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DEMONSTRATION OF MASSIVE HYDRAULIC FRACTURING
PICEANCE BASIN, RIO BLANCO COUNTY, COLORADO

Final Report, July 1, 1976—September 30, 1979

By
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August 1979

Work Performed Under Contract No. EY-76-C-08-0678

Mobil Research and Development Corp.
Dallas, Texas

MASTER

U. S. DEPARTMENT OF ENERGY

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PICEANCE BASIN, RIO BLANCO COUNTY, COLORADO

FINAL REPORT

FOR THE PERIOD JULY 1, 1976 - SEPTEMBER 30, 1979

J. L. FITCH, W. L. MEDLIN, AND M. K. STRUBHAR

MOBIL RESEARCH AND DEVELOPMENT CORP.

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NEVADA OPERATIONS OFFICE

MASTER

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DEMONSTRATION OF MASSIVE HYDRAULIC FRACTURING

PICEANCE BASIN, RIO BLANCO COUNTY, COLORADO

Abstract

Demonstration of massive fracturing to provide gas production from tight gas sands in the Piceance Basin was the objective of this jointly funded Mobil/DOE project. This effort has been at least partially successful. The uppermost interval fractured, the "Ohio Creek" formation at 7324-7476 ft., appears to be commercially viable. The remaining sequence to total depth of 10,800 ft. may also be commercially attractive, depending on fractured well costs, gas prices and the risk of failure to achieve production capacity equal to, or greater than, that achieved in the present well. Prior work was performed by Mobil in the Brush Creek Unit, Mesa County, Colorado. One well, Brush Creek 1-25, was drilled to 10,330 ft. and given two massive fracturing treatments before the well was plugged and abandoned as non-commercial. It was concluded that formation permeability was too low to justify additional work in the Brush Creek Unit.

Piceance Creek well F31-13G was drilled to 10,800 ft. Nine zones were tested in the Mesaverde and "Ohio Creek" formations between 7324-10,680 ft. Six massive fracturing treatments were performed covering 7 of the 9 intervals. Average first-year flow potential of the well is estimated at 2.9 MMCF/day with 1.1 MMCF/day of this amount attributed to the uppermost zone.

DEMONSTRATION OF MASSIVE HYDRAULIC FRACTURING

PICEANCE BASIN, RIO BLANCO COUNTY, COLORADO

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DEMONSTRATION OF MASSIVE HYDRAULIC FRACTURING

PICEANCE BASIN, RIO BLANCO COUNTY, COLORADO

I. SUMMARY.

The results of this massive fracturing demonstration are very encouraging. Sufficient gas productive capacity was developed to make the well modestly profitable under current conditions. However, when risk is considered the economic viability of development wells in this location is uncertain. The unrisks DCF rate of return is 22% for the demonstration well; using a gas price of \$2.25/MCF and long-term production rates estimated from short production test periods. This estimate of production rates is subject to significant uncertainty. A diagram of the well with notes on testing and fracturing is given on the next page. The flow test data are summarized in the table which follows.

SUMMARY

PICEANCE CREEK 31-13 WELL

PICEANCE CREEK UNIT NO. F31-13G

PRODUCTION TEST DATA

Zone No. Days of Flow		Flow Rate, MCF/Day - Before and After Fracturing																
		1		2		3		4A&B		5		6	7	6&7	8		9	
		Before	After	Before	After	Before	After	Before	After	Before	After	Before	Before	After	Before	After	Before	After
1		375	500	-	-	930	-	430	-	800	330	860	-	500	-	150	2,000	4,000
2		300	750	-	-	-	-	310	-	590	360	690	250	450	575	150	-	-
3		300	1,000	-	-	800	-	250(?)	-	480	350	380	250	450	575	150	1,000	4,000
4			900	137	-	700	1,200				370	320	250	450	440	160		
5			780				1,100				430			400		180		
6			800				*				-			400				
7							3,200				-			400				
8							2,700				-			400				
9							2,600				-			380				
10											260			360				
		← Zones 1 — 4 After →																
1					3,000													1,900
10					2,000													1,900
20					1,600													1,800
30					1,500													1,700
40					1,400													
50					1,300													
60					1,200													
70					1,200													
80					1,100													

*Well cleaned out.

II. BACKGROUND AND PRIOR WORK BY MOBIL.

The presence of very large gas resources in low permeability reservoirs of the Piceance Basin and other Rocky Mountain basins is well known. The U.S. Government, Mobil, and other private companies have mounted a substantial effort to convert at least part of these resources to recoverable reserves. In recognition of their common interest, Mobil and the Government have contracted to jointly fund a project of this type. The primary objective of this project was to demonstrate the commercial feasibility of massive hydraulic fracturing (MHF) for recovery of gas from the Mesaverde formation of the Piceance Basin.

Mobil's efforts to obtain commercial gas from the Mesaverde reservoir of the Piceance Basin began in 1971. After extensive analysis and planning, the Brush Creek Federal Unit near Collbran, Colorado, was selected as the site of the first well (see Figure 1, p. AII-3).

Geology of the Brush Creek Site

The Brush Creek unit is near the southwest margin of the Piceance Basin. Mesaverde outcrop is present along Plateau Creek some 20 miles west-southwest of the unit. At Brush Creek Unit No. 1-25 the surface elevation is 8,417 feet. The geological section is generally similar to that present in most of the basin. The top of Mesaverde occurs at about 5,700 feet. The Williams Fork Formation comprises most of the Mesaverde Group. Total thickness of the Mesaverde is about 3,200 feet. The Mesaverde is overlain by a relatively thin Ohio Creek* interval, followed by the Wasatch. Underlying the Mesaverde are the transitional or marine sands and shales of the Mancos Formation.

Porosity of the sands averages 8-9%. Water saturations calculated from the logs average around 55%. Considerable uncertainty remains in the water saturation values due to the usual difficulties of log interpretation in low porosity sand-shale sequences. In the three Mesaverde intervals tested in the Brush Creek Well (see Appendix A) production of formation water was not a problem. Reservoir pressure was approximately hydrostatic.

Sand lens continuity at the Brush Creek site can only be inferred from general studies in the basin since well-to-well correlation of individual sand intervals from available logs is difficult or impossible. A review of the publications on this subject plus outcrop studies in the area by Mobil personnel lead to the conclusion that the sand lenses vary in length from about 400 ft. to at least 2,000 ft., with a reasonable average being around 1,000 ft. The lenses appear to become more continuous on the southwest side of the basin. This is consistent with the generally agreed upon west-to-east direction of sediment transport during most of the deposition.

*In most of the geological literature the interval between the Wasatch formation and the Mesaverde formation is called the "Fort Union". This same interval is called the "Ohio Creek" in this report.

Brush Creek Well 1-25

The well was spudded on April 5, 1974 and drilled to T.D. of 10,330 ft. After logging, 7" casing was set at plugged-back total depth of 8432 ft.

On July 13, 1974 the well was fractured in the interval 7195 ft.-8159 ft. with 95,000 pounds of sand carried by an aqueous gel at 75 barrels per minute. The purpose of this small frac job was to test the potential of the zone and to determine whether or not a moderate viscosity aqueous gel would be a satisfactory frac fluid. The well cleaned-up satisfactorily and flowed gas at rates up to 500 MCF/day.

On July 26, 1974 a massive frac was attempted in the same zone using the same aqueous gel. The job screened out after pumping less than 300,000 pounds of the planned 1,000,000 pounds of sand. Because of a large increase in treating pressure we believe that most of this treatment left the zone of interest. Attempts to clean up the well failed and the zone was plugged off.

On August 29, 1974 the interval 7516 ft.-7720 ft. was fractured with 1,000,000 pounds of sand carried in 376,000 gallons of a more viscous aqueous gel at 70 bpm. The well cleaned up satisfactorily and flowed gas at rates up to 300 MCF/day. Pressure buildup data indicated that permeability-thickness of the zone was too small to make a commercial well.

In 1975 an additional zone was broken-down, flowed and a pressure buildup obtained. The pressure buildup data showed that this zone also did not have sufficient permeability-thickness for commercial production. The well is now plugged and abandoned.

Additional details on the Brush Creek Well are given in Appendix A.

III. GEOLOGICAL DISCUSSION OF THE PICEANCE CREEK SITE.

The Piceance gas field is located in the Piceance Basin in northwestern Colorado (Figure 1). The Basin is asymmetrical with steeper dips on the east side. The Piceance Creek Field is located in the north-central part of the Basin, west of the steeply dipping east side. The Williams Fork formation has an overall thickness varying from about 3300 ft. to 4200 ft. west to east across the Piceance Creek Unit. The Williams Fork contains numerous tight lenticular gas bearing sands. The attached maps cover a nine township area centered on the Piceance Creek Unit which is outlined by heavy solid lines.

The Structure Map (Figure 2) shows the configuration of the top of the Mesaverde Group in the area of the Piceance Creek Unit. Wells penetrating the Mesaverde are circled. Projected Mesaverde tops were estimated for some of the deeper wells and were used to provide additional structural control. A northwest-southeast trending anticlinal fold has been mapped in part of the Unit. It has almost 600 ft. of closure as mapped on the Mesaverde. Synclinal folds to the southwest and north-east parallel this feature. The steep east side of the Piceance Basin is shown by contours in T2S-R95W. The Cretaceous Mesaverde Group crops out about 5 to 6 miles east of the Piceance Creek Unit boundary.

The Isopach Map (Figure 3) shows the thickness variation of the clean reservoir quality sand in the upper 2400 ft. of the Mesaverde Group - Williams Fork Formation. The upper 2400 ft. of Mesaverde in each penetrating test was divided into eight 300 ft. intervals and the reservoir quality sand present in each interval is listed on the Isopach. Some wells penetrated only part of the 2400 ft. interval and the thicknesses of reservoir quality sand are calculated for the portion not drilled by using ratios from nearby wells. Wells penetrating the Mesaverde are circled with the thickness drilled shown above the circle. The Mobil #54-13, Section 13-2S-97W, and the Mobil #52-19, Section 19-2S-96W, both penetrated the entire Mesaverde Group made up of the Williams Fork and Iles Formations. It was found to have a thickness in excess of 4500 ft. in these wells.

As shown by the contouring, an average of more than 700 ft. of reservoir quality sand should be encountered in the upper 2400 ft. of the Mesaverde in the test area.

At the present time, only the upper 2400 ft. of the Mesaverde Williams Fork Formation in the Piceance Creek Unit area is considered to have Massive Frac potential because it has a higher ratio of reservoir quality sand. The average ratio of reservoir quality sand versus gross interval in the upper 2400 ft. of Mesaverde Williams Fork in the Mobil #52-19 in Section 19-2S-96W and the Mobil #54-13 in Section 13-2S-97W is 0.315 (see Figure 4A). The remaining 1000 ft.-1100 ft. of the Williams Fork in these two wells has an average ratio of 0.204. The sands in the lower portion of the Williams Fork are also thinner and appear to have poorer reservoir quality. Most of the lower portion of the Williams Fork was probably deposited in swamp and marsh low energy environments whereas the upper portion of the Williams Fork probably represents deposition in a fluvial environment where higher energy levels are possible. Coals are much more numerous in the lower Williams Fork also indicating deposition in swamp or marsh environments. For comparison with these two wells, the Dual Induction-Laterolog and the Compensated Neutron-Formation Density logs from F31-13G are illustrated in Figure 4B.

The parameters used in preparing for the MHF test evolved from previous work done by Mobil. Some of the parameters used can be defined within narrow limits while others are subject to considerable variation. Those that are subject to variation and are necessary to cover in a discussion of the geology are tabulated below:

<u>Parameter</u>	<u>Average Value</u>
Porosity, %	8.9
Water Saturation, %	55
Permeability, md	0.005
Net Productive Sand, Ft.	575'
Drainage Distance, Ft.	1084'

The porosity and permeability used are based on measurements on cores from the Mobil #52-19 well. These average values agree very well with published data from the Rulison and Rio Blanco Project Areas. The water saturation has its origin mostly from published data from other projects with the Mesaverde as one of their objectives.

Log evaluations were made using the Induction, Borehole Compensated Sonic and Gamma Ray logs from Mobil #52-19. The Sonic log of this well is of questionable value because of numerous skip cycles caused by gas in the mud. Skip cycling also makes the Sonic Log run through the Mesaverde in the #54-13 of questionable value.

The 575' net productive sand thickness is considered to be reasonable. Some uncertainty exists as to whether all of the reservoir quality sand has low enough water saturation to be gas productive. Testing indicates that gas productive sands can be expected in at least the upper 1500' the Mesaverde at the location.

A drainage distance of 1084' has been estimated. This distance is one-half the average length of the sand lenses that are expected to be cut by the induced fractures. This parameter can vary greatly. The average length of Mesaverde sand lenses has been the subject of numerous studies. In a review of these studies we concluded that values of one-half the average lens length range from 235' to 1,084'.

IV. THE WORK PLAN.

Plans for the Piceance Creek test, as formulated in 1976, are summarized below.

The purpose of this field project is to demonstrate the efficiency and economics of massive hydraulic fracturing (MHF) technology for stimulating production from large natural gas reservoirs which are presently non-commercial because of low permeability. The work was performed in three phases involving a well to be drilled in the Piceance Creek gas field, Rio Blanco County, Colorado. The work plan is summarized in Figures 2-7 and the discussion below.

Phase I: Drill Well and Select a Zone for MHF Treatment

The well location is 1,126 feet from north line and 1,683 feet from east line of Section 13, T2S, R97W, Rio Blanco County, Colorado. We will drill and complete the well with cemented 7-inch O.D. casing to a subsurface depth of 10,600 feet to penetrate intervals to be tested for MHF in the Mesaverde formation. Coring points will be picked as the well is drilled. Two 60-foot lengths of core are desired in intervals expected to contain reservoir quality sand. Routine core analyses, and measurements of permeability vs stress and water saturation, stress vs strain, and "M" and "N" values for use in log interpretation, will be made. A full suite of open-hole logs will be run including induction or laterolog type electrical survey with SP, density with gamma ray, sonic with caliper, and neutron porosity log. Cased hole logs will include base temperature survey, correlation gamma ray log, and cement bond log. Perforated intervals will be inspected using the Borehole Televiewer. The lowest zone in the well which is considered favorable for application of MHF will be selected as the first interval to be tested and fractured. Before fracturing, the interval (maximum height of about 250 feet) will be flow tested and a pressure buildup taken. Well to reservoir communication will be established by pumping 1 percent KCl water at fracturing rates. Ball sealers will be dropped in sufficient number to seal all perforations near the end of the breakdown treatment. The well will be flowed until it has cleaned up and a reasonably uniform rate has been maintained for several days. Temperature and noise logs will be run to investigate the flow profile. The well will then be shut in and bottom-hole pressure measurements taken for a period of at least twice the flowing time. The pressure buildup will be analyzed to determine reservoir pressure and permeability thickness product (kh). To be favorable for MHF, we believe that the interval must have: kh of 0.5 millidarcy-feet (md-ft) or greater; ratio of net sand to gross thickness, minimum 0.3; permeability, minimum .003 md; and net sand thickness, minimum 30 feet. If the interval is judged not suitable for MHF, the perforating and testing operations will be repeated until a suitable interval is found.

Phase II: Design and Perform MHF Treatment and Test Well Productivity

Using information developed in the first phase, the first MHF treatment will be designed based on the best available technology. It is anticipated that approximately 400,000 gallons of water containing a cellulose polymer or other low-cost gelling agent carrying approximately 1,000,000 pounds of sand will be injected at a rate of 70 to 100 barrels per minute. Production testing and logging will be used to determine success of the treatment.

Phase III: Select Other Zones, Perform

Additional MHF Treatments and Test Well

This phase depends on the presence of other intervals suitable for MHF as judged by criteria stated for selecting the Phase II interval, production performance calculations, and economic analysis. Phase III will commence if a second zone deemed suitable for demonstration of the commercial feasibility of MHF in this area is found. This phase will then continue until a total of six zones, or all zones suitable for commercial feasibility of MHF in this area are found and fractured.

Forecast of the Piceance Creek Test Results

Well logs, flow tests, pressure build-ups and core analyses from two previous wells suggest that the new Piceance Creek well should have the equivalent of 400 ft. of net sand with total kh of about 2 md-ft. Stimulation by massive hydraulic fracturing should provide a commercially attractive well deliverability at existing interstate gas prices. We estimate initial production rates of around 5 MMCFD. Cumulative production should reach about 15 bcf in 30 years.

V. PHASE I ACTIVITIES.

Drilling and Casing

The well was drilled and cased by Signal Drilling Company, Rig No. 5 in 68 days, beginning April 2, 1977. Seven inch casing was set to near the total depth of 10,800 feet and cemented from T.D. to about 8,100 feet, in a single stage, using a high-strength, light-weight cement. The Daily Drilling Report is given in Appendix 4.

Coring

Cores were taken in the intervals 8440-8500 feet and 9940-10,000 feet. Approximately one-half of the cored material is classified as sandstone. Standard core analysis shows that porosity varies from about 5 to 10%, averaging about 8%. Specific permeability of all samples is less than, or equal to, 0.1 md. Core analysis results are shown in Table I. Tests of permeability under confining stress conditions have been performed on selected samples; these results are shown in Table II. Although these data are quite limited, the results suggest that in-situ permeability of the sands represented by these samples is in the micro-darcy range.

Quality control checks were run and "m" and "n" values determined on selected core samples. These measurements were made at Mobil's Field Research Laboratory using well known equipment and procedures. The data are shown in Table 11B. The commercial laboratory (CLI) values of porosity, permeability, and grain density compare satisfactorily with those which we obtained (FRL). The "m" and "n" values are all less than 2.0. The "n" values are less than what is usually considered "normal". The low values of "n" should be viewed with some suspicion. It is possible that either (1) the water saturation was not uniformly distributed during the partial saturation measurement, due to low permeability, or (2) some evaporation occurred which increased the salinity of the saturating water, or both. Use of these lower than "normal" values of "n" in log interpretation will make the derived values of saturation more optimistic.

Logging

Open-hole logs included; dual-induction with SP, Compensated Sonic with -ray, Compensated Density and Neutron Porosity, and 4-Arm Caliper. All logs were run to 10,600 ft., the original planned depth. A good mud gas show near 10,600 ft., lead to a decision to drill to 10,800 ft. Induction and Sonic logs were run over this additional interval.

The log characteristics are similar to those recorded in nearby well No. 54-13. Some of the sands can be correlated from well to well; majority of the sands can not, suggesting that the extent of most sand lenses is less than about 2000 ft. (The distance between the surface location of these two wells is about 1700 ft.)

Core data were used to calibrate the porosity logs. Log derived porosity of the sands varies from about 5 to 12% with a few thin intervals having porosity up to 15%. Water saturation is very difficult to determine due to uncertainty in R_w . None of the sands can be said with confidence to have 100% water saturation and no formation water samples have been obtained which are known to be free of contamination, either by fluids introduced through the wellbore or by water condensed from produced gas. Because of this uncertainty, net pay can only be determined by flow tests. The logs have been made available to commercial log information service companies.

Testing

Intervals which contain promising sands were perforated, broken down with a small amount of fluid pumped at fracturing pressure, and flow tested. In addition to the usual flow rate and pressure buildup data, a combination noise and temperature log was run to determine the location and approximate amount of gas flow.

Breakdown and Flow

The perforations, 10,549-10,680 ft. (131 gross ft.), were broken down on June 2 by pumping 5000 gallons of 2% KCl water at 10 barrels per minute. Ball sealers in excess of the number of perfs were dropped but ball-off was not achieved. The breakdown treating record is given in Figure 8.

The well was flowed back immediately with gas to the surface in 2 hours. Measured gas flow rates in MCF/day are: June 3 - 375, June 4 - 300, June 5 - 300. Noise/temperature logs indicated that most of the interval was contributing to flow.

Pressure Buildup

After 6 days of shut-in sufficient buildup data was obtained to calculate kh. The value obtained is 0.3 md-ft. The pressure buildup data are given in Figure 9 and Table III.

Although a kh of 0.5 or greater is desirable for application of MHF, a decision to fracture this lower-most interval was made. This decision was based on the following considerations:

1. The 0.5 md-ft cut-off was based on economic calculations in which a 1980 gas price of \$1.38/MCF was assumed. It is likely that the actual gas sales price will be higher than the assumed value.
2. A frac job, and subsequent test data, of the lower-most promising interval would be useful in evaluation of other zones.
3. Sequential upward testing without fracturing imposes severe mechanical constraints on subsequent fracturing of the lower, bypassed zones, if this should prove desirable.
4. All of the interval may not have been open to flow because ball-off was not achieved in the breakdown treatment.
5. The negative skin obtained from pressure buildup analysis suggests natural fracturing. The effect of natural fractures on after-frac production rate could be positive or negative, depending on their geometry.

Fracture Design and Pre-Frac Test

A fracture was designed to accomplish the following objectives:

1. To positively prop the fracture over most of its height, since the top-most sand appears to be the best one in the interval.

2. To frac the entire interval by the limited-entry technique.

3. To obtain a propped fracture long enough to obtain a high degree of stimulation of lenses assumed to be of the order of 1000 ft. in total length, but short enough to reduce the chances of the fracture propagating out of the zone.

4. To test the effectiveness of a relatively low cost treatment in this formation using an aqueous fluid.

The treatment selected to accomplish these objectives called for 600,000 pounds of 20/40 mesh sand carried by a 40 lb/1000 gallon cellulose gel pumped at 60 barrels per minute. Treatment design details are given in Table IV.

In addition to treatment design calculations, a pre-frac pump-in test was performed to investigate the "fracturability" of the zone. The main objective of this test was to obtain fracture propagating data for use in estimating the "plasticity" of the zone. A treating pressure increase would indicate a tendency of fracture width to grow at the expense of fracture length and, also, a tendency of the fracture to propagate out of the prospective pay sands. The test consisted of pumping 20,000 gallons of 2% KCl water at 8 barrels/minute. No fracturing treatment pressure increase was observed. The treatment data are shown in Figure 9. On the basis of these data, no fracturing problems were anticipated.

VI. PHASE II ACTIVITIES.

Fracturing Treatment

The treatment was performed on June 22, 1977 according to the schedule in Table IV, except that a "screen-out" occurred after 580,000 lbs. of the planned 600,000 lbs. of sand was pumped. This "screen-out" late in the treatment should insure that the fracture is completely propped near the well.

During the treatment a large treating pressure increase occurred. This pressure increase began as soon as fracturing pressure was reached and was quite large before any sand entered the perforations. The data are shown in Figure 10. This treating pressure increase was completely unexpected in view of the pre-frac pumping data shown in Figure 8. The treating pressure increase certainly created a wider, shorter fracture than planned, and the larger than planned fracture width undoubtedly caused, or at least contributed to, the "screen-out" near the end of the treatment. Of potentially greater significance, such a treating pressure increase strongly suggests that the fracture propagated into mechanically different rock, such as shale.

After-Frac Flow Testing

About 15 minutes after fracturing the well was gradually opened to flow. The flow rate was increased to about 4 barrels/minute within the first hour. Some sand was produced during the early flow period--estimated at equal to, or less than, the amount of sand left in the pipe when the pumps were shut down due to "screen-out". Gas-to-surface was observed within 4 hours. The amount of sand in the flow stream rapidly decreased and no sand was detected after 12 hours of flow. Flow data are given in Table V.

The well was shut in for buildup on June 29. As of that date, the water production rate was 40 bbl/day with estimated total frac fluid recovery of about 25%.

After Frac Buildup Tests

After-frac pressure buildup data were collected during the period June 29-July 11. The data are presented in Table VI and plotted in Figures 11A and 11B. Figure 11C provides a different interpretation of the pre-frac buildup data.

Interpretation of the buildup data is subject to considerable uncertainty. If one performs the usual procedure of plotting p^2 vs dimensionless time and taking the slope at the longest time one gets $kh = 0.3$ md-ft; as shown in Figure 8. If one plots $m(p)^2$ the intermediate time segment becomes a straight line which can be interpreted as due to flow from two zones with $kh = 0.86$ md-ft. This interpretation removes the need to invoke a rather large negative skin--as is required by the p^2 plotting procedure.

In the case of the post-frac buildup the major uncertainty lies in the amount of correction which should be applied to kh for the presence of the frac. Because both the geometry of the fracture and the reservoir are uncertain, this becomes a matter of judgement. Our opinion is that kh was not greatly increased by fracturing.

A short flow test was performed after the buildup. The flow data are given in Table V. It appears that performance of the well is somewhat better after the buildup than before. This is not surprising since the frac water remaining in the reservoirs could have been redistributed during the shut-in period.

VII. PHASE III ACTIVITIES.

A. Zone 2 - Gross Interval 10,186-10,476 Ft. (290 ft.)

During the period July 18-31, 1977 preparations were made for a second MHF test. The well was killed and a retrievable bridge plug set at 10,530 ft.

The interval, denoted as Zone 2, contained four thin sands: 10,473-77 ft. (Sand A), 10,415-29 ft. (Sand B), 10,255-61 ft. (Sand C), and 10,186-10,204 ft. (Sand D).

Thicknesses were 4, 14, 6, and 18 ft., respectively. Sands A and B were perforated with 3 and 10 holes, respectively, and broken down in one treatment using 5000 gallons of 2% KCl water pumped at 8 BPM with excess ball sealers. A retrievable bridge plug was set above these perforations. Pump-in tests were performed on sands A and B to obtain fracturing pressure data. The results are shown in Figure 12. Sands C and D were then perforated with 4 and 12 holes, respectively, and broken down in the same way. Good ball action was observed in both breakdown treatments. The retrievable bridge plug was moved to below Sand D and the entire Zone 2 interval opened to flow. After some swabbing, gas flow was initiated but the maximum rate was only 137 MCFD. Noise-temperature logs run during the flow period showed that all four sands were contributing to flow. Based on the experience of Zone 1 it seemed unlikely that the kh for Zone 2 would exceed 0.1 md-ft. Therefore, the well was killed with KCl water and a retrievable bridge plug set above Zone 2 for isolation.

B. Zone 3 - Gross Interval 9,392-9,538 Ft. (146 ft.)

Selection and Testing of Zone-3

The rock sequence above Zone-2 between 10,150 and 9,690 ft. contains a number of sands up to about 20 ft. thick. None of these sands appear to have better porosity and saturation than the Zone-2 sands. For this reason we chose not to test these sands.

The gross interval 9,392-9,538 contains two sands with relatively good properties--9,517-9,538 (Zone-3A) and 9,392-9,432 (Zone-3B) ft.

These sands were perforated on August 6-7, 1977 with 34-0.388 inch diameter jet shots; 16 in Zone-3A and 18 in Zone-3B.

On August 8 the perforations were broken-down with 12,000 gallons of 2% KCl water. Good ball action was observed but ball-off was not achieved. A series of pump-in tests was then performed using Apollo Gel-40 at 5, 10, and 15 bpm. Some increase in treating pressure was observed as follows:

<u>Rate, bpm</u>	<u>Barrels</u>	<u>ISIP</u>
5	40	900
10	50	1050
15	100	1250

We concluded that the planned 600,000 pound treatment could be performed at 15 bpm without exceeding pressure limitations. We also concluded that the anticipated treating pressure increase would insure treatment of both sands without use of limited entry or ball sealers.

After the above tests the well was flowed to the pit. Measured gas rates were 930 MCFD on August 9 declining to 700 MCFD on August 12 when the well was shut in for buildup.

Noise/temperature logs were run on August 10, during the flow period. Gas production was observed from both perforated intervals with Zone-3A apparently producing at a higher rate than Zone-3B.

Pressure buildup data taken from August 12-17 are given in Table VII. A plot of these data, Figure 13, gives $kh = 1.1$ md-ft.

Fracturing, Zone-3

The frac job was performed down 2 7/8 in. tubing as planned on August 24. A total of 232,000 gal. of Apollo Gel-40 was used to place 600,000 pounds of 20-40 sand. The pump rate was held constant at 15 bpm. The initial ISIP was 1200 psi; final ISIP was 2700 psi, declining to 1100 psi in 15 min.

A temperature log was run immediately after the frac job. Sand fill was found at about 9500 ft. The log indicated that the frac fluid entered both sets of perfs because a temperature anomaly was present at the lowest depth reached by the logging tool. The log indicates that the fracture, at the wellbore, did not extend much above the uppermost perforation.

The well was opened to flow at 10:48 p.m., about 5 hours after conclusion of the treatment. The well flowed water and gas to the pit until August 30 when the water rate declined enough for a gas flow rate measurement. Frac fluid recovery at that time was estimated at 35-40% with continued water

production rate of about 100 bpd. Gas flow rate was 1.2 MMCFD on August 30 and 1.1 MMCFD on August 31. A decision was made to clean the sand fill from the casing. The well was killed on August 31 and an unsuccessful attempt was made to unseat the packer, set at 9,360 ft. Solid material was produced and the well began flowing gas and water at a high rate. To check the possibility that the sand fill had been removed, a gamma log was run on September 2. Sand was found to still be present at about 9,500 ft.

Because of the strong flow observed on September 1-2 a decision was made to obtain additional flow data. The results are:

<u>Date</u>	<u>Gas Rate, MMCFD</u>	<u>Est. Water Rate, BPD</u>
9-3	3.2	290
9-4	2.7	100
9-5	2.6	100

The stuck packer was unseated and removed from the well on September 13. Sand fill on the casing was found at 9405 ft.--about 100 ft. above the previously measured level. The casing fill, which consisted of frac sand, was circulated out to a level just above the bridge plug at 9600 ft. After dressing the threads, 2 3/8 in. production tubing was landed at 9110 ft. During the above operations, a substantial quantity of KCl-treated water was lost to the formation; estimated load to recover as of 9/20/77 was 5500 bbl.

The well was opened to flow on September 21. No swabbing was required. Approximate flow rates are given in the table below:

<u>Date</u>	<u>Gas Rate, MMCF/D</u>	<u>Water Rate, BBL/D</u>
9/22	--	500
9/23	Some	500
9/24	est 1+	500
9/25	1.1	350
9/26	1.1	140
9/27	1.1	75

The reduced rate compared to that previously observed is attributed to the large amount of water remaining in the interval.

Noise/temperature and gamma ray logs were run during the flow period. In spite of much water production the noise log is of fair quality. It shows approximately equal amounts of gas coming from about five feet at the top of each of the perforated intervals. The remaining perfs in each interval were producing little gas. This is taken as evidence of high water saturation in the bottom part of each fracture.

The gamma ray log shows good radioactive sand distribution over both of the perforated intervals. However, it appears that the frac extends some 20 ft. above the top of the lower set of perforations.

The well was shut in for pressure buildup on September 28. The PBU data are given in Table VIII and Figure 14.

At long time, the after-frac pressure data do not coincide even approximately with the before-frac data. The comparison is difficult to interpret. It is not clear that the after-frac curve has reached its final slope. If it has, the after-frac condition corresponds to an increased kh and a reduced reservoir pressure. Alternatively, if it is assumed that the after-frac buildup curve will turn up at longer times to match the before-frac reservoir pressure, the kh value would be significantly reduced after fracturing. A clear interpretation of these results seems impossible. However, the mismatch in buildup data, together with the anomalous flow back behavior indicate that the condition of the fractured zone is less than ideal.

After the buildup, flow data were obtained as follows:

<u>Date</u> <u>October</u>	<u>Gas Rate</u> <u>MCF/d</u>	<u>Water Rate</u> <u>Bbl/d</u>	<u>Cond. Rate</u> <u>Bbl/d</u>
12	1,900	48	10
13	1,850	116	5
14	1,700	105	19
15-16	--	--	--
17	1,513	85	23

During the flow period, noise-temperature logs were run which showed the greatest amount of gas entry in the interval 9392-9432 ft.

Following these tests the well was killed with KCl water and the retrievable bridge plug was moved from 9600 ft. to 9370 ft.

C. Zone 4 - Gross Interval 9086-9320 Ft.

Testing Gross Interval 9254-9320 Ft. (66 ft.) - Zone 4A

This interval consists of an almost continuous sand sequence containing about 55 net feet. On the basis of log analysis it appeared to have about the same quality as the Zone 3 sands. The well was swabbed down to 3,000 ft. and perforated with 33 jet shots using a 4-inch O.D., centralized, hollow carrier gun. The perfs were broken down on October 19 with KCl water at 12.5 bpm. Good ball action was observed with ball-off occurring with approximately 50 balls at the perfs. Initial ISIP was 925 psi; final ISIP was 1000 psi. The well was immediately opened to flow. After about 4 hours the rate was about 400 MCF/day. Additional flow data are as follows:

<u>Date</u> <u>October</u>	<u>Gas Rate</u> <u>MCF/day</u>	<u>Water Rate</u> <u>Bbl/day</u>	<u>Cond. Rate</u> <u>Bbl/day</u>
20	250	290+	--
21	155	22	2
22	125	--	--

Noise-temperature logs run during the flow period showed most of the gas coming from the lower part of the perforated interval.

The well was shut in for buildup on October 22. Some difficulty was experienced with the Hewlett-Packard, surface recording, quartz pressure gauge. However, sufficient readings were obtained with the H-P gauge, a bottom-hole Kuster gauge and surface gauge readings to provide a well defined buildup curve; kh of the interval is about 0.07 md-ft.

The PBU data are given in Table IX-A and Figure 15A.

Testing of Gross Interval 9086-9125 Ft. (39 ft.) - Zone 4-B

This interval was perforated on November 4, 1977 with 32 jet shots using a centralized, 4-inch hollow carrier gun. The perforations were broken down on November 7 with 5,000 gallons of KCl water at 12.5 barrels per minute; maximum pressure 6900 psi; ISIP 1600 psi. Ball-off was achieved. Flow-back began at 12:30 p.m. on November 7; gas flow rate reached 400 MCF/day about 5:00 p.m. The well flowed for three days, as shown in the table below. Noise/temperature logs during the flow period indicated that most of the perforated interval was producing some gas, especially near the bottom and near the top of the interval. The low flow rate made interpretation of the logs difficult.

<u>Date</u>	<u>Rate, MCF/day</u>
Nov. 7	400
Nov. 8	185
Nov. 9	158
Nov. 10	125

We believe this is a good flow test since all operations proceeded normally. The well was shut in for PBU on November 10. The PBU data are given in Table IX-B and Figure 15B. Results indicated kh of this zone to be about 0.03 md-ft.

Testing of Zones 1-4 During the Winter

Following testing of Zone 4 a decision was made not to fracture because kh was < 0.5 md-ft. The well was then prepared for flow of Zones 1-4 during the winter months.

Removal of the two bridge plugs and sand fill from the well was completed on December 13. The well was flowed to the pit during December 14-17. At the end of the flow period the well was making an estimated 350 barrels of load water plus a substantial amount of gas (estimated at between 1 and 3 MMCFD) at 225 psi tubing pressure, 1200 psi casing pressure on 3/4 inch choke.

The well remained shut in from December 18 until January 17 while awaiting connection to the pipeline. The well was opened briefly to flow on January 17, then shut in to correct difficulties with the separator. Flow data beginning January 18 are given in Table X. Choke size was 1 inch on January 19 and 3/4 inch for the remainder of the period.

Production Logging, Zones 1-4

Following the flow test the tubing was pulled, through a stripper head, to 8967 ft. so that production logs could be run inside the casing. Commercial spinner flowmeter, temperature and Gradiomanometer logs were run from 8,967 to 10,595 ft. on 4/12/78. Field interpretation of the flow survey is as follows:

<u>% of Total Flow</u>	<u>Depth, Ft.</u>
5	10,420
5	10,340
5	10,170
15	9,520
70	9390-9520

Flow indications were obtained with Mobil's noise/temperature log. The flow profile estimates from this log are as follows:

<u>% of Total Flow</u>	<u>Depth, Ft.</u>
5-10	10,600 and below
5-10	10,550-60
5	10,515-35
5-10	10,420-25
5	10,425-60
5	10,210
5	10,185
10-15	9,520-30
45-70	9,390-9,420
5-10	9,100-20

Further interpretation and analysis of the flow data is presented in Section VIII, Evaluation of Fracture Effectiveness and Well Performance.

Following the flow surveys, a retrievable bridge plug was set at a depth of 9040 feet.

D. Zone 5 - Gross Interval 8765-8972 Ft.

Perforating and Pre-Frac Testing

Zone 5 was perforated on 4/23/78 with a centralized, hollow carrier gun and nominal 0.4" jets as follows:

<u>Depth*</u>	<u>No. of Shots</u>
8765-73	5
8790-8810	11
8826-34	5
8914-30	9
8954-72	10

*Schlumberger Sonic log dated May 3, 1977 - Run 3.

The perfs were broken down on 4/23/78 with 244 bbls. of 2% KCl water containing 3#/1000 gal. of Western's FR-16 at 10-12 bpm. Good ball action was obtained and ball-off was achieved. There was some indication of a treating pressure increase during the breakdown. Final ISIP was 1200 psi declining to 600 psi in 5 min. The well was flowed to the pit after breakdown with gas to the surface in 1 1/2 hours. The flow was strong but too wet to measure until late in the afternoon of April 24. Measured flow rates are as follows:

<u>Date</u>	<u>Gas MCF/day</u>	<u>Water BBL/day</u>	<u>Condensate BBL/day</u>
4/24 (late p.m.)	800	--	--
4/25 (10:00 a.m.)	588	18.4	9.0
4/26 (8:00 a.m.)	479	18.0	5.5

The well was shut in for buildup at 6:30 p.m. on 4/26/78. The buildup data are given in Table XI and Figure 16. The buildup has two well defined slopes which we attribute to flow from two (or more) zones with different properties. The intermediate slope gives $kh = 1.0$ md-ft, which we take to be the true flow capacity.* A noise log run on May 4, after the buildup, shows most of the gas flow from the interval 8964-70 ft.

*This interpretation is strengthened by analysis of data from a brief draw-down after completion of the buildup. These data indicate $kh = 1.0$ md-ft.

Fracturing and Testing of Zone 5

The zone from 8765 to 8972 ft. was fractured on May 10. The treatment was terminated by a screen-out after 388,000 pounds of sand were placed. Cause of the screen-out was excessive fracture width generated by sharply increasing treating pressure during the treatment. The rise in treating pressure was clearly associated with rock properties, rather than proppant transport. A sketch of the treating pressure record is shown in Figure 17. The observed rate of treating pressure increase is approximately constant up to the onset of screen-out regardless of sand concentration and pumping rate. We view the treating pressure increase as a far more serious problem than failure to place all of the planned amount of sand. A pressure increase of this magnitude guarantees a much wider and shorter fracture than desired and suggests that the fracture may have propagated in non-pay.

Clean-up of Zone 5 after fracturing was slow. Production data are given in the table below. Although the initial flow rate was less than the initial pre-frac rate, the zone is clearly stimulated by the fracture since the decline rate is much less after fracturing. Because of water slugging, the rates given below are only approximate 24-hour averages.

<u>Date</u>	<u>Flow, MCF/day</u>
5/14	330
5/15	360
5/16	350
5/17	370
5/18	430
5/22	260

Pressure drawdown analysis of the after fracturing data gave a kh of approximately 1 md-ft.

Following the flow tests on Zone 5, a RBP was set at 8715 feet.

E. Testing and Fracturing Zones 6 and 7 - Gross Interval 8173-8650 Ft.

Perforation and Testing of Zone 6

The zone between 8443-8650 ft. was perforated on May 25 with 47 jet shots. The perforations were broken down with 2% KCl water on May 27; good ball action was observed. Flow rates after the breakdown were as follows:

<u>Date</u>	<u>Rate, MCF/day</u>
5/27	850 (after 5 hrs. of flow)
5/28	688
5/29	383
5/30	318

The pressure buildup plot (Figure 18) gives an intermediate slope k_h of about 0.5 md-ft and a final slope k_h of 0.14 md-ft. The data for this buildup are given in Table XII. From the intermediate slope k_h , Zone 6 appeared to have sufficient k_h to justify fracturing. It was decided to perforate and test Zone 7 at 8163-8372 ft. and then to fracture both zones in one stage. The anticipated treating pressure increase should guarantee that both zones accept frac fluid.

Prior to perforating Zone 7, a RBP was set at 8427 feet.

Perforation and Testing of Zone 7

Zone 7 at 8173-8372 ft., overall, was perforated on June 12 with 40 Hyper-Jet charges using a 4" O.D. centralized, hollow carrier. The shot spacing was 2-feet in the intervals 8163-8181, 8210-8226, 8250-8266, 8279-8285, and 8349-8372 ft. No flow was observed after perforating. The perfs were broken down on June 13 with KCl water; good ball action was observed. The instantaneous shut-in pressure was 1100 psi.

Flow could not be sustained after breakdown. Wellhead pressures observed after perforating and breakdown indicate that reservoir pressure in Zone 7 is about 500 psi below hydrostatic. The well was swabbed in on June 14. The gas flow rate was not sufficient to provide a steady flow rate in the presence of a substantial water flow; occasional swabbing was required. This made rate measurements difficult. The rate was approximately constant at 200 MCF/day during the period June 14-16. Estimated water production was 80 bbl. greater than the load, indicating that the zone is making formation water. A sample of this water was analyzed and the results are shown in Table XIII.

The well was shut-in for pressure buildup on June 16. Analysis of the buildup gives an intermediate slope of 0.8 md-ft and a final slope of 0.3md-ft. The buildup plot is shown in Figure 19, and the data are listed in Table XIV.

Prior to the fracture treatment, the RBP at 8427 feet was retrieved.

Fracturing Zones 6 and 7

Zones 6 and 7 (8443-8650 and 8173-8372 ft. overall) were fractured on July 6. The planned treatment was for 900,000 pounds of 20-40 mesh sand carried by 346,000 gallons of Polaris Gel-40 plus 5% condensate at 15 barrels per minute. The treating plan was followed until treating pressure increase led to a sand-out. The treatment summary is as follows:

Rate - 15 bpm

Fluid volume - 288,000 gal., incl. 15,120 gal. condensate

Sand - 660,000 pounds

Initial ISIP - 600 psi

Treating Pressure - 1000 psi increasing to 2900 psi before screen-out

Final ISIP - Could not be determined.

Treating pressure increased from the beginning of the job but "broke back" sharply at three points in the treatment. The treating record is shown in Figure 20.

After the screen-out an attempt was made to run a temperature log. Sand fill was encountered just above the perforations. A decrease in temperature was observed at the lowest depth logged indicating that the upper zone took some frac fluid.

Excess sand was circulated from the well on July 7-8. In the absence of sustained natural flow, the well was swabbed and flowed intermittently until July 12 when sustained flow was achieved. During the flow period July 12-25 the hourly flow rate was highly variable due to insufficient gas to lift the water at a steady rate. Best estimates of the average flow rates are as follows:

<u>July</u>	<u>Gas, MCF/day</u>	<u>Water, bbl/day (Est.)</u>
13	500	650
14-16	450	550
17-20	400	300
21	380	200
22	360	200
23	330	200
24	325	200
25	320	200

Noise/temperature logs run during the flow period show that most of the production is from Zone 6. An analysis of the produced gas is given in Table XV.

Prior to initiating work on Zone 8, the RBP at 8715 feet was retrieved, redressed, and set again at 8100 feet.

F. Testing and Fracturing Zone 8 - Gross Interval 7704-7796 Ft.

The top of the cement (8020 feet) after primary cementing did not include Zones 8 and 9. Remedial cementing of Zone 8 was accomplished during the period August 4-17. The casing was perforated at 7818-20 ft. with 8 shots. Circulation to the surface was attempted but failed. After perforation at 7650-52 ft. with 8 shots, circulation across the zone was established. The zone was cemented with 150 sacks of Class H plus Haldad 9. Circulation was lost during cementing. The bond log shows good bonding to at least 7670 ft. Prior to perforating the zone, the RBP was reset at 7812 feet.

Zone 8 was perforated on August 19 in the intervals 7704-36 and 7776-96 ft. with 27 Hyperjet charges (nominal 0.4"; one hole/2 ft.) carried in a 4" centralized gun. After perforating the zone was broken down with 138 bbl of 2% KCl water @ 10-12 bpm; ISIP 750 psi. Ball-off was achieved. After breakdown the well flowed a little water for 2 hours and died. After a few hours, the well began flowing gas and water. Observed flow data are:

<u>Date</u>	<u>Gas, MCF/day</u>	<u>Water, bbl/day</u>
8/20	Est. 500+	--
8/21	575	--
8/22	575	552
8/23	443	480

Noise/temperature logs show most of the fluid is coming from the lower zone. An analysis of produced water is listed in Table XVI.

Pressure buildup data (Table XVI.1, plotted in Figure 21) show two distinct slopes on the Horner plot, as in some previous zones. The final slope gives kh approximately 0.5 md-ft; kh from the intermediate slope is greater than 1 md-ft. Extrapolation of the buildup data to "infinite time" gives reservoir pressure about 2800 psi. Although this value is uncertain due to short buildup time, it is consistent with the well's flow behavior and with estimated reservoir pressure in Zone 7, i.e., some 500 psi below hydrostatic pressure.

Zone 8 was fractured on September 7. The most severe treating pressure increase to date was encountered while pumping the treatment. Initial ISIP was 800 psi, after pumping 3000 gal. of pad. Initial (static) treating pressure, measured on the tubing, while pumping Polaris Gel-40 was 900 psi. Pressure increased rapidly to about 3400 psi when sand-out occurred after pumping 218,000 pounds of 20-40 mesh sand in 120,000 gallons of Polaris Gel-40 at 15 bpm. A sketch of the treating pressure record is shown in Figure 22.

Following the frac and a brief flow-back period, sand fill was found at about 7780 ft., just below the top of the lower set of perfs. Attempts to get the well to flow by swabbing and unloading with nitrogen resulted in only intermittent flow. A packer was set above the perfs on September 12. Flow rates observed were:

<u>Date</u>	<u>Gas, MMCF/day</u>	<u>Water, bbl/day</u>
9/13	148	68
9/14	148	28
9/15	149	--
9/16	161	--
9/17	181	23

It is believed that sand covering the lower set of perfs was severely restricting flow from that interval. Because of approaching winter, it was decided to shut the well in and begin work on Zone 9. The RBP at 7812 feet was retrieved. Another plug was set at 7595 feet prior to the initiation of remedial work on Zone 9.

G. Workover, Testing, and Fracturing of Zone 9.

Most of October was spent in completing preparations for perforating and testing Zone 9. Following remedial cementing on Zone 9, the upper perfs failed to hold pressure. These perfs were successfully squeezed on October 10. The cement retainer was drilled out on October 12 and a bond log run. Poor bonding was observed between Zone 9 and the bottom set of perfs used in cementing. On October 18 a squeeze was performed just above these perfs at 7510 ft. Bond was improved by the squeeze. After drilling out cement attempts were started to move the bridge plug to above the lower cementing perfs. After several days of effort, the plug was jarred loose on October 25. While coming out of the hole with the plug, pressure built up below it and blew the plug and retrieving tools out of the hole. No one was hurt and the well was quickly brought under control. Only modest physical damage was incurred. A drillable plug was set at 7495 feet on October 30.

The zone was perforated between 7324-7476 ft. with 77 shots (one shot per two feet) on October 31-Nov. 1. After perforating the well flowed at 650 psi wellhead pressure through a 3/4 inch choke.

Zone 9 was broken down on November 1 with 2% KCl water at 9 bpm with 3300 psi treating pressure. No ball action was observed. The breakdown was repeated on November 2 at 13 bpm with 5300 psi treating pressure. Little, if any, ball action was observed; ISIP was 500 psi. Swabbing was required to obtain sustained flow to the pit. The maximum flow rate of 2 MMCF/day was achieved on November 4, declining to 1 MMCF/day on November 6 when the well was shut in for pressure buildup. During the flow period water production declined from 700 bpd to 500 bpd.

Analysis of the pressure buildup data gives: $kh = 2.0$ md-ft; skin -4.2 ; estimated reservoir pressure 2865 psi. These data are shown in Figure 23 and Table XVIII. A gas analysis for the zone is given in Table XIX.

The fracture treatment was executed as planned on November 15. The treatment consisted of 700,000 pounds of 20-40 mesh sand carried by 365,000 gallons of Western's Apollo Gel-40 pumped at 60 barrels per minute. The initial ISIP was about 500 psi, increasing to 800 psi at the end of the treatment. Radioactive tracer was added to all of the sand. Temperature and gamma ray logs were obtained on November 16 which indicated that the fracture did not extend much above the perforations at the wellbore and that all of the perforated interval took fluid. Sand fill was tagged at 7466 ft.

Flow to the pit began on November 16. No swabbing was required. Gas rate measurements began on November 16. Problems caused by produced frac sand required flowing to the pit without separation during November 21-27. Measured gas rates are given in the Table XX-A for the period from the beginning of flow after frac until the well was shut in on December 31. Water production data for this period is given in Table XX-B. A comparison of gas production from Zone 9 for the period November 16-December 31, 1978 is made with the gas production from Zones 1-4 for the period January 17-April 11, 1978. The "smoothed" curves are shown in Figure 24.

H. Final Status of the Well.

The well was shut in during the month of January (1979) awaiting decisions for final completion status. It was flowed into the pipeline from February 1-14, averaging about 1.8 MMCFPD with 18 BPD of condensate. Final completion activities began on February 14. Work began to remove the plugs from the well so all zones would be open for production.

Efforts to drill the plug at 7495 feet were only partly successful. Some "junk" from the plug remained in the hole and was pushed down the hole until it lodged on sand fill at about 8830 ft. During efforts to mill the "junk" at this depth, the mill (with jars and bumper sub) became stuck. While attempting to recover this fish, fishing tools also became stuck. Continued attempts at fishing all of these materials from early March until April 5 were unsuccessful. Operations were suspended at this time to make a thorough study of the problem.

The trouble appeared to be resulting from frac sand coming from one or more of the zones (part of 5 and 6-9) open above the stuck point. Tools were getting sand locked inside the casing. Furthermore, circulating sand out to prepare for fishing attempts was consuming a major part of a working day. By the next morning, additional sand fill was present and had to be removed before fishing operations could proceed.

Fishing operations resumed on May 7. With considerable effort using milling techniques and circulation, the fish was recovered on June 11. The hole was cleaned to the RBP at 9040 feet. In an attempt to retrieve this plug, the bypass valve apparently was opened but retrieval efforts failed. By this time, large quantities of water were required to keep the well dead while attempting retrieval. A decision was made to flow the well for a period of time in order to lower the near-well pressure enough to simplify kill operations.

The well was put on production beginning mid-June. It was flowed to the pit for a few days to allow for some cleanup before turning through production equipment. Considerable sand production was noted for a time with some elbows and tees in the flow line having to be replaced as a result of sand erosion. The well was shut in July 15 for annual gas plant "turnaround" operations. Production into the pipeline was resumed on June 25.

On July 26 a spinner flowmeter survey was run through the tubing. Tubing bottom was at 8970 feet. The survey showed considerable flow coming from below the bottom-most open perforation (8972 feet) indicating the plug at 9040 to be open through the bypass. Due to the two phase flow regime, a quantitative determination of the amount of gas coming from below the plug could not be made. Nevertheless, the data did indicate a substantial flow from these zones, which increased when the surface choke size was increased. The assessment was made that flow from the zones below the plug is only partly restricted, and this should be a temporary (lasting no more than perhaps a year) condition. Further attempts at this time to retrieve the plug may prove more harmful than helpful. Therefore, the plan is to leave the plug until a later, more opportune time.

During the flowing periods since late-June, the well has flowed fairly steadily at about 2.9 MMCFPD with surface pressure slowly declining. Water production has declined from 800+ BPD to about 700 BPD, and condensate production is averaging 4-5 bbls/MMSCF. On August 17 the production was 2.5 MMCF, 630 bbl water, 14 bbl condensate per day with tubing pressure 635 and casing pressure 1440 psi.

VIII. EVALUATION OF FRACTURE EFFECTIVENESS AND WELL PERFORMANCE.

During fracture treatments, pumping pressures increased by well over 2000 psi in all zones except for Zone 9. The reason for the large pressure increase is unknown but it is not related to sand transport. The onset of the treating pressure increase is at the beginning of the pad volume--before sand is even started into the wellbore. Because of this, calculations of fracture dimensions based on brittle rock failure are undoubtedly incorrect. Therefore, it would be meaningless to attempt to match fracture lengths determined from pressure data to those calculated from treatment data. The one exception to this is Zone 9. Pressure increased only about 300 psi during treatment. Calculation of fracture dimensions from treatment variables should be fairly accurate. For Zone 9, packed fracture lengths should be of the order of 600-800 feet wellbore-to-tip.

For long-term production behavior and economic evaluations, it was desirable to determine the effectiveness of the fracture network that had been created. The procedure followed is described below.

Zone Evaluation Procedure

Pressure build-up tests were performed on each zone of interest (with the exception of Zone 2). In 1977, zones that were fractured (Nos. 1 and 3) were tested both before and after fracturing. The pre-frac tests appeared to give the most reliable results. Therefore, in the zones (Nos. 5-9) completed in 1978, only pre-frac PBU tests were performed.

The technique used to analyze these data was a standard Horner plot. In most cases, the data were still curving upward at the time the test was terminated. (Zone 1, pre-frac is possibly the one exception.) It is recognized that the actual kh of a zone is not determined from such a test. However, by connecting the last measured pressure value to a known or reasonable value for reservoir pressure on the Horner plot, a maximum value for kh can be obtained. Following that, a judgement must be made as to the degree of correction required to adjust this maximum kh to obtain true kh.

Results obtained using this approach are shown in the figures. Preliminary results were presented in DOE Symposia⁴. It is believed the values obtained using this procedure are reasonably accurate. Additional confidence in this method is provided through analysis of short-term flow data measured from each of the various zones before and/or after the PBU tests. Reasonable matches of actual production data were obtained for zones 1-4 using a computer model⁵ and kh approximations obtained from PBU tests. For the zones fractured, reasonable fracture lengths based on quantities pumped were used. The best match obtained for each zone is illustrated in Figures 25-28B.

Zone 1

Flow rates taken after the PBU following fracturing were matched (see Figure 25) using the model. A small amount of cleanup may have still been taking place during this measurement period. Formation kh determined from the pre-frac PBU was used.

Zone 2

No PBU test was performed. Assuming Darcy radial flow for the brief (4-day) flow period, a kh estimate of 0.3 md-ft was obtained. This was used to match (Figure 26) the one measured flow rate of 137 MCF/day after four days of swabbing and flowing following breakdown.

Zone 3

There were several flow periods following fracturing of this zone. The one used for the purpose of doing a history match followed the PBU test. While frac and workover fluids were still being produced at this time, the effects of cleanup should have been reduced compared to the other flow periods. Because they still existed, however, a match at the end of the flow period should be more valid than a match at the beginning (Figure 27).

Zones 4A and 4B

While tested separately, the behavior and treatment of each of these zones was quite similar. Following breakdown, they flowed back easily without swabbing, declining quickly (over about 3 days) from 500+ MCF/day to a little more than 100 MCF/day. PBU tests on the zones indicated kh too low to justify fracturing. The PBU tests indicated a significant negative skin in each of the zones, perhaps due to natural fracturing. The best production matches were obtained by using short fractures along with kh as approximated from the PBU tests (Figures 28A and B).

Composite of Zones 1-4

Of the individual zone production matches, some esthetically are more pleasing than others. These are, however, considered the best matches. They were then extended over a longer period (80 days) of time, and a composite of all zones producing at once was determined. This composite was then compared to actual co-mingled production from all zones over a period from January 17-April 11, 1978. This comparison is shown in Figure 29. In addition, the percent contribution of each zone to the total was determined from the composite prediction. This is plotted in Figure 30 along with a flow profile determined from a borehole flowmeter survey. The profile plotted is an average of three surveys run by taking stations above each of the completed intervals. The match of the composite prediction with production data for a three month period is excellent. Therefore, the approximations of kh from the Horner analyses of PBU data must be reasonably accurate.

Zones 5-8

No effort to match individual production data from Zones 5-8 has been attempted. Since there will be no long-term flow test from these zones alone, there can be no confirmation of the validity of the matches such as was obtained for Zones 1-4. However, the behavior of the fracture treatments in these zones was such that effective fracture lengths should be comparable to those determined for Zones 1 and 3--i.e., of the order of 150-200 feet.

Zone 9

It has been difficult to obtain a good match of predicted vs. actual production data from Zone 9. The best match of all combinations of fracture length and kh tried to date is shown in Figure 31. The production rate and the rate of decline of both the predicted and actual data are approximately the same at the end of 40+ days of flow. If cleanup is continuing to take place, agreement between theoretical and actual would improve with time. The fracture length (525 feet) required to give this match is in reasonable agreement with that (600-800 feet) calculated for for this zone. A flow test of longer than 40 days would, perhaps, have resolved the differences.

A summary of results obtained from pre-frac pressure buildup analyses is shown in Table XXI. Values for kh were determined using the slope of the line connecting the last measured pressure value with an estimated value of formation pressure.

IX. ECONOMIC EVALUATION.

With the results from pressure and flow testing as reported, an evaluation was made to determine the commercial potential of the well. The basic reservoir assumptions used in this evaluation are listed in Table XXII-A (Mesaverde) and Table XXII-B (Ohio Creek). Note that these

assumptions do not agree exactly with the results shown in Table XXI. The test results as shown would reflect maximum possible kh values. Therefore, for economic evaluation, assumptions of kh were reduced to what should be more realistic values for this well. In the case of Zone 9, the assumed values provided a better history match with production data. The economic parameters are given in Table XXIII. Using the data listed, the performance prediction model⁷, and a profit and loss calculation program, profitability was determined for three situations of varying costs or completion interval. These cases are: (1) production from the Mesaverde only, using as well cost the total costs accrued in the F31-13G well minus \$300M for not completing the Ohio Creek zone; (2) production from both Mesaverde and Ohio Creek zones using the total cost of F31-13G; (3) production from the Mesaverde and Ohio Creek zones using a well cost that is approximately 75% that of F31-13G, assuming a development well program would streamline operations and eliminate some of the testing performed on F31-13G.

Results of these calculations indicate development of the low permeability gas sands in the Piceance Creek area to be potentially profitable, depending on how representative F31-13G is of a typical well. As an illustration, DCFROR vs. wellhead gas price is plotted in Figure 32. These determinations have assumed no risk, of which there would obviously be some. Dry hole risk and poorer well quality at the edges of the field could significantly reduce profitability.

X. REFERENCES.

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7. Strubhar, M. K., Fitch, J. L., and Uhri, D. C.; "Simplified Performance Prediction Method for Vertically Fractured Gas Wells," SPE 6021, Deep Drilling and Production Symposium of SPE, Amarillo, Texas, April 17-19, 1977.

APPENDIX IMASSIVE FRAC PROJECTBRUSH CREEK WELL NO. 1-25

The purpose of this discussion will be to review operations on the initial test well--Brush Creek Unit #1-25.

The construction work on the road and location site began on March 14, 1974. The well was spudded on April 5, 1974 and drilled to a total depth of 10,330 feet with 13-3/8" surface casing set at 993 feet. The well was plugged back to a depth of 8432 feet and 7" casing set at 8329 feet in the Mesaverde with 650 sacks of 50:50 pozmix spearheaded by nitrogen. The cement top was found at 6600 feet with good bonding from 6900 feet to 8288 feet. For the first stage fracture treatment, the interval 7995-8159 O.A. (164 feet) in the Mesaverde was to be perforated with a total of 60 holes. Following the initial perforating operations, a Borehole Televier log was run to check the actual perforations and only 29 holes of the planned 60 holes were detectable. On this basis, an additional 30 holes were shot. The Borehole Televier was then re-run and only a total of 48 holes were identified.

On July 13 the well was acidized with 6,000 gallons of 15% HCl and 120 ball sealers at a rate of 27 BPM down the casing with an average treating pressure of 2000 psi. The 2-3/8" tubing string was run open ended to 7800 feet and the well was given a "pilot frac" treatment down the casing-tubing annulus with 50,000 gallons of 2% KCl water plus additives and 95,000 pounds of 20-40 sand at a rate of 75 BPM with an average treating pressure of 3500 psi as follows:

- 15,000 gals. fluid - no sand
- 5,000 gals. fluid w/10,000 lbs. sand - 2 ppg
- 5,000 gals. fluid w/15,000 lbs. sand - 3 ppg
- 5,000 gals. fluid w/20,000 lbs. sand - 4 ppg
- 10,000 gals. fluid w/50,000 lbs. sand - 5 ppg
- 12,000 gals. fluid for flush
- Max. treating pressure - 4425 psi.
- Min. treating pressure - 3150 psi.
- Final treating pressure - 4425 psi.

Temperature logs were run which indicated that the entire perforated interval took fluid with the top of the frac at 7980 and the bottom at 8170. Pressure measurement analysis indicated that 50-60 holes were open and taking fluid. Estimated fracture dimensions from the treatment were as follows:

AI-2

Gross Fracture Height = 175 ft.
Net Fracture Height = 70 ft.
Created Fracture Length = 1000 ft. radius (wellbore to tip)
Created Fracture Width at Wellbore = 0.20 inches
Created Fracture Volume = 35,000 gallons
% Sand Fillup = 25%

On July 15, swabbing operations were started with the fluid level at 250 feet from the top. Twenty barrels of load water was swabbed during the first one hour and the well kicked off and flowed 303 barrels of load water in 5 hours with a tubing pressure at 70 psig. At this point we were short 850 barrels of load and acid water. The well was shut in overnight and on the morning of the 16th a 13-hour shut-in casing pressure of 745 psi and shut-in tubing pressure of 930 psi were observed with a good show of gas. On the 16th the well flowed 318 barrels of load water in 12 hours with a tubing pressure of 450 psi and a casing pressure of 860 psi. The gas volume was 490 MCFD on a 20/64" choke. Load to recover was 532 barrels. Flow testing continued on the 17th with the well flowing 60 barrels of load water in 24 hours with a tubing pressure of 505 psi, casing pressure of 765 psi on 20/64" choke. Gas volume was 326 MCFD with a back pressure of 500 psi. Load to recover was 472 barrels. During the next five days, July 18-22, pressure surveys and sonic tools were run to determine points of gas entry. The well was shut in at 9:00 p.m. on the 22nd for a pressure buildup test prior to the 1st stage Massive Fracture treatment.

Following is the design of the 1st stage treatment:

On day before 1st stage treatment (Thursday 7/25) pump 20,000 gallons of frac fluid (40# guar) at 50-70 BPM, with pressure transducers on casing annulus and tubing, and shut down for ISIP measurement. Fracture treat the Mesaverde O.A. Interval 7995-8159' down the 7" x 2-3/8" annulus with 370,000 gallons of fluid and 1,100,000 pounds of 20-40 sand. The frac fluid to be used will be 2% KCl water containing 40#/1,000 gallons of MYF-1, 10#/1,000 gallons of CW-1 and necessary breakers added at the blender. The fracture fluid, excluding the breakers, will be pre-gelled. The fluid should be checked for rheological and break back properties prior to the treatment. Pump the treatment at 70 BPM at 4600 psi treating pressure. Stage the treatment as follows:

- a. Pump 20,000 gallons of frac fluid - no proppant.
- b. Pump 25,000 gallons of frac fluid containing 2 ppg. of 20-40 sand (50,000 lbs.). Start running 125 units of radioactive tagging material with this sand at 1 unit per thousand pounds of sand.
- c. Pump 200,000 gallons of frac fluid containing 3 ppg. of 20-40 sand (600,000 lbs.). Start running another 125 units of radioactive tagging material with last 125,000 pounds of this sand at 1 unit per thousand pounds of sand.

d. Pump 113,000 gallons of frac fluid containing 4 ppg. of 20-40 sand (452,000 lbs.). Start running last 125 units of radioactive tagging material with last 125,000 pounds of this sand at 1 unit per thousand pounds of sand.

e. Pump 12,000 gallons of frac fluid, flush--no proppant. Estimated fracture dimensions from the treatment were as follows:

Gross Fracture Height = 175 ft.
 Net Fracture Height = 70 ft.
 Created Fracture Length = 3700 ft. radius (wellbore to tip)
 Created Fracture Width = 0.35 inches
 Created Fracture Volume = 220,000 gallons
 % Sand Fillup = 40%

Following finalization of the last stage treatment design, a meeting was held in the afternoon with operating personnel, from Mobil and the service company, to insure that all logistic problems were handled and that everyone understood fully the mechanics of the job and their role in the treatment completion.

On Thursday, July 25 a trial pump-in test prior to the scheduled 1st stage treatment was made in order to obtain pressure measurements. The casing was loaded with 130 barrels of KCl water and the following gelled KCl frac fluid without proppant was pumped:

15,500 gals. @ 44 BPM and 4100 psi
 3,000 gals. @ 26 BPM and 2700 psi
 1,500 gals. @ 41 BPM and 3000 psi
 ISIP = 2100 psi

On Friday, July 26 at approximately 4:00 p.m. the 1st stage frac treatment began. The results of the 1st stage treatment were disappointing in that only 295,500 pounds of 20-40 sand was put away, far short of the planned 1,100,000 pounds. The total fluid pumped was 352,000 gallons compared to the design figure of 370,000 gallons. The average injection rate was 55 BPM with an average treating pressure of 5500 psi and a final treating pressure of 5800 psi.

Analysis of the treatment results indicate the major problem was the high unanticipated treating pressures resulting in lower pump rates (50-55 BPM vs. planned 70 BPM) and inability to transport the proppant as planned. The previous sand frac treatment may have contributed to this high pressure due to the inability to move or cause the in-place frac sand to become mobile again. The final instantaneous shut-in pressure on the tubing shows 400 psi or less perforation friction pressure which would indicate that all perforations were open and taking fluid and that the high treating pressure problem was in the reservoir and not at the perfs. Following is a schedule of the treatment:

AI-4

Fluid Incr. Vol. M Gals	Fluid Cum. Vol. M Gals	Sand Con- centration Lbs/Gal.	Sand Incr. M Lbs.	Sand Cumulative M Lbs.	Rate BPM	Pressure-Psi	
						Casing	Tubing
20	20	0	Pad	0	65-70	4500	2500
25	45	2	50	50	70	3800	2600
35	80	3	105	155	70	4000	2900
5	85	0	0	155	70-0	6000	6000
- Reverse Out Sand - Prepare To Continue Treatment -							
30	115	0	0	155	20-60	5000	3200
5	120	0.5	2.5	157.5	62	5000	3200
7	127	1	7	164.5	62	5000	3200
16	143	1.5	24	188.5	62	4900	3200
34	177	1	34	222.5	62	5100	3400
25	202	0	0	222.5	58	5700	4200
15	217	0.5	7.5	230	50	5500	4000
26	243	1	26	256	52	5300	3900
31	274	0	0	256	52	5400	4100
27.5	301.5	0.5	13.75	270	51	5600	4000
20.5	322	0.75	15.4	285	51	5500	4200
13.5	335.5	0.5	6.75	292	49	5600	4300
3.5	339	1	3.5	296	48	5700	4300
12.5	351.5	0	0	296	49	5800	4400

The gamma ray log run after the treatment shows that the total interval (7995-8159') was treated at the wellbore. Initial estimates of the propped fracture dimensions are:

Propped height - 170 feet

Fracture Width at Wellbore - 0.25 inches

Fracture Length (Tip to Tip) - 1000 feet

Prior to flowing well, the casing and tubing pressures were 150 psig. The casing was opened on 3/4" choke and flowed 1000 BLW to pits in 2 hours. The tubing flowed 2000 BLW in 20 hours, then started loading up. The well was shut-in for 13 hours prior to swabbing. Tubing and casing had 30 psig. Swabbed 1340 BLW with a fluid level at 2000 ft. Nitrogen was injected; however, fluid column was too great to lift. Continued swabbing well until fluid level was at 7700 ft. Gas volume was too small to measure on the surface. Continued swabbing did cause the well to flow gas at an average rate of about 90 MCFPD. Well was swabbed to the tubing seating nipple with no increase in gas rate. Approximately 8226 bbls of load water was recovered prior to setting cast iron bridge plug @ 7905 feet with 2 sacks of cement and testing same to 8000 psig. We jet perforated the 7" casing as follows: 7645'-7720' with one shot every three (3) feet; 7600'-7645' with one shot every five (5) feet; 7516'-7600' with one shot every three (3) feet (O.A. 7516'-7720' - 63 holes). Ran Mobil FRL Borehole Televiewer and interpretation was 95% of the shots penetrated pipe. Acidized perforations 7516'-7720' with 6000 gallons of 15% HCL acid plus 75 ball sealers. Had good ball action. Average treating pressure was 1200 psig @ 35 BPM.

On August 29, loaded hole with frac fluid and frac treated Mesaverde perms 7516-7720 O.A. with 376,000 gallons of fluid plus 1,009,000 pounds 20/40 sand. Frac fluid was 2% KCl water containing Hi Gel 130 plus 5% Methanol with AP breaker (1#/1,000 gals.) in last 100,000 gallons.

ISIP during pad = 1250 psi
Staged Treatment as follows:

<u>Incr. Vol.</u>	<u>Cum. Vol.</u>	<u>#/Gal. Sand</u>	<u>Incr. Sand</u>	<u>Cum. Sand</u>	<u>Rate</u>	<u>Avg. TP#</u>	<u>Avg. CP#</u>
26,000	26,000	0	0	0	70	1350	3200
100,000	126,000	2	200,000	200,000	72	1600	3200
50,000	176,000	2 1/2	125,000	325,000	71	1750	3300
100,000	276,000	3	300,000	625,000	71	1900	3400
50,000	326,000	3 1/2	175,000	800,000	71	1950	3500
50,000	376,000	4	200,000	1,000,000	71	2000	3600
11,500	387,500	0	0	1,000,000	70-46	2000	3600-3000

AIR 71 BPM, Avg. Trt. press. 3350 psig, Min. 3000 psig, Max. 3750 psig, Final 3750 psig, ISIP - 1900 psig, 5" - 1700, 10" - 1570, 30" - 1350, perf. friction was 250 psig thru job. TOTAL LOAD = 9354 bbls.

Ran G/R and temp. log survey from 7000'-7810'. Logs indicated entire treatment confined to interval 7516-7720.

Opened well at 7 p.m. 9/2/74 on 1" choke with 900 psig. Well flowed 1226 BLW in 12 hours with csg pressure of 270 psig and tbg of 50 psig. Had a show of gas after flowing approximately 5000 bbls of load water. Gas volume increased to 369 MCFPD with TP 100 psig and CP 1465 psig and a flow rate of 285 BLW/24. Gas volume continued to increase to a rate of 660 MCF/24 hr. Reduced rate to 228 MCF/24 hr. and ran sound logs and temperature survey with results indicating gas was being produced through 50 percent of the perforated interval.

Well continued to flow at a rate of 363 MCF/24 hr. and 100 BLW/24 hr. with TP 100 psig and CP 590 psig. Flowed well to atmosphere, then shut-in well at 6 p.m. 9/9/74. After a 16-hour shut-in period, the SICP was 1040 psig, SITP 1025 psig and BHP 1254 psig. This was the beginning of a 24-hour period of shutting in well for 16 hours and flowing well for 8 hours. The table below shows results:

<u>Date</u>	<u>Gas Rate</u>	<u>Water Rate</u>	<u>SITP</u>	<u>SICP</u>	<u>BHP</u>
9-10	300 MCFPD	2-3 (BPH)	998	1001	1205
9-11	300	3 1/2-4	1025	1040	1254
9-12	300	4 1/2	1020	1025	1247
9-13	292	4-4 1/2	955	1022	1232
9-14	300	4-4 1/2	960	1008	1200
9-15	270	-	990	995	1204
9-16	280	4	970	980	1184
9-17	288	4	854	974	1179
9-18	280	3 1/2	865	957	1191
9-19	290	4	925	937	Discontinued
9-20	272	4-3/4	918	918	"
9-21	-	-	-	-	"
9-22	130	3	825	825	"
9-23	129	-	845	845	"
9-24	-	-	-	-	-

On September 25, the well was shut-in for 3 days with the casing pressure building up to 1250 psig. The reason for this shut-in period was to develop pressure for a constant flow rate test period.

AI-7

Starting on September 28, the well was opened to flow 3 days and produced at a rate of 180 MCFPD with no water production. At the end of this period CP was 453 psig and TP was 450 psig. Well was turned into line. Results of this flow test was as follows:

<u>Date</u>	<u>CP</u>	<u>TP</u>	<u>Gas Rate</u>	<u>Water Rate</u>
10-1	425	420	168	No H ₂ O
10-2	545	400	147	10 Bbls
10-3	595	400	146	No H ₂ O
10-4	580	400	126	10 Bbls
10-5	) No Data Available			
10-6				
10-7	685	420	139	No H ₂ O
10-8	710	425	100	" "
10-9	725	500	117	" "
10-10	675	460	103	" "
10-11	710	460	104	" "
10-12	) No Data Available			
10-13				
10-14	660	430	114	" "
10-15	660	427	115	" "
10-16	660	430	106	" "
10-17	640	410	104	" "
10-18	695	490	90	" "
10-19	720	500	116	" "
10-20	740	500	114	" "
10-21	750	500	117	" "
10-22	760	495	117	" "
10-23	780	500	119	" "

AI-8

<u>Date</u>	<u>CP</u>	<u>TP</u>	<u>Gas Rate</u>	<u>Water Rate</u>
10-24	780	500	118	No H ₂ O
10-25	795	485	107	" "
10-26	810	500	98	" "
10-27	830	460	97	" "
10-28	840	400	93	" "
10-29	850	450	93	" "
10-30)				
10-31)	No Data Available			
11-1)				

Well was shut-in at 3 p.m. on November 2, 1974 for pressure buildup analysis.

The results of this shut-in period are as follows:

Pressure Buildup Data

<u>Date</u>	<u>Time</u>	<u>Elapsed Time, Hrs</u>	<u>BHP psi</u>	<u>Csg. Pr. Psi</u>	<u>Tbg. Pr. Psi</u>
11-2-74	15:00	0	1022	840	825
	16:00	1	1036		
	17:00	2	1047		
	19:00	4	1064		
11-3-74	01:00	10	1118	980 1012	975 990
	10:00	19	1182		
	16:00	25	1216		
11-4-74	09:00	42	1287	1065 1085	1056 1065 1074
	16:00	49	1309		
	22:00	55	1324		
11-5-74	04:00	61	1339	1125	1080 1086
	10:00	67	1352		
11-10-74	12:00	189	1497	1250	1200
11-17-74	12:00	357	1629	1350	1350

It was estimated that the well had flowed cumulative gas of 8000 MCF. Interpretation of the pressure analysis curves indicates the well has a k of 2.5 microdarcies, maximum. It is estimated that the true in-place permeability is about 1 microdarcy.

The second stage (7516'-7720') fracture treatment was calculated to have the following fracture dimensions:

Gross Fracture Height = 225 ft.

Net Fracture Height = 100 ft.

Created Fracture Length = 600 ft. radius (wellbore to tip)

Created Fracture Width at Wellbore = 1.0 inch

The well is now plugged and abandoned.

APPENDIX II - FIGURES

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- Figure 3 - Isopach Map, Mesaverde Sands
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APPENDIX 11 - FIGURES (Cont'd.)

Figure 20 - Frac Treatment - Zones 6 and 7

Figure 21 - Pre-Frac Pressure Buildup - Zone 8

Figure 22 - Frac Treatment - Zone 8

Figure 23 - Pre-Frac Pressure Buildup - Zone 9

Figure 24 - Production Behavior of Zone 9 and Zones 1-4

Figure 25 - Production Match - Zone 1

Figure 26 - Production Match - Zone 2

Figure 27 - Production Match - Zone 3

Figure 28A - Production Match - Zone 4A

Figure 28B - Production Match - Zone 4B

Figure 29 - Composite Production Match - Zones 1-4

Figure 30 - Flow Profile - Measured vs. Predicted

Figure 31 - Production Behavior - Zone 9

Figure 32 - Economic Potential of Piceance Creek Area Low
Permeability Gas Sands

FIGURE 1. INDEX MAP OF PICEANCE BASIN, NORTHWEST COLORADO WITH ISOPACHOUS MAP OF MESAVERDE GROUPS.

FIGURE 2

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FIGURE 3 - ISOPACH MAP, MESAVERDE SANDS

FIGURE 4B
LOGS FROM
PCU F31-13G

CASING & HOLE SIZE

TOPS

DEPTH

FIGURE 5 - SUMMARY OF DRILLING & COMPLETION OPERATIONS, PHASE I

TIME EVENT SCHEDULE

Planning

1. Prepare Drilling Bid	1. Spud Well	1. Move Out Rotary Tools
2. Prepare Road & Location	2. Drill 8 3/4" Hole to 1500' Ream to 15"	2. Clean Up Location
3. Award Drilling Contract	3. Run & Cement 1500' 10 3/4" Casing	3. Move In Comp Unit
4. Move In and Rig Up Drilling Rig	4. Drill 8 3/4" Hole to 10,600' - 2 60' Cores in Mesaverde	4. Run CBL-GR Logs
	5. Log Well - Run and Cement 10,600' 7" O.D. Casing - Release Drilling Rig	5. Perf 2 250' Mesaverde
		6. Break Down Formation with XCI Water
		7. Flow Well! Take 10 Day Build Up
		8. Calculate Kh
Build Locations	Drill Set Csg	Log, Perf, Break Down
	Drill Csg	Flow Well
		10 Day Build Up

FIGURE 6 - ACTIVITY CHART, PHASE II

FIGURE 7 - ACTIVITY CHART, PHASE III

TIME EVENT SCHEDULE	1. Clean Up Location 2. Gather Frac Tanks 3. Move In Pulling Unit 4. Set BP 5. Perf Mesaverde Zone 2 6. Break Down Perforations 7. Obtain 2-3 Day Flow Test 8. Kill Well, Prepare to Frac	MASSIVE FRAC	1. Flow Test Well 2. Run Production Tests & Logs	1. Kill Well 2. Pull Tubing 3. Set RCT B.P. 4. Perf Mesaverde 5. Break Down Zone 6. Obtain 2-3 Day Flow 7. Kill Well Pull Tbg 8. Prepare to Frac	MASSIVE FRAC	1. Flow Test Well 2. Run Production Tests & Logs	1. Kill Well 2. Pull Tubing 3. Set Res BP 4. Perf Mesaverde 5. Break Down Zone 6. Obtain 2-3 Day Flow 7. Kill Well Pull Tbg 8. Prepare to Frac	MASSIVE FRAC	1. Flow Test Well 2. Run Production Tests & Logs	1. Kill Well 2. Pull Tubing 3. Set Res BP 4. Perf Mesaverde 5. Break Down Zone 6. Obtain 2-3 Day Flow 7. Kill Well Pull Tbg 8. Prep to Frac
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MASSIVE FRAC	1. Flow Test Well 2. Run Production Tests & Logs	1. Kill Well 2. Pull Tubing 3. Set Res BP 4. Perf Mesaverde 5. Break Down Zone 6. Obtain 2-3 Day Flow 7. Kill Well Pull Tbg 8. Prep to Frac	MASSIVE FRAC	1. Flow Test Well 2. Run Production Tests & Logs	1. Kill Well 2. Retrieve Bridge Plug 3. Comm All Zones 4. Flow Test All Zones 5. Overall Evaluation	Final Report	Collect Production Data and Report to ERDA
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FIGURE 9
BREAKDOWN AND PLASTICITY TEST
ZONE 1 (10549-680)

AI1-13

FIGURE 10

MASSIVE FRAC TREATMENT

ZONE 1 (6-22-77)

3-MASSIVE FRAC TREATMENT (6-22-77)

BREAKDOWN AND PUMP-IN TESTS - ZONE 2

LEGEND FOR FIGURE 12

2A AND 2B BREAKDOWN 7/25/77

1. Load tubing.
2. Shut-in for initial ISIP.
3. Resume pumping @ 8 BPM.
4. Start inj. ball sealers @ 1 ball/4 $\frac{1}{2}$ bbl.
5. 1st RCN balls @ perfs; ball action.
6. Ball inj. jammed.
7. Repairing ball inj.; well shut-in to hold balls in place.
8. Resume pumping and inj. balls.
9. Ball action.
10. Ball out.
11. Back flow well to surge balls from perfs.
12. Resume pumping.
13. Final ISIP.

2A INJECTIVITY TEST 7/26/77

1. Pumping @ 2 BPM, pressure increasing; take initial ISIP.
2. Repeat @ 2 BPM.
3. Repeat @ 4 BPM.
4. Repeat @ 6 BPM.

2A AND 2B INJECTIVITY TEST 7/26/77

1. Pump @ 6 BPM and shut-in for initial ISIP.
2. Repeat @ 6 BPM.
3. Repeat @ 12 BPM.
4. Repeat @ 14 BPM.

FIGURE 14

POST FRAC PBU

ZONE 3 (9392-9538 O.A.)

FIGURE 15A
POST BREAKDOWN PBU
ZONE 4A (9254-9320)

FIGURE 16

ZONE 5 (8765-8972)

PBU AFTER BREAKDOWN

FIGURE 17

FIGURE 21

ZONE 8 (7704-94)

PBU AFTER BREAKDOWN

FLOW RATE,
MMSCF/D

FLOW RATE,
MSCF/D

FIGURE 32
ECONOMIC POTENTIAL OF PICEANCE CREEK
AREA LOW PERMEABILITY GAS SANDS

APPENDIX III - TABLES

Table I - Core Analysis Results

Table II-A - Permeability of Selected Samples Under Confining Stress

Table II-B - Plug Data, Including Resistivity

Table III - Pre-Frac Buildup Data - Zone 1

Table IV - Frac Plan for Zone 1

Table V - Post-Frac Flow Data - Zone 1

Table VI - Post-Frac Buildup Data - Zone 1

Table VII - Pre-Frac Pressure Buildup - Zone 3

Table VIII - Post-Frac Buildup Data - Zone 3

Table IX - Pressure Buildup Data - Zone 4

Table IX-A - Zone 4A

Table IX-B - Zone 4B

Table X - Flow Data - Zones 1-4

Table XI - Pre-Frac Pressure Buildup Data - Zone 5

Table XII - Pre-Frac Pressure Buildup Data - Zone 6

Table XIII - Water Analysis - Zone 7

Table XIV - Pre-Frac Pressure Buildup Data - Zone 7

Table XV - Gas Analysis - Zones 6 and 7

Table XVI - Water Analysis - Zone 8

Table XVII - Pre-Frac Pressure Buildup Data - Zone 8

Table XVIII - Pre-Frac Pressure Buildup - Zone 9

Table XIX - Gas Analysis - Zone 9

Table XX-A - Gas Production After Frac - Zone 9

Table XX-B - Water Production After Frac - Zone 9

Table XXI - Summary of Results From Pre-Frac PBU Tests

Table XXII-A - Reservoir Characteristics (Mesaverde)

Table XXII-B - Reservoir Characteristics (Ohio Creek)

Table XXIII - Economic Parameters

TABLE 1

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

1

MORIL OIL CORPORATION
PICEANCE CREEK UNIT #31-13G
PICEANCE CREEK FIELD
RIO BLANCO COUNTY, COLORADO

DATE: 5/2/77
FORMATION: MESAVERDE
DRLG. FLUID: WATER BASE MUD
LOCATION: NW NE SEC. 13-2S-97W

FILE NO: 3402-8959
ENGINEER: PUGH
ELEVATION: 7278' GL

SMP. NO.	DEPTH	PERM. TO AIR MD. PLUG	POROSITY PERCENT	FLUID SATS. OIL WTR.	GR. DEN.	DESCRIPTION
DEAN STARK PLUG ANALYSIS						
	8440.0-43.0					SH,VF
1	8443.0-44.0	<0.1	8.4	0.0 55.9	2.69	SD,LMY,SLTY,SHY,VF
2	8444.0-45.0	<0.1	9.1	0.0 56.1	2.70	SD,LMY,SLTY,SHY,VF
3	8445.0-46.0	<0.1	9.6	0.0 56.7	2.68	SD,LMY,SLTY,SHY,VF
4	8446.0-47.0	<0.1	8.1	0.0 54.6	2.70	SD,V/LMY,SL/SHY,VF
5	8447.0-48.0	<0.1	7.7	0.0 55.6	2.69	SD,V/LMY,SL/SHY,VF
6	8448.0-49.0	<0.1	2.7	0.0 59.0	2.69	LM,SDY,SL/SHY,VF
7	8449.0-50.0	<0.1	4.4	0.0 53.0	2.69	LM,SDY,SL/SHY,VF
8	8450.0-51.0	<0.1	2.9	0.0 53.4	2.71	LM,SHY,VF
9	8451.0-52.0	<0.1	4.9	0.0 54.9	2.70	LM,SDY,SHY,VF
	8452.0-60.0					SH,SLTY,VF
10	8460.0-61.0	<0.1	5.5	0.0 61.8	2.70	SD,V/LMY,SHY
11	8461.0-62.0	<0.1	6.2	0.0 48.2	2.70	SD,V/LMY,SH STKS
12	8462.0-63.0	<0.1	7.7	0.0 51.4	2.65	SD,V/LMY,LIG
13	8463.0-64.0	<0.1	7.7	0.0 40.3	2.70	SD,V/LMY,SL/SHY
14	8464.0-65.0	<0.1	8.6	0.0 45.9	2.68	SD,LMY,SLTY,SL/SHY
15	8465.0-66.0	<0.1	8.5	0.0 50.5	2.68	SD,LMY,SLTY,SL/SHY
16	8466.0-67.0	<0.1	8.2	0.0 55.4	2.69	SD,LMY,SLTY,SL/SHY
17	8467.0-68.0	<0.1	7.8	0.0 58.6	2.69	SD,LMY,SLTY,SHY,VF
	8468.0-92.0					SH,VF
18	8492.0-93.0	<0.1	7.8	0.0 48.5	2.66	SD,V/LMY,SLTY,LIG
19	8493.0-94.0	<0.1	6.5	0.0 71.5	2.69	SD,LMY,SLTY
20	8494.0-95.0	<0.1	9.2	0.0 64.7	2.67	SD,LMY,SLTY,SL/LIG
21	8495.0-96.0	<0.1	6.3	0.0 69.9	2.70	SD,LMY,SLTY,SH STKS
22	8496.0-97.0	<0.1	8.5	0.0 69.5	2.68	SD,V/LMY,SLTY,LIG
23	8497.0-98.0	<0.1	9.5	0.0 66.1	2.67	SD,V/LMY,SLTY,LIG

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TABLE 1
(Continued)

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

2

MOBIL OIL CORPORATION
PICEANCE CREEK UNIT #31-13G

DATE: 5/2/77
FORMATION: MESAVERDE

FILE NO: 3402-8959
ENGINEER: PUGH

SMP. NO.	DEPTH	PERM. TO AIR MD. PLUG	POROSITY PERCENT	FLUID SATS. OIL WTR.	GR. DEN.	DESCRIPTION
24	8498.0-99.0	<0.1	5.0	0.0 77.7	2.68	SD, LMY, SLTY, LIG
25	8499.0-00.0	<0.1	4.6	0.0 68.2	2.69	SD, LMY, SLTY, LIG
	8500.0-43.0	DRILLED				
	9943.0-47.0					SH, SLTY, SL/LMY
26	9947.0-48.0	<0.1	5.0	0.0 69.9	2.70	SD, V/LMY, SL/SHY
27	9948.0-49.0	<0.1	7.6	0.0 52.0	2.68	SD, SL/LMY, SLTY, SHY
28	9949.0-50.0	<0.1	8.1	0.0 50.4	2.66	SD, SL/LMY, SL/SHY
29	9950.0-51.0	<0.1	6.8	0.0 59.3	2.68	SD, SL/LMY, SL/SLTY
30	9951.0-52.0	<0.1	5.1	0.0 55.3	2.69	SD, V/LMY
31	9952.0-53.0	<0.1	7.5	0.0 58.5	2.68	SD, LMY
32	9953.0-54.0	<0.1	6.9	0.0 54.0	2.67	SD, LMY, SL/SLTY, SL/SH
33	9954.0-55.0	<0.1	9.0	0.0 51.0	2.67	SD, LMY, SL/SHY
34	9955.0-56.0	<0.1	9.2	0.0 45.9	2.67	SD, LMY, SL/SHY
35	9956.0-57.0	<0.1	8.1	0.0 59.3	2.67	SD, LMY, SL/SHY
36	9957.0-58.0	<0.1	9.4	0.0 46.9	2.67	SD, LMY, SL/SHY
37	9958.0-59.0	<0.1	8.4	0.0 43.1	2.67	SD, LMY, SL/SLTY, SHY
38	9959.0-60.0	<0.1	7.3	0.0 61.0	2.68	SD, LMY, SL/SHY
39	9960.0-61.0	<0.1	9.3	0.0 42.2	2.67	SD, LMY, SL/SHY
40	9961.0-62.0	<0.1	8.7	0.0 49.7	2.68	SD, LMY, SL/SHY
41	9962.0-63.0	<0.1	8.2	0.0 53.4	2.68	SD, LMY, SL/SHY
42	9963.0-64.0	<0.1	8.9	0.0 49.6	2.68	SD, LMY, SL/SHY
43	9964.0-65.0	<0.1	8.9	0.0 49.1	2.68	SD, LMY, SL/SHY
44	9965.0-66.0	<0.1	8.3	0.0 55.9	2.68	SD, LMY, SL/SHY
45	9966.0-67.0	<0.1	9.4	0.0 48.4	2.68	SD, LMY, SL/SHY
46	9967.0-68.0	<0.1	8.7	0.0 52.5	2.68	SD, LMY, SL/SHY
47	9968.0-69.0	<0.1	8.7	0.0 45.1	2.69	SD, LMY, SL/SHY
48	9969.0-70.0	<0.1	8.3	0.0 48.0	2.68	SD, LMY, SL/SHY
49	9970.0-71.0	<0.1	8.9	0.0 45.8	2.68	SD, LMY, SL/SHY
50	9971.0-72.0	<0.1	7.4	0.0 48.4	2.68	SD, LMY, SL/SHY
	9972.0-79.0					SH, SL/LMY

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TABLE I
(Continued)

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

3

MOBIL OIL CORPORATION
PICEANCE CREEK UNIT #31-13G

DATE: 5/2/77
FORMATION: MESAVERDE

FILE NO: 3402-8959
ENGINEER: PUGH

SMP. NO.	DEPTH	PERM. TO AIR-MD. PLUG	POROSITY PERCENT	FLUID SATS. OIL WTR.	GR. DEN.	DESCRIPTION
	9979.0-80.0	LOST CORE				
	9980.0-83.0					SH, SL/SDY
51	9983.0-84.0	<0.1	2.7	0.0 80.9	2.69	LM, SDY, SL/SHY
52	9984.0-85.0	<0.1	4.6	0.0 53.8	2.69	SD, V/LMY, SL/SHY
53	9985.0-86.0	<0.1	4.7	0.0 60.3	2.70	SD, V/LMY, SL/SHY
54	9986.0-87.0	<0.1	5.0	0.0 57.0	2.68	SD, V/LMY, SL/SHY
55	9987.0-88.0	<0.1	5.3	0.0 66.0	2.68	SD, V/LMY, SL/SHY
	9988.0-89.0					SH, LMY, SDY
56	9989.0-90.0	<0.1	4.0	0.0 56.7	2.69	SD, V/LMY, SL/SHY
	9990.0-92.0					SH, SL/SDY
57	9992.0-93.0	<0.1	4.4	0.0 46.5	2.69	SD, V/LMY, SL/SHY
58	9993.0-94.0	<0.1	6.5	0.0 46.3	2.69	SD, V/LMY, SL/SHY
59	9994.0-95.0	<0.1	6.9	0.0 43.9	2.69	SD, V/LMY, SL/SHY
60	9995.0-96.0	<0.1	7.3	0.0 43.8	2.69	SD, V/LMY, SL/SHY
61	9996.0-97.0	<0.1	6.6	0.0 45.9	2.69	SD, V/LMY, SL/SHY
62	9997.0-98.0	<0.1	8.3	0.0 40.1	2.68	SD, LMY, SL/SHY
63	9998.0-99.0	<0.1	7.5	0.0 48.1	2.67	SD, SL/LMY, SL/SHY
64	9999.0-00.0	<0.1	7.7	0.0 47.8	2.67	SD, SL/LMY, SL/SHY

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TABLE I
(Continued)

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

CORE SUMMARY

Company MOBIL OIL CORPORATION
Well PICEANCE CREEK UNIT NO. F31-13G
Page 4 of 4 File 3402-8959

<u>DEPTH</u>	<u>HORIZONTAL</u> <u>PERMEABILITY, Md.</u>	<u>POROSITY</u>	<u>SATURATION</u> <u>OIL</u> <u>WATER</u>	<u>GRAIN</u> <u>DENSITY</u>
8443- 8448	<0.1	8.6	0.0 55.8	2.69
8448- 8452	<0.1	3.7	0.0 55.1	2.70
8460- 8468	<0.1	7.5	0.0 51.5	2.69
8492- 8498	<0.1	8.0	0.0 65.0	2.68
8498- 8500	<0.1	4.8	0.0 73.0	2.69
9947- 9954	<0.1	6.7	0.0 57.1	2.68
9954- 9972	<0.1	8.6	0.0 49.7	2.68
9983- 9988	<0.1	4.5	0.0 63.6	2.69
9992-10000	<0.1	6.9	0.0 45.3	2.68

TABLE 11-A

PERMEABILITY OF SELECTED SAMPLES UNDER
CONFINING STRESS

Depth Ft. Confining Pressure-Psi	Permeability in Md			
	8463	8468	9953	9960
500	.0159	.0190	.0187	.0316
1000	.0128	.0140	.0151	.0246
2000	.0083	.0089	.0094	.0141
3000	.0054	.0051	.0064	.0100
5000	.0030	.0025	.0038	.0048
Porosity, %	7.7	7.8	4.7	7.3
Water Saturation, %	--	58.4	--	53.2

TABLE 11-B

PLUG DATAPICEANCE CREEK UNIT NO. F31-13G, MESAVERDE FORMATIONPICEANCE CREEK FIELD, RIO BLANCO COUNTY, COLORADO

CLI Sample No.	Depth Interval (ft.)	Air Permeability (md.)		Porosity (%)		Grain Density (gm/cc)		Resistivity Data			
		CLI	FRL	CLI	FRL	CLI	FRL	R_o (Ω -M)	F (1)	m (2)	n (3)
3	8445.0 - 46.0	<0.1	0.04	9.6	8.75	2.68	2.66	25.9	80.9	1.80	1.68
16	8466.0 - 67.0	<0.1	0.02	8.2	8.20	2.69	2.70	23.6	73.8	1.72	1.71
20	8494.0 - 95.0	<0.1	0.04	9.2	9.47	2.67	2.68	22.1	69.1	1.80	1.83
23	8497.0 - 98.0	<0.1	0.04	9.5	10.23	2.67	2.70	19.6	61.3	1.81	1.25
33	9954.0 - 55.0	<0.1	0.04	9.0	9.72	2.67	2.70	20.1	62.8	1.78	1.14
34	9955.0 - 56.0	<0.1	0.07	9.2	10.12	2.67	2.70	17.4	54.4	1.74	1.30
39	9960.0 - 61.0	<0.1	0.03	9.3	9.87	2.67	2.69	20.7	64.7	1.80	0.64
45	9966.0 - 67.0	<0.1	0.04	9.4	9.56	2.68	2.69	20.3	63.4	1.77	1.23
46	9967.0 - 68.0	<0.1	0.03	8.7	9.68	2.68	2.72	18.3	57.2	1.73	1.16
47	9968.0 - 69.0	<0.1	0.03	8.7	9.23	2.69	2.71	21.3	66.6	1.76	0.64
49	9970.0 - 71.0	<0.1	0.03	8.9	9.56	2.68	2.70	21.3	66.6	1.79	0.72
62	9997.0 - 98.0	<0.1	0.03	8.3	8.87	2.68	2.71	23.4	73.1	1.77	0.69

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$$(1) F = \frac{R_o}{R_w}, R_w = 0.320 \Omega - M @ 74.3^\circ F$$

$$(2) m = - \frac{\log F}{\log d}$$

$$= - \frac{\log I}{\log S_w}$$

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TABLE III

PRE-FRAC BUILDUP DATA - ZONE 1

Hewlett-Packard Pressure Measurement Device at 10,400 ft.

Flow Time, $t = 72$ hoursStabilized Average Flow Rate, $Q = 300,000 \text{ ft}^3/\text{day}$

Date	Hour	t (hours)	$t+\Delta t$ (hours)	$t+\Delta t/\Delta t$	BHP (psi)	P_w^2
6-5	1630	0	72.00	-	180	
	1645	.25	72.25	289.0	424	.179 x 10
	1700	.50	72.50	145.0	691	.477
	1715	.75	72.75	97.00	947	.897
	1730	1.00	73.00	73.00	1186	1.41
	1745	1.25	73.25	59.00	1396	1.95
	1800	1.50	73.50	49.00	1585	2.51
	1815	1.75	73.75	42.00	1758	3.09
	1830	2.00	74.00	37.00	1910	3.65
	1900	2.50	74.50	29.80	2162	4.67
	1930	3.00	75.00	25.00	2347	5.51
	2030	4.00	76.00	19.00	2598	6.75
	2130	5.00	77.00	15.40	2738	7.50
	2230	6.00	78.00	13.00	2830	8.01
	2330	7.00	79.00	11.30	2910	8.47
6-6	0030	8.00	80.00	10.00	2982	8.89
	0130	9.00	81.00	9.00	3023	9.14
	0230	10.00	82.00	8.20	3068	9.41
	0330	11.00	83.00	7.55	3100	9.61
	0430	12.00	84.00	7.00	3145	9.89
	0630	14.00	86.00	6.14	3207	10.28
	0830	16.00	88.00	5.50	3273	10.71
	1030	18.00	90.00	5.00	3311	10.96
	1230	20.00	92.00	4.60	3356	11.26
	1430	22.00	94.00	4.27	3396	11.53
	1630	24.00	96.00	4.00	3434	11.79
	2030	28.00	100.00	3.57	3502	12.26
6-7	0030	32.00	104.00	3.25	3563	12.69
	0430	36.00	108.00	3.00	3617	13.08
	0630	38.00	110.00	2.89	3642	13.26
	0830	40.00	112.00	2.80	3667	13.45
	1230	44.00	116.00	2.64	3717	13.82
	1630	48.00	120.00	2.50	3750	14.06
	2030	52.00	124.00	2.38	3793	14.39
6-8	0630	62.00	134.00	2.16	3881	15.06
	1830	74.00	146.00	1.97	3974	15.79
6-9	0630	86.00	158.00	1.84	4053	16.42
	1245	92.25	164.25	1.78	4090	16.73
6-10	0600	109.50	181.50	1.66	4177	17.44
	1215	115.75	187.75	1.62	4207	17.70
6-11	1500	142.50	214.50	1.51	4308	18.56
6-12	1215	163.75	235.75	1.44	4372	19.11
6-13	0640	182.25	254.25	1.40	4418	19.52

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TABLE IV

FRAC PLAN FOR ZONE 1

Gel: 40 lbs. of cellulose polymer/1000 gal.

Sand: 20-40 mesh

Pump Rate: 60 barrels/min.

Treatment Schedule:

<u>Incremental Vol., Gal.</u>	<u>Sand, lbs/gal</u>	<u>Sand, pounds</u>
10,000	0 (pad)	0
150,000	2	300,000
80,000	2 1/2	200,000
33,000	3	100,000
<u>15,000</u>	0 (flush)	<u>0</u>
Totals 288,000		600,000

Calculated Frac Properties:

Created Length: 1700 ft. (wellbore to tip)

Propped Length: 700 ft. (wellbore to tip)

Created Width: 0.55 in.

Propped Width: 0.38 in.

Propped Height: 130 ft.

Data Used in the Calculations Above Include:

Frac Height (Assumed): 150 ft.

Fox Field (Effective) Stress: 2000 psi

Porosity: 10%

Young's Modulus: 5×10^6

K' (Consistency Index of Frac Fluid): 0.001

N' (Flow Behavior Index of Frac Fluid): 0.75

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TABLE V

POST-FRAC FLOW DATA - ZONE 1First Period

<u>Date</u>		<u>Rate MCF/day</u>
June 23	-	500 (Estimated)
June 24	-	750
June 25	-	1000
June 26	-	900
June 27	-	800
June 28	-	780
June 29	-	800

Second Period

<u>Date</u>	<u>Rate, MCFD</u>	<u>CHP</u>	<u>THP</u>	<u>BHP</u>	<u>Water, BPD</u>
7-11	2800	-	-	-	-
7-12	1500	840	335	1041	20
7-13	1200	640	140	749	40
7-14	1060	510	140	580	30
7-15	960	465	140	574	38
7-16	875	-	140	531	25
7-17	827	-	140	520	20

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TABLE VI

POST-FRAC BUILDUP

Interval 10,549-680

Hewlett-Packard Pressure Measurement Device at 10,400 Ft.

Flow Time, $t = 168$ hoursStabilized Average Flow Rate, $Q = 800$ MCFD

Date	Hour	t (hours)	$t+\Delta t$ (hours)	$\frac{t+\Delta t}{t}$	BHP (psi)	P_w^2
6-29	2000	0	168	-	625	$.391 \times 10^6$
	2010	.17	168.17	989	642	.412
	2020	.33	168.33	510	679	.461
	2030	.50	168.50	337	715	.511
	2100	1.0	169.0	169	817	.667
	2130	1.5	169.5	113	908	.824
	2200	2.0	170.0	85.0	989	.978
	2300	3.0	171.0	57.0	1144	1.31
	2400	4.0	172.0	43.0	1283	1.65
	0100	5.0	173.0	34.6	1409	1.99
6-30	0200	6.0	174.0	29.0	1522	2.32
	0300	7.0	175.0	25.0	1625	2.64
	0400	8.0	176.0	22.0	1715	2.94
	0500	9.0	177.0	19.7	1800	3.24
	0600	10.0	178.0	17.8	1882	3.54
	0700	11.0	179.0	16.3	1953	3.81
	0800	12.0	180.0	15.0	2024	4.10
	1000	14.0	182.0	13.0	2160	4.66
	1200	16.0	184.0	11.5	2275	5.18
	1300	17.0	185.0	10.9	2329	5.42
	1400	18.0	186.0	10.3	2381	5.67
	1600	20.0	188.0	9.40	2477	6.14
	1800	22.0	190.0	8.64	2568	6.59
	1915	23.25	191.25	8.23	2610	6.81
	2000	24.0	192.0	8.00	2648	7.01
	2200	26.0	194.0	7.46	2723	7.41
	2400	28.0	196.0	7.00	2789	7.79
7-1	0250	30.0	198.0	6.60	2849	8.12
	0400	32.0	200.0	6.25	2902	8.42
	0600	34.0	202.0	5.94	2953	8.72
	1000	38.0	206.0	5.42	3082	9.50
	1400	42.0	210.0	5.00	3132	9.91
	1800	46.0	214.0	4.65	3199	10.23
	2200	50.0	218.0	4.36	3269	10.69
7-2	0200	54.0	222.0	4.11	3328	11.07
	0600	58.0	226.0	3.90	3381	11.43
	1800	70.0	238.0	3.40	3509	12.31
7-3	0600	82.0	250.0	3.05	3611	13.04
7-4	0600	106.0	274.0	2.58	3757	14.12
	1800	118.0	286.0	2.42	3812	14.53
7-5	0520	129.0	297.0	2.30	3859	14.89
	1800	142.0	310.0	2.18	3904	15.24

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TABLE VI (Cont'd)

POST-FRAC BUILDUP

<u>Date</u>	<u>Hour</u>	<u>t</u> (hours)	<u>t+Δt</u> (hours)	<u>t+Δt/Δt</u>	<u>BHP</u> (psi)	<u>P_w²</u>
7-6	0600	154.0	322.0	2.09	3951	15.61
	1800	166.0	334.0	2.01	3985	15.88
7-7	0600	178.0	346.0	1.94	4015	16.12
	1830	190.5	358.5	1.88	4045	16.36
7-8	0600	202.0	370.0	1.83	4071	16.57
	1800	214.0	382.0	1.79	4097	16.79
7-9	0600	226.0	394.0	1.74	4124	17.01
	1800	238.0	406.0	1.71	4146	17.19
7-10	0600	250.0	418.0	1.67	4167	17.36
	1800	262.0	430.0	1.64	4187	17.53
7-11	0600	274.0	442.0	1.61	4206	17.69

A111-14

TABLE VII

PRE-FRAC PBU DATA ZONE 3 INTERVAL 9392-9538STARTED FLOW 8-8 AT 1730. STARTED PBU 8-12 AT 0800

AVG STABILIZED FLOW RATE = 700 MCFD.

FLOWING TIME, t = 86.5 HOURS.

DATE	HOUR	Δt	$t + \Delta t$	$t + \Delta t / \Delta t$	BHP	$\frac{P_w^2}{10^6}$
8-12	0800	0	86.50	-	357	.127
	0810	0.17	86.67	510	420	.176
	0820	0.33	86.83	263	611	.373
	0830	0.50	87.00	.17	721	.520
	0900	1.0	87.5	87.50	1050	1.10
	0930	1.5	88.0	58.67	1283	1.65
	1000	2.0	88.5	44.25	1465	2.15
	1030	2.5	89.0	35.60	1607	2.58
	1100	3.0	89.5	29.83	1721	2.96
	1200	4.0	90.5	22.63	1893	3.58
	1300	5.0	91.5	18.30	2023	4.09
	1400	6.0	92.5	15.38	2137	4.57
	1500	7.0	93.5	13.36	2232	4.98
	1600	8.0	94.5	11.81	2309	5.33
	1700	9.0	95.5	10.61	2381	5.67
	1800	10.0	96.5	9.65	2449	6.00
	1900	11.0	97.5	8.86	2508	6.29
	2000	12.0	98.5	8.21	2536	6.43
	2100	13.0	99.5	7.65	2567	6.59
	2200	14.0	100.5	7.18	2599	6.75
8-13	2400	16.0	102.5	6.41	2660	7.08
	0200	18.0	104.5	5.80	2714	7.37
	0400	20.0	106.5	5.33	2762	7.63
	0600	22.0	108.5	4.93	2805	7.87
	1152	27.87	114.37	4.10	2921	8.53
	1745	33.75	120.25	3.56	3012	9.07
	2337	39.62	126.12	3.18	3091	9.55
8-14	0530	45.50	132.00	2.90	3159	9.98
	1122	51.37	137.87	2.68	3220	10.37
	1715	57.25	143.75	2.51	3273	10.71
	1900	59.0	145.5	2.47	3289	10.82
8-15	0600	70.0	156.5	2.24	3372	11.37
	1800	82.0	168.5	2.05	3453	11.92
8-16	0600	94.0	180.5	1.92	3508	12.31
	1930	107.5	194.0	1.80	3560	12.67
8-17	0600	118.0	204.5	1.73	3595	12.92

A111-15

TABLE VII.1

POST-FRAC BUILDUP

ZONE 3 (9392-9432 AND 9517-38)

Pressure Datum @ 9460'

Flow Time, T = 168 hours

Flow Rate Prior to Shut-In, Q = 1,000,000 SCF/day

<u>Date</u>	<u>Hour</u>	<u>ΔT</u> (hours)	<u>$T + \Delta T$</u> (hours)	<u>$T + \Delta T / \Delta T$</u>	<u>BHP</u> (psi)	<u>P_w^2</u>
9/28	0645	0	168	—	761	
	0700	.25	168.25	673	820	.672 x 10 ⁶
	0720	.58	168.58	291	932	.868
	0750	1.08	169.08	157	1091	1.19
	0830	1.75	169.75	97	1288	1.56
	0900	2.25	170.25	75.7	1428	2.04
	1000	3.25	171.25	52.7	1691	2.96
	1100	4.25	172.25	40.5	1931	3.73
	1200	5.25	173.25	33.0	2139	4.58
	1300	6.25	174.25	27.9	2295	5.27
	1500	8.25	176.25	21.4	2523	6.36
	1700	10.25	178.25	17.4	2687	7.22
	1900	12.25	180.25	14.7	2776	7.71
	2100	14.25	182.25	12.8	2848	8.11
	2400	17.25	185.25	10.7	2931	8.59
9/29	0400	21.25	189.25	8.91	3016	9.10
	1000	27.25	195.25	7.17	3104	9.63
	1400	31.25	199.25	6.38	3145	9.89
	1800	35.25	203.25	5.77	3177	10.09
	2200	39.25	207.25	5.28	3201	10.25
9/30	0200	43.25	211.25	4.88	3221	10.37
	0550	47.08	215.08	4.57	3236	10.47
	1230	53.75	221.75	4.13	3256	10.60
	2110	62.42	230.42	3.69	3275	10.73
10/1	0720	72.58	240.58	3.31	3293	10.84
	1630	81.75	249.75	3.06	3306	10.92
10/2	0715	96.15	264.15	2.74	3324	11.05
	1600	105.25	273.25	2.60	3334	11.12
10/3	0500	118.25	286.25	2.42	3348	11.21
	1900	132.25	300.25	2.27	3362	11.30
10/4	0545	143.00	311.00	2.17	3372	11.37
10/5	0535	166.83	334.83	2.01	3392	11.50
	1500	176.25	344.25	1.95	3400	11.56
10/6	0530	190.75	358.75	1.88	3411	11.63
10/7	0540	214.92	382.92	1.78	3428	11.75
	1600	225.25	393.25	1.75	3434	11.79
10/11	0900	314.25	482.25	1.53	3486	12.15

A111-16

TABLE IX-A

PRE-FRAC BUILDUP

ZONE 4A (9254-9320)

Pressure Datum @ 9290'

Flow Time, T = 77 hours

Flow Rate Prior to Shut-In, Q = 200,000 SCF/day

<u>Date</u>	<u>Hour</u>	<u>ΔT</u> (hours)	<u>$T + \Delta T$</u> (hours)	<u>$T + \Delta T / \Delta T$</u>	<u>BHP</u> (psi)	<u>P_w^2</u>
10/22	1700	0	77.00	—	372	
	1730	.50	77.50	155	381	.145 x 10 ⁶
	1800	1.00	78.00	78	437	.191
	1830	1.50	78.50	52.3	467	.218
	1900	2.00	79.00	39.5	496	.246
	2030	3.50	80.50	23.0	581	.338
10/23	1330	20.50	97.50	4.76	1385	1.92
	1545	22.75	99.75	4.38	1443	2.08
	2020	27.33	104.33	3.82	1529	2.34
	2110	28.17	105.17	3.73	1545	2.39
10/24	0007	31.12	108.12	3.47	1612	2.60
	0418	35.30	112.30	3.18	1736	3.01
Kuster	0822	39.36	116.36	2.96	1818	3.31
Gauge	1301	44.02	121.02	2.75	1901	3.61
	1843	49.72	126.72	2.55	2000	4.00
10/25	0148	56.80	133.80	2.36	2082	4.33
	0812	63.20	140.20	2.22	2163	4.68
	1504	70.06	147.06	2.09	2228	4.96
	2052	75.87	152.87	2.01	2278	5.19
10/26	0117	80.28	157.28	1.96	2343	5.49
	0507	84.12	161.12	1.92	2360	5.57
	0700	86.00	163.00	1.90	2376	5.65
	1530	94.50	171.50	1.81	2495	6.23
10/27	0800	111.00	188.00	1.69	2618	6.85
	0930	112.50	189.50	1.68	2625	6.89
	1000	233.00	310.00	1.33	3000	9.00

A111-17

TABLE IX-B

PRE-FRAC BUILDUP

ZONE 4B (9086-9124)

Pressure Datum @ 9105'

Flow Time, T = 72 hours

Flow Rate Prior to Shut-In, Q = 100,000 SCF/day

<u>Date</u>	<u>Hour</u>	<u>ΔT</u> (hours)	<u>T+ΔT</u> (hours)	<u>T+ΔT/ΔT</u>	<u>BHP</u> (psi)	<u>P_w²</u>
11/10	1200	0	72.00	—	622	
	1230	.50	72.00	145	650	.423 x 10 ⁶
	1300	1.00	73.00	73	673	.453
	1330	1.50	73.50	49	694	.482
	1400	2.00	74.00	37	715	.511
	1500	3.00	75.00	25	758	.575
	1600	4.00	76.00	19	797	.635
	1700	5.00	77.00	15.4	836	.699
	1800	6.00	78.00	13.0	873	.762
	1900	7.00	79.00	11.3	909	.826
	2000	8.00	80.00	10.0	944	.891
	2100	9.00	81.00	9.0	978	.956
	2200	10.00	82.00	8.2	1010	1.020
	2300	11.00	83.00	7.55	1041	1.084
	2400	12.00	84.00	7.00	1073	1.151
11/11	0200	14.00	86.00	6.14	1133	1.284
	0400	16.00	88.00	5.50	1189	1.413
	0600	18.00	90.00	5.00	1242	1.543
	1500	27.00	99.00	3.67	1442	2.079
11/12	1800	30.00	102.00	3.40	1513	2.289
	0600	42.00	114.00	2.71	1716	2.945
11/13	1800	54.00	126.00	2.33	1876	3.520
	0600	66.00	138.00	2.09	2007	4.028
11/14	1120	71.33	143.33	2.01	2061	4.248
	1800	78.00	150.00	1.92	2114	4.469
	0600	90.00	162.00	1.80	2213	4.897

TABLE X

FLOW DATA - ZONES 1-4

January-April, 1978

<u>Date</u>	<u>Gas MMCFD</u>	<u>Condensate BPD</u>	<u>Water BPD</u>	<u>C.P. psi</u>	<u>T.P. psi</u>
1/19	3.0	28	400	1200	450
1/21	2.4	10	260	1125	430
1/22	2.3	27	250	1120	376
1/23	2.2	33	150	1080	378
1/24	2.0	20	200	1023	370
1/25	2.0	20	180	1010	375
1/26	2.0	20	170	1010	370
1/27	2.0	20	150	1160	372
1/28	2.0	20	142	1160	372
1/31	2.0	—	140	—	—
2/1	—	—	—	—	—
2/2	—	—	—	—	—
2/3	1.61	20	85	370	909
2/4	1.61	20	85	370	909
2/5	1.57	19	80	370	909
2/6	1.57	19	80	370	891
2/7	1.57	18	80	370	882
2/8	1.51	17	75	370	873
2/9	1.51	16	75	315	808
2/10	1.59	16	75	304	800
2/11	1.54	16	70	304	795
2/12	1.53	16	70	294	795
2/13	1.51	16	65	294	777
2/14	1.51	16	65	294	777
2/15	1.51	16	65	294	777
2/16	1.51	16	65	294	777
2/17	1.50	16	55	294	770
2/18	1.48	17	55	294	765
2/19	1.45	17	50	294	765
2/20	1.42	17	45	294	760
2/21	1.42	18	45	294	755
2/22	1.44	18	45	294	750
2/23	1.39	18	45	294	750
2/24	1.41	16	40	294	747
2/25	1.37	16	40	294	747
2/26	1.35	16	40	294	747
2/27	1.37	16	40	294	747
2/28	1.35	16	40	294	747

TABLE X (Cont'd)

FLOW DATA - ZONES 1-4

January-April, 1978

<u>Date</u>	<u>Gas, MMCF/day</u>	<u>Condensate BBL/day</u>	<u>Water BBL/day</u>	<u>Pressure-psig</u>	
				<u>Tubing</u>	<u>Casing</u>
3/1	1.32	16	40	294	747
3/2	1.34	16	40	294	747
3/3-3/6	1.30	14	40	290	747
3/7-3/8	1.28	14	40	290	747
3/9	1.27	14	40	290	747
3/10-3/12	1.26	14	36	315*	758*
3/13	1.23	14	36	315	758
3/14	1.20	14	36	315	758
3/15-3/16	1.16	14	36	315	758
3/17-3/19	1.23	13	40	334	736
3/20-3/21	1.23	13	39	334	736
3/22	1.23	13	38	334	736
3/23	1.23	12	37	334	736
3/24-3/26	1.17	12	27	338	727
3/27-3/30	1.17	12	27	338	727
3/31	1.16	12	27	338	727

*Pressure gauges recalibrated.

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TABLE X (Cont'd)

FLOW DATA - ZONES 1-4

January-April, 1978

<u>Date - 1978</u>	<u>Gas MMCF/day</u>	<u>Condensate BBL/day</u>	<u>Water BBL/day</u>	<u>Pressure-psig</u>	
				<u>Tubing</u>	<u>Casing</u>
4/1-4/2	1.15	12	25	315	717
4/3	1.14	12	25	315	717
4/4	1.13	12	25	315	717
4/5	1.15	12	25	315	717
4/6-4/7	1.13	12	25	315	717
4/8	1.15	12	25	315	717
4/9	1.10	12	25	315	717
4/10	1.03	12	25	315	717

A111-21

TABLE XI

PCU #31-13
 ZONE 5 (8765-8972 (O.A.))
 PBU AFTER BREAKDOWN (4/26-5/2/78)

Total Production $\approx$ 1675 MCFFinal Rate $\approx$ 500 MCF/D
$$T_c = \frac{1675}{500} = 3.35 \text{ days or } 80 \text{ hours}$$

<u>Date</u>	<u>Time</u>	<u>ΔT</u> hrs	<u>$T+\Delta T$</u>	<u>$\frac{T+\Delta T}{\Delta T}$</u>	<u>BHP</u>	<u>$\frac{(BHP)^2}{\times 10^{-6}}$</u>	<u>$m(p)$</u> <u>$\times 10^{-7}$</u>
4/26	18:30	0	80	-	568	0.32	2.39
	19:00	.5	80.5	161	652	0.43	3.15
	19:30	1.0	81	81	734	0.54	3.97
	20:30	2.0	82	41	868	0.75	5.54
	21:30	3.0	83	27.7	986	0.97	7.13
	22:30	4.0	84	21.0	1088	1.18	8.66
	23:30	5.0	85	17.0	1178	1.39	10.12
4/27	01:30	6.0	86	14.3	1260	1.59	11.60
	02:30	8.0	88	11.0	1396	1.95	14.09
	04:30	10.0	90	9.0	1503	2.26	16.25
	06:30	12.0	92	7.7	1593	2.54	18.17
	09:00	14.5	94.5	6.5	1684	2.84	20.21
	12:00	17.5	97.5	5.57	1772	3.14	22.26
	15:00	20.5	100.5	4.90	1844	3.40	23.99
	20:00	25.5	105.5	4.14	1940	3.76	26.40
	24:00	29.5	109.5	3.71	1988	3.95	27.64
	04:00	33.5	113.5	3.39	2030	4.12	28.73
4/28	07:00	36.5	116.5	3.19	2056	4.23	29.42
	13:00	42.5	122.5	2.88	2103	4.42	30.68
	19:00	48.5	128.5	2.65	2129	4.53	31.39
	09:00	62.5	142.5	2.28	2214	4.90	33.73
4/29	21:00	74.5	154.5	2.07	2268	5.14	35.25
	10:00	87.5	167.5	1.91	2314	5.35	36.56
5/1	06:00	107.5	187.5	1.74	2371	5.62	38.22
	19:00	120.5	200.5	1.66	2402	5.77	39.13
5/2	07:00	132.5	212.5	1.60	2429	5.90	39.93

A111-22

TABLE XII

ZONE 6 PBU AFTER BREAKDOWN

T = 74 HOURS

HYDROSTATIC = $.43 \times 8550 = 3680$; $(3680)^2 = 13.54 \times 10^6$

DATE	TIME	ΔT	$T + \Delta T$	$\frac{T + \Delta T}{\Delta T}$	$\frac{BHP}{PSI}$	$\frac{(BHP)^2 \times 10^{-6}}{PSI^2}$
5/30	16:00	0	74	—	515	.265
	16:15	.25	74.25	297	537	.288
	16:30	.5	74.5	149	571	.326
	17:00	1.0	75.0	75	628	.394
	17:30	1.5	75.5	50.3	676	.457
	18:00	2.0	76.0	38.0	722	.521
	19:00	3	77	25.7	805	.648
	20:00	4	78	19.5	880	.774
	21:00	5	79	15.8	948	.899
	22:00	6	80	13.3	1011	1.022
	23:00	7	81	11.6	1068	1.141
	24:00	8	82	10.2	1121	1.257
5/31	02:00	10	84	8.4	1213	1.471
	04:00	12	86	7.17	1293	1.672
	06:00	14	88	6.29	1365	1.863
	07:00	15	89	5.93	1400	1.960
	08:00	16	90	5.62	1433	2.053
	10:00	18	92	5.11	1498	2.244
	12:00	20	94	4.70	1556	2.421
	14:00	22	96	4.36	1608	2.586
	16:00	24	98	4.08	1655	2.739
	20:00	28	102	3.64	1739	3.024
6/1	24:00	32	106	3.31	1811	3.279
	04:00	36	110	3.06	1873	3.508
	07:00	39	113	2.90	1913	3.660
	11:00	43	117	2.72	1962	3.849

TABLE XII (Cont'd)

ZONE 6 PBU AFTER BREAKDOWN

<u>DATE</u>	<u>TIME</u>	<u>ΔT</u>	<u>$T + \Delta T$</u>	<u>$\frac{T + \Delta T}{\Delta T}$</u>	<u>BHP, PSI</u>	<u>$\frac{(BHP)^2 \times 10^{-6}}{PSI^2}$</u>
6/1	15:00	47	121	2.57	2008	4.032
	19:00	51	125	2.45	2044	4.178
6/2	07:00	63	137	2.17	2140	4.580
	16:30	72.5	146.5	2.02	2200	4.840
6/3	17:00	97	171	1.76	2317	5.368
6/4	15:00	119	193	1.62	2396	5.741
6/5	09:00	137	211	1.54	2444	5.973
	17:00	145	219	1.51	2463	6.066
6/6	09:45	161.75	235.75	1.46	2500	6.250
	21:00	173	247	1.43	2521	6.355
6/7	10:15	186.25	260.25	1.40	2544	6.472

A111-24

TABLE XIII

Water Analysis of Zone 7

Operator	<u>Mobil Oil Corporation</u>	Date Sampled	<u>6-24-78</u>
Well	<u>F31-13G</u>	Date Received	<u>7-5-78</u>
Field	<u>Piceance Creek</u>	Submitted By	<u>Lewis Medlin (Mobil R&D - Dallas)</u>
Formation	<u>Mesa Verde</u>	Worked By	<u>Debra L. Gordon</u>
Depth	<u>8163-8372 (0.A.)</u>	Sample Description <u>One-pint sample was turbid, contained 1/8" oil layer on surface and gray sediment. Strong hydrocarbon odor present. Well flowing at time of sampling.</u>	
County	<u>Rio Blanco</u>		
State	<u>Colorado</u>		

Physical Determinations

Specific Gravity	<u>1.010</u>	at	<u>78</u>	°F	Total Dissolved Solids	<u>N/A</u>
pH	<u>7.9</u>				Total Organics	<u>N/A</u>
R_w	<u>= 0.65 Ω -m @ 80°F</u>					

Chemical Determinations

Iron Fe^{+3}	<u>none detected</u>	Fe^{+2}	<u>none detected</u>	Phosphate	<u>N/A</u>
Hydrogen Sulfide	<u>none detected</u>	Sulfate	<u>none detected</u>	ppm	
Total Hardness	<u>450</u>	ppm	Bicarbonate	<u>1476</u>	ppm
Calcium	<u>94</u>	ppm	Chloride	<u>4980</u>	ppm
Magnesium	<u>52</u>	ppm	as Sodium Chloride	<u>8183</u>	ppm (Corr.)
(Na^+)	(K^+)				
Sodium and Potassium	<u>$Na^+ = 3224$ ppm;</u>	<u>$K^+ = 357$ ppm</u>			

Comments: Sample appears to be predominately formation water.

for Stiff type plot (in meq./l.)

A111-25

TABLE XIV

PBU AFTER BREAKDOWNZONE 7 [8163-8372 (O.A.)]

$$T_c = \frac{736}{200} = 3.68 \text{ DAY} \approx 88 \text{ HOURS}$$

<u>DATE</u>	<u>TIME</u>	<u>ΔT</u>	<u>$T + \Delta T$</u>	<u>$\frac{T + \Delta T}{\Delta T}$</u>	<u>BHP, PSI</u>	<u>$\frac{(BHP)^2 \times 10^{-6}}{PSI^2}$</u>
6/17	15:00	0	88	—	1162	1.350
	15:30	0.5	88.5	177	1248	1.558
	16:00	1.0	89	89	1319	1.740
	16:30	1.5	89.5	59.7	1383	1.913
	17:00	2.0	90	45.0	1442	2.079
	18:00	3.0	91	30.3	1545	2.387
	19:00	4.0	92	23.0	1624	2.637
	20:00	5.0	93	18.6	1692	2.863
	21:00	6.0	94	15.7	1753	3.073
	23:00	8.0	96	12.0	1857	3.448
6/18	01:00	10.0	98	9.8	1940	3.764
	03:00	12.0	100	8.33	2005	4.020
	07:00	16.0	104	6.50	2098	4.402
	11:00	20.0	108	5.40	2155	4.644
	15:00	24.0	112	4.67	2195	4.818
	21:00	30.0	118	3.93	2224	4.946
6/19	06:00	39.0	127	3.26	2284	5.217
	12:00	45.0	133	2.96	2311	5.341
6/20	06:00	63.0	151	2.40	2368	5.607
	16:00	73.0	161	2.21	2397	5.746
6/21	06:00	87.0	175	2.01	2430	5.905
6/22	06:00	111.0	199	1.79	2472	6.111
	15:00	120.0	208	1.73	2486	6.180
6/23	06:00	135	223	1.65	2507	6.285
	15:10	144.17	232.17	1.61	2518	6.340

A111-26

TABLE XV

GAS ANALYSIS

ZONES 6&7

EFFECTIVE DATE: 8-1-78

GAS SOURCE: MOBIL-F 31-13 G ZONES 6 & 7

GAS DESTINATION: FLARE

COUNTY: RIO BLANCO

STATE: COLORADO

COMPONENT	MOLE PCT	GPM
X	.00000	
NITROGEN	.13640	
METHANE	87.64439	
CARB. DIOXIDE	1.48488	
ETHANE	6.35918	1.69578
PROPANE	2.11937	.58176
I-BUTANE	.44768	.14606
N-BUTANE	.50366	.15833
I-PENTANE	.21968	.08021
N-PENTANE	.15883	.05740
HEXANES PLUS	.92593	.39719
TOTAL	100.00	3.11674

SPECIFIC GRAVITY: .66803

BTU/CF = 1123.29 CALCULATED AT 14.69600 PSIA

A111-27

TABLE XVI

PRODUCED WATER ANALYSIS - ZONE 8

<u>Constituent</u>	<u>mg/l</u>
Carbonate	0
Bicarbonate	800
Sulfate	50
Chloride	8500
Sodium	4100
Potassium	2000
Magnesium	30
Calcium	170
TDS	15,650
pH	7.2
Sp. Gr.	1.008
R _w	0.5 @ 80° F

A111-28

TABLE XVII

PBU AFTER BREAKDOWN

ZONE 8

Avg. Rate for 5 days $\approx$ 450 MCF/D = 2250 MCF (Cumulative)

$$T_{c1} = \frac{2250}{300} = 7.5 \text{ (180 hours)}$$

Date	Time	ΔT	$T_c + \Delta T$	$\frac{T_c + \Delta T}{\Delta T}$	BHP, psi	$\frac{(\text{BHP})^2}{\text{psi}^2} \times 10^{-6}$
8/24/78	22:00	0	—	—	961	0.924
	23:00	1	181	181	1223	1.496
	24:00	2	182	91	1324	1.753
8/25/78	01:00	3	183	61	1395	1.946
	02:00	4	184	46	1459	2.129
	04:00	6	186	31	1514	2.292
	06:00	8	188	23.5	1562	2.440
	08:00	10	190	19.0	1618	2.618
	10:00	12	192	16.0	1668	2.782
	14:00	16	196	12.2	1733	3.003
	18:00	20	200	10.0	1775	3.151
	22:00	24	204	8.5	1810	3.276
8/26/78	04:00	30	210	7.0	1852	3.430
	10:00	36	216	6.0	1891	3.576
	17:10	43.17	223.17	5.17	1932	3.733
8/27/78	10:05	60.08	240.08	4.00	2012	4.048
	19:10	69.17	249.17	3.60	2048	4.194
8/28/78	06:45	80.75	260.75	3.23	2087	4.356
	17:05	91.08	271.08	2.98	2120	4.494
8/29/78	06:30	104.5	284.5	2.72	2159	4.661
	16:45	114.75	294.75	2.57	2186	4.779
8/30/78	06:30	128.5	308.5	2.40	2219	4.924
	17:20	139.33	319.33	2.29	2241	5.022
8/31/78	06:15	152.25	332.25	2.18	2267	5.139
	19:45	165.75	345.75	2.09	2289	5.240
9/1/78	06:30	176.5	356.5	2.02	2308	5.327
	20:30	190.5	370.5	1.94	2329	5.424
9/2/78	06:45	200.75	380.75	1.90	2343	5.490
	22:00	216.0	396.0	1.83	2363	5.584
9/4/78	19:45	261.75	441.75	1.69	2413	5.823

A111-29

TABLE XVIII

PBU AFTER BREAKDOWNZONE 9 (7324-7476)T $\approx$ 80 hours

Q = 1100 MCF/Day

<u>Date</u>	<u>Time</u>	<u>ΔT</u>	<u>T+ΔT</u>	<u>$\frac{T+\Delta T}{\Delta T}$</u>	<u>BHP,</u> psi	<u>$\frac{(P_w^2) \times 10^{-6}}{\text{psi}^2}$</u>	<u>Csg.</u>	<u>Tbg.</u>
Nov. 6	14:00	0	80	—	1017	1.034	800	60
	15:00	1	81	81	1261	1.590		
	16:00	2	82	41	1415	2.002	1050	1050
	17:00	3	83	27.7	1539	2.369		
	18:00	4	84	21.0	1605	2.576		
	19:00	5	85	17.0	1682	2.829		
	20:00	6	86	14.3	1747	3.052		
	22:00	8	88	11.0	1854	3.437		
Nov. 7	24:00	10	90	9.0	1931	3.729	1740	1740
	02:00	12	92	7.67	1979	3.916		
	04:00	14	94	6.71	2021	4.084		
	06:00	16	96	6.00	2055	4.223		
	08:00	18	98	5.44	2089	4.364		
	10:00	20	100	5.00	2126	4.520		
	12:00	22	102	4.64	2147	4.610		
	14:00	24	104	4.33	2171	4.713		
Nov. 8	18:00	28	108	3.86	2212	4.893	1920	1920
	22:00	32	112	3.50	2248	5.054		
	02:00	36	116	3.22	2280	5.198		
	06:00	40	120	3.00	2308	5.327		
	08:00	42	122	2.90	2321	5.387		
	18:00	52	132	2.54	2375	5.641		
	08:00	66	146	2.21	2435	5.929		
	18:00	76	156	2.05	2466	6.081		
Nov. 9	18:00	76	156	2.05	2466	6.081	1910	2040
Nov. 10	08:00	90	170	1.89	2506	6.280	2030	2050
Nov. 11	09:30	115.5	195.5	1.69	2556	6.533	2100	NA
Nov. 12	08:00	138	218	1.58	2588	6.698		

ATTI-30

TABLE XIX

GAS ANALYSIS

ZONE 9

GAS SOURCE: MOBIL MASSIVE FRAC F31-13G
GAS DESTINATION: FLARE
COUNTY: RIO BLANCO STATE: COLO

COMPONENT	MOLE PCT	GPM
X	.00000	
NITROGEN	.28718	
METHANE	98.57333	
CARB.DIOXIDE	1.76955	
ETHANE	6.31792	1.68478
PROPANE	1.72904	.47462
I-BUTANE	.40900	.13343
N-BUTANE	.33177	.10430
I-PENTANE	.11943	.04300
N-PENTANE	.09146	.03306
HEXANES PLUS	.37082	.15907
TOTAL	100.00	2.63286

SPECIFIC GRAVITY: .64669

BTU/CF = 1081.04 CALCULATED AT 14.69600 PSIA

ALL-31

TABLE XX-A

PRODUCTION FROM ZONE 9

AFTER FRAC

<u>Date</u>	<u>After Frac</u> <u>Daily Production, MCF</u>	<u>Remarks</u>
11/16-20/78	≈ 4000	Water Rate, 670 → 570 BPD
11/21-27	NA	Logging; cleaning up to pit
11/27/78	1897	
11/28	1908	
11/29	1820	
11/30	1883	
12/1/78	1946	
12/2	1879	
12/3	1738	
12/4	1656	Off about 2 hours
12/5	1935	
12/6	1153	Off almost 10 hours
12/7	1335	Off about 8 hours
12/8	1685	
12/9	592	Off 12 hrs-freezing up
12/10	1270	Off 8 hrs
12/11	1710	
12/12	1656	Off 2 hours
12/13	1860	
12/14	1734	
12/15	1597	
12/16	1714	
12/17	1810	
12/18	1776	
12/19	1741	
12/20	1767	
12/21	1812	
12/22	1758	
12/23	1750	
12/24	1757	
12/25	1722	
12/26	1745	
12/27	1720	
12/28	1703	
12/29	1667	
12/30	1735	
12/31	716	Shut-in @ 10:00 on 12/31

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TABLE XX-B

ZONE 9

REPORTED WATER PRODUCTION

AFTER FRAC

<u>Date</u>	<u>Water Produced, bbls</u>
11/18/78	700
11/20	550
12/7	85
12/14	90
12/20	85
12/29	87

A111-33

TABLE XXI

SUMMARY OF RESULTS FROM PRE-FRAC PBU TESTS

<u>ZONE</u>	<u>APPROX. NET FT.</u>	<u>KH FROM PRE-FRAC PBU (FINAL SLOPE)*</u>	<u>K</u>	<u>EST. RESERVOIR PRESS., PSI</u>
1	60	0.3	.005	4800
2	30	0.3 (est.)	.01	4650
3	50	1.0	.02	4200
4A	50	.07	.0014	4000
4B	30	.03	.001	4000
5	60	0.2	.0033	3815
6	70	0.14	.002	3680
7	<u>50</u>	<u>0.22</u>	.0044	3200
Total (Mesaverde Only)	400	2.26	.00565 (avg)	
8	40	0.5	.0125	3000
9	125	2.0	.016	2865

*Final slope - last measured pressure value connected to est. value for reservoir pressure.

A111-34

TABLE XXII-A
RESERVOIR CHARACTERISTICS USED
IN ECONOMIC EVALUATION
(MESAVERDE)

<u>Item</u>	<u>Value</u>
Net thickness	400 feet
Gross thickness	600 feet
Porosity	.09 fraction
Water saturation	.60 fraction
Initial reservoir pressure	4000 psi
Flowing well pressure	500 psi
Average lens size	$(1500)^2$ (ft) ²
Effective fracture length	200 feet (wellbore to tip)
Gas Permeability	.005 md
Maximum permissible flow rate	3000 MSCFPD

A111-35

TABLE XXII-B

RESERVOIR CHARACTERISTICS USED

IN ECONOMIC EVALUATION

(OHIO CREEK)

<u>Item</u>	<u>Value</u>
Net thickness	125 feet
Gross thickness	150 feet
Porosity	.09 fraction
Water saturation	.60 fraction
Initial reservoir pressure	3000 psi
Flowing well pressure (BHP)	500 psi
Well spacing	160 acres
Effective fracture length	525 feet
Gas permeability	.012 md
Maximum permissible flow rate	2500 MSCFPD

TABLE XXIII

ECONOMIC PARAMETERS

<u>Item</u>	<u>Value</u>
Total well cost	\$3900 M*
Intangible costs (expense)	\$3400 M*
Tangible costs (capital)	\$ 500 M
Working interest	.875 fraction
Severance and ad-valorem tax	6.8% of wellhead price
State tax	6%
Federal tax	48%
Investment	Beginning of year discounting
Cash flow	Mid-year discounting
Gas sales price	Variable

*Add \$300 M when Ohio Creek Zone is included.

AIV-1

APPENDIX IV

DAILY DRILLING REPORT

AIV-2

PICEANCE CREEK UT F31-136
10,700' Mesa Verde
1126' FNL 1683' FEL
MM/RE Sec 13-25-97W
Rio Blanco Co., Colo.
Mobil 95.985
Signal Orig. Co.
Spudded 3/2/77

2/22 MIRT FIRST REPORT.
2/23 MIRT.
2/24 MIRT.
2/25 RURT
2/28 RURT
3/1 RUR.
3/2 RUR.
3/3 365'
3/4 905'
3/7 1545' Reaming fr 12-1/4" to 15" @ 1425'. Full ret in sh. Mud 9.1 Visc 40
(6) 1/2" @ 1545'. Lost 300 BM @ 1100' while drlg 12-1/4" & 200 BM @ 450' while
reaming. Logged 12-1/4" hole.
3/8 TD 1553' Running 10-3/4" surf csg @ 1100'. Mud 9.2 Visc 40 Ran Welex logs.
3/9 TD 1553' MCC 10-3/4" @ 1540' w/700 sx 65:25 Poz + 2% gel + 10% Gilconite
(8) sack + 200 sx C1 G reg. Full ret. Circ cmt. Recip csg. Niplng up.
3/10 TD 1553' Prep to drl ahead. Nipld up. Tested BOPs to 1500# OK.
3/11 1638' Stuck DP. Lost ret w/bit @ 1596' stuck pipe. Running Dialog
(10) f.pi - Lost 350 BM.
3/14 2034' drlg sh 1" @ 1006'. Mud 8.7 Visc 35 Rec fish aft washing
(13) over from 1520-87'. RW 15M#, 50 RPM.
3/15 2635' drlg sh. Mud 8.8 Visc 36 3/4" @ 2478'.
3/16 3115' drlg sh 1-1/4" @ 2715'. Mud 8.8 Visc 36 Lost 500 BM @ 2930'.
(15) 200 CH @ 2700'. Full ret.
3/17 3472' drlg sh. Mud 9.0 Visc 36 1-1/4" @ 3266'. Losfng mud by seepage.
3/18 3519' drlg cmt @ 1600'. Ran tracer log. Fnd loss zones fr 1550-2895'
(17) Spotted 100 sx Howco thix-tropic @ 2899' + 100 sx @ 1859'.
3/21 4038' drlg sh. 1" @ 3858'. No lost returns. Mud 9.1, Visc 43,
(20) WL 11.8.
3/22 5338' drlg sh. 3/4" @ 4906'. No lost returns. Mud 9.0, Visc 32.0.
3/23 5500' Conditioning mud. Bldg mud vol. Circ OK. Lost comp ret @ 5500'.
(22) 300 bbls. Pulled 7 stands. Well unloaded. Closed BOPs OK. Built vol.
Killed well w/300 BM. Regained ret. Mud 8.6 Visc 39 WL 21.
3/24 5796' drlg sh & sd 1-1/4" @ 5375'. Mud 8.8 Visc 41 WL 12.0. Full ret.
3/25 6230' drlg sh 2" @ 6026'. Mud 9.0 Visc 38 WL 11.2 No lost ret.
3/28 7300' drlg sh 1-3/4" @ 6724'. Mud 8.9 Visc 41 WL 9.2 Full ret.
3/29 7439' Losing ret. Prep to cmt w/thixtropic cmt. Lost ret @ 7439'.
(28) Lost 750 BM last 24 hrs. Mud 8.7 Visc 40.
3/30 7439' Going in hole aft sqz job w/thix-tropic cmt. Used 100 sx 7035-7405'
(29) Mud 8.6 Visc 46.
3/31 7439' drlg cmt @ 7358'. CO to 7360'. Hole sticky. COH to 6000'. Cond
(30) mud. WIH to 7000'. Cond mud. Redrld 7000-7358'. Mud 8.9 Visc 38 WL
22. Full ret.
4/1 7650' drlg sh. Mud 8.8 Visc 40 WL 22. Drld thru cmt @ 7390'. Full
(31) ret.
4/4 8299' drlg sd & sh 1" @ 6111'. Mud 9.0 Visc 47 WL 14.0. Full ret.
4/5 8414' drlg sd & sh. Mud 9.0 Visc 47 WL 10.8. RW 40M#. Pmp pres 1700#.
(35) Bit #14/90'/13-1/4 - Full ret.
4/6 8440' Conditioning hole - 1" @ 8440'. Mud 9.0 Visc 40 Ran core bbl.
(36) Stopped @ 2900' & 6254'. Prep to run 6-1/4" bbl & 7-7/8" core head.
4/7 8453' Coring on Core #1. Core #1 started @ 8440'. Mud 9.0 Visc 48
(37) WL 8.8.
4/11 8789' drlg sd & sh. Core #1 8440-53'. Rec 13' of sd & sh. Core #2
(41) 8453-8486' Rec 33' of sh & sd. Core #3 8486-8500' Rec 14' of sd. Mud 9.0
Visc 45 WL 8.2.
4/12 8975' drlg sd & sh. Mud 9.1 Visc 45.
4/13 9025' drlg sd & sh. Mud 9.1 Visc 45 WL 8. Made trip @ 9022'.
(43) Checked all DCs, Kelly sub etc.
4/14 9202' drlg sd & sh. 1" @ 9032'. Mud 9.1, Visc 45, WL 8.2.
4/15 9387' drlg sd & sh. Mud 9.1, Visc 50, WL 6.8.
4/18 9950' drlg sd & sh. 1 1/2" @ 9224'. Mud 9.1, Visc 45 WL 8.8. Bit #18/681'.
(48) in 82-1/4 hrs.
4/19 9940' Prpp to core in sd. Mud 9.1 Visc 55 WL 8.4 4X oil.
4/20 9977' Pulling core #4 from 9940-9977'. Barrel jammed. Mud 9.2
(50) Visc 55 WL 8.2.
4/21 10,000' Laying dn core bbl. Core #4 9940-77'. Rec 34' sd & sh. Core #5
(51) 9977-10,000'. Rec 23' sd. Mud 9.2 Visc 55 WL 6.0.
4/22 10,025' Making trip aft reaming core hole fr 9940-10,000' in sd & sh.
(52) Mud 9.2 Visc 55 WL 6.5.
4/25 10,274' drlg sh & sd. Mud 9.1 Visc 55 WL 8.0. Full ret.
4/26 10,420' drlg sh & sd. Mud 9.1 Visc 56 WL 6.8. No lost ret.
4/27 10,532' drlg sd & sh. 1 1/2" in 24 hrs. Mud 9.1 Visc 57 WL 6.8
4/28 TD 10,600' Making trip to log in sd. Reached TD @ 1 AM 4/28/77.
Made short trip OK.

AIV-3

PICEANCE CREEK UT #F31-13G
10,600' Mesa Verde
1126' FNL 1683' FEL
NW/NE Sec 13-25-97W
Rio Blanco Co., Colo.
Mobil 100%
Signal Drig. Co.
10-3/4" @ 1540'

- 4/29 TD 10,600' Running elec logs. Have run 3 logs. Lack 2 logs. Schlumberger's measurement on hole was 10,624'.
- 5/2 10,795' drlg sh & sd. Lack 5'. Ran logs. Decided to make more hole while drlg fr 10,620-635'. Lost 280 BM. Aft running 1st series of logs, bit stopped @ 3350'. Had trouble getting on btm. Mud 9.2 Visc 55 WL 6.8.
- (62) 5/3 10,800' running logs. Now running FRL experimental log. Mud 9.2 Visc 58 WL 6.8.
- 5/4 10,800' Circ & cond mud. Finished logging OK. Lost 100% ret aft
- (64) GIH to cond. Lost 450 bbls. Gas cut mud 4 hrs aft regaining circ. Mud 9.0 Visc 45 WL 8 PH 10.
- 5/5 TD 10,600' Ringing up to run 7" csg. Mud 9.0 Visc 58 WL 6.8 Circ & cond mud 8 hrs. Made sh. trip OK. Ld dn drl pipe.
- (65) 5/6 TD 10,800' Ran 276 Jts 7" csg. 10,798', 26# S-95 LT&C. Float @ 10,713'. Cmt w/1025 sx Trinity lt-wt + 3% K Cl + 0.4% HR4 fol by 250 sx Cl G + 3% HR4. Lost ret while running csg @ 2000'. Regain 5% circ while cmtg. Recip csg - disp w/fr wtr. PD @ 6:20 AM 5/6/77. Plug failed to bump @ 0.1% excess disp. Mx disp: pres 1860 psi. Standing pres 1700 psi.
- 5/9 TD 10,800' Ran temp surv. Temp anomaly not distinct. Est top of cmt @ 7450'. Rel Signal Drig. Co. rig @ 12 PM 5/8/77.
- 5/10 TD 10,800' WOCU. Will move in next week. REMOVE FROM REPORT UNTIL COMP. DEGIINS.
- 5/17 TD 10,800' Will move in comp rig tomorrow.
- 5/18 TD 10,800' MICU. Prep to pick up tubing.
- 5/19 TD 10,800' Rigged up comp rig. Installed BOPs. Picking up tbq.
- 5/20 TD 10,800' Picked up & ran 2-3/8" thg to 10,580'. Rig up drlg tools. Prep to drl out cmt fr 10,580-10,750'.
- 5/23 TD 10,800' PD 10,737'. Drl cmt fr 10,610-10,737'. Disp hole w/fresh wtr. Ran G/R CCL under 2000# pressure. Bond log satisfactory thru zones to be pfd. Top of cmt 8024'. SWION. Prep to unload hole. Pressure lstd csg & COP's to 5000# OK. Ran FRL noise log fr 8000-10,737'.
- 5/24 TD 10,800' PB 10,737' Ran 2-3/8" thg to 10,733'. Unloaded hole w/nitrogen. Loaded w/30 bbls 2% K Cl wtr. Pulled tbq. SWION. Prep to pf.
- 5/25 TD 10,800' PB 10,737' Mesa Verde perfs. - 1 shot at 10605, 10609, 10613, 10617, 10621, 10625, 10629, 10633, 10637, 10641, 10645, 10649, 10651, 10653, 10655, 10657, 10658, 10662, 10666, 10668, 10670, 10672, 10674, 10676, 10678, 10680. Total of 26 perfs. 0.40" dia.
- SWION: 10 hr. SICP 400 psi. Schlumberger perforated the above intervals. Preparing to continue perforating.
- 5/26 TD 10,800' PB 10,737' Finished pftg. Mesa Verde one shot at following intervals 10,549; 10,553; 10,557; 10,561; 10,565; 10,567; 10,569; 10,571; 10,573; 10,575; 10,577; 10,579; 10,581; 10,593; 10,597; and 10,601 feet. Overall interval 10,549' - 10,680' 46 holes SWION 12 hr. SICP - 750#. Prep. to run FRL noise log and BHP bomb.
- 5/27 TD 10,800' PB 10,737' Ran FRL noise log. Gas entry @ 10,578' & 10,613'. 10-hr SICP 3600.
- 5/31 TD 10,800' PB 10,737' Prep to run FRL BHTV 10,549-10,680'. 84 hr SICP 1340#. BHP 2478#.
- 6/1 TD 10,800' PB 10,737' Running FRL BHTV 10,549-680'. 12 hr SICP 150#. Loaded hole w/240 bbls 2% K Cl wtr. Ran BHTV. Tool did not function. SWION. Prep to re-run BHTV.
- 6/2 TD 10,800' PB 10,737' Pfs 10,549-680' 14 hr SICP 150#. Ran FRL BHTV log. Log indicated 35 holes - certain, 4 probable, 7 uncertain. Indication of all holes. SWION. Prep to run tbq & break down w/K Cl wtr.
- 6/3 TD 10,800' PB 10,737' Mesa Verde pfs 10,549-680' OA. Cleaning up well. RIH w/tbg & pkr. Set pkr @ 10,469'. Installed Xmas tree. Pres back to 2500#. Pkr held OK. BD Mesa Verde pfs 10,549-680' OA. 46 holes, w/SM gals 2% K Cl wtr cont 1 gal per M gals FR 14 + 1 gal per M gal FSF + 70 Ball Silrs. MxTP 5600#, Mn 4000#, Avg 4000#, AIR 10 BPM, ISIP 1800#. Sh 256 BLW. SWI 40 min. 40 min SITP 1100#. Open well. Well kicked off. Cleaning up to pit. Gd show of gas. Flowed well all night. Cont to test.
- 6/6 TD 10,800' PB 10,737' Mesa Verde pfs 10,549-680' F/150 BLW/72. Sh 106 BLW. TP 0-25#, 1" ch. Orifice well test msmt 300 MCF/24. Making sl amount of wtr. SWION. Ran FRL noise log & temp surv. Tool would not go thru pkr. 14 hr SITP 2485#. BHP @ 10,400', 3200#. Will continue to run buildup test.
- 6/7 TD 10,800' PB 10,737' Mesa Verde pfs 10,549-680' OA. Ran FRL noise log. Now evaluating log.
- 6/8 TD 10,800' PB 10,737' Mesa Verde pfs 10,549-680' OA. 62 hr SITP 3050#. 62 hr SWION 3331#. Continuing to run buildup test.

AIV-4

PICLANCE CREEK UT #F31-13G
 10,600' Mesa Verde
 1126' FNL 1683' FEL
 NW/NE Sec 13-25-97W
 Rio Blanco Co., Colo.
 Mobil 100%
 10-3/4" @ 1540'
 7" @ 10,798'

- 6/9 TD 10,600' PB 10,737' Mesa Verde pfs 10,549-680' OA. 84 hr SITP 3200#, SIBHP 4053#. Continuing to run BU test.
- 6/10 TD 10,800' PB 10,727' Mesa Verde pfs 10,549-680' OA. Cont to run BU tests. 107 hr - SITP 3325, 107 hr - SIBHP 4177. Will test until Tues.
- 6/13 TD 10,800' PB 10,727' Mesa Verde pfs 10,549-680' OA.
 Buildup test: 113 hrs BHP 4207#, tbg 3350#
 140 hrs BHP 4307#, tbg 3400#
 161 hrs BHP 4372#, tbg 3500#
 179 hrs BHP 4417#, tbg 3525#
- 6/14 TD 10,800' PB 10,727' Mesa Verde pfs 10,549-680' OA.
 Final Buildup pres 179-1/2 hrs BHP 4417 tbg 3525. Open well. Pulled press to 2000#. Pulled FBL tools. 15 hr flow test 562 MCF, FTP 230. Rec est 3 bbls d/Lillate 15 hrs. Will cont to test.
- 6/15 TD 10,800' PB 10,727' Mesa Verde pfs 10,549-680' OA. Flowed well 24 hrs, 3/4" ch. FTP 230 psi. GV 393 MCF, 1-1/2 bbls condensate 24 hrs. Will pump into well today.
- 6/16 TD 10,800' PB 10,727' Mesa Verds pfs 10,549-680' OA. Pmpd in 17,400 gal treated 2% K Cl wtr into form. Pmpd 5000 gal S.D. ISIP 1800. Pmpd 12,400 gal S.D. ISIP 1900#, 15 min SIP 1500#. Sh 456 BLW. Open well to pits. Flowed 300 bbls LW 14 hrs. Well flowing - est 3.5 MCF wet gas. P.D. 3/4" ch. Will put thru test eqpt today. Sh 156 BLW.
- 6/17 TD 10,800' PB 10,727' Mesa Verde pfs 10,549-680' OA. Testing - 24 hr test: GV 300 MCFPD + 1/2 BC, 48 BLW. Sh 16 BLW, 3/4" ch, 150# FTP.
- 6/20 TD 10,800' PB 10,727' Mesa Verde pfs 10,549-680' OA. Testing - 72 hr flow test: GV stabilized @ 384 MCF/24 + 2 bbls condensate/24. Making approx 12 BLW/24. Decreasing. TP 330#, 3/4" ch. Prep to kill well. Frac plan 6/22/77.
- 6/21 TD 10,800' PB 10,727' Mesa Verde pfs 10,549-680' OA. Pulled pkr & reran tbg open ended. Flow testing. GV 384 MCF/24. TP 300#, 3/4" ch. Wtr is decreasing. Made 10 BLW + 2 bbl cond/24. Will frac tomorrow.
- 6/22 TD 10,600' PB 10,727' Mesa Verde pfs 10,549-680' OA. Killed well. Circ hole w/2% K Cl wtr. Landed tbg @ 10,429'. Installed tree. Prep to frac.
- 6/23 TD 10,600' PB 10,727' Mesa Verde pfs 10,549-680'. Frac treated Mesa Verde w/580M# sd + 281,400 gals of 2% K Cl wtr. Screened out while on flush. Lacked only 20M# of sd when screen-out occurred. Sd concentration @ the time of screen-out was 3#/gal. ATP 4650#, AIR 58 BPM, ISIP 4200#, Sh 6700 BLW. F/1450 BLW/18-1/2. Sh 5250 BLW. Making approx 40 BLW/hr. 1" ch. TP 95#. Gd show of gas. Flowing well.
- 6/24 TD 10,600' PB 10,727' Mesa Verde pfs 10,549-680'. GV 750 MCF/24. F/300 BLW/24. Sh 4950 BLW. TP 500#, CP 1380#, 1" ch.
- 6/27 TD 10,600' PB 10,727' Mesa Verde pfs 10,549-680'. Flowed well for 72 hrs. F/142 BLW + 3.5 bbls condensate/72. Sh 4808 BLW - TP 100# CP 510# GV 800 MCF/24, 3/4" ch. GV reached 1.1 MM/24 Sat.
- 6/28 TD 10,600' PBTD 10,727' Mesa Verde pfs 10,549-680' F1 well for 24 hrs. F/40 BLW + 3.5 bbls cond/24. Sh 4768 BLW. TP 90#, CP 480#. GV 775 MCF/24, 3/4" ch.
- 6/29 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' F/40 BLW + 3 bbls cond/24. Sh 4728 BLW. TP 90#. CP 480#. GV 800 MCF/24, 3/4" ch. Running noise log.
- 6/30 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680'. GV 800 MCF/24. Ran noise log, BHP & temp surveys. Will run build-up tests for 14 days. Gas entry @ 10,580' & 10,614'.
- 7/1 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680'. 34 hr SITP 2350, SICP 2255, BHP 2953. Will continue to run BU.
- 7/5 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' RHG BHP BU tests 128 hr DHSIP 3861#, SICP 2965#. Will cont to run test.
- 7/6 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' 152 hr DHSIP 3953#, SICP 3017#. DWG. Will cont to run BU tests.
- 7/7 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' 176 hr SIBHP 4016, SICP 3008 DWG. Will cont to run BU tests. Will open well on 7/11/77.
- 7/8 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' 200 hr SIBHP 4066, SICP 3112. Will cont to run BU tests.
- 7/11 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' 272 hr SIBHP 4207 SICP 3245. Will open well today for drawdown tests.
- 7/12 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680'. F1 well 22 hrs. Rec 10 bbls cond, 20 BLW - 2.8 MCFPD. TP 335#, CP 840#, FBHP 1042#. This morning 1.5 MCFPD. Will cont to flow test. Sh 4708.
- 7/13 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' F1 well 24 hr. Rec 40 BLW + 10 bbls cond/24. GV 1.2 MM/24. TP 140#. CP 640#. FBHP 749. Sh 4668 BLW. Will cont to test.
- 7/14 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680'. F1 well 24 hr. Rec 40 BLW + 10 bbls cond/24. F/30 BLW + 2.5 bbls cond/24. GV 1.06 MM/24. Open ch. TP 140#. CP 510#. FBHP 580. Sh 4638 BLW. Will cont to test.

AIV-5

FIDELANCE CREEK UT #F31-13G
10,600' Mesa Verde
1126' FNL 1683' FEL
NW/NE Sec 13-25-97W
Rio Blanco Co., Colo.
Mobil 100%
10-3/4" @ 1540'
7" @ 10,798'

- 7/15 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680'. F1 well 24 hrs. F/38 ULW + 3 bbls cond/24. GV 960 MCF/24. TP 140#, CP 465# FBHP 574. Sh 4600 BLW. Will cont to test.
- 7/18 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680'. F1 well 72 hrs. F/70 BLW + 4 bbls cond/24. CP 465#. GV 827 MCF/24. Sh 4530 BLW. Open ch. Pulled BHP bomb. Waiting on pfs to test upper zones.
- 7/19 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680'. F/20 BLW + 3 bbls cond/24. GV 732 MCF/24, open choke, TP 140#, CP 420#. Short 4510 BLW. Will continue to flow until completion unit is on loc.
- 7/20 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' F/25 BLW + 3 bbls cond/24. Open ch. GV 775 MCF/24. TP 140#, CP 420#. Sh 4485 BLW. MICU.
- 7/21 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' MICR. Killed well w/460 bbls K Cl wtr. Removed tree. Installed BOPs. Prep to pull tbg.
- 7/22 TD 10,800' PBTD 10,727' Mesa Verde pfs 10,549-680' Well kicked & unloaded. Killed well several times. Used 700 bbls K Cl wtr. Pulled tbg. Running BP @ 2000'.
- 7/25 TD 10,800' PB 10,539' Mesa Verde pfs 10,415-476' OA. Set Ret BP @ 10,539'. Pres tested to 6000#. OK. Pulled tbg. Pf Mesa Verde ABH zones. A zone 10,415', 10,416', 10,417', 10,418', 10,419', 10,421', 10,422', 10,423', 10,425', 10,427', 10,472', 10,474', 10,476', w/1 spf. Sh well in - 36 hr SICP 200#. Prep to kill well & run pkr.
- 7/26 TD 10,800' PB 10,539' Mesa Verde pfs 10,415-476' OA. Killed well. Set pkr @ 10,355'. BD w/1681 gals 2% K Cl wtr + 42 ball slrs. BD 2300-2100. AIR 3 BPM. MxTP 7000#. MxTP 2100#, In 5400#, AIP 5200 @ 8 BPM, ISIP 2200#, 5" SIP 1800#. Balled out. Sh 250 BLW. F/70 BLW/11. Sh 180 BLW GV 25 MCF/24. Prep to move pkr & run FRL injectivity tests.
- 7/27 TD 10,800' PB 10,539' Mesa Verde pfs 10,415-476' OA. Ran FRL injectivity tests. Will pf Mesa Verde C&D zones today.
- 7/28 TD 10,800' PB 10,539' Mesa Verde pfs 10,186-10,476' OA. Pf Mesa Verde 10,186-10,261' w/16 holes. Ran pkr & BP to 700'. Well kicked. Pmpd in 100 bbls K Cl wtr. SWION. Prep to kill well & run injectivity tests.
- 7/29 TD 10,800' PB 10,539' Mesa Verde pfs 10,186-10,476' OA. Killed well. Ran pkr & BOP. Set BOP @ 10,350' & pkr @ 10,320'. Plug would not hold pres. SWION. Prep to pull pkr & BP.
- 8/1 TD 10,800' PB 10,539' Mesa Verde pfs 10,186-10,476' OA. Pulled pkr & BP. Re-ran. Set ret BP @ 10,360'. Tested to 6000#. Set pkr @ 10,105'. BD Mesa Verde pfs 10,186-10,261' OA w/1090 gals 2% K Cl wtr + 30 US. BD 2250#. MxTP 6500#, MxTP 2250#, MxTP 6500#, AIP 4500#, AIR 10 BPM, ISIP 2300#. Balled out. Ran FRL injectivity test. AIP 3200# @ 5 BPM, 4500# @ 10 BPM, 6000# @ 15 BPM. Sh 325 BLW. Killed well. Re-set bridge plug @ 10,510'. Set pkr @ 10,105'. Set Mesa Verde pfs 10,186-10,476'. F&S/100 BLW/51. Sh 225 BLW. Will continue to flow test & run FRL noise log.
- 8/2 TD 10,800' PB 10,539' Mesa Verde pfs 10,186-10,476' OA. Running noise logs. Logs show gas entry @ 10,476', 10,472' & 10,415-10,427', 10,250-260' & 10,186-196'. Will continue to flow test.
- 8/3 TD 10,800' PB 10,539' Mesa Verde pfs 10,186-10,476' OA. F/5 BLW/24. GV 30 MCF/24. Will pf additional intervals for fracturing.
- 8/4 TD 10,800' PB 10,539' Mesa Verde pfs 10,186-10,476' OA. Flowed well 24 hrs. GV 137 MCF/24. Prep to kill well & leave zone 10,186-476'. Will pf 9392-9538' tomorrow.
- 8/5 TD 10,800' PB 10,539' Mesa Verde pfs 10,186-476' OA. Killed well. Pulled tbg & pkr. Prep to pf 9392-9538'. Set BP @ 9600'. Tested plug to 6000#.
- 8/8 TD 10,800' PB 9600' Mesa Verde pfs 9392-9598' (OA). Pfd above interval. W/1 w/pkr. Set @ 9287'. SWION. Prep to breakdown and run injectivity test.
- 8/9 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. Flow testing. TWTH. BD above int dn 2-7/8" tbg/16M gal 2% K Cl H₂O + 14/1000 gal FR-14 + 80 GS. MxTP 6500#, MxTP 1200#, FTP 6000#, AIP 5000# @ 13 BPM. ISIP 1000. Gd ball act. Ran FRL injectivity test/Apollo gel. 5 BPM, AIP 1300#, 10 BPM, AIP = 3100#, 15 BPM, AIP 5000#, Sh 710 BLW. Flowed well 12 hrs. Rec 175 BLW. Sh 535 BLW. Will cont to flow test & run noise log.
- 8/10 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. F/48 BLW + 5 bbls cond/24. GV 230 MCFPD. TP 85. Sh 487 BLW. Will run FRL noise log today.
- 8/11 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. F/30 BLW + 2 bbls cond/24. GV 799 MCFPD. Sh 457 BLW. FTP 55# Open ch. Ran FRL noise log. Most of gas entry 9524-30', 9410-22'. BHFP 206#. Will cont to test.
- 8/12 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. F/25 BLW + 2 BC, 684 MCFPD. TP 90 psi, FBHP 385 psi. Sh 432 BLW. Prep to run PBU test.
- 8/15 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. Well SI for buildup test @ 8 AM 3/12/77. 71 hr BHP 3374 TP 2555 Continue to run buildup test.
- 8/16 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. Running buildup test. Cont to run buildup test. 95 hr BHP 3508 psi. TP 2745 psi.
- 8/17 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. Running buildup test. Cont to run buildup test. 119 hr BHP 3594 psi. TP 2790#.

AIV-6

PICEANCE CREEK UT #F31-13G

10,600' Mesa Verde
1126' FNL 1683' FEL
NW/NE Sec 13-2S-97W
Rio Blanco Co., Colo.
Mobil 100%
10-3/4" @ 1540'
7" @ 10,798'

- 8/18 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. Running buildup test. 143 hr BHP 3652 psi. TP 2865 psi.
- 8/19 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. Running buildup test. 167 hr BHP 3711, TP 2375.
- 8/22 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. 215-hr SISHP 3782#, 215-hr SITP 2930#. Blowing well down. Prep to kill well. Will frac Wednesday.
- 8/23 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. GV 730 MCF/24. Killing well. Will frac tomorrow.
- 8/24 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538' OA. Killed well. Prep to massive frac Mesa Verde pfs 9392-9538' w/2% KCl wtr.
- 8/25 TD 10,600' PB 9600' Mesa Verde pfs 9392-9538' OA. Western Co. frac treated above pfs w/332,600 gals Apollo gel. 40 + 600# 20/40 sd dn 2-7/8" tbg as fol: 10,500 gals gelled pre pad + 2100 gals of Apollo gel pad + 70M gals Apollo gel + 2# sd/gal + 140M gals Apollo gel + 3# sd/gal + 10M gals Apollo gel + 4# sd/gal + 2310 gals of gel flush. MxTP 5800#, MnTP 3800#, ATP 4200#, AFR 15 BPM, ISIP 2700#, 15" SIP 1650#. Sh 5592 BLW. Sh well in for 3 hrs. Opened to pits on 3/4" ch. F/2000 BLW/10. TP 50#-200#. Show of gas last 2 hrs. Sh 3592 BLW. Flowing well.
- 8/26 TD 10,800' PB 9,600'. Mesa Verde pfs 9392-9538' (OA). Flwg to pits. Cleaning well after frac. 3/4" choke, TP 75-100#. F/200 BLW/24, short 4592 BLW. GV to wet to measure.
- 9/2 TD 10,800' PB 9,600' Mesa Verde pfs 9392-9538' OA. Open well. Made considerable sand. Decided to Co well thru 2-7/8" tubing. F 300 BLW/23 TP 100#, 2-3/4" choke GV-TWTM SH 3346 BLW.
- 9/6 TD 10,800' PB 9,600' Mesa Verde pfs 9392-9538' OA. Flwd. 583 BLW + 91 bbls condensate/96, 3/4" choke, GV 2,527 MM/24. GV was 3MM/24 on Friday PM. TP 300#. Short 2763 BLW. Last 24 hrs. F/110 BLW + 26 bbls condensate. Ran radio-active tracer survey. Log indicated tracer material from 9392' to 9500' or to top of sand fill-up.
- 9/7 T.D. 10,800' PB 9,600'. Mesa Verde pfs. 9392-9638' OA. Decided to fish pkr & run 2-3/8" tbg. for buildup tests. Killed well. Ran free point. Found pkr stuck @ 9282'. SWION. Prep to cut tbg. w/chemical cutter.
- 9/8 T.D. 10,800' PB 9,600'. Mesa Verde pfs. 9392-9638' OA. Applied 4000# pres to tbg. csg. annulus. Tbg parted 10 jts. above pkr. Now running impression block. Top of fish @8950'.
- 9/9 TD 10,800' PB 9,600' Mesa Verde pfs 9392-9538' OA. Ran impression block. Impression block indicated top of tbg collar was bent. Now replacing bad string of 2-7/8" tbg. w/string which has recently been tested. Top of fish @8950'.
- 9/12 T.D. 10,800' PB 9,600'. Mesa Verde pfs 9392-9538' OA. Picked up string of 2-7/8" tbg. Ran tbg. cutter. Went over fish 4". Could not latch on to fish. Now running washover shoe, overshot jars and 1 jt of wash-over pipe.
- 9/13 TD 10,800' PB 9,600'. Mesa Verde pfs 9392-9538' OA. Dressed top of fish latched on to tbg; jarred for 30". Believe pkr came loose. Coming out of hole & hope to have rec. pkr.
- 9/14 TD 10,800' PB 9,600'. Mesa Verde pfs 9392-9538'. Pulled out of hole w/fish pkr 6 jts. 2-7/8" tbg & pkr. Ran in hole w/tbg then ended & notched collar to 9037'. Reverse circulated to check circ. SWION. Prep to clean out sd over lower pfs. Will C.O. to 9600'.

AIV-7

PICEANCE CREEK UT #F31-16-
 10,600' Mesa Verde 136
 1126' FNL 1683' FEL
 NW/NE Sec. 13-25-97W
 Rio Blanco Co., Colo
 MOBIL - 100%
 10-3/4" @1540'
 7" @10,798'

- 9/15 TD 10,800', PB 9600'. Mesa Verde pfs 9397-9538'. Sh-
 down on account of rig repairs. Will start up this
 morning.
- 9/16 TD 10,800', PB 9600'. Mesa Verde pfs 9392-9538'. Clean-
 ed out sand from 9405-9425'. Stopped going. Pulled
 knotted collar. Recovered several small pieces of junk
 Running magnet.
- 9/21 TD 10,800', PB 9,600', Mesa Verde pfs. 9392'/
 9538'. Ran 2-3/8" tbg. Cleaned threads
 landed tbg at 9110'. Installed tree & SI
 overnight. Prep swab. Short 6000 BLW.
- 9/20 TD 10,800', PB 9600'. Mesa Verde pfs. 9392-9538'.
 Picked up 25 jts. of 2-3/8" tbg. Now cleaning scale
 from threads. Should have tbg. run today.
- 9/23 TD 10,800', PB 9600'. Mesa Verde pfs 9392-9538'. F/475 BLW
 24, CP 600 psi, TP 20 psi, open choke. GV 1.5 MMCFPD. FRL
 ran GR log. Indicated tracer sand @ 9387-9432' & 9503-9519'.
 Sh 5025 BLW. Continue to flow well.
- 9/26 T.D. 10,800', PB 9600'. Mesa Verde pfs. 9392-9538'.
 Running noise & temp logs. FRL tool is not func-
 tioning properly. GV 1.1 MM/24, open choke, TP 25#,
 CP 570#. F/885 BLW/72. Short 4140 BLW.
- 9/27 TD 10,800', PB 9600'. Mesa Verde pfs 9392-9538'. Ran
 Flo log. Flwd 24 hrs., TP 50#, CP 550#, open choke,
 GV 1.1 MMCF. Rec 135 BLW, sh 4005 BLW. Continue
 test.
- 9/28 TD 10,800', PB 9600'. Mesa Verde pfs 9392-9538'.
 Re-run noise & temp logs. Shut well in. Ran BHP
 bomb. Running buildup test. F/70 BLW/20, short
 3935 BLW. GV 1.1 MM/24.
- 9/29 T.D. 10,800', PB 9600', Mesa Verde pfs. 9392-9538'.
 Well is SI - 2-1/4 hr SITP 2405#, SICP 2300#, SIBHP
 3049#.
- 9/30 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'. Well
 is SI - 471/4 hr SITP 2440#, SICP 2550#, SIBHP 3236#.
- 10/3 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'. Well
 is SI - 119-1/4 hr. SITP 2590#, SICP 2600#, SIBHP
 3380#.
- 10/4 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'.
 Well is SI - 1431/4 hr SITP 2590#, SICP 2610#, SIBHP
 3390#.
- 10/5 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'.
 Well is SI - 167-1/4 hr. SITP 2610#, SICP 2650#, SIBHP
 3395#.
- 10/6 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'. Well is SI -
 191-1/4 hr SITP 2610#, SICP 2650#, SIBHP 3405#.
- 10/7 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'.
 Well is SI - 215-1/4 hr SITP 2600#, SICP 2650#.
 (9) SIBHP 3427#.
- 10/10 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'.
 Well is SI. No pressure readings this morning.
 Will open & flow test tomorrow.
- 10/11 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'.
 Well is SI. 311 hr SITP 2620#, SICP 2690#. Prep
 to open well & flow test. Will also run noise
 log.
- 10/12 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'.
 F/48BLW + 10 bbls condensate/21-1/2. GV 1.9
 MM/24, 1/2" choke. TP 390#, CP 1025#. Short
 3887 BLW.

AIV-8

PICEANCE CREEK UT #31-13G

10,600' Mesa Verde
1126' FNL, 1683' FEL
NW/NE Sec. 12-2S-97W
Rio Blanco Co., Colo.
Mobil - 100#
10-3/4" @1540'
7" @10,798'

- 10/13 TD 10,800' PB 9600 Mesa Verde pfs 9392-9538'.
F/116 BLW + 5 bbls condensate/24 hrs. GV 1.85
MM/24, TP 330#, CP 950#, 1/2" choke. Short
3771 BLW. Prep to run noise log.
- 10/14 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538'.
F/105 BLW + 19 bbls con 24. GV 1.7 MM/24. TP
330#. CP 925#, 1/2" ch. Sh 3666 BLW. Ran noise
logs. Int 9392-9432' indicates greatest amount
of gas entry. Will cont to flow.
- 10/17 TD 10,800' PB 9600' Mesa Verde pfs 9392-9538'.
F/256 BLW + 70 bbls condensate/72. GV 1.513 MM/24
TP 330#, CP 875#, 1/2" ch. sh 3410 BLW. MICR. P:
to kill well & pull BP @9600'.
- 10/18 TD 10,800' PB 9600'. Mesa Verde pfs 9392-9538'.
Kill well w/2 1/2 KCl wtr. Install BOPE. CO sand
from 9560'. Release BP @ 9600'. Moved BP to 9370
Pressure test to 6000# for 15". Swab well down t
3000'. Prep to pull 2-3/8" tbq & perforate.
- 10/19 TD 10,800' PB 9370'. Pulled 2-3/8" tbq. Pfd Mesa
Verde Zone #4 9254-9320' overall - 33 holes. Show
of gas. Ran tbq to 7000'. SWION. Will run tbq
break down.
- 10/20 TD 10,800' PB 9370'. Mesa Verde pfs 9254-9320'.
Landed tbq @9167' open ended. Treated above pfs
w/700 gals. KCl wtr + additives + 70 ball sealers
BD 5250-4750. Mx 6850#, Mn 4750, AIR 12 BPM, ISIP
1000#, 15" SIP 750#. Short 497 BLW. F/290 BLW/1
Short 207 BLW. Now flowing well. GV 250 MCF/24,
open choke, TP 30#, CP 440#.
- 10/21 TD 10,800' PB 9370'. Mesa Verde pfs. 9254-9320'.
Short 185 BLW. F/22 BLW + 2 bbls condensate/24" c
GV 155 MCF/24, TP 40#, CP 290#. Will continue to
well. FRL will run noise log.
- 10/24 TD 10,800' PB 9370'. Mesa Verde pfs 9254-9320'.
FRL ran noise log. Gas coming from lower pfs.
SWI 5 PM 10/22/77. Ran BHP bomb. 37hr SICP 1355#
TP 1350#.
- 10/25 FRL monitoring BHP BOMB, tool not reading BHP.
61 HR SICP = 1480, SITP = 1474
- 10/26 TD 10,800' PB 9370'. Mesa Verde pfs 9254-9320'. FRL monit.
BHP bomb. 85-hr SITP 1755#, SICP 1650#.
- 10/27 TD 10,800' PB 9370'. Mesa Verde pfs 9254-9320'. BHP Bomb
hole 109- hr. SITP 1920# SICP 1850#.
- 10/28 TD 10,800' PB 9370'. Mesa Verde pfs. 9254-9320'.
133 hr. SITP 1680#, SICP 1960#, SIBHP 2562#. Will
run additional noise logs on Monday.
- 10/31 TD 10,800' PB 9370'. Mesa Verde pfs. 9254-9320'
229 hr SITP 2265#, SICP 2255#. Prep to pull BHP
bomb.
- 11/1 TD 10,800' PB 9370'. Mesa Verde pfs. 9254-9320'.
253 BHP, SITP 2286#, SICP 2320#. MICU today.
- 11/2 TD 10,800' PB 9370'. Mesa Verde pfs 9254-9320'.
FRL pulled BHP bomb. Bled well down. SWION.
- 11/3 TD 10,800' PB 9370'. Mesa Verde pfs 9254-9320'. M
Pulling unit. Kill well w/2 1/2 KCl wtr, ND wellhead.
BOPE, PU 7 jts. 2-3/8" tbq. Attempt to reverse cir
Ball off top of BP. Lost returns. No success re-
trieving BP. Started out of hole to check retrievi
head. SWION.
- 11/4 TD 10,800' PB 9370'. Mesa Verde pfs 9254'-9320'. R
retrieving head and sand pump. Cleaned out 2' of sa.
Pulling BP.
- 11/7 T.D. 10,800' PB 9225'. Mesa Verde pfs 9086-9124'.
BP. Ran scraper to 9400'. Set ret BP @9225'. Teste
plug to 6000# OK. S/2500. Pfd. 9086-9124' w/1 spf.
tbq to 9010'. SWION. Prep to break down.
- 11/8 TD 10,800' PB 9225. Mesa Verde pfs 9086-9124. BD Mesa Verde pfs w/2
bbls 2% KCl wtr + 58 ball sealers. BD 1900-1600#, Mx 7000#, Mn 1600#
Final 7000#, AIP 69.0W, AIR 12 BPM, ISIP 1600#, 2" 1400#, 15" 1100#.
Good ball action. Short 625 BLW. F/454 BLW + 1 BC/18 hrs. TP 50#, CP
3/4" choke. GV 186 MCFPD. Short 175 BLW. Continue to flow

AIV-9

PICARCEL CRLEK UT #F31-13G
 10,600' Mesa Verde
 1126' FNL 1683' FEL
 NW NE Sec. 12-2S-97W
 Rio Blanco Co., Colo.
 Mobil -100#
 10-3/4" @1640'
 7" @10,799'

GV 158 MCF/24. Short 1/2 BLW. Continue to flow.

11/10 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. F/8 BLW + 2 BC/24 hrs. 3/4" choke, TP 25-60#. CP 360#. GV 125 MCF/24. Short 120 BLW. Ran FRL noise logs. Prep to shut in for buildup pressure.

11/11 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. 18 hr SITP 960#, SICP 930#, SIBHP 1242#. F/2 BLW/6 hrs. 3/4" choke, TP 25-60#, CP 360#. GV 325 MCF/24. Short 118 BLW. Continuing to run buildup tests.

11/14 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. 90-hr SITP 1710#, SICP 1725#, SIBHP 2216#. Continuing to run buildup tests.

11/15 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. 114-hr SITP 1830#, SICP 1890#, SIBHP 2363#. Continuing to run buildup tests.

11/16 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. 138 hr. SITP 1890# SICP 1920#. Prep to pull BHP bomb.

11/17 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. Pulled BHP bomb. Will start pulling BPs when pulling UT is available. REMOVE FROM REPORT UNTIL PLUGS ARE REMOVED AND WELL IS TESTED.

11/28 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. MICU.

11/29 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. MIRU completion rig. Killed well w/2% KCL wtr. Installed BOP's. Pulling tbq. SWION.

11/30 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. Killed well w/2% KCL wtr. POH w/remainder of 2-7/8" tbq. GOH w/Ping washover shoe. Tag sd fill @ 9222'. Wash 3' to top of RBP. Pulling tbq.

12-1 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. POH w/tbg & washover shoe. RHP w/retrieving head. Washed over RBP @ 9225'. Could not latch to RBP. POH w/tbg. SWION. Prep to run overshot.

12/2 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. Pulling unit down for repair.

12/5 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. Repaired rig. Prep to start operations.

12/6 TD 10,800' PB 9225'. Mesa Verde pfs 9086-9124'. Finished running tbq. Circ hole clean. Rec BP @ 9225'. SWION. Prep to recover BP @ 10,539'.

12/7 TD 10,800' PB 10,539' Mesa Verde pfs 9086'/10,429'. Rn 2-3/8" tbq and retrieving head. Cleaned out sand from 10,525' to 10,539'. Latched onto Bridge Plug. Well kicked off. SWION. Prep to kill well and go in hole with retrieving tool.

12/8 TD 10,800' PB 10,539' Mesa Verde pfs 9086'/10,429'. Killed well - cond. fluid 6 hrs. SWION. Prep to Rec. BP.

12/9 TD 10,800' PB 10,539'. Mesa Verde pfs 9086'-10,429'. Ran retrieving tool. Latched on to BP. Well kicked off. Released BP. Prep to kill well & attempt to pull BP.

12/12 TD 10,800' PB 10,737'. Mesa Verde pfs 9086-10,680'. Recovered all BP. Ran notched collar. Tagged sand fill-up @ 10,605'. Prep to clean out.

12/13/77 TD 10,800' PB 10,732'. Mesa Verde pfs 9086-10,680'. Cleaned out sand from 10,605-10,732'. Pulled 5 jts. Prep to land tbq & install tree. REMOVE FROM REPORT UNTIL POTENTIAL TEST IS TAKEN.

Note: No formal drilling reports were issued after this date.