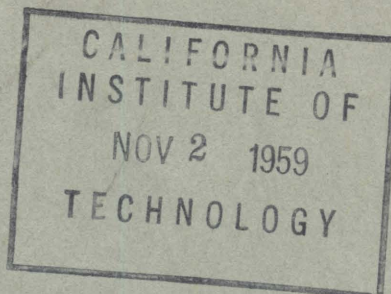


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RESERVOIR-OIL CHARACTERISTICS  
ANETH FIELD, SAN JUAN COUNTY, UTAH

BY R. F. ZAFFARANO, C. Q. CUPPS, AND J. FRY

United States Department of the Interior — 1959

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\* \* \* \* \* **Report of Investigations 5511**



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# RESERVOIR-OIL CHARACTERISTICS, ANETH FIELD, SAN JUAN COUNTY, UTAH<sup>1/</sup>

by

R. F. Zaffarano,<sup>2/</sup> C. Q. Cupps,<sup>3/</sup> and J. Fry<sup>2/</sup>

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## INTRODUCTION AND SUMMARY

Data presented on the physical characteristics of the reservoir oil, Aneth field, represent the initial phase of a study of Paradox basin reservoir oils being made by petroleum engineers of the Federal Bureau of Mines, Petroleum Research Center, Laramie, Wyo. The purpose of the study is to determine the original reservoir-oil characteristics in several important new discoveries in the Paradox Basin and to investigate correlations between the properties of these reservoir oils and structural or areal position within the basin.

If migration is limited and oil accumulates near its source, then it seems probable that few differences should be found in the composition and characteristics of reservoir oils occurring in given age rocks and within the confines of a geological basin. Within these limits, conditions that effected the formation of oil and its transfer from parent to storage rocks probably were rather uniform in an area the size of most of our geological basins. However, if oils should migrate considerable distances, it seems logical to expect that the relative quantities of gas and liquid components may differ in traps occurring along the direction of migration, corresponding with the theory of differential entrapment (5).<sup>4/</sup>

In the first instance, no consistent or uniform variation in the relative quantities of gas and liquid, and thus the pressure-volume-temperature (P-V-T) characteristics, should occur, as would be expected if oils were entrapped following a directional distant migration. On the other hand, a radial variation in composition and characteristics of reservoir oils from the central to boundary parts of a basin may occur as a result of changing character and thickness of source beds and limited migration of the oil.

It is hoped that the study of the physical characteristics of several reservoir oils in the Paradox basin may provide a better understanding

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<sup>1/</sup> Work on manuscript completed February 1959.

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<sup>4/</sup> Underlined numbers in parentheses refer to citations in the bibliography at the end of this report. Page references refer to pages in the citation and not in this report.

of the processes of origin, migration, and accumulation of oils. The study will also provide fundamental data on the reservoirs studied for present and future use in the engineering control of production to promote efficient recoveries of the Paradox-basin oils.

The data reported have been obtained from laboratory analyses of subsurface oil samples taken from five wells in the Aneth field. To these have been added analyses furnished by operating companies from two other wells. On the basis of these data, the average characteristics of the original reservoir oil have been determined. Data are also given on the composition of the associated gas and the crude-petroleum analyses of the produced oil. General information on the history, development, and geology of the area are given as background information.

Sampling programs also have been completed in the McElmo Creek, White Mesa, and Rutherford fields, which lie a few miles southeast and south of the Aneth field. The characteristics of the reservoir oils in these fields will be described in future reports.

#### ACKNOWLEDGMENTS

The Bureau of Mines wishes to acknowledge the wholehearted cooperation of the managements of Gulf Oil Corp., Shell Oil Co., The Superior Oil Company, and Texaco, Inc., for making wells available for this study and to their field personnel for assistance in arranging the field tests.

#### HISTORY AND DEVELOPMENT OF ANETH FIELD

The Aneth field, San Juan County, is in the southeastern corner of Utah, about 40 miles west of Cortez, Colo., and 20 miles southeast of Blanding, Utah. Aneth, the largest of several oilfields discovered in the Paradox basin in recent years, lies in the southern part of the Paradox basin, northwest of the San Juan basin, and northeast of the Black Mesa basin. All but a small section of the Aneth field lies within the Navajo Indian Reservation, as shown by the broken boundary line in figure 1. From the junction point of the Montezuma Creek and the San Juan River to the west, the river becomes the boundary line. Figure 1 locates the Aneth field in relation to the geographic Four Corners intersection and surrounding oilfields within the area.

Oil production in the Four Corners area of the Paradox basin dates back to 1908, when a well, Crossing No. 1, in sec. 7, T. 42 S., R. 19 E., was completed in the Rico formation near the settlement of Mexican Hat, Utah (3, p. 156). During the next 43 years sporadic wildcatting in the area resulted in a few discoveries of little significance. In 1951, Shell Oil Co. reported shows of oil in a wildcat well near Bluff, Utah. These reports helped to stimulate interest in the area and led to discovery of the Desert Creek field in November 1954.

The discovery well in the Aneth field was Texaco, Inc., Navajo C-1 in Center NW1/4 NE1/4, sec. 23, T. 40S., R. 24 E. This well was completed February 1956, for a natural flowing potential of 1,704 barrels of 43° API

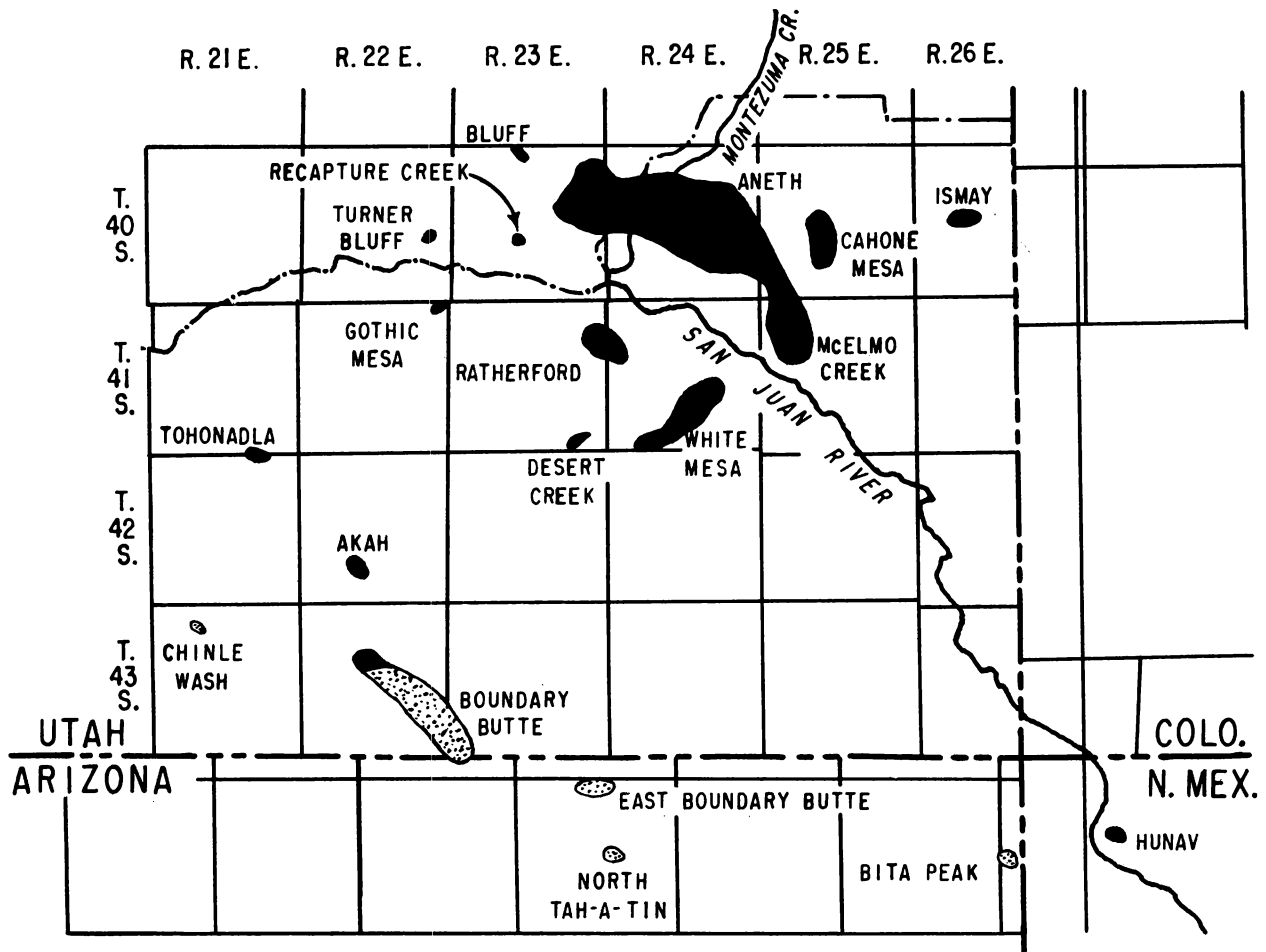


FIGURE 1. - Oil and Gas Fields, Four Corners Area.

gravity oil a day, through a 1-inch choke. Production is from the Paradox member of the Hermosa formation.

Terrain in this area of Utah is rough, strewn with rocks, and cut by canyons and washes. Drainage is toward the south to the San Juan River. Most field roads have been cut with bulldozers; they are extremely rough, and quickly turn into quagmires during wet weather, yet they must be depended upon to carry the large volume of traffic required to transport personnel and equipment to and from the field area.

Drilling in the Pennsylvanian formation in the Aneth field is relatively easy if a well-planned drilling program is used. Field transportation is a major problem because of poor road conditions. Water for drilling is either trucked from the San Juan River or supplied from junked holes that produce "gyp" water from 550 to 1,250 feet in depth (8, p. 154).

Most wells in the Aneth field have been treated with varying proportions of acid during completion. Normal field procedure is to set pipe through the

producing formation and perforate. Only a few open-hole completions have been made, and these are in the central part of the field. Oil strings are usually 5-1/2-inch or 7-inch casing.

Mud programs have varied; however, the use of water-base mud to 2,500 feet, then gyp-base, oil-emulsion mud to a total depth is the practice used by most operators. The use of oil-emulsion mud decreases mud cost and increases penetration rate and bit life. The cost of drilling and completing a development well in the Aneth field is about \$90,000.

In April 1958 the Aneth field contained over 120 producing wells within 17,280 proved acres and had produced 2,380,000 barrels of oil. The reservoir is being developed on 80-acre spacing.

During the 25 months after discovery of the Aneth field, 10 other fields were discovered in the surrounding area to the east, south, and west. From 1956 to 1958 most of the crude-oil output was moved from the Aneth field by truck to a railroad terminal at Thompson, Utah, and by rail to refineries in Salt Lake City, Utah. In May 1958 the Four Corners Pipeline Co. completed its 16-inch line to the Los Angeles area and began moving crude oil from the Paradox and San Juan basins at near capacity of 70,000 barrels a day. In late June 1958 the Texas-New Mexico Pipeline Co. completed its 16-inch crude-oil line, which connects with existing facilities near Jal, N. Mex. Initial capacity of the line is 50,000 barrels a day. The construction of these two pipelines has accelerated development and exploration activity in the basin, and this increased activity should continue over the next few years.

## THE ANETH RESERVOIR

### Structure

The Aneth-field structure (shown in fig. 2) is an elongated anticline with the axis trending west-northwest to east-southeast and with an indicated closure of less than 50 feet. The maximum closure in the productive area is about 150 feet, although this is not evident in figure 2, because individual well data used to construct the contour map are not shown. There is no evidence of faulting in the Aneth field. Dry holes have shown the probable productive limits of the field on all but the south flank.

### Stratigraphy

Oil production in the Aneth field is obtained from a vuggy, fossiliferous limestone in the Paradox member of the Hermosa formation. One or two wells have also been completed in the upper Hermosa member of the Hermosa formation, but production is limited. The relative position of these members within the Hermosa formation is shown on the stratigraphic classification chart in table 1 which was adapted from Herman and Barkell (6, p. 864). Oil production is attributed to both structure and stratigraphy but may be effected more by porosity development in the carbonate rocks. The Hermosa formation is of Pennsylvanian age and is divided into three members: (1) The lower Hermosa member, (2) Paradox member, and (3) upper Hermosa member. The lower Hermosa

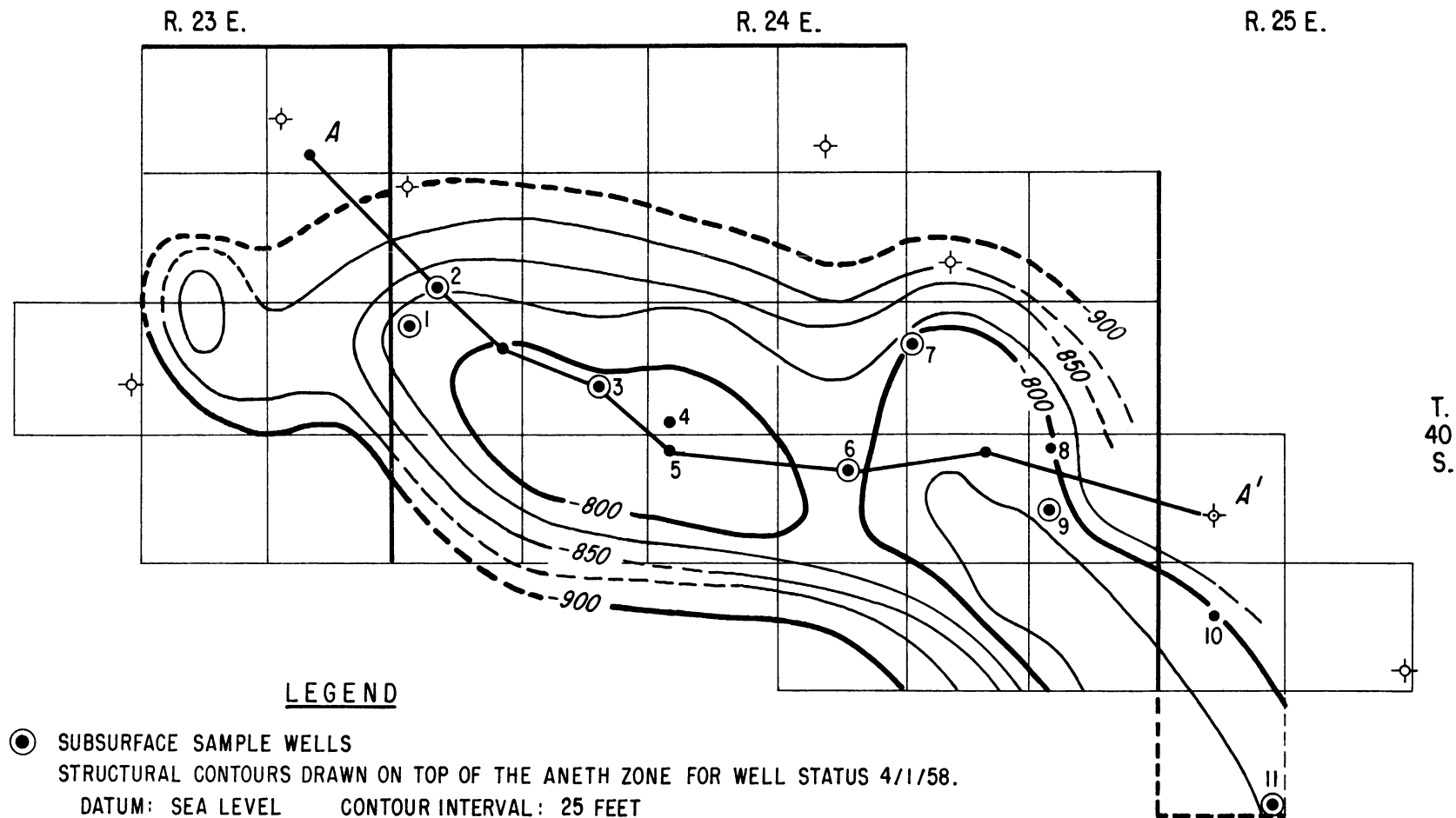


FIGURE 2. - Structure Contour Map of Aneth Field.



member is mainly a sequence of varicolored limestones interbedded with minor beds of green-gray shales and siltstones; this member has not proved productive within the field area. The Paradox member includes complex evaporitic sequences with minor carbonate and black-shale interbeds (6, p. 867). A zone in this member, known as the Ismay or Bluff (preferably Ismay) has produced only small amounts of oil from the Aneth field; however, in some of the surrounding fields this zone is the most important producer. The Ismay zone, composed of limestones and black-shale beds, overlies the Aneth zone and is separated from it by the Paradox shale.

TABLE 1. - Stratigraphic classification chart of southeastern Utah (6)

SYSTEM	SERIES	FORMATION	MEMBER
PERMIAN	WOLFCAMP	CUTLER	
PENNSYLVANIAN	VIRGIL	HERMOSA	UPPER HERMOSA  <div>(Ismay or Bluff zone)</div> <div>(Aneth or Desert Creek zone)</div> PARADOX  LOWER HERMOSA
	MISSOURI		
	DES MOINES		
	ATOKA	MOLAS	
	MORROW		
	SPRINGER		
CHESTER			
MERAMEC			
MISSISSIPPIAN	OSAGE	LEADVILLE	

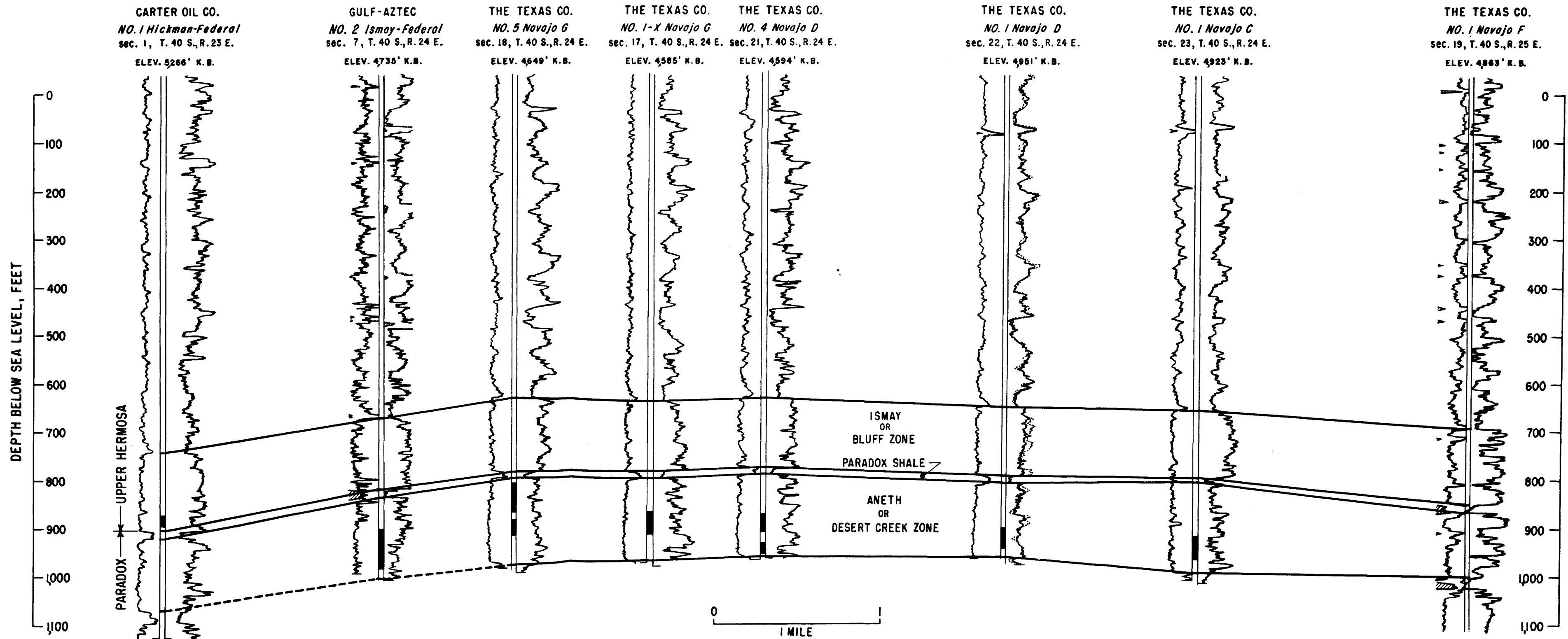


FIGURE 3. - Northwest-Southeast Correlation Cross Section of Aneth Field.

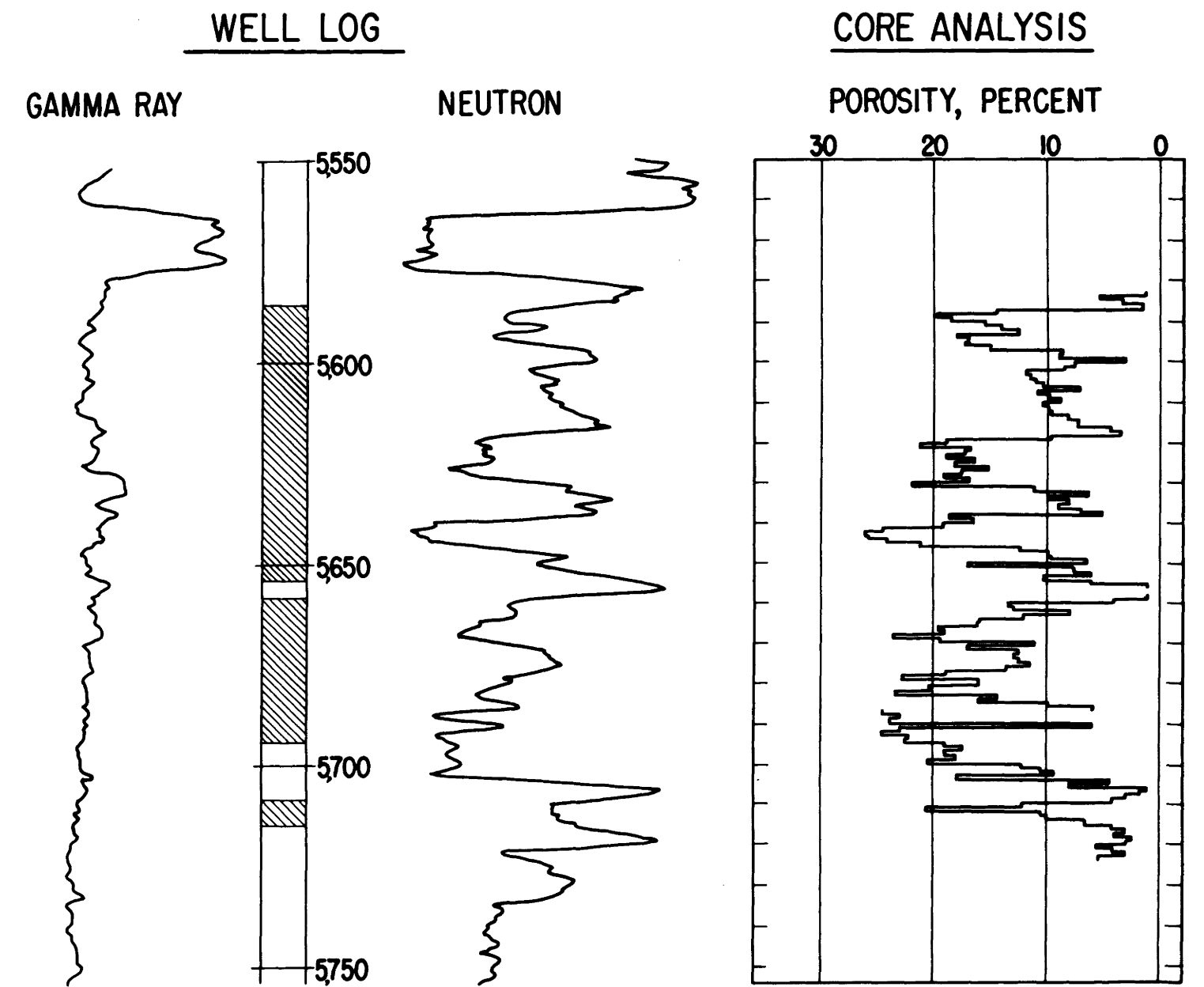


FIGURE 4. - Gamma Ray-Neutron Log and Core Analysis Correlation.

This study has been confined to oil from the Aneth zone of the Paradox member. A northwest-southeast cross section of the Aneth field (fig. 3) shows relative positions of the Ismay and Aneth zones, their thicknesses, and completed intervals as developed with gamma ray-neutron logs from eight wells across 8 miles of the structure. The cross section is identified in figure 2 by A-A'. The Aneth zone occurs at depths ranging from 5,600 to 5,800 feet and comprises both porous and nonporous carbonates with an average thickness of about 170 feet. The upper part is crystalline and vuggy; the lower part is a fossiliferous limestone. Developed porosity may be found at any level from the top to the bottom of the Aneth zone, but few of these porous zones can be followed for any appreciable distance across the field. Most initial completions were made near the lower part of the zone.

The detection and correlation of porous intervals in the Aneth zone are facilitated by the gamma ray-neutron log. A comparison of a gamma ray-neutron log and a porosity log, constructed from plug-core-analyses data, is shown in figure 4. These data were obtained from well 7, figure 2. A good correlation between values of porosity and values on the neutron curve at corresponding depths is evident. The calibration of neutron curves with porosity data permits use of the neutron curve to determine the porosity of uncored intervals. In well 7 porosity ranged from 1 to 26 percent and averaged 13.9 percent in the 110 feet of perforated interval. This interval is shown by crosshatching on the depth scale of the well log.

The Paradox shale, a consistent black-shale bed and a dependable geological marker separating the Aneth zone from the overlying Ismay zone, is characteristically shown by the well log between depths of approximately 5,560 and 5,580 feet. The thickness of the Paradox shale ranges from 6 to 17 feet in the cross section previously discussed. (See fig. 3.)

Little attention has been given to exploration for production below the Pennsylvanian formations. However, prospects for future development of production from the Mississippian system are considered good in view of successful completion of The Pure Oil Co.'s discovery well in the Big Flat field near Moab, Utah, in the northern part of the Paradox basin. This well was completed for an initial production of 319 barrels a day of 43° API gravity oil from the Mississippian.

#### WELL SAMPLING AND TESTING

The subsurface sampling program in the Aneth field was planned to provide samples from various parts of the reservoir along the major axis of the structure and known producing area. Specific wells were selected on the basis of location, availability for testing and sampling, performance, and production of water-free oil.

Sampling early in the life of a field provides the best opportunity for obtaining the most representative samples of original reservoir oil, as the decline in reservoir pressure is slight and has little effect on the oil. The period after discovery, when optimum sampling conditions may exist, can be extended where market outlets for the oil are slow in developing. This was

done in the Aneth field; however, the restricted production also posed problems in the selection of wells for the sampling program. Tank storage at many wells was inadequate to permit conditioning the wells for sampling at low flow rates, and production facilities were lacking at many wells that were in a shut-in status.

The first subsurface oil samples were obtained in April 1957 from wells 2, 3, and 6, about 13 months after discovery of the field. These and other sampled wells are identified by symbols in figure 2. Additional sampling was conducted October 1957 in wells 7 and 9 to provide data from the eastern end of the field. Attempts to obtain subsurface samples from wells 8, 10, and an additional well southeast of well 9 were prevented because of mechanical obstructions that prevented lowering the sampler in the tubing. Although samples were not obtained from this area, knowledge of the oil characteristics is provided by sample data from well 11 furnished by the operating company. This well is not within the producing area of the Aneth field, as defined by the Oil and Gas Conservation Commission of Utah; however, recent extensions to the proved productive area have indicated that well 11 produces from the same reservoir and that the sample data are representative of the oil in the southeastern part of the Aneth field. Sample data from well 1 were also furnished by the operating company and have been included in the study.

Procedures used in selecting and preparing wells for subsurface sampling and for obtaining samples were basically the same as those developed and reported in 1941 by Bureau of Mines engineers (4). Generally, when preparing a well for subsurface sampling, it is desirable to condition the well at the lowest rate of stable flow for enough time to remove oil near the well bore that had been affected by lower bottom-hole pressures on previous higher rates of flow. The minimum stable flow rates were not known for wells in the Aneth field, and their determination before the sampling tests was impractical. Thus, an arbitrary rate of 100 to 200 barrels a day for a period up to 2 weeks, depending on available tank space, was used in conditioning most of the wells. Where the conditioning flow period was necessarily short, the procedure was to bleed 100 to 150 p.s.i. off both the tubing and casing just before sampling to cause additional oil to flow into the well bore with only a slight drop in bottom-hole pressure. No attempt was made to evaluate the effectiveness of this means of improving sampling conditions. During the final 24 hours of the conditioning period, oil and gas production rates were measured with a Rolo well checker or with existing lease facilities. The bottom-hole flowing pressure and temperature were also measured.

After the conditioning period, each well was shut in approximately 24 hours; then the bleeding procedure was applied, and subsurface samples were taken. Shut-in pressure-depth traverses were used to locate fluid levels and select the lowest possible sampling point.

The subsurface sampler used in this study is self-closing for clock operation. The valves are locked in the open position, and the clock is set for a predetermined time before the sampler is lowered into the well. The volume of the sampler between valves is approximately 620 ml.



Duplicate samples were obtained from each well, as determined by tests of each sample before transfer to a storage cylinder. These tests, at atmospheric temperature, are for valve-opening pressure, saturation pressure, and volume compression of the sample during resaturation of evolved gas and compression of the sample to several hundred pounds per square inch above the saturation pressure. Where values of saturation pressure and volume compression for two samples from the same well agreed within 1 percent the samples were considered duplicates, and both were transferred to separate storage cylinders and brought to the laboratory for analysis. The tests were also useful in determining that each of the samples obtained was a single-phase liquid when the sampler valves closed and that leakage did not occur while the sampler was being brought to the surface. Thus, no samples can be considered faulty owing to sampler malfunction or trapping of extraneous gas or water during sampling.

Table 2 gives data on sampling and testing seven wells and on gas-oil ratio tests of two wells. By appraising these and other data relating to well conditions before sampling, during the conditioning period, and at time of sampling, the writers have concluded that the four samples from wells 1, 6, 9, and 11 are representative of the original reservoir oil. Three of these wells were sampled relatively soon after they were completed when well conditions were almost ideal for representative sampling of the reservoir fluid. Conditions were good in the fourth well because of its high productivity index, although considerable production had been taken from the area of this well. Samples from the other three wells represented reservoir oil that had undergone some degree of modification during flow from the formation into the well. The modification resulted from an evolution of solution gas from the oil while the bottom-hole flowing pressure was less than the original saturation pressure, followed by at least a partial re-solution of the evolved gas with buildup of pressure after the well was shut in. More detailed discussions of well conditions and the effects on quality of the samples are given in appendix III for each of the seven wells sampled.

The subsurface sample from well 7 is believed to represent only slightly modified reservoir oil, whereas the samples from wells 2 and 3 represent oil that had been modified to a greater degree. Therefore, none of the three samples indicates the saturation pressure of the original reservoir oil in the vicinity of the wells. The gas liberated from solution in the samples shows little change in composition in the first few hundred pounds per square inch below saturation pressure. Thus, the modification of the reservoir oil that occurred in sampling these wells may be thought of merely as a decrease in the saturation pressure of the oil. Moreover, these samples are considered to be representative of the physical properties and behavior of the reservoir oil at pressures equal to and below the sample saturation pressure.

TABLE 2. - Field data relating to well tests and subsurface sampling

Well No.	1	2	3	5	6	7	8	9	11
Sampling point elevation....feet	<u>1</u> /-666	-768	-873		-894	-899		-757	-930
Completion date.....	10-56	11-56	6-56	10-56	4-56	6-57	12-56	10-57	1-57
Preconditioning period:									
Flow rate, estimated ..... barrels per day	225	250	250-550	-	400-800	225	-	100-150	-
Conditioning period:									
Flow rate.....do.	-	182	248	471	266	223	232	150 (est.)	85
Length of flow test..... hours	-	-	46	-	-	-	-	-	144
Gas-oil ratio test..... do.	-	19	19	16	20	22	6	-	-
Minimum flowing pressure at sampling point..... p.s.i.a.	-	1,349	1,515	-	<u>2</u> /1,737	<u>3</u> /1,625	<u>4</u> /1,554	1,878	-
Gas-oil ratio ..cu.ft./bbl. stock tank oil <sup>5/</sup>	-	680	504	501	599	667	505	-	-
Average separator conditions:									
Pressure..... p.s.i.a.	-	60	82	81	71	57	105	-	-
Temperature..... °F.	-	60	61	70	59	70	67	-	-
Specific gravity of separator gas, air = 1.000.....	-	0.900	0.960	0.852	0.830	0.860	0.798	-	-
Sampling conditions:									
Duration of shut-in period....	6 days	76 hr.	27 hr.	-	54 hr.	14 days	-	( <u>6</u> /)	46 hr.
Static pressure prior to sampling..... p.s.i.a.	<u>7</u> /2,068	<u>7</u> /1,763	1,681	-	1,836	1,791	-	<u>6</u> /1,894	2,158
Date of sampling.....	11-56	4-57	4-57	-	4-57	10-57	-	10-57	3-57

<sup>1/</sup> Datum, sea level.<sup>2/</sup> Estimated from 15-hour drawdown, assumed stabilization in 45 hours.<sup>3/</sup> Flowing pressure during gas-oil ratio test following sampling.<sup>4/</sup> Measured at -953 ft. elevation.<sup>5/</sup> Gas volumes at 14.4 p.s.i.a. and 60° F.<sup>6/</sup> Well flowing.<sup>7/</sup> Calculated value.

Production gas-oil ratio tests of a few wells were included in the sampling program of April 1957. It was intended that these tests would be used to supplement the subsurface samples and permit a satisfactory coverage of the field with a minimum number of subsurface samples. However, because market outlets were limited, lease tanks of most of the wells sought for the gas-oil ratio tests were full, and the wells were not available for testing. Only two tests were made; these were on wells 5 and 8. The tests were made with a Rolo well checker, and the results are shown in table 2. The effort to obtain gas-oil ratio data was discontinued, and emphasis was placed on obtaining enough samples to provide the field coverage considered necessary for proper evaluation of the reservoir-oil characteristics of the large producing area.

During the April 1957 tests, static pressure and temperature measurements were also made in two wells for data on the initial reservoir conditions. Wells 1 and 4 had been shut in approximately 5 months before subsurface measurements. Pressures and temperatures were recorded at several depths in the tubing with Amerada-type gages lowered on a wire line. The effects of mud circulation during drilling of the wells and of limited production after completion probably were eliminated during this relatively long shut-in period. The temperature data are believed to be representative of true subsurface temperatures in the field area. The recorded pressures represent reservoir pressures around the wells at the time of measurements. Additional pressure data were obtained from measurements made in conjunction with preliminary testing of well 10 for sampling. These pressure and temperature data are presented and discussed in the following section on original reservoir conditions.

#### ORIGINAL RESERVOIR PRESSURE AND TEMPERATURE

Bottom-hole static pressures measured by other investigators in two wells in 1956 and those measured by the Federal Bureau of Mines in April and October 1957 are as follows:

Well	Location	Completion date	Shut-in time	Pressure at datum 900 feet below sea level, p.s.i.a.	Date test made
(1/)	Center NW1/4 NE1/4 sec. 23, T. 40 S., R. 24 E.	Feb. 20, 1956	102 hr.	2,173	(2/)
6	NW1/4 SW1/4 NE1/4 sec. 22, T. 40 S., R. 24 E.	Apr. 28, 1956	3/72 hr.	2,183	(2/)
1	Center NW1/4 NW1/4 sec. 18, T. 40 S., R. 24 E.	Oct. 1, 1956	5 mo.	2,146	Apr. 3, 1957
10	SE1/4 SE1/4 NW1/4 sec. 30, T. 40 S., R. 25 E.	May 23, 1957	do.	2,064	Oct. 16, 1957

1/ Texaco, Inc., Navajo C-1 discovery well.

2/ At time of completion. These data obtained from the transcript of the Aneth Spacing Hearing, Salt Lake City, Utah, Sept. 25, 1957.

3/ Exact shut-in time not known; company procedure required a minimum of 72 hours.

The pressure measurements in the first two wells were made about 2 months after the field was discovered and when less than 500 barrels of oil had been produced from the wells. Except for the effect of well completion and the limited production before the measurements were made, these pressures are approximately representative of the original reservoir pressure, which is estimated to be 2,200 p.s.i.a. at a datum of 900 feet below sea level. The measurements in wells 1 and 10 reflect the decline in reservoir pressure with production.

The subsurface-temperature curve (fig. 5) was constructed from temperature-elevation measurements taken from wells 1 and 4 with a subsurface-temperature-recording instrument. The curve is representative of subsurface temperatures in the Aneth field area. The temperature gradient is  $1.4^{\circ}$  F. per

hundred feet of depth, and the formation temperature 900 feet below sea level is  $133^{\circ}$  F.

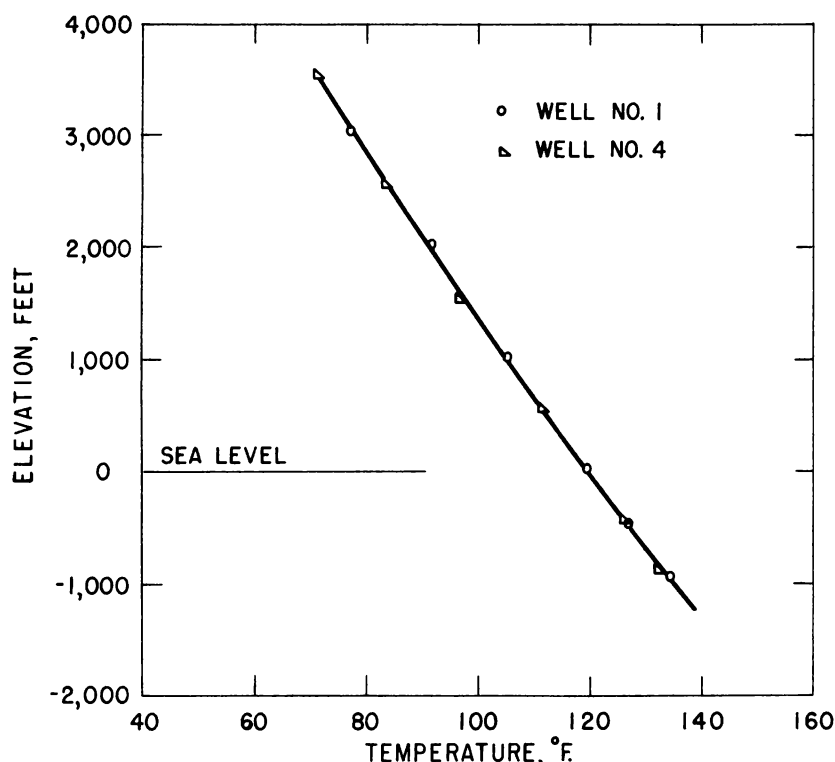


FIGURE 5. - Subsurface Temperature Gradient in Aneth Field.

Temperatures applied in the analysis of the subsurface samples were derived from maximum thermometer measurements in the sampled wells. These temperatures were corrected to the midpoint elevations of the perforated intervals and agree with the temperature-elevation curve (fig. 5).

#### LABORATORY ANALYSES

The two samples from each well were reexamined in the laboratory for saturation pressure at the field transfer temperature and, if found unchanged, were combined to avoid the minor dif-

ferences in values that often result when duplicate samples are analyzed separately. Combining the samples also provided enough sample for the extensive laboratory analyses.

The combined sample from each well was analyzed by several methods to determine its physical characteristics. These methods are differential liberation, flash liberation, pressure-volume-temperature relations, and pressure-viscosity relations. Procedures and equipment used for the first three are basically the same as those described in Federal Bureau of Mines Technical Paper 629 (4).

About 170 ml. of sample is used for the differential liberation. In this method a small gas space forms in the upper sight-gage section of the apparatus while the sample is being expanded at a constant weight to determine expansion properties and saturation pressure. Thereafter, the volume of the cell (and sample) is maintained constant, and gas is liberated from the top of the sight gage in several nearby equal pressure decrements until atmospheric pressure is reached. Shrinkage of the liquid and a corresponding increase in the gas volume are observed directly by measurement of the gas-oil interface in the sight gage. At each step in the process the saturation pressure of the oil is the cell pressure reached after a period of agitating the cell. The gas liberated during each step is collected and measured, and samples are taken for determining specific gravity and composition.

The differential-liberation analysis is made at the average formation temperature, determined from measurements in the well sampled. The changes in characteristics with pressure determined by this method are believed to approach those of the vaporization process that occurs in a reservoir with decline of reservoir pressure.

Differential-liberation data are given with pressure-viscosity data in tables 8 to 14, appendix I, for the seven sampled wells. Gas in solution, in cubic feet per barrel, is the ratio of the volume of gas liberated between an indicated pressure and atmospheric pressure to the volume of residual oil at 60° F. Specific gravity of gas in solution (with air = 1.000) is the specific gravity of the gas that is differentially liberated between an indicated pressure and atmospheric pressure. Relative oil volume is the volume of the liquid phase at an indicated pressure divided by the volume of the residual oil at 60° F. All gas volumes are corrected to 14.4 p.s.i.a. and 60° F.

Data for wells 1 and 11 were analyzed by other investigators and furnished by the operating companies for use in this study. It is recognized that data for wells 1 and 11 might have differed slightly if the samples had been analyzed in the Laramie laboratory because of differences in procedures and equipment and the low atmospheric pressure, 11 p.s.i.a., at Laramie. Where the data appeared to deviate appreciably from averages of data for the five samples analyzed by the Bureau of Mines, they were not included in estimating the original average reservoir-oil characteristics.

Pressure-viscosity relations were determined in a rolling-ball-type viscosimeter described by Hocott and Buckley (7). The determinations are made at formation temperature and various pressures from several hundred pounds per square inch above saturation pressure to atmospheric pressure. The values are in centistokes and are converted to centipoises by multiplying the values by the density at corresponding pressure, as determined with the differential liberation. Pressure is reduced in approximately equal decrements by bleeding part of the sample from the viscosimeter; thus, the method of vaporization of the sample in the cell corresponds closely to that during differential liberation. The viscosity of the residual oil at atmospheric pressure is determined with a modified Ostwald viscometer.



The viscosity-pressure relationship is the viscosity of the liquid phase in the reservoir at various reservoir pressures. The viscosity is minimum at saturation pressure and maximum at atmospheric pressure, where the oil is completely denuded of gas under the imposed conditions of the analysis.

Flash liberations were made on approximately 60 ml. of sample in a large-volume cell. The method consists essentially of expanding a constant weight of sample, at some pressure above saturation pressure and at formation temperature, to an average pressure and temperature as recorded at the field gas-oil separator. At these separator conditions the liquid and gas phases are brought into equilibrium, and the gas phase is transferred out of the cell at constant pressure. The remaining liquid phase is then expanded to atmospheric (equivalent stock-tank) conditions of 11 p.s.i.a. and 60° F., the liquid and gas phases are again brought to equilibrium, and the gas is transferred out of the cell.

Flash liberation approaches the vaporization process that occurs when oil flows up the tubing, through the flowline, and into the oil and gas separator, where the liquid and gas phases are separated under dynamic equilibrium conditions. Flash of the separator liquid represents the vaporization process between the field separator and the stock tank. Comparison of field-production gas-oil ratios with those obtained by flash liberation of a subsurface sample provides a means of detecting excessive gas production at the well or indicating the amount a subsurface oil sample may have been conditioned by a drop in bottom-hole pressure before sampling.

Flash-liberation data for samples from the seven wells are summarized in table 4, page 21. The values for gas in solution at saturation pressure and separator conditions equal the total volumes of gas liberated between these and stock-tank conditions. Data are shown as ratios of volume of gas per barrel of residual or equivalent stock-tank oil at 60° F. Differences between gas in solution at the saturation pressures and at separator conditions give production gas-oil ratios corresponding to field-production gas-oil ratios.

The formation volume factor is the relative volume of the oil at an indicated pressure and temperature divided by the volume of residual or equivalent stock-tank oil. It represents the volume that 1 barrel of stock-tank oil occupied in the reservoir when saturated with gas at the indicated pressure and temperature.

Pressure-volume relationships were determined on the samples from wells 2, 3, 6, 7, and 9 at several temperatures between 60° F. and formation temperature. The data are given in tables 15 to 19, appendix I. They were determined by stepwise expansions of approximately 65 ml. of a sample at a given temperature in a large-volume cell. The specific volume of each sample, at 2,500 p.s.i.a. and the indicated temperature, was determined separately in a pressure-density pycnometer, which has been described by Eilerts and others (2). These pressure-volume-temperature data are useful for determining the compressibility and thermal contraction properties of a reservoir oil.

The composition of the gas in solution was calculated from analyses of the gas liberated between each pressure step of the differential-liberation analysis. The liberated gas was analyzed by either a mass spectrometer or gas chromatograph. Tables 20 to 24, appendix I, show the data for composition of gas in solution. The value at a given pressure represents the composition of the gas that would be liberated, by the differential-liberation method, between that pressure and atmospheric pressure.

Composition of the gas in solution was derived similarly from the flash-liberation analyses, and the data are given in table 6, page 25.

## RESERVOIR-OIL CHARACTERISTICS

### Original Saturation Pressure

The average saturation pressure of the original reservoir oil in the Aneth zone is estimated to be 1,850 p.s.i.a. This estimate is based upon saturation pressures obtained from the sampling of wells 1, 6, 9, and 11. These samples, which are believed to be representative of the original reservoir oil in the vicinity of the wells, had saturation pressures of 1,816, 1,820, 1,875, and 1,745 p.s.i.a. Because of their locations, the first three wells represent the major part of the Aneth field. The saturation pressures of samples from wells 1 and 6 may be slightly less than that of the reservoir oil due to well conditions attending sampling, as discussed in appendix III. Thus, 1,850 p.s.i.a. is considered a realistic value for the average saturation pressure of the original reservoir oil in most of the Aneth field. The relatively low value of saturation pressure, 1,745 p.s.i.a., found for well 11 is believed to be due to a local condition existing in the extreme southeast extension of the field. It is also recognized that this lower saturation pressure may represent a change in characteristics of the reservoir oil between the major part of the Aneth field and the McElmo Creek field to the southeast, but additional data will be required to determine if this is so.

The available production gas-oil ratio data for wells in the Aneth field vary so widely that they are unreliable for quantitative evaluation of average solution gas-oil ratio of the reservoir oil. Reliable gas-oil ratio data should provide a check on the estimate made of the average saturation pressure. However, these production gas-oil ratios have not indicated any areas of low or high gas-oil ratio, which would be expected if the reservoir oil differed significantly in various parts of the field. That the reservoir oil is essentially the same throughout the field is illustrated more precisely by comparing the characteristics of the subsurface samples obtained from the field. Because of the similarity of the subsurface samples, values for the characteristics of the original reservoir oil have been obtained by averaging the data derived from the samples.

### Characteristics From Differential Liberations

Several graphs were prepared showing the variation of oil characteristics with pressure. Tables 8 to 14, in appendix I, give the basic data used to prepare these graphs. Smoothed curves were drawn through the data points and

extrapolated to the estimated average saturation pressure of the original reservoir oil, 1,850 p.s.i.a. From these curves, values were obtained for each oil characteristic at six pressures between atmospheric and saturation pressure. Averages of these values are given in table 3 and were used to construct the pressure-characteristic relations of the reservoir oil in figures 6, 7, and 8.

TABLE 3. - Characteristics of reservoir oil<sup>1/</sup>

Pressure, p.s.i.a.	Gas in solution, cu. ft./bbl. residual oil at 60° F. <sup>2/</sup>	Relative oil volume, residual oil volume at 60° F. = 1.000	Oil density, g./ml.	Specific gravity of gas in solution, (air = 1.000)	Viscosity, centipoises
2,200.....	-	1.383	0.6983	-	0.56
1,850 <sup>3/</sup> .....	726	1.388	.6955	0.940	.55
1,600.....	654	1.358	.7034	.975	.59
1,300.....	564	1.321	.7130	1.018	.66
1,000.....	469	1.280	.7231	1.076	.74
700.....	374	1.241	.7343	1.165	.84
400.....	277	1.199	.7464	1.306	.98
100.....	143	1.139	.7643	1.594	1.30
11.....	-	1.039	.7892	-	1.93
11 <sup>4/</sup> .....	-	-	.8204	-	-

<sup>1/</sup> Analysis temperature, 133° F.

<sup>2/</sup> Gas volumes at 14.4 p.s.i.a. and 60° F.

<sup>3/</sup> Saturation pressure.

<sup>4/</sup> Temperature, 60° F.

Figure 6 shows the variations in the volume and specific gravity of the gas in solution with pressure from the average original saturation pressure to atmospheric pressure. The average gas in solution at 1,850 p.s.i.a. is 726 cubic feet per barrel of residual oil at 60° F.; the specific gravity of this gas averages 0.940.

Figure 7 shows variations in relative oil volume and viscosity of the original oil with pressure. At the saturation pressure, relative oil volume is 1.388 barrels per barrel of residual oil at 60° F., and oil viscosity is 0.55 centipoise.

Figure 8 shows variations in oil density with pressure. At saturation pressure the oil density is 0.696 gram per milliliter. The shape and slope of the curves for density, relative oil volume, and viscosity above saturation pressure were drawn to correspond to averages of curves for the samples from wells 6 and 9, whose saturation pressures were close to the average original saturation pressure, 1,850 p.s.i.a.

#### Characteristics From Flash Liberations

Table 4 summarizes flash-liberation data for the seven wells. The average formation-volume factor of the original reservoir oil and its variation

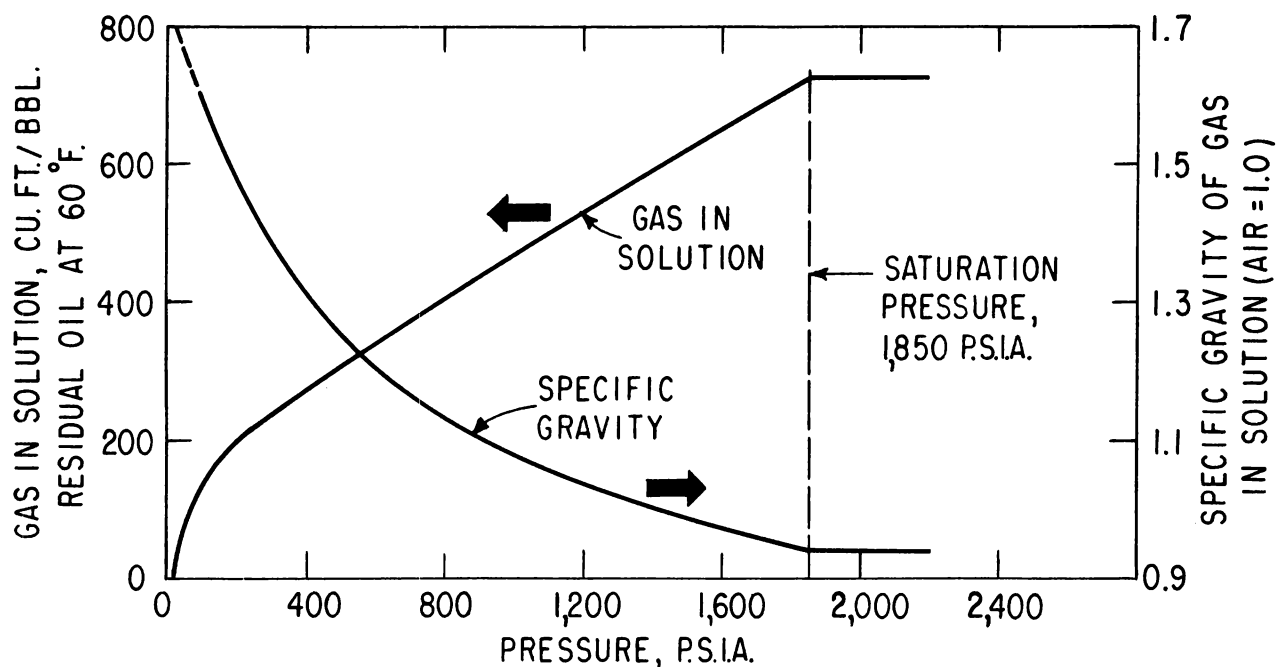


FIGURE 6. - Volume and Specific Gravity of Gas in Solution at 133° F.

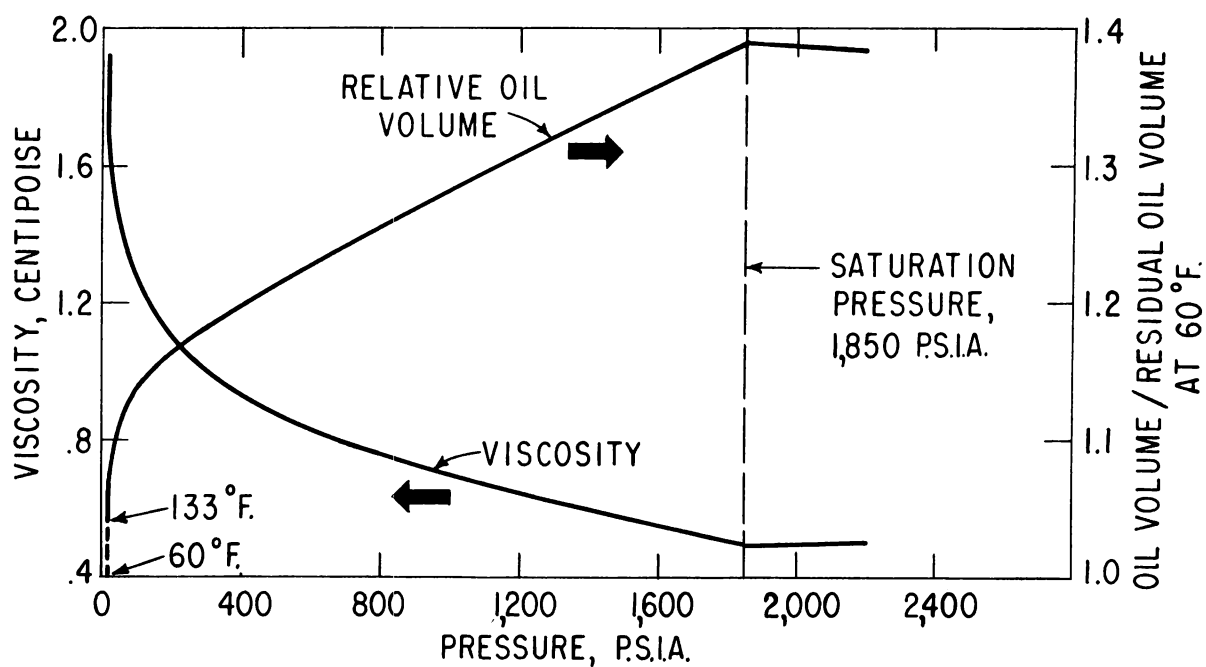


FIGURE 7. - Relative Oil Volume and Oil Viscosity at 133° F.

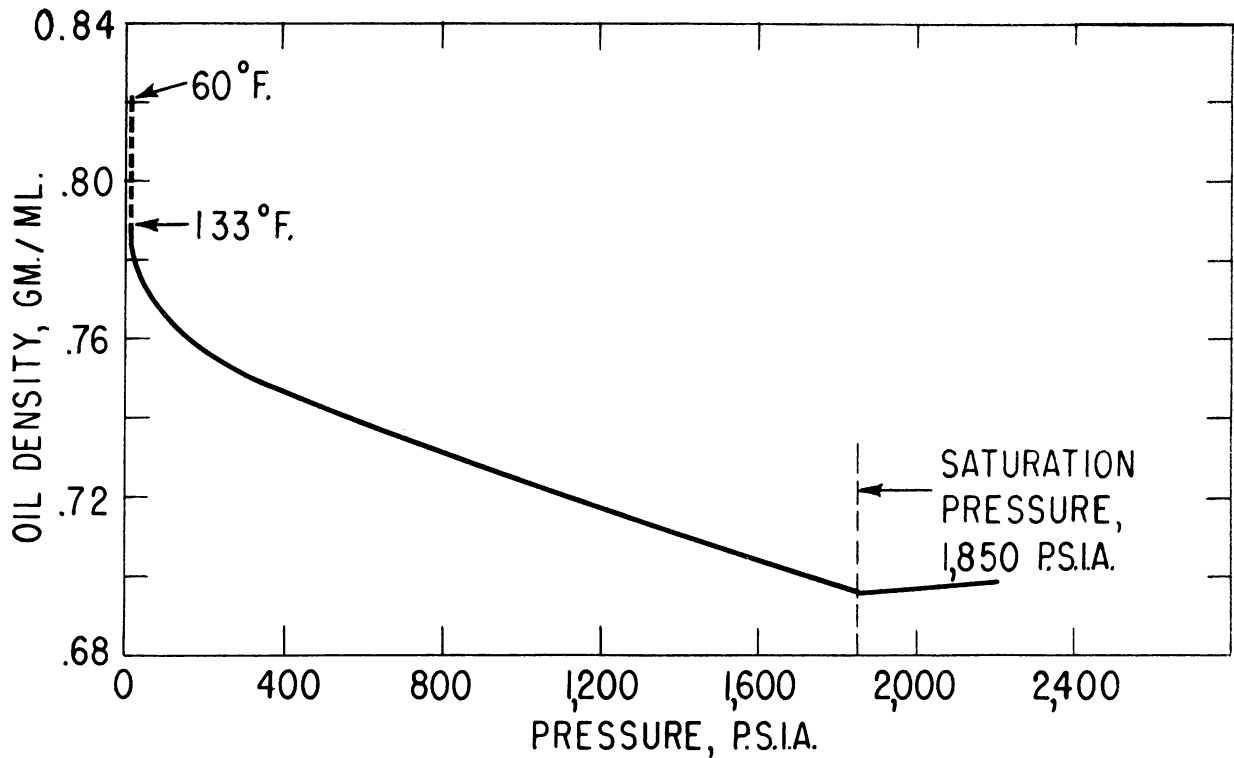


FIGURE 8. - Oil Density at 133° F.

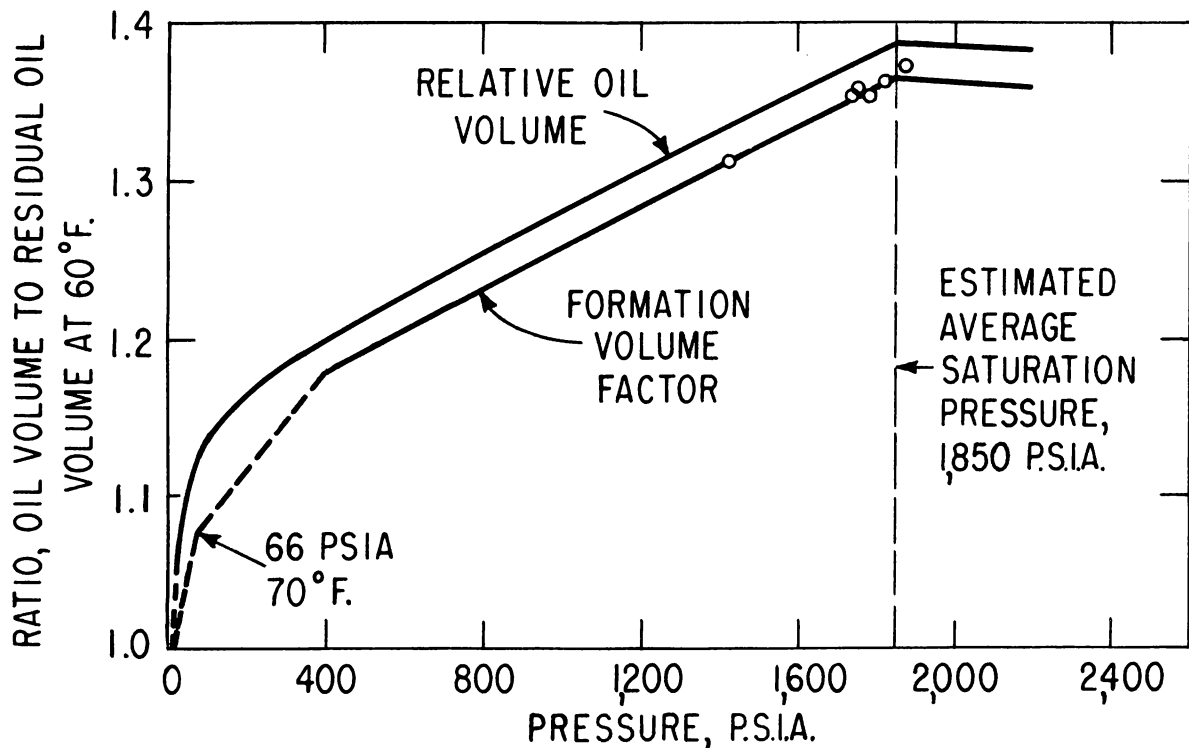


FIGURE 9. - Formation Volume Factor at 133° F.



with pressure is shown by the lower curve in figure 9. The upper curve in figure 9 gives relative oil volumes obtained from figure 7. The solid part of the formation-volume-factor curve was drawn so that the ratio between values on the curve to values at the same pressures on the relative-oil-volume curve equals 0.983. This ratio is the average value at saturation pressure as determined from flash and differential liberations of six subsurface samples.

The average formation-volume factor of the original reservoir oil is 1.365 barrels at 1,850 p.s.i.a. and 133° F. per barrel of stock-tank oil at 60° F. This applies to a two-stage separation of oil and gas at average separator conditions of 66 p.s.i.a. and 70° F. and stock-tank conditions of 11 p.s.i.a. and 60° F.

The dashed part of the formation-volume-factor curve (fig. 9) at pressures from 400 to 66 p.s.i.a. has little significance, except to indicate the effect of decreasing the temperature from 133° F. to the average separator temperature of 70° F. The remaining part of the curve, from 66 to 11 p.s.i.a., indicates the decrease in formation-volume factor resulting from the second-stage flash to stock-tank conditions.

TABLE 4. - Summary of flash-liberation analyses

Well No.....	1	2	3	6	7	9	11
Analysis temperature.....° F.	134	134	132	133	133	132	135
Average separator conditions:							
Pressure..... p.s.i.a.	64	60	83	71	57	80	54
Temperature.....° F.	77	60	60	60	70	60	100
Saturation pressure..... p.s.i.a.	1,816	1,740	1,420	1,820	1,785	1,875	1,745
Gas in solution, cu. ft./bbl. stock-tank oil:1/							
At saturation pressure.....	693	661	566	684	658	709	654
At separator conditions.....	52	66	96	70	47	86	46
Equivalent production gas-oil ratio ..... cu. ft./bbl. stock-tank oil	641	595	470	614	611	623	608
Formation volume factor, bbl./bbl. stock-tank oil:							
At 2,500 p.s.i.a.....		1.342	1.297	1.351	1.343	1.363	
At saturation pressure.....	1.363	1.354	1.311	1.361	1.353	1.373	1.355
At separator conditions.....		1.054	1.081	1.052	1.052	1.091	
Gravity of equivalent stock-tank oil..... °API	42.1	41.7	41.6	41.8	41.7	42.1	41.5
Specific gravity of gas in solution (air = 1.000):							
At saturation pressure.....	0.877	0.742	0.794	0.749	0.873	0.877	0.935
At separator conditions.....	1.389	1.397	1.351	1.342	1.351	1.389	1.386

1/ Gas volumes are at 14.4 p.s.i.a. and 60° F.; stock-tank oil is residual oil at 11 p.s.i.a. and 60° F.

The average production gas-oil ratio in the field should be about 624 cubic feet per barrel, as determined from the flash-liberation data in table 4. From a plot of total gas in solution against the sample saturation pressure, the volume of gas in solution in the average reservoir oil may be obtained; this amounts to 690 cubic feet per barrel. The average of the gas in solution at separator conditions is 66 cubic feet per barrel. The difference (690 - 66) gives the equivalent production gas-oil ratio of 624 cubic feet per barrel.

#### Pressure-Volume-Temperature Relationships

Pressure-volume data at 60°, 90°, 120°, and 133° F. for the average reservoir oil are given in table 5 and shown graphically in figure 10. These data were obtained by averaging data obtained from analysis of the subsurface samples from wells 6 and 9. These two samples were used because their saturation pressures were almost equal to the average original saturation pressure. The use of data obtained from the other samples would have involved considerable extrapolation to obtain data corresponding to the average original saturation pressure and higher pressures; this was considered unwarranted.

TABLE 5. - Pressure-volume-temperature relationships  
of the reservoir oil

60° F.		90° F.		120° F.		133° F. <sup>1/</sup>	
Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.
2,500	1.362	2,500	1.389	2,500	1.416	2,500	1.428
2,200	1.366	2,200	1.392	2,200	1.421	2,200	1.432
1,900	1.370	1,900	1.396	1,900	1.425	1,900	1.437
1,600	1.374	<sup>2/</sup> 1,625	1.400	<sup>2/</sup> 1,782	1.426	<sup>2/</sup> 1,850	1.438
1,475 <sup>2/</sup>	1.375	1,500	1.449	1,600	1.494	1,700	1.488
1,400	1.404	1,400	1.496	1,500	1.540	1,600	1.529
1,300	1.450	1,300	1.553	1,400	1.594	1,500	1.577
1,200	1.506	1,200	1.620	1,300	1.656	1,400	1.634
1,100	1.580	1,100	1.696	1,200	1.728	1,300	1.703

<sup>1/</sup> Reservoir temperature.

<sup>2/</sup> Saturation pressure at indicated temperature.

Average values of coefficients of isothermal expansibility and isobaric thermal contraction may be determined from the data given in table 5 and figure 10. The coefficient of isothermal expansibility is  $12.0 \times 10^{-6}$  barrel per barrel of reservoir oil at 2,200 p.s.i.a. and 133° F. per pound-per-square-inch decrease in pressure from 2,200 to 1,850 p.s.i.a. The coefficient of isobaric thermal contraction is  $6.3 \times 10^{-4}$  barrel per barrel of reservoir oil at 2,200 p.s.i.a. and 133° F. per degree decrease in temperature between 133° and 60° F.

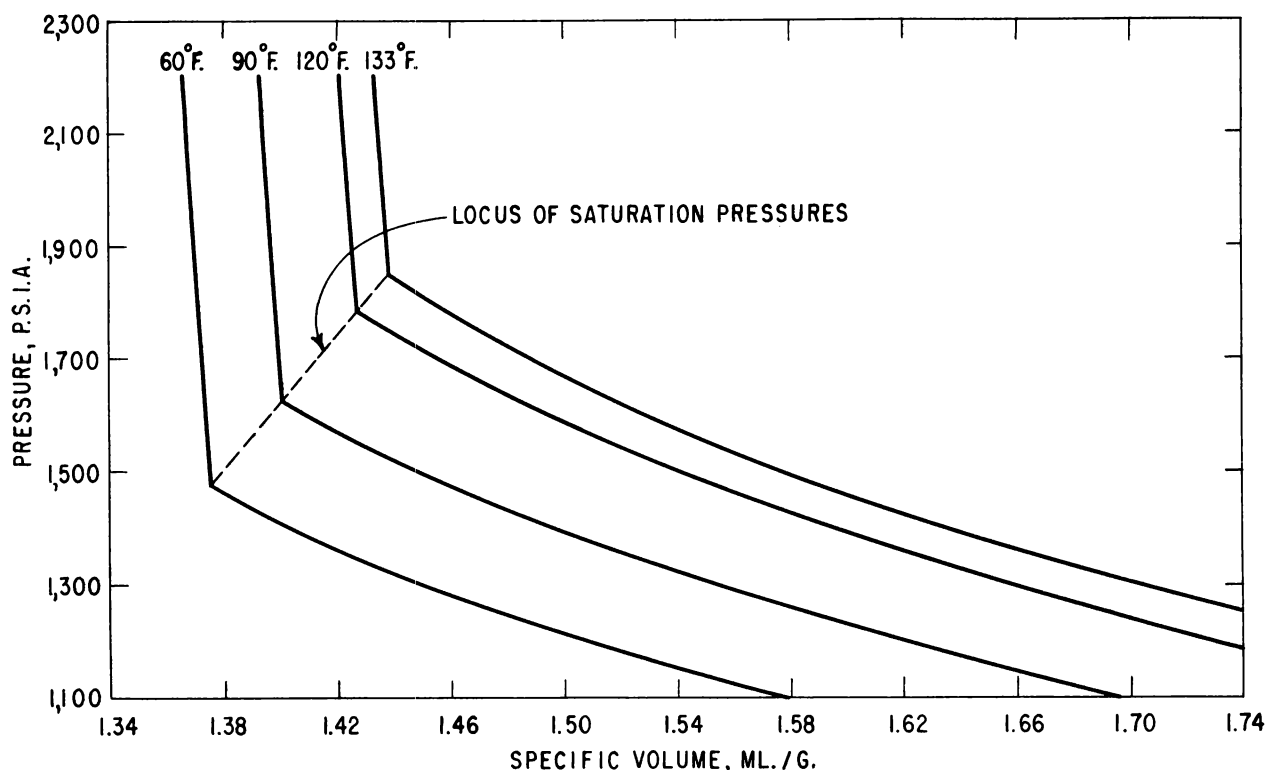


FIGURE 10. - Pressure-Volume-Temperature Relationships.

#### Oil-Gas Viscosity Ratio and Gas-Formation-Volume Factor

The oil-gas viscosity ratio and gas-formation-volume factor are two characteristics of a reservoir fluid system that have important effects on reservoir performance. Values of these characteristics at various pressures were calculated for the Aneth reservoir oil and are shown graphically in figure 11.

To determine the oil-gas viscosity ratio, the oil-viscosity data in table 3 and shown graphically in figure 7 were used. The gas-viscosity data were averages at several pressures of the viscosity of gas differentially liberated from solution in five subsurface oil samples. The viscosities of these liberated gases were determined from their specific gravities or composition, using correlations of Carr, Kobayashi, and Burrows (1). Specific gravity was used for samples from wells 6, 7, and 9 and composition for samples from wells 2 and 3.

The change in gas viscosity at reservoir temperature with decrease in pressure is considerably less than the change in oil viscosity; thus, the variation in the oil-gas viscosity ratio from 34.5 at 1,850 p.s.i.a. to 93.0 at 300 p.s.i.a. results principally from the increase in oil viscosity.

The gas-formation-volume factor is the volume that 1 cubic foot of gas at standard conditions, 14.4 p.s.i.a. and 60° F., will occupy at reservoir conditions; it is expressed in barrels and varies with pressure, as shown in figure

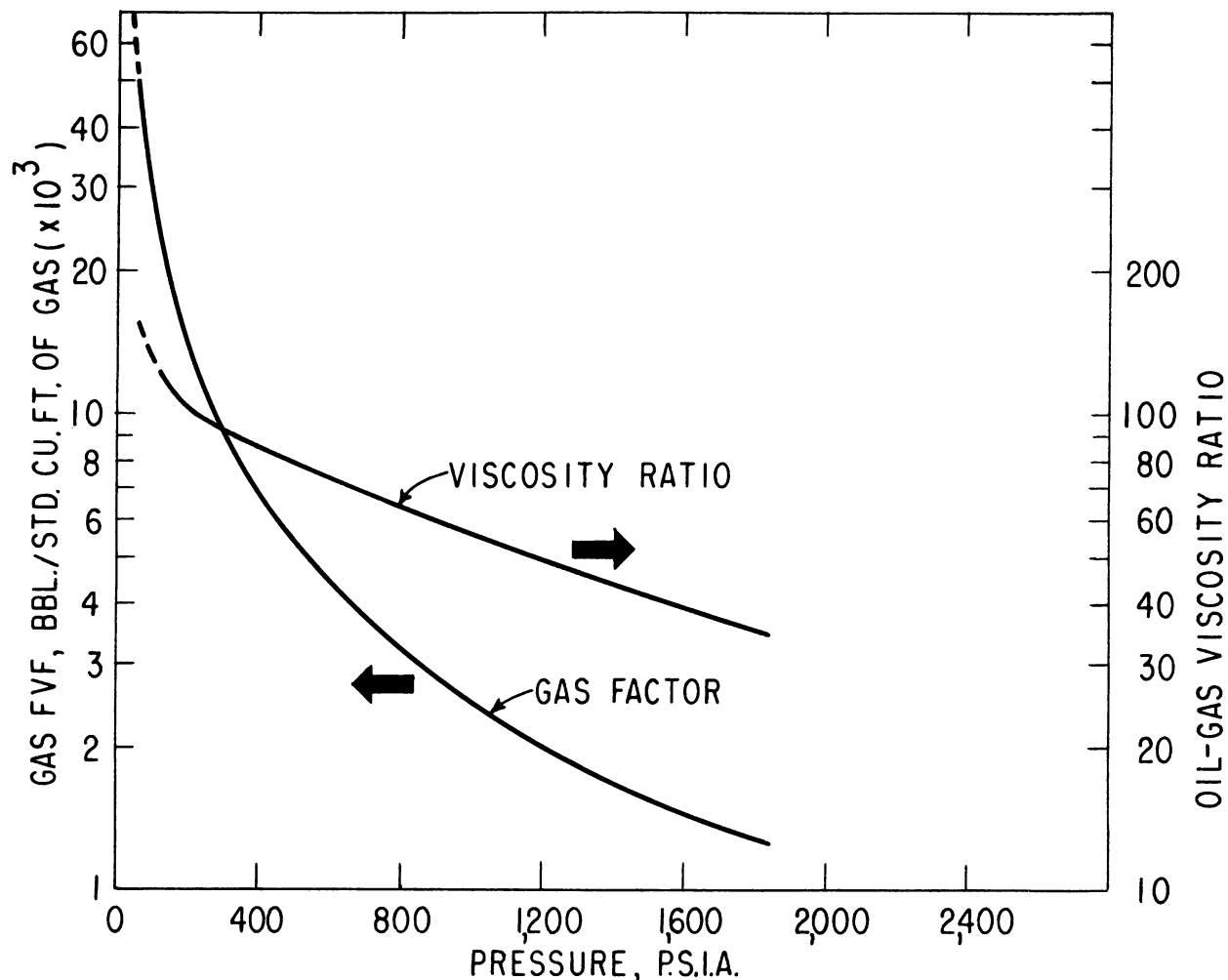


FIGURE 11. - Gas-Formation Volume Factor and Oil-Gas Viscosity Ratio.

11. The factor was determined from differential-liberation data for wells 2, 3, 6, 7, and 9. Data for wells 1 and 11 were not included in the determinations because of the appreciable differences between specific gravities of gas reported for these subsurface samples and the specific gravities obtained from the subsurface samples analyzed by the Bureau of Mines. The gas-formation-volume factor at the average original saturation pressure (1,850 p.s.i.a.) and reservoir temperature (133° F.) is  $1.24 \times 10^{-3}$  barrel per standard cubic foot of gas.

#### Composition of Produced and Solution Gas

The mole-percentages of hydrocarbon components in samples of produced gas from wells 2, 3, 5, 6, 7, and 8 ranged as follows: Methane 63.1 to 74.7, ethane 18.1 to 22.4, propane 5.1 to 10.7, butanes 1.6 to 4.4, and pentanes and heavier components 0.3 to 1.4. The compositions averaged methane 67.3,

ethane 20.4, propane 8.5, butanes 2.8, and pentanes and heavier components 0.7. Table 2 shows the production gas-oil ratios of these wells when the gas samples were collected; the ratios ranged from 501 to 680 cubic feet per barrel. The average of these ratios is 576 cubic feet per barrel. The liquefied-petroleum-gas (LPG) content for this average composition and average gas-oil ratio is 2.0 gallons per barrel of stock-tank oil, equivalent to 3.5 gallons per thousand cubic feet of separator gas.

Table 6 gives data comparable to produced-gas composition. These data were obtained from analysis of gas flash-liberated from subsurface oil samples. The average composition of gas liberated at separator conditions from the subsurface oil samples from wells 2, 6, 7, and 9 is 76.5 percent methane, 15.2 percent ethane, 5.9 percent propane, 1.8 percent butanes, and 0.6 percent pentanes and heavier components. The average equivalent production gas-oil ratio (table 4) for these four samples is 611 cubic feet per barrel. By converting the LPG components to liquid equivalents on the basis of the average composition and average equivalent production gas-oil ratio, the LPG content of separator gas is 1.49 gallons per barrel of stock-tank oil, or 2.4 gallons per thousand cubic feet of separator gas. Data for the subsurface sample from well 3 (table 6) were not included in the averages, owing to the low saturation pressure of the sample.

TABLE 6. - Summary of compositional analyses of flash-liberated gas

Well No.....	2	3	6	7 <sup>1/</sup>	9 <sup>1/</sup>
Average separator conditions:					
Pressure, p.s.i.a.....	60	82	71	57	80
Temperature, ° F.....	60	61	59	70	60
Composition of separator gas, mole-percent:					
Methane.....	78.1	82.4	81.9	70.4	75.4
Ethane.....	15.1	12.6	11.9	17.9	16.0
Propane.....	4.6	3.5	4.1	8.4	6.6
Butanes.....	1.5	1.0	1.4	2.7	1.7
Pentanes.....	.4	.4	.6	.6	.3
Hexanes plus.....	.3	.1	.1	-	-
Composition of stock-tank gas, <sup>2/</sup> mole-percent:					
Methane.....	15.4	14.1	10.6	20.8	22.2
Ethane.....	30.5	32.8	22.4	29.8	30.2
Propane.....	34.2	33.6	34.7	32.0	31.5
Butanes.....	15.8	14.8	22.7	14.1	13.2
Pentanes.....	3.7	3.8	7.9	3.0	3.0
Hexanes plus.....	.6	.8	1.6	.4	-

<sup>1/</sup> Analyses by gas chromatograph; all others by mass spectrometer.

<sup>2/</sup> Gas liberated between separator pressure and atmospheric pressure (11 p.s.i.a.) at separator temperature.

The LPG content of gas produced from field separators during the early life of the field should average 2.4 to 3.5 gallons per thousand cubic feet of gas. The difference in LPG content obtained from produced-gas samples and

from similar gas flash-liberated from subsurface oil samples may have been caused by inaccuracies resulting from the gas sampling. All produced-gas samples were taken from the sight gage on the separator of the Rolo well checker. The gas port of the sight gage is only a few inches above the normal liquid level in the separator, where vapors rich in the heavier hydrocarbon gases probably would be present. It is suspected that these gas samples contain a higher content of the LPG components than they would if taken from a more remote point on the gas-outlet line. Later sampling has been done from a valve on the meter run.

The gas flash-liberated at separator conditions from the subsurface oil samples from wells 2, 3, and 6 was displaced from the cell and measured with a wet test meter. Samples of the gas were taken just ahead of the meter, immediately after the gas displacement was begun. If the gas in the flash-liberation cell was not completely mixed before displacement, the samples might contain too many light hydrocarbons and too few heavier hydrocarbons. It is indicated that this may have occurred by comparison of the separator gas compositions for wells 2, 3, and 6 (table 6) with those for wells 7 and 9. The gas liberated from the last two samples was collected and measured in a cylinder by mercury displacement, then sampled as a batch. The average LPG content of the gas flash-liberated from the subsurface oil samples from wells 7 and 9 is 2.9 gallons per thousand cubic feet of gas. Because the characteristics of these subsurface samples are very close to those of the average reservoir oil, their LPG content should be representative of average LPG content of separator gas produced in the field.

Samples of stock-tank vapors were not collected. However, the probable composition of stock-tank vapors may be determined from the composition of gas flash-liberated from subsurface oil samples between separator and stock-tank conditions. Table 6 gives these compositions for wells 2, 3, 6, 7, and 9. The average of these compositions is 16.6 percent methane, 29.1 percent ethane, 33.2 percent propane, 16.1 percent butanes, and 5.0 percent pentanes and heavier components. Corresponding stock-tank gas-oil ratios for these wells ranged from 47 to 96 cubic feet per barrel and averaged 73 cubic feet per barrel. The LPG content for this average composition and gas-oil ratio amounts to about 16 gallons per thousand cubic feet of gas; this is equivalent to about 1.2 gallons per barrel of stock-tank oil produced.

The composition of gas differentially liberated from the subsurface oil samples differs noticeably from that of gas flash-liberated, owing somewhat to inherent differences in the two processes but mostly to the large difference in temperature of the two analyses. Differential liberations are made at reservoir temperature, whereas flash liberations are made at separator temperature. The probable variation in the composition of gas in solution in the reservoir oil with pressure is shown in figure 12. The data were obtained from the differential liberation of the sample from well 6. This relationship between gas composition and pressure may be considered representative of that of the average reservoir oil in the Aneth field, because the sample from well 6 closely approaches the average reservoir oil in most of its characteristics and properties. Figure 10, page 23, shows quantities of the various components of the gas in solution relative to the total gas in solution. From saturation

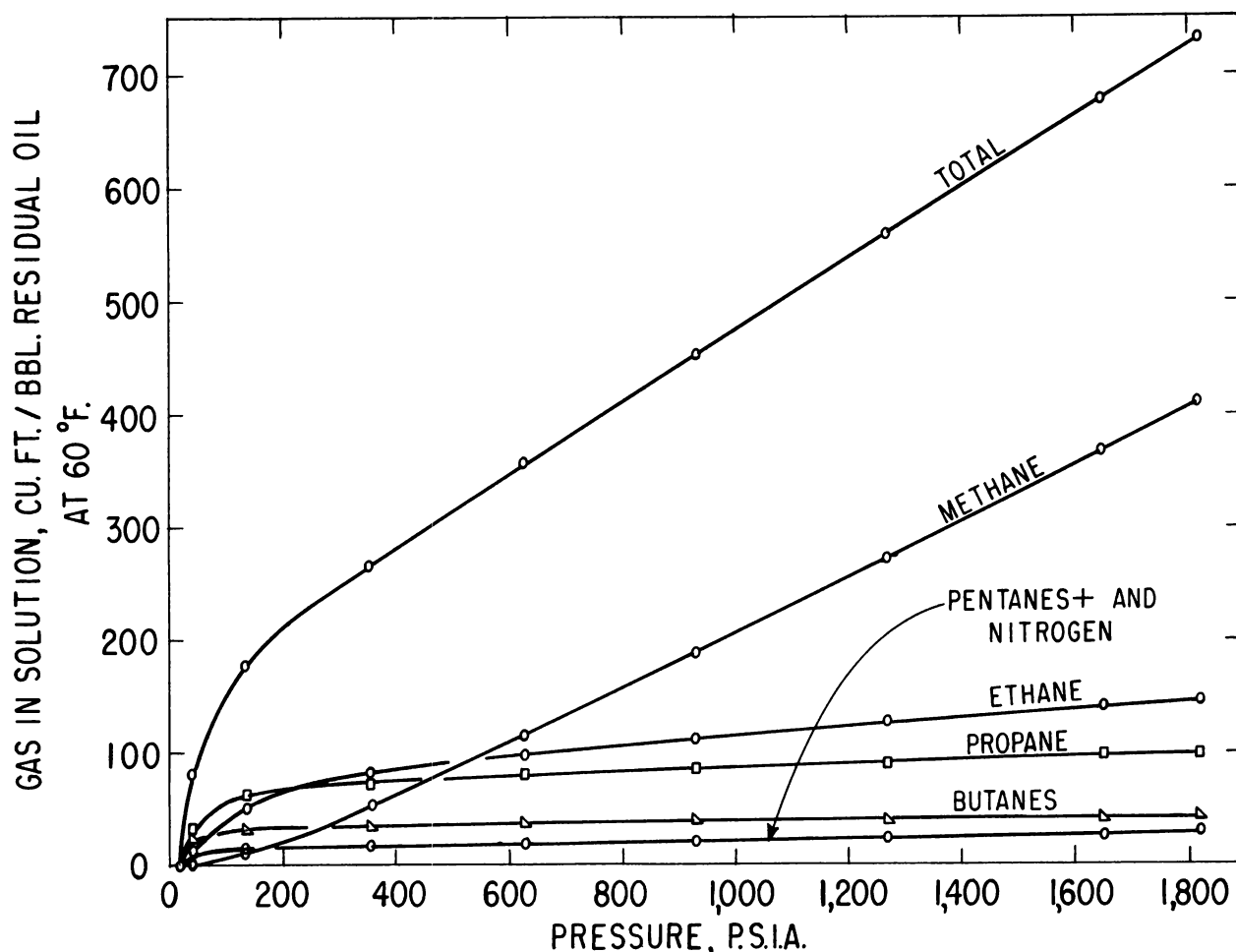


FIGURE 12. - Composition of Gas in Solution, Well 6.

pressure (1,820 p.s.i.a.) to pressures near 300 p.s.i.a., the change in total gas in solution results almost entirely from the change in volume of methane in solution. Thus, gas liberated from oil within the reservoir, with pressures in this range, will be composed principally of methane gas. Effects of the liberation of higher boiling components of the gas in solution become more and more noticeable as the pressure is reduced further and approaches atmospheric. Moreover, much of the propane and heavier gaseous components will remain in solution in the unrecoverable reservoir oil unless the reservoir pressure at abandonment approaches a pressure near or less than 100 p.s.i.a.

#### CRUDE-PETROLEUM ANALYSES OF PRODUCED OIL

Table 7 summarizes Bureau of Mines crude-petroleum analyses of crude oils from seven wells in the Aneth field. Similar analyses of crude oils from the Ashley Valley, Dove Creek, and Rangely fields are included for comparisons. All of these fields produce from formations of Pennsylvanian age in the Paradox and Uinta basins of Colorado and Utah. A correlation-index pattern for these

oils is shown in figure 13. Tables 25 through 30, appendix II give individual analysis results for items 2 through 7, table 7; these items correspond to wells 2, 3, 5, 6, 8, and 7, respectively.

TABLE 7. - Summary of crude-petroleum analyses of Pennsylvanian oils from Paradox and Uinta basins

Item	Company	Well	Field	Grav- ity, °API	Viscosity at 100° F., S.U. Ss.	Pour- point, ° F.	Sulfur, weight- percent	Nitrogen, weight- percent
1..	Texaco, Inc.	Navajo C-1	Aneth	41.3	37	10	0.11	0.042
2..	Gulf-Aztec	Ismay- Federal-2	do.	41.5	38	15	.02	.041
3..	Texaco, Inc.	Navajo G-1-X	do.	41.3	36	10	.03	.035
4..	do.	Navajo D-4	do.	41.5	37	10	.03	.035
5..	do.	Navajo D-1	do.	41.7	37	35	.05	.044
6..	do.	Navajo C-5	do.	42.1	37	10	.02	.040
7..	The Superior Oil Co.	Navajo A-6	do.	41.5	35	10	.13	.040
8..	H.B.R. Drilling Co.	Eva Marr No. 1	Dove Creek	48.5	34	30	<.10	.003
9..	Byrd-Frost- Western Natural Gas & P.B. English	White Federal No. 1	do.	43.8	36	25	<.10	.010
10..	Western Natural Gas	Driscoll No. 1	do.	63.4	32	<5	<.10	.000
11..	Pan American Petroleum Co.	M.C. Hagood A-2	Rangely	33.2	47	5	.85	-
12..	do.	U.S.A. Stanolind well 4	Ashley Valley	30.8	61	15	.83	.134

The correlation index (C.I.) is a number whose magnitude indicates types of hydrocarbons present in a crude-oil distillation fraction. The index system is based upon the average boiling points and specific gravities of the analysis fractions. It is so arranged that benzene has an index of 100, and the straight-chain paraffins have a C.I. value of 0.

The Aneth oils, bounded by lines 1 and 2 (fig. 13), are more naphthenic than the Dove Creek oils and slightly more paraffinic than the Ashley Valley or Rangely oils in the high-boiling range. The Aneth oils have a higher aromatic content in the gasoline range (analysis fractions 1-7) than Ashley Valley and Rangely oils. Although not evident from figure 13, the Aneth oils have gasoline contents ranging from 33 to 35 percent, whereas those of the Rangely and Ashley Valley oils range from 22 to 23 percent.



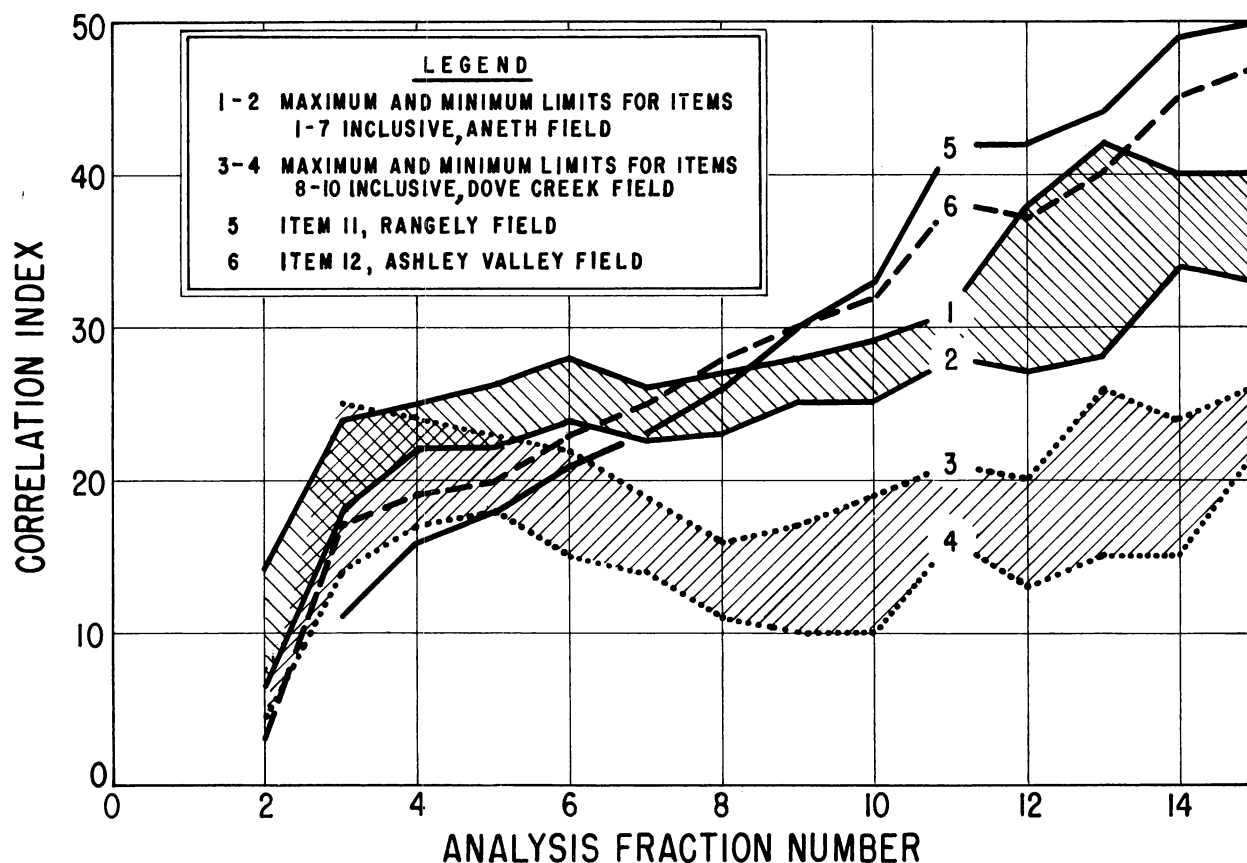


FIGURE 13. - Correlation-Index Pattern Representing Oil From Pennsylvanian Formations in Paradox and Uinta Basins.

The sulfur content of the Pennsylvanian oils from the Aneth field (items 1-7, table 7) range from 0.02 to 0.13 percent and average 0.06 percent. Aneth and Dove Creek oils, with sulfur percentages less than 0.50, are classified as low-sulfur oils. The Rangely and Ashley Valley oils have sulfur contents of 0.85 and 0.83; these are classified as high-sulfur oils.

The pourpoints of the Aneth oils range from 10° to 15° F. Item 5, table 7, shows a pourpoint of 35° F.; however, this value is probably not representative and may have been caused by wax accumulating in the Rolo well checker at the time the sample was taken. Items 8 and 9, table 7, have pourpoints of 30° and 25° F., possibly indicating the upper pourpoint limit expected in Pennsylvanian oils within the Paradox and Uinta basins.

An average of the values of nitrogen content shown for the Aneth oils in table 7 is 0.040 weight-percent. Because of its low nitrogen content, the Aneth oil should be desirable refining stock.

## CONCLUSIONS

Comparisons of the results of laboratory analyses of subsurface oil samples from seven wells in the Aneth field show that the physical characteristics of the oil in the Paradox-member oil reservoir have no significant variations either vertically or horizontally. Averages of the characteristics of these subsurface oil samples give representative values of the physical characteristics of the reservoir oil and show the changes in characteristics with pressure.

Indications are that the oil has an original saturation pressure of 1,850 p.s.i.a. at the reservoir temperature, 133° F., and is undersaturated by 350 p.s.i. at the initial reservoir pressure approximately 2,200 p.s.i.a.

At the saturation pressure, the oil contains 726 cubic feet of gas in solution per barrel of residual oil. It has a relative volume of 1.388 barrels per barrel of residual oil, and a viscosity of 0.55 centipoise. These properties relate to a differential liberation of gas.

From flash-liberation data, average production gas-oil ratio is indicated to be 624 cubic feet per barrel of stock-tank oil at average separator conditions of 66 p.s.i.a. and 70° F. The gravity of the stock-tank oil is about 42° API. The oil has a formation-volume factor at saturation pressure of 1.365 barrels per barrel of stock-tank oil.

Gas produced from separators in the field may contain about 2.9 gallons of LPG per thousand cubic feet of gas. Equivalent stock-tank vapors, flash-liberated from subsurface oil samples, indicate that the field stock-tank vapors will contain as much as 16 gallons of LPG per thousand cubic feet of gas.

The produced crude oil has a total gasoline and naphtha content of 33 to 35 percent, a relatively low pourpoint, and low sulfur and nitrogen contents. The crude oil should be desirable refining stock.

# APPENDIX I. - LABORATORY DATA

TABLE 8. - Differential-gas-liberation and pressure-viscosity data,  
subsurface oil sample from well 1<sup>1/</sup>

Differential gas liberation						Pressure-viscosity	
Pressure, p.s.i.a.	Expansion of sample, percent	Gas in solution, cu. ft./bbl. residual oil at 60° F. <sup>2/</sup>	Relative oil volume, residual oil volume at 60° F. = 1.000	Oil density, g./ml.	Specific gravity of gas in solution (air = 1.000)	Pressure, p.s.i.a.	Viscosity, centipoises
1,914,...	(3/)	726	1.388	(3/)	0.954	2,124	0.414
1,816 <sup>4/</sup> ..		726	1.390		.954	1,924	.409
1,614....		660	1.362		.978	<sup>4/</sup> 1,816	.405
1,401....		593	1.334		1.009	1,674	.441
1,167....		521	1.304		1.050	1,564	.463
922....		443	1.272		1.107	1,334	.505
683....		369	1.241		1.179	1,039	.574
449....		292	1.208		-	644	.702
248....		217	1.175		-	349	.847
136....		165	1.149		-	14	1.863
14... <sup>5/</sup>		0	1.037		-	-	-
14 <sup>5/</sup> ..		0	1.000		-	-	-

<sup>1/</sup> Analysis temperature, 134° F.

<sup>2/</sup> Gas volumes at 14.4 p.s.i.a. and 60° F.

<sup>3/</sup> Values were not available from the analysis provided by the operating company.

<sup>4/</sup> Saturation pressure.

<sup>5/</sup> Temperature, 60° F.

TABLE 9. - Differential-gas-liberation and pressure-viscosity data,  
subsurface oil sample from well 2<sup>1/</sup>

Differential gas liberation						Pressure-viscosity	
Pressure, p.s.i.a.	Expansion of sample, percent	Gas in solution, cu. ft./bbl. residual oil at 60° F. <sub>2/</sub>	Relative oil volume, residual oil volume at 60° F. = 1.000	Oil density, g./ml.	Specific gravity of gas in solution (air = 1.000)	Pressure, p.s.i.a.	Viscosity, centipoises
2,500....	0	715	1.374	0.7029	0.978	2,577	0.60
2,265....	.27	715	1.378	.7010	.978	2,339	.59
2,054....	.52	715	1.381	.6993	.978	2,067	.58
1,837....	.77	715	1.385	.6975	.978	<u>3/</u> 1,740	.56
1,740 <u>3/</u> ..	.88	715	1.386	.6968	.978	1,501	.61
1,729....	1.10	-	-	-	-	1,449	.62
1,719....	1.43	-	-	-	-	1,355	.64
1,693....	1.96	-	-	-	-	1,226	.67
1,665....	2.70	-	-	-	-	1,065	.72
1,624....	4.04	-	-	-	-	937	.76
1,557....	5.71	660	1.365	-	1.002	768	.82
1,273....	-	565	1.325	.7118	1.050	588	.90
947....	-	461	1.282	.7234	1.126	348	1.04
648....	-	370	1.244	.7342	1.224	168	1.20
379....	-	280	1.206	.7452	1.352	61	1.44
161....	-	192	1.166	.7568	1.550	11	2.01
47....	-	97	1.114	.7691	1.815	-	-
19....	-	30	1.068	.7800	1.970	-	-
11....	-	0	1.044	.7867	-	-	-
11 <u>4/</u> ..	-	0	1.000	.8210	-	-	-

1/ Analysis temperature, 134° F.

2/ Gas volumes at 14.4 p.s.i.a. and 60° F.

3/ Saturation pressure.

4/ Temperature, 60° F.

TABLE 10. - Differential-gas-liberation and pressure-viscosity data,  
subsurface oil sample from well 31/

Differential gas liberation						Pressure-viscosity	
Pressure, p.s.i.a.	Expansion of sample, percent	Gas in solution, cu. ft./bbl. residual oil at 60° F. <sup>2/</sup>	Relative oil volume, residual oil volume at 60° F. = 1.000	Oil density, g./ml.	Specific gravity of gas in solution (air = 1.000)	Pressure, p.s.i.a.	Viscosity, centipoises
2,500....	0	615	1.327	0.7163	1.013	2,765	0.68
2,265....	.23	615	1.330	.7147	1.013	2,380	.67
2,017....	.49	615	1.334	.7128	1.013	1,951	.65
1,786....	.74	615	1.337	.7110	1.013	1,506	.63
1,553....	.99	615	1.340	.7093	1.013	<sup>3/</sup> 1,420	.62
1,420 <sup>3/</sup> ..	1.13	615	1.342	.7083	1.013	1,399	.63
1,413....	1.30	-	-	-	-	1,310	.65
1,407....	1.72	-	-	-	-	1,178	.68
1,384....	2.37	-	-	-	-	985	.74
1,348....	3.68	-	-	-	-	731	.82
1,295....	5.63	578	1.329	-	1.030	491	.92
976....	-	475	1.287	.7221	1.100	292	1.03
669....	-	378	1.247	.7334	1.200	142	1.20
397....	-	287	1.209	.7444	1.313	11	1.95
171....	-	198	1.167	.7566	1.500	-	-
51....	-	103	1.114	.7708	1.770	-	-
31....	-	51	1.080	.7785	1.880	-	-
11....	-	0	1.041	.7884	-	-	-
11 <sup>4/</sup> ..	-	0	1.000	.8204	-	-	-

<sup>1/</sup> Analysis temperature, 132° F.

<sup>2/</sup> Gas volumes at 14.4 p.s.i.a. and 60° F.

<sup>3/</sup> Saturation pressure.

<sup>4/</sup> Temperature, 60° F.

TABLE 11. - Differential-gas-liberation and pressure-viscosity data,  
subsurface oil sample from well 61/

Differential gas liberation						Pressure-viscosity	
Pressure, p.s.i.a.	Expansion of sample, percent	Gas in solution, cu. ft./bbl. residual oil at 60° F. <sup>2/</sup>	Relative oil volume, residual oil volume at 60° F. = 1.000	Oil density, g./ml.	Specific gravity of gas in solution (air = 1.000)	Pressure, p.s.i.a.	Viscosity, centipoises
2,500....	0	723	1.381	0.7018	0.964	2,682	0.59
2,195....	.34	723	1.385	.6996	.964	2,403	.58
2,004....	.56	723	1.388	.6980	.964	2,134	.57
1,820 <sup>3/</sup> ...	.79	723	1.392	.6963	.964	1,860	.56
1,800....	1.27	-	-	-	-	<sup>3/</sup> 1,820	.56
1,774....	1.79	-	-	-	-	1,786	.57
1,749....	2.44	-	-	-	-	1,719	.58
1,704....	3.75	-	-	-	-	1,559	.60
1,649....	5.05	679	1.370	-	.983	1,330	.65
1,268....	-	558	1.320	.7142	1.041	1,039	.73
930....	-	453	1.276	.7261	1.114	705	.83
627....	-	358	1.236	.7376	1.216	424	.98
353....	-	267	1.197	.7490	1.353	226	1.11
134....	-	178	1.156	.7612	1.570	121	1.25
40....	-	81	1.099	.7758	1.800	66	1.34
11....	-	0	1.041	.7893	-	11	1.94
11 <sup>4/</sup> ...	-	0	1.000	.8215	-	-	-

1/ Analysis temperature, 133° F.

2/ Gas volumes at 14.4 p.s.i.a. and 60° F.

3/ Saturation pressure.

4/ Temperature, 60° F.

TABLE 12. - Differential-gas-liberation and pressure-viscosity data,  
subsurface oil sample from well 71/

Differential gas liberation						Pressure-viscosity	
Pressure, p.s.i.a.	Expansion of sample, percent	Gas in solution, cu. ft./bbl. residual oil at 60° F. <sup>2/</sup>	Relative oil volume, residual oil volume at 60° F. = 1,000	Oil density, g./ml.	Specific gravity of gas in solution (air = 1,000)	Pressure, p.s.i.a.	Viscosity, centipoises
2,500....	0	686	1.356	0.7058	0.934	2,691	0.60
2,275....	.23	686	1.359	.7042	.934	2,353	.59
2,056....	.47	686	1.362	.7025	.934	2,016	.58
1,872... <sup>3/</sup>	.69	686	1.365	.7010	.934	1,791	.57
1,785 <sup>3/</sup> ..	.81	686	1.367	.7002	.934	<u>3/</u> 1,785	.57
1,774....	1.01	-	-	-	-	1,705	.58
1,750....	1.42	-	-	-	-	1,465	.63
1,729....	1.90	-	-	-	-	1,177	.70
1,700....	2.68	-	-	-	-	892	.78
1,617....	4.93	637	1.348	-	.951	588	.90
1,237....	-	520	1.300	.7166	1.002	318	1.03
898....	-	417	1.258	.7281	1.072	122	1.23
590....	-	323	1.219	.7397	1.177	11	1.86
325....	-	234	1.181	.7511	1.322	-	-
122....	-	151	1.141	.7630	1.518	-	-
39....	-	68	1.092	.7760	1.700	-	-
11....	-	0	1.039	.7892	-	-	-
11 <sup>4/</sup> ..	-	0	1.000	.8202	-	-	-

1/ Analysis temperature, 133° F.

2/ Gas volumes at 14.4 p.s.i.a. and 60° F.

3/ Saturation pressure.

4/ Temperature, 60° F.

TABLE 13. - Differential-gas-liberation and pressure-viscosity data,  
subsurface oil sample from well 91/

Differential gas liberation						Pressure-viscosity	
Pressure, p.s.i.a.	Expansion of sample, percent	Gas in solution, cu. ft./bbl. residual oil at 60° F. <sup>2/</sup>	Relative oil volume, residual oil volume at 60° F. = 1,000	Oil density, g./ml.	Specific gravity of gas in solution (air = 1,000)	Pressure, p.s.i.a.	Viscosity, centipoises
2,500....	0	755	1.386	0.6991	0.939	2,770	0.58
2,325....	.19	755	1.388	.6977	.939	2,517	.57
2,115....	.44	755	1.392	.6960	.939	2,227	.56
1,907....	.69	755	1.395	.6943	.939	1,909	.55
1,875 <sup>3/</sup> ..	.74	755	1.396	.6940	.939	<sup>3/</sup> 1,875	.55
1,864....	1.07	-	-	-	-	1,846	.55
1,842....	1.50	-	-	-	-	1,635	.58
1,817....	2.03	-	-	-	-	1,231	.67
1,778....	2.92	-	-	-	-	977	.75
1,697....	5.04	699	1.373	-	.959	640	.86
1,317....	-	575	1.323	.7112	1.008	267	1.05
977....	-	467	1.279	.7232	1.070	92	1.25
671....	-	368	1.237	.7354	1.164	11	1.87
390....	-	276	1.198	.7465	1.294	-	-
160....	-	184	1.158	.7577	1.462	-	-
46....	-	84	1.104	.7712	1.692	-	-
11....	-	0	1.039	.7898	-	-	-
11 <sup>4/</sup> ..	-	0	1.000	.8209	-	-	-

<sup>1/</sup> Analysis temperature, 132° F.

<sup>2/</sup> Gas volumes at 14.4 p.s.i.a. and 60° F.

<sup>3/</sup> Saturation pressure.

<sup>4/</sup> Temperature, 60° F.



TABLE 14. - Differential-gas liberation and pressure-viscosity data,  
subsurface oil sample from well 111/

Differential gas liberation						Pressure-viscosity	
Pressure, p.s.i.a.	Expansion of sample, percent	Gas in solution, cu. ft./bbl. residual oil at 60° F. <sup>2/</sup>	Relative oil volume, residual oil volume at 60° F. = 1.000	Oil density, g./ml.	Specific gravity of gas in solution (air = 1.000)	Pressure, p.s.i.a.	Viscosity, centipoises
1,745 <sup>3/</sup> ..	(4/)	675	1.364	0.6997	0.933	2,214	0.470
1,541....		612	1.339	.7059	.955	1,914	.454
1,339....		552	1.313	.7128	.982	<sup>3/</sup> 1,745	.442
1,144....		494	1.289	.7193	1.013	1,614	.463
927....		428	1.262	.7265	1.057	1,414	.500
716....		364	1.235	.7343	1.117	1,114	.570
511....		299	1.208	.7419	1.193	714	.692
310....		230	1.178	.7508	1.302	414	.826
159....		167	1.147	.7595	1.426	14	1.932
96....		131	1.128	.7646	1.508	-	-
14....		0	1.037	.7896	-	-	-
14 <sup>5/</sup> ..		0	1.000	.8190	-	-	-

<sup>1/</sup> Analysis temperature, 135° F.

<sup>2/</sup> Gas volumes at 14.4 p.s.i.a. and 60° F.

<sup>3/</sup> Saturation pressure.

<sup>4/</sup> Values not available from the analysis provided by the operating company.

<sup>5/</sup> Temperature, 60° F.

TABLE 15. - Pressure-volume-temperature data, subsurface  
oil sample from well 2

60° F.		90° F.		120° F.		134° F. <sup>1/</sup>	
Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.
2,500	<sup>2/</sup> 1.357	2,500	<sup>2/</sup> 1.382	2,500	<sup>2/</sup> 1.409	2,500	<sup>2/</sup> 1.423
2,187	1.360	2,200	1.386	2,256	1.413	2,231	1.427
1,872	1.363	1,905	1.389	1,928	1.418	1,965	1.431
1,519	1.367	1,614	1.394	<sup>3/</sup> 1,671	1.422	1,768	1.434
1,368 <sup>3/</sup>	1.369	<sup>3/</sup> 1,520	1.395	1,631	1.431	<sup>3/</sup> 1,740	1.435
1,349	1.372	1,497	1.403	1,577	1.453	1,722	1.443
1,336	1.382	1,449	1.422	1,466	1.501	1,658	1.462
1,303	1.396	1,369	1.457	1,284	1.608	1,525	1.520
1,243	1.425	1,087	1.651	989	1.901	1,157	1.774
1,118	1.502	775	2.100	744	2.372	878	2.166
886	1.735	536	2.884	571	3.001	716	2.560
643	2.223	-	-	-	-	570	3.150
495	2.809	-	-	-	-	-	-

<sup>1/</sup> Reservoir temperature.

<sup>2/</sup> Determined with density pycnometer.

<sup>3/</sup> Saturation pressure at indicated temperature.

TABLE 16. - Pressure-volume-temperature data, subsurface  
oil sample from well 3

60° F.		90° F.		120° F.		134° F. <sup>1/</sup>	
Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.
2,500	<sup>2/</sup> 1.335	2,500	<sup>2/</sup> 1.358	2,500	<sup>2/</sup> 1.384	2,500	<sup>2/</sup> 1.396
2,193	1.338	2,150	1.362	2,149	1.388	2,201	1.400
1,885	1.341	1,858	1.366	1,819	1.393	1,881	1.404
1,578	1.344	1,472	1.371	1,487	1.397	1,569	1.409
1,194	1.348	<sup>3/</sup> 1,245	1.374	<sup>3/</sup> 1,366	1.399	<sup>3/</sup> 1,420	1.411
1,114 <sup>3/</sup>	1.349	1,238	1.377	1,346	1.407	1,405	1.417
1,088	1.360	1,196	1.394	1,308	1.423	1,367	1.434
1,060	1.376	1,154	1.418	1,262	1.448	1,326	1.454
1,022	1.401	1,091	1.459	1,217	1.477	1,255	1.495
947	1.462	975	1.558	1,136	1.532	1,156	1.563
844	1.627	808	1.764	896	1.780	948	1.770
705	1.771	569	2.322	680	2.194	643	2.392
525	2.245	-	-	528	2.713	499	3.016

<sup>1/</sup> Reservoir temperature.

<sup>2/</sup> Determined with density pycnometer.

<sup>3/</sup> Saturation pressure at indicated temperature.

TABLE 17. - Pressure-volume-temperature data, subsurface  
oil sample from well 6

60° F.		90° F.		120° F.		134° F. <sup>1/</sup>	
Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.
2,500	<sup>2/</sup> 1.360	2,500	<sup>2/</sup> 1.386	2,500	<sup>2/</sup> 1.413	2,500	<sup>2/</sup> 1.425
2,229	1.363	2,194	1.390	2,233	1.417	2,280	1.428
2,014	1.366	1,899	1.394	2,021	1.421	2,058	1.432
1,855	1.368	1,607	1.398	1,803	1.424	1,856	1.435
1,511	1.372	<sup>3/</sup> 1,598	1.398	<sup>3/</sup> 1,757	1.425	<sup>3/</sup> 1,820	1.436
1,448 <sup>3/</sup>	1.373	1,577	1.406	1,730	1.432	1,790	1.446
1,430	1.380	1,534	1.421	1,698	1.445	1,750	1.458
1,388	1.392	1,469	1.446	1,642	1.463	1,692	1.477
1,338	1.415	1,390	1.487	1,540	1.505	1,597	1.514
1,283	1.442	1,242	1.575	1,349	1.609	1,399	1.619
1,155	1.519	1,069	1.722	1,104	1.819	1,209	1.766
935	1.728	853	2.016	852	2.199	953	2.082
700	2.148	677	2.438	691	2.622	759	2.505
545	2.674	566	2.860	585	3.045	571	3.247

<sup>1/</sup> Reservoir temperature.

<sup>2/</sup> Determined with density pycnometer.

<sup>3/</sup> Saturation pressure at indicated temperature.

TABLE 18. - Pressure-volume-temperature data, subsurface  
oil sample from well 7

60° F.		90° F.		120° F.		134° F. <sup>1/</sup>	
Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.
2,500	<sup>2/</sup> 1.360	2,500	<sup>2/</sup> 1.376	2,500	<sup>2/</sup> 1.403	2,500	<sup>2/</sup> 1.417
2,235	1.364	2,226	1.379	-	-	2,280	1.420
2,007	1.367	1,987	1.382	-	-	2,059	1.423
1,745	1.370	1,697	1.386	-	-	1,810	1.427
1,475 <sup>3/</sup>	1.374	<sup>3/</sup> 1,565	1.388	-	-	<sup>3/</sup> 1,785	1.427
1,469	1.376	1,547	1.394	-	-	1,757	1.437
1,421	1.395	1,497	1.413	-	-	1,684	1.458
1,346	1.427	1,392	1.459	-	-	1,564	1.506
1,234	1.480	1,197	1.576	-	-	1,243	1.700
1,135	1.522	918	1.867	-	-	896	2.132
974	1.701	717	2.257	-	-	697	2.619
814	1.927	531	2.940	-	-	556	3.208
624	2.384	-	-	-	-	-	-
469	3.075	-	-	-	-	-	-

<sup>1/</sup> Reservoir temperature.

<sup>2/</sup> Determined with density pycnometer.

<sup>3/</sup> Saturation pressure at indicated temperature.

TABLE 19. - Pressure-volume-temperature data, subsurface  
oil sample from well 9

60° F.		90° F.		120° F.		134° F. <sup>1/</sup>	
Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.	Pressure, p.s.i.a.	Specific volume, ml./g.
2,500	<sup>2/</sup> 1.364	2,500	<sup>2/</sup> 1.391	2,500	<sup>2/</sup> 1.419	2,500	<sup>2/</sup> 1.430
2,256	1.368	2,241	1.395	-	-	2,290	1.434
2,006	1.371	2,009	1.398	-	-	2,100	1.437
1,761	1.374	1,815	1.400	-	-	1,923	1.440
1,505 <sup>3/</sup>	1.378	<sup>3/</sup> 1,653	1.402	-	-	<sup>3/</sup> 1,875	1.441
1,499	1.378	1,642	1.406	-	-	1,849	1.448
1,439	1.400	1,581	1.425	-	-	1,789	1.467
1,366	1.432	1,494	1.460	-	-	1,684	1.504
1,174	1.540	1,201	1.636	-	-	1,407	1.641
945	1.764	875	2.029	-	-	1,038	1.996
714	2.174	701	2.424	-	-	784	2.490
518	2.866	569	2.917	-	-	598	3.184

<sup>1/</sup> Reservoir temperature.

<sup>2/</sup> Determined with density pycnometer.

<sup>3/</sup> Saturation pressure at indicated temperature.

TABLE 20. - Composition of gas in solution, well 2

Pressure, p.s.i.a.	Volume percent <sup>1/</sup>						
	Methane	Ethane	Propane	Butanes	Pentanes	Hexanes +	Nitrogen
1,740 <sup>2/</sup> .....	56.6	21.1	13.3	6.3	2.0	0.6	0.1
1,557.....	54.3	21.9	14.2	6.7	2.1	.7	.1
1,273.....	49.9	23.5	15.8	7.6	2.4	.7	.1
947.....	43.1	26.0	18.3	9.0	2.8	.8	0
648.....	34.3	28.7	21.7	11.0	3.4	.9	0
379.....	23.0	31.6	26.4	13.6	4.3	1.1	0
161.....	9.0	32.1	33.2	18.2	6.1	1.4	0
47.....	.6	20.1	41.7	25.9	9.7	2.1	0
19.....	0	9.3	40.3	33.8	12.8	3.7	0

<sup>1/</sup> Calculated composition based on mass spectrometer analysis of gas differentially liberated at a temperature of 134° F. Each value shown for an indicated pressure is equivalent to composition of all gas liberated between that pressure and atmospheric pressure.

<sup>2/</sup> Saturation pressure of sample.

TABLE 21. - Composition of gas in solution, well 3

Pressure, p.s.i.a.	Volume percent <sup>1/</sup>					
	Methane	Ethane	Propane	Butanes	Pentanes	Hexanes +
1,420 <sup>2/</sup> .....	52.4	23.2	14.8	6.8	2.3	0.5
1,295 .....	50.4	23.9	15.5	7.2	2.4	.5
976 .....	43.9	26.4	18.0	8.4	2.7	.6
669 .....	35.0	29.3	21.4	10.2	3.2	.8
397 .....	24.0	32.4	25.8	12.7	4.1	1.0
171 .....	10.5	33.6	32.7	16.6	5.3	1.3
51 .....	.4	22.2	41.0	26.0	8.2	2.1
31 .....	0	15.1	48.3	21.1	12.1	3.4

<sup>1/</sup> Calculated composition based on mass spectrometer analysis of gas differentially liberated at a temperature of 132° F. Each value shown for an indicated pressure is equivalent to composition of all gas liberated between that pressure and atmospheric pressure.

<sup>2/</sup> Saturation pressure of sample.

TABLE 22. - Composition of gas in solution, well 6

Pressure, p.s.i.a.	Volume percent <sup>1/</sup>						
	Methane	Ethane	Propane	Butanes	Pentanes	Hexanes +	Nitrogen
1,820 <sup>2/</sup> .....	56.3	20.1	13.6	6.1	2.4	1.0	0.5
1,649 .....	54.3	20.7	14.4	6.5	2.6	1.0	.5
1,268 .....	48.6	22.7	16.5	7.6	2.9	1.2	.5
930 .....	41.6	25.0	19.3	9.0	3.4	1.4	.3
627 .....	32.4	27.8	23.0	11.0	4.0	1.6	.2
353 .....	20.3	30.5	28.1	13.9	5.1	2.0	.1
134 .....	7.5	28.6	35.7	18.7	6.8	2.7	0
40 .....	.3	16.8	41.7	27.4	9.8	4.0	0

<sup>1/</sup> Calculated composition based on mass spectrometer analysis of gas differentially liberated at a temperature of 133° F. Each value shown for an indicated pressure is equivalent to composition of all gas liberated between that pressure and atmospheric pressure.

<sup>2/</sup> Saturation pressure of sample.

TABLE 23. - Composition of gas in solution, well 7

Pressure, p.s.i.a.	Volume percent <sup>1/</sup>					
	Methane	Ethane	Propane	Butanes	Pentanes	Hexanes +
1,785 <sup>2/</sup> .....	65.1	17.9	11.2	4.4	1.3	0.2
1,617 .....	63.2	18.7	11.8	4.7	1.4	.2
1,237 .....	58.2	20.7	13.7	5.5	1.6	.2
898 .....	51.7	23.2	16.3	6.6	1.9	.3
590 .....	40.8	26.6	20.0	9.8	2.4	.4
325 .....	26.0	32.6	26.4	11.2	3.3	.5
122 .....	10.4	33.6	35.3	15.6	4.3	.7
39 .....	0	25.1	44.0	23.4	6.7	.9

<sup>1/</sup> Calculated composition based on gas chromatograph analysis of gas differentially liberated at a temperature of 133° F. Each value shown for an indicated pressure is equivalent to composition of all gas liberated between that pressure and atmospheric pressure.

<sup>2/</sup> Saturation pressure of sample.

TABLE 24. - Composition of gas in solution, well 9

Pressure, p.s.i.a.	Volume percent <sup>1/</sup>					
	Methane	Ethane	Propane	Butanes	Pentanes	Hexanes +
1,875 <sup>2/</sup> .....	63.2	18.9	11.6	4.8	1.3	0.2
1,697 .....	61.3	19.7	12.3	5.1	1.4	.2
1,317 .....	56.2	21.8	14.2	5.9	1.6	.2
977 .....	49.6	24.4	16.7	7.0	2.0	.3
671 .....	40.9	27.4	20.2	8.7	2.4	.4
390 .....	28.4	31.3	25.4	11.3	3.1	.5
160 .....	12.8	33.2	33.3	15.6	4.3	.7
46 .....	0	24.4	41.9	25.0	7.4	1.3

<sup>1/</sup> Calculated composition based on gas chromatograph analysis of gas differentially liberated at a temperature of 132° F. Each value shown for an indicated pressure is equivalent to composition of all gas liberated between that pressure and atmospheric pressure.

<sup>2/</sup> Saturation pressure of sample.

## APPENDIX II. - CRUDE-PETROLEUM ANALYSES OF PRODUCED-OIL SAMPLES

Crude-petroleum analyses are given for six samples of produced crude oil. Four of the samples were obtained from wells 2, 3, 6, and 7, from which sub-surface oil samples were taken. The other two samples were obtained in connection with gas-oil ratio tests made on wells 5 and 8. Figure 2, page 5 shows the location of these wells, and table 2, page 12 gives data pertinent to the tests made on the wells.

Bureau of Mines Laramie Laboratory  
Sample PC-57-88

IDENTIFICATION

Aneth field  
Paradox limestone (P<sub>2</sub> Pay) Well 2  
5,643-5,725 feet  
Utah  
San Juan County  
SE 1/4 SW 1/4 sec. 7,  
T. 40 S., R. 24 E.

GENERAL CHARACTERISTICS

Specific gravity, 0.818 A. P. I. gravity 41.5 ° Pour point, ° F. 15  
Sulfur, percent, less than 0.10 Color, green  
Saybolt Universal viscosity at 100° F., 38 sec.; at ° F., sec. Nitrogen, percent, 0.041

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.  
First drop, 28 ° C. (82 ° F.)

Fraction No.	° C.	° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	3.7	3.7	0.648	86.9				
2	75	167	2.7	6.4	682	76.0	13	54.9		
3	100	212	5.4	11.8	716	66.1	19	50.9		
4	125	257	6.7	18.5	741	59.5	22	49.2		
5	150	302	6.2	24.7	759	54.9	23	49.6		
6	175	347	6.7	31.4	778	50.4	25	51.5		
7	200	392	3.1	34.5	791	47.4	25	54.7		
8	225	437	4.6	39.1	801	45.2	24	60.7		
9	250	482	5.4	44.5	813	42.6	25	65.1		
10	275	527	6.5	51.0	824	40.2	25	69.2		

STAGE 2—Distillation continued at 40 mm. Hg.

11	200	392	6.0	57.0	0.839	37.2	28	77.3	40	15
12	225	437	6.1	63.1	843	36.4	27	82.9	46	35
13	250	482	5.6	68.7	858	33.4	30	88.1	59	60
14	275	527	4.8	73.5	876	30.0	36	93.9	86	75
15	300	572	4.6	78.1	884	28.6	37	98.3	140	90
Residuum			19.6	97.7	920	22.3		too dark		

Carbon residue of residuum, 5.9 percent; carbon residue of crude, 1.3 percent.  
Ramsbottom 4.5 1.0

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	11.8	0.687	74.5	
Total gasoline and naphtha	34.5	0.737	60.5	
Kerosine distillate	16.5	814	42.3	
Gas oil	10.9	842	36.6	
Nonviscous lubricating distillate	10.4	848-878	35.4-29.7	50-100
Medium lubricating distillate	5.8	878-888	29.7-27.9	100-200
Viscous lubricating distillate				Above 200
Residuum	19.6	920	22.3	
Distillation loss	2.3			

Bureau of Mines Laramie Laboratory  
Sample PC-57-89

IDENTIFICATION

Aneth field  
Paradox limestone (Aneth Pay) Well 3  
5,449-5,496 feet  
Utah  
San Juan County  
NW 1/4 SE 1/4 sec. 17,  
T. 40 S., R. 24 E.

GENERAL CHARACTERISTICS

Specific gravity, 0.819 A. P. I. gravity 41.3 ° Pour point, ° F. 10  
Sulfur, percent, less than 0.10 Color, green  
Saybolt Universal viscosity at 100 ° F., 36 sec.; at ° F., sec. Nitrogen, percent, 0.035

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.  
First drop, 28 ° C. (82 ° F.)

Fraction No.	° C.	° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	3.0	3.0	0.644	88.2				
2	75	167	4.2	7.2	681	76.3	13	52.3		
3	100	212	4.8	12.0	717	65.9	20	50.7		
4	125	257	7.0	19.0	740	59.7	22	48.9		
5	150	302	5.1	24.1	757	55.4	22	48.9		
6	175	347	6.4	30.5	777	50.6	25	50.5		
7	200	392	3.9	34.4	790	47.6	25	54.7		
8	225	437	6.8	41.2	802	44.9	25	60.7		
9	250	482	4.6	45.8	816	41.9	26	66.1		
10	275	527	5.4	51.2	825	40.0	26	70.1		

STAGE 2—Distillation continued at 40 mm. Hg.

11	200	392	5.4	56.6	0.838	37.4	28	76.2	40	10
12	225	437	6.0	62.6	846	35.8	28	82.5	46	35
13	250	482	5.4	68.0	856	33.8	29	87.6	57	55
14	275	527	5.9	73.9	874	30.4	35	93.3	88	75
15	300	572	8.5	82.4	891	27.3	40	100.9	175	100
Residuum			15.4	97.8	927	21.1		too dark		

Carbon residue of residuum, 6.3 percent; carbon residue of crude, 1.1 percent.  
Ramsbottom 5.2 .9

APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	12.0	0.686	74.8	
Total gasoline and naphtha	34.4	0.736	60.8	
Kerosine distillate	16.8	813	42.6	
Gas oil	10.6	842	36.6	
Nonviscous lubricating distillate	10.0	850-876	35.0-30.0	50-100
Medium lubricating distillate	8.4	876-896	30.0-26.4	100-200
Viscous lubricating distillate	2.2	896-901	26.4-25.6	Above 200
Residuum	15.4	927	21.1	
Distillation loss	2.2			



Bureau of Mines Laramie Laboratory  
Sample PC-57-90

#### IDENTIFICATION

Aneth field  
Paradox limestone (Aneth)  
5,384 - 5,550 feet  
Well 5  
San Juan County  
NW1/4NW1/4 sec. 21,  
T. 40 S., R. 24 E.

#### GENERAL CHARACTERISTICS

Specific gravity, 0.818 A. P. I. gravity 41.5 ° Pour point, ° F. 10  
Sulfur, percent, less than 0.10 Color, green  
Saybolt Universal viscosity at 100 ° F., 37 sec.; at    ° F.,    sec. Nitrogen, percent, 0.035

#### DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.  
First drop, 26 ° C. (79 ° F.)

Fraction No.	Cut at ° C.   ° F.		Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	3.6	3.6	0.648	86.9				
2	75	167	3.6	7.2	0.675	78.1	9.8	53.1		
3	100	212	5.5	12.7	0.718	65.6	20	50.4		
4	125	257	6.6	19.3	0.742	59.2	23	48.9		
5	150	302	5.5	24.8	0.758	55.2	23	49.3		
6	175	347	5.0	29.8	0.777	50.6	25	50.5		
7	200	392	5.6	35.4	0.790	47.6	25	54.9		
8	225	437	4.3	39.7	0.803	44.7	25	61.0		
9	250	482	5.5	45.2	0.814	42.3	25	65.2		
10	275	527	5.9	51.1	0.824	40.2	25	69.5		

STAGE 2—Distillation continued at 40 mm. Hg.

11	200	392	8.3	59.4	0.841	36.8	29	78.1	41	20
12	225	437	5.7	65.1	0.850	35.0	30	85.2	50	45
13	250	482	4.9	70.0	0.874	30.4	38	89.3	66	65
14	275	527	3.8	73.8	0.878	29.7	37	94.5	130	80
15	300	572	5.4	79.2	0.887	28.0	38	99.2	150	95
Residuum			18.4	97.6	0.922	22.0		too dark		
Carbon residue of residuum, <u>6.3</u> percent; carbon residue of crude, <u>1.3</u> percent.										
Ramsbottom <u>4.8</u>										

#### APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	12.7	0.686	74.8	
Total gasoline and naphtha	35.4	0.737	60.5	
Kerosine distillate	15.7	0.815	42.1	
Gas oil	11.1	0.843	36.4	
Nonviscous lubricating distillate	7.6	0.850-0.876	35.0-30.0	50-100
Medium lubricating distillate	9.4	0.876-0.892	30.0-27.1	100-200
Viscous lubricating distillate				Above 200
Residuum	18.4	0.922	22.0	
Distillation loss	2.4			

Bureau of Mines Laramie Laboratory  
Sample PC-57-91

#### IDENTIFICATION

Aneth field  
Paradox limestone (Aneth Pay)  
5,758-5,938 feet  
Well 6  
San Juan County  
SW1/4NE1/4 sec. 22,  
T. 40 S., R. 24 E.

#### GENERAL CHARACTERISTICS

Specific gravity, 0.817 A. P. I. gravity 41.7 ° Pour point, ° F. 35  
Sulfur, percent, less than 0.10 Color, green  
Saybolt Universal viscosity at 100 ° F., 37 sec.; at    ° F.,    sec. Nitrogen, percent, 0.044

#### DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.  
First drop, 28 ° C. (82 ° F.)

Fraction No.	Cut at ° C.   ° F.		Percent	Sum, Percent	Sp. Gr., 60/60° F.	° A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Test, ° F.
1	50	122	3.3	3.3	0.641	89.3				
2	75	167	3.2	6.5	0.668	80.3	6.5	54.3		
3	100	212	5.8	12.3	0.715	66.4	19	50.9		
4	125	257	6.2	18.5	0.744	58.7	24	48.8		
5	150	302	6.0	24.5	0.758	55.2	23	49.5		
6	175	347	4.7	29.2	0.775	51.1	24	50.7		
7	200	392	4.5	33.7	0.786	48.5	23	54.3		
8	225	437	4.8	38.5	0.798	45.8	23	60.5		
9	250	482	5.7	44.2	0.813	42.6	25	64.5		
10	275	527	6.2	50.4	0.826	39.8	26	69.3		

STAGE 2—Distillation continued at 40 mm. Hg.

11	200	392	11.7	62.1	0.844	36.2	31	79.5	42	25
12	225	437	9.9	72.0	0.868	31.5	38	89.5	67	60
13	250	482	1.8	73.8	0.882	28.9	42	96.9	120	85
14	275	527	0.8	74.6	0.885	28.4	40		145	90
15	300	572	4.7	79.3	0.891	27.3	40	101.1	185	100
Residuum			17.6	96.9	0.924	21.6		too dark		
Carbon residue of residuum, <u>2.0</u> percent; carbon residue of crude, <u>0.4</u> percent.										
Ramsbottom <u>2.0</u>										

#### APPROXIMATE SUMMARY

	Percent	Sp. Gr.	° A. P. I.	Viscosity
Light gasoline	12.3	0.683	75.7	
Total gasoline and naphtha	33.7	0.734	61.3	
Kerosine distillate	10.5	0.806	44.1	
Gas oil	15.4	0.835	38.0	
Nonviscous lubricating distillate	11.1	0.852-0.877	34.6-29.9	50-100
Medium lubricating distillate	6.7	0.877-0.893	29.9-27.0	100-200
Viscous lubricating distillate	1.9	0.893-0.898	27.0-26.1	Above 200
Residuum	17.6	0.924	21.6	
Distillation loss	3.1			

Bureau of Mines Laramie Laboratory  
Sample PC-57-140

## IDENTIFICATION

Aneth field  
Aneth limestone (Hermosa)  
5,586-5,654 feet  
5,659-5,695 )  
5,709-5,715 )  
Well 7  
San Juan County  
SW 1/4 sec. 14,  
T. 40 S., R. 24 E.

## GENERAL CHARACTERISTICS

Specific gravity, 0.818 A. P. I. gravity 41.5 ° Pour point, ° F. 10  
Sulfur, percent, 13 Color, green  
Saybolt Universal viscosity at 100 ° F., 35 sec.; at    ° F.,    sec. Nitrogen, percent, 0.040

## DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.  
First drop, 23 ° C. (73 ° F.)

Fraction No.	Cut at ° C.	° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	* A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Temp., ° F.
1	50	122	2.9	2.9	0.665	81.3				
2	75	167	3.4	6.3	684	75.4	14	54.2		
3	100	212	6.7	13.0	726	63.4	24	50.2		
4	125	257	5.4	18.4	747	57.9	25	49.6		
5	150	302	5.3	23.7	764	53.7	26	50.2		
6	175	347	5.5	29.2	779	50.1	26	52.4		
7	200	392	5.0	34.2	793	46.9	26	56.0		
8	225	437	5.1	39.3	806	44.1	27	61.5		
9	250	482	6.6	45.9	820	41.1	28	66.3		
10	275	527	6.7	52.6	831	38.8	29	71.9		

STAGE 2—Distillation continued at 40 mm. Hg.

11	200	392	1.2	53.8	845	36.0	31	76.5	39	15
12	225	437	5.1	58.9	845	36.0	28	79.9	42	25
13	250	482	6.4	65.3	852	34.6	28	85.0	50	50
14	275	527	5.4	70.7	872	30.8	34	90.1	67	65
15	300	572	4.7	75.4	876	30.0	33	94.5	99	80
Residium			22.5	97.9	914	23.3		too dark		

Carbon residue of residuum, 2.5 percent; carbon residue of crude, 0.5 percent.  
Ramsbottom 2.5

## APPROXIMATE SUMMARY

	Percent	Sp. Gr.	* A. P. I.	Viscosity
Light gasoline	13.0	0.701	70.4	
Total gasoline and naphtha	34.2	0.744	58.7	
Kerosine distillate	11.7	814	42.3	
Gas oil	16.2	841	36.8	
Nonviscous lubricating distillate	11.1	852-.876	34.6-30.0	50-100
Medium lubricating distillate	2.2	876-.878	30.0-29.7	100-200
Viscous lubricating distillate				Above 200
Residium	22.5	914	23.3	
Distillation loss	2.1			

Bureau of Mines Laramie Laboratory  
Sample PC-57-92

## IDENTIFICATION

Aneth field  
Paradox limestone (Aneth Pay)  
5,740 - 5,910 feet  
Well 8  
San Juan County  
NW 1/4 NW 1/4 sec. 24,  
T. 40 S., R. 24 E.

## GENERAL CHARACTERISTICS

Specific gravity, 0.815 A. P. I. gravity 42.1 ° Pour point, ° F. 10  
Sulfur, percent, less than 0.10 Color, green  
Saybolt Universal viscosity at 100 ° F., 37 sec.; at    ° F.,    sec. Nitrogen, percent, 0.040

## DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg.  
First drop, 28 ° C. (82 ° F.)

Fraction No.	Cut at ° C.	° F.	Percent	Sum, Percent	Sp. Gr., 60/60° F.	* A. P. I., 60° F.	C. I.	Aniline Point, ° C.	S. U. Visc., 100° F.	Cloud Temp., ° F.
1	50	122	3.3	3.3	0.644	88.2				
2	75	167	3.1	6.4	674	78.4	9.4	54.3		
3	100	212	6.4	12.8	714	66.7	18	50.9		
4	125	257	6.5	19.3	741	59.5	22	49.1		
5	150	302	6.9	26.2	761	54.4	24	49.1		
6	175	347	5.2	31.4	783	49.2	28	51.4		
7	200	392	3.7	35.1	792	47.2	26	55.5		
8	225	437	5.6	40.7	802	44.9	25	60.9		
9	250	482	4.7	45.4	817	41.7	27	65.4		
10	275	527	7.4	52.8	828	39.4	27	70.5		

STAGE 2—Distillation continued at 40 mm. Hg.

11	200	392	2.6	55.4	840	37.0	29	76.6	40	15
12	225	437	6.2	61.6	845	36.0	28	81.9	45	30
13	250	482	6.0	67.6	858	33.4	30	86.9	58	55
14	275	527	4.2	71.8	877	29.9	36	92.7	82	75
15	300	572	4.0	75.8	883	28.8	36	96.9	125	90
Residium			21.0	96.8	920	22.3		too dark		

Carbon residue of residuum, 1.7 percent; carbon residue of crude, 0.4 percent.  
Ramsbottom 1.7

## APPROXIMATE SUMMARY

	Percent	Sp. Gr.	* A. P. I.	Viscosity
Light gasoline	12.8	0.686	74.8	
Total gasoline and naphtha	35.1	0.737	60.5	
Kerosine distillate	10.3	809	43.4	
Gas oil	15.5	836	37.8	
Nonviscous lubricating distillate	10.5	850-.879	35.0-29.5	50-100
Medium lubricating distillate	4.4	879-.886	29.5-28.2	100-200
Viscous lubricating distillate				Above 200
Residium	21.0	920	22.3	
Distillation loss	3.2			

### APPENDIX III. - WELL CONDITIONS ATTENDING SAMPLING

A representative sample of a reservoir oil should contain the same proportions of liquid and associated solution gas as the reservoir oil. Depending on the bottom-hole pressure drawdown, producing a well may cause these proportions to be changed owing to release of gas from solution as the oil moves through the formation and into the well bore. Thus conditioning a well just before sampling, by flowing it at a reduced rate to eliminate the effects of previous higher rates, is an important part of sampling. However, in a saturated or near-saturated reservoir oil, release of gas from solution may accompany even very low rates of production and prevent sampling oil that has not been modified to some degree. Knowledge of well conditions attending sampling often provides the only reliable means of interpreting results of sample analyses. The following discussions of well conditions that preceded and existed during sampling of wells in the Aneth field are given to show the evaluations that were made of the quality of the subsurface samples and their limitations for determining the original reservoir-oil characteristics.

#### Well 1

The sample from well 1 was obtained and analyzed by other investigators. The sample data were furnished by the operating company for use in this study. Data reported with the sample analysis showed that the well had been shut in 6 days when the subsurface sample was taken and that the bottom-hole static pressure was 2,068 p.s.i.a. No data were reported on the pressure-production history of the well; however, as far as could be determined, less than 500 barrels of oil had been produced from the well during its completion and initial flow test before sampling. During the initial flow test oil was produced at a rate of 547 barrels a day. Considering the probable producing characteristics of the well relative to those of other wells in the field, it seems almost certain that at this rate the bottom-hole flowing pressure would have been less than the saturation pressure of the sample. Unfortunately, the degree of modification of the original reservoir oil with evolution and re-solution of gas during the imposed flow and shut-in conditions cannot be determined owing to lack of production gas-oil ratio data. The saturation pressure of the sample (1,816 p.s.i.a.) compares favorably with values obtained from sampling other wells in the field where conditions were known to favor representative sampling. Thus, for all practical purposes, the sample is considered representative of the original reservoir oil in the vicinity of well 1.

#### Well 2

Well 2 had been producing at a rate of 250 barrels of oil a day for approximately 22 days when it was put on a conditioning rate of 182 barrels a day. The conditioning rate was maintained for a period of 44 hours, during which the minimum bottom-hole flowing pressure was 1,349 p.s.i.a. After the well had been shut in 67 hours for a pressure build-up test, gas was bled from the tubing and casing heads, and subsurface oil samples were taken. The static pressure before sampling was 1,763 p.s.i.a. Comparing the saturation pressure of the sample (1,740 p.s.i.a.) with the minimum bottom-hole flowing pressure and the static pressure existing just before sampling indicated that

much of the gas liberated from solution during the flow period was redissolved during the shut-in period before sampling. The production gas-oil ratio measured during the conditioning rate was 680 cubic feet per barrel of stock-tank oil; this is approximately 85 cubic feet per barrel higher than the equivalent production gas-oil ratio obtained from the flash-gas liberation analysis of the sample. However, the value of these data is questionable for determining the original saturation pressure of the reservoir oil, because a stabilized flow was not obtained during conditioning. The unstable, heading-type flow during conditioning is attributed to the 300-foot increase in elevation between the wellhead and the separator and to the small water production that intermittently loaded the flow line causing varying back pressures on the wellhead. Although the sample probably is not representative of original reservoir oil in the vicinity of well 2, it is considered that the release and re-solution of gas during flow of oil from the formation and accumulation in the tubing, where sampled, caused little change in the composition of the original reservoir oil. The sample is considered representative of the reservoir oil at its saturation and lower pressures reported for the laboratory analyses. The saturation pressure of the original reservoir oil is believed to be somewhat higher than that of the sample.

### Well 3

Poor conditions existed in well 3 for sampling original reservoir oil. These conditions were attributed to previous high rates of flow imposed on the well, to a local pressure sink that had developed in the area, and to effects of a paraffin-cutting operation a few days before the tests.

The first two conditions were not known at the time of the tests; the high cleanout rate imposed during paraffin cutting was not considered serious in itself because of its short duration. It was believed that the well could be made suitable for sampling even though conditioning of the well would be limited due to lack of tank space. The well was placed on a conditioning rate of 248 bbl. a day for 46 hours; it was then shut in for 27 hours, and subsurface oil samples were taken. The minimum bottom-hole flowing pressure on the conditioning rate was 1,515 p.s.i.a., the bottom-hole static pressure just before sampling was 1,681 p.s.i.a., and the sample saturation pressure was 1,420 p.s.i.a. Thus, it might appear that the reservoir oil was undersaturated, but this is contrary to results of previous and subsequent sampling. Additional investigation of well conditions that may have affected sampling disclosed that the well had been produced on rates as high as 550 bbl. a day for 10 days just before sampling. Pressure data recorded in well 4, which had been shut in approximately 5 months, substantiated the existence of a pressure sink in this area of the field. Because of these conditions, it seems apparent that gas was being liberated from solution within the reservoir formation and that representative proportions of original oil and associated gas components were not being produced into the well or the surface producing equipment. The measured production gas-oil ratio on the conditioning rate is not considered representative of the original oil or useful in determining its saturation pressure. Therefore, the subsurface sample is not representative of the original unmodified reservoir oil but may be considered representative of the reservoir oil at the saturation and lower pressures reported in the laboratory analyses.

### Well 6

Well 6 was conditioned 64 hours on a relatively high rate of 266 barrels a day because of the much higher rates at which the well had been produced before conditioning. The well was not available for a longer period of conditioning, which would have been required had a lower rate of flow been used; it was shut in to allow the pressure to build up before sampling. The bottom-hole flowing pressure and static buildup were not reported because the pressure-gage clock stopped. On two occasions during the shut-in period and before the first of two subsurface oil samples was taken, gas was bled from the wellhead at a slow rate to move fresh oil from the formation into the tubing for sampling. This procedure was repeated just before taking the second sample. The second sample had the highest saturation pressure, and it was used for the laboratory analyses. After sampling, the well was flowed again and then shut in, so as to duplicate and measure, as nearly as possible, the pressure conditions that existed before sampling, for which period pressure data were lacking. This measurement and a static-pressure measurement made just before taking the second sample indicated that the minimum bottom-hole flowing pressure on the conditioning rate was about 1,740 p.s.i.a. and the static pressure at the time of sampling was 1,840 p.s.i.a. Saturation pressure of the sample was 1,820 p.s.i.a. Liberation of gas from solution in the reservoir oil is indicated during flow on the conditioning rate. The measured production gas-oil ratio, 599 cubic feet per barrel of stock-tank oil agrees well with the equivalent gas-oil ratio obtained by flash gas-liberation of the sample, 614 cubic feet per barrel. Thus, the gas evolved from the reservoir oil was essentially redissolved when the sample was obtained. The sample is considered representative of the original reservoir oil near well 6.

### Well 7

Well 7 had been shut in 14 days at the time of sampling. Previously, it was produced for several weeks at a normal rate of 225 barrels of oil a day. To condition the well by flowing it at a lower rate would have delayed sampling scheduled for other wells and was not considered warranted. However, an attempt to improve the existing well conditions was made by bleeding gas slowly from the wellhead to cause fresh oil to move into the bottom of the tubing. Then, the subsurface samples were taken. The bottom-hole static pressure at time of sampling was 1,791 p.s.i.a. The saturation pressure of the sample was 1,785 p.s.i.a. After the well was sampled, it was placed on the normal choke setting and produced at a rate of 223 barrels a day. From this test, bottom-hole-pressure and production-rate data were obtained for interpreting the sample analyses. The minimum bottom-hole flowing pressure recorded on this rate was 1,625 p.s.i.a. As the flowing pressure is 160 p.s.i. less than the sample saturation pressure, obviously gas was being evolved from solution in the oil during the producing period. Regardless, the sample was approximately saturated at the bottom-hole static pressure existing at the time of sampling. The production gas-oil ratio was about 56 cubic feet per barrel higher than the equivalent production gas-oil ratio determined by flash-gas liberation of the sample. Although this amount indicates that the sample should have had more gas in solution it seems excessive and not representative of the degree to which the reservoir oil had been

modified. It is concluded that the sample is representative of the reservoir oil at the saturation and lower pressures reported for the laboratory analyses and that the saturation pressure of the original reservoir oil was probably somewhat higher than that of the sample.

#### Well 9

Well 9 had been producing oil on a conditioning rate estimated at 100 to 150 barrels a day for about 1 week when the flowline was accidentally broken, causing the well to be shut in. Tests were begun 2 days later, when the well was still shut in. The bottom-hole static pressure was 1,908 p.s.i.a. when the well was put on a 6/64-inch choke. After 1-1/2 hours, the bottom-hole pressure had dropped to only 1,878 p.s.i.a. The subsurface oil samples were taken immediately with the well flowing. Saturation pressure of the sample is 1,875 p.s.i.a. Accordingly, saturation of the oil is indicated at the bottom-hole flowing pressure during sampling. Pressure-volume data, determined during testing of the sample before transferring it to a storage cylinder, show that the sample was a single-phase liquid when the sampler valves closed. Thus, if free gas existed in the flow stream at the time of sampling it was not trapped with the sample on two sampling runs. It is believed that the flow stream coming into the bottom of the well was a single-phase liquid, and it is concluded that the sample is representative of the original reservoir oil near well 9.

#### Well 11

Well 11 was sampled and analyzed by others; the sample data were furnished by the operating company for use in this study. Data furnished with the sample report show that the well had been produced at a rate of 85 barrels of oil a day for 6 days and had been shut in 46 hours at the time the subsurface sample was taken. The bottom-hole static pressure at the time of sampling was 2,158 p.s.i.a. The saturation pressure of the sample was 1,745 p.s.i.a. No information was reported on the bottom-hole-flowing-pressure or gas-oil-ratio tests. It is doubtful if flow at 85 barrels a day would have caused the bottom-hole pressure to drop as low as the saturation pressure of the sample; therefore, it is concluded that the sample is representative of the original reservoir oil near well 11.

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