guar.

   c. A tailored breaker schedule was also selected to provide for a total break in four hours from the time pumping started. This would allow for a shorter shut-in time so flowback could be started immediately after temperature surveys. The water used to prepare the frac fluid was tested several times, including prior to and after the on-site storage tanks were filled. Storage silos and sand quality were checked prior to the fracturing operations.

   d. A very low surface tension additive, along with another surfactant that has clay stabilizing properties, was also employed in the fracturing treatment.

   e. The calculated injection required was 37 BPM. This rate would provide approximately 650 psi differential pressure across the perforations. The spacer technique was also designed into the treatment to insure maximum prop penetration. FLA 100 was used to inhibit fluid loss in any natural fractures encountered and to promote deeper penetration of the fracture.

8. A single temperature run was planned after the fracturing operation. A short shut-in time was desired so flowback could be started as soon as possible to reduce fluid inbibition by the formation; therefore, only one temperature run was planned.

The Treatment

The following is a summary of the treatment history. Detailed well history along with Dowell's field report for the stimulation is in Appendix B.

1. Moved workover unit to location on September 7, 1976.

2. A drillable bridge plug was set at 6,525 feet KB.

3. Block squeezed at 6,365 and 6,120 feet KB. The upper zone was squeezed in one attempt, while the lower zone took four attempts to obtain a satisfactory squeeze. Both squeezes were tested to 4,000 psig. A cement bond log was run across the two squeezed intervals and a slight improvement of bonding was shown. Block squeezing and pressure testing were completed on September 14, 1976.

4. After the casing was swabbed dry, the well was perforated on September 16, 1976, with 17 0.4-inch holes at the following locations:

    a. First run: 6,312, 6,310, 6,298, 6,296, 6,290, 6,288, 6,280, 6,278 and 6,264 feet.

    b. Second run: 6,246, 6,232, 6,230, 6,214, 6,194, 6,190, 6,152 and 6,150 feet.

5. Drill-stem test tools were run in the hole and the well was flowed for five hours. The rate stabilized at about 6 MSCF/D. The well was shut in for 61 hours, but the packer leaked and the test was considered a misrun.

6. On September 19, 1976, an attempt was made to run another DST, but the gas flow was too small to measure.

7. On September 21, 1976, perforations were broken down with 3% KCl water, nitrogen, Dowell's F-75 surfactant and ball sealers. A total of 111 barrels of fluid were injected into the formation and approximately 10 to 12 balls sealed on the perforations. About 60% of the breakdown fluid was recovered after 21 hours. The well was then intermittently flow-tested through an orifice well tester for a few hours at a time between swab runs. Continuous flow tests for 24 hours and 29 hours were also recorded. The rate ranged from 72 to 52 MSCF/D, with an average of about 58 MSCF/D.

8. The well was shut in on September 25, 1976, for a seven-day buildup. Two tandem 4,000 psig bottom-hole pressure bombs with 180-hour clocks were run in the hole to a depth of 6,050 feet KB.

9. The pressure bombs were pulled on October 2, 1976. The clock on the bottom gauge did not work. A new bomb was rerun to the same depth, along with one which was used during the first week.

10. On October 9, the bombs were pulled. Tables I and II show bottom-hole pressure data.

11. An acoustic survey to determine the gas-flow profile was run on October 19, 1976. The results of the final interpretation of the 'BATS' (noise log) are shown in Table III, along with the net feet of pay allocated to each set of perforations. The net feet are based on the Saraband.

12. The actual pumping for the Massive Fracturing started at 10:00 a.m. on October 22, 1976. A total of 7,617 barrels was pumped, including sand volume and flush. Injection rate was 37 BPM at 1,200 to 1,800 psig, with rate being reduced at the end of the treatment. The job was performed as scheduled.

An average depth of 6,231 feet was used for the following calculations:

Hydrostatic pressure 2% KCl water	2,729 psi
Hydrostatic pressure 1% KCl water	2,710 psi

Pre-frac breakdown:

ISIP = 1,300 Frac gradient = 0.647 psi/ft

Start of frac: (perforation diameter = 0.38 - 0.40 inch)

37 BPM @ 2,000 psi Pipe friction = 373 psi

Perforation friction = 650 psi

Frac gradient = 0.594 psi/ft

End of frac:

10 BPM @ 1,300 psi ISIP = 1,100 psi

Pipe friction = 187 psi

Perforation friction = 13 psi

Frac gradient = 0.611 psi/ft

Perforation friction pressure indicates that the holes were enlarged to 0.45 inch during the fracturing treatment.

Average frac gradient:

Prefrac breakdown	0.647
Start of frac	0.594
End of frac	0.611
Average frac gradient:	0.617 psi/foot of depth

The calculated average frac gradient is a reasonable value for naturally fractured formations. It should be noted that these natural fractures do not contribute to gas production as evidenced by low natural productivity of all wells in the area.

13. A single temperature run was made after the fracturing operation, but the well was shut in longer than desired prior to this temperature run. This was partially due to the small location and the fact that most of the frac equipment had to be moved to allow the logging unit access to the well. A short shut-in time was desired so flowback could be started as soon as possible to reduce fluid imbibition by the Formation; therefore, only one temperature run was made. The temperature survey shows fairly uniform coverage of the entire section from 6,126 feet to 6,308 feet (182 feet). Some fluid cooling can be detected starting at 6,104 feet at the top end and normal gradient is reached at approximately 6,318 feet. This is a total of 214 feet. It is not possible to interpret this survey quantitatively, since only one run was made. It may indicate, however, that cement bonding was poor throughout the section and/or that the entire section is naturally fractured. The squeeze holes were located at 6,120 feet and 6,365 feet. The bottom squeeze required four attempts. This may be evidenced by better confinement of the fracture at the bottom, since much more cement was used and may have traveled farther up the annulus.

14. The post-frac cleanup proceeded quite satisfactorily. In brief, 30% of the fluid flowed back in the first 36 hours after which the well died. Following eight days of swabbing and a total fluid recovery of 46%, the zone began continuous flow, which within an additional three days brought total fluid recovery to 70%. Then gas flow increased from gas-cut water to 800 MSCF/D. Within 22 days the gas flow declined to the 200 MSCF/D range, with average fluid production being 3.5 barrels of water and 3.5 barrels of oil per day.

This production rate appears to reach a stable rate of 130 MSCF/D after four months of production. Low temperatures during the last two months have resulted in mechanical difficulties at the well site; i.e., mainly equipment malfunctioning due to freezing. The well was shut in on February 28, 1977.

ANALYSIS OF PRE-MHF TESTS

Analysis

1. Figures 9 and 10 show the pressure buildup plots of p versus $\frac{t + \Delta t}{\Delta t}$ and p^2 versus $\frac{t + \Delta t}{\Delta t}$, respectively. The flow time used was 62.5 hours, which is the time from recovery of 60% of the frac fluid to the time the well was shut in. Other values such as the time from breakdown to shut in (83.5 hours) were tried, but had little or no effect on the results. It is felt the 62.5 hours is an appropriate value to use in the buildup analysis, since by that time a continuous flow of natural gas was established and, subsequently only another 13% of breakdown fluid was slowly recovered.

2. The kh is calculated from Figures 9 and 10 as follows:

p plot

$$m_1 = \underline{404} \text{ psia/cycle}$$

$$m_2 = 891 \text{ psia/cycle}$$

$$p_1^* = 2{,}315 \text{ psia}$$

$$p_2^* = \underline{2{,}390} \text{ psia}$$

$$p_f = 208.7 \text{ psia}$$

$$p_{avg} = \frac{2{,}390 + 208.7}{2} = 1{,}299.4 \text{ psia}$$

$$T = 210° \text{ F} = 670° \text{ R}$$

$$SG = 0.7 \text{ (air} = 1.0)$$

$$p_r = \frac{1{,}299}{640} = 2.03$$

$$T_r = \frac{670}{380} = 1.76$$

$$z = 0.91$$

$$\mu = 0.015 \text{ cp}$$

$$q = 58 \text{ MSCF/D}$$

$$kh = \frac{818.5\ q\ \mu\ T\ z}{p_{avg}\ m_1} = \frac{818.5(58)(0.015)(670)(0.91)}{1{,}299\ (404)} = 0.8 \text{ md-ft}$$

p^2 plot

$$m_1 = \underline{177 \times 10^4} \text{ psia}^2\text{/cycle}$$

$$m_2 = 410 \times 10^4 \text{ psia}^2\text{/cycle}$$

$$p_1^* = 2{,}313 \text{ psia}$$

$$p_2^* = \underline{2{,}388} \text{ psia}$$

q, μ, z and T: Same as for the p plot

$$kh = \frac{1{,}637\ q\ \mu\ z\ T}{m} = \frac{1{,}637(58)(0.015)(0.91)(670)}{177 \times 10^4} = 0.5 \text{ md-ft}$$

3. A break in the buildup curve is evident on both plots at the end of the first week of shut in. The slope of the later straight line is approximately twice the slope of the earlier one and occurs

rather abruptly. If errors in gauge measurement and reading of the charts can be ruled out, the pressure buildup plot would be indicative of a permeability change in the reservoir. The errors due to gauge problems are normally reflected by a break at the changing of the gauge (or recalibration), but the second straight line would have the same slope until a boundary is felt. The readings analyzed in this report are from the same gauge (bomb No. 38235, 4,000 psig range), which was calibrated on September 9, 1976, and no calibration was done during the test period. The charts for the first and second week for this bomb were inspected to determine if there was an error in setting the base line. It seems that the base line was properly selected. It is therefore concluded that the break in the buildup curve is due to the presence of some permeability change.

Steepening of slopes at longer shut-in times is usually interpreted to mean a reduction in permeability away from the well or even a flow barrier. However, all of the literature shows that in that instance the slope change should occur over a period of time representated by about 0.6 cycles. The subject buildup curve shows an abrupt change.

Unpublished work by our company (originally required for another client) shows that an abrupt increase in slope and longer shut in is indicative of an increase in transmissibility if flow times are short. It is our conclusion that if the slope change is considered to be real and the result of reservoir properties, the reservoir flow capacity is greater than calculated from the slopes we used.

4. Table III shows that only 75 feet of a total of 95 feet of net pay contributed to the post-breakdown flow. Had all the perforated pay zones been open to the wellbore, the buildup curve would have indicated a higher transmissibility (kh).

5. Evaluation of multiple layers is complicated. Probably the best reference on the subject is Lefkowitz, et al (SPEJ, March 1961, pages 43 - 58).

An extension of this work (unpublished work in Marathon Oil Company) shows that the modified buildup equation reads:

$$\Delta p = \frac{162.6\ q\ \mu\ B}{kh} \log \frac{t + \Delta t}{\Delta t} + f(q,\ s,\ \Delta t)$$

The latter term represents the crossflow in the wellbore from a highly damaged layer to one of low damage.

Evaluation of this extension for a two-layer reservoir shows an increase in slope on the buildup curve (hence lower calculated kh) if the contrast between skins for the two layers increases. The following numbers resulted for a given reservoir (only one available):

$s_1 = s_2$ $\quad$ m = 35 psi/cycle

$s_1 = 10$, $s_2 = 0$ $\quad$ m = 44 psi/cycle

$s_1 = 20$, $s_2 = 0$ $\quad$ m = 58 psi/cycle

The appropriate kh should be calculated with 35 psi/cycle, hence the calculated values for kh for the next two cases are 1.26 and 1.66 times too low. If the contrast becomes great enough, only one of the layers contributes to kh.

From this discussion, it should be concluded that the calculated kh in multiple layers with varying skins is lower than the real value. This is an argument to state that values calculated for kh from this test are pessimistic.

Conclusions

1. The calculated transmissibility (kh) from the p and p^2 plots is about 0.8 and 0.5 md-ft, respectively.

2. The 'BATS' log indicated that 21% of the perforated pay zone did not contribute to pre-MHF production.

3. Had all the perforated pay zones contributed to production, the kh values would have been in the range of 0.97 and 0.61 md-ft.

4. If the abrupt slope change is real, actual reservoir kh is greater than indicated above.

5. Because of the multilayer character of the reservoir and the real probability of contrasting skins in each layer, all kh values in this report should be considered to be pessimistic.

POST-MHF ANALYSIS

Previous Stimulation Work on Federal No. 498-4-1

Prior to the MHF, two fracs were performed on zones 300 feet to 600 feet below the Contract Zone. The details of this work are contained in our report, "Reservoir and Economic Analysis, Federal 498-4-1, Zones 1 and 2", dated July 1976. The report is included as Appendix C. Both fracs were performed with basically the same materials used in the MHF, but with smaller fluid volumes.

The lower (first) frac recovered its 1,200 barrels of fluid in a manner similar to the MHF. After two weeks the interval was delivering an average of 225 MSCF/D. This is a stimulation ratio of about 15 to 1.

The upper (second) frac used 1,600 barrels of fluid. Following the frac, 8 days of swabbing were required to recover the first 400 barrels of fluid at increasingly smaller swab rates. The zone was then shut in for six months. After swabbing was restarted, the well flowed gas and fluid by heads for ten days, at which time one half of the injected fluid had been recovered. In four more days the zone was producing 150 MSCF/D with minor fluid volumes. This was a stimulation ratio of 3 to 1. It is believed the gelling agent in the frac fluid had not performed as expected following the frac and after the six months of shut in, it still had not yet completely broken down.

The two zones were subsequently commingled and produced for a total period of two months. The above-mentioned report demonstrates that under F.P.C. pricing procedures, the zones will pay the cost of drilling and completion in 4.74 years.

Based on the performance of these two zones, the USGS on December 3, 1976, approved the initial Mesaverde Formation participating area, recognizing the Federal No. 498-4-1 to be a commercial well for unit purposes. This approval is important in that it is the first official recognition of the commercial capability of the Mesaverde in the general Rio Blanco area. The added deliverability obtained from the MHF further emphasizes the commercial nature of the production.

Geologic Implications of Area Testing and Stimulation Work

A 1,400-foot thick sequence of Mesaverde rocks exhibits the classic characteristics of hydrocarbon generation. If we assume this sequence to be the prime producing target in the area and divide it vertically into upper, middle and lower thirds, the Contract interval would be in the middle third. The CER-MHF well is about 2,000 feet structurally lower than Federal No. 498-4-1, with the Nuclear well being 1,500 feet structurally lower than Federal No. 498-4-1. The first two fracs in CER-MHF and Federal No. 498-4-1 were in the lower third of the sequence. The bottom device in the Nuclear well and third perforations in CER-MHF well were in the upper third of the sequence. Drill-stem tests have been taken in other wells along structural strike throughout the target sequence. A total of 20 testing or frac operations have taken place with no appreciable quantities of formation water having been recovered. This includes air drilling of the lower half of the sequence in one well. Natural flows of gas have ranged from too small to measure to 200 MSCF/D.

It has been established that KCl-based frac fluids, although causing some clay swelling, are more compatible than any used thus far in the sequence. The three fracs performed in Federal No. 498-4-1 when commingled will produce in the 450 MSCF/D range. Some 350 feet (1/4 of the 1,400-foot section) have been stimulated in Federal No. 498-4-1. These intervals contain some of the more fully developed sandstones in the sequence, as shown by Saraband and lithologic logs. There are, however, good geologic reasons to contend that the entire 1,400-foot thickness of rocks is in effect one reservoir.

The stimulation ratios observed in Federal No. 498-4-1, which ranged from 15:1 to 3:1, although almost certainly influenced by the variable efficiency of the mechanical work, were probably also influenced by the variable communication of sandstone lenses penetrated by the borehole.

Analysis of Log Characteristics

General

Figure 11 is a composite of the logs run to date in subject zone. The Saraband and fracture gradient logs were derived from the same data. All other logs were derived from mutually independent data.

The ten sandstone units as shown on Saraband and their log characteristics are as follows:

Unit No.	Sand Thickness feet	Sand %	Degree of Cementation	Drlg. Break	Gas Show	Fracture Gradient	Post Bkdn Flow	Post Frac Temp
1	10	90	Tight	Fair	Good	Good Top & Bottom	Zero	140
2	16	100	Friable	Good	Fair	Good Middle	14.4	-140*
3	10	95	Friable	Fair	Fair	Poor	Zero	-140*
4	12	90	Tight	?	Fair	Good Top	9.7	140
5	8	75	Tight	Fair	Good	Fair	Zero	140
6	6	50	?	Poor	Poor	Poor	8.4	-140*
7	9	95	Friable	Fair	Good	Fair Top	19.1	-140*
8	6	100	Friable	Poor	Poor	Good	16.8	+140
9	3	60	Friable	Good	Good	Poor	16.0	-140*
10	10	70	Tight	Fair	Good	Good Top	15.6	+140

*43 Net Feet.

Before frac, Units 1, 3 and 5 indicated no communication. After frac, communication was established best in Unit 3. Frac penetration was best into Unit 3, moderate into Units 2, 3, 5, 6, 7, 9 and 10 and least into Units 1, 4 and 8.

Log Indications for Best Penetrations:

Unit 2: Positive in all characteristics.

Unit 3: Positive except for fracture gradient and post breakdown flow.

Unit 5: Positive except for post breakdown flow.

Unit 6: Negative in all characteristics except post breakdown flow and temperature logs.

Unit 7: Positive except for fracture gradient.

Unit 9: Positive except for overall sand quality.

Log Indications for Poorest Penetration:

Unit 1: Positive except for firmness and poor frac gradient in the middle.

Unit 4: Positive except for firmness and poor frac gradient in the middle.

Unit 8: Positive except for comparatively poor drilling break.

Summary

Units 1, 3 and 5 were not contributing to post breakdown flow. The frac established best communication with Unit 3 because of probably receptive sand quality.

Units 2, 3, 4 and 5 probably comprise one sandstone body 68 feet in thickness. The frac made its main penetration into Units 2 and 3, because of probably receptive sand quality.

Unit 6 may be a separate 24-foot unit of fractured or laminated sandy siltstone into which the frac penetrated.

Units 7, 8, 9 and 10 probably comprise one sandstone body 42 feet in thickness. The main frac penetration was into Unit 9, because of its probably receptive sand quality.

No combination of prefrac log characteristics appears to uniformly supply information indicative of specific sandstone unit receptiveness to frac stimulation in the Phase I Zone.

There appears to be good general correlation of the various logs, but a number of crucial inconsistencies are noted:

> Unit 4 (although drilling time calculations are confused by a change of bits) did not receive as much frac fluid as other zones with comparable Saraband fracture gradient and pre-frac flow characteristics.
>
> Unit 6 with poor Saraband, drilling time, gas show and fracture gradient characteristics, had good post breakdown flow and temperature log characteristics.
>
> Unit 8 with good Saraband, gas show and fracture gradient characteristics, has poor drilling time and temperature log.
>
> Unit 9, in which the temperature log indicated receiving the largest volume of frac fluid even with a fast drilling rate, has comparatively less Saraband sand percentage and comparatively poor fracture gradient.

Conclusions

1. Sandstone units, which are the most friable with the fastest drilling times, were those most receptive to fracture stimulation.
2. The presence and quantity of, or the absence of, gas in the drilling fluids and/or drill cuttings may not be dependable indicators as to potential productivity of any particular sandstone unit.
3. If a continuous core had been taken of the zone where the MHF treatment was performed, its careful description and analysis would have been instrumental in understanding information furnished by the Saraband analysis, the meaning of which, for purposes of enhanced recovery of gas from sandstones low in permeability, is presently obscure.

Post-frac Flow Test

Table IV shows the post-MHF cleanup and flow data up to February 23, 1977. The flow rate and percent of fluid recovery are shown graphically in Figure 12.

The following are the highlights of the post-frac cleanup and flow period thus far. For details, see the well history in Appendix C.

1. The actual pumping started at 10:00 a.m. October 22, 1976, and ended at 1:00 p.m. The frac equipment had to be moved off location to give the logging truck access to the well. After one temperature run, the well was opened to flow at 5:30 p.m. The temperature survey tool was run below all the perforations and it showed no sand across the perforations. The flow-back rate was controlled through a choke on the wellhead and once no sand was observed in the frac fluid, the choke was fully opened.

2. After about 30 hours and a cumulative fluid recovery of 30%, the well died. No sand was observed in the frac fluid.

3. After four days of swabbing, the sandline parted and 2,000 feet of sandline along with the sinker bar and swab caps dropped in the hole. The fish was subsequently recovered and a new string of tubing was run in the hole. Another check on sand fillup was made by tagging bottom with the tubing and no sand was found across the perforations.

4. The well started unloading gassy frac fluid after about eight days of swabbing and a cumulative fluid recovery of 46%. Two days later the well was put through the separator. Even though the flowline and test equipment were winterized, equipment malfunctioning due to the cold weather resulted in some erratic flow data, which are reflected on the graph in Figure 12.

5. The gas flow rate started at about 800 MSCF/D and within 22 days declined to 200 MSCF/D. Subsequently the rate declined gradually and seems to have stabilized at about 130 MSCF/D after a period of over three months, since the frac job. If this flow rate continues, the post-frac to pre-frac production ratio would be 2:1.

PROJECT COSTS

This project was jointly funded by U.S.-ERDA and Rio Blanco Natural Gas Company. The financial arrangements between the two parties are described in the subject Contract.

Appendix D shows third party invoice summary and statement as of February 15, 1977. The summary also shows project costs which are reimbursable to the contractor under the subject Contract. Costs incurred by the contractor relative to this stimulation treatment total $40,000.

A financial comparison between the MHF and the other two fracs on this well was made. Drilling costs were allocated based on a ratio of net feet of pay for each zone, divided by the total net feet of pay for the well. The economic comparison between the MHF and the two fracs are shown as follows:

BEFORE INCOME TAX

	Discounted Cash Flow Rate of Return percent	Payout Undiscounted years
Fracs 1 and 2	38.49	3.04
MHF	18.09	5.89

AFTER INCOME TAX

	Discounted Cash Flow Rate of Return percent	Payout Undiscounted years
Fracs 1 and 2	38.40	2.72
MHF	19.83	5.07

As shown by the comparison, the incremental economics indicate that the two smaller fracs are more economical than the MHF.

TABLE I

CABLE

Drilling, Temperature and Well Servicing Co.

BOX 1187
STERLING, COLORADO

Name of Company Rio Blanco Natural Gas Company

Field

Date of Survey Sept. 25 - Oct. 2, 1976

County & State Rio Blanco, Colorado

BH Temp. 194 °F at 6050 ft.

Lease & Well No. Gov't. 498-4-1

Approx. Well Shut In 1:15 P. M. 9-25 1976

Elevation

Bomb On Bottom 12:15 P. M. 9-25 1976

Survey Datum- Ft. or Ft.

BOMB NO. 38235 38233 CALIB NO. 9-1-76

Type Survey 7 day BHP buildup

180 HRS.= 5 INCHES

FLOWING				
DEPTH	DEFLECT	PRESSURE (PSIG)	PRESSURE DIFFERENCE	PSIG/FT. GRADIENT

STATIC				
DEPTH	DEFLECT	PRESSURE (PSIG)	PRESSURE DIFFERENCE	PSIG/FT. GRADIENT

NOTE: Readings are from Bomb No. 38235

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
1	0.096	189	0	45	
2	0.099	195	30 Min		
3	0.100	198	1 Hour		
4	0.100	109	0		
5	0.142	283	30 Min.		
6	0.187	375	1 Hour		
7	0.279	562	2 "		
8	0.375	757	3 "		
9	0.462	934	4 "		
10	0.540	1092	5 "		
11	0.614	1243	6 "		
12	0.678	1373	7 "		
13	0.734	1486	8 "		
14	0.826	1673	10 "		
15	0.889	1801	12 "		
16	0.946	1915	15 "		
17	0.986	1997	20 "		
18	1.006	2038	25 "		
19	1.020	2066	30 "		

Well Flow

BUILDUP					
PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
20	1.044	2114	40 Hours		
21	1.063	2153	50 "		
22	1.073	2173	60 "		
23	1.079	2185	70 "		
24	1.085	2198	80 "		
25	1.089	2206	90 "		
26	1.093	2214	100 "		
27	1.096	2220	110 "		
28	1.100	2228	120 "		
29	1.102	2232	130 "		
30	1.104	2235	140 "		
31	1.107	2242	150 "		
32	1.110	2248	160 "		
33	1.112	2252	166 " 20 Min.		

FORM 2-64

TABLE II

CABLE

Drilling, Temperature and Well Servicing Co.

BOX 1187
STERLING, COLORADO

Name of Company Rio Blanco Natural Gas

Field Wildcat

County & State Rio Blanco, Colorado

Lease & Well No. Gov't. 498 -4-1

Elevation

Survey Datum- ______ Ft. or ______ Ft.

Type Survey BHP buildup

Date of Survey Oct. 2, 9, 1976

BH Temp. 194 °F at 6050 ft.
Approx.
Well Shut In 1:15 P. M. 9-25 1976

Bomb On Bottom 11:55 A. M. 10-2 1976

BOMB NO. 38235 37233 CALIB NO. 10-1-76*

180 HRS.= 5 INCHES

FLOWING

DEPTH	DEFLECT	PRESSURE (PSIG)	PRESSURE DIFFERENCE	PSIG/FT. GRADIENT

STATIC

DEPTH	DEFLECT	PRESSURE (PSIG)	PRESSURE DIFFERENCE	PSIG/FT. GRADIENT

NOTE: Readings are from Bomb No. 38235

*Calibration No. 9/1/76

BUILDUP

PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.
1	1.113	2254	170 Hours		
2	1.116	2260	180	"	
3	1.119	2266	190	"	
4	1.122	2272	200	"	
5	1.124	2277	210	"	
6	1.126	2281	220	"	
7	1.128	2285	230	"	
8	1.130	2289	240	"	
9	1.132	2293	250	"	
10	1.133	2295	260	"	
11	1.135	2299	270	"	
12	1.137	2302	280	"	
13	1.138	2305	290	"	
14	1.139	2307	300	"	
15	1.140	2309	310	"	
16	1.141	2311	320	"	
17	1.142	2313	330	"	
18	1.143	2315	337	" 20 Min.	

BUILDUP

PT. NO.	PRES. DEF.	PRES. (PSIG)	TIME	TBG. PRES.	CSG. PRES.

TABLE III

FEDERAL NO. 498-4-1
RESULTS OF 'BATS' LOG INTERPRETATION

Perforation Depth ft	Noise Level 1,000 H_z MV	$(1{,}000\ H_z\ MV)^{1/3}$	% Total Production	Net Pay ft
6,150	Not Producing			10
6,152	Not Producing			
6,190	250	6.31	6.7	16
6,194	250	6.3	6.7	
6,214	Not Producing			10
6,230	75	4.22	4.5	12
6,232	80	4.31	4.6	
6,246*	180	5.65	6.0	8
6,264	400	7.37	7.9	6
6,278	700	8.88	9.5	9
6,280	500	7.94	8.5	
6,288	400	7.37	7.9	6
6,290	400	7.37	7.9	
6,296	350	7.05	7.5	8
6,298	350	7.05	7.5	
6,310	320	6.84	7.3	10
6,312	320	6.84	7.3	
		93.49	99.8%	95

* This perforation was not reported in Go International's interpretation (Lee Britt's letter dated November 1, 1976) even though they showed it in their field interpretation. A value for the noise level (1,000 H_z MV) was read from the log at this perforation, and the flow profile recalculated.

TABLE IV

RIO BLANCO NATURAL GAS COMPANY
WELL FEDERAL 498-4-1
POST MHF FLOW TEST DATA

Date M/D/Y	Day of Test	Orifice Size in.	Average Orifice Reading	Q MCF/D	Cumulative Gas MCF	Tubing Pressure psig	Liquid Recovered Bbls	Cumulative Liquid Recovered Bbls	% of Injected Volume	Remarks
10/22/76	1					500-300		--		Open to flow on 1 1/4" choke 96-50 BPH
10/23/76	2					100-30		1,730		Choke fully open, rate down to ≈10 BPH
10/24/76	3					0		1,951	30	Well died
10/25/76	4						34	1,984	30	Started swabbing
10/26/76	5						154	2,139	32	Gassy, no blow after swabs
10/27/76	6						153	2,292	34	Gassy, no blow after swabs
10/28/76	7						282	2,574	38	Gassy, no blow after swabs
10/29/76	8						95	2,669	40	≈2,000' of sandline, sinker bar in hole
10/30/76	9						60	2,764	41	Swabbing from 3,400'
10/31/76	10						105	2,869	43	Fishing, checked bottom, no sand fill
11/01/76	11						--	2,869	43	
11/02/76	12						--	2,869	43	RIH w/new tubing string
11/03/76	13						--	2,869	43	RIH w/new tubing string
11/04/76	14						64	2,933	44	Swabbing, gas after swab
11/05/76	15						175	3,108	46	Swabbing, no blow
11/06/76	16						400	3,508	52	Well started unloading, frac fluid & gas
11/07/76	17						900	4,408	62	Still unloading to pit
11/08/76	18	1 1/4	20"Hg	793	793	200*	175	4,583	68	Put well through separator
11/09/76	19	1 1/4	20"Hg	793	1,586	300*	119	4,702	70	Released workover unit
11/10/76	20	1 1/4	16"Hg	691	2,277	275*	114	4,816	72	
11/11/76	21	1 1/4		672	2,949	280*	91	4,907	73	
11/12/76	22	1 1/4	12"Hg	593	3,542	275*	60	4,967	74	
11/13/76	23	1 1/4	--	(500)	4,042	--	(30)	4,997	74+	Separator malfunctioning
11/14/76	24	1 1/4	7.8"Hg	468	4,510	--	(20)	5,017	75	Separator malfunctioning
11/15/76	25	1 1/4	7.10"Hg	445	4,955	250*	(15)	5,032	75	Separator working okay
11/16/76	26	1 1/4	5.66"Hg	395	5,350	95*	5	5,037	75	Dropped soap sticks
11/17/76	27	1 1/4	5.66"Hg	395	5,745	75*	3	5,040	75	
11/18/76	28	1 1/4	4.17"Hg	337	6,082	80*	5	5,045	75	Installed new pressure recorder on wellhea
11/19/76	29	1 1/4	3.40"Hg	303	6,385	75*	1	5,046	75	
11/20/76	30	1 1/4	3.40"Hg	303	6,638	70*	1	5,047	75	
11/21/76	31	1 1/4	3.40"Hg	303	6,991	70*	(5)	5,052	75	Watermeter stuck
11/22/76	32	1 1/4	3.40"Hg	303	7,294	60*	(6)	5,058	75	
11/23/76	33	1 1/4	3.40"Hg	303	7,597	60*	6	5,064	75	
11/24/76	34	1 1/4	3.40"Hg	303	7,900	40?	14	5,078	76	
11/25/76	35	1 1/4	3.40"Hg	303	8,203	79*	20	5,098	76	
11/26/76	36	1 1/4	2.61"Hg	264	8,467	112 Avg.	(10)	5,108	76	Watermeter froze
11/27/76	37	1 1/4	1.81"Hg	220	8,687	65 Avg.	(6)	5,114	76	Watermeter froze
11/28/76	38	1 1/4	2.61"Hg	264	8,951	140 Avg.	(6)	5,120	76	
11/29/76	39	1 1/4	1.81"Hg	220	9,171	120 Avg.	2	5,122	76	
11/30/76	40	1 1/4	1.81"Hg	220	9,391	145 Avg.	(2)	5,124	76	Watermeter froze

TABLE IV (Cont'd.)

POST MHF FLOW TEST DATA

Date M/D/Y	Day of Test	Orifice Size in.	Average Orifice Reading	Q MCF/D	Cumulative Gas MCF	Tubing Pressure psig	Liquid Recovered Bbls	Cumulative Liquid Recovered Bbls	% of Injected Volume	Remarks
12/01/76	41	1 1/4	3.40"Hg	179	9,570	120 Avg.	(2)	5,126	76	Changed orifice plate to 1"
12/02/76	42	1	4.17"Hg	198	9,768	120 Avg.	(2)	5,128	76	Watermeter stuck
12/03/76	43	1	6.39"Hg	249	10,017	120 Avg	(4)	5,132	76	Watermeter stuck
12/04/76	44	1	4.17"Hg	198	10,215	120 Avg.	(5)	5,137	77	Watermeter stuck
12/05/76	45	1	4.17"Hg	198	10,413	130 Avg.	9	5,146	77	
12/06/76	46	1	5.66"Hg	233	10,646	120 Avg.	7	5,153	77	
12/07/76	47	1	4.17"Hg	198	10,344	120 Avg.	7	5,160	77	Dump valve stuck open
12/08/76	48	1	4.17"Hg	198	11,042	120 Avg.	3	5,163	77	
12/09/76	49	1	4.92"Hg	216	11,258	120 Avg.	12	5,175	77	Ran sinker bar on wireline, no sand fillup
12/10/76	50	1	2.61"Hg	155	11,413	130 Avg.	8	5,183	77	
12/11/76	51	1	4.17"Hg	198	11,611	125 Avg.	7	5,190	77	
12/12/76	52	1	4.92"Hg	216	11,827	125 Avg.	8	5,198	77	
12/13/76	53	1	3.40"Hg	179	12,006	125 Avg.	7	5,205	78	
12/14/76	54	1	3.40"Hg	179	12,185	120 Avg.	11	5,216	78	
12/15/76	55	1/2	36.63"Hg	166	12,351	70 Avg.	8	5,224	78	Changed orifice plate to 1/2"
12/16/76	56	1/2	33.71"Hg	156	12,507	92 Avg.	9	5,233	78	
12/17/76	57	1/2	34.14"Hg	157	12,664	130 Avg.	16	5,249	78	
12/18/76	58	1/2	31.98"Hg	152	12,816	140 Avg.	14	5,263	78	
12/19/76	59	1/2	32.42"Hg	153	12,969	160 Avg.	14	5,277	79	
12/20/76	60	1/2	--	164**	13,133	180 Avg.	12	5,289	79	
12/21/76	61	1/2	--	180**	13,313	--	3	5,292	79	Put press. recorder on orifice well tester, 7-day chart
12/22/76	62	1/2	--	(190)	13,503	--				
12/23/76	63	1/2	--	200**	13,703	--	↓ 14	5,306	79	
12/24/76	64	1/2	--	200**	13,903	--				
12/25/76	65	1/2	--	326?**	14,229	--				Separator malfunctioning gas rate questionab
12/26/76	66	1/2	--	440?**	14,669	--				Separator malfunctioning gas rate questionab
12/27/76	67	1/2	--	442?**	15,111	--	↓ 7	5,313	79	Separator malfunctioning gas rate questionab
12/28/76	68	1/2	--	129**	15,240	--				
12/29/76	69	1/2	--	177**	15,417	--				
12/30/76	70	1/2	--	153**	15,570	--				
12/31/76	71	1/2	18 psig	166	15,736	--	↓ 16	5,329	79	
1/01/77	72	1/2	22 psig	189	15,925	--				
1/02/77	73	1/2	20 psig	177	16,102	--	↓ 13	5,342	80	
1/03/77	74	1/2	18 psig	166	16,268	--				
1/04/77	75	1/2	19 psig	171	16,439	--	↓ 18	5,360	80	Separator malfunctioning
1/05/77	76	1/2	16 psig	171	16,610	--				Separator malfunctioning
1/06/77	77	1/2	14 psig	141	16,751	--	↓ 15	5,375	80	Separator malfunctioning
1/07/77	78	1/2	20 psig	177	16,928	--				Separator malfunctioning
1/08/77	79	1/2	40 psig	285?	17,213	--	↓ 16	5,391	80	Separator malfunctioning

October 29, 1976

0730-1000 Well dead. Swabbing from 3,200 feet. Found fluid level at ∿ 300 feet. No blow after swab.

1000-1600 Swabbing as above. At 2:00 p.m. swab cups got stuck in tight spot in tubing at about 3,000 feet. Attempted to pull loose, sand line parted and left sinker bar, cups and about 2,000 feet of line in hole. Possibly fell to bottom afterwards.

Plan to get another sinker bar and check if fish fell down hole. If so, continue swabbing and leave fish till later. If fish is still in tubing, release packer and POH with tubing.

Recovery for the day = 95 Bbls.
Cumulative recovery = 2,669 Bbls (40% of injected volume).

October 30, 1976

0730-1700 Cut off about 200 feet of bad sand line.

1000 Put another mandrel and started swabbing at 3,400 feet. Found fluid level at 300 feet.

Recovery for the day = 60 Bbls.
Cumulative recovery = 2,764 Bbls (41% of injected volume).

October 31, 1976

0730-1130 Swabbing from about 3,400 feet. Found fluid level at ∿ 300 feet.

1100 Sand line parted and left about 1,000 feet of sand line and sinker bar in the hole.

1130-1730 ND wellhead. Release packer and POH with tubing. Recovered second fish (sinker bar still stuck in tubing at about 1,900 feet).

Plan to call for fishing tool and recover first fish.

Fluid recovery for the day approximately 105 Bbls?
Cumulative recovery 2,869 Bbls (43% of injected volume).

November 1, 1976

0730-1530 RIH with tubing and spear and POH with fish.

1530-1730 Started RIH with tubing to tag bottom and check for sand fillup.

October 25, 1976

Plan to RIH with Baker Model E packer and tubing and start swabbing at 1400 hours. Released all frac tanks. Tanks were emptied into pit. Pit is in good condition.

0730-1500 Well still dead. ND 4-inch valve and RIH with tubing and Baker Model E packer. Set packer at 5,995 feet (tallied and run swab mandrel in each joint).

1500-1800 NU wellhead and RU to swab. Found fluid level at ∿ 200 feet. Make three swab runs from 2,000 feet. Well started unloading gas and water. Fluid recovery for the day = 34 Bbls. Cumulative fluid recovery = 1,985 Bbls (30% of injected volume). Left well open to flat tank.

October 26, 1976

0730-1000 Found well dead and flow line frozen up. Swabbed from 2,200 feet with fluid level at ∿ 200 feet. Recovered 8 Bbls.

1000-1500 Swabbing from 2,200 feet. Well unloads after each swab for 20 minutes and dies.

1500-1800 Swabbing as above. Recovery for the day = 154 Bbls. Cumulative recovery = 2,139 Bbls (32% of injected volume).

October 27, 1976

0730-1100 Found well dead. Did not make any fluid overnight. Swabbed from 3,500 feet with fluid level at 400 feet. Recovered about 80 Bbls of fluid. No blow after swab.

1100-1300 Dowell moving sand silos off location; could not swab.

1300-1900 Swabbing as above approximately 6 to 7 Bbls/swab. No flow after swab. Fluid recovery for the day = 153. Cumulative recovery = 2,292 Bbls (34% of injected volume).

October 28, 1976

0730-1100 Well dead. Swabbing from 3,200 feet with fluid level at 400 feet. No blow after swab. Recovered ∿ 70 Bbls.

1100-1600 Swabbing as above, about 15 to 20 BPH. Recovered ∿ 100 Bbls.

1600-1930 Swabbing as above. No blow. Recovery for the day = 282 Bbls. Cumulative recovery = 2,574 Bbls (38% of injected volume).

October 22, 1976

Replaced Chicksan and pressure tested to 4,000 psi. Fractured well according to pumping schedule, except increased rate to 37 BPM from 34 BPM in an effort to attain more perforation friction. Used 6,572 Bbls YF4PSD, 2,250 sacks 100 mesh, 4,340 sands 20/40 mesh and 1,160 sacks 10/20 mesh. Average treating pressure, 1,500 psi. ISIP 1,100 psi. Calculated frac gradient approximately 0.62 psi/ft. See treatment report for job details.

Rig down Dowell and rig up Schlumberger to run temperature survey. Temperature survey showed treatment stayed in zone and all perfs, except possibly the top and bottom ones, took fluid.

1730 Opened well up and flowed back. Initial rate: 96 Bbl/hour.

Date	Time	Rate BPH	Cumulative Received barrels	Pressure psi	Remarks
10/22/76	1745	--	--	500	Open to flow on 1/4" choke.
	1800	96	24	416	1/4" choke.
	1900	80	124	380	1/4" choke.
	2000	50	--	300	Some sand HGC 3/4" choke.
10/23/76	8:00 a.m.	--	--	100	HGC, no sand Full open choke.
	9:30 a.m.	--	1,500	80	No sand, HGC Full open choke.
	1400	--	--	40	No sand, HGC Full open choke.
	1800	10	1,730	30	No sand, HGC Full open choke.
	(From 1400 to 1800, rig up Twin Arrow.)				
10/24/76	0930	--	1,951 30% of load	0	Well dead.

Noise tool (field interpretation):

Perforated Interval feet	Flow %
6,150 & 6,152	1.3
6,190 & 6,194	19.2
6,240	1.0
6,230 & 6,232	3.0
6,246	3.4
6,264	7.5
6,278 & 6,280	24.5
6,288 & 6,290	14.8
6,296 & 6,298	13.6
6,310 & 6,312	11.7

1900 Rig down GO and shut down.

October 19, 1976

0800-1400 Pulled out of hole with tubing and packer, laid down tubing string.

1400-1700 Rig down Twin Arrow Service unit.

Rig went on standby.

October 20, 1976

0800 Dowell on location.

Two blenders on loaction. Rig on standby.

0800-1700 Mix chemical for frac fluid. Rig up some (but not all) Dowell equipment.

Called Schlumberger to run temperature survey right after frac.

October 21, 1976

Finished rigging up Dowell. Will start fracing at 12:00 noon.

Move in remaining Dowell frac equipment and rig up to frac. Pressure test revealed leaky frac head (Chicksan). Postpone job until October 22, 1976, in order to replace Chicksan.

October 21, 1976

No frac job.

Dowell frac head leaking. Dowell now changing packing in Chicksan joint. Will be ready to frac tomorrow about 0900 hours; pumping time = 3 1/2 hours. (Bill feels job will probably start at 1000.)

October 9, 1976

Pulling bottom-hole pressure bombs after second week of shutin.

1430 Off bottom.

1125 Clock ran out (?). RD Cable, Inc., and left well SI.

Field reading off chart:

Time, hours	Pressure, psig
30 (from 1155-Oct. 2, 1976)	2,256
60 (" ")	2,272
90 (" ")	2,285
120 (" ")	2,301
180 (" ")	2,315

October 16, 1977

1300 Twin Arrow rig on location.

1300-1700 Rig up, service unit, nipple down wellhead.

1700-1830 Reduced packer, pulled out of hole with 1/2 of the tubing.

1830 Shut down.

October 18, 1976

0800-1000 Completed pulling out of hole with packer, tubing and tubing stop.

1000-1200 RIH with tubing and Model E packer. Set packer at 6,094 feet.

1220 GO on location.

1430 Tubing pressure at 2,000 psig, casing pressure 50 psig.

1200-1530 Rigged up to swab tubing. Tight spot in the tubing between 1,600 feet and 2,700 feet. Got stuck at 2,700 feet; managed to free swab. Swabbed with one mandrel and one swab cup from 1,600 feet. Fluid level at 900 feet (initial).

1500 Well started flowing and unloading.

1530-1900 Rig down swab and lubricator. Rigged up GO and ran 'BAT' tool (noise log with temperature log).

Field interpretation:

Temperature shows gas flow at:

1. 6,190 feet and 6,194 feet (moderate flow).
2. 6,278 feet and 6,280 feet (most of gas).
3. 6,310 feet and 6,312 feet (some gas).

Rio Blanco Federal No. 498-4-1
First Week of Buildup
Final Chart Readings
(from Cable, Inc., by phone)

Time, hours	Pressure, psig	
	189	Flow
	195	Flow
	198	Flow
0	198 SI	
0.5	283	
1	375	
2	562	
3	757	
4	934	
5	1,092	
6	1,243	
7	1,373	
8	1,486	
10	1,673	
12	1,801	
15	1,916	
20	1,997	
25	2,038	
30	2,066	
40	2,114	
50	2,153	
60	2,173	
70	2,185	
80	2,198	
90	2,206	
100	2,214	
110	2,220	
120	2,228	
130	2,232	
140	2,236	
150	2,242	
160	2,248	
166.33	2,252	

October 2, 1976

Pulling, re-running bottom-hole pressure bombs after first week of shutin.

1035 Off bottom.

Clock on bottom gauge did not work. Unable to find fluid level. RIH with two tandem 3,000 psi bottom-hole pressure gauges and 180-hour clocks.

1155 On bottom.

Cable, Inc., did not bring surface pressure recorder as requested. Will bring one Sunday, October 3, 1976.

Field reading of chart:

Time, hours	Pressure, psig
0 (flow)	193
0.5	269
1	401
2	588
3	778
4	902
5	1,046
10	1,586
15	1,875
20	1,979
25	2,025
30	2,060
35	2,084
40	2,106
45	2,127
50	2,145
60	2,167
70	2,182
80	2,195
90	2,206
100	2,212
120	2,228
140	2,240
160	2,252
180	2,260
	1,900 (surface pressure)

0930-1200 Put well on orifice tester--rate declined slowly from 60.4 MSCF to 58.3 MSCF.

Made swab run hit fluid, 5,758 feet. 250-foot fillup (1 Bbl).

Dropped soap sticks.

1600 Put well on tester. Released crew.

September 24, 1976

Results of 29-hour test (1600 9/23/76 to 0900 9/24/76):
Rate fluctuates between 55 and 61 MSCF/D with an average of about 57 MSCF/D.

0900-1430 Swabbed well dry to ≈ 6,000 feet, found F.L. at 4,500 feet, 6 Bbls fillup. Total fluid recovered 107 Bbls (≈ 30 Bbls still in formation).

1430-1900 Made swab run recovered 1/2 Bbl. Put well on orifice tester. Average rate = 52 MSCF/D.

1900-2000 Made swab run, recovered 1/2 Bbls. Put well on orifice tester. Average rate = 52 MSCF/D.

1000-0100 (9/25/76) RU well testers (Cable, Inc.) and RIH with two tandem 3,000 psig bottom-hole pressure bombs, 180-hour clocks.

Note: Bombs did not pass through valve which had been put on wellhead. So well was SI for 5 minutes to unscrew valve and put up lubricator valve.

1145 On bottom. Bomb depth 6,050 feet, KB.

0100 Well shut in 9/25/76.

September 25, 1976

Valve between surface pressure recorder and lubricator was left closed--no pressure readings.

1220 Opened valve, pressure 1,420 psig.

Note: Maximum range of recorder 1,500 psig; Cable, Inc., did not provide recorder.

1300 Twin Arrow RD and moved off location.

Well left SI for 7-day buildup.

110 Bbls fluid into formation (6.47 Bbl/perf) when 35 balls dropped. Saw 10 to 12 balls hit perfs.

1250 End job; rig down Dowell and Nowsco.

1330 Open well to flat tank.

1410 Approximately 50 Bbls recovered in 40 minutes. Continue to flow.

1530 60 Bbls recovered. Heading Nitrogen and gas.

1730 Rate = 4 Bbls/hour. Dropped 6 Howco suds sticks.

1830 70 Bbls recovered; 66 Bbls to recover. Left open to flat tank. Will begin swabbing in the morning.

<u>September 22, 1976</u>

Well open to flat tank, heading water every 20 minutes. Continuous gas flow. Liquid recovery rate 1 to 2 Bbl/hour.

1030 85 Bbls back, 50 in formation.

1130 Gas flow--no liquid.

1200 Rigged to swab tubing. Hit fluid at 3,000 feet; swabbed to 3,800 feet. Ran two more swab runs to 5,800 feet. Recovered less than 1 Bbl.

Put well on orifice tester with 1/4-inch orifice. Measured 75 inches. H_g estimated flow rate Q = 71.6 MSCF/D. Gas will burn (minimum of Nitrogen).

1530 Pull swab from 6,000 feet, fluid at 5,600 feet [approximately 1 Bbl fillup single last pull (1 1/2 hours)].

1700-1800 Test with orifice tester. Q = 72 MSCF/D.

1830 Run swab. Hit fluid at 5,700 feet, pull from 6,000 feet. Put on orifice tester overnight.

Total fluid back 95 Bbls (40 Bbls still in formation).

<u>September 23, 1976</u>

0800 Well flowed with the following rates:

9/22/76	2000 hours	67 MSCF/D
9/23/76	0800 hours	55 MSCF/D

Made swab run. Fluid level at 4,500 feet, 6 Bbls fillup (1/2 Bbl/hour). Swabbed to 6,000 feet.

September 20, 1976

0823 Opened DST tool and flowed for 1 hour, 19 minutes. The rates were as follows:

Time	Rate
0800	7.29 MCF/D
0830	6.00 MCF/D
0845	5.00 MCF/D
0900	3.4 MCF/D
0915	2.58 MCF/D
0930	2.11 MCF/D
0942	Close tool

Shut tool in for buildup.

1400 Pull out of hole with tool.

DST card showed the following pressures:

Initial hydrostatic	135 psi
First flow	54 psi
Second flow	67 psi
First closed in	1,041 psi
Second flow	162 psi
Final flow	162 psi
Final shut in	661 psi
Final hydrostatic	135 psi

360 feet water recovered--resistivity of 3% KCl water.

Made up 6-joint stringer and Baker Model E packer. Tried to push 2 3/8-inch swab cups through packer. Cups would not pass. Decision made to run no stringer and swab to bottom with tubing on bottom and annulus open.

September 21, 1976

0800-1000 RIH with Baker Model E packer on 2 3/8-inch tubing. Mix 300 Bbls 3% KCl. Nipple down BOP and nipple up wellhead. Displace 165 Bbls 3% KCl with 0.02% Dowell F-75 surfactant. Displace tubing with 25 Bbls 3% KCl water with 0.02% F-75 and 400 SCF/Bbls Nitrogen.

Set packer at 6,094 feet. Put 1,000 psi on casing. Start breakdown job.

Broke down perfs at 2,700 psi. Pump into formation at 2,500 psi--3 BPM.

Begin dropping balls after 16 Bbls. Drop 2 balls/10 Bbl interval for first 50 Bbls. Drop 2 balls/1-2 Bbl increments for the remainder of job.

September 17, 1976

0930 Well still shut in.

Tubing pressure = 1.5 psig
Casing pressure = 40 psig

Packer apparently leaking, (Put pressure recorder on casing.)

September 17-18, 1976

Well still shut in.

Tubing pressure = 1.5 psig

Chart reading casing pressure increasing as follows:

9/17/76	1200	40 psig
	1400	45 ≃ psig
	1800	50 ≃ psig
	2100	57 psig
9/18/76	2400	60 psig
	0300	62 psig
	0600	65 psig
	09	70 psig

September 19, 1976

0730 Crew arrived.

0820 Bled casing; 100 psig → 0 in 5 minutes.

0830 Unseated packer; no gas.

0830-1100 POH with tubing and DST tools.

Note: 150 feet fluid above tool took 3 samples (water apparently KCl water). → Packer rubber torn off and some joints not made up completely--MISRUN.

1100-1640 Put new rubber element on packer. RIH with tubing and DST tools (Two 72-hour clocks with 3,500 psig; One 48-hour clock with 5,000 psig).

Note: Hit fluid ≃ 200 feet above perfs.

1640 On bottom. Packer set at 6,104 feet.

1717 Open tool. Gas to surface in 20 minutes. Gas too small to measure.

1747 Closed tool.

1600 Shut down.

Note: Put recorders on tubing and casing.

September 13, 1976

Finished pulling out with Baker packer. Run in hole with 4 3/4-inch bit and scraper. Hit cement stringers at 5,996 feet. Solid cement at 6,027 feet. Rig up to drill cement. Drilled cement and broke through at 6,120 feet. Pressure test perfs to 4,000 psi. Pull one single and shut down overnight.

September 14, 1976

Drilled out cement stringer and hard cement to top of bridge plug at 6,400 feet. Pressure test lower squeeze to 4,000 psi. Drilled out bridge plug and pushed to 6,525 feet. Pulled out of hole with bit and scraper. Run cement bond log. Tag bottom at 6,525 feet. Logged 5,800 feet to 6,525 feet. Bond improved at squeeze locations. Fifteen tanks spotted.

September 15, 1976

Waited one hour on casing swab. Swabbed casing to 6,320 feet. Pulled 200 feet per swab run. Plans for the 16th are to perforate both zones in an empty hole and to run in with DST tool.

September 16, 1976

0730 Crew arrived.

0820 OWP

RU to perforate.

Ran two runs with perforating gun. Shot 17 0.4-inch holes through both zones at the following locations:

1st Run--6,312, 6,310, 6,298, 6,296, 6,290, 6,288, 6,280, 6,278 and 6,264 feet.

2nd Run--6,246, 6,232, 6,230, 6,214, 6,194, 6,190, 6,152 and 6,150 feet.

Gas to surface in 30 minutes--too small to measure. Ran in with drill-stem test string. Set on 2 3/8-inch tubing.

1400 Opened tool. Rates as follows:

Time	Rate, MSCF/D
1415 - 1500	7.29
1500 - 1600	7.62
1600 - 1700	6.65
1700 - 1800	5.95
1800 - 1900	5.95

1910 Shut in at surface.

1918 Shut in downhole.

RIO BLANCO NATURAL GAS COMPANY
FEDERAL NO. 498-4-1
WELL HISTORY--MHF FRAC

September 8, 1976

Arrived at well and flare was out. Relit flare. Mixing KCl to kill well.

September 9, 1976

0730 Crew arrived at location.
Well flowing--slight to mist to pit.

Mixed 300 Bbls KCl water. Pumped 175 Bbls. Well dead. Pulled remaining tubing out of hole. Run Baker Drillable Bridge Plug on wireline and set at 6,525 feet. Run second Baker Drillable Bridge Plug and set at 6,400 feet. Perforate with 4 holes with 120° phasing at 6,365 feet.

Make up Baker retrievable packer in preparation to squeeze tonight.

September 10, 1976

Rigged up to resqueeze lower zone. Squeezed 50 sacks--low fluid loss (Class G). Maximum pressure = 1,000 lbs. Shut down for 30-minute intervals. Squeeze will not hold pressure. Waiting on more cement to resqueeze.

September 11, 1976

Pressured up cement-squeeze. Would not hold. Resqueezed with 50 sacks Class G with $CaCl_2$. Squeeze to 4,000 psi. Pulled tubing RIH with tubing and packer. Attempt to run through tubing gun. Could not get down. Pull pipe and packer. Run 4-inch casing gun. Perforate with 4 holes at 6,120 feet.

Pressure up cement squeeze. Would not hold. Resqueezed with 50 sacks Class G cement with 2% CaCl. Squeeze to 4,000 psig. Pulled tubing to 5,836 feet. Rig up Oil Well Perforators to perforate. Could not run through tubing gun (1 11/16-inch). Pull pipe and packer. Run 4-inch casing gun. Perforate with 4 holes at 6,120 feet.

Run new squeeze packer and squeezed cement perforations with 59 sacks Class C FLAC and 75 sacks Class G with 2% $CaCl_2$. Squeeze to 4,000 psi. Pull 10 stands and shut in for weekend.

APPENDIX B

WELL HISTORY--MHF FRAC

November 2, 1976

0730-1730 Unloaded new tubing string joints, 6,958 feet (tubing arrived on location at 2300 on November 1, 1976).

Completed RIH with tubing tagged sand fill at 6,356 feet KB. Perfs are all clear.

Started POH and lay down of old tubing string.

November 3, 1976

0730-1730 Turn sand line around on drum. Pick up new tubing and RIH with packer and seating nipple. Ran 90 joints in hole.

November 4, 1976

0730-1730 Completed RIH with tubing, packer and seating nipple. Set packer at 6,114 feet (194 joints of tubing in hole).

NU wellhead and RU to swab.

1300 Started swabbing from 2,300 feet, fluid level staying at 300 to 400 feet. Some gas flow after swab for about 15 minutes and then it dies out.

Recovery for the day = 64 Bbls.
Cumulative recovery = 2,933 Bbls (44% of injected volume).

November 5, 1976

0730-1730 Swabbing from 2,300 feet--approximately 5 Bbls/swab. Some gas after swab. No blow. Fluid level staying at 400 to 500 feet.

Recovery for the day = 175 Bbls.
Cumulative recovery 3,108 Bbls (46% of injected volume).

November 6, 1976

0730-1000 Rig repairs.

1000-1730 Swabbing from 2,300 feet.

1300 Well started unloading water. Estimated initial flow 100 Bbls/hour. Well flowing to pit, flowed across pit, put an 'L' to keep flow in pit. Tubing pressure 100 psig.

Pollard Trucking hauled four loads of water from pit and dumped on road.

Estimated recovery for the day = 400 Bbls.
Estimated cumulative recovery = 3,508 Bbls (52% of injected volume).

November 7, 1976

0730-1730 Well still unloading water. More gas than the previous day. Tubing pressure 50 psig. Rate of fluid recovery approximately 50 Bbls/hour.

Estimated recovery overnight = 400 Bbls.
Estimated recovery for the day = 500 Bbls.
Estimated cumulative recovery = 4,408 Bbls (66% of injected volume).

November 8, 1976

Well still unloading to pit. Put well to separator at noon. Rate fluctuating between 15" and 20" Hg, 1 1/4-inch Orifice (672 -793 MSCF/D).

Fluid: Rate 175 Bbls day. Tubing pressure 200 psig. Separator pressure 25 psig.

Estimated fluid recovery for the day = 175 Bbls.
Estimated cumulative fluid recovery = 4,583 Bbls (68% of injected volume).

Note: For the remainder of the post-MHF flow test see Table IV.

APPENDIX A

MHF TREATMENT PROCEDURE

APPENDIX A

RIO BLANCO FEDERAL NO. 498-4-1
MHF TREATMENT DESIGN

Procedure, Fracturing, 37 BPM Down Casing

1.	12,000 gals.	288 Bbls YF4PSD Pad	
2.	8,000 gals.	192 Bbls YF4PSD, FLA* 100 @ 2 lbs	16,000 lbs sand
3.	3,000 gals.	72 Bbls YF4PSD, Spacer	
4.	11,000 gals.	264 Bbls YF4PSD, FLA 100 @ 3 lbs	33,000 lbs sand
5.	4,000 gals.	96 Bbls YF4PSD, Spacer	
6.	13,000 gals.	312 Bbls YF4PSD, FLA 100 @ 4 lbs	52,000 lbs sand
7.	5,000 gals.	120 Bbls YF4PSD, Spacer	
8.	15,000 gals.	360 Bbls YF4PSD, FLA 100 @ 4 lbs	60,000 lbs sand
9.	5,000 gals.	120 Bbls YF4PSD, Spacer	
10.	16,000 gals.	384 Bbls YF4PSD, FLA 100 @ 4 lbs	64,000 lbs sand
11.	5,000 gals.	120 Bbls YF4PSD, Spacer	
12.	13,000 gals.	312 Bbls YF4PSD, 2,040 @ 2 lbs	26,000 lbs sand
13.	14,000 gals.	336 Bbls YF4PSD, 2,040 @ 3 lbs	42,000 lbs sand
14.	4,000 gals.	96 Bbls YF4PSD, Spacer	
15.	15,000 gals.	360 Bbls YF4PSD, 2,040 @ 3 lbs	45,000 lbs sand
16.	9,000 gals.	216 Bbls YF4PSD, 2,040 @ 4 lbs	36,000 lbs sand
17.	4,000 gals.	96 Bbls YF4PSD, Spacer	
18.	23,000 gals.	552 Bbls YF4PSD, 2,040 @ 3 lbs	69,000 lbs sand
19.	10,000 gals.	240 Bbls YF4PSD, 2,040 @ 4 lbs	40,000 lbs sand
20.	3,000 gals.	72 Bbls YF4PSD, Spacer	
21.	22,000 gals.	528 Bbls YF4PSD, 2,040 @ 4 lbs	88,000 lbs sand
22.	3,000 gals.	72 Bbls YF4PSD, Spacer	
23.	22,000 gals.	528 Bbls YF4PSD, 2,040 @ 4 lbs	88,000 lbs sand
24.	3,000 gals.	72 Bbls YF4PSD, Spacer	

25.	5,000 gals.	120 Bbls YF4PSD, 1,020 @ 3 lbs	15,000 lbs sand
26.	9,000 gals.	216 Bbls YF4PSD, 1,020 @ 4 lbs	36,000 lbs sand
27.	3,000 gals.	72 Bbls YF4PSD, Spacer	
28.	10,000 gals.	240 Bbls YF4PSD, 1,020 @ 4 lbs	40,000 lbs sand
29.	5,000 gals.	120 Bbls YF4PSD, 1,020 @ 5 lbs	25,000 lbs sand
30.	2,000 gals.	24 Bbls YF4PSD, Clear lines, pumps, blender	
31.	5,000 gals.	120 Bbls Breaker Solution	

32. Flush with 1% KCl water, 2 gals./1,000 F52.

33. Shut in for a minimum time (1-hour maximum if possible). Immediate flowback is very important and one temperature run may be all that there is time for.

    a. Inject Pad at 20-25 BPM until it starts in the Formation, then increase slowly to 34 BPM.

    b. When breaker solution (Step 31) is half in the Formation, reduce rate to 10 BPM and maintain to job completion.

    c. Rig well for flowback prior to start of fracturing operation.

    d. Once the well is flowing, do not shut in until maximum load is recovered based on time.

    e. Increase frac rate as required during the job to maintain differential pressure across perforations. Perforations will enlarge due to erosion.

    f. Design compensates for natural fractures and multiple frac gradients.

Fluid Required (Does not include tank bottoms)

Frac	276,000 gals.	YF4PSD	6,624 Bbls
Breaker Solution	5,000 gals.	3% HCl	120 Bbls
Flush	6,700 gals.	1% KCl	160 Bbls

Water source must be tested prior to loading frac tanks. Tanks should be clean and free of residue, old pre-mixed gel, swab fluid, etc. Water will contain 1/2 gal./1,000 Bactericide.

Additives: YF4PSD will consist of the following:

1. 1% Potassium Chloride (KCl).
2. 2 gals./1,000 F75N in Steps 1 through 10.
3. 2 gals./1,000 M38 in Steps 11 through 29.
4. Breaker solution: 2 gals./1,000 A170 inhibitor and 10 lbs/1,000 L41 Iron Stabilizer.

Sand Required

100 Mesh (FLA 100)	225,000 lbs
2,040 Mesh	434,000 lbs
1,020 Mesh	116,000 lbs
Total Prop	775,000 lbs

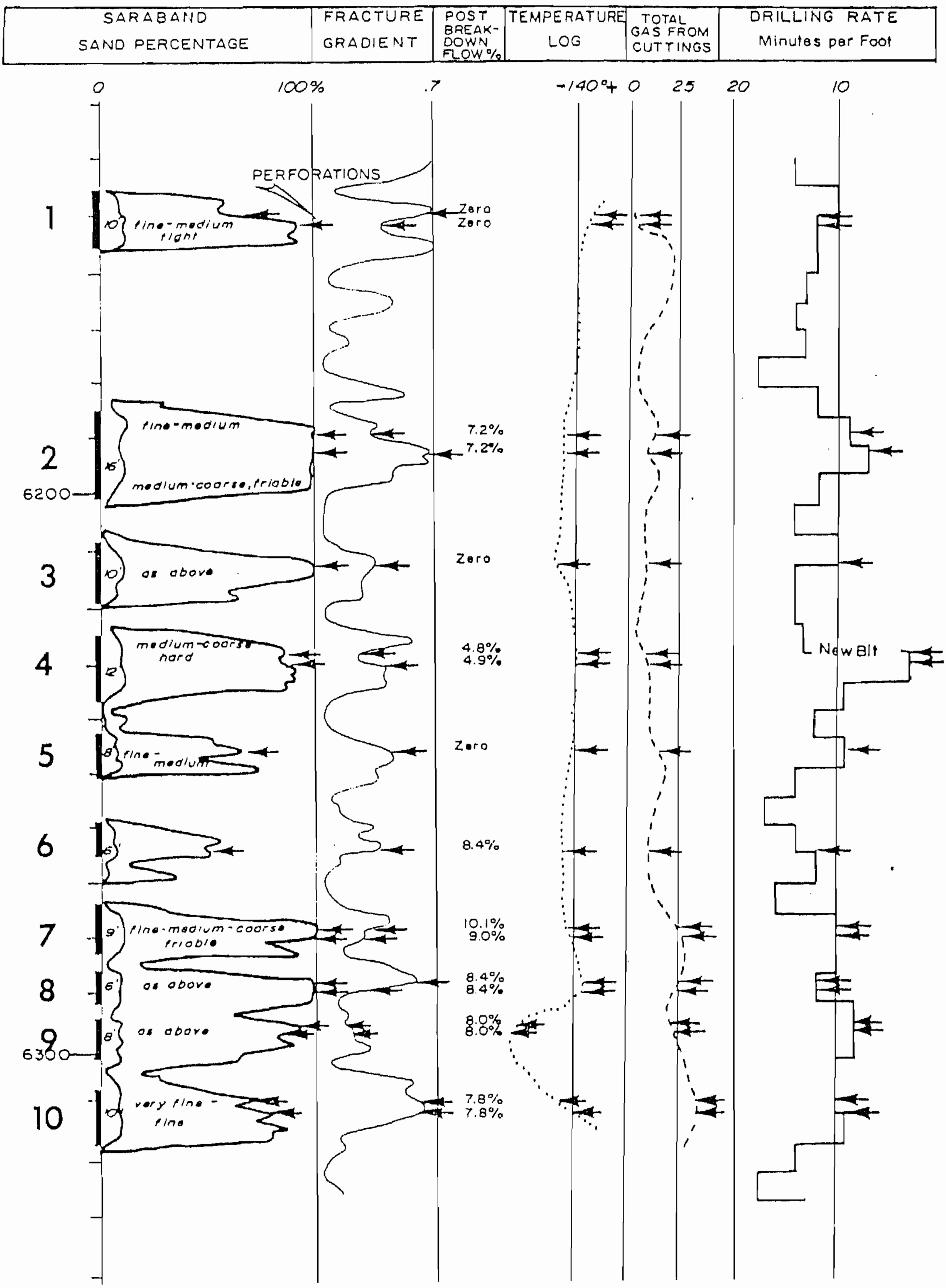
FIGURE 11

RIO BLANCO NATURAL GAS CO. - ERDA MHF 498-4-1

CONTRACT NO. EY-76-C-08-0677

PHASE I

10 SANDSTONE UNITS 95' TOTAL



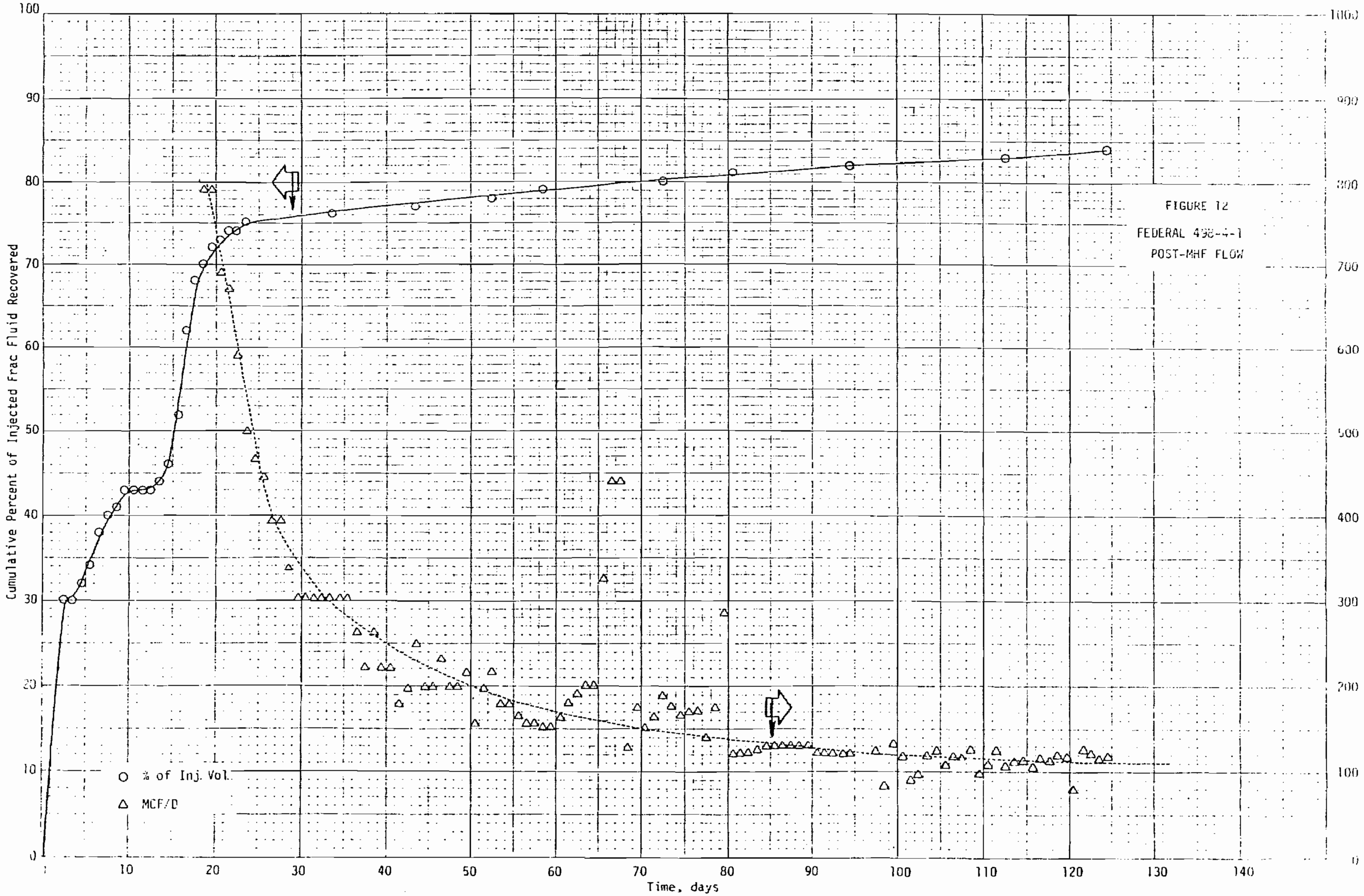


FIGURE 12
FEDERAL 498-4-1
POST-MHF FLOW

TABLE IV (Cont'd.)

POST MHF FLOW TEST DATA

Date D/M/Y	Day of Test	Orifice Size in.	Average Orifice Reading	Q MCF/D	Cumulative Gas MCF	Tubing Pressure psig	Liquid Recovered Bbls	Cumulative Liquid Recovered Bbls	% of Injected Volume	Remarks
1/09/77	80	1/4	72 psig	120	17,333	--				Separator malfunctioning
1/10/77	81	1/4	72 psig	120	17,453	--	30	5,421	81	Separator malfunctioning
1/11/77	82	1/4	74 psig	123	17,576	--				Separator malfunctioning
1/12/77	83	1/4	76 psig	126	17,702	--	24	5,445	81	Separator malfunctioning
1/13/77	84	1/4	80 psig	131	17,833	--				Separator in good working condition
1/14/77	85	1/4	80 psig	131	17,964	--	11	5,456	81	
1/15/77	86	1/4	79 psig	130	18,094	--				
1/16/77	87	1/4	79 psig	130	18,224	--	5	5,461	81	
1/17/77	88	1/4	79 psig	130	18,354	--				
1/18/77	89	1/4	79 psig	130	18,484	--	4	5,465	81	
1/19/77	90	1/4	74 psig	123	18,607	--				
1/20/77	91	1/4	74 psig	123	18,730	--	4	5,469	81	
1/21/77	92	1/4	74 psig	123	18,853	--				
1/22/77	93	1/4	74 psig	123	18,976	--				
1/23/77	94	1/4	74 psig	123	19,099	--				
1/24/77	95	1/4	74 psig	123	19,222	--	21	5,490	82	
1/25/77	96	1/4	74 psig	123	19,345	--				
1/26/77	97	1/4	74 psig	123	19,468	--				
1/27/77	98	1/4	74 psig	123	19,591	--	17	5,507	82	
1/28/77	99	1/4	44 psig	81	19,672	--				
1/29/77	100	1/4	80 psig	131	19,803	--				
1/30/77	101	1/4	70 psig	118	19,921	--	11	5,518	82	
1/31/77	102	1/4	50 psig	90	20,011	--				
2/01/77	103	1/4	52 psig	96	20,107	--				
2/02/77	104	1/4	71 psig	119	20,226	--	12	5,530	82	
2/03/77	105	1/4	75 psig	125	20,351	--				
2/04/77	106	1/4	63 psig	108	20,459	--				
2/05/77	107	1/4	70 psig	118	20,577	--	15	5,545	83	
2/06/77	108	1/4	70 psig	118	20,695	--				
2/07/77	109	1/4	75 psig	125	20,820	--				
2/08/77	110	1/4	52 psig	96	20,916	--	24	5,569	83	
2/09/77	111	1/4	63 psig	108	21,024	--				
2/10/77	112	1/4	74 psig	123	21,147	--				
2/11/77	113	1/4	62 psig	106	21,253	--	22	5,591	83	
2/12/77	114	1/4	65 psig	111	21,364	--				
2/13/77	115	1/4	65 psig	111	12,475	--				
2/14/77	116	1/4	62 psig	106	21,561	--	12	5,603	84	
2/15/77	117	1/4	68 psig	115	21,696	--				

TABLE IV (Cont'd.)

POST MHF FLOW TEST DATA

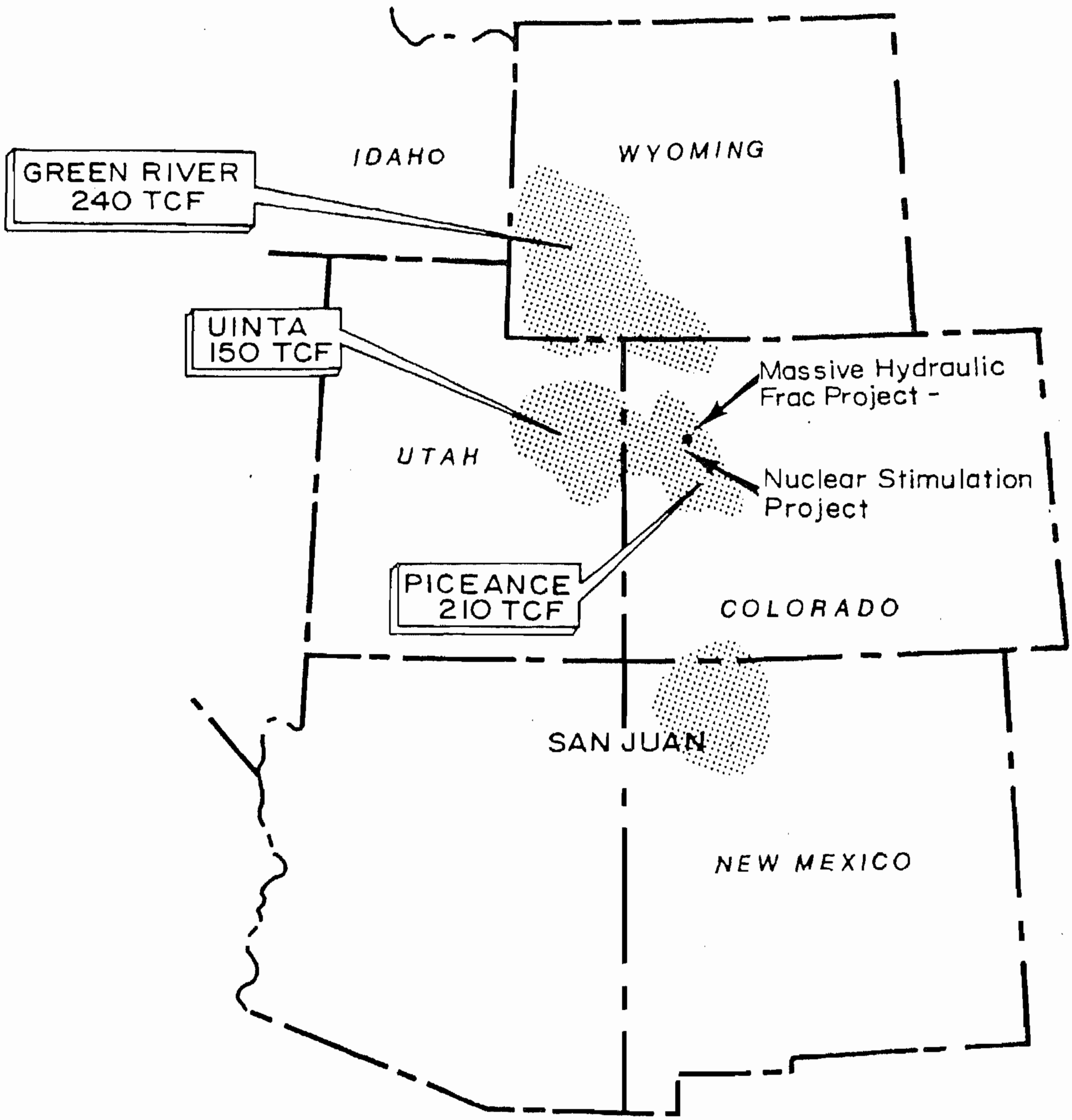
Date D/M/Y	Day of Test	Orifice Size in.	Average Orifice Reading	Q MCF/D	Cumulative Gas MCF	Tubing Pressure psig	Liquid Recovered Bbls	Cumulative Liquid Recovered Bbls	% of Injected Volume	Remarks
2/16/77	118	1/4	66 psig	112	21,808	--	12			
2/17/77	119	1/4	72 psig	120	21,928	--	5	5,608	84	
2/18/77	120	1/4	70 psig	118	22,046	--				
2/19/77	121	1/4	42 psig	79	22,125	--				
2/20/77	122	1/4	76 psig	126	22,251	--	13	5,621	84	
2/21/77	123	1/4	72 psig	120	22,371	--				
2/22/77	124	1/4	68 psig	115	22,486	--				
2/23/77	125	1/4	70 psig	118	22,604	--	15	5,636	84	

Notes:

( ) Estimated

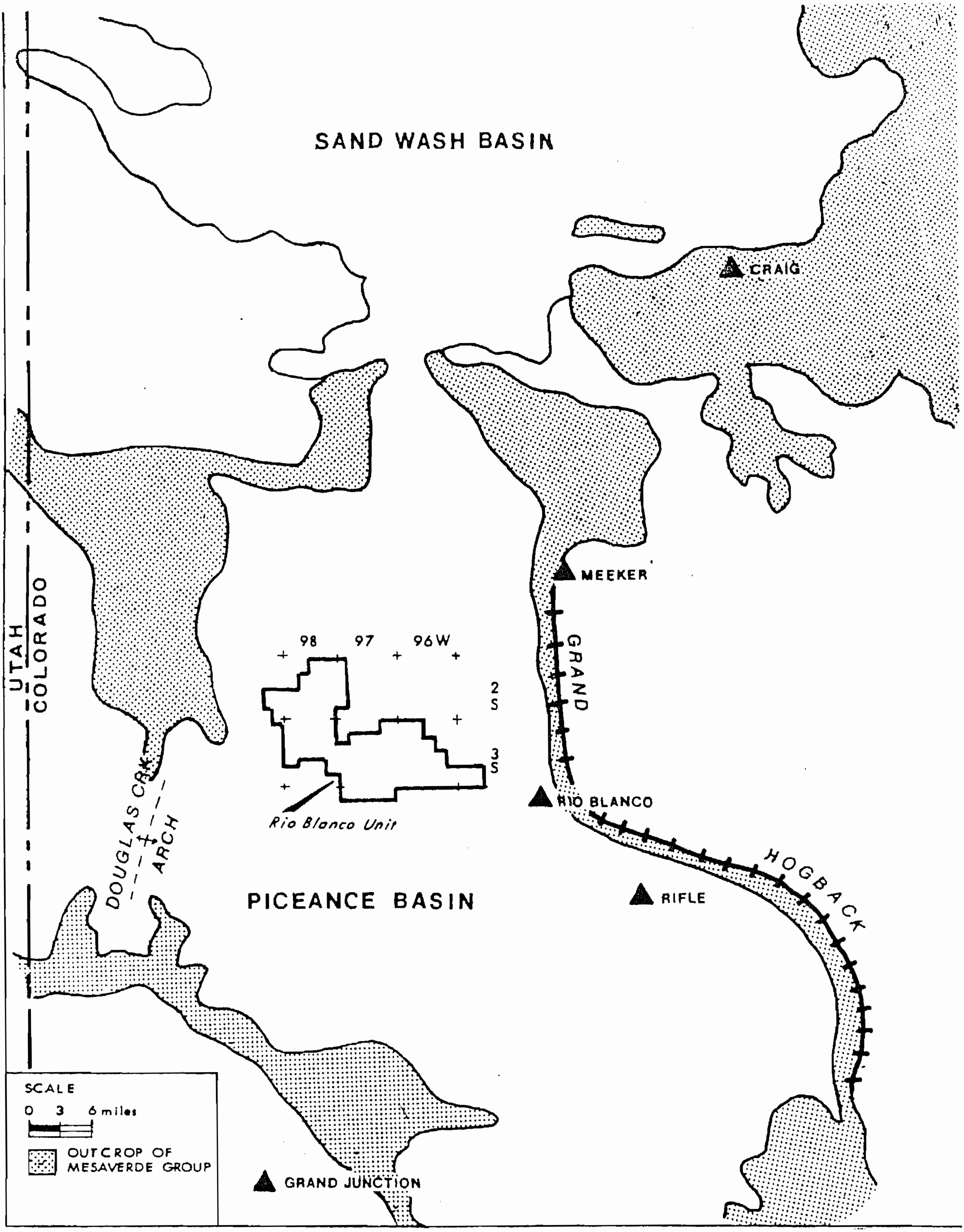
* Spot readings at 10 a.m. each day.

** Estimate, pen goes off chart and gets stuck.



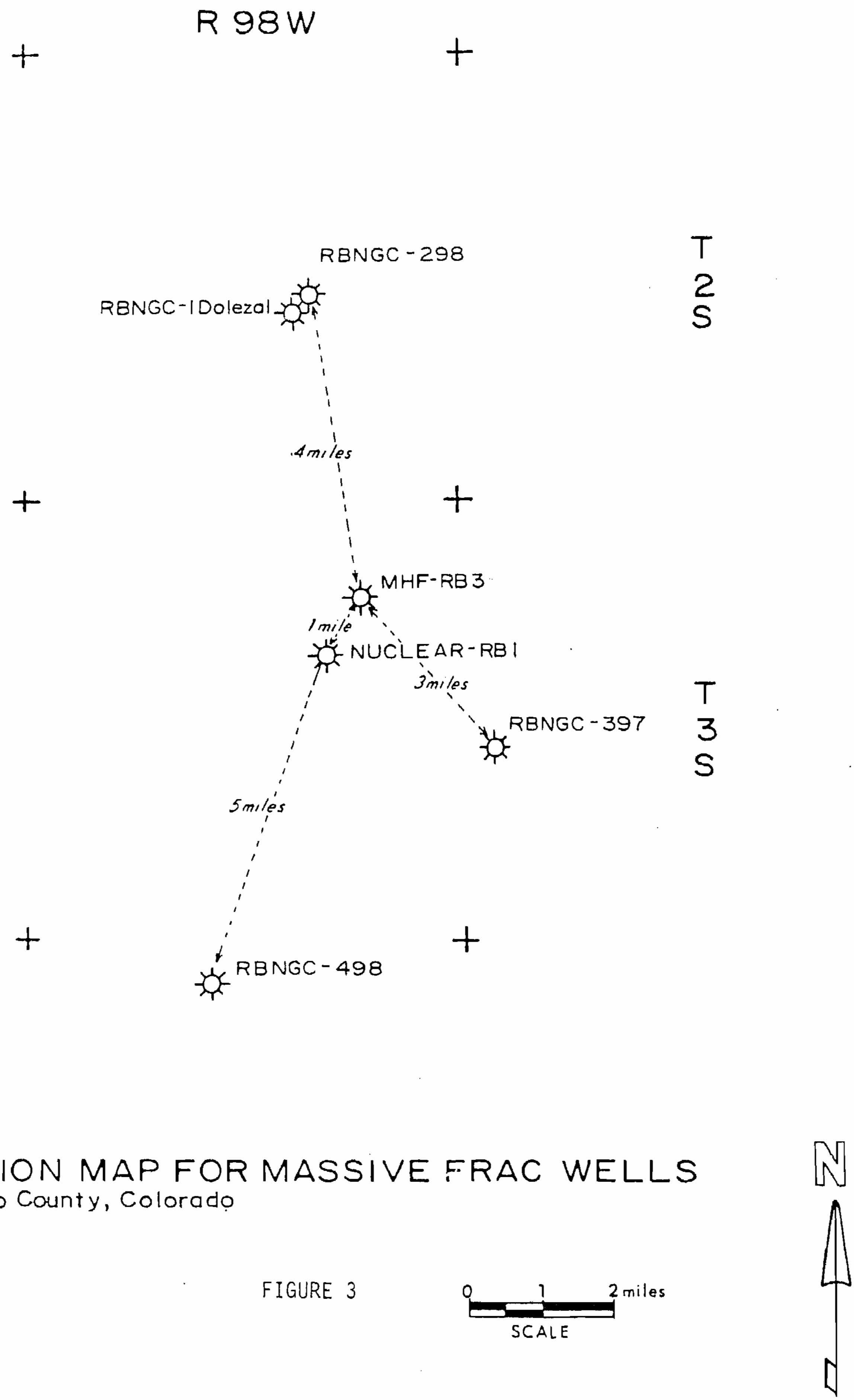
TIGHT GAS RESERVOIRS IN THE ROCKY MOUNTAINS

FIGURE 1



PICEANCE BASIN-NW COLORADO, Rio Blanco Unit

FIGURE 2



LOCATION MAP FOR MASSIVE FRAC WELLS
Rio Blanco County, Colorado

FIGURE 3

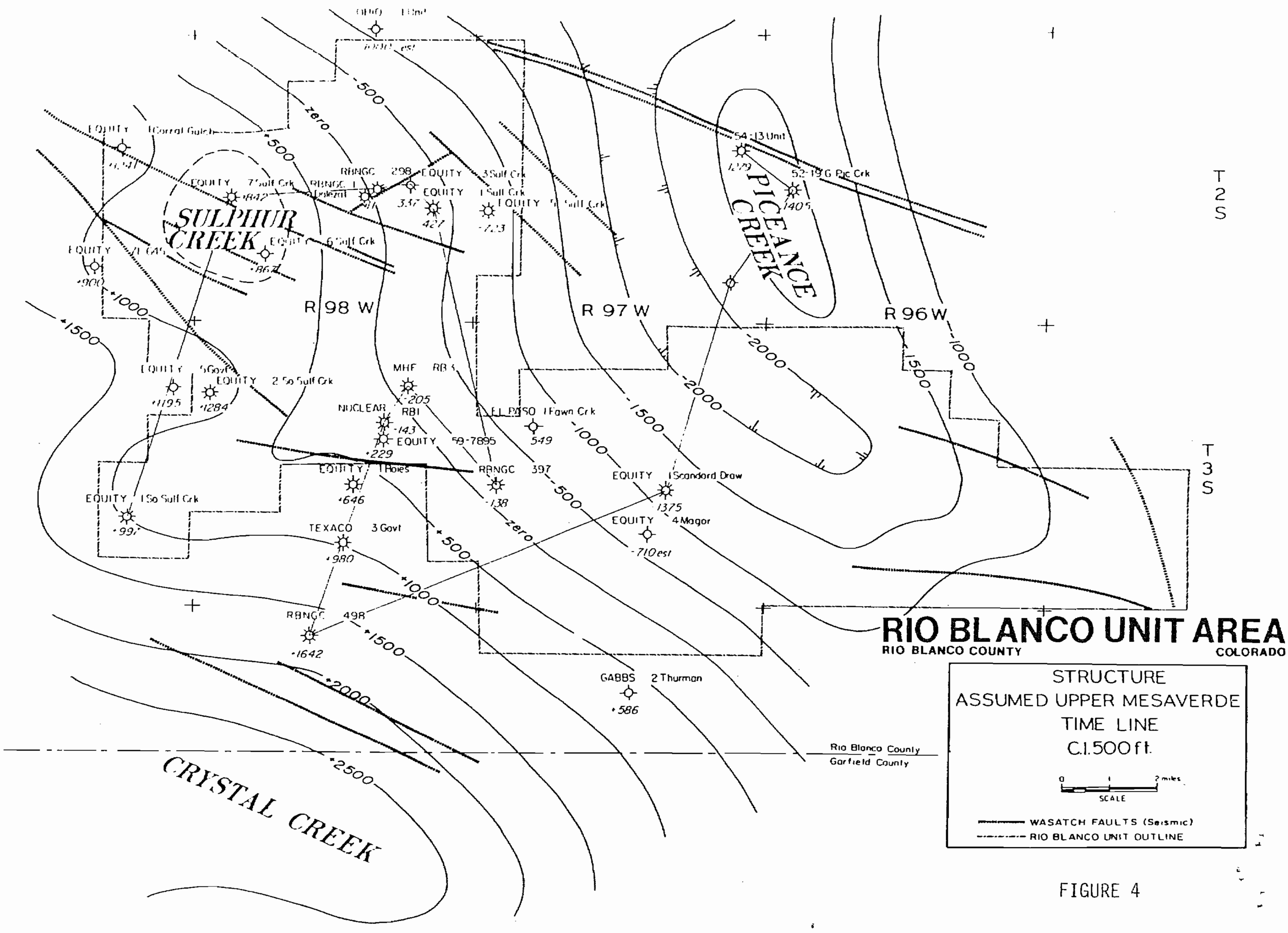

RIO BLANCO UNIT AREA
RIO BLANCO COUNTY
COLORADO
STRUCTURE
ASSUMED UPPER MESAVERDE
TIME LINE
C.I.500 ft.
SCALE
2 miles
WASATCH FAULTS (Seismic)
RIO BLANCO UNIT OUTLINE
PICEANCE CREEK
SULPHUR CREEK
CRYSTAL CREEK
R 98 W
R 97 W
R 96 W
T 2 S
T 3 S
Rio Blanco County
Garfield County
-2000
-1500
-1000
-500
zero
+500
+1000
+1500
+2000
+2500
54-13 Unit
52-19 G Pic Crk
EQUITY 1 Scandard Draw
EQUITY 4 Magor
-710 est
GABBS 2 Thurman
+586
EL PASO 1 Fawn Crk
RBNGC 397
-138
MHF
NUCLEAR
EQUITY
TEXACO 3 Govt
+980
RBNGC 498
+1642
EQUITY 1 So Sulf Crk
EQUITY 2 So Sulf Crk
EQUITY 1 Corral Gulch
EQUITY 7 Sulf Crk
EQUITY 6 Sulf Crk
EQUITY 3 Sulf Crk
EQUITY 1 Sulf Crk
RBNGC 298
+646
+1195
+1284
+997
+900
+867
+842
-723
+229
-143
+205
1405

FIGURE 4

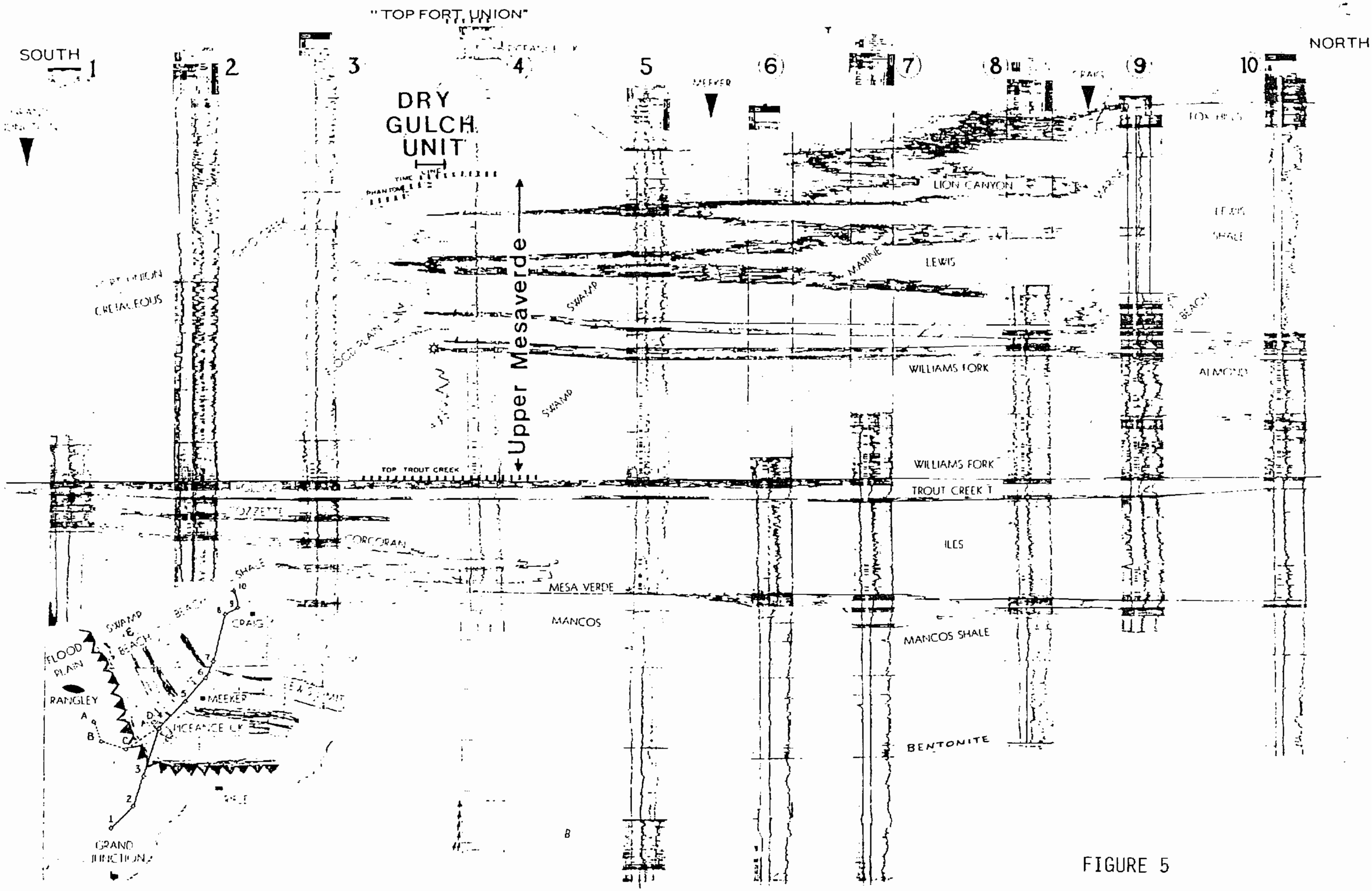

"TOP FORT UNION"
SOUTH
NORTH
1
2
3
4
5
6
7
8
9
10
DRY GULCH UNIT
Upper Mesaverde
MEEKER
CRAIG
LION CANYON
LEWIS
MARINE
SWAMP
WILLIAMS FORK
TOP TROUT CREEK
TROUT CREEK T
ILES
CORCORAN
MESA VERDE
MANCOS
MANCOS SHALE
BENTONITE
CRETACEOUS
FLOOD PLAIN
RANGLEY
GRAND JUNCTION

FIGURE 5

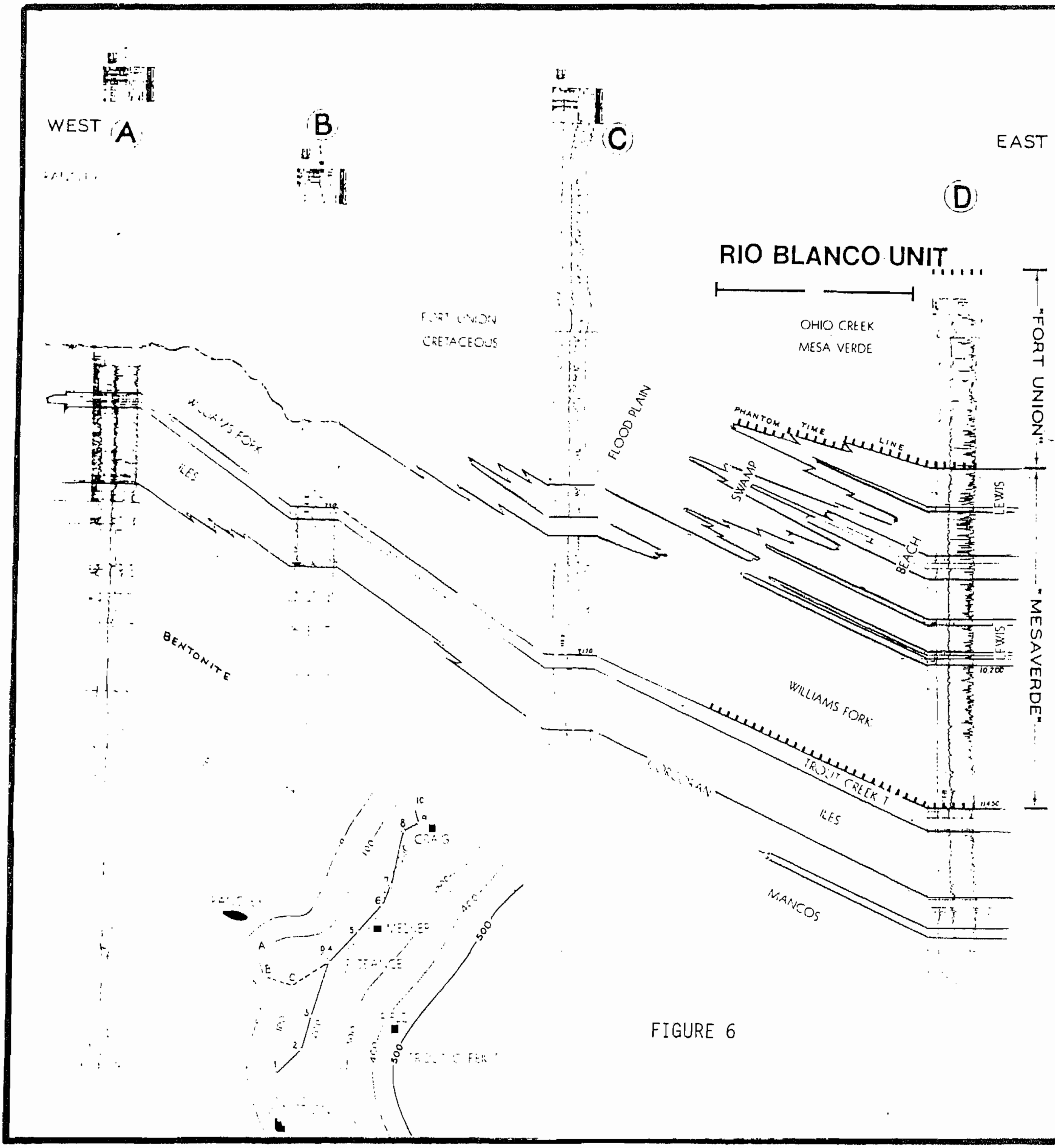
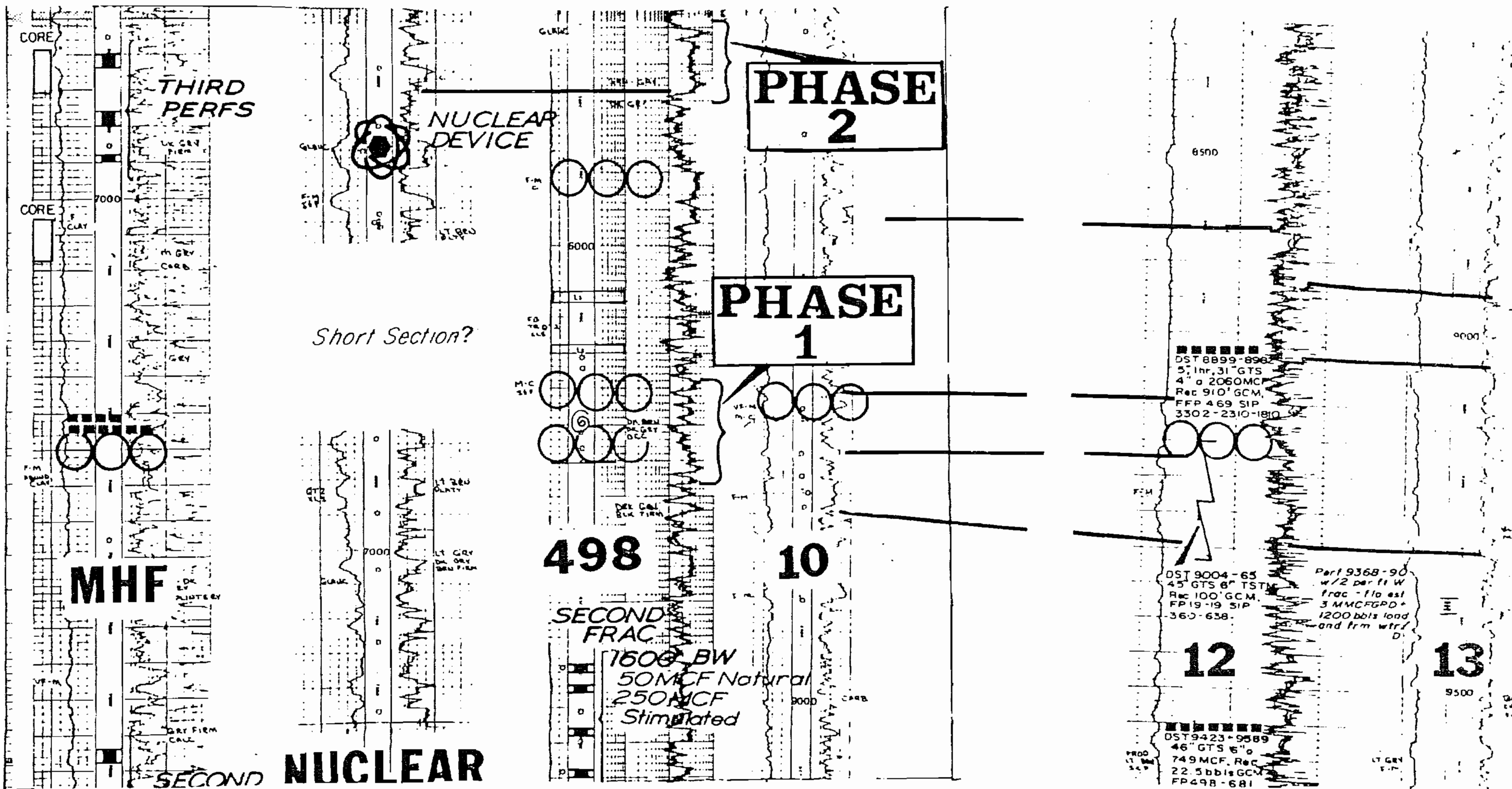

WEST
A
B
C
D
EAST
RIO BLANCO UNIT
FORT UNION
CRETACEOUS
OHIO CREEK
MESA VERDE
"FORT UNION"
"MESAVERDE"
FLOOD PLAIN
PHANTOM TIME LINE
SWAMP
BEACH
LEWIS
LEWIS
10,200
WILLIAMS FORK
ILES
BENTONITE
WILLIAMS FORK
TROUT CREEK T
ILES
MANCOS
CRAIG
500
500

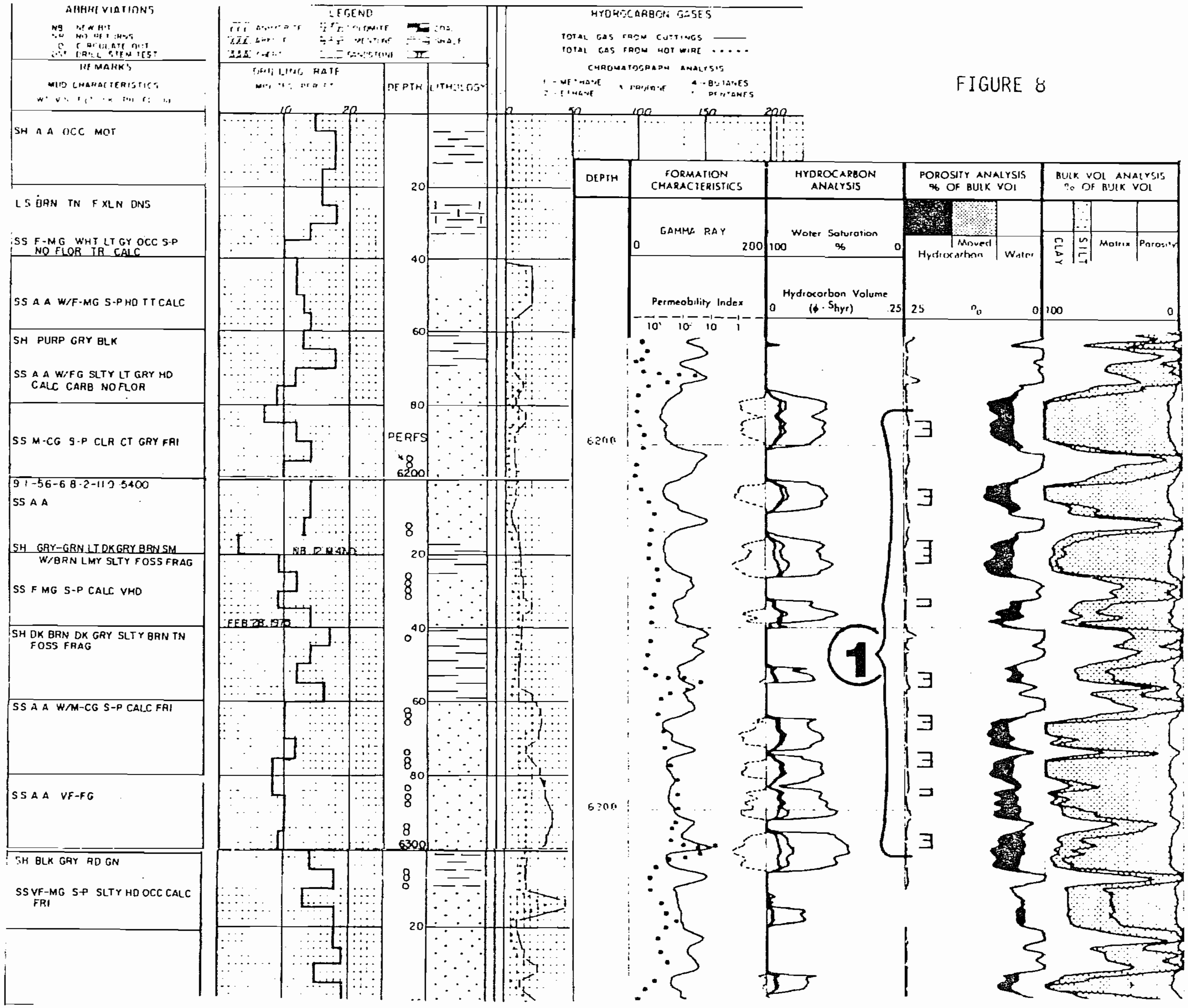
FIGURE 6



CORE
THIRD PERFS
MHF
SECOND
NUCLEAR DEVICE
Short Section?
NUCLEAR
PHASE 2
PHASE 1
498
SECOND FRAC
1600 BW
50MCF Natural
250MCF
Stimulated
10
DST 8899-8962
5' Inr, 31" GTS
4" a 2060MCF
Rec 910' GCM.
FFP 469 SIP
3302-2310-1810
DST 9004-65
45" GTS 6" TSTM
Rec 100' GCM.
FP19-19 SIP
360-638.
12
DST 9423-9589
46" GTS 6"a
749 MCF. Rec
22.5 bbls GCM
FP 498-681
Perf 9368-90
w/2 per ft W
frac - flo est
3 MMCFGPD+
1200 bbls load
and frm wtr/
13

FIGURE 7

FIGURE 8



ABBREVIATIONS
REMARKS
MUD CHARACTERISTICS
LEGEND
DRILLING RATE
DEPTH
LITHOLOGY
HYDROCARBON GASES
TOTAL GAS FROM CUTTINGS
TOTAL GAS FROM HOT WIRE
CHROMATOGRAPH ANALYSIS
SH A A OCC MOT
LS BRN TN F XLN DNS
SS F-MG WHT LT GY OCC S-P NO FLOR TR CALC
SS A A W/F-MG S-P HD TT CALC
SH PURP GRY BLK
SS A A W/FG SLTY LT GRY HD CALC CARB NO FLOR
SS M-CG S-P CLR CT GRY FRI
SS A A
SH GRY-GRN LT DK GRY BRN SM W/BRN LMY SLTY FOSS FRAG
SS F MG S-P CALC VHD
SH DK BRN DK GRY SLTY BRN TN FOSS FRAG
SS A A W/M-CG S-P CALC FRI
SS A A VF-FG
SH BLK GRY RD GN
SS VF-MG S-P SLTY HD OCC CALC FRI
PERFS
6200
6300
FEB 28 1978
DEPTH
FORMATION CHARACTERISTICS
GAMMA RAY
Permeability Index
HYDROCARBON ANALYSIS
Water Saturation %
Hydrocarbon Volume
POROSITY ANALYSIS % OF BULK VOL
Moved Hydrocarbon
Water
BULK VOL ANALYSIS % OF BULK VOL
CLAY
SILT
Matrix
Porosity
1

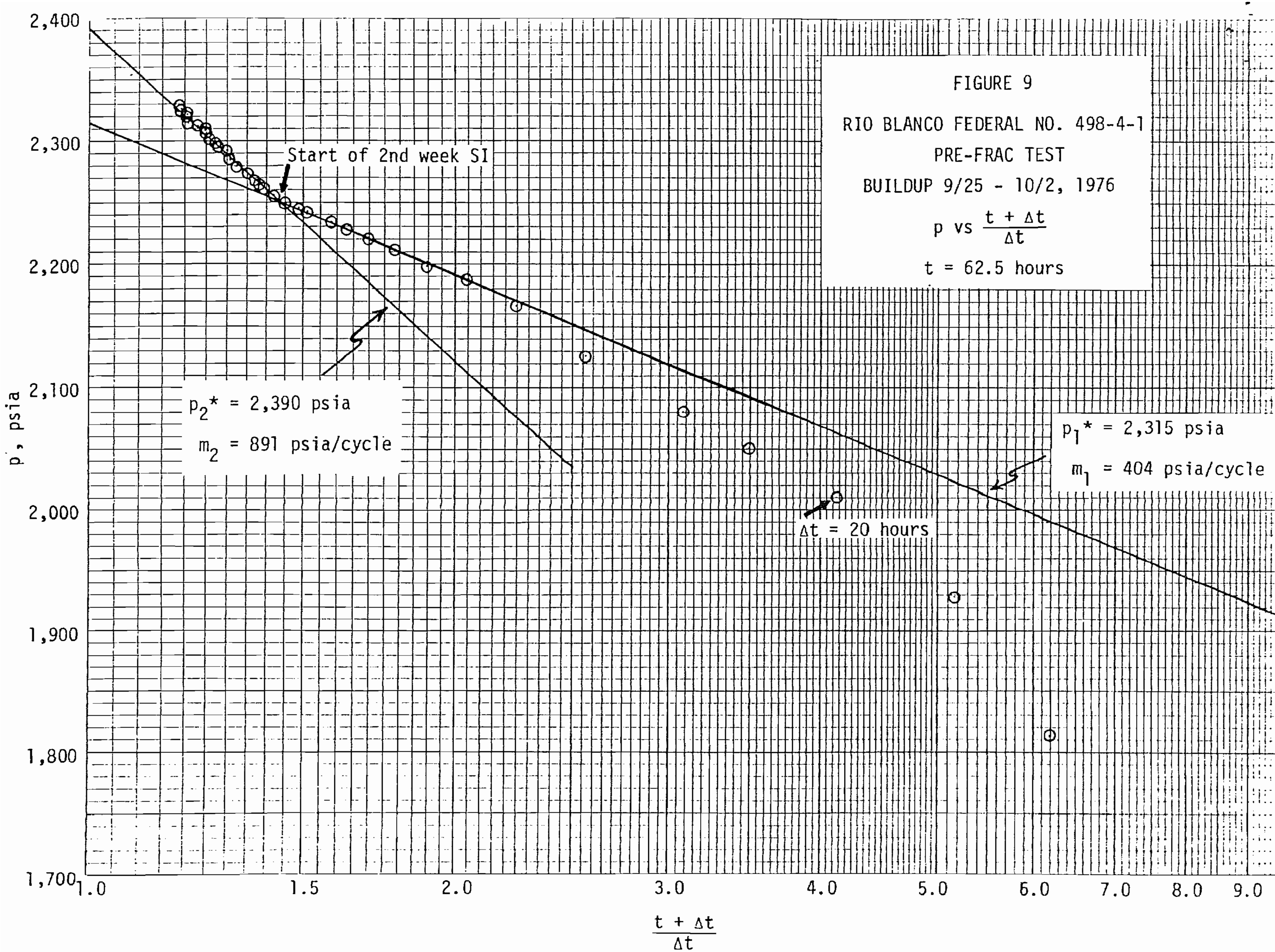


FIGURE 9
RIO BLANCO FEDERAL NO. 498-4-1
PRE-FRAC TEST
BUILDUP 9/25 - 10/2, 1976
p vs $\frac{t + \Delta t}{\Delta t}$
t = 62.5 hours
Start of 2nd week SI
p_2^* = 2,390 psia
m_2 = 891 psia/cycle
p_1^* = 2,315 psia
m_1 = 404 psia/cycle
Δt = 20 hours
p, psia
2,400
2,300
2,200
2,100
2,000
1,900
1,800
1,700
1.0
1.5
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
$\frac{t + \Delta t}{\Delta t}$

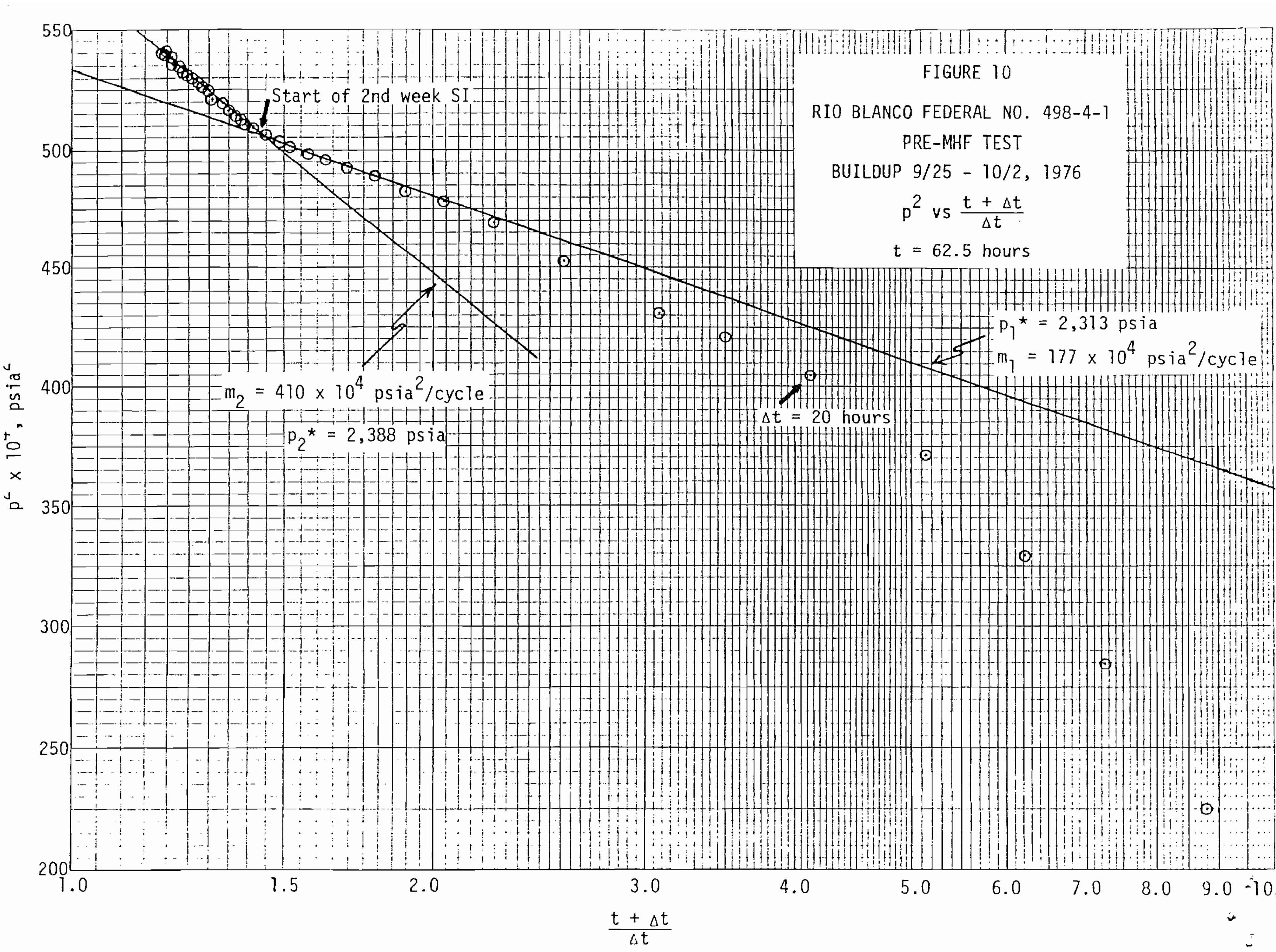


FIGURE 10
RIO BLANCO FEDERAL NO. 498-4-1
PRE-MHF TEST
BUILDUP 9/25 - 10/2, 1976
p^2 vs $\frac{t + \Delta t}{\Delta t}$
t = 62.5 hours
Start of 2nd week SI
m_2 = 410 x 10^4 $psia^2$/cycle
p_2^* = 2,388 psia
p_1^* = 2,313 psia
m_1 = 177 x 10^4 $psia^2$/cycle
Δt = 20 hours
p^2 x 10^4, $psia^2$
550
500
450
400
350
300
250
200
1.0
1.5
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10
$\frac{t + \Delta t}{\Delta t}$

STIMULATION TREATMENT REPORT

DOWELL

B-16

DATE: Oct 22-76

DOWL-494-K PRINTED IN U.S.A.

DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

WELL NAME AND NUMBER	LOCATION	CUSTOMER REPRESENTATIVE	TREATMENT NUMBER
Fed 498-4-1		Bill Abbott	15-03-

POOL

FORMATION

JOB DONE DOWN: TUBING ☐ CASING ☐ ANNULUS ☐

ALLOWABLE PRESSURE: TBG: CSG:

COUNTY

STATE

TYPE OF WELL: OIL ☐ GAS ☐ WATER ☐ INJ. ☐

TYPE OF SERVICE

AGE OF WELL: NEW WELL ☐ REWORK ☐

TOTAL DEPTH	CIRC. BHT.

CASING SIZE	CASING DEPTH	TUBING SIZE	TUBING DEPTH

LINER SIZE	LINER TOP-BOTTOM	PACKER TYPE	PACKER DEPTH

OPEN HOLE	CSG. OR ANUL. VOL.	TBG VOLUME	STATIC BHT.

NAME AND ADDRESS: Rio Blanco Nat Gas Continued

ZIP CODE

REMARKS:

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION:

TIME	INJECTION RATE	INJECTION BBLS IN	PRESSURE CSG.	PRESSURE TBG.	SERVICE LOG
ISIP	37	3313	1100	—	st 15,000 gal PSD 3PPG 20/40 45,000
1146	37	3718	1200	—	st 9,000 gal PSD 4PPG 20/40 36,000
171853	37	3970	1300	—	st 4,000 gal PSD Spacer
131155	37	4066	1500	—	st 23,000 gal PSD 3PPG 20/40 69,000
	37	4687	1400	—	st 10,000 gal PSD 4PPG 20/40 40,000
	37	4967	1400	—	st 3,000 gal PSD Spacer
	37	5039	1400	—	st 22,000 gal PSD 4PPG 20/40 88,000
	37	5655	1200	—	st 3,000 gal PSD Spacer
	37	5727	1300	—	st 22,000 gal PSD 4PPG 20/40 88,000
	37	6343	1500	—	st 3,000 gal PSD Spacer
	37	6415	1600	—	st 5,000 gal PSD 3PPG 10/20 15000
	37	6550	1600	—	st 9000 gal PSD 4PPG 10/20 36,000
	37	6802	1500	—	st 3000 gal PSD Spacer
	37	6874	1500	—	st 10,000 gal PSD 4PPG 10/20 40,000
	37	7154	1500	—	st 5,000 gal PSD 5 PPG 10/20 25,000
	37	7299	1500	—	st 2000 gal PSD Clear Blender & lines
	37	7347	1500	—	st 5000 gal Braker Solution
	37	7467	1700	—	st Flush 1% KCL water
	30	7557	1800	—	slow 10 BPM
	10	7617	1300	—	Shut down Job Complete

TIME LEFT LOCATION	AVG. LIQUID INJ. RATE	ADJ.INJ.RATE (SOLIDS INC.)	TOTAL FLUID PUMPED OIL	WATER

MAX. PRESSURE	AVG. PRESSURE	FINAL PUMP IN PRESSURE	SHUT IN PRESSURE IMMEDIATE	15 MINUTES
			1100 1100	

DOWELL LOCATION

DOWELL REPRESENTATIVE

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT
Sand	100 mesh	225000
Sand	20/40	434000
Sand	10/20	116000

CALL BACK	DATE	CUSTOMER REP. CONTACTED	CUSTOMER CONSIDERED SERVICE	PROD. BEFORE TREATMENT	PROD. AFTER TREATMENT
			☐ SATISFACTORY ☐ UNSATISFACTORY ☐ UNKNOWN	☐ TEST ☐ ALLOWABLE	☐ DAYS ☐ TEST ☐ ALLOWABLE

STIMULATION TREATMENT REPORT

DOWELL

B-17

DWL-494-K PRINTED IN U.S.A.

DOWELL, DIVISION OF THE DOW CHEMICAL COMPANY

DATE: 10-21-76

WELL NAME AND NUMBER	LOCATION	CUSTOMER REPRESENTATIVE	TREATMENT NUMBER
Federal 498-4-1	SE¼ NE¼ Sec 4 4S 98W	Bill Abbott	15-03

POOL:

FORMATION: Mesa Verde

JOB DONE DOWN: TUBING ☐ CASING ☑ ANNULUS ☐

ALLOWABLE PRESSURE: TBG: — CSG: 4000

COUNTY: Rio Blanco

STATE: Colorado

TYPE OF WELL: OIL ☐ GAS ☑ WATER ☐ INJ. ☐

TYPE OF SERVICE: YF4 PSD

AGE OF WELL: NEW WELL ☐ REWORK ☑

TOTAL DEPTH	CIRC. BHT.
6970	

CASING SIZE	CASING DEPTH	TUBING SIZE	TUBING DEPTH
5½ 15.5	6970	—	—

LINER SIZE	LINER TOP-BOTTOM	PACKER TYPE	PACKER DEPTH
—	—	—	—

OPEN HOLE	CSG. OR ANUL. VOL.	TBG VOLUME	STATIC BHT.
—	150	—	

NAME: Rio Blanco Natural Gas Company

AND: 916 Patterson Building

ADDRESS: Denver Colorado 80202 ZIP CODE

REMARKS:

PERFORATED INTERVALS

DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES	DEPTH	NO. OF HOLES
		6150		6230	6280
	17	6152		6232	6288
		6190		6246	6290
		6194		6264	6296
		6214		6278	6298
					6310
					6312

FOR CONVERSION PURPOSES 24 BBLS EQUALS 1000 GALLONS

ARRIVED ON LOCATION:

TIME	INJECTION RATE	BBLS IN	PRESSURE CSG.	TBG.	SERVICE LOG
ISIP	1100				Hold Safety meeting Rig up Dowell
5 min	1050				Mix Tanks For Frac
10 min	1000				Test lines PSI
15 min					Hold Pre Job Safety meeting
10:00	34	0	2200	—	Start 12,000 gal YF4PSD Pad 2/1000 F-75
	37	288	2000	—	St 8000 gal YF4PSD 2PPG 100 mesh 16,000#
	37	496	2100	—	St 3000 gal PSD Spacer
	37	568	2000	—	St 11,000 gal PSD 3PPG 100 mesh 33,000
	37	865	1600	—	St 4,000 gal PSD Spacer
	37	961	1600	—	St 13,000 gal PSD 4PPG 100 mesh 52,000
	37	1273	1700	—	St 5,000 gal PSD Spacer
	37	1393	1800	—	St 15,000 gal PSD 4PPG 100 mesh 60,000
	37	1813	1500	—	St 5,000 gal PSD Spacer
	37	1933	1600	—	St 16,000 gal PSD 4PPG 100 mesh 64000
	37	2381	1400	—	St 5,000 gal PSD Spacer 2/1000 M38
	37	2501	1500	—	St 13,000 gal PSD 2PPG 20/40 Sand 26,000
	37	2839	1300	—	St 14,000 gal PSD 3 PPG 20/40 Sand 42,000
330	37	3217	1300	—	St 4000 gal PSD Spacer

TIME LEFT LOCATION:

AVG. LIQUID INJ. RATE:

AVG. INJ. RATE (SOLIDS INC.):

TOTAL FLUID PUMPED: OIL — WATER —

MAX. PRESSURE:

AVG. PRESSURE:

FINAL PUMP IN PRESSURE:

SHUT IN PRESSURE: IMMEDIATE 1000 15 MINUTES

DOWELL LOCATION:

DOWELL REPRESENTATIVE:

PROPS AND LIQUIDS INJECTED

TYPE	SIZE OR PURPOSE	AMOUNT
Sand	100 mesh	225000#
Sand	20/40	434000#
Sand	10/20	116.000#

CALL BACK	DATE	CUSTOMER REP. CONTACTED	CUSTOMER CONSIDERED ☐ SATISFACTORY ☐ UNSATISFACTORY	PROD. BEFORE TREATMENT	PROD. AFTER TREATMENT

APPENDIX C

RESERVOIR AND ECONOMIC ANALYSIS
FEDERAL 498-4-1
ZONES 1 and 2

RESERVOIR AND ECONOMIC ANALYSIS
FEDERAL 498-4-1
ZONES 1 AND 2

Prepared for

RIO BLANCO NATURAL GAS COMPANY

by

H. K. van Poollen and Associates, Inc.

July, 1976

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RESERVOIR AND ECONOMIC ANALYSIS
FEDERAL 498-4-1
ZONES 1 AND 2

INTRODUCTION

Rio Blanco Natural Gas Company's Well 498-4-1 was drilled through the Wasatch, Fort Union and Mesaverde Formations. The initial completions were in the Mesaverde group. Two frac jobs were performed over several intervals. The well has subsequently been flow-tested and pressure buildups run in order to define reservoir and production parameters. The commercial exploitation of this well has been estimated from the parameters obtained from testing. Several previous reports have been submitted by H. K. van Poollen and Associates, Inc., concerning these formations and this well, in particular, and will be referred to within this discussion.

CONCLUSIONS

1. The two commingled flow tests were run with the final flow rate of the first test stabilized at ±225 MSCF/D against a tubing pressure of 65 psi. The second flow test did not stabilize due to cyclic fluid and gas production.
2. From the performance of Federal 498-4-1 in both flow tests, it is thought that an adequate method for liquid removal will be required to maintain the maximum gas production rates.
3. The well should be produced against a minimum amount of backpressure. A low pressure (50 to 100 psi) gathering system could connect the area wells and tie in to a compressor station which would boost the pressure to an expected line pressure of 480 psi.

4. The two flow tests and the buildup test supply adequate data to model the well performance of Federal 498-4-1. The model shows an initial rate at 30 days of 205 MSCF/D and a rate after one year of 156 MSCF/D.
5. The buildup tests indicate a long linear flow period. How much of the flow tests are exhibiting linear flow rather than radial flow is unknown.
6. Economics run on the 498-4-1 model results and based on a well cost of $400,000 with 25% tangibles, are summarized below:

Initial Gas Price $	Escalation Clause $/yr	Before Taxes Undiscounted Payout	Before Taxes ROR
0.87	0.02	7.83	12.11
1.00	0.02	6.86	14.30
1.42	0.04	4.74	23.05

WELL HISTORY

Following drilling operations, pipe was set through the Mesaverde Formation. Gas-bearing zones behind pipe are the Wasatch, Fort Union and Mesaverde. Fracture stimulation jobs were performed on two gross intervals of the Mesaverde. A short summary of these frac jobs is shown in Table I.

A letter report from Wayne Beeks to Bob Chancellor of July 31, 1975, commented on the difference in performance between the two frac jobs. The report concluded that the poor flow performance of Frac No. 2 can be attributed to the imbedment of the frac sand in the incompetent sandy shale interval. This resulted in the loss of 60% of the frac volume. Study of the recent commingled flow tests (Frac No. 1 and Frac No. 2) leaves some question as to the contribution of the second zone.

A flow test was run immediately following each frac job. These tests were of relatively short duration and can be used for comparison purposes. The first zone (Frac No. 1) was flowed for ten days with an average flow rate of 225 MSCF/D. The flow test was immediately followed by a pressure buildup test. Results of the buildup analysis will be discussed later.

The second zone (Frac No. 2) never established a stabilized flow rate during swabbing operations. The rate fluctuated from 2.3 MMSCF/D after the first swab pull of the day to 50 to 100 MSCF/D after the well was unloaded.

A 32-day flow test of commingled production (i.e., Zones 1 and 2) was begun on March 2, 1976. This test was followed by a 48-day pressure buildup. A final 27-day flow test was run during June, 1976. The well is currently shut in.

FLOW TESTS (Commingled Production)

A flow test was initiated following the Frac No. 2 rework. In this test, the well was vented to the atmosphere. The flow rates reported declined from an initial 600 MSCF/D to a relatively stable 225 MSCF/D before dropping to 200 MSCF/D for the last day (day 32). Figure 1 presents the reported flow data.

The flow test data were presented to the U.S.G.S. to consider the economic production of these zones. The U.S.G.S. requested that an additional test be run. At this time, H. K. van Poollen and Associates, Inc., was asked to conduct another flow test. Rather than duplicate the data already obtained from the first flow test, it was decided to vary the tubing pressure and measure the different flow rates. The raw data of this test are presented in Table II and Fig. 2.

The well had cyclic production through most of the test. Flow rate would fluctuate as much as 213 MSCF/D as the well unloaded excess water. To account for the cycling effect, the critical flow prover charts were planimetered to determine an accurate average flow rate for the day. However, the well was not cycling on a 24-hour period and this fluctuation shows up in the flow rate table and curve. A statistical approach has also been used to smooth the data. Three-day and five-day moving averages are presented in Fig. 3.

A fluid flow test was run during the last four days. The data are shown in Table III. The water/oil ratio of the fluid production was measured and a water analysis done. An average water cut of 71.2% was used to calculate the net oil production of 1 B/D. A copy of the water analysis from Dowell is shown in Table IV. It shows that the Guar gum test is positive and, therefore, shows that frac fluid is still returning. It can, therefore, be concluded that the second frac is still cleaning up.

A comparison of the first flow test, Fig. 1, and the second flow test, Fig. 2, shows a much lower flow rate in the second test. The tubing pressure of the second test was kept significantly higher. A correlation between the flow rate and tubing pressure of the second test was made with an exponential curve fit (Fig. 4). This correlation is for the linear flow period and must be modified when the well has reached radial flow.

The data obtained in the first and second flow tests were used to model the wells' performance on the Garrett Systems "GASIM" Program. The results of these simulation runs will be discussed later.

PRESSURE BUILDUP TESTS

As previously mentioned, two pressure buildup tests have been run on 498-4-1. The first test was run on the zones of Frac Job No. 1. This test was run immediately following the cleanup. Analysis and results of this test have been reported in the H. K. van Poollen and Associates, Inc., report of August 15, 1975, on "Frac Treatment No. 1, Well Government 498-4-1, Rio Blanco County, Colorado, Stimulation Results with Performance Prediction". The results are summarized below:

$$p^* = 2{,}140$$

$$kh = 1.014 \text{ md-ft}$$

$$k = 0.0267 \text{ md}$$

$$s = -4.65$$

Estimated Frac Length = 95.8 ft.

In addition, the pressure data were analyzed for linear flow effects. In the tight gas sands of Colorado, the linear flow period of a buildup can be extremely lengthy. This period has often been mistaken for the radial flow period and has been inadvertently used for analysis. The first buildup showed a wellbore fillup period followed by a linear flow period. The well was not shut in a sufficient length of time to exhibit total radial behavior.

A second buildup was run from April 2, 1976 until May 21, 1976, with both the Frac No. 1 and the Frac No. 2 zones open. This test followed the initial commingled flow test.

The buildup data were plotted using the available techniques such as pressure vs log time, pressure vs log $\frac{(t + \Delta t)}{\Delta t}$, p^2 vs log $\frac{(t + \Delta t)}{\Delta t}$, and m(p) vs log $\frac{(t + \Delta t)}{\Delta t}$. Analysis of the methods gave comparable results. Since the m(p) function should give the most reliable results, only the m(p) curve is attached (Fig. 5).

The plot of log $\Delta[m(p)]$ vs log buildup time (Fig. 6) indicates a slope of about 0.5 (which is often associated with the linear flow period) during the time period of 6 hours to +200 hours. Later data suggest the possibility of radial flow and the m(p) vs log $\frac{(t + \Delta t)}{\Delta t}$ (Fig. 5) shows little or no curvature after about 240 hours $\left(\frac{(t + \Delta t)}{\Delta t} \simeq 4.0\right)$. This suggests that the extrapolation probably approaches radial flow configuration.

Analysis of the data yields the following results:

$$kh = 1.33 \text{ md-ft}$$

$$k = 0.024 \text{ with } h = 56 \text{ ft (both zones)}$$

$$s = -3.94.$$

This compares with the permeability calculated from the first buildup ($k = 0.027$ md) and also the core permeability of 0.25 md, corrected to 0.025 md when overburden effects are added. The calculated skin is -3.94, showing a fractured well with a frac length of 47 feet. The reliability of the frac length calculation from the skin effect technique is quite questionable.

CALCULATIONS FOR SECOND BUILDUP TEST

$$p^* = 2{,}180$$

$$kh = \frac{1{,}637 \times q_{sc} \times T}{m} = \frac{1{,}637 \times 285 \times 664}{233 \times 10^6} = 1.33 \text{ md-ft}$$

$$k = 0.024 \text{ md}$$

$$s = 1.151 \left[\frac{-181 - 7}{233} - \log \frac{0.024}{(0.11)(0.4)(0.0144)(0.0525)(0.001)} + 3.23\right] = -3.94$$

$$r_w' = r_w\, e^{-s} = 0.229\, e^{-(-3.94)} = 11.77 \text{ ft}$$

Frac length ≃ 47 ft.

If the Frac No. 2 interval is not open and the net pay $h = 38$ feet, then the results are:

$$k = 0.035 \text{ md}$$

$$s = -4.13$$

$$r_w' = 14.27 \text{ ft}$$

Frac length = 57 ft.

Presented below is a summary of pressure buildup results:

Test	kh md-ft	k md	s	Estimated Frac Length ft	p*
1	1.014	0.027	-4.65	96	2,140
2	1.33	0.024	-3.94	47	2,180

The discussion of radial versus linear flow still has not been completely satisfied. The second buildup exhibits either a second zone breaking in or the actual change to radial flow. It is recommended to run a much longer drawdown test if and when the well is put in commercial production.

RESERVOIR EVALUATION AND MODELING

In order to use the data obtained from the various flow and buildup tests to the best advantage, a computer model of the well and reservoir was run. The computer programs used were the Garrett Computing Systems Gas Well Simulation and Gas Well Radius of Investigation Program. Using these two programs, the flow test data were analyzed, an effective permeability calculated (including frac), and a 20-year production simulation generated.

The initial step in developing this model was to evaluate the test data using the "GRIP" (Gas Well Radius of Investigation Program) Program. This program takes the flow rate and time data for the flow tests and calculates an effective average permeability for various radii from the well. Selection of 4 to 6 permeabilities and their respective radii is made from all data input.

The selected permeabilities and radii are input into the "GASIM" (Gas Well Simulation) Program to allow for a permeability variation in the reservoir. The "GASIM" output is presented in Table V and has been plotted as a decline curve in Fig. 7.

This simulation was compared to a number of other simulations which were made for the report titled "Fort Union/Mesaverde Sandstones, North Piceance Basin Core, Log, Test and Gas Deliverability Data". In this report, simulations were made with permeabilities of 0.01 md, 0.027 md, 0.1 md and 0.5 md. These runs were made with a frac simulated in the effective well-bore radius input. The new simulation matches the k = 0.027 md run within 2% in early years and 13% after 20 years.

The match of two deliverability runs made with different type permeability inputs supports the actual input of the flow test data. This match, combined with the calculated permeability of the buildup tests, supports the use of the new gas well simulation as an adequate prediction of future well performance.

ECONOMICS

Using the gas deliverability rates from the "GASIM" program, economic runs were made. The parameters used in the runs are shown in Table VI with the major ones presented below:

Total Well Cost	$400,000, 25% tangible
Royalty	12.5%
Working Interest	100%
Condensate Producing Rate	1 BBl/D
Condensate Sales Price	$10/BBl
Project Life	20 years
BTU Adjustment	14% (1,140 BTU to 1,000 BTU sales).

Eight runs were made changing the initial wellhead gas price and the escalator clause. These cases are outlined below:

Case	Initial Price $/MSCF	Escalation Factor $/yr
1 (Base)	0.87	0.02
2	1.00	0.02
3	1.25	0.02
4	1.50	0.02
5	0.87	0.03
6	1.25	0.03
7	1.50	0.03
8	1.42	0.04

Table VII summarizes the results of all eight runs. Case No. 1 (base case) had a before-tax undiscounted payout of 7.83 years and a rate of return of 12.11%. The after-tax figures assume that a tax credit in this project can be used to reduce overall company taxes. In this manner, a tax credit acts as a cash inflow to a singular project. The after-tax payout of 7.39 years and rate of return of 12.42% exhibits this affect. Any consideration of the after-tax figures should be done with this tax credit condition in mind.

Cases 2 through 7 were run to analyze the affect of changing initial prices and the escalator clause. This is shown in Table VII and Figs. 8 and 9. An increase in the initial price of gas will have a substantial beneficial affect on the economics. The increase in the escalation clause has a relatively negligible affect.

Case 8 was run with the recently announced gas ceiling price of $1.42/MSCF and a $0.04/year escalator clause. This case should reflect the actual price conditions as Federal 498-4-1 was completed in Zones 1 and 2 of the Mesaverde in June and July, 1975. The before-tax undiscounted payout is 4.74 years with a rate of return of 23.05%. Under these conditions, Federal 498-4-1 should be considered economic.

TABLE I

FEDERAL 498-4-1

FRACTURE STIMULATIONS IN THE MESAVERDE FORMATION

Frac Treatment	Date M/D/Y	Gross Interval	Remarks
1	6/25/75	6,850-6,928	50,000 gal. Halliburton My-T-Frac (gelled water) with 130,000 lbs. of sand, 32 BPM, 1,900 psi. Greater than 89% of frac fluid recovered. Flow test following job- 225 MSCF/D. Flow was heading.
2	7/22/75	6,594-6,742	57,000 gal. Halliburton My-T-Frac (gelled water) with 27,000 lbs. 40/60 sand and 127,000 lbs. 20/40 sand, 39 BPM, 2,400 psi. 21% of frac fluid recovered as of 7/31/75.
2a	2/ 6/76- 3/ 2/76	6,594-6,742	Frac No. 2 rework. Recovered 53% of frac fluid before killing well in which another 150 BBls of fluid were lost. First flow test commenced following the swabbing operations.

TABLE II

FLOW TEST DATA
ZONES 1 AND 2

Date M/D/Y	Day of Test	Orifice Size in.	Tubing Pressure psig	Average Δp in. Hg	Q MSCF/D	Remarks
6/ 3/76	1	3/4		27.44	387.4	
6/ 4/76	2	3/4	325	53.28	440.8	
6/ 5/76	3	3/4	320	41.67	375.1	
6/ 6/76	4	3/4	320	29.74	301.8	
6/ 7/76	5	3/4	320	19.97	237.7	
6/ 8/76	6	3/4	320	22.57	254.9	
6/ 9/76	7	3/4	320	19.43	234.0	
6/10/76	8	3/4	320	17.23	218.0	
6/11/76	9	1/2	320	53.61	197.1	Cycling
6/12/76	10	1/2	320	51.29	190.8	Well cycling
6/13/76	11	1/2	320	45.73	176.9	Cycling
6/14/76	12	1/2	320	49.59	186.8	Slight cycling
6/15/76	13	1/2	320	13.13	83.6	
6/16/76	14	1	110	11.26	312.9	Blew well down in attempt to clean up water. Big fluid dump.
6/17/76	15	1	40-50	38.58	636.9	Cycling
6/18/76	16	1/2	250	28.83	131.6	Cycling
6/19/76	17	1/2	250	45.37	176.1	Cycling
6/20/76	18	1/2	250	47.51	181.5	Cycling
6/21/76	19	1/2	250	11.89	79.0	Cycling
6/22/76	20	1/2	200	2.02	31.4	
6/23/76	21	1/2	190	86.58	276.7	Cycling with 1/2 in. stream of fluid
6/24/76	22	1/2	190	42.05	167.3	
6/25/76	23	1/2	190	42.43	168.8	
6/26/76	24	1/2	190	36.57	147.3	
6/27/76	25	1/2	190	35.76	151.3	
6/28/76	26	1/2	190	38.58	158.4	Cycling 1/4 in. stream
6/29/76	27	1/2	190	33.67	145.1	Cycling
6/30/76	28	1/2	190	11.26	76.1	Cycling
7/ 1/76	29	1/2	190	45.01	175.5	Cycling

TABLE III

RIO BLANCO FEDERAL 498-4-1
FLUID FLOW RATE

Date M/D/Y	Time	Incremental Fluid Recovered Bbls	Total Fluid Bbls
6/29/76	11 a.m.	0	0
6/30/76	11 a.m.	3.27	3.27
7/ 1/76	11 a.m.	0	3.27
7/ 2/76	10 a.m.	7.09	10.36

Flow Rates (gross):

$$\frac{\text{Total flow}}{\text{Total time}} = \frac{10.36 \text{ Bbls}}{71 \text{ hrs}} = 0.15 \text{ Bbl/hr}$$

$$= 3.5 \text{ Bbl/D}$$

Average Water Cut = 71.2%

Net Flow Rate = 3.5 Bbl/D x (1-0.712) = 1 Bbl/D Condensate

TABLE IV

WATER ANALYSIS

DWL-451-2-A DOWELL

DOWELL DIVISION OF THE DOW CHEMICAL COMPANY

LABORATORY LOCATION Casper

API WATER ANALYSIS REPORT FORM

DATE July 9, 1976

LAB NO CL5908

Company			Sample No.	Date Sampled
Rio Blanco Nat. Gas			38536	6-28-76

Field	Legal Description	County or Parish	State
		Rio Blanco	Colo.

Lease or Unit	Well	Depth	Formation	Water, B/D
Piceance Creek	498-4-1	6900	Mesa Verde	

Type of Water (Produced, Supply, etc.)	Sampling Point	Sampled By
Produced		

DISSOLVED SOLIDS

CATIONS	*mg/l*	*me/l*
Sodium, Na (calc.)	4043	175.8
Calcium, Ca	122	6.1
Magnesium, Mg	36	3.0
Barium, Ba		

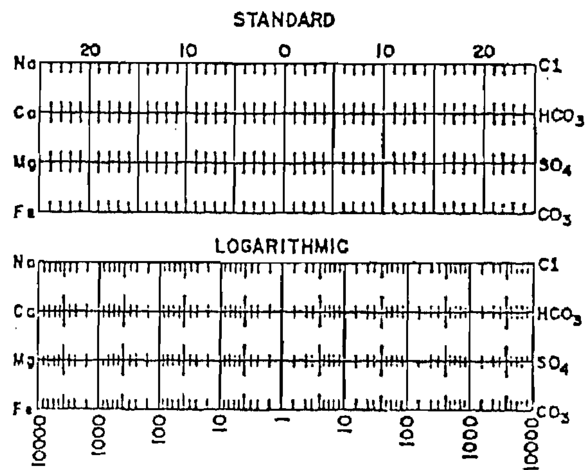
ANIONS	*mg/l*	*me/l*
Chloride, Cl	6,100	174.3
Sulfate, SO_4	15	.3
Carbonate, CO_3	0	---
Bicarbonate, HCO_3	630	10.3

Total Dissolved Solids (calc.)	
Iron, Fe (total)	140
Sulfide, as H_2S	

OTHER PROPERTIES

pH	6.9
Specific Gravity, 60/60 F.	1.006
Resistivity (ohm-meters) ____ F.	

WATER PATTERNS — *me/l*



REMARKS & RECOMMENDATIONS:

Grindout - 100% water .2% solid (iron)

Guar gum test - positive (strong)

J. E. White ml
J. E. White
JEW/mhh

J. Warembourg
D15 - Denver Regional Office
Sales - Casper Office File

TABLE V

GAS WELL SIMULATION

PREPARED FOR	PROJECT NO. 0
RIO BLANCO NATURAL GAS	DATA FILE: BURT1
BY H.K. VAN POOLLEN &ASSOC.	DATE: 07/14/76.
FEDERAL #498-4-1	TIME: 18.41.15.
PRODUCTION CURVES GENERATED	
FROM FLOW DATA 2/76-7/76	

G A S   W E L L   S I M U L A T I O N

ACRES	640	NET THICKNESS, FT.	38.0
INITIAL PRESSURE, PSIA	2160	RESERVOIR TEMPERATURE	206
POROSITY, PCT.	11.50	WATER SAT., PCT.	56.0
GAS GRAVITY	.700	VISCOSITY, CP.	.0176
INITIAL 'Z'	.860	GAS-IN-PLACE, BCF	7.140
WELL DEPTH, FT.	6926	FLOW STREAM ID	0.
WELLHEAD TEMPERATURE	50	FLOW STREAM OD	2.000
*SERIES AVG. MDS	.087	EST. DAYS TO STABILIZE	2422
RADIUS USED IN AVG. MDS	400	COMPLETION EFFICIENCY	100.00
WELLBORE RADIUS, FT.	1.000	PROJECT LIFE (YEARS)	21.0

ENDING DATE	CALC. AOF MCF/D	AVG. SALES MCF/D	ENDING DELVR. MCF/D	CUM. PROD. BCF	CUM. REC. PCT.	DELVR. PSIA	S.I. PSIA
1- 1-76	221*	0	221*	0.	0.	100	2160
1- 2-76	221	221	221	.000	.0	100	2160
1- 4-76	221	221	221	.001	.0	100	2160
1- 7-76	221	220	221	.001	.0	100	2160
1-14-76	221	220	220	.003	.0	100	2159
1-31-76	221	213	205	.006	.1	100	2158
2-28-76	205	199	192	.012	.2	100	2156
3-31-76	193	188	184	.018	.3	100	2155
4-30-76	184	181	178	.023	.3	100	2153
5-31-76	179	176	174	.029	.4	100	2151
6-30-76	174	172	170	.034	.5	100	2150
12-31-76	171	163	156	.064	.9	100	2141
3-31-77	156	154	151	.078	1.1	100	2137
6-30-77	152	149	148	.091	1.3	100	2133
9-30-77	148	146	144	.105	1.5	100	2129
12-31-77	145	143	141	.118	1.7	100	2125
6-30-78	142	139	137	.143	2.0	100	2118
12-31-78	137	135	133	.168	2.4	100	2110
6-30-79	133	131	130	.192	2.7	100	2103
12-31-79	130	128	127	.215	3.0	100	2096
6-30-80	128	126	125	.238	3.3	100	2090
12-31-80	126	124	123	.261	3.7	100	2083
12-31-81	124	122	120	.305	4.3	100	2070
12-31-82	121	119	117	.349	4.9	100	2057
12-31-83	118	116	115	.391	5.5	100	2044
12-31-84	115	114	113	.433	6.1	100	2032
12-31-85	113	112	111	.474	6.6	100	2020
12-31-86	111	110	109	.514	7.2	100	2008
12-31-87	109	108	107	.553	7.7	100	1996
12-31-88	107	106	105	.592	8.3	100	1986
12-31-89	106	105	104	.630	8.8	100	1975
12-31-96	104	691	94	.882	12.4	100	1904

**166.0 MINUTES AFTER WELL OPENED.

*The series average permeability reported here is a dummy permeability and is not used in the deliverability calculations.

TABLE VI

RIO BLANCO NATURAL GAS
FEDERAL 498-4-1
ECONOMICS

Royalty: 12.5%

Working Interest: 100%

Investment:

$400,000 drilling, 25% tangible

Operating Costs: $125/month

Federal Income Tax Rate: 48%

Depletion Percentage: 22%

Depreciation Method: units of production

Condensate Production: 1 BBl/day

Condensate Price: $10/Bbl

Discounting Method: annual mid-period at 10%

Project Life: 20 years

Prices

Case	Initial Price $/MSCF	Escalation Factor $/year
1	0.87	0.02
2	1.00	0.02
3	1.25	0.02
4	1.50	0.02
5	0.87	0.03
6	1.25	0.03
7	1.50	0.03
8	1.42	0.04

TABLE VII

RIO BLANCO NATURAL GAS
FEDERAL 498-4-1
ECONOMICS

			Before Taxes					After Taxes				
Case	Initial Price $	Escalation $	Payout Undiscounted	DCF POP	Profit / Investment	Profit $M	Profit Discounted @ 10% $M	Payout Undiscounted	DCF ROR	Profit / Investment	Profit $M	Profit Discounted @ 10% $M
1	0.87	0.02	7.83	12.11	1.49	597.8	51.8	7.38	12.42	1.04	417.3	42.4
2	1.00	0.02	6.86	14.30	1.79	717.8	109.4	6.55	14.45	1.23	491.5	77.6
3	1.25	0.02	5.52	18.67	2.37	948.5	220.1	5.38	18.20	1.59	634.2	145.3
4	1.50	0.02	4.60	23.20	2.95	1,179.3	330.7	4.56	21.95	1.94	776.9	[illegible]
5	0.87	0.03	7.57	12.89	1.70	678.3	77.6	7.17	13.20	1.17	467.7	58.6
6	1.25	0.03	5.42	19.45	2.57	1,029.0	245.8	5.30	18.33	1.71	684.5	161.4
7	1.50	0.03	4.54	23.83	3.15	1,259.7	356.5	4.51	22.58	2.07	827.2	229.0
8	1.42	0.04	4.74	23.05	3.17	1,266.4	346.9	4.68	21.95	2.08	831.9	223.5

NOTES: 1. 20-year project life

2. This economic program assumes that a tax credit in the first year can be used to reduce the overall company taxes. In this manner, a tax credit acts as a cash inflow to a singular project. As a result of this, the after-tax figures are higher than the before-tax figures.

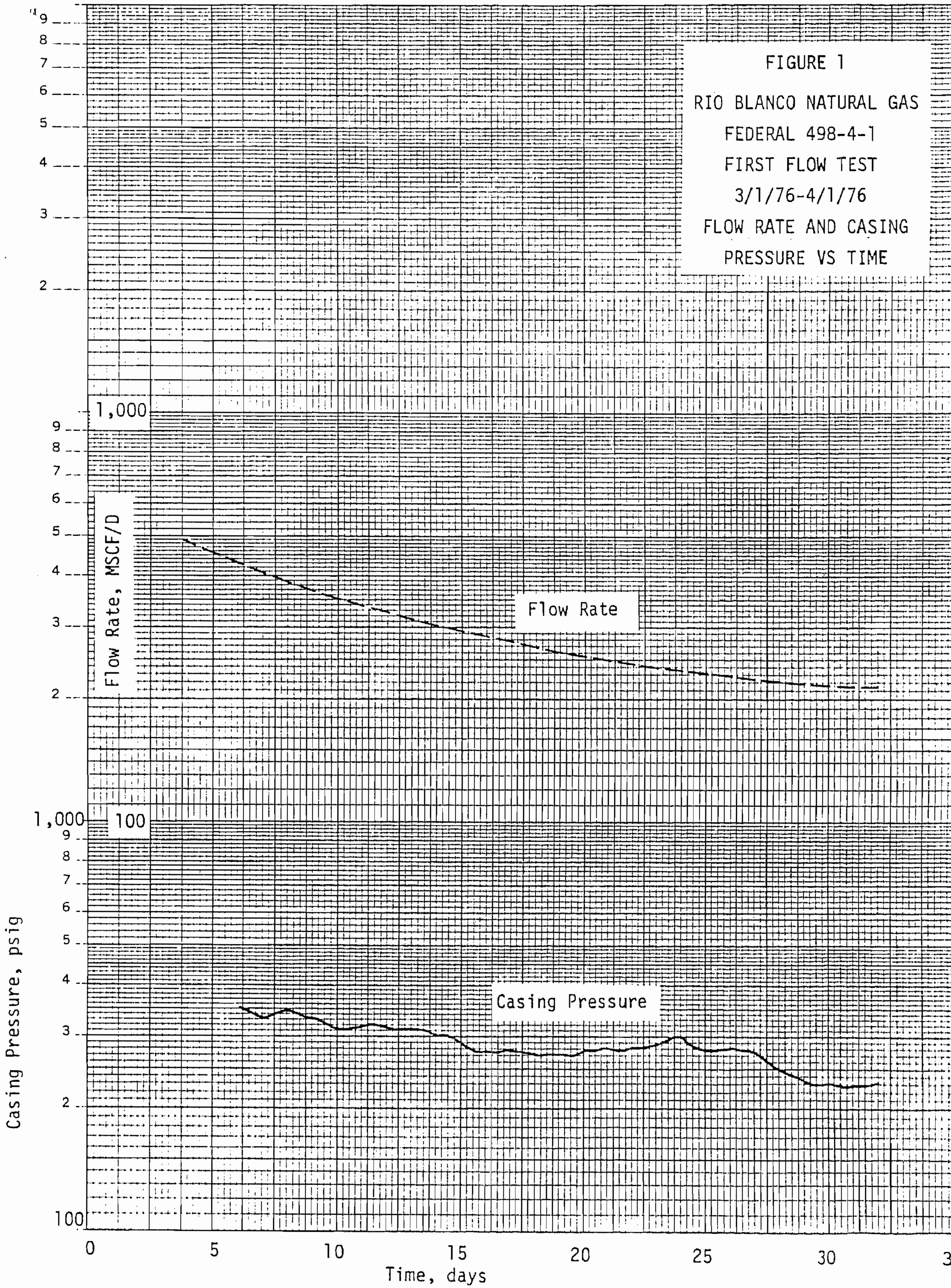


FIGURE 1
RIO BLANCO NATURAL GAS
FEDERAL 498-4-1
FIRST FLOW TEST
3/1/76-4/1/76
FLOW RATE AND CASING
PRESSURE VS TIME
Flow Rate, MSCF/D
Flow Rate
Casing Pressure
Casing Pressure, psig
Time, days
1,000
100
0
5
10
15
20
25
30

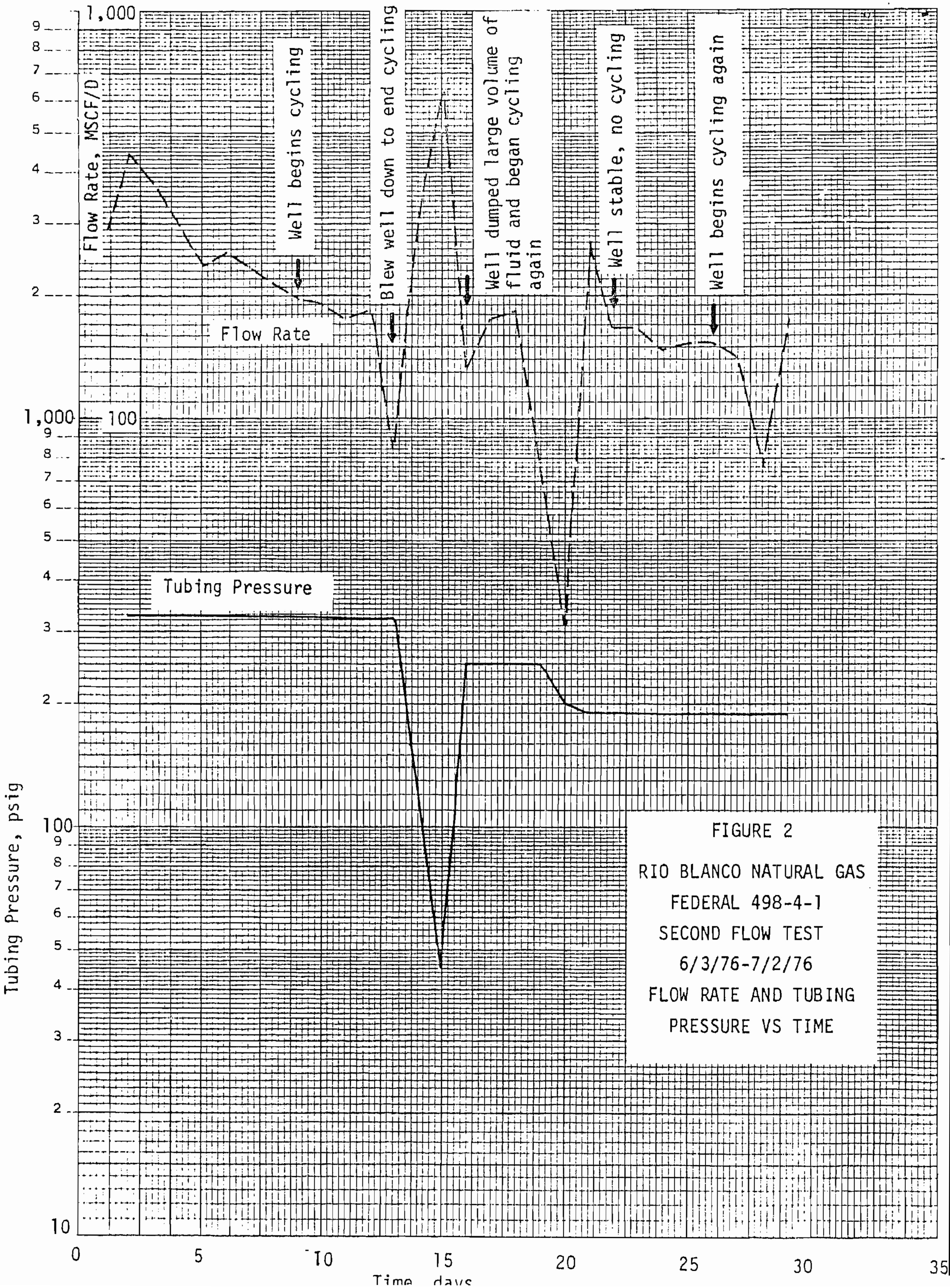


FIGURE 2

RIO BLANCO NATURAL GAS

FEDERAL 498-4-1

SECOND FLOW TEST

6/3/76-7/2/76

FLOW RATE AND TUBING PRESSURE VS TIME

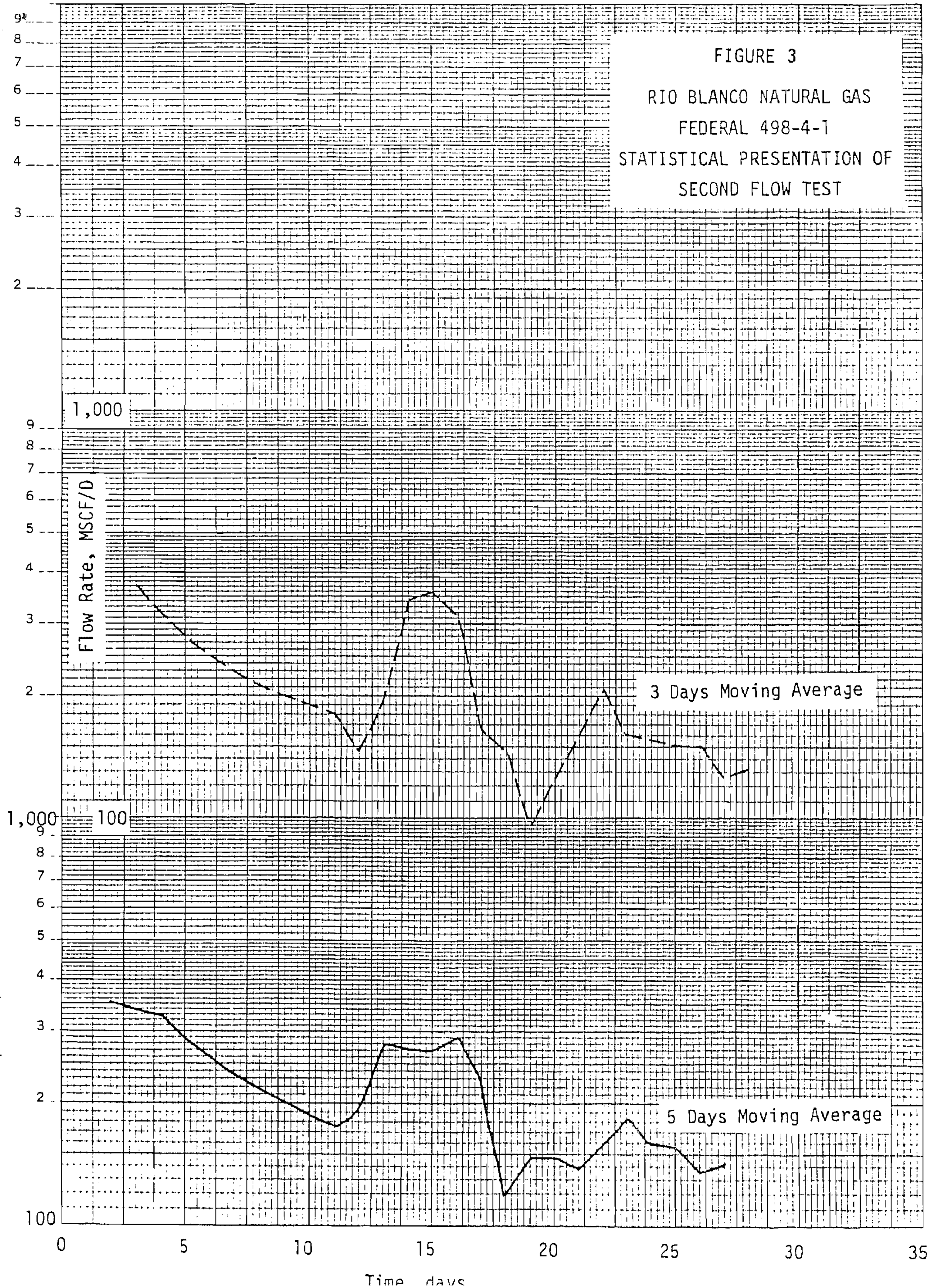


FIGURE 3
RIO BLANCO NATURAL GAS
FEDERAL 498-4-1
STATISTICAL PRESENTATION OF
SECOND FLOW TEST
3 Days Moving Average
5 Days Moving Average
Flow Rate, MSCF/D
Flow Rate, MSCF/D
1,000
100
1,000
100
0
5
10
15
20
25
30
35
Time, days

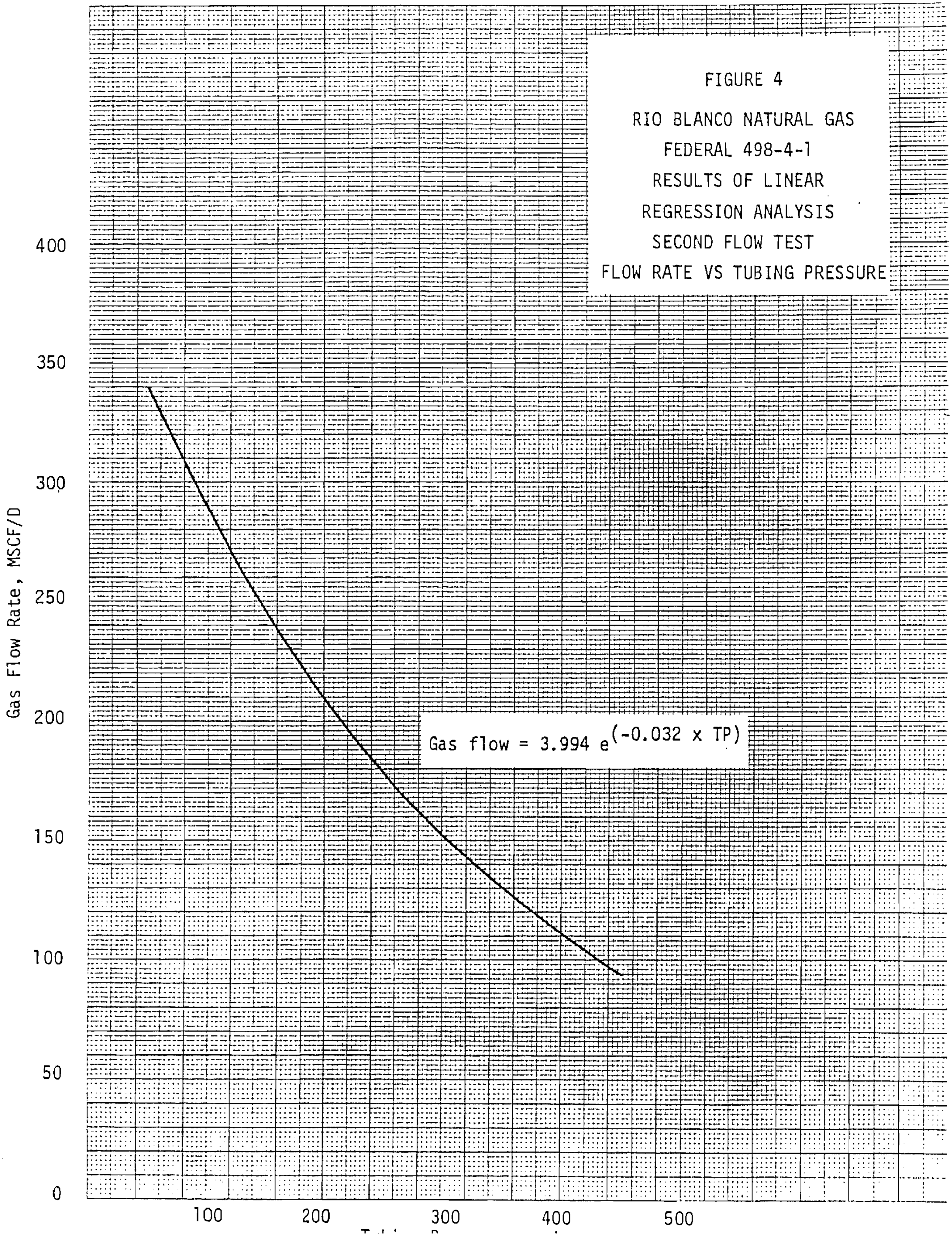


FIGURE 4

RIO BLANCO NATURAL GAS

FEDERAL 498-4-1

RESULTS OF LINEAR

REGRESSION ANALYSIS

SECOND FLOW TEST

FLOW RATE VS TUBING PRESSURE

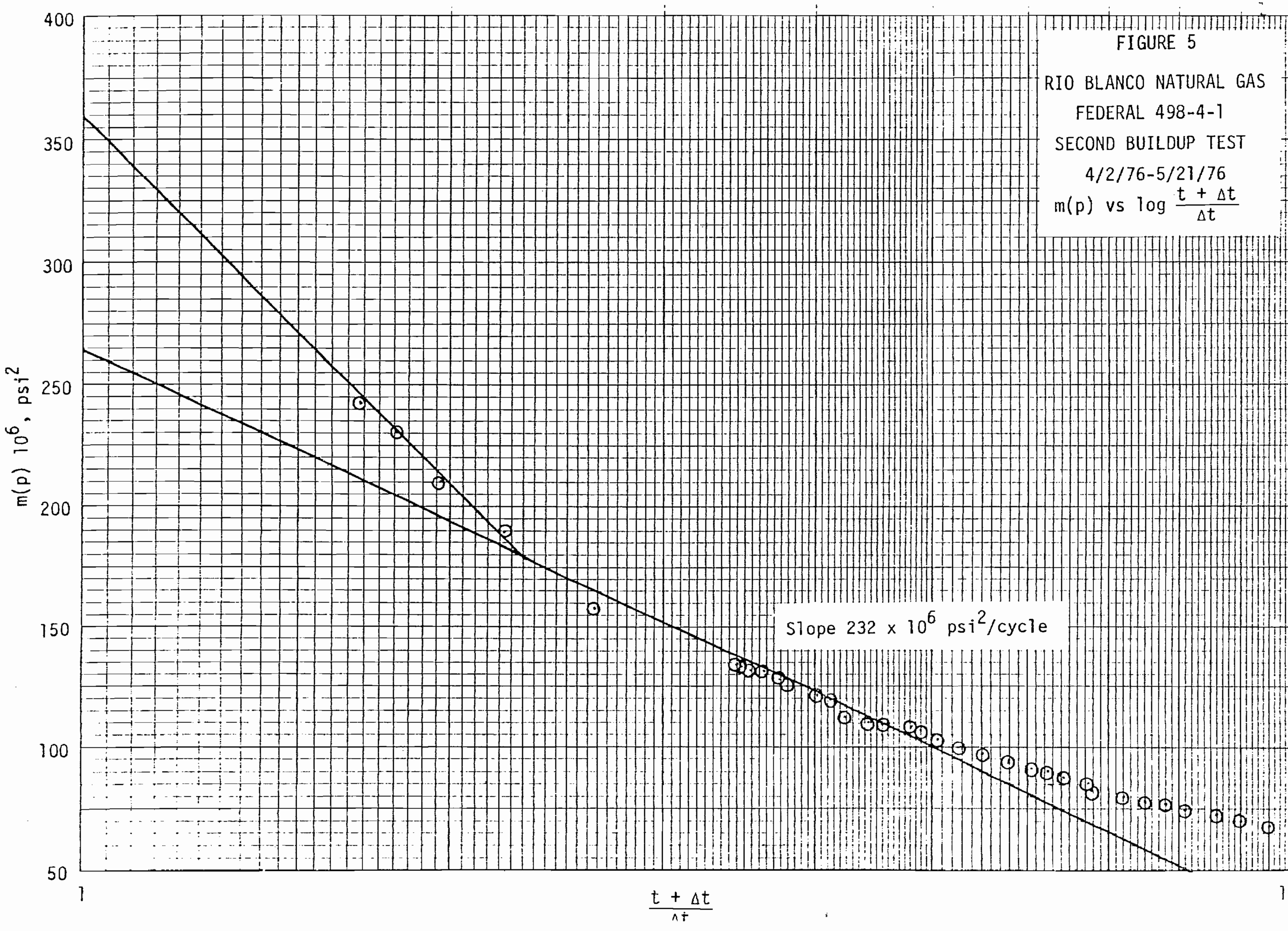


FIGURE 5
RIO BLANCO NATURAL GAS
FEDERAL 498-4-1
SECOND BUILDUP TEST
4/2/76-5/21/76
m(p) vs log $\frac{t + \Delta t}{\Delta t}$
Slope 232 x 10^6 psi^2/cycle
m(p) 10^6, psi^2
400
350
300
250
200
150
100
50
1
1
$\frac{t + \Delta t}{\Delta t}$

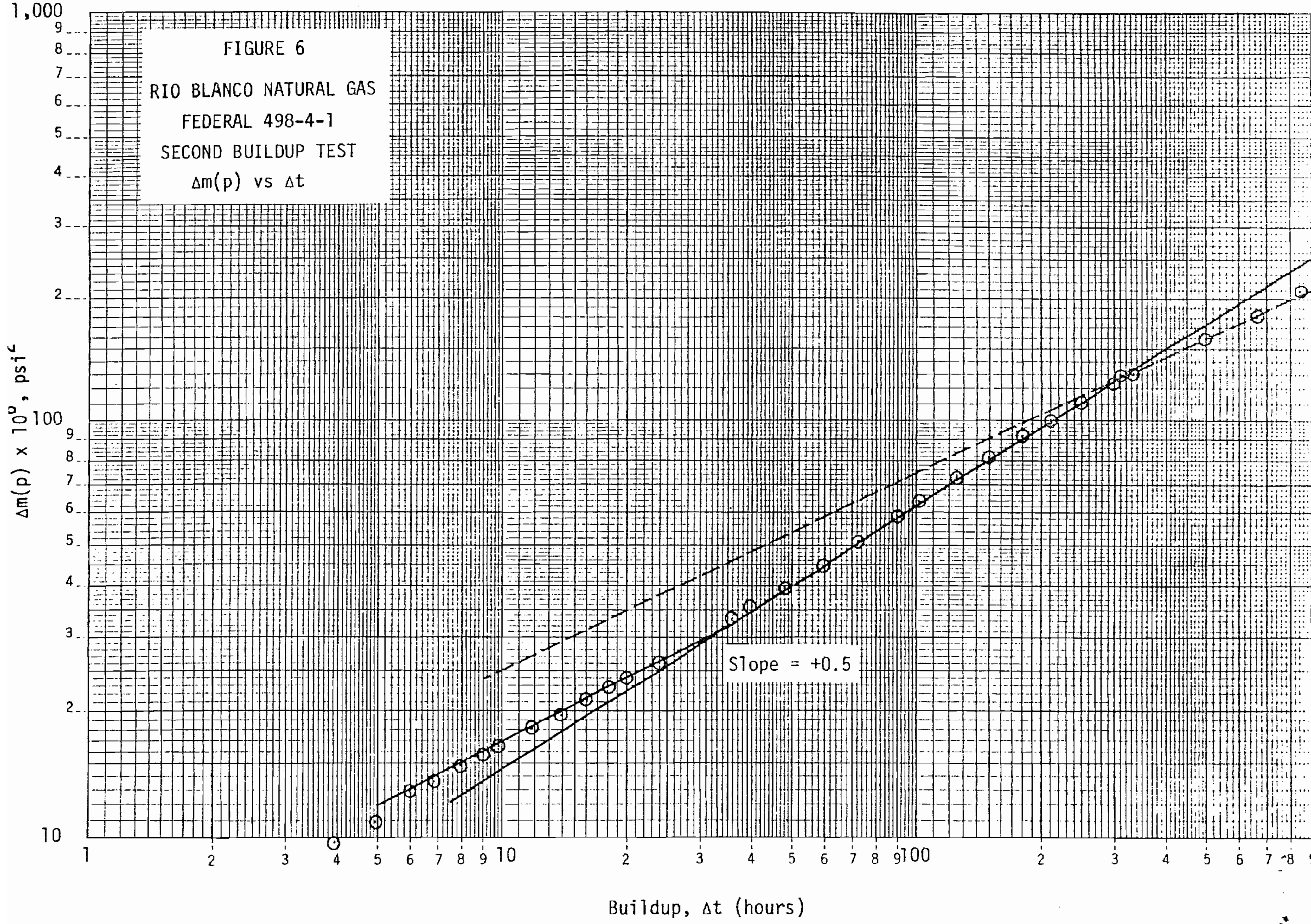


FIGURE 6
RIO BLANCO NATURAL GAS
FEDERAL 498-4-1
SECOND BUILDUP TEST
Δm(p) vs Δt
Slope = +0.5
Δm(p) x 10⁶, psi²
Buildup, Δt (hours)
1,000
100
10
1
10
100

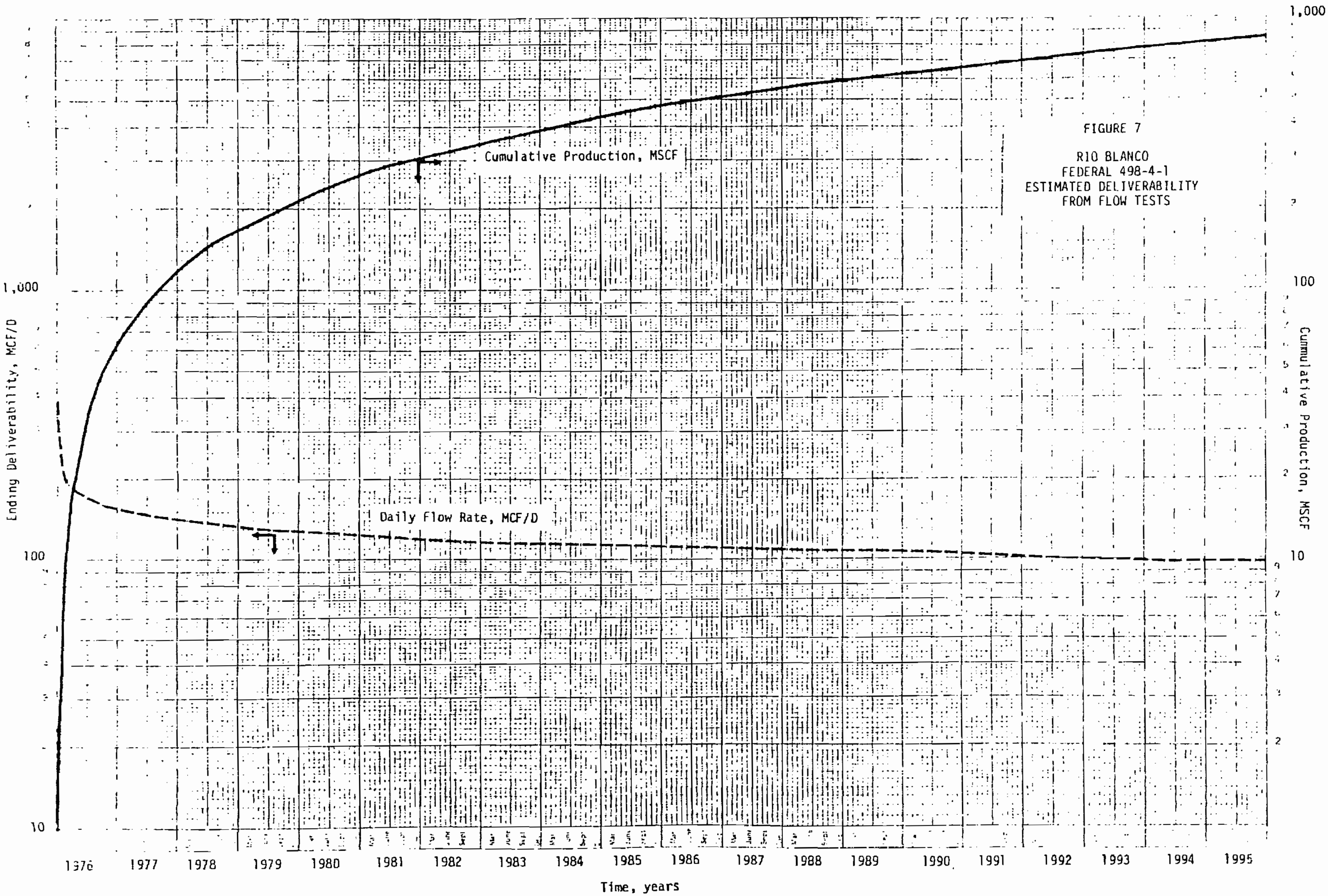


FIGURE 7
RIO BLANCO
FEDERAL 498-4-1
ESTIMATED DELIVERABILITY
FROM FLOW TESTS
Cumulative Production, MSCF
Daily Flow Rate, MCF/D
Ending Deliverability, MCF/D
Cummulative Production, MSCF
1,000
100
10
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
Time, years

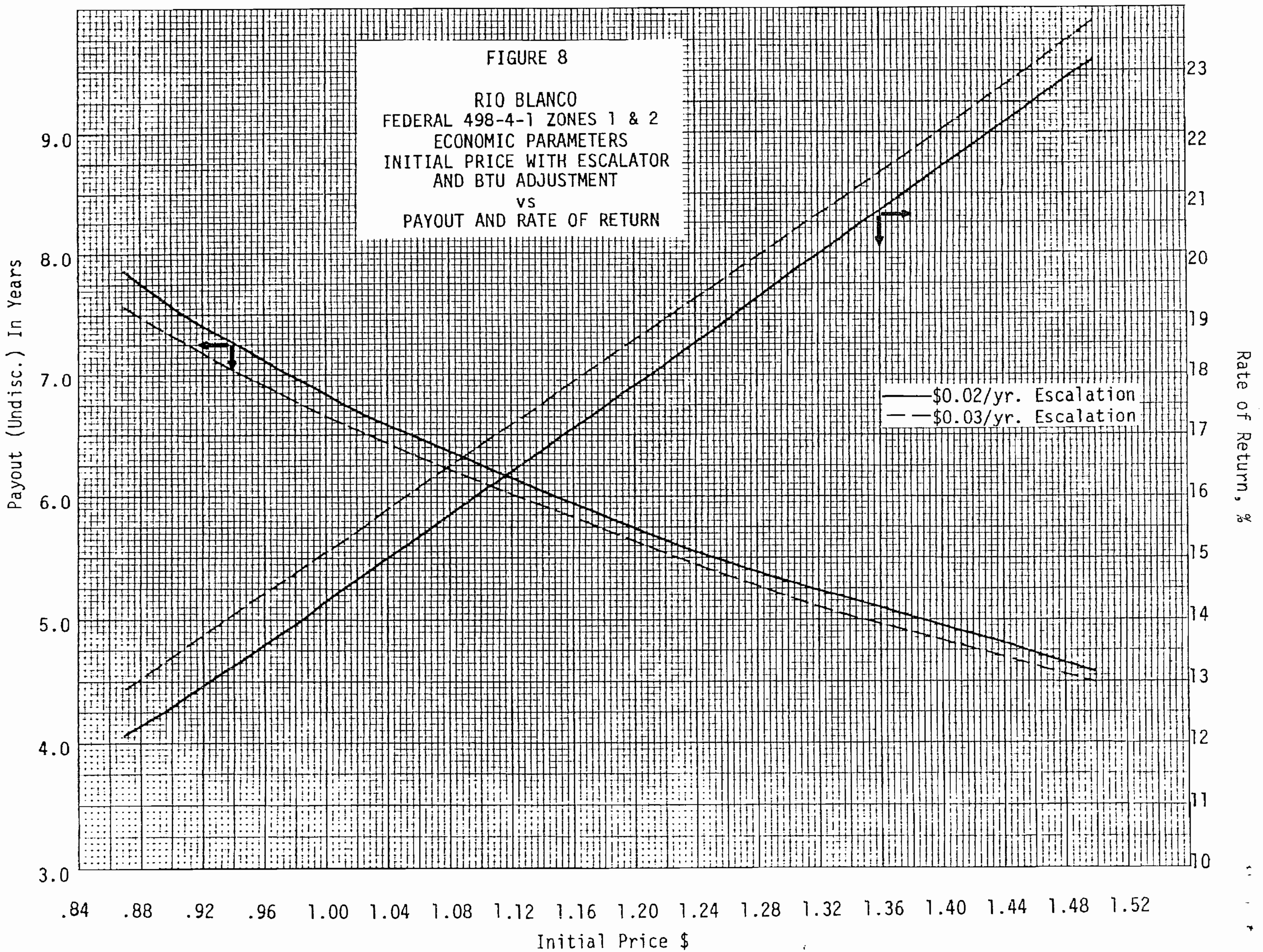


FIGURE 8
RIO BLANCO
FEDERAL 498-4-1 ZONES 1 & 2
ECONOMIC PARAMETERS
INITIAL PRICE WITH ESCALATOR
AND BTU ADJUSTMENT
vs
PAYOUT AND RATE OF RETURN
$0.02/yr. Escalation
$0.03/yr. Escalation
Payout (Undisc.) In Years
9.0
8.0
7.0
6.0
5.0
4.0
3.0
Rate of Return, %
23
22
21
20
19
18
17
16
15
14
13
12
11
10
.84
.88
.92
.96
1.00
1.04
1.08
1.12
1.16
1.20
1.24
1.28
1.32
1.36
1.40
1.44
1.48
1.52
Initial Price $

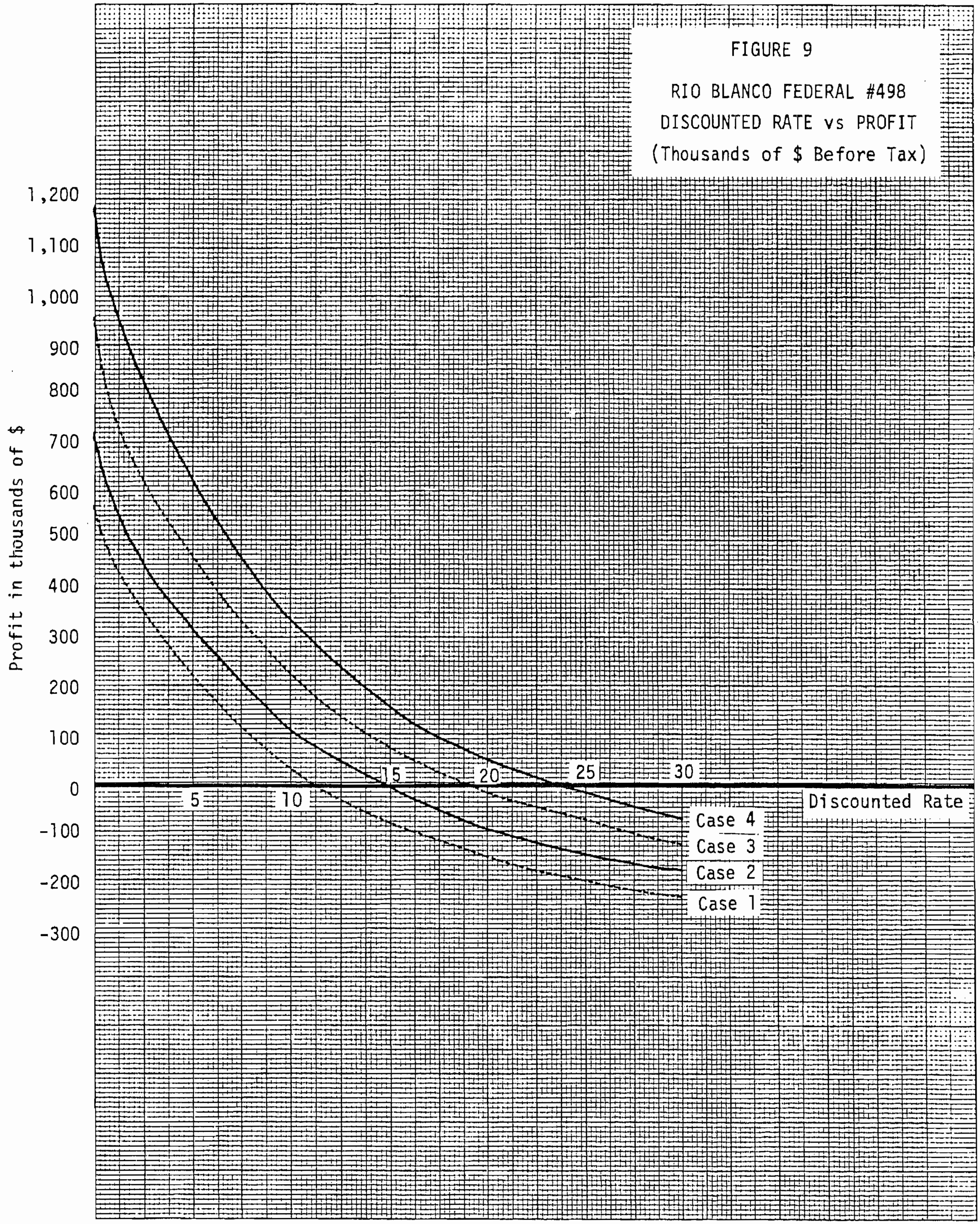


FIGURE 9
RIO BLANCO FEDERAL #498
DISCOUNTED RATE vs PROFIT
(Thousands of $ Before Tax)
Profit in thousands of $
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
-100
-200
-300
5
10
15
20
25
30
Discounted Rate
Case 4
Case 3
Case 2
Case 1

APPENDIX

CASES 1 THROUGH 8

CASE 1

* * * * * * * * * * * * *
*   *
* OIL AND GAS LEASE   *
* ECONOMIC EVALUATION   *
*   *
* * * * * * * * * * * * *

PREPARED FOR
RIO BLANCO NATURAL GAS
BY H.K. VAN POOLLEN & ASSOC
P.W. REFERENCE DATE 1-1-77

********** BEFORE AND AFTER INCOME TAX **********

YEAR	GROSS OIL + COND. STB	GROSS RES. + SL GAS MMCF	NET REV. AFTER ROYLTY M$	NET OP EXP LCL TX + CAP M$	NET PROFIT B. TAX M$	CUM. NET PROFIT B. TAX M$	NET PROFIT A. TAX M$	CUM. NET PROFIT A. TAX M$
77	365.0	63.9	58.6	401.5	-342.9	-342.9	-218.8	-218.8
78	365.0	55.1	52.1	1.5	50.6	-292.3	34.7	-184.2
79	365.0	54.0	52.2	1.5	50.7	-241.5	34.7	-149.5
80	365.0	52.6	52.0	1.5	50.5	-191.1	34.4	-115.0
81	365.0	51.5	52.0	1.5	50.5	-140.6	34.4	-80.6
82	365.0	50.0	51.6	1.5	50.1	-90.5	34.1	-46.5
83	365.0	48.5	51.1	1.5	49.6	-40.9	33.7	-12.8
84	365.0	47.4	51.0	1.5	49.5	8.6	33.6	20.8
85	365.0	46.4	50.8	1.5	49.3	57.9	33.4	54.2
86	365.0	45.6	51.0	1.5	49.5	107.4	33.5	87.7
87	365.0	44.9	51.1	1.5	49.6	157.0	33.5	121.2
88	365.0	43.8	50.8	1.5	49.3	206.3	33.3	154.5
89	365.0	42.7	50.5	1.5	49.0	255.3	33.0	187.5
90	365.0	42.0	50.5	1.5	49.0	304.3	33.0	220.5
91	365.0	41.2	50.5	1.5	49.0	353.3	33.0	253.5
92	365.0	40.5	50.5	1.5	49.0	402.3	32.9	286.4
93	365.0	39.8	50.4	1.5	48.9	451.2	32.8	319.2
94	365.0	39.1	50.3	1.5	48.8	500.1	32.7	351.9
95	365.0	38.3	50.2	1.5	48.7	548.8	32.6	384.5
96	365.0	38.0	50.5	1.5	49.0	597.8	32.8	417.3
TOT.	7300.0	925.3	1027.8	430.0	597.8	597.8	417.3	417.3

CASE 1
(CONTINUED)

********** SUMMARY **********

INTERESTS *

INTL WORKING INT (PCT) = 100.000	INTL ROYALTY INT (PCT) = 12.500
INTL CAPITAL INT (PCT) = 100.000	AVG. ROYALTY INT (PCT) = 12.500

RESERVES + PROJECT LIFE *

LIFE (YRS) = 20.00

RESERVES

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS	0.	0.	925.3	7.3	0.	0.	0.
NET	0.	0.	809.6	6.4	0.	0.	0.

NET PRESENT VALUE *

	*** BEFORE INCOME TAX ***			*** AFTER INCOME TAX ***		
DISC. RATE	OP. INC (M$)	INV. (M$)	PROFIT (M$)	OP. INC (M$)	INV. (M$)	PROFIT (M$)
0.	997.8	400.0	597.8	817.3	400.0	417.3
5.00	641.6	400.0	241.6	573.7	400.0	173.7
10.00	451.8	400.0	51.8	442.4	400.0	42.4
15.00	342.0	400.0	-58.0	365.2	400.0	-34.8
20.00	273.5	400.0	-126.5	316.0	400.0	-84.0
30.00	196.0	400.0	-204.0	258.3	400.0	-141.7
10.00	451.8	400.0	51.8	442.4	400.0	42.4

NET PROFIT INDICATORS *	* BEFORE INCOME TAX *	* AFTER INCOME TAX *
PAYOUT (YRS)	7.83	7.38
RATE OF RETURN (PCT)	12.11	12.42
INTL. OP. INC. ($/DAY)	156.51	496.33
AVG LSE OP CST ($/UNIT)	0.19	0.39
AVG LS PROD VAL ($/UNT)	1.27	1.27
UNDIS PROFIT/UNDIS INV	1.49	1.04
DIS PROFIT/DIS INV	0.13	0.11
DIS PROFIT/UNDIS INV	0.13	0.11

CASE 2

* * * * * * * * * * * * *

OIL AND GAS LEASE
ECONOMIC EVALUATION

* * * * * * * * * * * * *

PREPARED FOR
RIO BLANCO NATURAL GAS
BY H.K. VAN POOLLEN & ASSOC
P.W. REFERENCE DATE 1-1-77

********** BEFORE AND AFTER INCOME TAX **********

YEAR	GROSS OIL + COND. STB	GROSS RES. + SL GAS MMCF	NET REV. AFTER ROYLTY M$	NET OP EXP LCL TX + CAP M$	NET PROFIT B. TAX M$	CUM. NET PROFIT B. TAX M$	NET PROFIT A. TAX M$	CUM. NET PROFIT A. TAX M$
77	365.0	63.9	66.9	401.5	-334.6	-334.6	-214.5	-214.5
78	365.0	55.1	59.3	1.5	57.8	-276.8	39.2	-175.4
79	365.0	54.0	59.2	1.5	57.7	-219.1	39.1	-136.3
80	365.0	52.6	58.8	1.5	57.3	-161.8	38.7	-97.6
81	365.0	51.5	58.6	1.5	57.1	-104.7	38.6	-59.0
82	365.0	50.0	58.1	1.5	56.6	-48.1	38.1	-20.9
83	365.0	48.5	57.4	1.5	55.9	7.8	37.7	16.8
84	365.0	47.4	57.2	1.5	55.7	63.5	37.4	54.2
85	365.0	46.4	56.8	1.5	55.3	118.8	37.2	91.4
86	365.0	45.6	56.9	1.5	55.4	174.2	37.2	128.6
87	365.0	44.9	56.9	1.5	55.4	229.6	37.2	165.8
88	365.0	43.8	56.5	1.5	55.0	284.6	36.8	202.6
89	365.0	42.7	56.0	1.5	54.5	339.1	36.5	239.1
90	365.0	42.0	56.0	1.5	54.5	393.6	36.4	275.5
91	365.0	41.2	55.9	1.5	54.4	447.9	36.3	311.8
92	365.0	40.5	55.7	1.5	54.2	502.2	36.2	348.0
93	365.0	39.8	55.6	1.5	54.1	556.2	36.1	384.0
94	365.0	39.1	55.4	1.5	53.9	610.1	35.9	419.9
95	365.0	38.3	55.2	1.5	53.7	663.8	35.7	455.6
96	365.0	38.0	55.4	1.5	53.9	717.8	35.9	491.5
TOT.	7300.0	925.3	1147.8	430.0	717.8	717.8	491.5	491.5

CASE 2
(CONTINUED)

********** SUMMARY **********

INTERESTS *

INTL WORKING INT (PCT) = 100.000   INTL ROYALTY INT (PCT) = 12.500
INTL CAPITAL INT (PCT) = 100.000   AVG. ROYALTY INT (PCT) = 12.500

RESERVES + PROJECT LIFE *

LIFE (YRS) = 20.00
RESERVES

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS	0.	0.	925.3	7.3	0.	0.	0.
NET	0.	0.	809.6	6.4	0.	0.	0.

NET PRESENT VALUE *

DISC. RATE	*** BEFORE INCOME TAX *** OP. INC (M$)	INV. (M$)	PROFIT (M$)	*** AFTER INCOME TAX *** OP. INC (M$)	INV. (M$)	PROFIT (M$)
0.	1117.8	400.0	717.8	891.5	400.0	491.5
5.00	721.1	400.0	321.1	622.7	400.0	222.7
10.00	509.4	400.0	109.4	477.6	400.0	77.6
15.00	386.5	400.0	-13.5	392.2	400.0	-7.8
20.00	309.7	400.0	-90.3	337.9	400.0	-62.1
30.00	222.5	400.0	-177.5	274.2	400.0	-125.8
10.00	509.4	400.0	109.4	477.6	400.0	77.6

NET PROFIT INDICATORS *	* BEFORE INCOME TAX *	* AFTER INCOME TAX *
PAYOUT (YRS)	6.86	6.55
RATE OF RETURN (PCT)	14.30	14.45
INTL. OP. INC. ($/DAY)	179.20	508.13
AVG LSE OP CST ($/UNIT)	0.21	0.45
AVG LS PROD VAL ($/UNT)	1.42	1.42
UNDIS PROFIT/UNDIS INV	1.79	1.23
DIS PROFIT/DIS INV	0.27	0.19
DIS PROFIT/UNDIS INV	0.27	0.19

CASE 3

OIL AND GAS LEASE
ECONOMIC EVALUATION

PREPARED FOR
RIO BLANCO NATURAL GAS
BY H.K. VAN POOLLEN & ASSOC
P.W. REFERENCE DATE 1-1-77

********** BEFORE AND AFTER INCOME TAX **********

YEAR	GROSS OIL + COND. STB	GROSS RES. + SL GAS MMCF	NET REV. AFTER ROYLTY M$	NET OP EXP LCL TX + CAP M$	NET PROFIT B. TAX M$	CUM. NET PROFIT B. TAX M$	NET PROFIT A. TAX M$	CUM. NET PROFIT A. TAX M$
77	365.0	63.9	82.8	401.5	-318.7	-318.7	-206.2	-206.2
78	365.0	55.1	73.0	1.5	71.5	-247.1	47.8	-158.5
79	365.0	54.0	72.7	1.5	71.2	-175.9	47.5	-111.0
80	365.0	52.6	71.9	1.5	70.4	-105.6	46.9	-64.1
81	365.0	51.5	71.5	1.5	70.0	-35.6	46.6	-17.5
82	365.0	50.0	70.5	1.5	69.0	33.4	45.9	28.5
83	365.0	48.5	69.5	1.5	68.0	101.5	45.2	73.7
84	365.0	47.4	69.0	1.5	67.5	169.0	44.8	118.5
85	365.0	46.4	68.4	1.5	66.9	235.8	44.4	163.0
86	365.0	45.6	68.3	1.5	66.8	302.6	44.3	207.3
87	365.0	44.9	68.1	1.5	66.6	369.2	44.2	251.4
88	365.0	43.8	67.4	1.5	65.9	435.2	43.7	295.1
89	365.0	42.7	66.7	1.5	65.2	500.3	43.1	338.2
90	365.0	42.0	66.4	1.5	64.9	565.3	42.9	381.2
91	365.0	41.2	66.1	1.5	64.6	629.9	42.7	423.9
92	365.0	40.5	65.8	1.5	64.3	694.2	42.5	466.4
93	365.0	39.8	65.5	1.5	64.0	758.2	42.3	508.7
94	365.0	39.1	65.1	1.5	63.6	821.9	42.0	550.7
95	365.0	38.3	64.7	1.5	63.2	885.1	41.7	592.4
96	365.0	38.0	64.9	1.5	63.4	948.5	41.8	634.2
TOT.	7300.0	925.3	1378.5	430.0	948.5	948.5	634.2	634.2

CASE 3
(CONTINUED)

********** SUMMARY **********

INTERESTS *

INTL WORKING INT (PCT) = 100.000   INTL ROYALTY INT (PCT) = 12.500
INTL CAPITAL INT (PCT) = 100.000   AVG. ROYALTY INT (PCT) = 12.500

RESERVES + PROJECT LIFE *

LIFE (YRS) = 20.00

RESERVES

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS	0.	0.	925.3	7.3	0.	0.	0.
NET	0.	0.	809.6	6.4	0.	0.	0.

NET PRESENT VALUE *

	*** BEFORE INCOME TAX ***			*** AFTER INCOME TAX ***		
DISC. RATE	OP. INC (M$)	INV. (M$)	PROFIT (M$)	OP. INC (M$)	INV. (M$)	PROFIT (M$)
0.	1348.5	400.0	948.5	1034.2	400.0	634.2
5.00	874.1	400.0	474.1	716.8	400.0	316.8
10.00	620.1	400.0	220.1	545.3	400.0	145.3
15.00	472.2	400.0	72.2	444.2	400.0	44.2
20.00	379.4	400.0	-20.6	379.9	400.0	-20.1
30.00	273.6	400.0	-126.4	304.7	400.0	-95.3
10.00	620.1	400.0	220.1	545.3	400.0	145.3

NET PROFIT INDICATORS *	* BEFORE INCOME TAX *	* AFTER INCOME TAX *
PAYOUT (YRS)	5.52	5.38
RATE OF RETURN (PCT)	18.67	18.20
INTL. OP. INC. ($/DAY)	222.84	530.83
AVG LSE OP CST ($/UNIT)	0.25	0.58
AVG LS PROD VAL ($/UNT)	1.70	1.70
UNDIS PROFIT/UNDIS INV	2.37	1.59
DIS PROFIT/DIS INV	0.55	0.36
DIS PROFIT/UNDIS INV	0.55	0.36

CASE 4

* * * * * * * * * * * * *
* OIL AND GAS LEASE *
* ECONOMIC EVALUATION *
* * * * * * * * * * * * *

PREPARED FOR
RIO BLANCO NATURAL GAS
BY H.K. VAN POOLLEN & ASSOC
P.W. REFERENCE DATE 1-1-77

********** BEFORE AND AFTER INCOME TAX **********

YEAR	GROSS OIL + COND. STB	GROSS RES. + SL GAS MMCF	NET REV. AFTER ROYLTY M$	NET OP EXP LCL TX + CAP M$	NET PROFIT B. TAX M$	CUM. NET PROFIT B. TAX M$	NET PROFIT A. TAX M$	CUM. NET PROFIT A. TAX M$
77	365.0	63.9	98.8	401.5	-302.7	-302.7	-198.0	-198.0
78	365.0	55.1	86.8	1.5	85.3	-217.5	56.4	-141.6
79	365.0	54.0	86.2	1.5	84.7	-132.8	55.9	-85.7
80	365.0	52.6	85.0	1.5	83.5	-49.3	55.1	-30.6
81	365.0	51.5	84.3	1.5	82.8	33.5	54.6	24.1
82	365.0	50.0	83.0	1.5	81.5	115.0	53.7	77.8
83	365.0	48.5	81.6	1.5	80.1	195.1	52.8	130.6
84	365.0	47.4	80.8	1.5	79.3	274.4	52.2	182.9
85	365.0	46.4	80.0	1.5	78.5	352.9	51.6	234.5
86	365.0	45.6	79.7	1.5	78.2	431.1	51.4	285.9
87	365.0	44.9	79.3	1.5	77.8	508.9	51.2	337.1
88	365.0	43.8	78.3	1.5	76.8	585.7	50.5	387.6
89	365.0	42.7	77.3	1.5	75.8	661.5	49.8	437.4
90	365.0	42.0	76.9	1.5	75.4	736.9	49.5	486.9
91	365.0	41.2	76.4	1.5	74.9	811.8	49.2	536.1
92	365.0	40.5	75.9	1.5	74.4	886.3	48.8	584.9
93	365.0	39.8	75.4	1.5	73.9	960.2	48.5	633.4
94	365.0	39.1	74.9	1.5	73.4	1033.6	48.1	681.5
95	365.0	38.3	74.3	1.5	72.8	1106.4	47.7	729.1
96	365.0	38.0	74.4	1.5	72.9	1179.3	47.7	776.9
TOT.	7300.0	925.3	1609.3	430.0	1179.3	1179.3	776.9	776.9

CASE 4
(CONTINUED)

********** SUMMARY **********

INTERESTS *

INTL WORKING INT (PCT) = 100.000   INTL ROYALTY INT (PCT) = 12.500
INTL CAPITAL INT (PCT) = 100.000   AVG. ROYALTY INT (PCT) = 12.500

RESRVES + PROJECT LIFE *

LIFE (YRS) = 20.00
RESERVES

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS	0.	0.	925.3	7.3	0.	0.	0.
NET	0.	0.	809.6	6.4	0.	0.	0.

NET PRESENT VALUE *

	*** BEFORE INCOME TAX ***			*** AFTER INCOME TAX ***		
DISC. RATE	OP. INC (M$)	INV. (M$)	PROFIT (M$)	OP. INC (M$)	INV. (M$)	PROFIT (M$)
0.	1579.3	400.0	1179.3	1176.9	400.0	776.9
5.00	1027.2	400.0	627.2	810.8	400.0	410.8
10.00	730.7	400.0	330.7	612.9	400.0	212.9
15.00	557.8	400.0	157.8	496.2	400.0	96.2
20.00	449.1	400.0	49.1	422.0	400.0	22.0
30.00	324.7	400.0	-75.3	335.2	400.0	-64.8
10.00	730.7	400.0	330.7	612.9	400.0	212.9

NET PROFIT INDICATORS *	* BEFORE INCOME TAX *	* AFTER INCOME TAX *
PAYOUT (YRS)	4.60	4.56
RATE OF RETURN (PCT)	23.20	21.95
INTL. OP. INC. ($/DAY)	266.48	553.52
AVG LSE OP CST ($/UNIT)	0.28	0.72
AVG LS PROD VAL ($/UNT)	1.99	1.99
UNDIS PROFIT/UNDIS INV	2.95	1.94
DIS PROFIT/DIS INV	0.83	0.53
DIS PROFIT/UNDIS INV	0.83	0.53

CASE 5

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* * * * * * * * * * * * *
*                       *
*   OIL AND GAS LEASE   *
*  ECONOMIC EVALUATION  *
*                       *
* * * * * * * * * * * * *
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PREPARED FOR
RIO BLANCO NATURAL GAS
BY H.K. VAN POOLLEN & ASSOC
P.W. REFERENCE DATE 1-1-77

********** BEFORE AND AFTER INCOME TAX **********

YEAR	GROSS OIL + COND. STB	GROSS RES. + SL GAS MMCF	NET REV. AFTER ROYLTY M$	NET OP EXP LCL TX + CAP M$	NET PROFIT B. TAX M$	CUM. NET PROFIT B. TAX M$	NET PROFIT A. TAX M$	CUM. NET PROFIT A. TAX M$
77	365.0	63.9	58.6	401.5	-342.9	-342.9	-218.8	-218.8
78	365.0	55.1	52.7	1.5	51.2	-291.7	35.0	-183.8
79	365.0	54.0	53.3	1.5	51.8	-239.9	35.4	-148.4
80	365.0	52.6	53.5	1.5	52.0	-187.9	35.4	-113.0
81	365.0	51.5	54.0	1.5	52.5	-135.4	35.7	-77.3
82	365.0	50.0	54.1	1.5	52.6	-82.8	35.6	-41.7
83	365.0	48.5	54.0	1.5	52.5	-30.2	35.5	-6.1
84	365.0	47.4	54.3	1.5	52.8	22.6	35.7	29.5
85	365.0	46.4	54.5	1.5	53.0	75.6	35.7	65.3
86	365.0	45.6	55.1	1.5	53.6	129.2	36.0	101.3
87	365.0	44.9	55.6	1.5	54.1	183.3	36.3	137.6
88	365.0	43.8	55.6	1.5	54.1	237.4	36.3	173.9
89	365.0	42.7	55.6	1.5	54.1	291.5	36.2	210.1
90	365.0	42.0	56.0	1.5	54.5	345.9	36.4	246.5
91	365.0	41.2	56.3	1.5	54.8	400.7	36.6	283.1
92	365.0	40.5	56.5	1.5	55.0	455.7	36.7	319.8
93	365.0	39.8	56.8	1.5	55.3	511.0	36.8	356.6
94	365.0	39.1	57.0	1.5	55.5	566.4	36.9	393.5
95	365.0	38.3	57.1	1.5	55.6	622.0	36.9	430.4
96	365.0	38.0	57.7	1.5	56.2	678.3	37.3	467.7
TOT.	7300.0	925.3	1108.3	430.0	678.3	678.3	467.7	467.7

CASE 5
(CONTINUED)

********** SUMMARY **********

INTERESTS *

INTL WORKING INT (PCT) = 100.000 INTL ROYALTY INT (PCT) = 12.500
INTL CAPITAL INT (PCT) = 100.000 AVG. ROYALTY INT (PCT) = 12.500

RESERVES + PROJECT LIFE *

LIFE (YRS) = 20.00

RESERVES

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS	0.	0.	925.3	7.3	0.	0.	0.
NET	0.	0.	809.6	6.4	0.	0.	0.

NET PRESENT VALUE *

DISC. RATE	*** BEFORE INCOME TAX *** OP. INC (M$)	INV. (M$)	PROFIT (M$)	*** AFTER INCOME TAX *** OP. INC (M$)	INV. (M$)	PROFIT (M$)
0.	1078.3	400.0	678.3	867.7	400.0	467.7
5.00	685.3	400.0	285.3	601.1	400.0	201.1
10.00	477.6	400.0	77.6	458.6	400.0	58.6
15.00	358.3	400.0	-41.7	375.4	400.0	-24.6
20.00	284.5	400.0	-115.5	322.9	400.0	-77.1
30.00	201.8	400.0	-198.2	262.0	400.0	-138.0
10.00	477.6	400.0	77.6	458.6	400.0	58.6

NET PROFIT INDICATORS *	* BEFORE INCOME TAX *	* AFTER INCOME TAX *
PAYOUT (YRS)	7.57	7.17
RATE OF RETURN (PCT)	12.89	13.20
INTL. OP. INC. ($/DAY)	156.51	496.33
AVG LSE OP CST ($/UNIT)	0.20	0.43
AVG LS PROD VAL ($/UNT)	1.37	1.37
UNDIS PROFIT/UNDIS INV	1.70	1.17
DIS PROFIT/DIS INV	0.19	0.15
DIS PROFIT/UNDIS INV	0.19	0.15

CASE 6

OIL AND GAS LEASE
ECONOMIC EVALUATION

PREPARED FOR
RIO BLANCO NATURAL GAS
BY H.K. VAN POOLLEN & ASSOC
P.W. REFERENCE DATE 1-1-77

********** BEFORE AND AFTER INCOME TAX **********

YEAR	GROSS OIL + COND. STB	GROSS RES. + SL GAS MMCF	NET REV. AFTER ROYLTY M$	NET OP EXP LCL TX + CAP M$	NET PROFIT B. TAX M$	CUM. NET PROFIT B. TAX M$	NET PROFIT A. TAX M$	CUM. NET PROFIT A. TAX M$
77	365.0	63.9	82.8	401.5	-318.7	-318.7	-206.2	-206.2
78	365.0	55.1	73.6	1.5	72.1	-246.6	48.1	-158.1
79	365.0	54.0	73.8	1.5	72.3	-174.3	48.2	-110.0
80	365.0	52.6	73.4	1.5	71.9	-102.4	47.9	-62.1
81	365.0	51.5	73.5	1.5	72.0	-30.3	47.9	-14.2
82	365.0	50.0	73.0	1.5	71.5	41.2	47.5	33.3
83	365.0	48.5	72.4	1.5	70.9	112.1	47.1	80.4
84	365.0	47.4	72.3	1.5	70.8	182.9	46.9	127.3
85	365.0	46.4	72.1	1.5	70.6	253.5	46.7	174.0
86	365.0	45.6	72.4	1.5	70.9	324.4	46.9	220.9
87	365.0	44.9	72.6	1.5	71.1	395.5	47.0	267.8
88	365.0	43.8	72.2	1.5	70.7	466.2	46.7	314.5
89	365.0	42.7	71.8	1.5	70.3	536.5	46.3	360.9
90	365.0	42.0	71.9	1.5	70.4	606.9	46.4	407.2
91	365.0	41.2	71.9	1.5	70.4	677.3	46.3	453.5
92	365.0	40.5	71.9	1.5	70.4	747.6	46.3	499.9
93	365.0	39.8	71.8	1.5	70.3	818.0	46.2	546.1
94	365.0	39.1	71.8	1.5	70.3	888.3	46.1	592.2
95	365.0	38.3	71.6	1.5	70.1	958.4	46.0	638.2
96	365.0	38.0	72.1	1.5	70.6	1029.0	46.3	684.5
TOT.	7300.0	925.3	1459.0	430.0	1029.0	1029.0	684.5	684.5

CASE 6
(CONTINUED)

********** SUMMARY **********

INTERESTS *

INTL WORKING INT (PCT) = 100.000 INTL ROYALTY INT (PCT) = 12.500
INTL CAPITAL INT (PCT) = 100.000 AVG. ROYALTY INT (PCT) = 12.500

RESERVES + PROJECT LIFE *

LIFE (YRS) = 20.00
RESERVES

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS	0.	0.	925.3	7.3	0.	0.	0.
NET	0.	0.	809.6	6.4	0.	0.	0.

NET PRESENT VALUE *

DISC. RATE	*** BEFORE INCOME TAX *** OP. INC (M$)	INV. (M$)	PROFIT (M$)	*** AFTER INCOME TAX *** OP. INC (M$)	INV. (M$)	PROFIT (M$)
0.	1429.0	400.0	1029.0	1084.5	400.0	684.5
5.00	917.9	400.0	517.9	744.1	400.0	344.1
10.00	645.8	400.0	245.8	561.4	400.0	161.4
15.00	488.5	400.0	88.5	454.5	400.0	54.5
20.00	390.4	400.0	-9.6	386.8	400.0	-13.2
30.00	279.5	400.0	-120.5	308.3	400.0	-91.7
10.00	645.8	400.0	245.8	561.4	400.0	161.4

NET PROFIT INDICATORS *	* BEFORE INCOME TAX *	* AFTER INCOME TAX *
PAYOUT (YRS)	5.42	5.30
RATE OF RETURN (PCT)	19.45	18.83
INTL. OP. INC. ($/DAY)	222.84	530.83
AVG LSE OP CST ($/UNIT)	0.26	0.63
AVG LS PROD VAL ($/UNT)	1.80	1.80
UNDIS PROFIT/UNDIS INV	2.57	1.71
DIS PROFIT/DIS INV	0.61	0.40
DIS PROFIT/UNDIS INV	0.61	0.40

OIL AND GAS LEASE ECONOMIC EVALUATION

PREPARED FOR
RIO BLANCO NATURAL GAS
BY H.K. VAN POOLLEN & ASSOC
P.W. REFERENCE DATE 1-1-77

********** BEFORE AND AFTER INCOME TAX **********

YEAR	GROSS OIL + COND. STB	GROSS RES. + SL GAS MMCF	NET REV. AFTER ROYLTY M$	NET OP EXP LCL TX + CAP M$	NET PROFIT B. TAX M$	CUM. NET PROFIT B. TAX M$	NET PROFIT A. TAX M$	CUM. NET PROFIT A. TAX M$
77	365.0	63.9	98.8	401.5	-302.7	-302.7	-198.0	-198.0
78	365.0	55.1	87.3	1.5	85.8	-216.9	56.7	-141.3
79	365.0	54.0	87.3	1.5	85.8	-131.2	56.6	-84.7
80	365.0	52.6	86.6	1.5	85.1	-46.1	56.1	-28.6
81	365.0	51.5	86.4	1.5	84.9	38.7	55.9	27.4
82	365.0	50.0	85.5	1.5	84.0	122.7	55.3	82.7
83	365.0	48.5	84.5	1.5	83.0	205.8	54.6	137.3
84	365.0	47.4	84.1	1.5	82.6	288.4	54.3	191.6
85	365.0	46.4	83.6	1.5	82.1	370.6	54.0	245.6
86	365.0	45.6	83.7	1.5	82.2	452.8	54.0	299.5
87	365.0	44.9	83.8	1.5	82.3	535.1	54.0	353.5
88	365.0	43.8	83.1	1.5	81.6	616.8	53.5	407.0
89	365.0	42.7	82.4	1.5	80.9	697.7	53.0	460.0
90	365.0	42.0	82.3	1.5	80.8	778.5	52.9	512.9
91	365.0	41.2	82.2	1.5	80.7	859.2	52.8	565.7
92	365.0	40.5	82.0	1.5	80.5	939.7	52.6	618.3
93	365.0	39.8	81.8	1.5	80.3	1020.0	52.4	670.8
94	365.0	39.1	81.5	1.5	80.0	1100.0	52.2	723.0
95	365.0	38.3	81.2	1.5	79.7	1179.7	52.0	775.0
96	365.0	38.0	81.6	1.5	80.1	1259.7	52.2	827.2
TOT.	7300.0	925.3	1689.7	430.0	1259.7	1259.7	827.2	827.2

CASE 7
(CONTINUED)

********** SUMMARY **********

INTERESTS *

INTL WORKING INT (PCT) = 100.000 INTL ROYALTY INT (PCT) = 12.500
INTL CAPITAL INT (PCT) = 100.000 AVG. ROYALTY INT (PCT) = 12.500

RESERVES + PROJECT LIFE *

LIFE (YRS) = 20.00

RESERVES

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS	0.	0.	925.3	7.3	0.	0.	0.
NET	0.	0.	809.6	6.4	0.	0.	0.

NET PRESENT VALUE *

	*** BEFORE INCOME TAX ***			*** AFTER INCOME TAX ***		
DISC. RATE	OP. INC (M$)	INV. (M$)	PROFIT (M$)	OP. INC (M$)	INV. (M$)	PROFIT (M$)
0.	1659.7	400.0	1259.7	1227.2	400.0	827.2
5.00	1070.9	400.0	670.9	838.2	400.0	438.2
10.00	756.5	400.0	356.5	629.0	400.0	229.0
15.00	574.1	400.0	174.1	506.5	400.0	106.5
20.00	460.1	400.0	60.1	428.9	400.0	28.9
30.00	330.6	400.0	-69.4	338.8	400.0	-61.2
10.00	756.5	400.0	356.5	629.0	400.0	229.0

NET PROFIT INDICATORS *	* BEFORE INCOME TAX *	* AFTER INCOME TAX *
PAYOUT (YRS)	4.54	4.51
RATE OF RETURN (PCT)	23.83	22.58
INTL. OP. INC. ($/DAY)	266.48	553.52
AVG LSE OP CST ($/UNIT)	0.29	0.76
AVG LS PROD VAL ($/UNT)	2.09	2.09
UNDIS PROFIT/UNDIS INV	3.15	2.07
DIS PROFIT/DIS INV	0.89	0.57
DIS PROFIT/UNDIS INV	0.89	0.57

CASE 8

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OIL AND GAS LEASE
ECONOMIC EVALUATION

* * * * * * * * * * * * *

PREPARED FOR
RIO BLANCO NATURAL GAS
BY H.K. VAN POOLLEN & ASSOC
P.W. REFERENCE DATE 1-1-77

********** BEFORE AND AFTER INCOME TAX **********

YEAR	GROSS OIL + COND. STB	GROSS RES. + SL GAS MMCF	NET REV. AFTER ROYLTY M$	NET OP EXP LCL TX + CAP M$	NET PROFIT B. TAX M$	CUM. NET PROFIT B. TAX M$	NET PROFIT A. TAX M$	CUM. NET PROFIT A. TAX M$
----	------	------	------	------	------	------	------	------
77	365.0	63.9	93.7	401.5	-307.8	-307.8	-200.6	-200.6
78	365.0	55.1	83.5	1.5	82.0	-225.9	54.3	-146.3
79	365.0	54.0	84.0	1.5	82.5	-143.3	54.6	-91.7
80	365.0	52.6	83.9	1.5	82.4	-60.9	54.5	-37.3
81	365.0	51.5	84.3	1.5	82.8	21.9	54.6	17.3
82	365.0	50.0	84.0	1.5	82.5	104.4	54.4	71.7
83	365.0	48.5	83.6	1.5	82.1	186.5	54.0	125.7
84	365.0	47.4	83.7	1.5	82.2	268.6	54.0	179.8
85	365.0	46.4	83.6	1.5	82.1	350.8	54.0	233.7
86	365.0	45.6	84.2	1.5	82.7	433.5	54.3	288.0
87	365.0	44.9	84.7	1.5	83.2	516.7	54.5	342.5
88	365.0	43.8	84.5	1.5	83.0	599.6	54.3	396.8
89	365.0	42.7	84.1	1.5	82.6	682.3	54.1	450.9
90	365.0	42.0	84.4	1.5	82.9	765.2	54.2	505.1
91	365.0	41.2	84.7	1.5	83.2	848.3	54.3	559.4
92	365.0	40.5	84.8	1.5	83.3	931.7	54.4	613.8
93	365.0	39.8	84.9	1.5	83.4	1015.1	54.4	668.3
94	365.0	39.1	85.0	1.5	83.5	1098.6	54.4	722.7
95	365.0	38.3	85.0	1.5	83.5	1182.1	54.4	777.1
96	365.0	38.0	85.7	1.5	84.2	1266.4	54.8	831.9
TOT.	7300.0	925.3	1696.4	430.0	1266.4	1266.4	831.9	831.9

CASE 8
(CONTINUED)

********** SUMMARY **********

INTERESTS *

INTL WORKING INT (PCT) = 100.000 INTL ROYALTY INT (PCT) = 12.500
INTL CAPITAL INT (PCT) = 100.000 AVG. ROYALTY INT (PCT) = 12.500

RESERVES + PROJECT LIFE *

LIFE (YRS) = 20.00
RESERVES

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS	0.	0.	925.3	7.3	0.	0.	0.
NET	0.	0.	809.6	6.4	0.	0.	0.

NET PRESENT VALUE *

	*** BEFORE INCOME TAX ***			*** AFTER INCOME TAX ***		
DISC. RATE	OP. INC (M$)	INV. (M$)	PROFIT (M$)	OP. INC (M$)	INV. (M$)	PROFIT (M$)
0.	1666.4	400.0	1266.4	1231.9	400.0	831.9
5.00	1065.6	400.0	665.6	835.4	400.0	435.4
10.00	746.9	400.0	346.9	623.5	400.0	223.5
15.00	563.0	400.0	163.0	500.0	400.0	100.0
20.00	448.8	400.0	48.8	422.3	400.0	22.3
30.00	320.1	400.0	-79.9	332.7	400.0	-67.3
10.00	746.9	400.0	346.9	623.5	400.0	223.5

NET PROFIT INDICATORS *	* BEFORE INCOME TAX *	* AFTER INCOME TAX *
PAYOUT (YRS)	4.74	4.68
RATE OF RETURN (PCT)	23.05	21.95
INTL. OP. INC. ($/DAY)	252.52	546.26
AVG LSE OP CST ($/UNIT)	0.29	0.76
AVG LS PROD VAL ($/UNIT)	2.10	2.10
UNDIS PROFIT/UNDIS INV	3.17	2.08
DIS PROFIT/DIS INV	0.87	0.56
DIS PROFIT/UNDIS INV	0.87	0.56

APPENDIX D

PROJECT COSTS

Rio Blanco Natural Gas Co.
2000 WESTERN FEDERAL SAVINGS BUILDING
718 17TH STREET
DENVER COLORADO 80202
(303) 292-1350

THIRD PARTY INVOICE SUMMARY AND STATEMENT*
AS OF FEBRUARY 15, 1977
Contract No. EY-76-C-08-0677

	Vendor	Invoice No.		Invoice Amount	Total
1.	Twin Arrow, Inc.:	10-15-WO		$ 15,796.35	
		11-75-WO		17,992.43	
		11-26-M		590.65	
		12-20-M		198.19	
		0215-M		412.66	
			Subtotal	$ 34,990.28	$ 34,990.28
2.	Dowell, Division of Dow Chemical Co.:	15-03-0997		$ 1,847.53	
		15-03-1002		2,600.42	
		15-03-1006		3,219.61	
		15-03-1012		770.00	
		15-03-1011		770.00	
		15-03-1037		1,362.92	
		15-03-1171		120,697.50	
		15-03-1171-A		2,912.96	
			Subtotal	$ 134,180.94	134,180.94
3.	H. K. van Poollen & Associates, Inc.:	L-657		$ 16,350.87	
		L-651 (Corrected)		14,306.07	
		L-662-B (Corrected)		3,108.87	
		L-675		801.25	
		L-699		1,956.24	
			Subtotal	$ 36,523.30	36,523.30
4.	Oil Well Perforators, Inc.:	A-4961		$ 2,696.50	
		A-4962		1,310.00	
		A-5417		1,041.50	
		A-5418		2,285.70	
			Subtotal	$ 7,333.70	7,333.70

*SOURCE: Contractor's letter to Director of Engineering and Construction Management Division, U.S.-ERDA Las Vegas, Nevada, dated February 15, 1977.

Rio Blanco Natural Gas Co.
Third Party Invoice Summary and Statement as of February 15, 1977
Contract No. EY-76-C-08-0677

	Vendor	Invoice No.		Invoice Amount	Total
5.	Baker Oil Tools and as 11/4/76 name changed to Baker Service Tools:	76280		$ 1,996.60	
		72641		1,138.60	
		78391		1,043.00	
		80336		221.00	
		73594		753.25	
		73007		442.00	
		73328		979.00	
			Subtotal	$ 6,573.45	$ 6,573.45
6.	A-1 Service:	452S		$ 1,360.00	
		511S		8,790.00	
		985S		520.00	
			Subtotal	10,670.00	10,670.00
7.	Transport Clearings	122770		$ 140.00	140.00
8.	Dalgarno Transportation Inc.:	1518		$ 414.40	
		1530		1,360.80	
		1782		114.00	
		1741		91.20	
			Subtotal	$ 1,980.40	1,980.40
9.	Bi-Co. Rental, Inc.:	395-QV		$ 1,551.75	
		395-QV		46.55	
			Subtotal	$ 1,598.30	1,598.30
10.	Rucker Acme Tool:	371451		$ 399.00	
		372553		320.80	
			Subtotal	$ 719.80	719.80
11.	Dalbo, Inc.:	1044		$ 800.00	
		1108		2,400.00	
			Subtotal	$ 3,200.00	3,200.00
12.	M & P Roustabouts:	1853 thru 1856		$ 728.50	728.50
13.	Halliburton Services, a Division of Halliburton Co.:	060044		$ 1,650.00	
		060062		1,785.50	
			Subtotal	$ 3,435.50	3,435.50

Rio Blanco Natural Gas Co.
Third Party Invoice Summary and Statement as of February 15, 1977
Contract No. EY-76-C-08-0677

	Vendor	Invoice No.		Invoice Amount	Total
14.	Nitrogen Oil Well Service Co.	101457		$ 1,374.54	$ 1,374.54
15.	Cable, Inc.:	10-6		$ 2,144.90	
		10-64		1,919.90	
		12-173		498.70	
			Subtotal	$ 4,563.50	4,563.50
16.	Kilpatrick Associates, Inc.	2573		$ 105.00	105.00
17.	Go International, Inc.	750642		$ 2,455.00	2,455.00
18.	Schlumberger Well Service	4-26390		$ 3,949.74	3,949.74
19.	Franklin Supply Company	008-18359		$ 82.30	82.30
20.	Dallas Goodrich	October 1976		$ 250.00	
		November 1976		600.00	
			Subtotal	$ 850.00	850.00
21.	Pollard Construction Co., Inc.	4953		$ 260.00	260.00
22.	White River Roustabout Service:	149		$ 112.00	
		150		56.00	
		176		42.00	
		177		42.00	
		178		112.00	
		179		42.00	
		180		42.00	
		181		56.00	
		182		56.00	
		183		219.85	
		193		114.51	
		194		42.00	
		195		42.00	
		196		31.50	
		197		42.00	
		198		42.00	
		199		42.38	
		200		31.50	

Rio Blanco Natural Gas Co.
Third Party Invoice Summary and Statement as of February 15, 1977
Contract No. EY-76-C-08-0677

	Vendor	Invoice No.		Invoice Amount	Total
22.	White River Roust-about Service Continued:	209		$ 31.50	
		211		31.50	
		213		348.58	
		216		42.00	
		219		42.00	
		222		31.50	
		225		31.50	
		253		73.50	
		255		79.25	
		257		31.50	
		260		42.00	
		263		42.00	
		267		31.50	
		271		31.50	
		275		31.50	
		279		31.50	
		281		31.50	
		283		42.00	
		285		42.00	
		287		31.50	
		289		52.50	
		290		42.00	
		291		63.00	
		294		31.50	
		295		56.00	
		296		31.50	
		298		42.00	
		299		98.00	
		351		63.00	
		352		42.00	
		353		49.50	
		356		42.00	
		358		31.50	
		360		42.00	
		361		42.00	
		362		42.00	
		363		42.00	
		364		42.00	
			Subtotal	$ 3,122.07	$ 3,122.07
23.	Precision Pumpers, Inc.	5900		$ 81.50	
		8380		155.00	
		7464		155.00	
			Subtotal	$ 391.50	391.50

Rio Blanco Natural Gas Co.
Third Party Invoice Summary and Statement as of February 15, 1977
Contract No. EY-76-C-08-0677

	Vendor	Invoice No.		Invoice Amount	Total
24.	U. S. Geological Survey: 12.50% Royalty paid on Flared Gas:	Sept. 1976		$ 6.63	
		Nov. 1976		557.67	
		Dec. 1976		366.19	
		Jan. 1976		288.22	
			Subtotal	$ 1,218.71	$ 1,218.71
			GRAND TOTAL		$ 260,446.53

Total amount due to Rio Blanco Natural Gas Co. under terms of Contract No. EY-76-C-08-0677 effective the 1st day of August, 1976, and modified by Supplemental Agreement effective the 9th day of November 1976. $ 257,663.57