

ACQUISITION, CLASSIFICATION, AND EVALUATION OF
ENGINEERING AND GEOLOGIC INFORMATION AND
CHARACTERISTICS OF WEST VIRGINIA PETROLEUM
RESERVOIRS AMENABLE TO ENHANCED OIL RECOVERY
TECHNOLOGY, PARTICULARLY CARBON DIOXIDE INJECTION

Final Report

Prepared for the Department of Energy
Under Contract No. DE-AC05-78MC05602

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PETROLEUM RESERVOIRS AMENABLE TO ENHANCED OIL RECOVERY TECHNOLOGY,
PARTICULARLY CARBON DIOXIDE INJECTION**

Final Report

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FOREWORD

Under Contract No. DE-AC05-78MC05602 with the U. S. Department of Energy, Oak Ridge Operations Office and Morgantown Energy Technology Center, Gruy Federal, Inc. undertook a study with the following objectives:

- Prepare an overall assessment of West Virginia reservoirs as candidates for one or more EOR processes.
- Compile, synthesize and analyze the geologic/engineering data necessary to evaluate the EOR potential of those reservoirs identified as possible EOR candidates.
- Evaluate and interpret the results of ongoing and proposed CO₂ injection field tests in West Virginia.

This volume is the final report on the contract study. It presents Gruy Federal's methodology, results, and conclusions organized under the three study objectives listed above.

ACQUISITION, CLASSIFICATION, AND EVALUATION OF ENGINEERING
AND GEOLOGIC INFORMATION AND CHARACTERISTICS OF WEST VIRGINIA
PETROLEUM RESERVOIRS AMENABLE TO ENHANCED OIL RECOVERY TECHNOLOGY,
PARTICULARLY CARBON DIOXIDE INJECTION

The Need for Enhanced Oil Recovery in West Virginia

Historically, recovery from Appalachian Basin oil fields has been low, in spite of the fact that many of these reservoirs have produced oil continuously for more than 100 years. In West Virginia, the average total recovery, including both primary and secondary, is 160 barrels per acre-foot. Low-pressure gas displacement has been the most widely used technique to maintain production from the major reservoirs. Waterflooding has been successful in a few cases, but has not been widely used. Consequently, significant amounts of oil, producible with existing technology and awaiting favorable economics, still exist in West Virginia.

Enhanced oil recovery can be defined in the broadest sense as any oil production achieved after primary production has become ineffective. In current usage, the term is applied more narrowly to a group of techniques which can be used to obtain some of the oil left in the rocks after conventional primary and secondary production. In this report, enhanced oil recovery techniques or processes will refer to techniques that have not been widely applied in West Virginia. The techniques considered in this study are:

- nitrogen miscible, flue gas, and dry gas miscible displacement;
- enriched gas miscible displacement;
- CO₂ miscible displacement;
- polymer-augmented waterfloods and micellar-polymer techniques;
- in situ combustion;
- steam injection;
- caustic waterflooding.

I. AN OVERALL ASSESSMENT OF WEST VIRGINIA OIL RESERVOIRS AS CANDIDATES FOR ONE OR MORE ENHANCED OIL RECOVERY PROCESSES

Methodology.

To prepare an assessment of an oil reservoir as a candidate for one or more enhanced oil recovery (EOR) processes, complete reservoir information is, ideally, desirable. However, most West Virginia fields were discovered before the beginning of the 20th century, and many had been abandoned before the advent of modern logging practices. As a result, little if any of the desired reservoir information is directly available. Moreover, production records from the fields in West Virginia are largely non-existent.

Because the available information is limited, it was necessary to develop methods to use such data as was obtainable in performing this study within the time and scope of the initial contract. Fortunately, West Virginia oil fields are remarkably uniform in many important respects, which facilitates the use of such methods.

Two-Parameter Screening of West Virginia Reservoirs.

As they are currently understood, all EOR techniques except caustic water-flooding are primarily limited by oil gravity (or, more properly, viscosity) and all have either a maximum or minimum depth (or depth-related feature, such as pressure or temperature) constraint.¹⁻⁵ These two very important features of a reservoir, namely depth and oil gravity, are normally considered unchangeable. Thus a preliminary screening for potential amenability to EOR can be conducted using only these two parameters. A field that passes this primary screening for a particular technique can then be examined in greater detail to see whether it also meets the less-critical criteria (see Table 1).

The state-of-the-art limitations on oil gravity and reservoir depth for the EOR techniques listed above are shown graphically in Figure 1.

West Virginia oil reservoirs have a rather narrow depth distribution. Detailed data are not given in this report, but are summarized in Figure 2. This evaluation covered 157 fields for which separate depths could be found, including all the major fields and some very small ones. Reserve estimates have been published for only 104 of these. Over 300 field names for oil reservoirs in West Virginia have been found; however, many of these have been combined with other fields.

Complete oil analysis is available for only 27 fields in West Virginia (see Appendix B), and other published values (an additional 14) are surprisingly uniform.¹¹ The average of 62 gravity determinations from these fields is 44.6° API, with a standard deviation of 4.62° and a range of 30° to 65° (Fig. 3a). Even fewer viscosity measurements (only 40) are available.

Ignoring one 60 centipoise value as obviously atypical, the average dead oil viscosity is 3.99 cp, with a standard deviation of 1.79 (Fig. 3b).

Using these values for reservoir depth and oil gravity, it is clear from Figure 1 that CO₂ miscible displacement is the most promising EOR technique for the type of reservoir and the crude oil found in West Virginia. Micellar-polymer and caustic waterfloods, not shown on Figure 1, are considered to have minimum permeability requirements, given in the National Petroleum Council's Study⁴ as 20 and 50 millidarcies, respectively. These minimum requirements seem to be higher than the typical permeability for West Virginia reservoirs, although few permeability values are available. This will be treated in greater detail in a subsequent section of this report.

Since it seems that the CO₂ miscible displacement process is potentially the most applicable to West Virginia reservoirs, this study concentrates on this method.

Screening of Reservoirs for the CO₂ Process

One critical prerequisite for the CO₂ process is that the reservoir will competently hold miscible pressure.* This has been determined in similar studies^{3,4} by estimating the miscibility pressure and calculating the depth at which the rocks are competent to support this pressure loading, using established relationships to predict the breakdown pressure. Studies made in conjunction with the three CO₂ displacement processes now under way in West Virginia were scrutinized to determine the pressure at which highly efficient displacement occurred. For Griffithsville crude, this was 1100 psi at 85°F (reservoir temperature)⁶; for Rock Creek crude, 1000 psi at 73°F but not 800 psi at 73°F⁷; Granny's Creek crude was miscibly displaced at 1000 psi and 75°F.⁸ These three oils are typical West Virginia Penn grade crudes.

Based on these tests and the uniformity of the crude oil, the pressure necessary for miscible displacement of West Virginia crude oils was judged to be approximately 900 to 1000 psi.

This pressure can be related to the minimum acceptable depth of a reservoir if the strength of the rocks is known. For unconsolidated sediments, using 0.465 psi per foot as hydrostatic gradient and 1 psi per foot for overburden pressure, and assuming the least principal stress is horizontal,

*Miscible pressure, as used here, is the pressure at which CO₂ will displace more than 90% of the oil in place before breakthrough in a linear sand pack.

a breakdown gradient of 0.68 psi per foot can be calculated.⁵⁹ However, the oil reservoirs of West Virginia are normally in well indurated and competent rocks. Data on breakdown pressures for Rock Creek and Griffithsville fields are presented in Table 2, showing that these rocks are locally capable of bearing hydraulic gradients in excess of 1 psi per foot. Both the Berea and Big Injun sands should be at least locally capable of bearing miscible pressures at depths as shallow as 1500 feet. In an attempt to confirm this estimate of the general strength of West Virginia reservoirs, field representatives of the Halliburton Company in the state were consulted. Discussions with them led to the conclusion that miscible pressures could normally be borne by reservoirs as shallow as 1800 feet,⁹ where the pressure is not much more than the normal hydrostatic. Some reservoirs, however, fracture rather easily.

Other screening criteria for the CO₂ process include such factors as a minimum residual oil saturation of 20%¹⁻³ and a minimum net thickness of 10 feet (see Table 1).³ Since the average West Virginia reservoir has never produced much water, and since few have been waterflooded, residual oil saturations are almost certainly greater than 20%. The net thickness requirement, found in only one set of screening criteria, was judged to be largely an economic criterion and was ignored in this screening.

Of the 104 most important fields in West Virginia, 56 have an average depth of 1800 feet or more.

The list of candidates can be further refined by considering only fields having an estimated 10 million barrels of oil remaining in place. Smaller volumes are likely to be uneconomic because of the initial costs of the EOR process. Estimates of remaining oil in place were obtained largely from previous studies.¹⁰⁻¹⁴

This reduces the number of candidates to 26 without dramatically reducing the amount of oil that might be recovered.

Another desirable feature for CO₂ miscible displacement is that the bulk of the reserves be in a single reservoir. This criterion limits the prime candidate list to 18 fields. One of these has been converted to gas storage and is inaccessible to EOR. The locations of the remaining 17 are given in Figure 4; the fields are further identified in Table 3. There are three Berea sand reservoirs, six Big Injun reservoirs, five Gordon sand reservoirs, one Gordon Stray sand reservoir, one Fifth sand reservoir, and one Squaw-Weir sand field. Also included in Figure 4 are four large reservoirs shallower than the 1800-foot minimum acceptable depth.

Figure 5 shows the potential applicability of CO₂ displacement to the major oil fields of West Virginia. The process is theoretically applicable to 22 of the 37 large (more than 10 million barrels of oil left in place) reservoirs of the state. Application of the CO₂ process to these reservoirs may be limited, however, by factors that cannot be properly assessed

with the existing data. These include permeability variations, the difficulty of finding and abandoning or reabandoning old wells, and uncertain reservoir descriptions.

Screening of Reservoirs for Other EOR Technology

Although the CO₂ process is the most promising EOR technique for the high-gravity Penn grade crudes of West Virginia, it is not the only applicable one. Therefore other recovery processes, such as waterfloods, polymer-augmented waterfloods, steam displacement, caustic waterfloods, and low-pressure gas cycling, have been considered, both for the fields previously listed and for those where the CO₂ process does not seem well suited.

Waterflooding has been used very little in West Virginia. The Cabin Creek field has been successfully waterflooded, and Granny's Creek is now being waterflooded with economic success. Waterfloods attempted in several other fields, however, gave poor results. Some have failed because of low injectivity, which can be caused by inherently low effective permeability to the injected phase; some because of reactions of the injected fluid with the formation; and some because of wellbore skin damage. Waterfloods may fail for many other reasons, including the existence of thief zones, failure to bank oil, poor completion practices, inadequate engineering, drastic permeability variations, and unfavorable economics. These factors are not independent; the economic factor, for example, is strongly related to injectivity. Little is known about the previous waterflood attempts that failed except that they were attempted and they did fail.

Two of the current CO₂ projects in West Virginia are in reservoirs where waterflooding attempts have met with some success in the past, the Griffithsville and Granny's Creek fields; the third is in the Rock Creek field. Rock Creek has been considered impossible to waterflood because three attempts in the 1950's and 1960's were unsuccessful. Failure in these attempts was attributed to the high relative permeability to water and high connate water saturation, so that the resulting oil bank was small. However, in a water injection program to raise the reservoir pressure to that required for miscible displacement with CO₂, it was found that a significant oil bank had been formed.⁵⁸ It was also found that there is at least one thief zone in the bottom of the Big Lime formation, which directly overlies the Big Injun reservoir rock. This portion of the reservoir had been previously gas-cycled for many years and thus would seem to be a poor place to operate a successful waterflood; however, this is apparently not the case.

Similarly, the Griffithsville CO₂ project is in an area of the field which had not been intentionally waterflooded, though it was found to have been dump-flooded accidentally, presumably through and around leaking casings of old, improperly abandoned wells. Nine wells in the pilot area are

currently producing approximately 70 barrels of oil per day⁴⁷, indicating that a significant oil bank had been formed.

The results of repressuring these fields by water injection suggests that a properly engineered waterflood can be successful in West Virginia, even in reservoirs with high connate water saturation.

If waterfloods can be successful, then polymer-augmented waterflooding should also be applicable, and even more effective, since the flow characteristics of polymer solutions can mitigate to some degree the adverse effects of unfavorable combinations of flow geometries and fluid mobilities. However, this assumes that the injectivity of the wells will not be drastically changed by the polymer solution, which is commonly the case in field applications of this technique. Intuitively it would seem that the injection of a more viscous phase would dramatically lower the injectivity; many years of actual field experience show that this is not normally the case,¹⁵ but clay problems and low permeability (below 20 md) can produce disastrous results. The chief advantage of the technique, for West Virginia reservoirs where it will work, is that the chemicals are relatively inexpensive and high pressures are not necessary.

Polymer-augmented waterflooding should be applicable if the reservoir permeability is greater than 20 md. Unfortunately, permeability values for West Virginia reservoirs either have not been recorded or have not been published or even widely released.

Steam injection has been demonstrated to be effective for some unusual high-gravity, high-viscosity oils in Pennsylvania,¹⁶ and more recently in a moderately high-gravity (34° API) reservoir, Texaco's Shiells Canyon project in California. Pratts has pointed out that the steam drive process may be used in light oil reservoirs, though it may not be economical.¹⁷ The conditions deemed favorable for a steam flood of a light oil reservoir are those that would be favorable for a waterflood. Steam injection sometimes causes formation injectivity problems; Texaco used a system of co-injecting potassium chloride solution to control clay problems and maintain injectivity in their Shiells Canyon project.

For steam flooding to be attractive in West Virginia reservoirs, it would have to be demonstrated that the following reservoir characteristics exist¹⁸:

- oil with low distillation residue;
- low reservoir pressures;
- high injection rates;

- thick layers;
- high porosity.

The first two criteria are commonly met for West Virginia reservoirs, but the last three are not.

An attempt to steam-flood the Rock Creek Field failed because of high heat loss and low injectivity.

Low-pressure gas cycling has been conducted to some extent on most of the large fields in West Virginia, and these projects have generally been successful. The drawback of this technique is that recoveries are normally quite low.

Distribution of Fields with EOR Potential

Table 3 shows that there are 22 reservoirs which seem to have high potential as candidates for enhanced oil recovery: one each in the Salt, Keener, and Squaw-Weir sands, nine in the Big Injun, three in the Berea, and seven in the Gordon series sands. Figure 6 shows the stratigraphic relationship of these reservoirs, which occur in three periods.

If secondary recovery is not feasible, then the more difficult and often financially less rewarding EOR techniques should be applied only with great caution. Application of conventional secondary recovery techniques to these fields has been varied, and is discussed under each system description below.

Devonian System

The Gordon series sands (Gantz, Fiftyfoot, Thirtyfoot, Gordon Stray, Gordon Fourth, Fifth, Bayard) occur in the upper parts of the Devonian shale as irregularly distributed "casual sands".¹⁹ They are usually thin zones with highly permeable streaks, often with low porosity and visibly conglomeratic.¹⁰ These characteristics would hinder the successful application of EOR techniques.

Some reservoir properties of the Gordon series reservoirs covered in this report are included in Table 4. As the table shows, the Gordon series sands selected for their EOR potential by the rationale developed in this report could indeed be described as highly conglomeritic and highly variable in thickness.

Because of their nature almost all of the old Gordon series reservoirs have been abandoned for many years.

There have been four recorded waterflood attempts in the Gordon sands, all unsuccessful. Low-pressure gas cycling, however, has been successful; twelve reservoirs have been subjected to such cycling. Of the seven Gordon sand fields selected by our preliminary screening, three have undergone low-pressure gas cycling (see Table 5). Results of the low-pressure gas injection program for one of the fields selected have been reported in detail. This particular project, affecting 250 acres, showed a dramatic response in oil production to the gas injection program. Figure 8 shows the decline curve for this project from 1944 to 1950. The sharp peak in 1949 resulted from field operations changing hands and the "pumping off" of all wells. Further details on this project, the Mills Gordon Project, are given in Table 5; the information was taken from a previous report.¹¹

A pilot waterflood project was carried out in the Mannington field. Details have not been made available, but some information has been disclosed. The following excerpt is from an unpublished report:

Gordon Sand Pilot Waterflood, Mannington Oilfield,
Marion County, West Virginia

Pennzoil operated a pilot waterflood project in the Mannington oilfield, Marion County, West Virginia. Detailed information on this project is not available for publication. Development of the pilot began in 1964 with the drilling of four new wells which were completed as water injection wells. The pattern used in the pilot was one normal five-spot. . . . An old well in the center of the pattern was used for the production well. Approximate area enclosed by the four injection wells was 38 to 40 acres.

The depth to the Gordon sand in the area of the pilot ranged from 2,700 to 2,950 feet. Thickness of the Gordon sand in the area usually ranges from 25 to 45 feet. Completion records of the new wells in the pilot area showed a range of sand thickness of 29 to 42 feet. The Gordon sand is not generally porous and permeable throughout, but usually contains one or more zones of porous and permeable "pay" sands. Often these are thin, highly permeable, pebbly or conglomeritic zones with several hundred millidarcys permeability. Porosity of the Gordon sand usually ranges between 9 and 15 percent and averages 12 percent. Porosity logs of the Gordon sand in Mannington oilfield also show this range of porosity. Fig. [7] shows some sand characteristics of the oilfield with gamma ray and density logs. No core

analyses of the Gordon in the Mannington oilfield are available for publication but a Gordon sand well in the Smithfield Gordon oilfield [refs. 21-23] approximately 8 miles west of the pilot area show very similar sand characteristics. In the Smithfield oilfield well, the Gordon sand was 16 feet thick, core analysis indicated a porosity range from 8 to 16 percent, and a permeability range from less than 1 to over 100 millidarcys. The "pay" zone in this well was 7 feet thick, typical of the Gordon "pay" zones. This 7-foot zone averaged 13 percent in porosity and 42 millidarcys in permeability, although only 3 feet of the zone contained high permeability. The water saturation of the Gordon reservoir in the Mannington area is usually low and wells produce very little water during primary production operations.

The success or failure of this pilot flood has not been reported. Permits to abandon some of the pilot wells were obtained for abandonment in 1970. One may therefore assume that the pilot test was a failure, inasmuch as it was not expanded beyond the original five-spot. Injection water was obtained from shallow water wells. Due to its low interstitial clay content, little trouble should have resulted from clay swelling or particle migration from contact by fresh water. Because this project enclosed a very large area, approximately 39 acres, for a pilot test, control could have been very difficult. A five-spot such as this may produce or sweep much more oil outside the pattern than would be produced in the pattern. The high permeability zones could also contribute to lack of control. These zones have probably produced a much higher percent of their initial oil in place during primary production than the low permeability zones and would have a correspondingly higher gas saturation. Channeling of flood water would probably occur because of the great range of permeability in the "pay" section.²⁰

Conclusions.

- (1) Gas injection has been shown to work quite effectively in several projects, 3 of which involved more than 20 wells.
- (2) Waterflooding in the Gordon and Gordon series sands has never been effectively demonstrated.

- (3) Even though gas injection has been conducted on 4 of 7 Gordon series reservoirs selected as having significant EOR potential, these projects have by no means included the entire field.
- (4) As Table 5 shows, the injectivities of these projects has been in the neighborhood of 50-200 MCFD per well at approximately 100-130 psi.

Mississippian System.

The bulk of the oil production from West Virginia comes from the sands of Mississippian period, notably the Big Injun and Berea sands. They have been called "blanket sands," chiefly on account of their widespread occurrence, and the Big Injun is highly variable. Watts and Overbey have subdivided the Big Injun sandstone on the basis of mineralogy into two types: The Northern Big Injun, classified as a pro-quartzite; and the Southern, a borderline sub-graywacke or graywacke.²⁴ The Berea sandstone is more uniform than the Big Injun.

Big Injun Sands.

Four of the six Big Injun sand reservoirs selected as having EOR potential have been subjected to low-pressure gas cycling (Table 6). Several fields have had more than one injection project. The injectivity of the Big Injun sand reservoirs in these projects has ranged from 60 MCFD/well at 3 psi to 320 MCFD/well at 235 psi (Table 6).

There have also been 12 water injection projects and some pilot projects, injection tests, or waterflood attempts in the Big Injun sand. Information in Table 8 was compiled from the work of Watts²⁰ and from Interstate Oil Compact Commission (IOCC) reports.¹¹⁻¹⁴

The injectivity in these Big Injun sand reservoirs can be computed from Table 8 as about 50-100 BWD/well at roughly 1000 psi. The highest injectivity of these projects was in the Big Injun sand in the Walton field. In one project in the Rock Creek field, the secondary recovery was about 44% of the primary when the 1950's reports were filed.

Berea Sands.

Two of the three Berea reservoirs have had low-pressure gas injection projects. Little information could be found on these projects, since they were inactive in the early 1950's when the secondary recovery information was published (Table 6a). The injectivity in two Cabin Creek projects seems to have been lower--roughly 20 MCFD/well at 50-200 psi. The Griffithsville project injected only 44 MCFD in 52 wells at 300 psi, if the information published in a previous report is correct.¹¹

The Berea sand reservoirs selected as having significant EOR potential have had several water injection reports, including one successful fieldwide waterflood in the Cabin Creek field. Table 7 shows the injectivity in the Cabin Creek project ranged from 85 BWD/well at 210 psi to 115 BWD/well at 800 psi, and in the Griffithsville project, 28 BWD/well at 1400 psi. Little additional information is accessible at this time.

Squaw and Weir Sands.

The Squaw and Weir sands have undergone several small low-pressure gas injection and water injection tests, all in the Blue Creek field. Portions of the Blue Creek field have been the sites of at least seven secondary recovery projects or tests. The earliest of these was a low-pressure natural gas injection project started in 1926, involving about 190 acres; the last was a single-well water injection test, which ended sometime in the early 1960's. Five of the projects have been covered in IOCC reports on secondary recovery in West Virginia. The information given on these projects indicates that they have ranged from highly successful to unsuccessful. However, as can be seen from the acreage of the projects (see Table 9), the bulk of the Blue Creek field has not been subjected to any large-scale secondary recovery efforts.

The projects that were tried included four low-pressure gas injection projects, two water injection tests, and one low-pressure air injection project. The injectivities of natural gas in three projects (information is unavailable on the fourth) are 33, 19 and 33 MCFD at 147, 35, and 115 psi, respectively. Injectivity of water in one test (1946) was 100 BWD at an average wellhead pressure of 605 psi. The air injection project had a recorded injectivity of 103 MCFD at an average pressure of 46 psi.

The highly successful gas injection project which affected 202 acres is summarized in the following extract from the IOCC report.

This field produces from the Squaw Sand (Pocono) at a depth of about 1,950 feet. The sand is lenticular with a pay thickness of about 15 feet. The production increase shown is rather unusual. Only three wells remained on the lease in question at the time repressuring was started in 1927. It is believed that the continued high recovery has been due, in part at least, to water encroachment because the amount of gained oil is far out of proportion to the secondary recovery potential by gas drive. A number of leases in this field have experienced water drives which have greatly augmented production from both primary and secondary recovery sources.¹¹

Figure 9 shows the decline curve for this project. By "water encroachment" on this lease, the authors probably mean an uncontrolled cross-flow of water from another formation, since the field definitely did not have a natural water drive. This provides indirect evidence that a water drive will work--at least in selected areas of this field.

Figure 9a shows the decline curve for a different project of comparable dimensions in the Weir sand. This project was suspected of having great permeability variation. Nevertheless, some oil was recovered by this process at a cost which at the time was economic.¹¹

Conclusions.

The significant conclusions for the Mississippian sand reservoirs are:

- (1) Waterflooding has been demonstrated as an effective displacement mechanism in one Berea reservoir and one Big Injun reservoir. Injectivity of water in both cases was more than 50 BWD per well at pump pressures near 1000 psi.
- (2) Waterflooding on a large scale has not been successfully demonstrated in Squaw or Weir sand reservoirs.
- (3) Low-pressure gas injection has been found to be successful in the Berea, Big Injun, Squaw, and Weir sand reservoirs throughout the state. These projects have had injectivities ranging from 320 MCFD per well at 235 psi to 20 MCFD at 50-200 psi.
- (4) Even with the successes of the low pressure gas injection, the projects have generally been limited in areal extent, usually involving less than 10 injection wells.

Pennsylvanian System.

Pennsylvanian System sands include the Salt, the Cow Run, the Burning Springs, and others. One Salt sand reservoir was selected as having high EOR potential, the Cairo-Ritchie field. The Salt sand has been described as highly variable in grain, size, thickness, and occurrence.²⁰

The Cairo-Ritchie field is carried by the West Virginia Geological Survey as the Cairo-Ritchie-Mine-Hartley field on the most recent oil and gas field maps. The Hartley field has been the site of a low-pressure gas injection project; the available information on this project is compiled in Table 10, which shows that the injectivity of this project was approximately 50 MCFD/well at about 250 psi.

Waterflooding has been attempted in the Salt sand and other Pennsylvanian age reservoirs. Although some encouraging results have been obtained, there has been no large-scale and systematic use of this secondary recovery technique in these sands.

Summary.

The following West Virginia oil fields were selected as candidates for EOR by CO₂ injection:

- | | |
|---------------------------|------------------------------|
| 1. Blue Creek | 10. Pine Grove |
| 2. Cabin Creek | 11. Porto Rico |
| 3. Cameron-Gardner | 12. Salem-Wallace |
| 4. Centerpoint | 13. Steel Run |
| 5. Granny's Creek | 14. Tariff |
| 6. Greenwood | 15. Walton + Clover-Rush Run |
| 7. Griffithsville | 16. Wolf Summit |
| 8. Jacksonburg-Stringtown | 17. Yellow Creek |
| 9. Mannington | |

Four other fields are candidates for other EOR processes:

18. Cairo-Richie
19. Sistersville
20. Rouzer
21. Kidwell-Elk Fork

II. EVALUATION OF THE EOR POTENTIAL OF CANDIDATE RESERVOIRS SELECTED IN SECTION I.

Reservoir features that limit the use of a secondary recovery technology often limit the utility of a more exotic EOR technology. Therefore the fields offering the lowest risk for EOR application are those in which secondary recovery techniques have been successfully applied. However, these fields generally have lower saturations than the ones where secondary recovery techniques have not been used, and therefore present a smaller target in terms of potential production.

The potential of any EOR technique in a particular reservoir depends upon the size of the reserve, the efficiency of the EOR technique, the relative difficulty in applying the technique (risk factor), a myriad of reservoir characteristics, and economic criteria (rate of return, tax incentives, and other factors). The scope of this study did not allow for any economic analysis, and therefore this factor will not be considered.

The best reservoir data that can be compiled at this time on the candidate reservoirs are contained in Appendix A.

Determination of Size of the Reserve.

The average total recovery for West Virginia reservoirs has been about 160 barrels per acre-foot. This estimate is based on the production figures for 24 largely single-pay fields (see Table 11). Production figures, acreage, and thickness values used to calculate these recoveries were taken largely from previous reports.^{10,26-36} The field outlines were independently checked and the agreement with reported acreages is good for each of the 21 fields selected under Section I. Thickness was obtained from driller's logs or modern logs (if any exist) for the field. Although the acreage, thickness, and total production figures are merely estimates, they may be the most accurate reservoir information existing on West Virginia oilfields.

The reserves originally in place in these 21 fields could be calculated volumetrically if the porosity, acreage, thickness, and water saturation were known. In fact, the first three quantities are known for most of the reservoirs selected under Section I of this study; water saturation values, however, are not. Because these fields do not normally produce water along with oil, they must have water saturations near the irreducible value. Irreducible water saturations may be estimated, if permeability is known,³⁷ from empirical relationships such as

$$S_{wir} = \frac{250\phi^3}{k^{\frac{1}{2}}}, \text{ where } \phi \text{ is porosity and } k \text{ is permeability.}$$

The relationship seems to work well on three pilot areas where the original saturation values have been estimated, but this is scarcely a valid test. It seems also to work with a large portion of the reservoir information filed in a 1951 secondary recovery report.¹¹ Unfortunately, permeability is not known for most of the fields of interest in the present study.

Further evidence of the utility of this well known empirical relationship is found by comparing its predictions with saturations derived from air/brine capillary pressure measurements.³⁸ As can be seen from Figure 11, the agreement between these values is good.

Conventional volumetric calculations will yield necessary water saturation from the original reserve estimates (see Table 13). Such calculations show that in some instances the reserves have been grossly misestimated. Oil saturations in excess of 100 percent, which are indicated for some fields, certainly cannot exist; and it is hard to understand water-free oil production from reservoirs having oil saturations as low as 16 percent.

The IOCC has published several reports in which saturations obtained by core analysis of several fields and reservoirs were averaged.¹²⁻¹⁴ These values are critical to estimating reserves, and a complete tabulation is given as Table 14. These average values can be used in estimating more realistic saturation values.

Reserve figures have been calculated for 10 of the fields selected in Section I, using data from two sources: original saturation and formation volume factors were taken from the 1954 IOCC report on secondary recovery in West Virginia¹²; values for acreage and thickness came from U.S. Bureau of Mines Bulletin No. 607.¹⁰ Results of the calculations are shown in Table 15.

It should be stressed that neither the original saturation values nor the original formation volume factors have been determined directly; consequently these reserve figures are highly speculative estimates. In two instances the 1963 Bureau of Mines estimates of original oil in place appear to be more reasonable; in eight other fields the calculated reserve estimates seem satisfactory.

The total estimate of oil originally in place in these 10 fields is 741.6 million barrels. Total production is 112.6 million barrels, leading to an estimated total recovery of 15% for these 10 fields. This is certainly a respectable figure, considering the completion practices in use when these fields were developed (mostly before 1920). Using reasonable numbers for unknown values in the remaining 11 fields reveals that more than one billion barrels of oil may remain in fields where the CO₂ displacement process should work.

Reservoir Data.

For some of the candidate fields, such as the 10 in Table 13, reservoir information is available in the technical literature to estimate the potential of EOR technology; for others, very little quantitative information exists. In an attempt to overcome this difficulty, all the known values that could be found for certain key reservoir features have been gathered. These were determined independently of the IOCC report and thus serve as checks on the values reported there.

Porosity. The averages of all published porosity measurements in the various reservoirs are given in Table 16. This table includes the IOCC values for comparison. These values can be used as guides in estimating unknown porosity values.

Formation volume factors. Values for this parameter were established for all fields for which an API gravity was available, using published correlations and estimating the unknown values. The results appear in Table 17. In 1954, the IOCC's West Virginia Committee published state averages for the original formation volume factors of all the major producing sands in the state. This information is not available from any other source. The formation volume factors taken from this report are compared with estimates made for the present study by the correlation in Table 17.

Current formation volume factors have been estimated from recently measured values for the reservoirs in the Griffithsville, Rock Creek, and Granny's Creek fields; these values are 1.04, 1.15, and 1.11, respectively, at approximately 1000 psi. The first field has had no gas repressuring; the other two have had large-scale low pressure gas injection projects. Since the crude oil is remarkably uniform throughout the state, the current formation volume factor can be estimated at around 1.04 if the field has not undergone extensive gas repressuring, or 1.13 if it has.

Permeability. One factor impeding the assessment of the potential of EOR techniques in these fields is the lack of permeability data, either absolute or relative. An attempt was made to assess at least qualitatively the permeability to oil of those reservoirs selected as having significant EOR potential.

Since the major reservoirs in the state have a narrow depth distribution, the original bottomhole pressures and temperatures should have been comparable. The viscosity of West Virginia crude oils also has a narrow distribution, as previously mentioned. Another feature of these reservoirs is that they were all solution gas or gas expansion drive reservoirs. In view of all these similarities, it is tempting to calculate a permeability for a given reservoir by estimating the unknown factors in Darcy's law.

Darcy's law for radial flow, ignoring gravitational effects, can be stated as

$$q = \frac{7.08kh(P_e - P_w)}{\mu B_0 \ln(r_e/r_w)} \quad (\text{Eq. 1})$$

where B_0 = formation volume factor,

h = net sand thickness in feet,

k = permeability in millidarcies,

μ = viscosity of oil at reservoir conditions in centipoises,

P_e = pressure at edge of drainage in psi,

P_w = pressure within the well in psi,

q = flow in barrels per day,

r_e = effective drainage radius in feet, and

r_w = wellbore radius in feet.

Assuming $(P_e - P_w) = 500$ psi, $r_w = 0.3$ feet, $r_e = 600$ feet, $\mu = 1$ cp, and $B_0 = 1.2$, then k is given by

$$k = \frac{q}{388h} \quad (\text{Eq. 2})$$

Admittedly, many approximations are used in deriving this relationship, but the agreement with results from the field tests studied in detail under Section I is quite good. Using the recorded maximum 24-hour potential and net thickness from driller's logs, the permeabilities calculated from Equation 2 for Rock Creek, Granny's Creek, and Griffithsville are 12, 6, and 9 md, respectively; the corresponding core-derived values from the pilot areas are 15, 2, and 4 md (geometric mean permeability using all measured values greater than 0.1 md).

The agreement is not perfect, suggesting that the above treatment and the relationship given by Equation 2 are oversimplified. However, permeability is inherently a property with a wide range of distributions, so it is not surprising that there is less than total agreement of the known permeabilities of the pilot areas with the approximated values for the whole fields derived above. Even though it is a roughly approximated value, such a number can at least be used to divide the candidate reservoirs into very high, medium, or low permeability categories. This has been done; the results are shown in Table 18 and graphically in Figure 9. Figure 9 shows that there are no obvious candidate reservoirs for the steam process.

Lack of permeability data means also that permeability variation is unknown, and high permeability variation is detrimental to all EOR processes. In an effort to provide reasonable values of this critical feature, permeability variations for selected formations have been determined from core analyses obtained in an earlier program.^{22,23} These data are displayed graphically in Figures 12 - 14.

The logical candidates for waterflood or polymer-augmented waterflood are fields in the medium to high permeability brackets that have not been waterflooded. The high permeability fields may be candidates for chemical EOR processes; this would depend on the specific crude oil composition, resident brine composition, and many other factors whose evaluation is beyond the scope of this discussion. The low-pressure gas process should be applicable to all the reservoirs; it has been applied to at least some portion of most large fields.

A summary of many of the salient features of each reservoir selected in Section I is given in Table 19.

The CO₂ process is potentially applicable to all of the listed fields. This assessment is only preliminary, and the application of the process to any of these reservoirs by industry will probably be deferred until certain features of each reservoir needed to make an economic evaluation can be determined.

Economic Considerations.

For an adequate economic assessment of any EOR project, an accurate determination of the residual oil saturation is necessary. This could be done by analysis of logs from a recently drilled well in the field. The method is, however, hampered by difficulties in the determination of one key variable, water resistivity. Determination of the correct water resistivity factor to use in log analysis of old reservoirs is always a problem, since extraneous water may have been introduced into the formation by crossflow behind pipe or by attempted waterfloods. Produced water, if in fact it is from the formation, will normally come from the more permeable intervals of

the sand, which are also the intervals most susceptible to flushing by extraneous water. Such intervals may also exhibit the most highly developed SP value. Thus both the SP-derived and the produced-water values for resistivity may be correct for the more permeable intervals but incorrect for the tighter portions of the sand. Salinity measurements on interstitial water may provide the correct resistivity to use in the tighter unswept and uncontaminated portions of the sand.

Other requirements for an adequate economic assessment include an evaluation of the current condition of the field and an estimate of the costs of rectifying any major problems.

One of the easily identifiable problems in applying the CO₂ miscible process (or any other process involving high pressure or expensive chemicals) is locating and properly plugging old wells. The nature of this problem is made clear in the discussion below, describing the casing practices used in drilling Walton Field. These were probably typical of the time, and most of the fields drilled before the late 1930's probably had similar programs.

The casing program used during the early development period included wooden conductor pipe set through the surface soil and gravel. Water from fresh water sands was excluded from the hole by setting a string of 10-inch surface casing to a depth of about 300 feet. An intermediate string of 8-inch casing usually was set in the top of the Big Dunkard sand to exclude red-rock caving. The production string, usually of 6-5/8 inch casing, was set in the upper portion of the Big Lime to prevent the invasion of salt water from the Salt sands. The seal around the production casing was made by allowing the drill cuttings to fall around the casing. Open-hole drilling then continued through the Big Injun and Squaw sands, allowing a 25- to 30-foot pocket below the bottom of the Big Injun sand. In completion, most of the wells were shot with 30 to 50 quarts of nitroglycerin. The size of the "nitro" charge was governed by the thickness of the sand, designed as "oil pay" in driller logs. In many instances the 8- and 10-inch strings of casing were pulled from the hole after the production casing was set.³⁹

Pulling the 8- and 10-inch casing leaves a 6-7/8 inch casing in a 10-inch hole, held in place by cuttings dropped down the hole. Of course the natural caving action of the shales would tend to fill this void, but without cement it appears that if the reservoir were subjected to high pressure the fluids could escape through and around the old well.

if the casing has been pulled and the hole plugged with cement, the danger of leakage will be less. Similarly, if the old wells are open and not concealed (cut off below ground level) it will be much easier to reenter and properly cement them. Therefore, fields still under production must be considered to have a higher potential for EOR by the CO₂ displacement method than those previously abandoned, simply because the location of the wells is known with certainty.

The last major obstacle to performing an adequate economic assessment at this time is the inability to estimate with any accuracy the amount of oil that might be gained by the application of the CO₂ process. Current industry estimates are that for a successful CO₂ displacement project, 2-7 MCF of CO₂ will be required for each barrel of additional oil. As will be discussed in Section III of this report, in the single CO₂ project for West Virginia for which results are available, the CO₂ required per barrel of additional oil was substantially higher than this.

III. EVALUATION AND INTERPRETATION OF THE RESULTS OF ONGOING AND PROPOSED CO₂ INJECTION FIELD TESTS IN WEST VIRGINIA

Three ongoing CO₂ projects in West Virginia, located in small portions of the Rock Creek, Granny's Creek, and Griffithsville fields, present a unique opportunity to thoroughly analyze the field performance of this EOR process. There are many similarities among these three projects, which may allow the evaluation of certain key variables if the reservoirs can be adequately characterized and which reduces the number of variables that must be considered in comparing the results of high-pressure CO₂ displacement.

The well spacing and injection patterns of two of the projects are very similar; the third is only slightly different. The total net sand thicknesses in all three pilot areas are also, within acceptable limits, comparable--approximately 14-35 feet (see Table 22).

The properties of the oil, and consequently of the CO₂-oil mixtures, are very similar in all three projects (see Table 20).

The geometric mean permeabilities in the pay sands are of the same order of magnitude (5-1.5, 8, 15 md).

Since in a miscible displacement the displacement efficiency is equal to 1, and in a near-miscible displacement it is nearly 1, the recovery from a reservoir is strongly dependent upon the amount of oil in place and the volume of the reservoir contacted.

The amount of oil currently in place is a function of the original saturations and subsequent field history. Two of the field reservoirs in the present study have similar current oil saturations, while that in the third project is higher. One of the reservoirs has been waterflooded, one has been subjected to low pressure gas injection, and the third has had only accidental crossflow since primary production.

The volume of oil contacted is a function of several factors:

- gravitational effects, which can separate the injected fluid from one or more of the resident fluids;
- stratification, permeability, and permeability distribution within the reservoir, which can cause the displacing fluid to come in contact with only part of the reservoir;
- possible chemical reactions, which can dissipate the miscible fluid or damage the reservoir;

- well spacing and reservoir size;
- size of the slug of miscible fluid, rate of injection, and mobility ratios.

For any miscible displacement, "viscous fingering" effects and "gravity override" difficulties are normally considered the major problems. Gravity segregation has not been observed to be a problem in ARCO's well documented and thoroughly studied test in the Willard Unit of Wasson Field in West Texas.⁴⁰ However, this is a highly stratified carbonate reservoir, and the results may not warrant direct extrapolation to sandstone reservoirs.

Warner found that gravity segregation of CO₂ and water in waterflooded sandstones could be predicted by mathematical simulation of the displacement process.⁴¹ The recovery predicted by the model decreased dramatically with increasing vertical/horizontal permeability ratios. Good agreement between the predicted and observed results of the Willard Unit mini-test were obtained when the K_v/K_h ratio was about 0.1.⁴⁰ Warner's study predicted that relatively severe override problems would occur at this ratio, which is lower than the ratios in the three West Virginia project areas (0.3, 0.8, and 0.9) (see Table 22).

The temperatures and pressures at which highly effective displacement is predicted to occur in all three projects are near the critical point of CO₂ (see Figures 22 and 27). If pressures are above 1029 psi at reservoir temperatures found in these projects, the CO₂ will be liquid, with a density of about 0.46 gm/cm³ and a viscosity of about 0.07 cp at 68°F. This density is about half that of the oil in the three projects, and the viscosity is lower by a factor of about 50. As oils become saturated with CO₂, the density increases; as water becomes saturated with CO₂, the density decreases.⁴⁶ Thus the inherently large differences in density between pure CO₂, oil, and water may not cause such serious gravity override problems as might be predicted. Limited field experience gives some evidence that this is the case.

Since the three CO₂ displacement field tests are in reservoirs of varying vertical permeability, it will be possible to determine whether the gravity override problem predicted by Warner's model will be observed in the field, and the K_v/K_h value at which gravitational effects become dominant (see Table 22). The plots of vertical vs. horizontal permeability for all the projects are given in Figures 28 through 30. Although the figures show some scatter in the data, there seems to be a fairly consistent relationship between horizontal and vertical permeability in all of the projects.

Permeability variation may be one of the most significant variables. The variation of permeability in the project areas can be found by plotting the permeability on log probability paper.⁴⁵ If these values are plotted

using the same permeability cutoffs to refine the values as were used in computing net pay thickness, then the variation calculated is the variation of permeability within the pay zones. This was done for all of the field project areas. For such calculations, and for comparison purposes, a uniform permeability cutoff of 1 md was used for all projects (see Figure 15). It was found that the variations obtained for these groups of data were not dramatically different (0.46 to 0.70). However, critical examination revealed that filtering the permeability values had produced a comparison of only the high permeability zones of the Griffithsville and Granny's Creek fields with the entire Rock Creek reservoir (see Figure 15).

An apparently more useful approach to the permeability distribution is to use every permeability measurement greater than 0.1 md in the probability plots. Such a plot conveys more information than a simple net/gross ratio, and should be a more useful guide to predicting reservoir performance. This was done for all the CO₂ field projects, yielding the plot shown in Figure 16. Only cores taken through the total sand interval were used, to avoid biasing the data. As can be seen from this figure, there is a large difference between the Rock Creek and the Griffithsville and Granny's Creek fields.

Viscous fingering is normally aggravated when there is a high variation, but lateral continuity of the variation is also a key characteristic: even a very large permeability variation would not be especially detrimental if it were randomly distributed. If the porosity and permeability are controlled by the original distribution of features in a reservoir, then they will be stratified, since, in general, all sedimentary rocks are inherently stratified. However, if the permeability is controlled by secondary reactions, such as differential cementing in reworked sediments, then this should produce a rather unstratified distribution of permeability. The Berea sand in the Griffithsville field seems to fit this latter category, and even though there is a large permeability variation, the tight streaks correlate poorly from well to well within the field. Viscous fingering or early breakthrough may be a less serious problem in this reservoir than one might expect.

A plot such as Figure 16 suggests intuitively that the ratio of the high permeability zones (taken as those at probability 0.9) to the geometric mean permeability ($k = 50\%$) should be of some use in predicting reservoir channeling problems, particularly if the permeability is stratified; however, not enough data exist at this time to validate this concept. Well spacing, slug size, injection rates, and mobility ratios would also have to be taken into account to make this treatment universally applicable. A plot of this type can be used to indicate the fraction of each reservoir that is accessible to CO₂, provided a minimum permeability can be assigned. For example, if a 5-md permeability cutoff is used for the Rock Creek field, more than 80% of the gross reservoir is accessible to CO₂ displacement. If a 1-md cutoff is used for Griffithsville, then 64% of the

gross reservoir is accessible. (Gross reservoir is defined as all parts of the reservoir having a permeability greater than 0.1 md.)

A three-dimensional panel diagram is probably the best way to adequately describe porosity (and therefore permeability distribution or stratification) in an oil reservoir. Panel diagrams of all three project areas are shown in Figures 31 - 33.

Injecting CO₂ into a reservoir raises the possibility of chemical solution. Calcite, dolomite, and ankerite are found in some of the project areas as cementing agents (ankerite is similar to dolomite, with iron in place of magnesium). Solubility product constants for some carbonate minerals are given in Table 21. The solubility of CaCO₃ is related to pH and to the pressure of CO₂ by the equation⁴²:

$$2 \text{ pH} + \log P_{\text{CO}_2} = 9.76 + \log \frac{1}{[\text{Ca}^{++}]}$$

$$\text{or } \log [\text{Ca}^{++}] = 9.76 - 2 \text{ pH} - \log P_{\text{CO}_2}$$

[Ca⁺⁺] is the concentration of the Ca⁺⁺ ion, which is a measure of the solubility of the mineral.

This equation shows that for a given pH of reservoir water, increasing the pressure of CO₂ will reduce the concentration of Ca⁺⁺ ions. If the pH of the reservoir water is decreased by the addition of CO₂, then the [Ca⁺⁺] should increase. Hence, increasing CO₂ pressure and decreasing pH tend to offset each other. Pushed too far in either direction, the effects are generally detrimental to EOR: permeability reduction could result from wholesale precipitation of CaCO₃, while high permeability channels could be created by large-scale dissolution of calcite.

All three of the projects have been designed to inject water and CO₂ alternately for mobility control.^{6,7,8} In the Rock Creek and Griffithsville projects, the slug size was chosen to be about 20-30% of the hydrocarbon pore volume. The Rock Creek project is calling for about 15,000 tons of CO₂ and the Griffithsville project about 8000 tons (for the original pilot project as planned). Later papers⁴⁷ have called for the Griffithsville project to be expanded to use 30,000 tons and evaluate 90+ acres rather than about 35 acres in and around the 10-acre five-spot. The Granny's Creek project injected 9878 tons of CO₂ to evaluate a 6.5-acre five-spot. CO₂ was found far outside the pattern, however. This will be discussed in greater detail below.

Summary of Granny's Creek Project.

Since the Granny's Creek project is the only one in which CO₂ has been injected up to the present time, an understanding of the results obtained there is critical to the valid extrapolation of the CO₂ displacement technique in West Virginia.

The Granny's Creek project was designed to evaluate the effectiveness of CO₂ displacement in a watered-out portion of a waterflooded reservoir. The nucleus of the project was an unconfined 6.5-acre five-spot. The reservoir was repressured with water to approximately 1500 psi in the immediate area; CO₂ and water were alternately injected through the four corner wells of the five-spot. A total of 9878 tons of CO₂ was injected, producing 8500 barrels of additional oil from both inside and outside the project area. This works out to about 1 barrel of additional oil per 20 Mcf of CO₂. Proprietary information indicates a much higher efficiency than this, about 2.5 Mcf per barrel, based on the fact that only 6 percent of the injected CO₂ entered the pattern. Recent publications have listed the cost of CO₂ at \$0.25 to \$1.15 per Mcf, not including costs of transportation to the well site and injection. It would seem that this project was not an economic success, and it therefore becomes important to determine as accurately as possible why this was the case.

Geology.

The Big Injun sand in the project area, as described in Columbia Gas Transmission Company's original proposal and in later company reports, consists of at least three separate sand lenses, labeled A, B, and C. There is a fourth less well-developed zone (D) in the immediate project area; however, it is normally tight. The project is located on the northwest side of a syncline which plunges to the northeast. The formation dips rather gently in the immediate project area.

The Big Injun sand in this field is characterized as a tight friable sandstone. Core descriptions indicate the sand to be slightly limey, slightly conglomeratic, and silty near the bottom. The sand is also described in core reports as coarse- to very coarse-grained quartz with minor amounts of feldspar and glauconite, containing silica cement near the top. Other minerals specifically indicated on core descriptions are pyrite and mica.

The C zone of the lower Big Injun is described as an argillaceous fine-grained or silty sandstone. The A and B zones consist of very coarse- to fine-grained sand and are normally clearer than the C zone. The term "conglomeratic" has been applied to portions of the A and B zones.

Columbia interpreted the C zone as an offshore bar lying parallel to the ancient shoreline and thickening toward the paleobasin. After the formation of the bar, a regression of the seas, with subsequent deposition of strandline deposits, has been evoked to explain the A and B zones. This interpretation adequately explains the major features of the sand.

Permeability. The A and B zones are of higher permeability than the C zone. The plots of permeability against porosity for the three zones, shown in Figures 17, 18, and 19, show dramatically that the sands are different. This difference in character suggests that the sands had either different environments of deposition or different post-depositional histories.

The average permeabilities of net pay in the A, B, and C zones in the project area are 5, 5, and 1.5 md, respectively. The average permeability of each sand, however, does not fully characterize the permeability at each well. A plot of the typical permeability distribution for well #20274, which was cored in the center of the project area, is presented in Figure 21. The significance of the highly variable permeability distribution, especially in the A and B zones, can best be understood in light of other well documented field tests.

In their Willard Unit mini-CO₂ test, ARCO used time-lapse logging to monitor the formation of an oil bank and the changes in CO₂ saturation. They observed different responses with the passage of the CO₂ front. In zones thicker than 20 feet, the CO₂ displacement formed a CO₂-free oil bank; this was not true for thinner zones (approximately 10 feet and 5 feet). In light of the existence of many thin permeable zones in the immediate Granny's Creek project area, especially in the A and B zones (see Figures 4 through 9), it is not surprising that no CO₂-free oil bank was formed, even though CO₂ was injected alternately with water for mobility control.

Production Response. Injection rates of more than 10 tons per day per well (about 106 bbl of liquid CO₂ per day) were achieved. The amounts of CO₂ and water injected, and the exact sequence of injection, are well documented.^{45,46} Deducing where these fluids went, however, is not an easy matter. Figure 20 shows the areal distribution of wells found to have concentrations of CO₂ greater than 4% at any time during the project. The fact that CO₂ was found over an area of more than 200 acres, rather than the 6.5 acres on which the project was based, will give new meaning to the recovery figures. See the panel diagram for the thickness and areal extent of the A, B, C, and D stratigraphic zones.

It is possible to calculate the number of pore volumes of CO₂ injected into each sand by apportioning the CO₂ injected on the basis of permeability and thickness, assuming the project area is representative of the entire field. The geometric mean permeabilities for zones A, B, and C are 5, 5, and 1.5 md, respectively. The D zone was tight in all wells. From the cored wells in the project area, the average net pay in the A zone sand with greater than 1 md permeability (no saturation cutoff was used because of lack of data) is 5 feet, in the B sand 3.2 feet, and in the C sand 17.5 feet. The product of permeability and thickness is 25 md-feet for zone A,

16 for zone B, and 26 for zone C. Allocating the injected CO₂ in these proportions gives 37% to zone A, 24% to zone B, and 39% to zone C.

Converting the total tonnage of CO₂ injected into cubic feet of pore space requires some knowledge of reservoir conditions. The pressure in the immediate project area was high enough that the CO₂ would remain liquid (see phase diagram, Fig. 15). At the critical point, CO₂ has a specific volume of 0.342 ft³/lb, or 68.4 ft³/ton. The project area was at slightly lower temperature (about 80°F) and higher pressure (1550 psi) than critical; at these conditions the Z factor for CO₂, if it is a super-compressed gas, should be 0.225 (from experimentally derived values), giving a specific volume of 39.2 ft³/ton (Figure 22). However, as the CO₂ moved away from the project area, it expanded with decreasing pressure, so that the figure 68.4 ft³/ton may be an adequate approximation for rough calculations. Assuming that it is, the 9878 tons of CO₂ injected would occupy 667,000 ft³ in the reservoir. Using the allocations calculated above, approximately 9 to 13% of the hydrocarbon pore volume was injected into zone A, approximately 8 to 11% into zone B, and 2 to 3% into zone C. The ranges in these values result from variations in hydrocarbon saturation from 50% to 35%, i.e., between the original saturation and the present estimated post-waterflood saturation. It is difficult to estimate or calculate how much of the injected CO₂ remained within the pattern.

Fluid Saturations.

Hydrocarbon saturations can be determined from a proper log suite provided certain values are known or can be approximated. Information was obtained from Columbia on several wells outside the immediate project area that could allow the calculation of hydrocarbon saturations. The nearest wells are #20317, about 2000 feet northwest of the project area, and #20237, about 1000 feet to the north-northwest.

Factors that must be estimated in order to conduct log analysis are a, m, and n factors, plus (most importantly) the water resistivity. The a, m, and n factors for zones A, B, and C have been estimated to be 1, 2, and 2, respectively, by analogy with the Rock Creek Big Injun sand, where these values have been measured. The water resistivity calculated from SP in the 20317 well is 0.075; but analysis of interstitial water from two wells (Summer's Heirs V-2018 and #20274) drilled within the pattern at widely separated dates (1963, before the waterflood, and 1975, after) indicates that the resistivity should be much lower, at least in the C zone. When the lower resistivity was used in the log analysis, however, with appropriate corrections for shale, the hydrocarbon saturations turn out to be about twice as high as the value used by Columbia in planning the project. Their value was presumably determined from detailed studies, including two reservoir simulations; hence the values calculated may not be representative, and they have not been included in this report.

Rock Creek and Griffithsville Projects.

Since CO₂ injection has not yet been initiated in Rock Creek or Griffithsville, it is impossible at present to summarize or evaluate the projects. It is possible to set the stage for the evaluations of these projects by characterizing the rock properties, reservoir conditions, reservoir repressuring, and planned procedures as fully as possible. This is the subject of the following sections, where each project area is discussed under the following headings:

- Rock properties
- Reservoir conditions
- Saturations
- Design features

Rock Properties in the Project Area of Griffithsville Field

Lithology.

The Berea sand has been described in the Guyan Oil Company technical progress reports as a gray quartz sand, uniform in thickness, cross bedded, fine-grained, with subangular grains, fairly well sorted and closely cemented.

Crossplots of the neutron vs density log values indicate that the cementing material is probably calcite or dolomite. Petrographic work in the files of METC, done on cores from Well #I-7, shows that the cementing material is, by and large, dolomite. Other accessory minerals identified in core analysis are pyrite and calcite. Shale was not a major constituent of most cores, although some shale streaks were noted. The grain size decreased toward the base of the sand, according to the petrographic analysis. The detrital-illitic or sericitic material increases towards the bottom.

Porosity and Permeability.

Porosity and permeability measurements in the pilot area have been made on cores taken from six of the new project wells. Horizontal permeability, directional horizontal permeability 90° from maximum, and vertical permeability have been measured on some whole cores and plugs.

Porosity values measured by sidewall neutron, compensated neutron, and compensated formation density logs can be used to calculate an effective porosity, and the results compare favorably with the core values. Figure 23

gives a porosity vs permeability plot for all recorded measurements in the field.

Both the average porosity and permeability increase toward the top of the Berea sand. The overall average porosity of the pilot area is 11.2%. Permeability values vary dramatically; however, the overall geometric average of the gross sand is 5-6 md. A Dykstra-Parsons type permeability variation plot is given in Figure 16. If a 1-md permeability limit is used in calculating net pay, the reservoir contains approximately 14 feet of net sand (mostly at the top), with an average porosity of 12.3% and an average permeability of 8.2 md.

Vertical permeability from core analysis on Well #I-4 is estimated to be about 0.3 of the horizontal permeability (see Figure 30).

A plot of permeability vs depth in one of the project wells is given in Figure 24.

An injectivity test for CO₂ was performed in Well I-6 (which was completed in open hole after fracturing). At an unspecified wellhead pressure, CO₂ was injected into this formation at a rate of 3.8 tons per hour. At reservoir conditions, this is about 829 barrels of liquid CO₂ per day.

Three-Dimensional Porosity Distribution.

A panel diagram for the pilot area has been made with intervals correlated on as fine a scale as possible (Figure 33). GR-FDC porosity logs with core porosity and permeability plotted on them were used as the basis for correlations. The detail on this diagram shows that there are no apparent deadend porosity intervals, and that the tighter intervals (porosity less than 10%) are interdigitating and do not seem to effectively divide the sand into separate zones. However, the highest porosity and permeability intervals in each well are nearly always in the top portion of the sand. This section will probably be the path of least resistance to the CO₂ slug. Even if the sand were divided into separate lenses or zones, the abundance of old wells fractured with explosives in this portion of the field would allow communication of all zones.

The above discussion of lithology and other properties, together with the regional framework of the Berea sand, suggests that this deposit has been reworked and that the hard (or low permeability) streaks that do not correlate between wells result from differential cement development.

The Griffithsville field is a synclinal oil field⁵³; the immediate project area dips gently (less than 0.5°) toward the northwest.⁵¹

Fractures.

To this point in the study, no evidence has been found for naturally occurring fractures in the field. The orientation of induced fractures has been carefully documented by impression packer work in Well #I-6. This direction is S. 55° E.

Reservoir Conditions.

The reservoir conditions in the pilot area are taken to be temperature, depth, original pressure, present pressure, and salinity and hardness of connate waters. The temperature of the reservoir corrected from the maximum reading taken at bottom hole (generally less than 100 feet below the formation) is 75-85°F. The depth of the field is approximately 1450 feet below sea level. Original pressure, as nearly as it can be established, was in the neighborhood of 1000 psi. Present pressure, of course, is dependent upon the amount and the rate of fluid injection. The properties of the connate water in the reservoir cannot be determined. However, the zone has been thoroughly flooded with water from the overlying Salt sand and analysis of produced water shows total dissolved solids of approximately 105,000 mg/l, with calcium and magnesium totaling 8800 mg/l.

Water Saturation Calculations.

Water saturations (S_w) were calculated for those wells in which an induction log and at least one porosity log have been run. (Table 5 lists the logs available for each well in the pilot area.) Porosities from cores were compared to porosities derived from logs to verify the efficacy of using log-derived data. Where two porosity logs were run (the FDC and CNL or SNP), a density-neutron solution for shale volume and effective porosity was performed. Since the volume of shale calculated by this method was normally very low or zero, shaly sand log analysis was considered unnecessary.

The water saturation value so obtained is about 54%, higher than the value of $S_w = 40\%$ calculated by using a lower water resistivity. Because of this difference, a short discussion is appropriate.

A Core Lab report dated March 2, 1978, shows a formation water resistivity of 0.065 ohm-meters³⁸, and the resulting computations of the water saturation yield values similar to those obtained in this study. On the other hand, measurements made in 1965 on Berea cores from Joe Stephen No. 1 gave interstitial water chloride concentrations averaging 216,000 ppm. Such highly saline formation water should have a resistivity of approximately 0.037 ohm-meters⁵¹; according to the SP measurement on the Griffithsville logs, the formation water resistivity in some wells was as low as 0.035 ohm-meters. Therefore it is impossible to ascertain the correct saturation value. Within the realm of engineering judgment either value could be taken as correct; for the purposes of this study, we have decided to carry both values (see Table 22).

Fluid Saturations in the Pilot Area.

In evaluating the efficiency of the CO₂ EOR process, it is probably better to use the highest reasonable in-place oil figure as a starting point, since this tends to underestimate rather than overestimate the efficiency of the displacement process.

In light of the reservoir's history, derived fluid saturations may vary widely across the project area. The reservoir, discovered in 1908, apparently produced by solution gas drive. Primary production probably left high residual gas saturation, on the order of 30-40%.

Estimates of oil recovery from the total field are around 20% of oil in place. The field has been abandoned for many years except for a few isolated producers.

The next significant event in the history of this portion of the field was accidental repressuring by crossflow (dump flooding), presumably from the Salt sand. This crossflow has repressured the reservoir in this area to around 725-975 psi, depending upon the exact location.^{53,57} When the water entered the formation it may have traveled preferentially through the zones of high gas saturation and moved little oil, since a high oil saturation still exists in the pilot area. Existing gas was either displaced or forced back into solution by the rising pressures. Guyan Oil Company noted that waterflooding, either from crossflow or from repressuring operations, has now mobilized some of the oil remaining in the reservoir. The reservoir is currently producing at the rate of about 50 BOPD from 9 producing wells. Injection tests by Guyan have found that the wells will take 80-150 BOPD at bottomhole pressures of 1600+ psi.

Design features.

The wells used in this project are conventional wells with various casing sizes and completed by various techniques. One well, I-6, is an open-hole completion with 7-inch casing.^{54,55} Other new wells in the project have 4-1/2 or 5-1/2-inch casing with set-through type completion. Well locations are plotted on the base maps of the panel diagrams included with this report.

Planned CO₂ injection rate is about 10 tons per day per well.⁵³ CO₂ for this project will be purchased, shipped, and stored at the location in liquid form. The planned facility calls for three storage tanks, each of 38-ton capacity, to store CO₂ at 250 psi and -15°F. Liquid will be moved from storage to main injection sites by electric booster pumps. Main injector pumps will have variable flow capacity.⁵⁴

Corrosion mitigation plans have not been disclosed, possibly because they have not been completed.

Major problems in this project have resulted from the difficulty in re-entering many old wells. Legal action by environmentalists has also imposed considerable remedial work.

Rock Properties in the Project Area of Rock Creek Field.

Lithology.

Pennzoil has provided what appears to be an excellent description of the lithology and mineralogy of the reservoir in their annual reports and two published articles. The following significant points are extracted from their work.^{7,50}

The Big Injun sandstone is described as "a light greenish-gray, very fine to medium grained well sorted subangular sandstone that is slightly to moderately calcareous."

X-ray diffraction and petrographic analysis were performed by Halliburton on one sample from L. W. Shaffer PI-2 at a depth of 2104.54 feet. Core analysis on this sample gave a porosity of 23.2% and a permeability of 19 md. The sample exhibited slightly better petrophysical rock properties than the average of the total sand. It was described as "sandstone, poorly sorted, very fine to medium grained quartz, feldspar, mica and rock fragments forming the framework, small amounts of quartz overgrowth, predominant clay is chlorite present as coating on pore walls, small amount of calcite is observed as pore fill. Good visible porosity with chlorite linings."

Pennzoil also reported occurrences of ankerite and siderite. These, however, are of minor importance, except that they probably cause some minor pore filling.

Porosity and Permeability.

Porosity and permeability measurements have been made on cores taken from the entire interval from several of the project wells. Most of the core analyses in the field were performed on whole cores. Horizontal permeability at 90° to first reading, vertical permeability, porosity, and residual oil and total water saturations have been measured on all cores. Other porosity measurements have been made by FDC-GR logs run through the interval. A porosity vs permeability plot is given in Figure 25.

The overall average porosity for the pilot area using 5 md cutoff was reported by Pennzoil to be 21.7%. For a 1 md permeability cutoff, the overall average porosity is 21.2%. Using the method of determining geometric

average permeability from plots of permeability vs probability, the geometric average for the project area would be 15 md or 12 md, respectively (Figure 16). As may be seen from Figure 16, the porosity cutoff of 19% used in the calculation of water saturation corresponds very nicely with the 5 md cutoff used by Pennzoil in their determination of net pay from core analysis.

As noted by Pennzoil, the vertical permeability measurements seem overly high, but they are consistent (see Figure 28). The vertical permeability appears to be 0.9 of the horizontal permeability, but this value is very high and may result from a consistent error in the data treatment.

Figure 26 is a plot of permeability vs depth for a typical well in this project.

Three-Dimensional Porosity Distribution.

A panel diagram has been made for the pilot area on which all porous intervals have been correlated on as fine a scale as possible. FDC-GR porosity logs and permeability from core analysis plotted on the logs were used as a basis for correlations, where possible. Where these logs were not available, the best available log was used instead. A half-size copy of the panel diagram for this project area is included with this report.

This diagram shows the sand to be remarkably uniform and consistent from well to well. There appears to be very little deadend porosity (see zone near the bottom of Shaffer #2 PI-#1 and Lewis #17). Most of the tight intervals of the sand are interdigitating and do not correlate from well to well (see zones in PI-#6). One tight zone, very near the bottom of the sand, does seem to be consistent and is present through most of the field (see PI-#2); it follows the zone through I-#3 and southerly through the field. Even if the sand were more extensively divided into lenses or zones, the abundance of old wells fractured with explosives would allow communication of all zones in the vicinity of the wellbores. Depositional and post-depositional environments of this sand should be very similar to those of the C zone at Granny's Creek. The Big Injun formation at Rock Creek correlates well with the C zone of the Big Injun sand of Granny's Creek, but the A and B zones are missing.

Pennzoil noted that depositional environment indicators other than textural and mineralogical data are largely nonexistent. Infrequent crossbedding has been noted with very low angle and of hummocky type. Also noted in the core were some micro-cross laminations, possibly from current ripples, as well as one pebble lens.

The occurrence of two chiefly syngenetic⁴³ (formed during diagenesis) minerals, siderite and ankerite, suggest that the deposit was subjected to a weakly-reducing to neutral environment shortly after deposition.

All of the above facts are consistent with the interpretation that the sand in this field was deposited as an offshore or near-shore bar with very little reworking of the sediment. This is also consistent with the overall geometry of the sand.

Structurally, the Walton field (which contains the Rock Creek field) is a synclinal oil field. The immediate project area is on the eastern flank of a northeast-plunging syncline. The formation dips toward the northwest at slightly more than 0.5° .

Fractures.

To this point in the study no evidence has been found for any naturally occurring fractures in this field. Some anomalies in injection water breakthrough have been attributed to a permeable zone in the Big Lime above the Big Injun sand.

Fluid Saturations in the Project Area of Rock Creek Field.

Special core analysis, an adequate suite of logs in some wells, and knowledge of the resistivity of the connate water of the reservoir allow the calculation of water saturation of the project area. The water saturation (S_w) of the project area is approximately 50-69% with an average of 54%. This value was calculated using a, m, and n factors from special core analysis (1.0, 2.0, and 1.97 respectively) and a water resistivity of 0.045 ohm-meters. The average water saturation was determined using a 19% porosity cutoff. These values are higher than those obtained by Pennzoil ($S_w = 46.2\%$).⁴⁴ This difference is probably the result of a shale correction used by Pennzoil to correct for the chlorite content of the reservoir rock noted above. The value used in the present study was based on a clean sand approach, because the information necessary to make a quantitative shale correction was not available to us. Therefore, the actual value of the present water saturation is probably about 46-50% and certainly no higher than 54%.

Design Features of the Rock Creek CO₂ Injection Project.

The following summary of the design features of the Rock Creek project is taken from a Pennzoil report.⁷

The project area is in an old portion of the field and uses both old and new wells. The two center producers in each five-spot (see panel diagram included with this report) are very old wells, drilled in 1908 and 1909. They were reconditioned by replacing 5-1/2 inch casing with 4-1/2 inch, with open-hole completion. The six water injection wells are all new with 4-1/2 inch casing and set-through completion.

Many existing wells were converted to backup water injection wells, with a new well drilled to complete the confinement. These wells are mostly open hole completions, which was the standard practice when they were drilled.

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Many existing wells were converted to backup water injection wells, with a new well drilled to complete the confinement. These wells are mostly open hole completions, which was the standard practice when they were drilled.

Details of the CO₂ injection system are as follows, quoted directly from the Pennzoil report:

Carbon dioxide will be maintained in the liquid state during the project. Four insulated tanks, each capable of storing 44 tons of carbon dioxide, have been installed at the plant site. Carbon dioxide will be hauled to the plant in tank trucks during the carbon dioxide injection phase. The carbon dioxide will be stored at approximately 0°F and 250 psi. A gear pump will take suction from the bottom of the tanks and charge a triplex pump with a 300 psi liquid. The triplex pump will then pressurize the carbon dioxide to the desired injection pressure. This injection pressure will be maintained through a by-pass system consisting of a series of back-pressure regulators.

After pressurization, the carbon dioxide will pass through an in-line indirect heater capable of heating the fluid to 70°F. The heated carbon dioxide then travels to an injection header via an uncoated 2-inch line. From the injection header, internally coated 2-inch lines run to each of the six injection wells. The injection header is constructed so that either water or carbon dioxide can be injected into any well at any time. This header was constructed in this manner to allow alternate water and carbon dioxide injection into each well individually instead of simultaneously during the WAG phase of the project.

Planned injection rate is about 15-20 tons of CO₂ per day per well. The injection sequence will be (1) a slug of CO₂ amounting to 6.5% of the hydrocarbon pore volume, (2) a slug of water amounting to 3% of the hydrocarbon pore volume, (3) nine alternating CO₂ and water slugs, each 1.5% of the hydrocarbon pore volume.

STUDY SUMMARY

Based on available reservoir information, CO₂ displacement seems to be the enhanced oil recovery technique most suitable for most West Virginia oil reservoirs. Seventeen reservoirs have been identified as potential candidates for the CO₂ displacement process: three Berea, six Big Injun, five Gordon, one Gordon Stray, one Fifth, and one Squaw-Weir sand reservoir. The total volume of oil remaining in these 17 reservoirs is estimated to be more than one billion barrels. The fields are all within a relatively small geographic area and constitute a significant target for enhanced oil recovery technology. There are, however, many difficulties in working with expensive fluids in old fields containing many abandoned wells.

Injectivity of liquid CO₂ in West Virginia oil reservoirs has been demonstrated to be higher than that for water or natural gas.

In connection with raising pressures prior to CO₂ injection, waterflooding has been shown to be effective in two reservoirs previously considered impossible to flood.

In the single CO₂ displacement process completed in West Virginia, the Granny's Creek project, efficiency of recovery was not high: less than one barrel of additional oil per 20 MSCF of CO₂ injected. The injected liquid was found far outside the project area, however, indicating a need for effective confinement. The CO₂ process has been demonstrated as effective in displacing oil from a previously waterflooded portion of the reservoir.

The three ongoing or projected CO₂ projects in the state have many common features, which should simplify the complete analysis when they are completed.

RECOMMENDATIONS FOR FUTURE CONSIDERATIONS

Several pertinent recommendations can be made for high-pressure CO₂ displacement projects contemplated in this part of the country.

First, considering the wide areal distribution of CO₂ observed in the Granny's Creek project, the confinement of injected CO₂ by backup water injection must be effective.

Second, based on experience at the Griffithsville project site, any operator planning an enhanced oil recovery project of any kind should allocate a substantial sum of front-end money to locating and repairing old, improperly abandoned wells, and must provide for remedial environmental work.

Based on the effectiveness of waterflooding in two reservoirs where previous attempts had failed (Rock Creek and Griffithsville), waterflooding may be a cost-effective alternative to CO₂ miscible displacement. Since waterflooding has never been demonstrated to be effective in a Gordon sand reservoir, the potential exists for a limited waterflood project. If this is successful, then a CO₂ injection project could be run in another portion of the field, to compare results with a similar project in a waterflooded section of the reservoir. Such a project would provide a sound basis for comparison of recovery by CO₂ injection before and after waterflood, and the comparative economics of the processes.

Naturally occurring CO₂ would probably be most economical in increasing oil production from the old reservoirs in the state. In fact, unless the efficiency of the process is substantially higher than was found in the Granny's Creek field, such naturally occurring supplies of CO₂ are probably the only source cheap enough to be considered for an enhanced oil recovery project.

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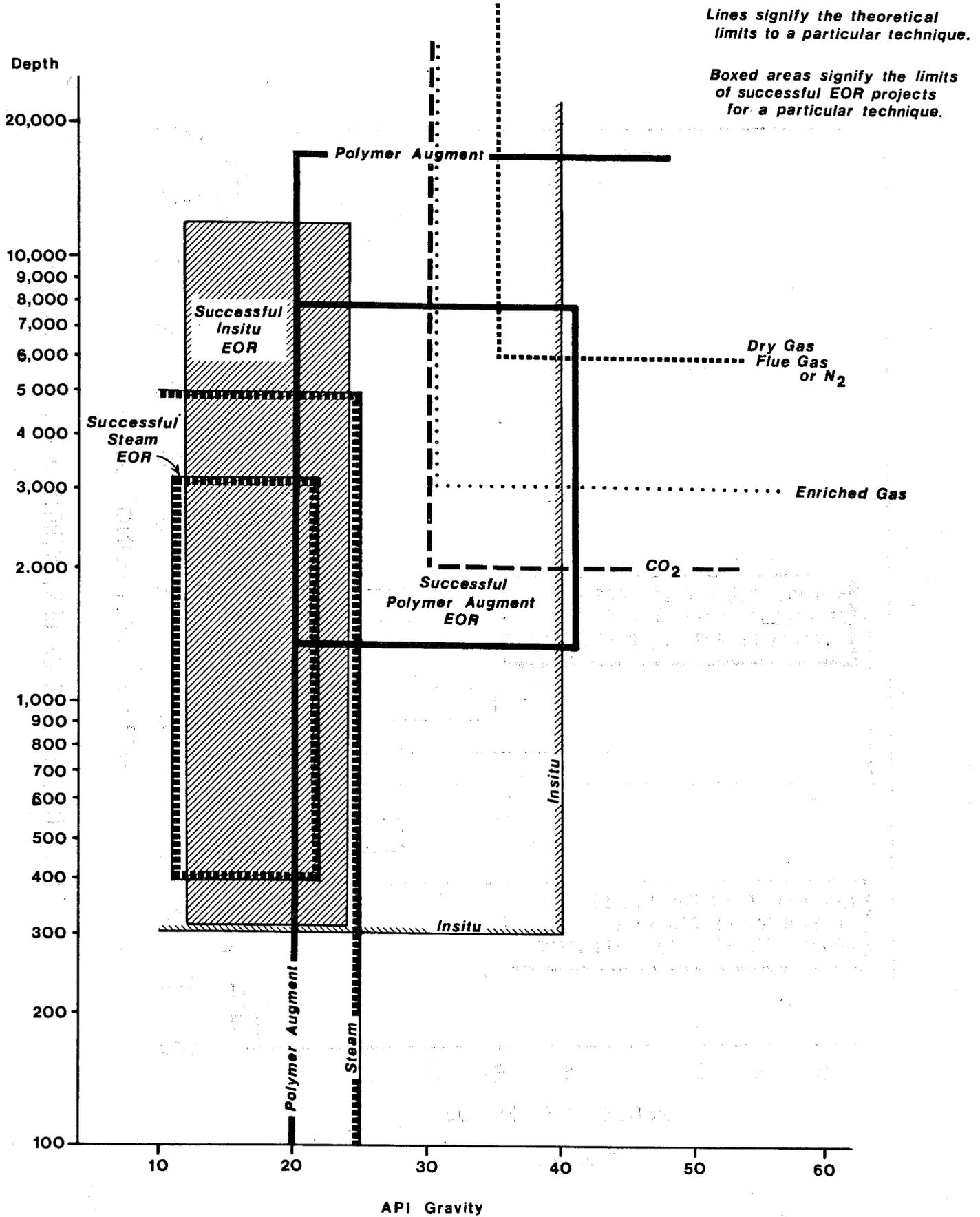


Fig. 1: Oil Gravity and Depth Limitations, Proven and Theoretical, of Most Enhanced Oil Recovery Techniques

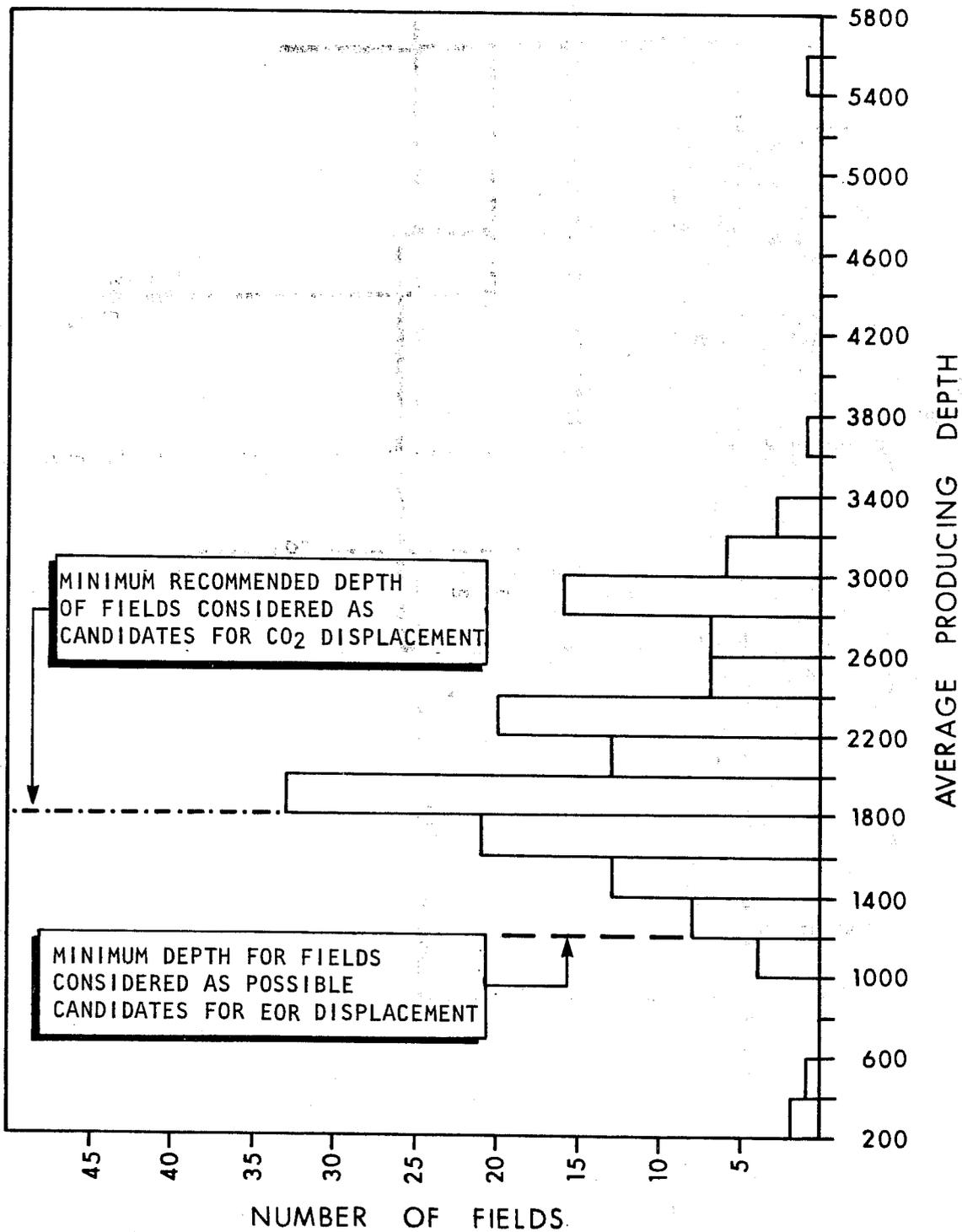


Figure 2

DEPTH DISTRIBUTION OF WEST VIRGINIA OIL RESERVOIRS

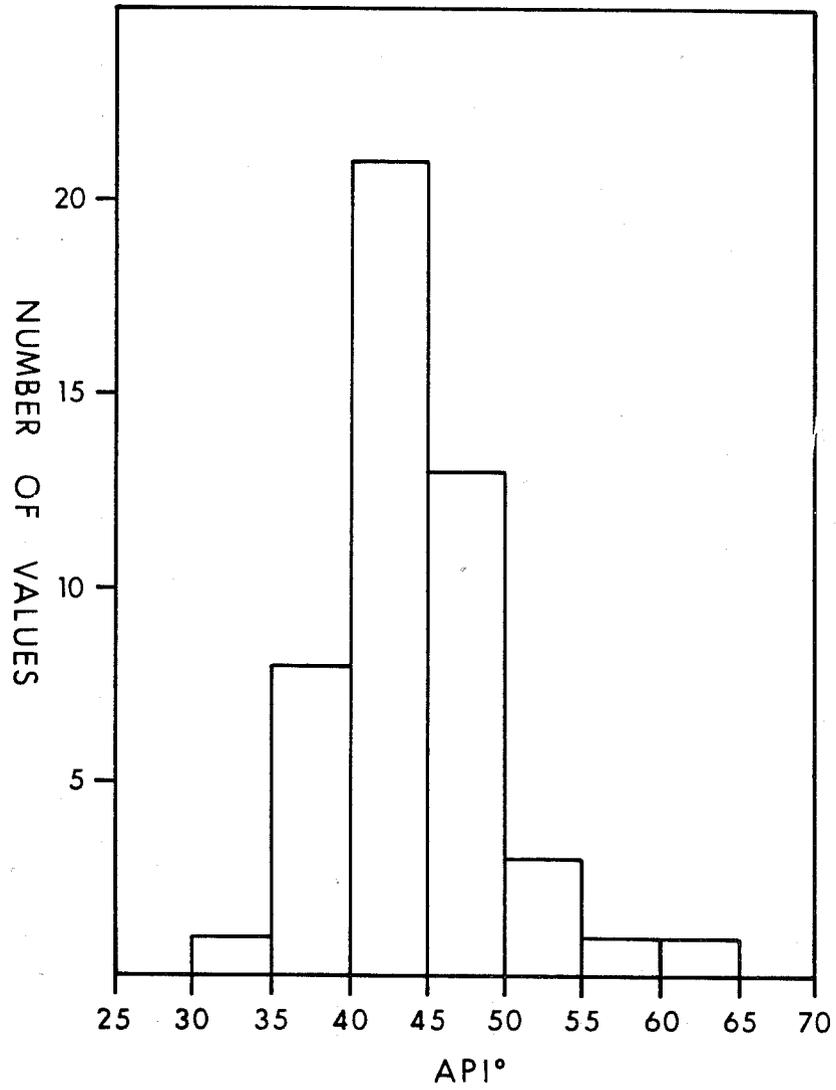


Fig. 3a: Gravity of West Virginia Crude Oils

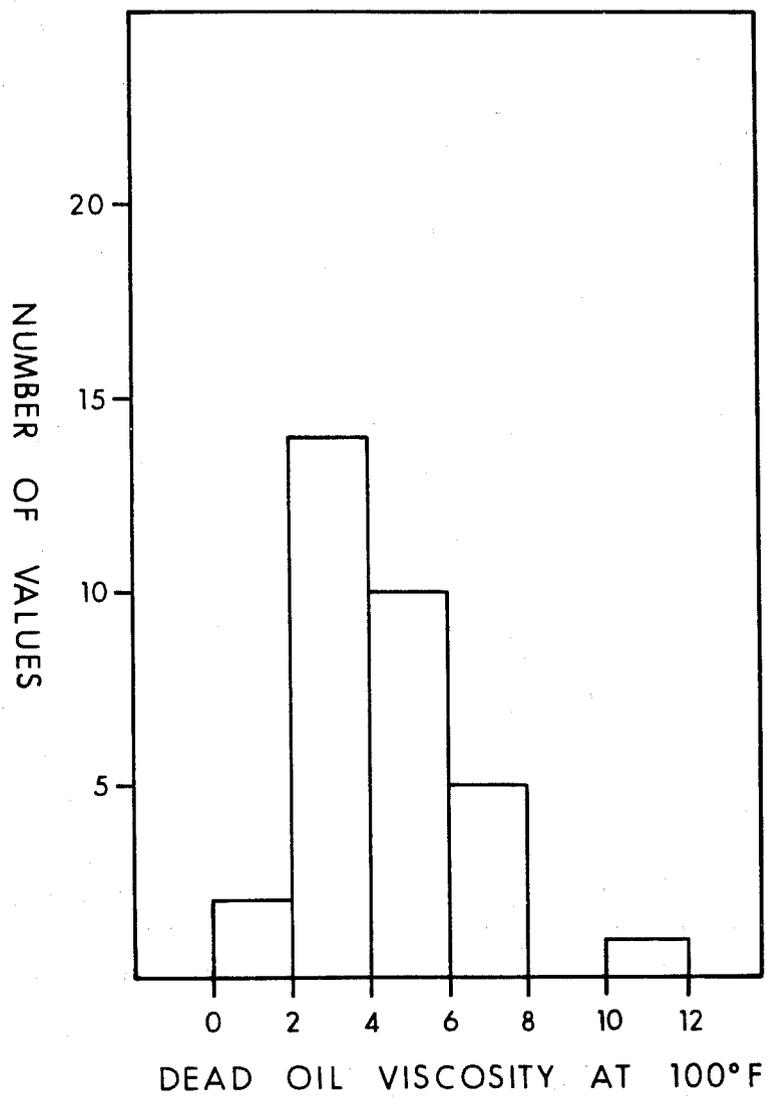


Fig. 3b: Viscosity of West Virginia Crude Oils

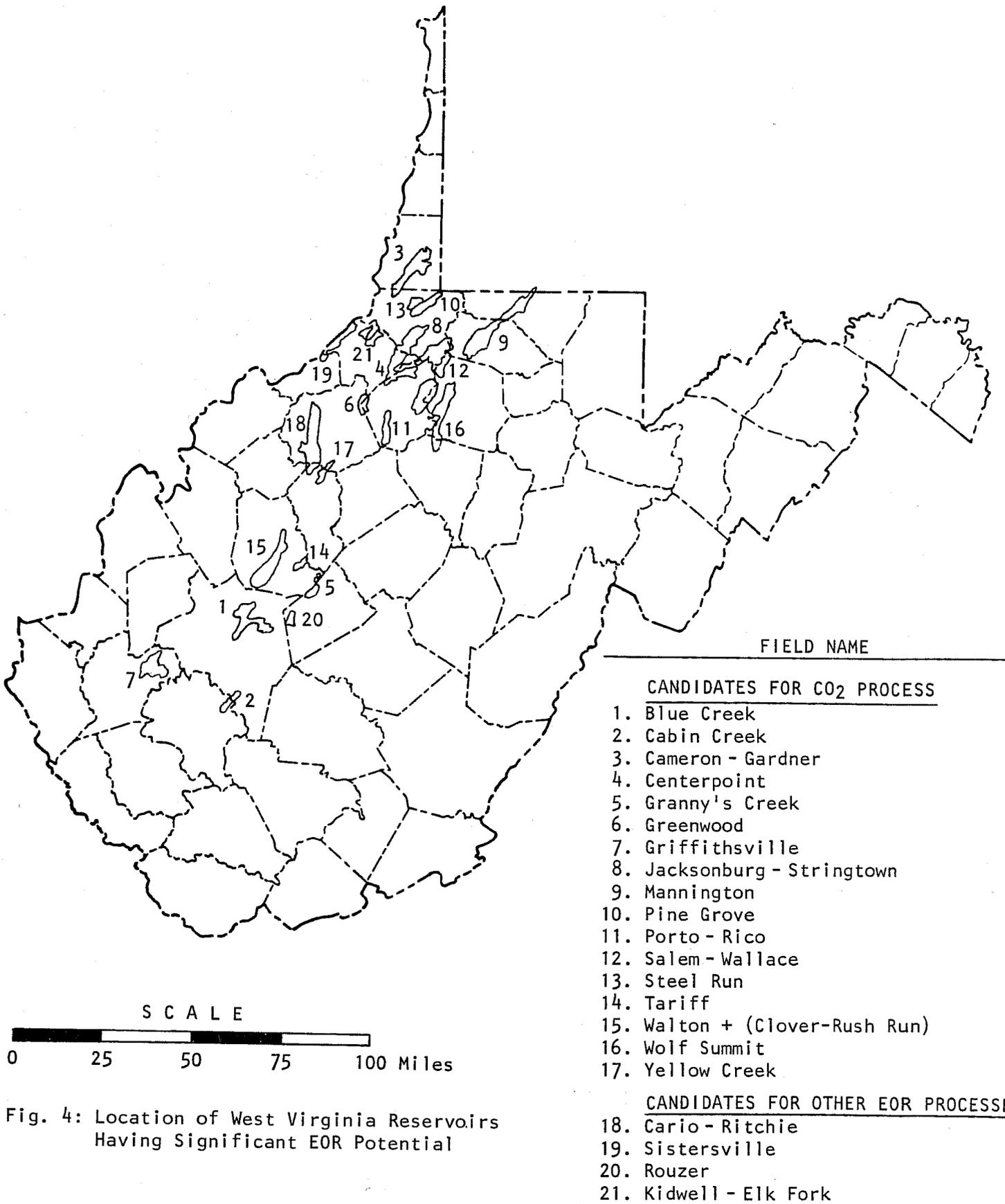


Fig. 4: Location of West Virginia Reservoirs Having Significant EOR Potential

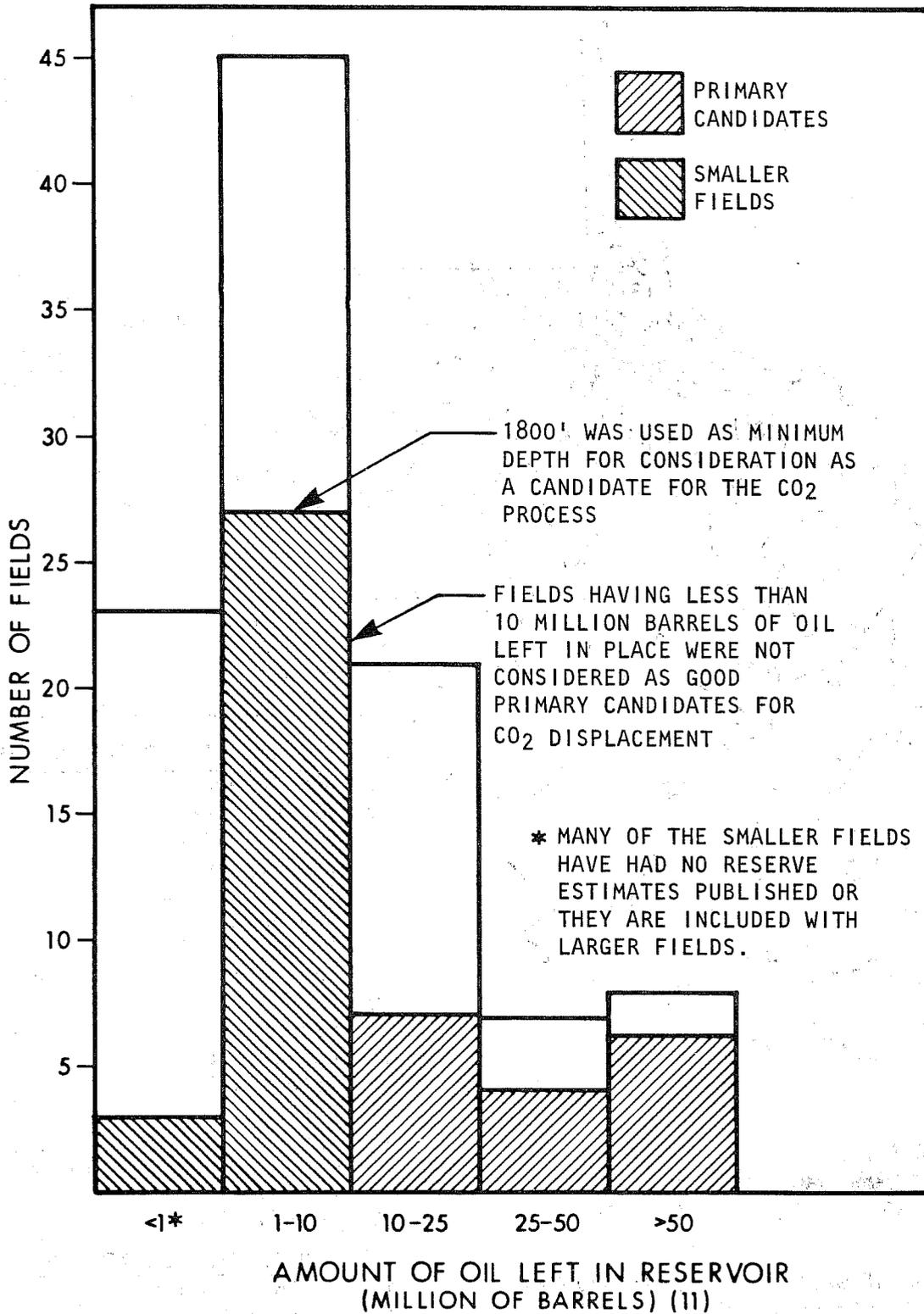
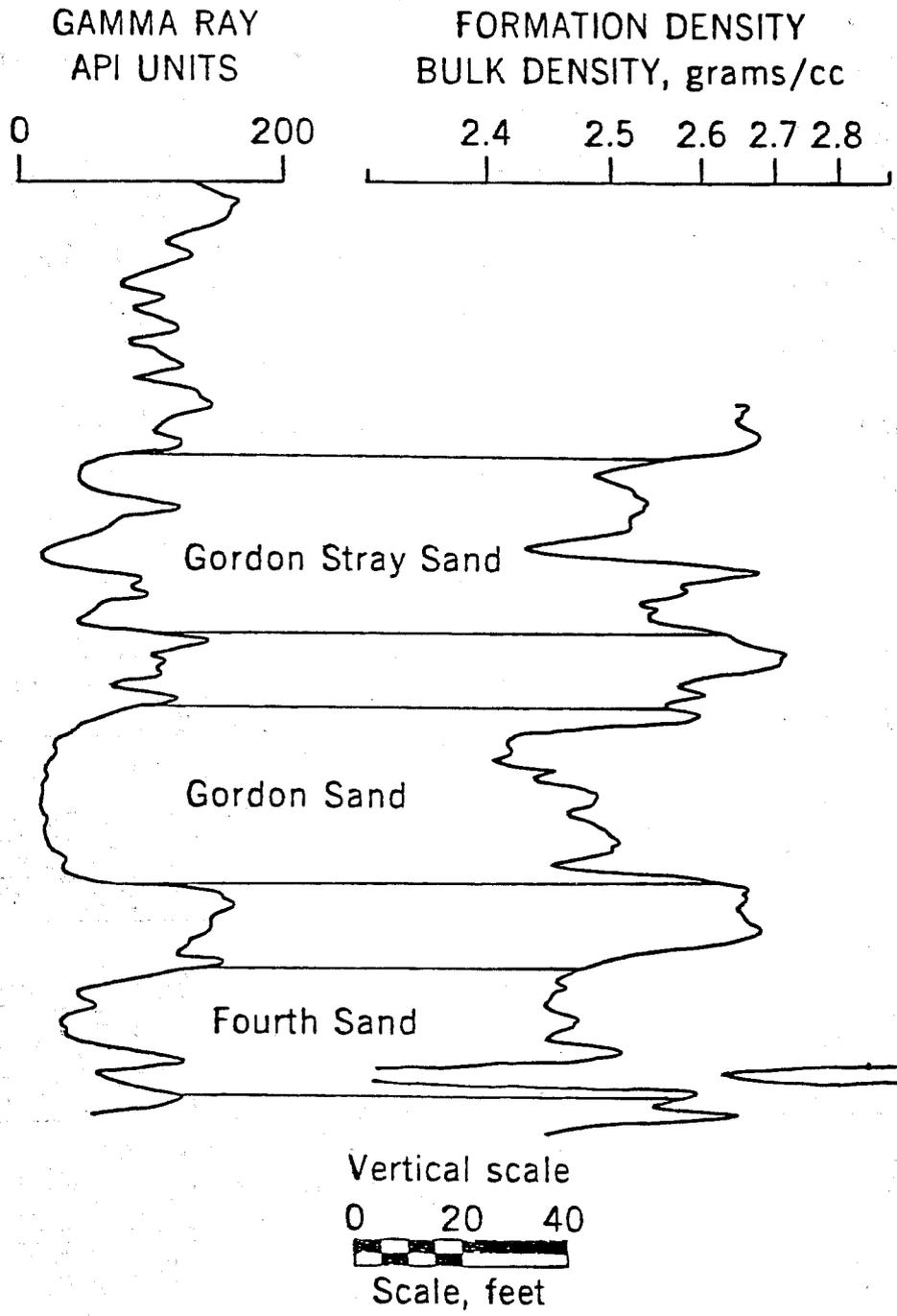


Fig. 5: Estimated Sizes and Number of Fields Suitable for CO₂ Enhanced Oil Recovery

GENERALIZED STRATIGRAPHIC COLUMN WITH OIL AND GAS RESERVOIRS WEST VIRGINIA

GEOLOGIC SYSTEMS AND SERIES	TERMINOLOGY USED ON 1968 STATE GEOLOGIC MAP	FORMER TERMINOLOGY (WVA GEOLOGICAL SURVEY COUNTY REPORTS) IF DIFFERENT	OIL AND GAS "SANDS" (DRILLERS' TERMS)
PERMIAN		DUNKARD GROUP	CARROLL BENSHALL MURPHY MOUNDSVILLE COW RUN LITTLE DUNKARD BIG DUNKARD
	UPPER	MONONGAHELA GROUP	BURNING SPRINGS GAS AND LOWER GAS HORSE NECK
PENNSYLVANIAN	MIDDLE	ALLEGHENY FORMATION	SALT SANDS (1st, 2nd, 3rd) PRINCETON RAVENCLIFF MAXON LOWER MAXON LITTLE LIME
	LOWER	POTTSVILLE GROUP	BLUE MONDAY BIG LIME KEENER BIG INJUN SQUAW WEIR BEREA
MISSISSIPPIAN	UPPER	MAUCH CHUNK GROUP	
	MIDDLE	GREENBRIER GROUP	
	LOWER	MACCRADY FORMATION POCONO GROUP	
DEVONIAN	UPPER	HAMPSHIRE FORMATION	CATSKILL
		CHEMUNG GROUP	
	MIDDLE	BRALLIER FORMATION	PORTAGE
		HARRELL SHALE	GENESEE
		MAHANTANGO FM.	HAMILTON
		MARCELLUS FM.	
		ONONDAGA LS.	HUNTERSVILLE
		HUNTERSVILLE CHERT	
	NEEDMORE SHALE		
	LOWER	ORISKANY SANDSTONE	
HELDERBERG GROUP			
SILURIAN	UPPER	TONOLOWAY FM.	BOSSARDVILLE
		WILLS CREEK FM.	ROCKOUT
		WILLIAMSPORT FM.	BLCCMSBURG
	MIDDLE	MC KENZIE FM.	NIAGARA
		ROCHESTER SHALE KEEFER SANDSTONE ROSE HILL FORMATION	CLINTON
	LOWER	TUSCARORA SANDSTONE	WHITE MEDINA
	ORDOVICIAN	UPPER	JUNIATA FORMATION
OSWEGO FORMATION			GRAY MEDINA
REEDSVILLE			MARTINSBURG
MIDDLE		TRENTON GROUP	MARTINSBURG FM. NEALMONT LS.
		BLACK RIVER GROUP	CHAMBERSBURG MOCCASIN
LOWER		ST. PAUL GROUP	CHAZY
		PINESBURG STATION COL. ROCKDALE FM. STONE-RIDGE LS.	STONES RIVER
CAMBRIAN	UPPER	CONOCOCHEAQUE FORMATION	KNOX
	MIDDLE	ELBROOK FORMATION	
	LOWER	WAYNESBORO FORMATION	
		TOMSTOWN DOLOMITE	
		ANTHETAM FM. HARPER'S FM. WEVERTON-LODDOUN FORMATION	
CATOCTIN FORMATION			
PRECAMBRIAN	CRYSTALLINE ROCKS		

FIGURE 6



Gamma Ray and Formation Density Logs From Mannington Oil Field

FIGURE 7

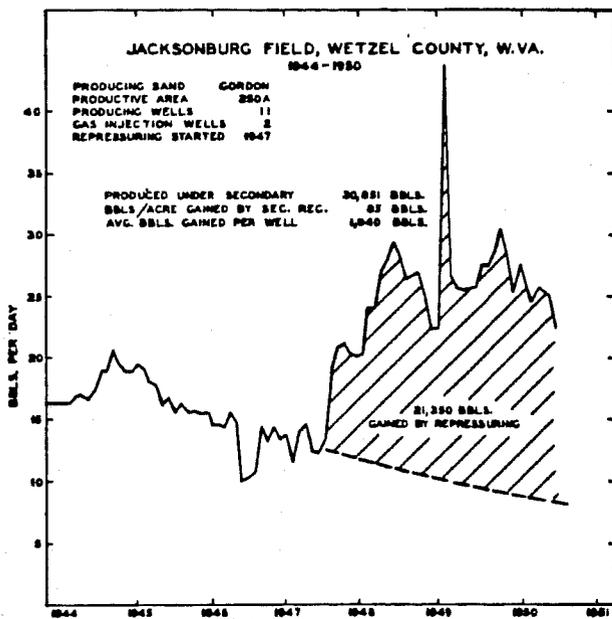


FIGURE 8

Decline Curve for a Gas Injection Project, Gordon Sand, Jacksonburg Field

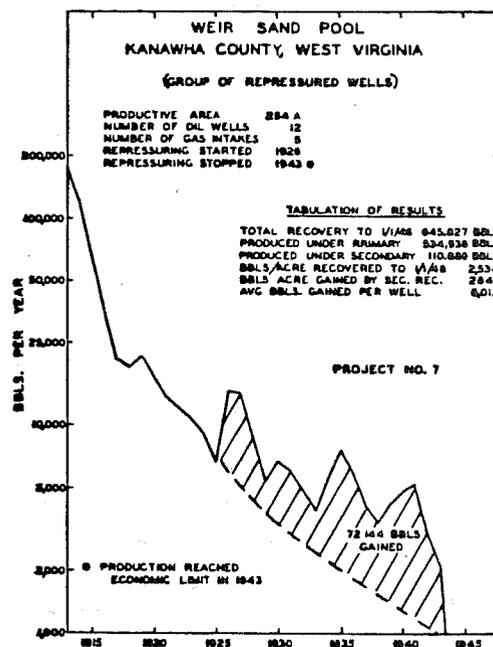


FIGURE 9

Decline Curve for a Gas Injection Project, Weir Sand, Blue Creek Field

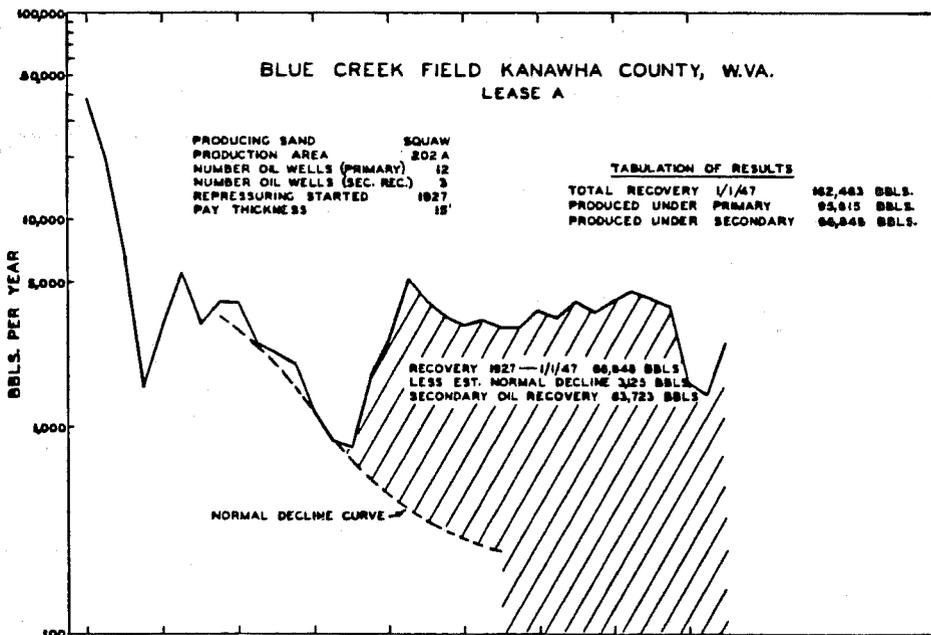


FIGURE 9a

Decline Curve for a Gas Injection Project, Squaw Sand, Blue Creek Field

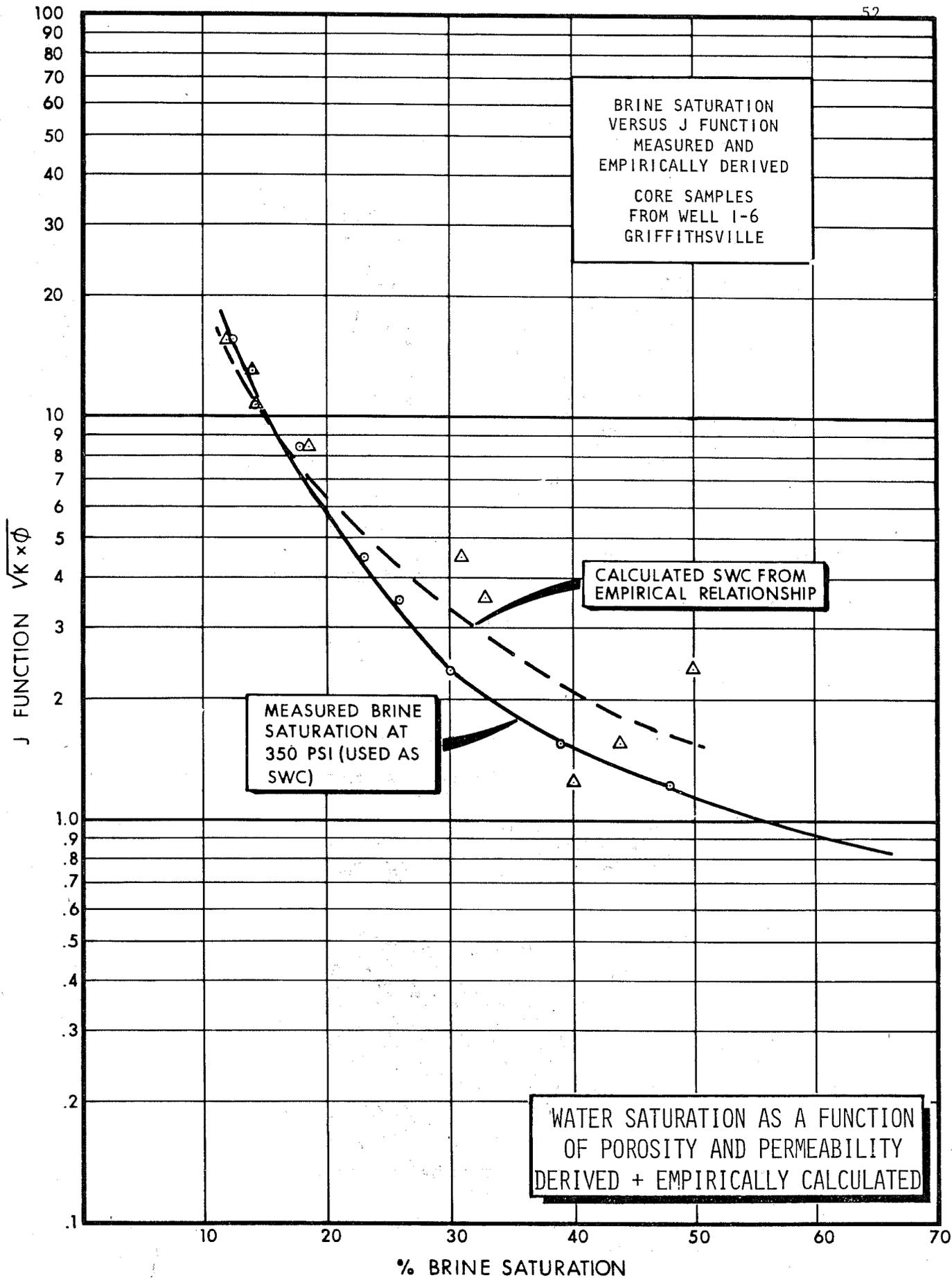


Figure 10

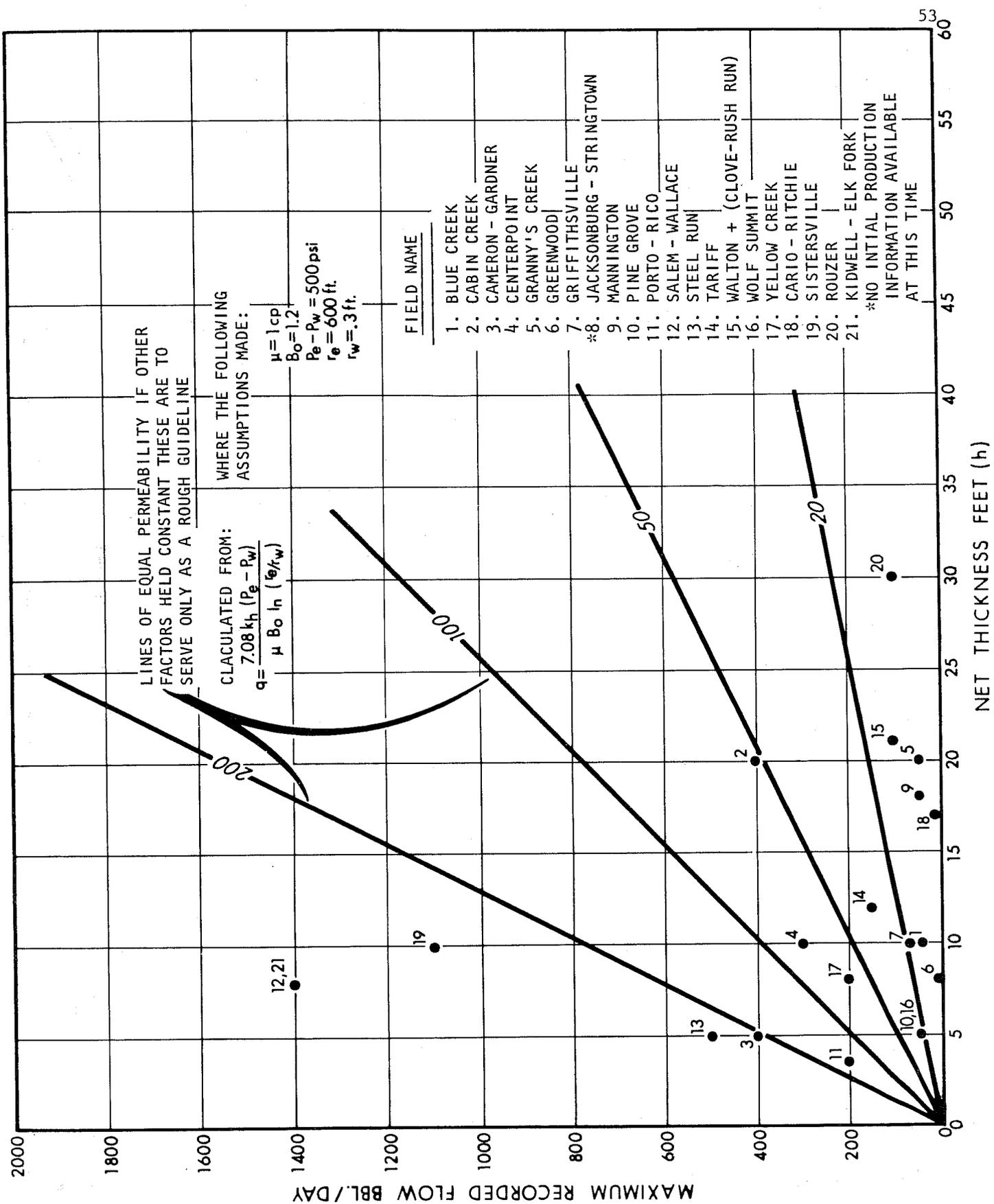


Fig. 11: Empirically Derived Permeability

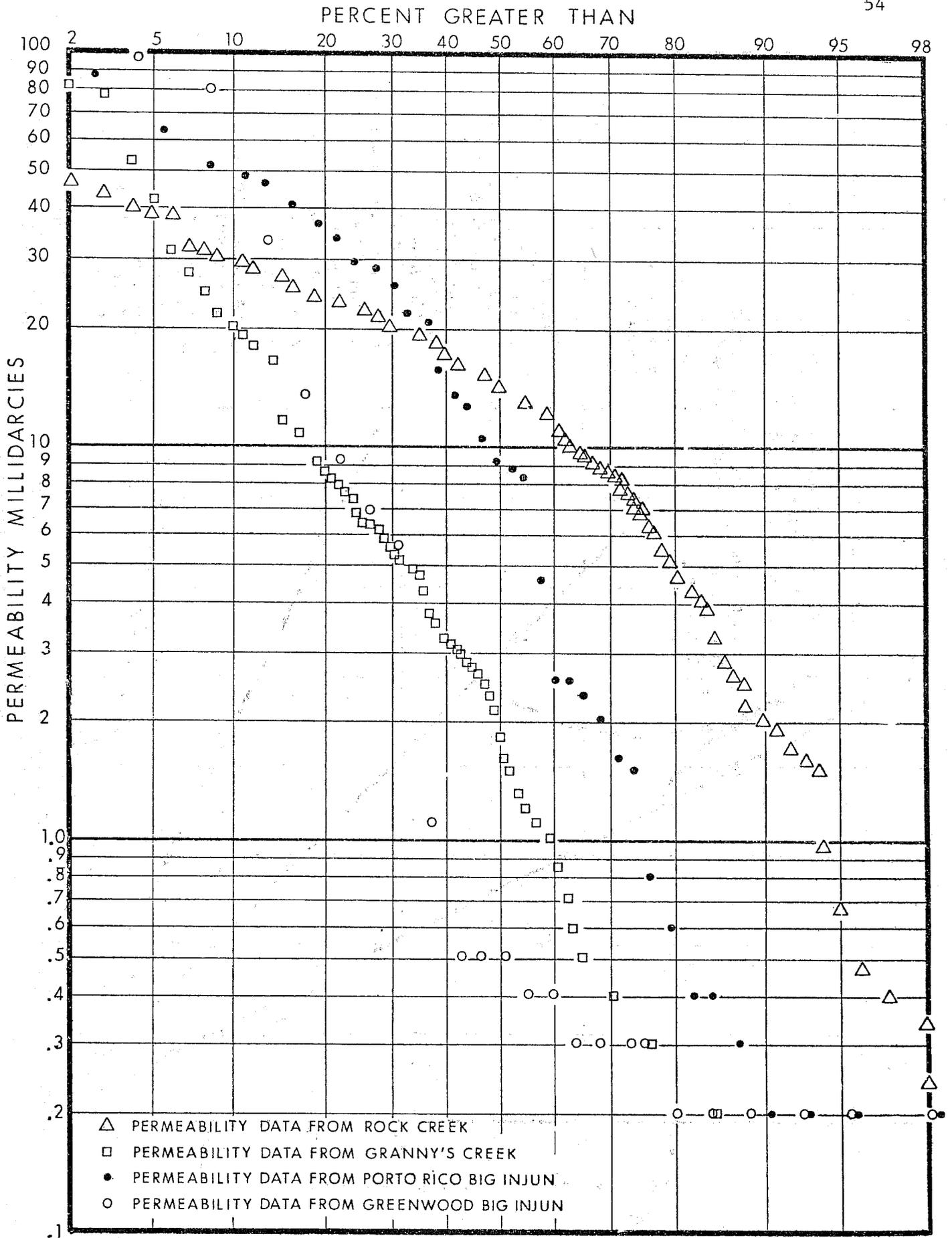


Fig. 12: Permeability Variation of Two Big Injun Sand Reservoirs in West Virginia

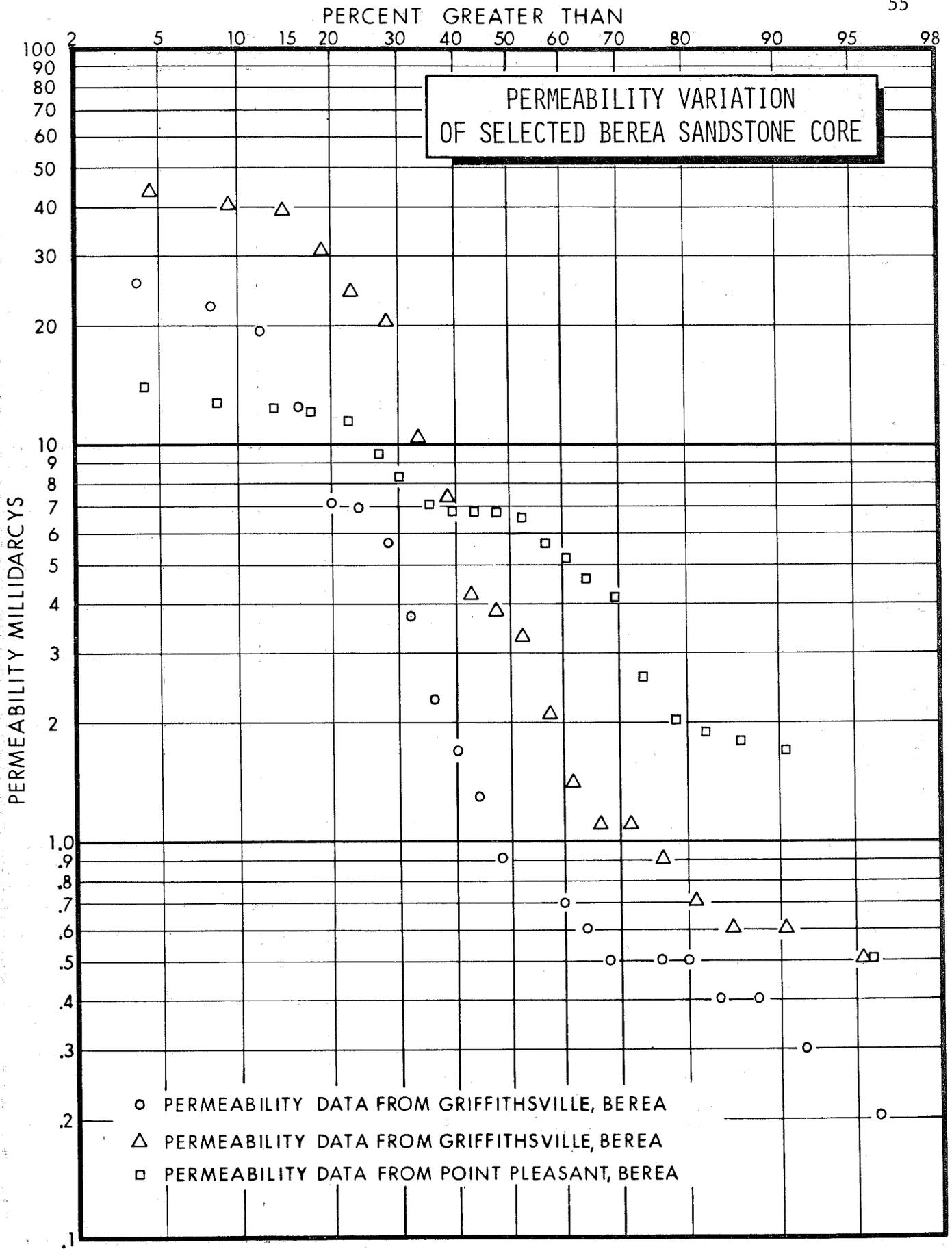


Figure 13

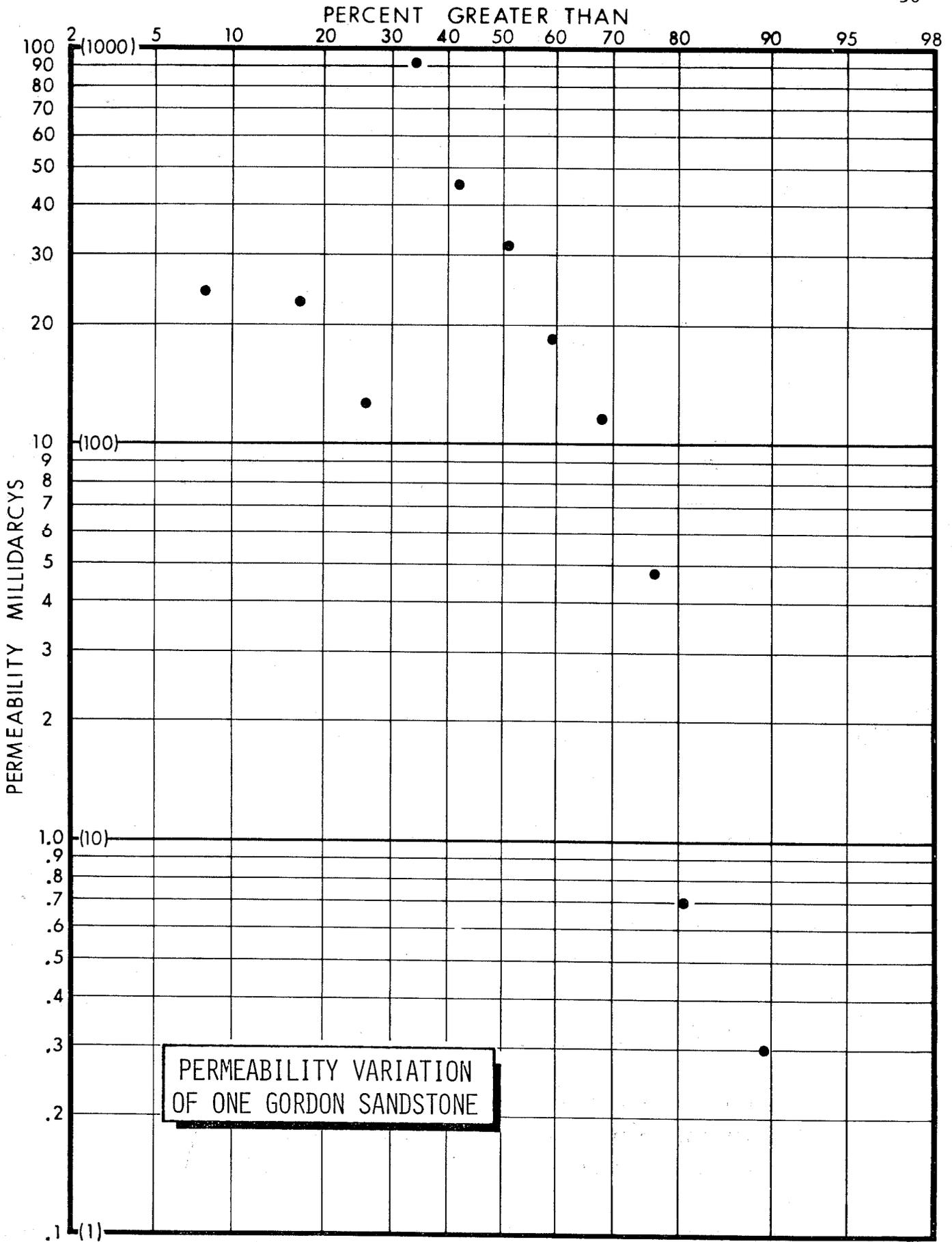


Figure 14

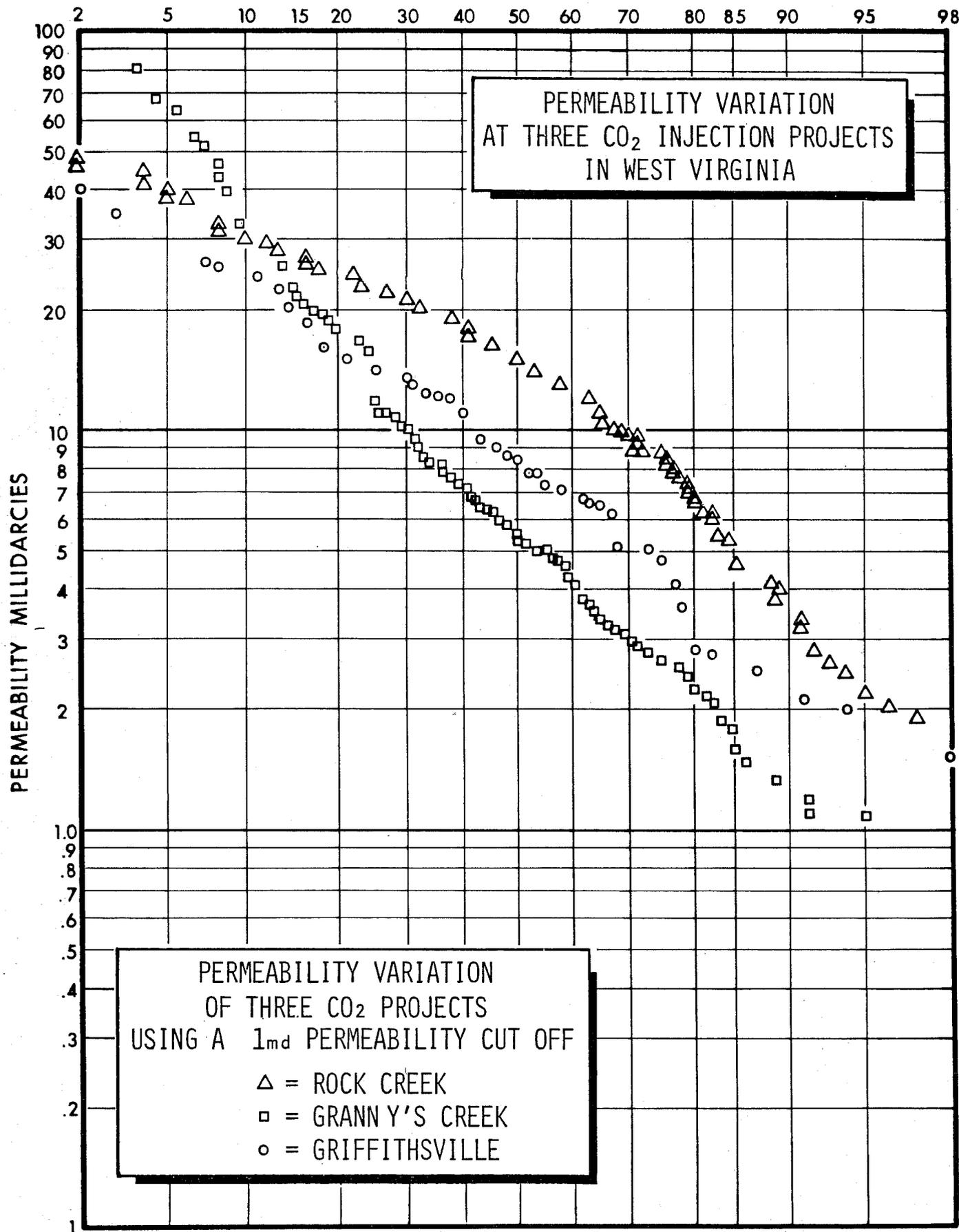


Figure 15

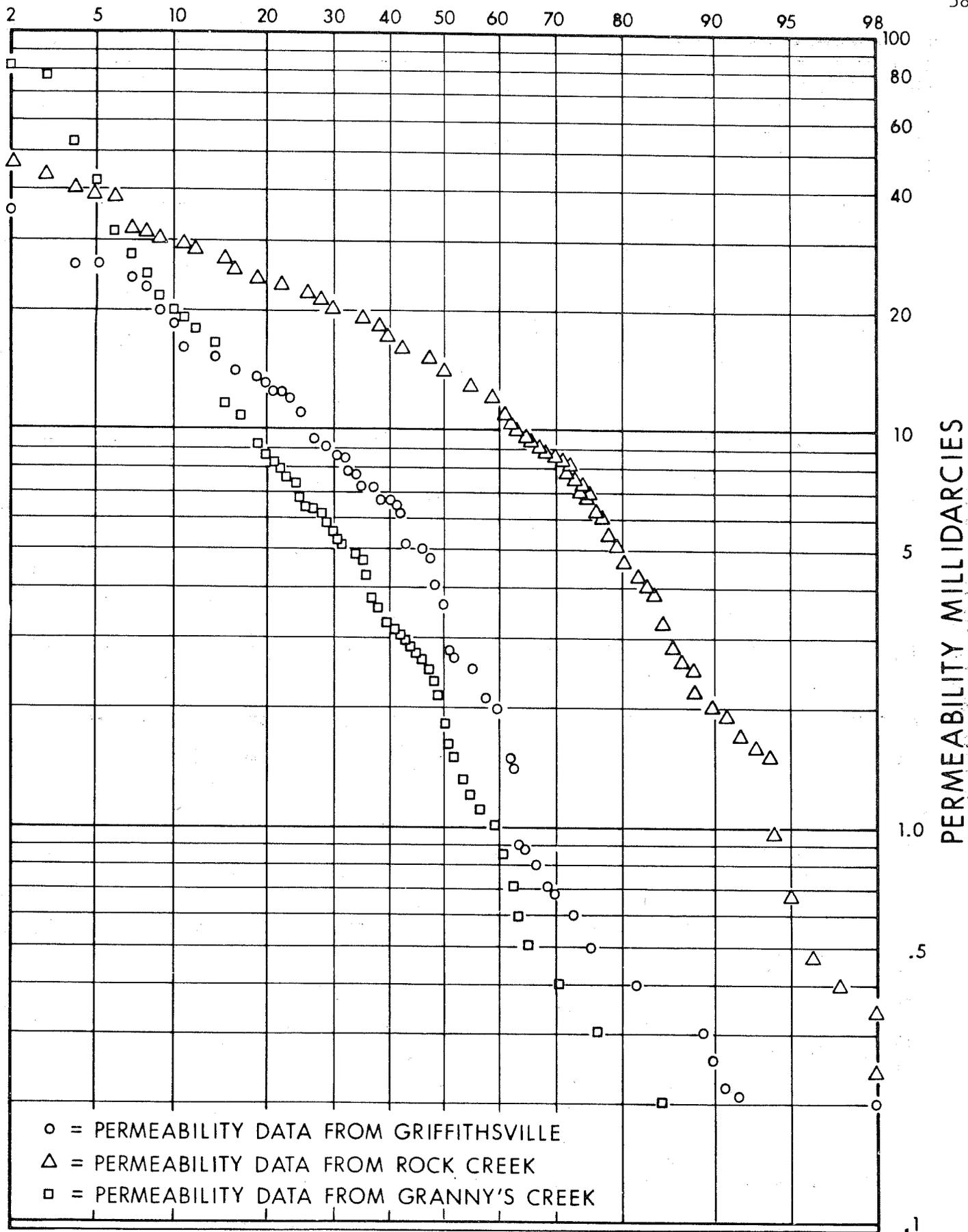


FIG. 16: PERMEABILITY VARIATION OF ALL THREE WEST VIRGINIA CO₂ INJECTION PROJECT AREAS USING 0.1-md CUTOFF.

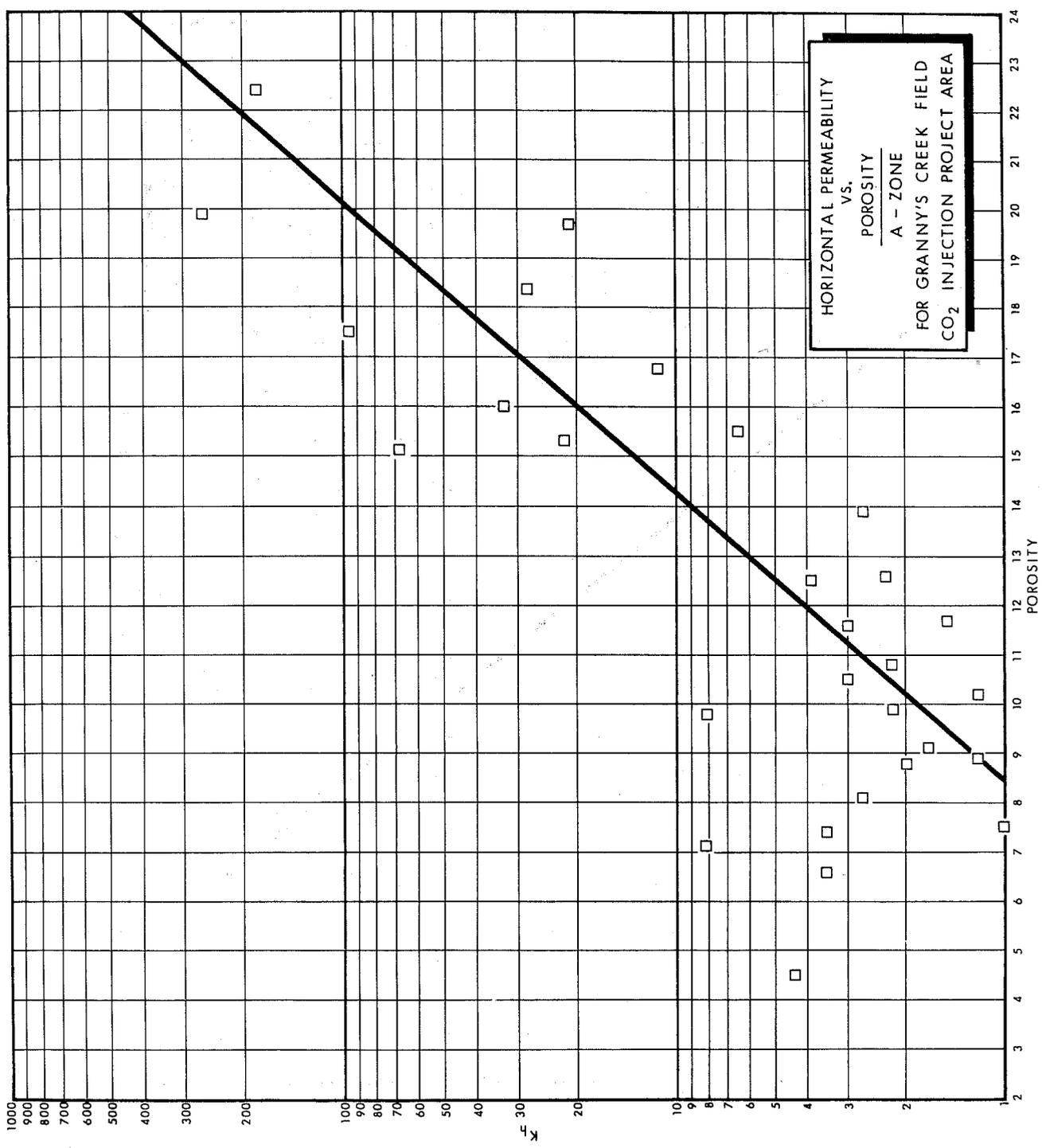


Fig.17: Permeability versus Porosity, A Zone, Granny's Creek Field

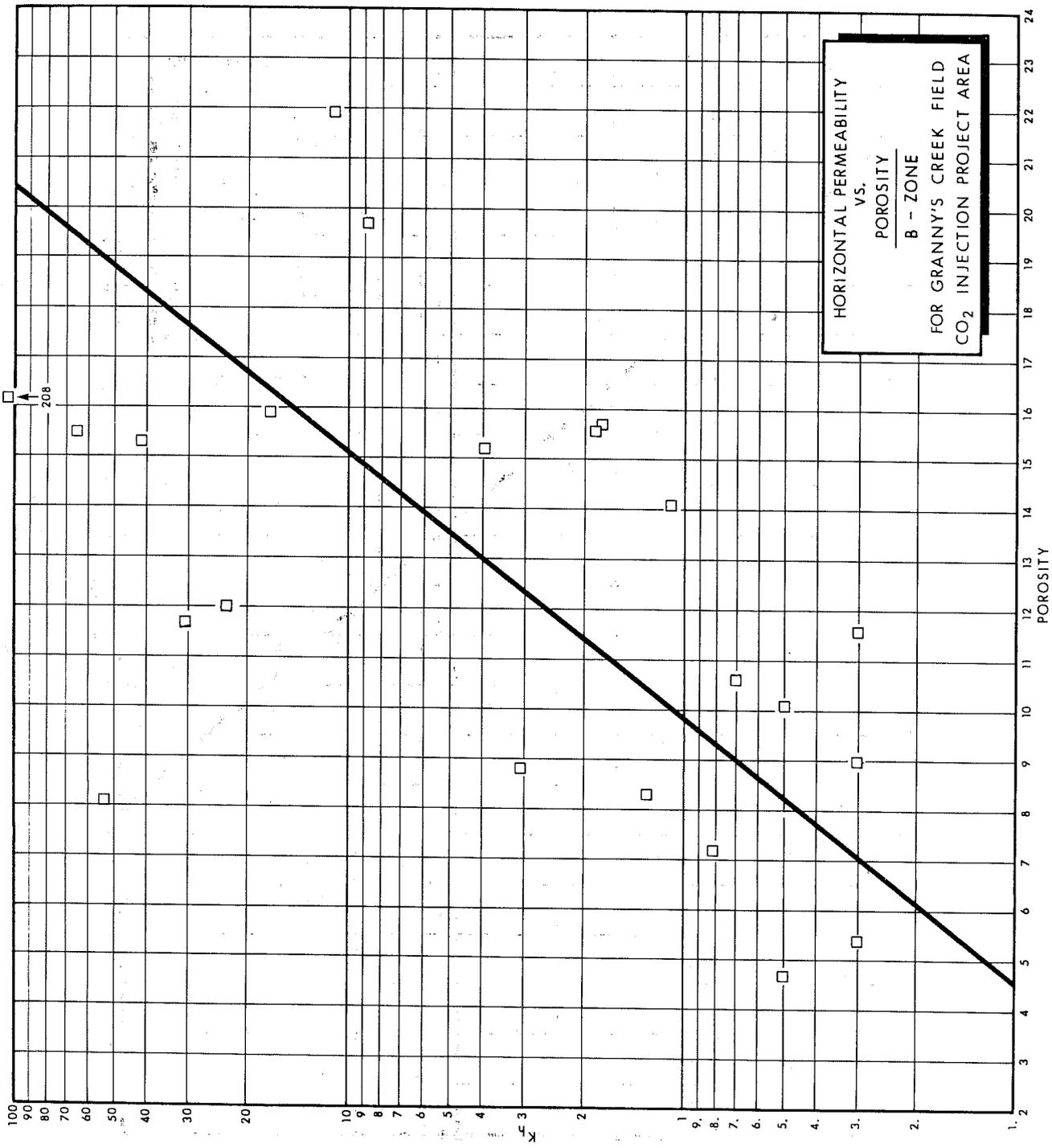


Fig. 18: Permeability versus Porosity, B Zone, Granny's Creek Field

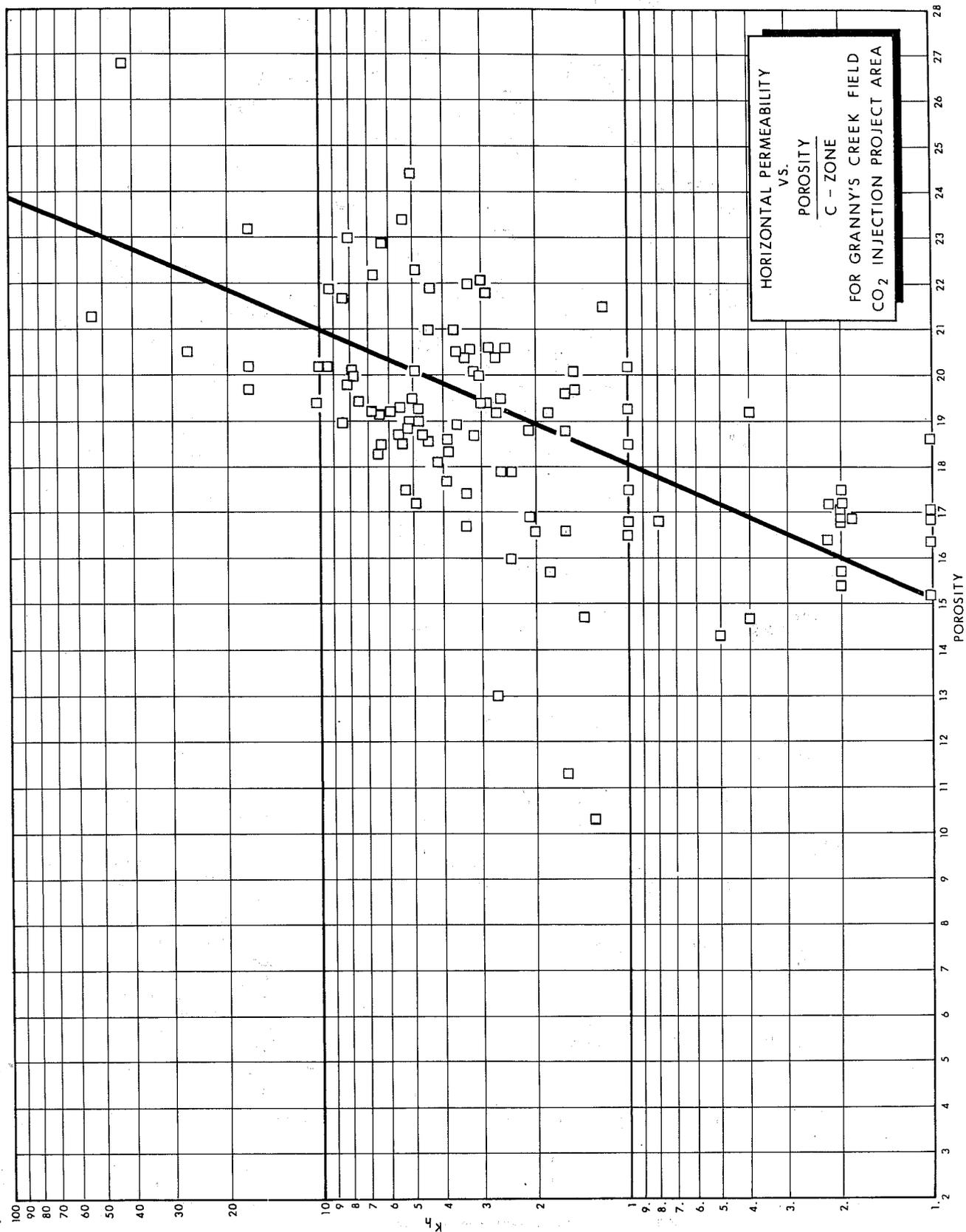


Fig. 19: Permeability versus Porosity, C Zone, Granny's Creek Field

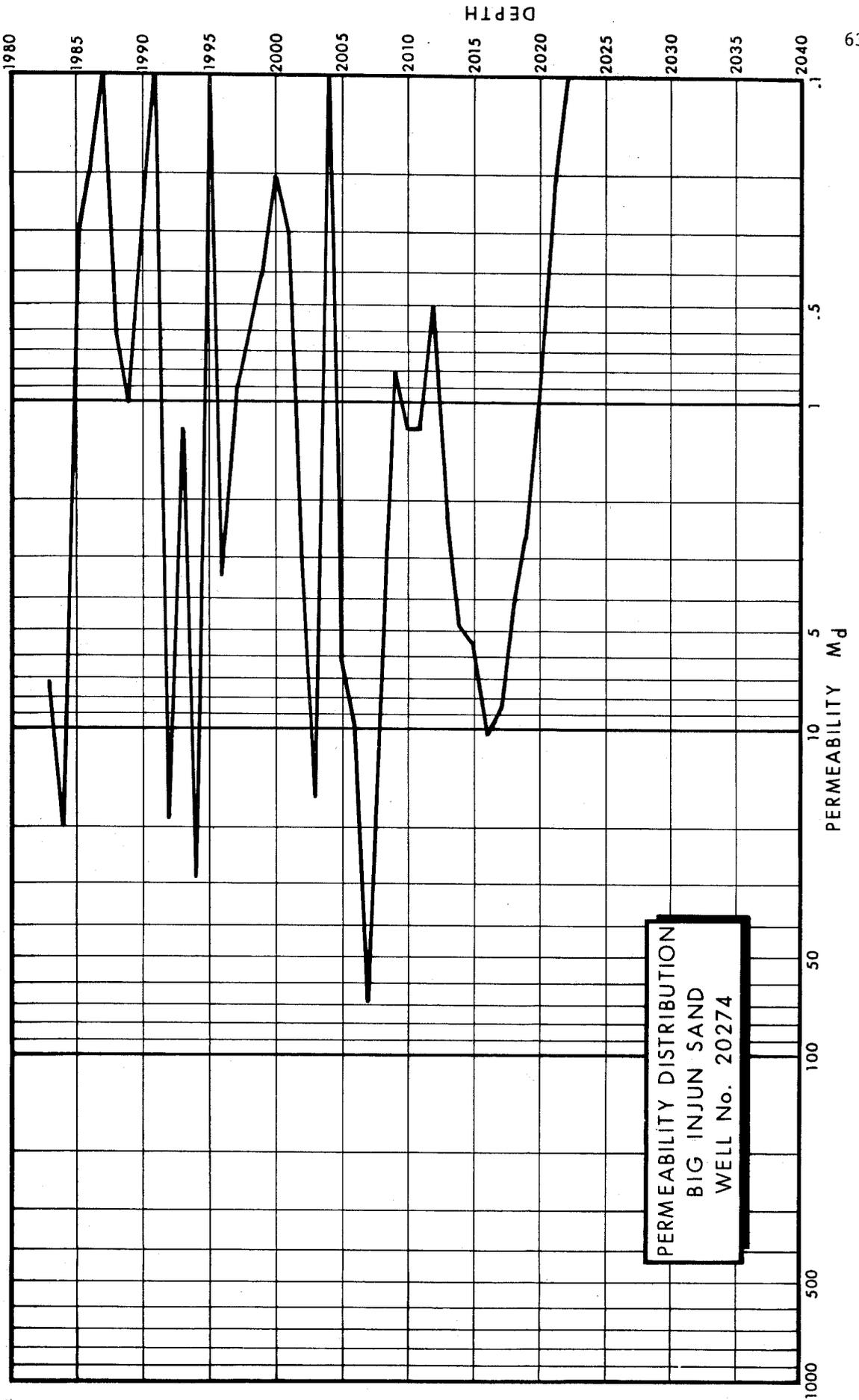


Figure 21

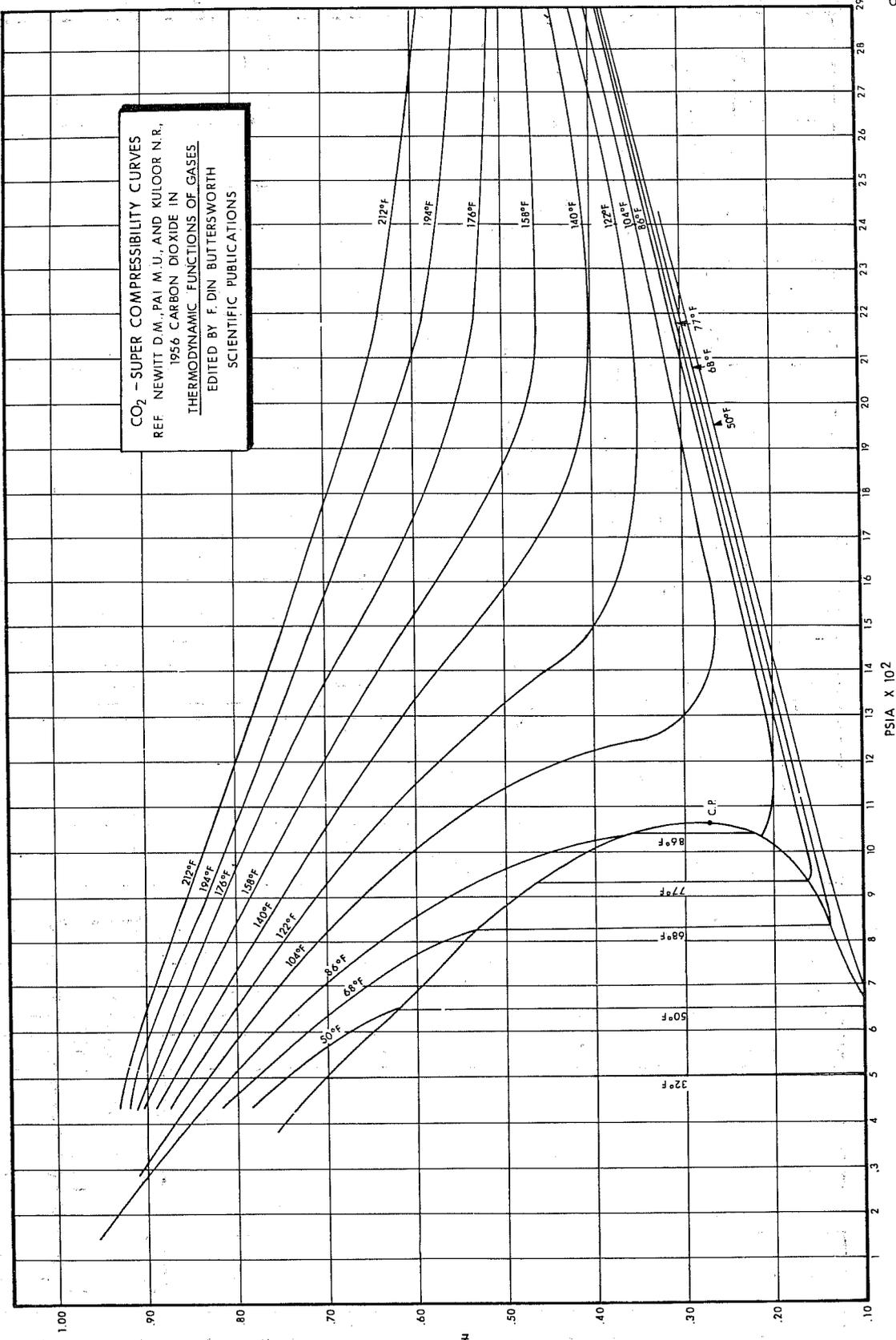


Figure 22

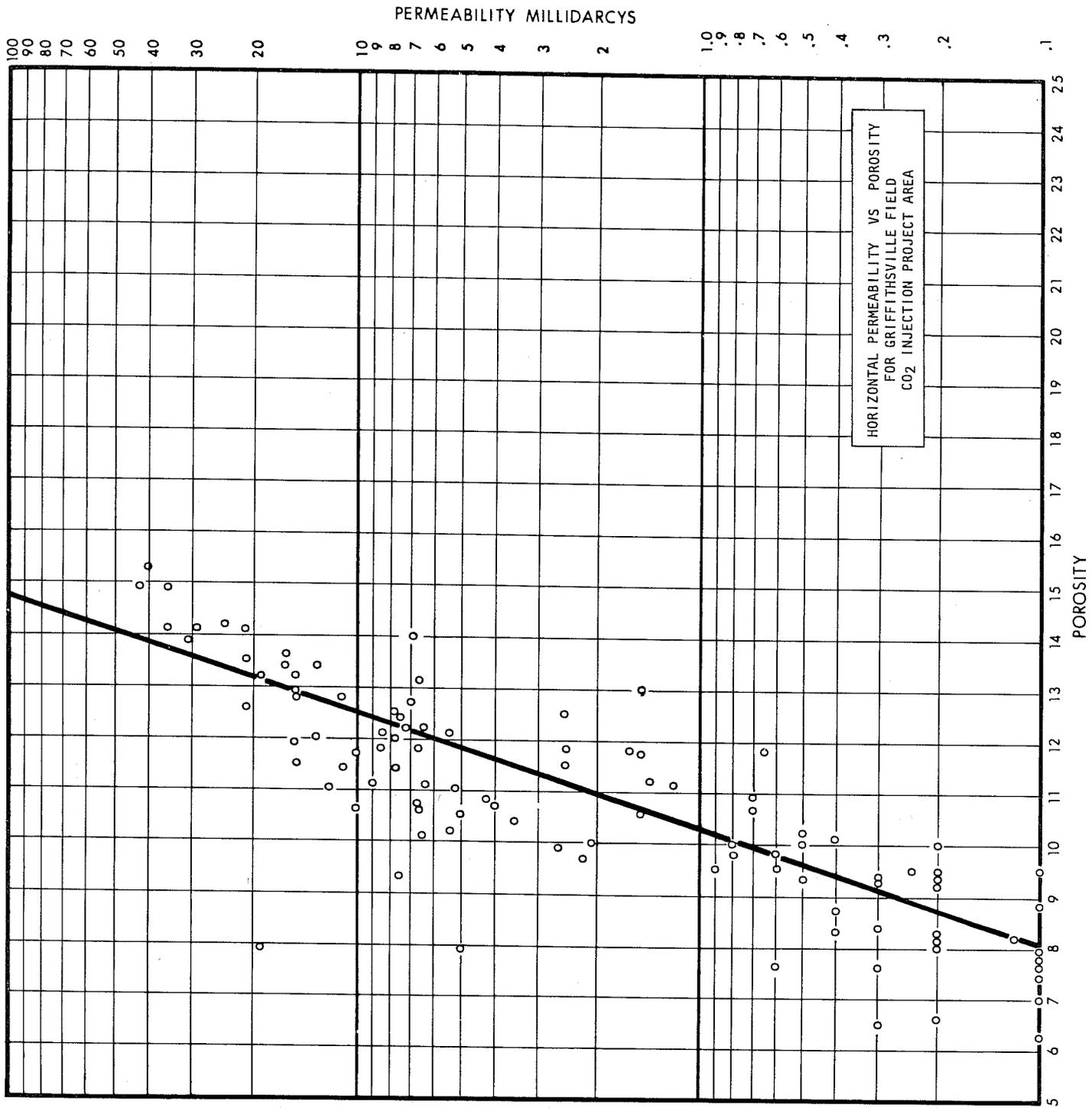


Figure 23

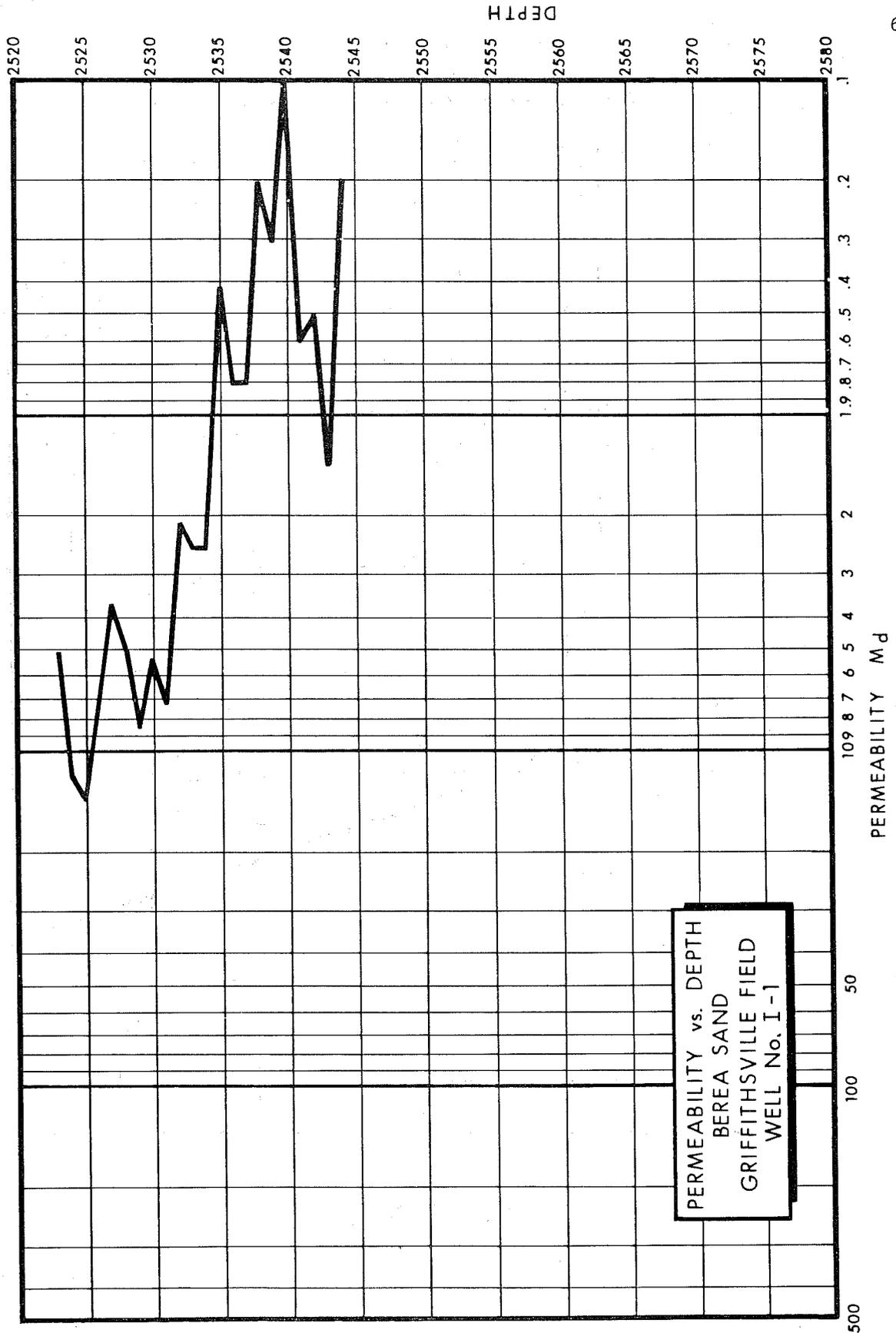


Fig. 24

PERMEABILITY MILLIDARCYS

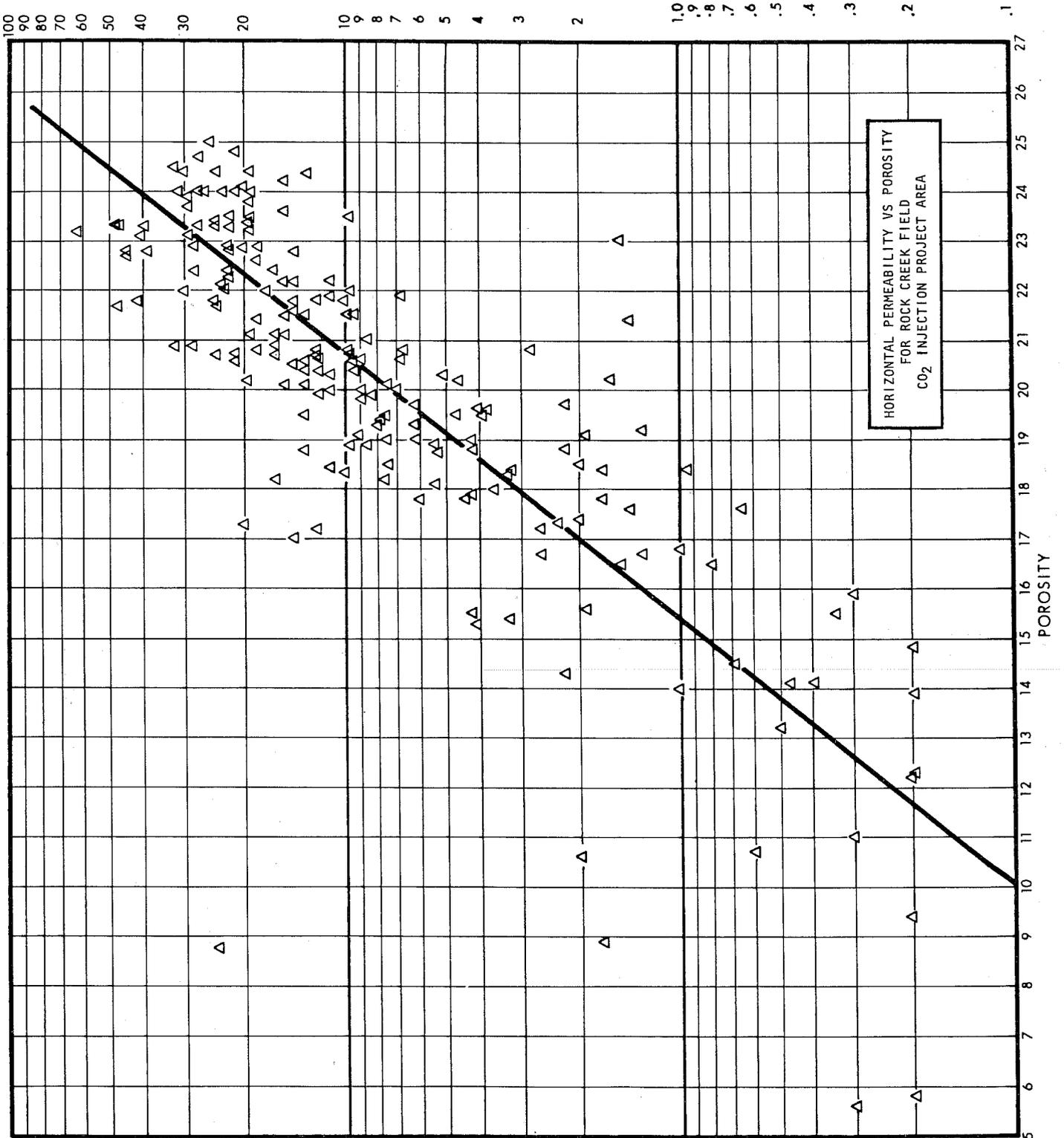


Figure 25

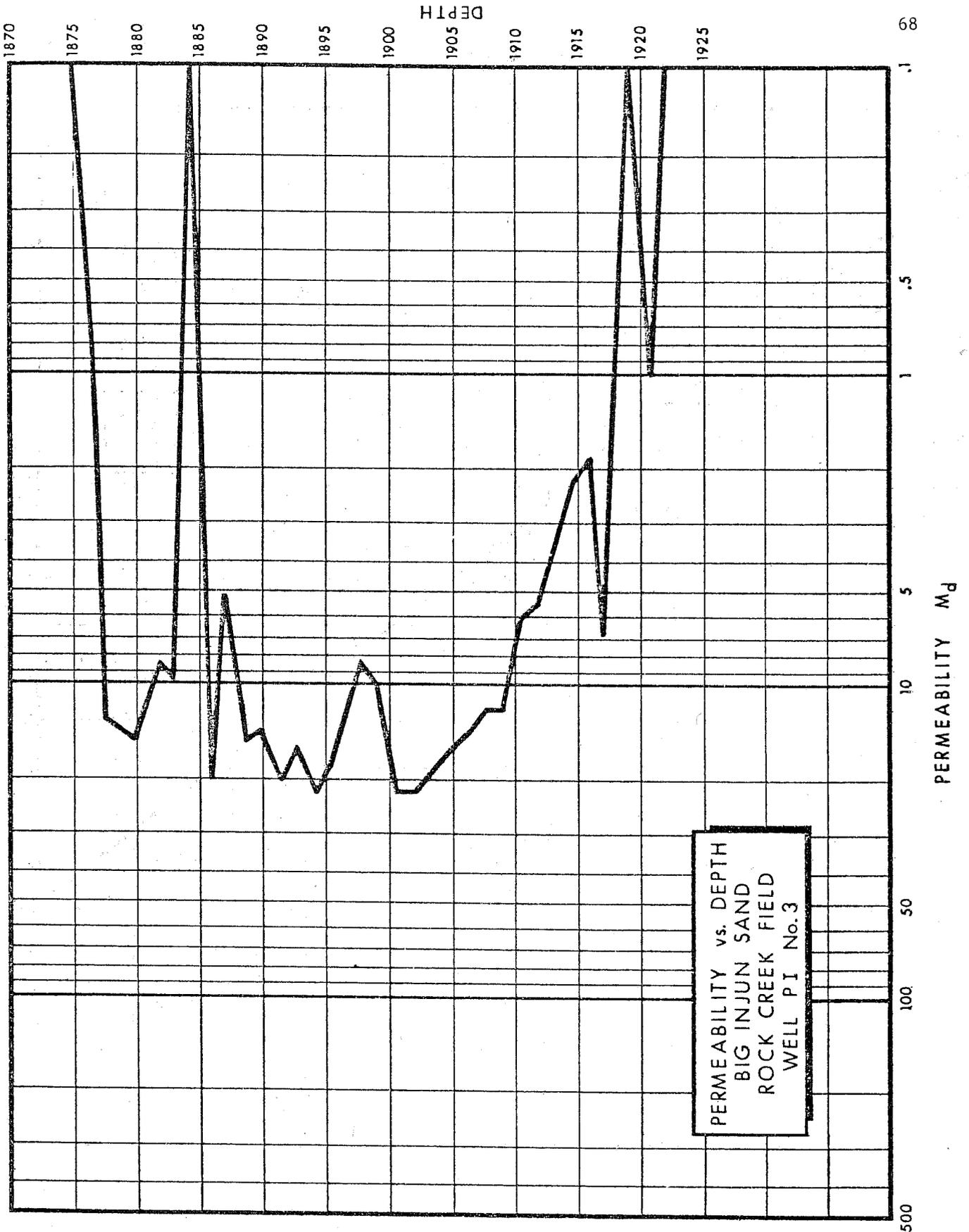


Figure 26

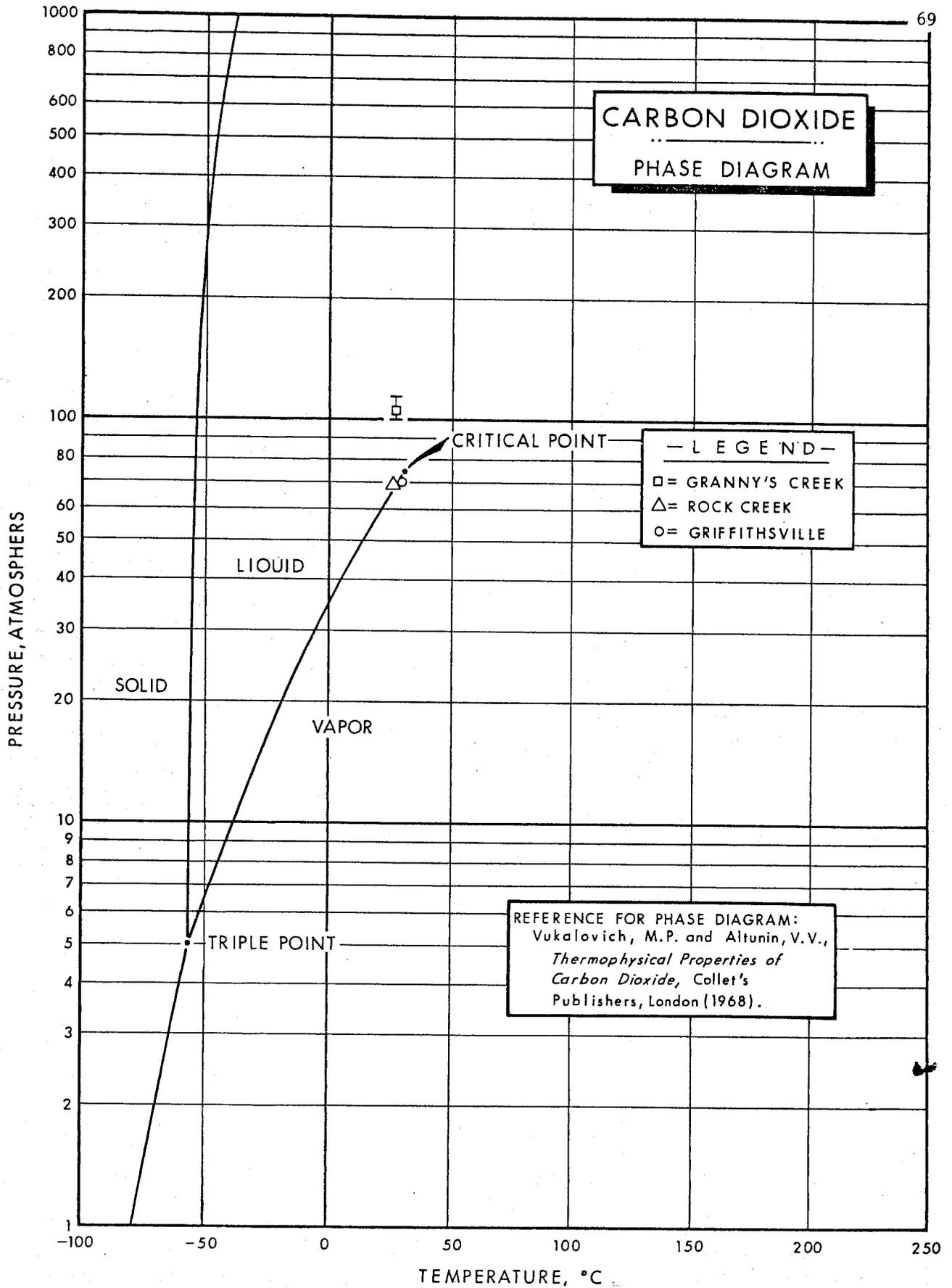


Fig. 27

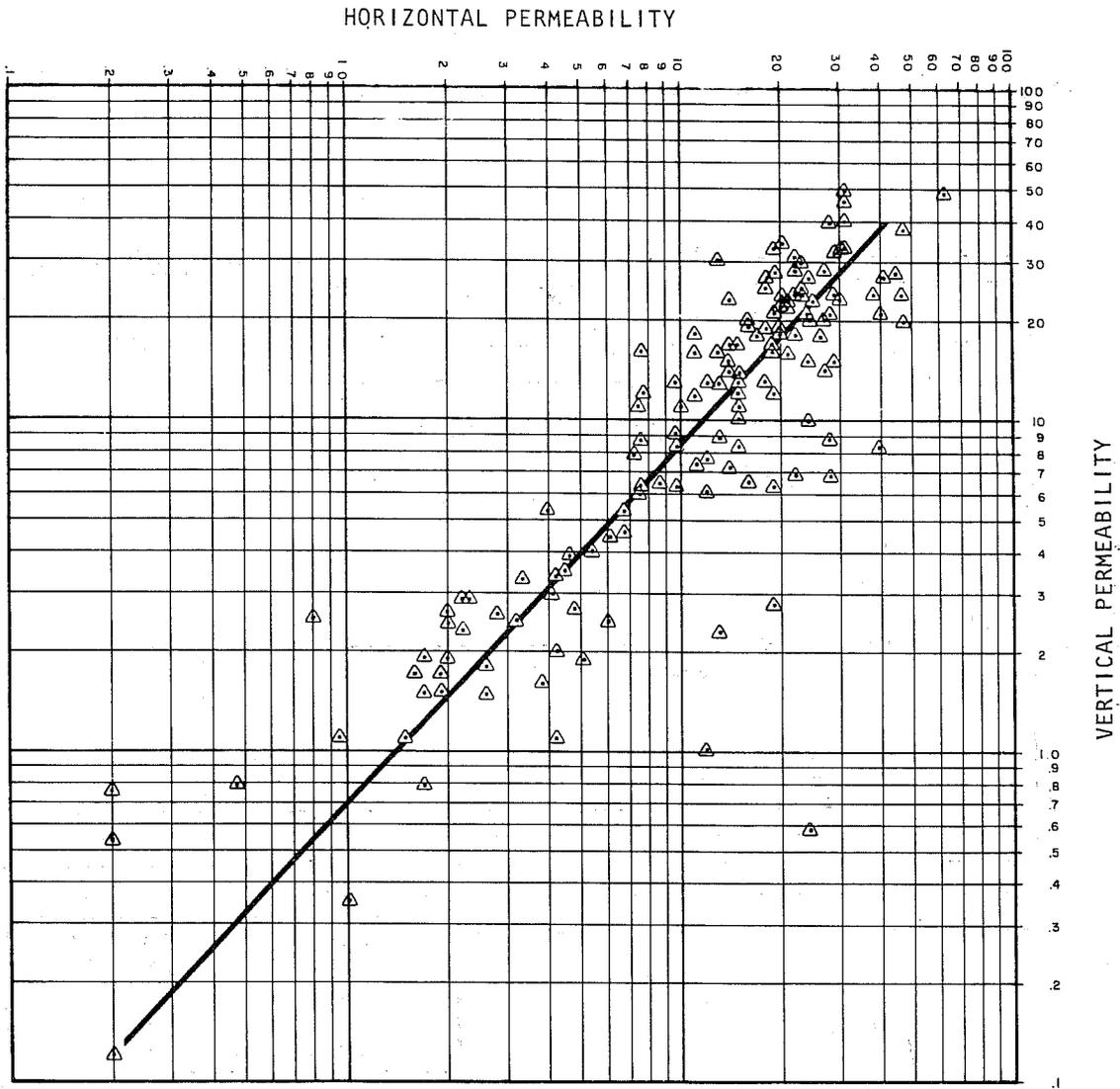


FIG. 28

HORIZONTAL PERMEABILITY VS VERTICAL PERMEABILITY

CO₂ INJECTION PROJECT AREA

ROCK CREEK FIELD WEST VIRGINIA

HORIZONTAL PERMEABILITY

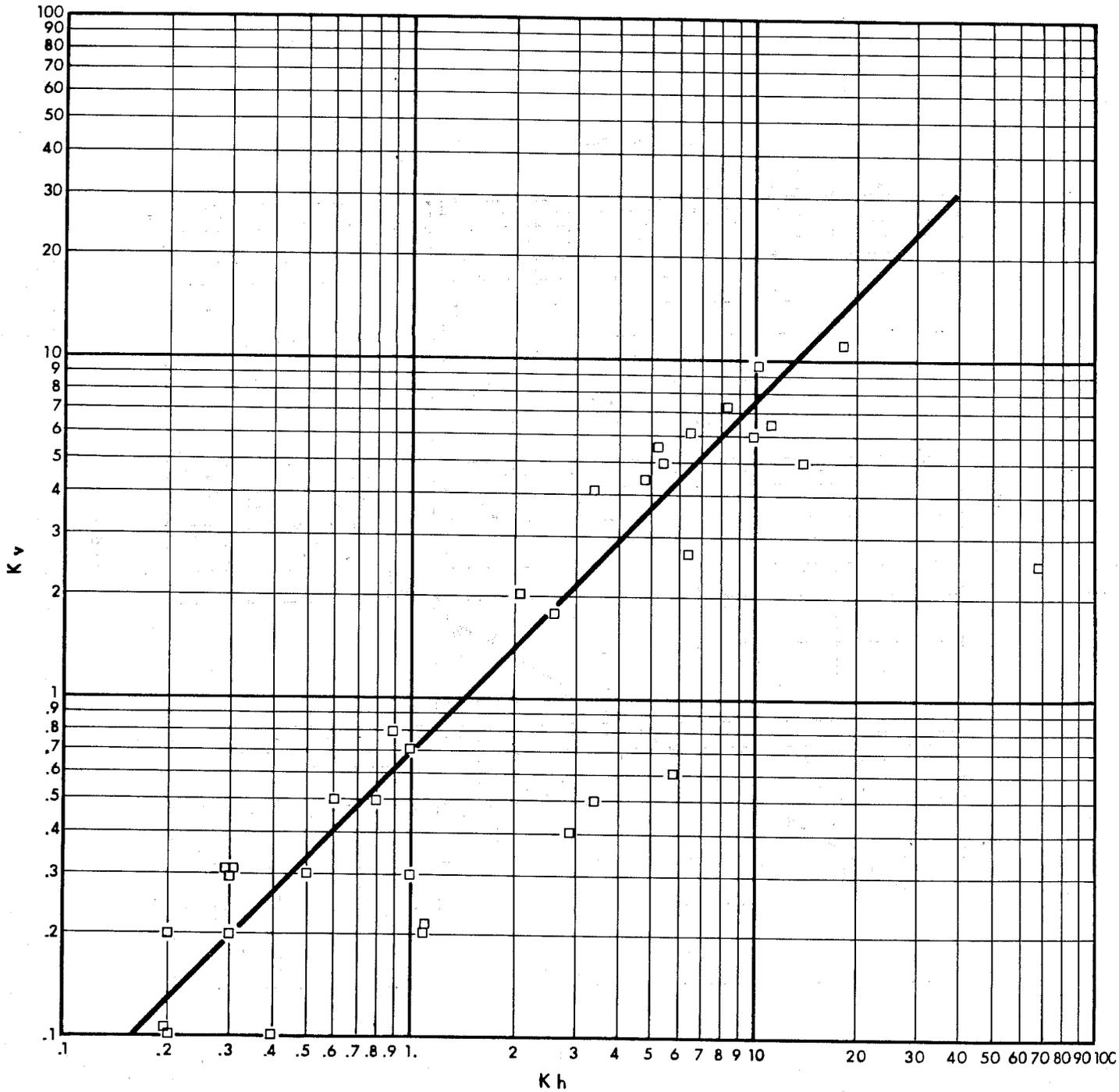


FIGURE 29

HORIZONTAL PERMEABILITY VS VERTICAL PERMEABILITY

CO₂ INJECTION PROJECT AREA

GRANNY'S CREEK FIELD

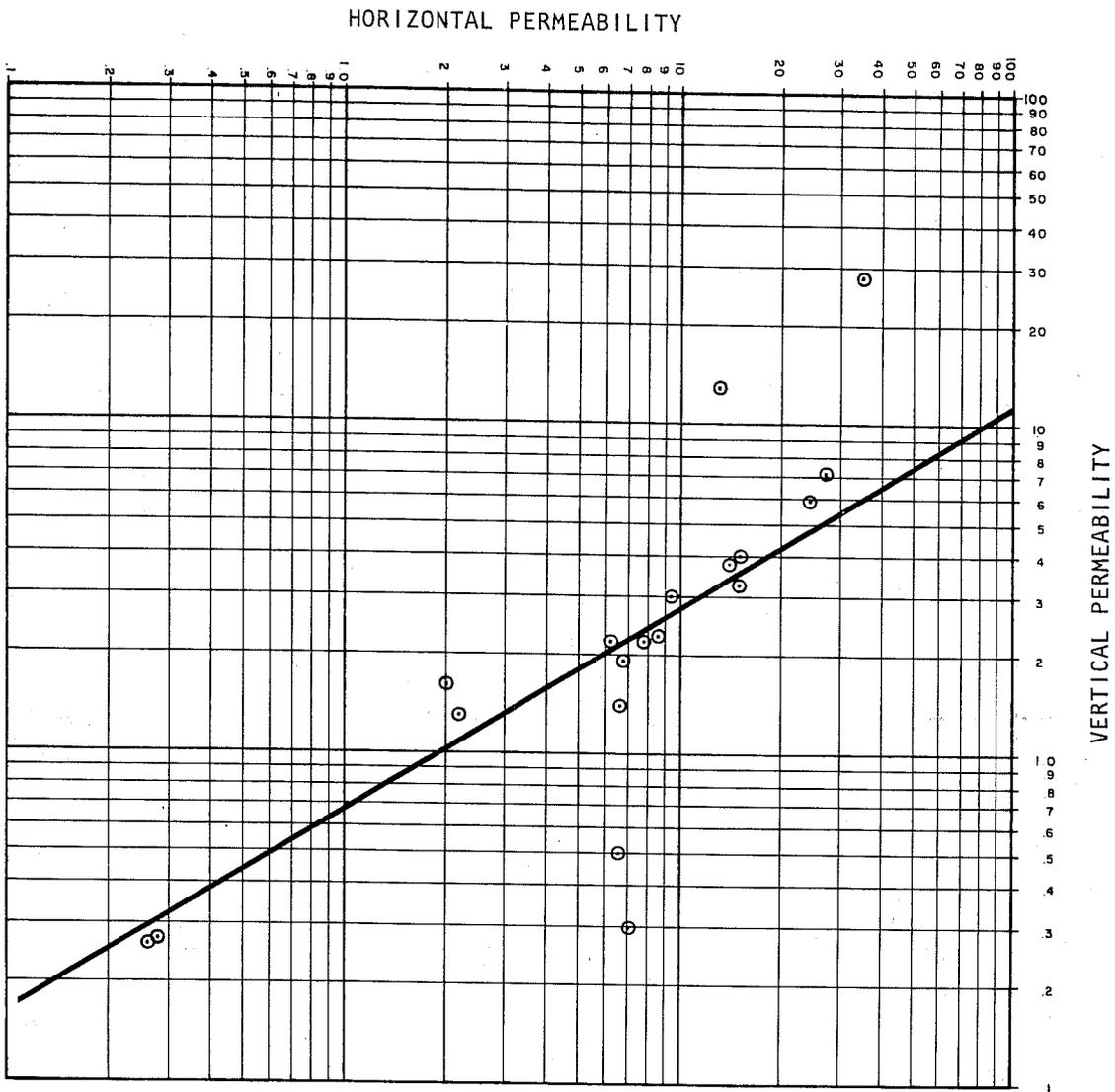
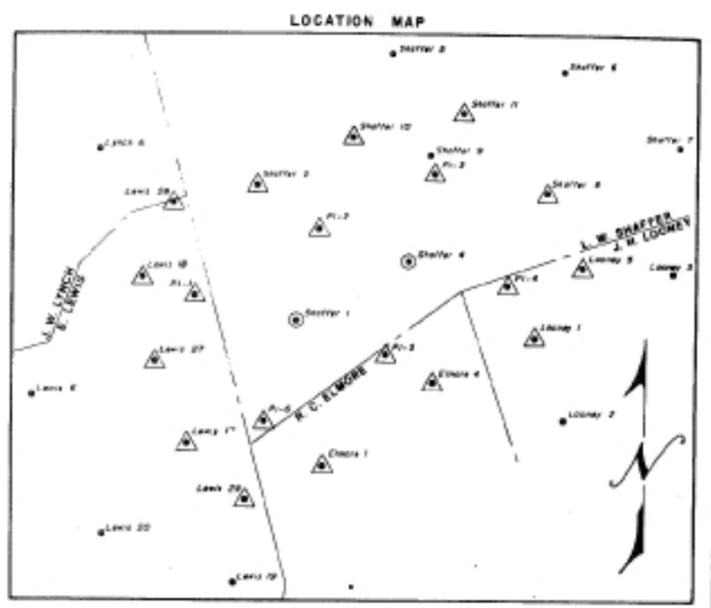
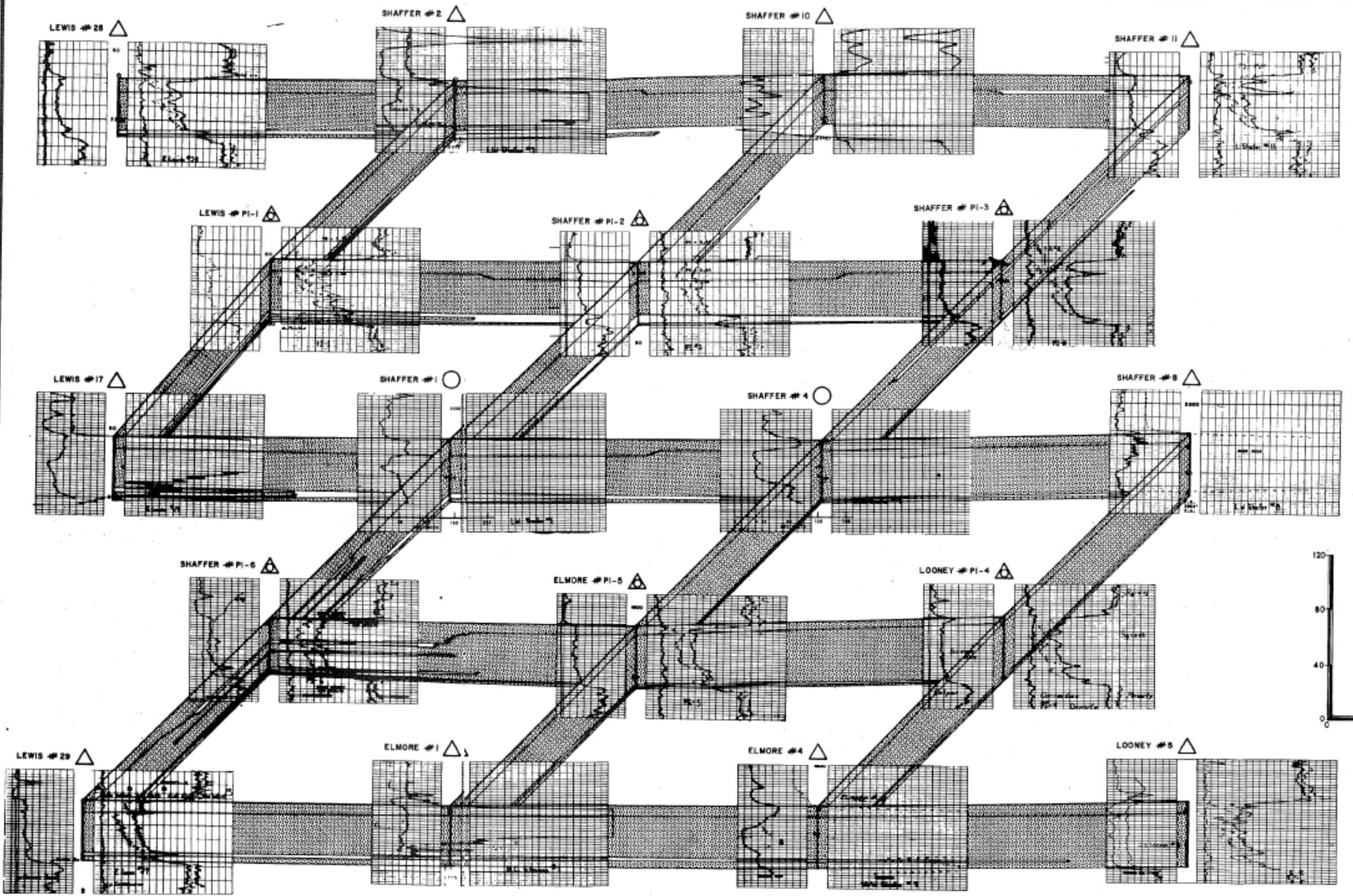
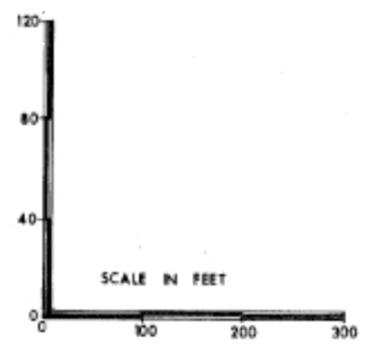


FIG. 30
 HORIZONTAL PERMEABILITY VS VERTICAL PERMEABILITY
 CO₂ INJECTION PROJECT AREA
 GRIFFITHSVILLE FIELD WEST VIRGINIA



LEGEND

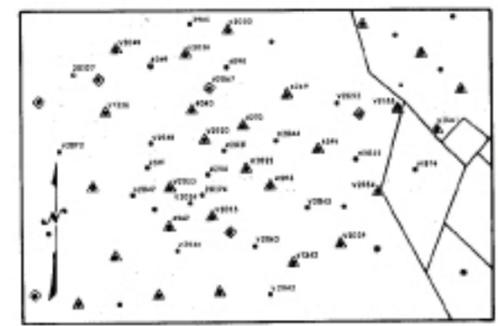
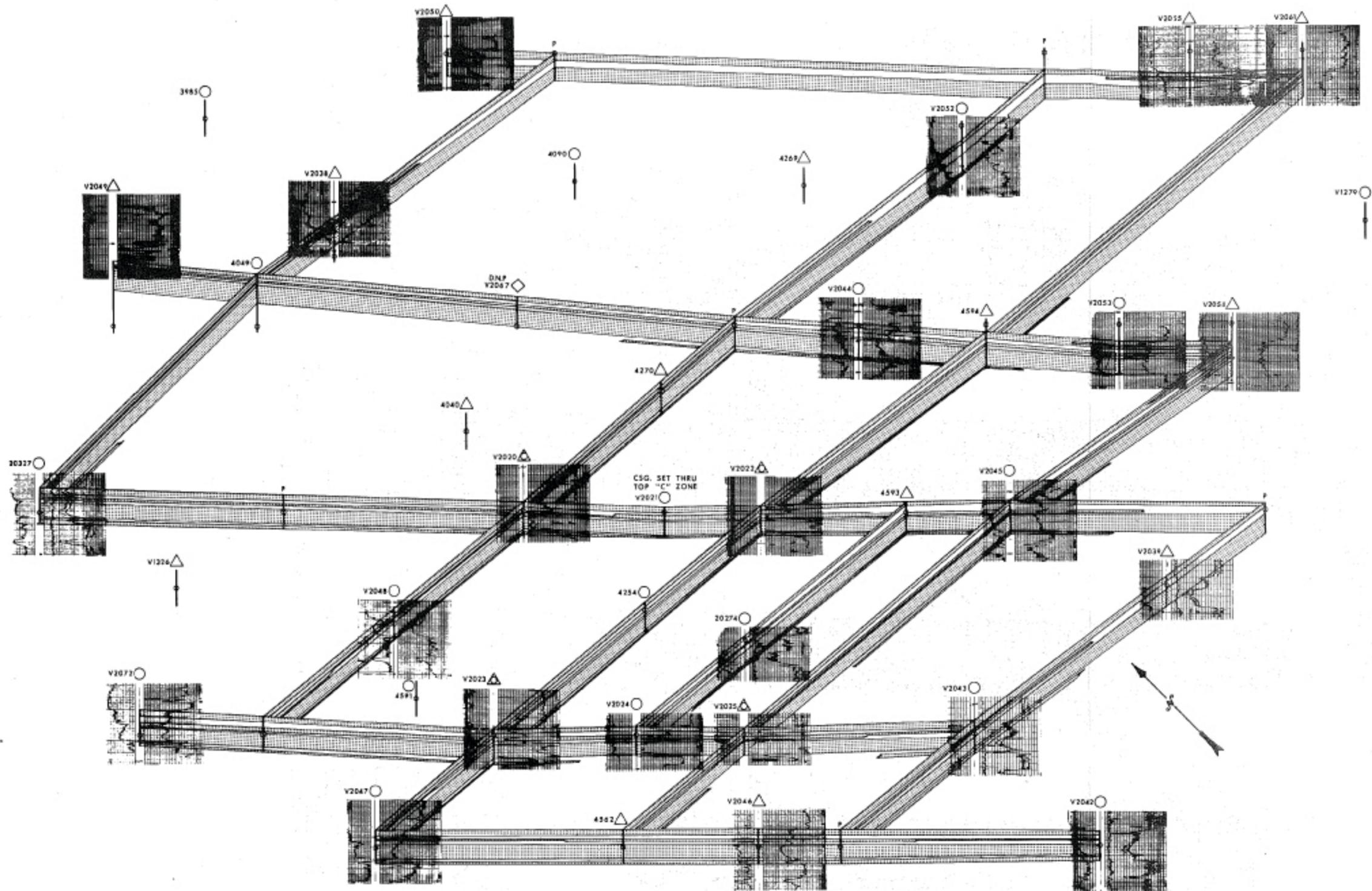
- PRODUCING WELL
- △ WATER INJECTION WELL
- ▲ CO₂ INJECTION WELL



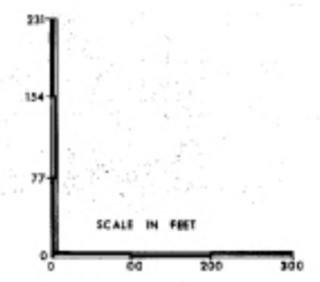
GRUY FEDERAL, INC.
HOUSTON, TEXAS

FIGURE 32
CO₂ INJECTION PROJECT
ROCK CREEK FIELD
ROANE COUNTY, WEST VIRGINIA

FENCE DIAGRAM
'BIG INJUN SAND'



Location Map



Legend

- PRODUCING WELL
- △ WATER INJECTION WELL
- ◇ WATER SUPPLY WELL
- ▽ CO₂ INJECTION WELL

GRUY FEDERAL INC.
HOUSTON, TEXAS

FIGURE 31
CO₂ INJECTION PROJECT
GRANNY'S CREEK FIELD
CLAY COUNTY, WEST VIRGINIA

FENCE DIAGRAM
"BIG INJUN SAND"

TABLE 1 (CONTINUED)

PUBLISHED SCREENING CRITERIA FOR THE SELECTION OF ENHANCED OIL RECOVERY TECHNIQUES

	CO ₂ MISCIBLE			SURFACTANT POLYMER			POLYMER		CAUSTIC WATERFLOOD
	Lewin 1976	Geffen 1973	GURC #148 1976	Lewin 1976	Geffen 1973	GURC #148 1976	Lewin 1976	GURC #148 1976	
Viscosity, centipoises	>12	>3	<10	<20	<10		{200		<200 good
API Gravity (California crudes)	>30 ^o (>26 ^o)	>30 ^o	>30 ^o	>28 ^o (>25 ^o)	NC	>25 ^o	>18 ^o (>16 ^o)	>20 ^o	15-25 ^o good
% of oil in area to be flooded before EOR	25	>25	>25	25	>25		50		>25 good
Oil concentration, B/AF	NC	NC	NC	NC	NC		NC		
Porosity x oil saturation	>3000	>2000	3000	NC	NC		NC		
Depth, ft.	NC	NC	NC	<200	<200	475	<200	>225	<200 good
Temperature, of BHP, original	>1500			NC			NC		
Net pay, ft.	NC	NC	>10	NC	NC	>10	NC	>5	
Permeability, md	NC	NC	NC	>20*	>20-50	>50	>20	25-1500	30-5000 good
Transmissibility (permeability x thickness / viscosity)	NC			NC			NC		
Natural water drive	none to weak		none to weak	none to weak		none	none to weak	none to weak	none to weak
Gas cap	none to minor		none to minor	none to minor		none	none to minor	none to minor	none to minor
Fractures	none to minor		none to minor	none to minor		none	none to minor	none to minor	none to minor
Lithology	NC		sandstone & carbonate	sandstone		sandstone	NC	sandstone good	sandstone good carbonate fair to poor
Salinity, ppm total dissolved solids	NC		<50,000			>2% by wt.	NC	NC	<2500 good
Hardness, ppm Ca + Mg	NC		<1,000			>2% by wt.	NC	NC	NC
Operating pressure, psi		>1100			NC				
k _{field} /k _{core}		<5			<5				
φ _h		low best			high best				
Well spacing		NC			NC				

*with polymer drive.

TABLE 2FRAC BREAKDOWN PRESSURES VS. DEPTH

<u>WELL NO.</u>	<u>BREAKDOWN PRESSURE, PSI</u>	<u>DEPTH, FEET</u>	<u>APPROXIMATE BREAKDOWN GRADIENT, PSI/FT</u>
Griffithsville Field - Berea Sandstone			
I-6	1900	2208	1.19
P-20	1400	2222	1.06
P-17	1600	2385	1.10
I-5	1600	2310	<u>1.13</u>
			Average 1.15
Rock Creek Field - Big Injun Sandstone			
PI-1	2200	2059	1.50
PI-2	1650	2098	1.22
PI-3	1550	1889	1.25
PI-4	1650	1937	1.28
PI-5	1450	1918	1.19
PI-6	1150	1973	<u>1.02</u>
			Average 1.24

TABLE 3
 WEST VIRGINIA OIL FIELDS
 HAVING SIGNIFICANT POTENTIAL FOR ENHANCED OIL RECOVERY
 BY CO₂ INJECTION

<u>FIELD NAME</u>	<u>ESTIMATED REMAINING OIL IN PLACE, MM BBL.</u>	<u>RESERVOIR</u>
<u>Primary Candidates</u>		
Blue Creek	85	Squaw - Weir
Cabin Creek	65	Berea
Cameron - Gardner	16.5	Gordon
Centerpoint	67	Big Injun
Granny's Creek	27.5	Big Injun
Greenwood	11	Big Injun
Griffithsville	60	Berea
Jacksonburg - Stringtown	68	Gordon
Mannington	97-115* (97)+	Big Injun and Gordon
Pine Grove	15-31* (31)+	Gordon
Porto Rico	30-37* (30)+	Gordon
Salem-Wallace	201-218* (201)+	Gordon
Steel Run	12-23* (23)+	Gordon Stray
Tariff	19	Big Injun
Walton + Clover-Rush Run	158	Big Injun
Wolf Summit	47-56* (56)+	Fifth Sand
Yellow Creek	16-20* (16)+	Berea
TOTAL, PRIMARY CANDIDATES	1.0-1.1 Billion bbl.	
<u>Secondary Candidates</u>		
Cairo - Ritchie	90+	Salt Sand
Sistersville	45+	Big Injun
Rouzer	11+	Big Injun
Kidwell - Elk Fork	19	Keener
TOTAL, SECONDARY CANDIDATES	.165 Million bbl.	

*Range of estimates because of lack of sufficient qualitative data to make a volumetric estimate. Reasonable data were used.

+1963 estimate.

TABLE 4

LITHOLOGIC DESCRIPTION OF GORDON SERIES RESERVOIRS
SELECTED IN THIS REPORT AS POTENTIAL EOR CANDIDATES

<u>FIELD NAME</u>	<u>FORMATION</u>	<u>LITHOLOGIC DESCRIPTION</u>	<u>AVERAGE THICKNESS NET/GROSS</u>
Cameron-Gardner	Gordon	Tightly cemented sandstone containing large pebbles	5/10-50
Jacksonburg-Stringtown	Gordon	Conglomeritic sandstone	4-5/10-35
Pine Grove	Gordon	Conglomeritic sandstone	5/10-70
Porto Rico	Gordon	Sandstone - variable thickness thins to the west	4/05-20
Salem Wallace	Gordon	Hard conglomeritic sandstone	8/05-50
Steel Run	Gordon Stray	Loosely cemented conglomeritic sandstone	5/10-40
Wolf Summit	Fifth	Coarse-grained well cemented sandstone	5'

TABLE 5

SUMMARY OF LOW-PRESSURE GAS INJECTION PROJECTS IN GORDON SERIES RESERVOIRS

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	FORMATION	DEPTH, THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/ INJECTION	INJECTION WELLS/ HEAD PRESSURE	DAILY PRODUCTION OIL, GAS, WATER, BBL. MCF. BBL.
1898	Pine Grove (Wetzel Co.) (Grant Dist.)	1954	1951	Gordon	2900 30	Hoyt-S 1/2	7/1	120/84	16 100 0
		1957					7/1	150/105	15 150 0
		1960					7/1	150/105	15 150 0
1898	Jacksonburg (Wetzel Co.) (Grant Dist.)	1951	1947	Gordon	2800 30	Mills-Gordon	19/4	600/135	60 600 0
		1954					19/4	600/135	40 600 0
		1957					19/4	800/135	40 800 0
		1960					19/4	850/135	40 800 0
1897	Stringtown (Wetzel-Tyler Co.) (McElroy-McClellan)	1951	1936	Gordon	18	Stringtown	12/1	57/145	9 - 14
		1954					23/2	170/145	20 - 7
		1957					37/3	310/135	26 - 15
		1960					36/3	342/135	26 - 12
1899	Wolf Summit (Harrison Co.) (Tenmile Dist.)	1951	1926	Fifth	2900 7	Lynch	72/8	375/81	67 - 2
		1954					77/11	800/81	80 - 5
		1957					77/11	910/100	77 - 4
1960					75/11	1062/112	66 - 4		

TABLE 6

SUMMARY OF SELECTED LOW-PRESSURE GAS CYCLING PROJECTS IN BIG INJUN SAND RESERVOIRS

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/ INJECTION	INJECTION WELLHEAD PRESSURE	DAILY PRODUCTION OIL, GAS, WATER BBL. MCF. BBL.	
1890	Sistersville (Tyler Co.) (Lincoln Dist.)	1951 1954 1957 1960	1933	1700	100	Sistersville		403/3	65 3500 4507	
								36/6	365/3	62 3500 375
								30/6	365/3	55 - 340
								29/6	337/9	54 - 235
1890	Sistersville (Tyler Co.) (Lincoln Dist.)	1951 1954 1957 1960		1700	100	Sistersville		403/3	65 3500 450	
								61/9		14.2 3000 500
								61/9		14.2 3000 500*
								61/9		- - -
1890	Mannington (Marion Co.) (Lincoln-Mannington Dist.)	1951 1954 1957 1960		2075	9.2/119	Blacksheare		1003/126	101 - 60	
								99/12		87 - 50
								99/12	920/126	81 - 30
								70/113	960/126	70 - 35
1889	Mannington (Marion Co.)	1951 1954 1957 1960	1926	1900	29/128	Mannington		970/122	30 40 -	
								12/3	275/100	12 30 7
								12/3	160/240	10 700 4
								12/3	65/255	10 700 4

TABLE 6 continued

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/INJECTION	INJECTION MCF/WELLHEAD PRESSURE	DAILY PRODUCTION OIL, GAS, WATER BBL. MCF. BBL.
1907	Rock Creek (Roane Co.)	1951	1935	2025	30	Shaffer-Ellewis	78/6	501/170	134 - 14
	(Walton Dist.)	1954					103/9	800/170	158 - 51
		1957					105/10	600/170	159 - 33
		1960					99/11	509/158	136 - 33
1909	Walton (Roane Co.)	1951	1946	2000	30	Walton	15/2	325/350	30 - -
	(Walton Dist.)	1954					15/5	400/350	85 425 -
1909	Walton (Walton Dist.)	1951	1946			Walton	7/1	100/265	39 125 -
		1954							
1909	Clover	1951							
		1954							
		1957					33/4	135/275	25 - 10
		1960					37/5	274/328	29 - 6
1895	Elk Fork (Tyler Co.)	1951	1934	1850	12	Elk Fork	47/6	310/32	51 - 14
	(Ellsworth Dist.)	1954					55/10	345/32	60 - 14
		1957					53/11	445/32	67 - 20
		1960					48/12	573/31	67 - 31

TABLE 6 continued

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/INJECTION	INJECTION MCF/WELLHEAD PRESSURE	DAILY PRODUCTION OIL, GAS, WATER BBL. MCF. BBL.
1898	Jacksonburg	1954	1950	2100	40	Mills-Injun	6/1	250/150	10 - -
		1957					6/1	320/235	5 320 -
		1960					6/1	320/235	5 320 -
	Tariff	1957	1951				64/9	420/245	25 - 1
		1960					64/9	481/276	86 - 20
1924	Granny's Creek (Stockly)	1951	1943				75/7	1875/300	72 158 -
		1957					36/4	310/285	25 - 1
		1960					33/4	265/265	17 - 1

TABLE 6a

SUMMARY OF SELECTED LOW-PRESSURE
GAS INJECTION PROJECTS IN BEREA SAND

	<u>DATE OF FIRST INJECTION</u>	<u>NO. WELLS PRODUCTION/ INJECTION</u>	<u>INJECTION MCF/ WELLHEAD PRESSURE</u>
Cabin Creek	1930	19/4	96/190
Cabin Creek	1932	244/27	732/50-200
Griffithsville	1926	/52	44/300

TABLE 7

SUMMARY OF SELECTED WATERFLOODS IN THE BEREA SAND

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	NO. WELLS	PRODUCTION/INJECTION PRESSURE, PSI	INJECTION WELLHEAD	B/D	DAILY PRODUCTION OIL, BBL.	GAS, MCF	WATER, BBL.
1907	Griffithsville (Lincoln Co.)	1951	1945	2300	22	/5	130/2000		-	-	-	-
	(Duval-Union Dist.)	1954				8/3	85/1400		6	-	-	4
		1957				/1	-		-	-	-	-
		1960				/3	-		-	-	-	-
1914	Cabin Creek (Boone & Kanawha Co.)	1951	1947	2850	44	5/19	600/1000		190	275	50	50
	(Cabin Creek & Sherman Dist.)	1954				4/7	600/210		17	-	50	-
		1957				-	-		-	-	-	-
1914	Cabin Creek (Boone & Kanawha Co.)	1951	1939	3000	30-55	69/106	10000/2300		1360	-	-	-
	(Cabin Creek & Sherman Dist.)	1954				62/130	15000/800		3218	-	1850	-
		1957				23/80	6650/800		535	-	200	-
		1960				15/51	3700/1200		325	-	125	-

TABLE 8
SUMMARY OF SELECTED WATER INJECTION PROJECTS OR TESTS IN BIG INJUN SAND RESERVOIRS

LOCATION	I OCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	ACREAGE	NO. WELLS PRODUCTION/ INJECTION	B/D WATER IN- JECTED/WELLHEAD PRESSURE	DAILY PRODUCTION OIL, GAS, WATER, BBL. MCF. BBL.	TOTALS		
									WATER INJECTED BBL.	OIL RECOVERED BBL.	
Clover - Rush Run	1957	1955	1950	10 ?	42						
	1960					6/3	175/800	-	-		
Waterflood Inc. Walton	1957	1954	2000	30	584	21/20					
	1960					15/17	1642/1000	-	-		
Piedmont Oil Co. Walton	1957	1954	2025	30	7.5	1/4					
	1960					5/7		-	-	2,762,442	14,667
Ryan Oil Walton	1957	1954				1/4	223/1150	7	14		
	1960					1/4		-	-	280,000	19,721
Cities Service Walton		1965			15	2/4		-	-	329,169	7,805
		1970			6.6	4/1		-	-	64,000	1,883
Pennzoil (Steam) Granny's Creek		1963 to present			350	19 five-spots	50 per injection well				
		1971				2/6				4000 bbl. oil per acre recovered in pilot area	

TABLE 9

SUMMARY OF SELECTED LOW-PRESSURE GAS INJECTION PROJECTS IN PENNSYLVANIAN SANDS

DISCOVERY DATE	FIELD NAME (LOCATION)	IOCC REPORT YEAR	DATE OF FIRST INJECTION	DEPTH, FT.	THICKNESS, FT.	PROJECT NAME	NO. WELLS PRODUCTION/INJECTION	INJECTION MCF/WELLHEAD PRESSURE	DAILY PRODUCTION OIL, BBL. GAS, WATER, MCF. BBL.
1903	Hartley (Cairo-Mine)	1951	1941	1800	94	Lemon-Haught	43/4	279/244	24 - 80
	(Ritchie-Hartley)	1954				Lambert	107/12	541/244	94 - 155
	(Ritchie Co.)	1957					107/12	588/244	86 - 197
	(Murphy Dist.)	1960					115/12	530/327	83 - 226

TABLE 10

SECONDARY RECOVERY PROJECTS IN BLUE CREEK, SQUAW, AND WEIR SAND FIELDS*

LOCATION, FLUID INJECTED, SAND	YEAR OF FIRST INJECTION	ACRES	NO. WELLS PRODUCTION/ INJECTION	PRODUCTION- INJECTION WELL DISTANCE, FT.	MCF OR BBL/DAY	PRESSURE RANGE/AVG.	DAILY PRODUCTION OIL, GAS, WATER, BBL. MCF. BBL.
Pinch (Blue Creek) (Bannster Heirs) Air Squaw	1932	175	5/2	595	206	25-67/46	8 - - 7
Pinch (Gordon Creek) (Blue Creek) (Estep) Gas Squaw	-	-	14/2	700	66	135-159/147	8 - - 0.5
Blue Creek (Pinch Block) Gas (Water in 1954?) Weir	1926	190 (202)	10/3	595	-	32-78	- - -
Blue Creek Blue Creek Gas Squaw	1925	646	33/4	600	75	/35	- - -
Blue Creek (Falling Rock) Gas Squaw	1939	200	18/2	1000	65	/115	- - -
Blue Creek (Skinner) (Water) Weir	1946	10	/1	600	100	/605	- - -

*Summary as of 1951; all projects stopped reporting information in 1954.

TABLE 11

AVERAGE RECOVERY FROM WEST VIRGINIA RESERVOIRS

<u>PRODUCING FORMATION</u>	<u>AVERAGE RECOVERY, B/AF</u>		<u>NO. OF RESERVOIRS</u>
	<u>PRIMARY, EST.</u>	<u>TOTAL</u>	
Berea	100	138	9
Big Injun	100	114	7
Gordon	180	195	4
Fourth	300	361	2
Fifth	150	197	1
Keener	150	198	1
		<u>164*</u>	

*Average recovery

TABLE 12

SUMMARY OF WELL DATA FROM WEST VIRGINIA GEOLOGICAL SURVEY
SHALLOW WELL FILE

FIELD	RESERVOIR	NO. OF WELLS	INITIAL POTENTIAL RANGE	INITIAL POTENTIAL AVG.	THICKNESS RANGE	THICKNESS AVG.
Blue Creek (Falling Rock)	Weir	8	0-8	2.89	19-198	94.13
	Squaw	1	0	0	28	28
Blue Creek (Hackberry Branch)	Weir	3	1-21	7.33	17-110	67.33
Yellow Creek (Big Spring)	Berea	4	0-3	2.25	ND	-
Walton (Johnson's Creek & Rock Creek)	Big Injun (undifferentiated)	19	0-25	6.95	29-48	39.64 (14)*
	Big Injun (Pocono)	1	0-25	6	ND	-
Wallace Folsom	Gordon	3	2-17	7.67	20-34	28.33
Tariff (Tailman)	Big Injun (Pocono)	1	20	20	44	44
	Big Injun (undiff.)	10	3-28	8.80	24-56	36.33 (3)*
Salem	Gordon	1	ND	-	14	14
Rouzer	Big Injun (Greenbrier)	21	2-125	41.24	19-86	45.71 (7)*
	Big Injun (Pocono)	7	10-160	46.14	28	28 (1)*
	Big Injun (undiff.)	23	0-50	18.52	36-78	54.95 (19)*
Porto Rico (Stout)	Gordon	5	1-10	6.20	4-16	9.50
Mannington	Big Injun (undiff.)	4	3-15	4.50	114-116	115 (2)*
Kidwell - Elk Fork Area	Keener	3	ND	-	-	-
Jacksonburg - Stringtown	Gordon	12	2-41	18.42	41-53	35.17
Griffithsville	Berea	205	1-25	30.74	10-46	10.11
Greenwood	Big Injun (Pocono)	63	0-400	26.90	ND	-
	Big Injun (undiff.)	2	12-15	13.50	ND	-
	Big Injun (Greenbrier)	1	4	4	ND	-
Granny's Creek	Big Injun (undiff.)	48	0-100	11	13-111	44 (43)*
Clover - Rush Run (Fisher)	Big Injun (undiff.)	47	1-207	26.51	11-64	23.33 (21)*
Centerpoint	Big Injun (Greenbrier)	1	1	1	ND	-
	Big Injun (undiff.)	3	3-4	3.33	101-128	111.33
Cairo - Ritchie Mine - Hartley	Salt Sands (general)	8	1-30	12.63	54	54 (1)*
Cabin Creek	Berea	58	0-136	12.33	4-54	38.64

ND = no data available

* Number in parentheses, if less than number of wells, is number for which thickness is recorded.

TABLE 13

DERIVED ORIGINAL OIL SATURATION VALUES
FOR ALL FIELDS WHERE DATA PERMIT VOLUMETRIC CALCULATIONS*

FIELD	ϕ	h	ACREAGE	OIL ORIGINAL ESTIMATE	DERIVED S_o ESTIMATE
Blue Creek	0.12	10	17,254	69,016,000	0.52
Cabin Creek	0.16	20	4,480	32,704,000	0.36
Cameron Gardner	0.11	5	8,340	25,160,000	0.85
Centerpoint	0.17	10	12,980	51,920,000	0.36
Granny's Creek	0.17	20	2,803	16,818,000	0.17
Greenwood	0.06? 0.12?	8	2,253	13,518,000	1.93 0.815
Griffithville	0.11	10	12,877	74,043,000	0.79
Jacksonburg Stringtown	0.125	4.5	16,000	88,469,000	1.52
Tariff	0.17	12	3,000	13,809,000	0.35
Walton	0.22	21	11,200	54,165,000	0.16

* B_o assumed to be 1.2 in all cases.

TABLE 14
STATE OF WEST VIRGINIA
RESERVOIR DIMENSIONS AND OIL SATURATIONS BY PRODUCING SANDS, JANUARY 1, 1954

SAND	NO. OF FIELDS	DEPTH	NO. WELLS PRO-DUCING	ABAN-DONED	ORIGINAL PRODUCING ACREAGE	VISCOSITY STOCK TANK OIL RES. TEMP.	PAY, FT.	PORO-SITY	FORMA-TION VOLUME FACTOR	OIL SATURATIONS				
										% OF PORE VOLUME		NON-REC.		BBL/AC.-FT. ORIGINAL STOCK TANK
										NATURAL STOCK	1/1/54 STOCK TANK	STOCK TANK	STOCK TANK	
Cow Run	4	700-1100	1064	4046	10,200	4.9	20	15.9	1.05	54	51.4	43.4	27	634
Burning Springs	1	845	279	790	4,200	-	20*	15*	1.05	55*	52.4	43.2	28	610
Salt	4	360-1600	1028	4046	15,850	3.2	20*	12*	1.05	70*	66.7	53.5	35	621
Haxton	4	1200-2100	271	41	2,288	6.0	25	12.0	1.10	90	81.8	63.2	45	761.5
Big Lime	2	1235-1500	28	8	252	6.2	25*	16.0*	1.10	50*	45.4	37.4	25	564
Keener	4	1650-1860	530	658	6,120	3.7	16	10.5	1.13	64	56.6	48.6	32	461
Big Injun	24	1050-2100	3638	3321	54,423	4.3	25	17.6	1.14	52.5	46.1	38.9	26.2	629
Squaw	1	1800	327	142	3,020	3.2	16	11.0	1.13	74	65.5	54.1	37	559
Weir	2	1900	592	141	6,040	4.5	30*	11.3	1.14	73	64.0	50.0	37	561
Berea	16	1000-2800	2489	1911	31,944	5.2	13	15.0	1.17	80	68.4	53.8	40	796
Fifty Foot	1	2135	104	118	2,480	3.8	11*	9.0*	1.15	70*	60.9	47.9	35	425
Thirty Foot	1	2900	190	127	1,525	5.3	12	9.0	1.20	80	66.7	53.7	40	465
Gordon	16	2200-3200	1578	3939	73,800	5.2	17	10.1	1.20	76	63.3	53.2	38	496
Fourth	4	2240-3200	222	136	3,020	6.1	10	5.0	1.20	48	40.0	32.7	24	155
Fifth	6	2800-3100	798	784	19,300	5.6	10*	17.0*	1.20	60*	50.0	39.8	30	659
TOTALS	90		13138	20208	234,462									

*Estimated.

TABLE 15

VOLUMETRIC RESERVE ESTIMATES

SELECTED FIELDS IN WEST VIRGINIA

FIELD (FORMATION)	ϕ	h	ACREAGE	EST. ORIG. S _o †	ESTIMATED FORMATION VOLUME FACTOR, ORIG. †	B/AF	ESTIMATED ORIGINAL OIL IN PLACE, BBL.	PRODUCTION, BBL.	RECOVERY, PERCENT
Blue Creek (Weir)	0.12	10	17,254	0.73	1.14	596	102,833,840	18,185,000*	18
Cabin Creek (Berea)	0.16	20	4,480	0.80	1.17	849	76,070,400	11,077,000*	15
Cameron Gardner (Gordon)	0.11	5	8,340	0.76	1.20	540	22,518,000	5,975,000*	27
Centerpoint (Big Injun)	0.17	10	12,980	0.525	1.14	607	78,788,600	11,646,000	15
Granny's Creek (Big Injun)	0.17	20	2,803	0.525	1.14	607	34,028,420	6,466,000*	19
Greenwood (Big Injun)	0.06 ?	8	2,253	0.525	1.14	214 ?	135,070,000§	2,700,000	2
Griffithsville (Berea)	0.11	10	21,877	0.80	1.17	583	75,138,300	14,790,000*	20
Jacksonburg-Stringtown (Gordon)	0.125	4.5 ?	16,000 ?	0.76	1.20	614	88,500,000¶	20,458,000*	23
Tariff (Big Injun)	0.17	12	3,000	0.525	1.14	607	21,852,000	3,170,000*	15
Walton (Big Injun)	0.22	20	11,200	0.525	1.14	786	176,064,000	18,097,000**	10
TOTAL							810.8 million	112.6 million	

NOTES: *1963 Estimate
 **Probably higher - 1963 estimate
 † From IOCC 1954
 ‡ 1963 estimate is reasonable.
 § 1963 estimate is more reasonable.

TABLE 16

AVERAGE POROSITY OF WEST VIRGINIA RESERVOIRS

FORMATION	THIS REPORT		IOCC REPORTS **	
	AVERAGE ϕ^*	NO. OF FIELDS WHERE AVERAGE ϕ IS KNOWN	AVERAGE ϕ^*	NO. OF FIELDS WHERE AVERAGE ϕ IS KNOWN
Big Injun	0.16	14	0.176	14
Berea	0.14	5	0.15	16
Fifth	0.18	2	0.17*	6
Gordon	0.12	2	0.101	16
Keener	0.115	2	0.105	4
Fifty Foot	0.13	1	0.09	1

*Average value for fields where there is some production from the reservoir.

**Used some confidential core data from S. Penn Oil Co. files.

TABLE 17
AVERAGE FORMATION VOLUME FACTORS FOR
WEST VIRGINIA OIL RESERVOIRS

<u>FIELD</u>	<u>FORMATION</u>	<u>VOLUME FACTOR</u>	
		<u>fvf(correl.)</u>	<u>fvf (IOCC)</u>
Blue Creek	Weir?	1.2	1.14
Cabin Creek	Berea	1.2	1.17
Cario	Salt		1.05
Griffithsville	Berea	1.2	1.17
Jacksonburg	Gordon	1.2	1.20
Mannington	Big Injun	1.2	1.14

TABLE 18

PERMEABILITY RANKING OF SELECTED CANDIDATE RESERVOIRS

	FIELD	RESERVOIR
<u>High Permeability</u>		
	Cameron-Gardner	Gordon
	Porto Rico	Gordon
	Steel Run	Gordon Stray
	Sistersville	Big Injun
	Kidwell Elk Fork	Keener
<u>Medium Permeability</u>		
	Cabin Creek	Berea
	Centerpoint	Big Injun
	Pine Grove	Gordon
	Tariff	Big Injun
	Wolf Summit	Fifth sand
	Yellow Creek	Berea
<u>Low Permeability</u>		
	Blue Creek	Wier
	Granny's Creek	Big Injun
	Greenwood	Big Injun
	Griffithsville	Berea
	Mannington	Big Injun
	Walton	Big Injun
	Cario Ritchie	Salt
	Rouzer	Big Injun

TABLE 19

SUMMARY OF SALIENT RESERVOIR FEATURES
OF RESERVOIRS SELECTED FOR EOR POTENTIAL

FIELD (FORMATION)	\bar{n}	ϕ	EST. S _o , B/AF	ORIG. OIL IN PLACE EST., MMB	PERCENT RECOVERY	k	SECONDARY RECOVERY	WELLS DRILLED SINCE 1929	PRODUCING/ ABANDONED
Blue Creek (Weir)	10	0.12	596	103	18	low	No major projects	9	P
Cabin Creek (Berea)	20	0.16	849	76	15	med.	Waterflood	50	P
Cameron-Gardner (Gordon)	5	0.11	540	23	27	high	Current gas injection	0	A
Centerpoint (Big Injun)	10	0.17	607	79	15	med.	Gas injection (current?)	4	P
Granny's Creek (Big Injun)	20	0.17	607	34	15	low	Waterflood	48	P
Greenwood (Big Injun)	8	0.06	428	13	20	low	None	66	A?
Griffithsville (Berea)	10	0.11	583	75	12	low	3-well water- flood	205	P
Jacksonburg-Stringtown (Gordon)	4-5 ? (10)*	0.125	614	88	23	high?	Some (50-well) gas injection	12	A
Tariff (Big Injun)	12	0.17	607	22	15	med.	None	11	P
Walton (Big Injun)	20	0.22	786	176	10	low	Gas injection Waterflood pro- ject not expanded	20†	P

*4-5 is the value in the literature; 10 seems more reasonable.

†Actually much higher.

TABLE 20

CRUDE OIL PROPERTIES
OF THREE CURRENT CO₂ DISPLACEMENT PROJECT AREAS
AND ONE PROPOSED PROJECT AREA, FROM PREVIOUS REPORTS

<u>FIELD NAME</u>	<u>API GRAVITY</u>	<u>VISCOSITY, CP</u>	<u>SURFACE TENSION</u>	<u>INTERFACIAL TENSION</u>
Griffithsville	40.0	2.81	24.3	30.7
Granny's Creek	45.4	2.46	24.6	37.0
Rock Creek	46.5	3.11	25.1	30.8
Walton	43.5	3.97	25.1	30.8
Blue Creek	42.0	4.20	25.8	37.7
Blue Creek	45.8	2.15	24.0	41.7
Blue Creek	47.5	1.87		

TABLE 21SOLUBILITY PRODUCT CONSTANTS
OF SELECTED CARBONATE MINERALS

<u>MINERAL</u>	<u>CHEMICAL FORMULA</u>	<u>K_{sp}</u>
Calcite	CaCO ₃	3.98 x 10 ⁻⁹
Aragonite	CaCO ₃	5.62 x 10 ⁻⁹
Dolomite	CaMg(CO ₃) ₂	10 ⁻¹⁷
Nesquehonite	MgCO ₃ ·3H ₂ O	10 ⁻⁵
Magnesite	MgCO ₃	7.9 x 10 ⁻⁹
Hydromagnesite	Mg ₅ (CO ₃) ₄ (OH) ₂ ·4H ₂ O	6.3 x 10 ⁻³¹
Lansfordite	MgCO ₃ ·5H ₂ O	3.47 x 10 ⁻⁶
Nahcolite	NaHCO ₃	1.2 x 10 ⁻³
Soda	Na ₂ CO ₃ ·10H ₂ O	0.752 mole/liter at 0°C
Trona	Na ₂ CO ₃ ·NaHCO ₃ ·2H ₂ O	0.58 mole/liter at 0°C

TABLE 22
COMPARISON OF THREE CO₂ OIL DISPLACEMENT PROJECTS IN WEST VIRGINIA

	GRANNY'S CREEK	GRIFFITHSVILLE	ROCK CREEK
<u>Rock Properties (Formation)</u>	(Big Injun)	(Berea)	(Big Injun)
Lithology	Sandstone, slightly limey silty near bottom	Sandstone, quartz, dolomitic	Sandstone, quartz, ankerite (dolomite)
Average ϕ	0.17	0.123	0.212
Average k_h	5, 5, 1.5 (3 zones)	8.2	15
Average k_v	0.8 x k_h	0.3 x k_h	1.0 x k_h
Variation k_h /md cutoff	High/0.70	High/0.56	High/0.46
Stratification	At least three stratigraphically continuous layers	Impermeable zones not correlative between wells; high permeability zone at top	Nearly homogeneous
Ave. net/ave. gross	30/50	14/23	35/44
<u>Fluid Saturations</u>			
S_o original, est.	0.50	0.80	0.54
S_o present, est.	=0.30-0.35	=0.54-0.60	=0.35-0.46
Est. original FVF	1.14	1.17	1.14
<u>Reservoir Conditions</u>			
Temperature	77-80°F	78-85°F	73-75°F
Depth	2000 ft	2300 ft	1900 ft
Production history	Primary, then waterflood	Primary, then accidental crossflow (dump flood)	Primary, then gas injection
Dip of reservoir	=10	<0.50	<0.40

TABLE 22 (continued)
 COMPARISON OF THREE CO₂ OIL DISPLACEMENT PROJECTS IN WEST VIRGINIA

	GRANNY'S CREEK	GRIFFITHSVILLE	ROCK CREEK
<u>Oil Properties</u>			
Gravity, OAPI	45.4	40-43	46.5
Viscosity, cp	2.46	2.81-3.1 @ 85°	3.11
Miscible pressure/temp.	1000/75°	1100/85°	1000/73°
Surface tension	24.6	24.3	25.1
Interfacial tension	37.0	30.7	30.8
<u>Design Features</u>			
New or existing wells	Used all existing wells from previous waterflood pilot project	All new wells: 4 CO ₂ injectors, 12 water injectors, 9 producers	6 new wells (CO ₂ injectors), 2 inside producers, 13 backup injectors
Size (acres), design	6.5 - 1 skewed five-spot, 2 inside wells		
Injection pattern		1 confined five-spot 8 additional five-spots 10 acres/five-spot, 90 ac. total	2 confined 10-acre five-spots
<u>CO₂</u>			
Slug size	9888 tons	8000 tons for 4 injection wells	25,000 tons with 50% confined within pattern
Pressure range	1200-1700 psi	>1000 psi	>1000 psi
Injection procedure	Alternating water, CO ₂	Alternating water, CO ₂ planned	Alternating water, CO ₂ planned
<u>Recovery</u>			
Bbl/Mcf CO ₂ injected	1/20 overall*	no results yet	no results yet
Acres affected	>200	no results yet	no results yet

* If 6% of CO₂ assumed to enter pattern area, efficiency could have been 1/2.

APPENDIX A

FIELD DATA

COMMENTS ON FIELD DATA

The following field data have been compiled in assessing the potential of the CO₂ displacement process in West Virginia reservoirs. Detailed quantitative information on these reservoirs is both scarce and of uncertain quality. The goal was to obtain as much reservoir information as possible for each field and to include a log, if one could be found, and at least one map.

The maps that we found are highly variable in quality. We have normally included an old county report map and, where it would be useful, a newer location plat map. The location plat maps have accurate locations for all wells on which permits have been filed to drill, abandon, fracture, recomplete, or log since 1929. As can be seen by glancing at a few of these, for most fields very few wells are recorded.

The older county maps show the locations of many wells. In cases of overlap, where a county or section of a county is included on two maps, the maps are not the same; however, the general orientation, general number, and spacing are about the same. It is possible from these older maps (the best that exist, in most cases) to see how well the limits of the field are defined by dry holes. They are included here as indications of the number of old wells that exist in each field area.

The logs included in this report are also highly variable in quality. In many cases the log included with the field data sheet is the only modern log that could be located; in others there were more than 50 logs to choose from.

GRUY FEDERAL, INC.

FIELD NAME - Blue Creek CO. (s) - Kanawha
 DIST. - Big Sandy and Elk

PRINCIPAL OPERATOR - Pennzoil, F. D. Smith
 Weir and Squaw Sands largely abandoned.

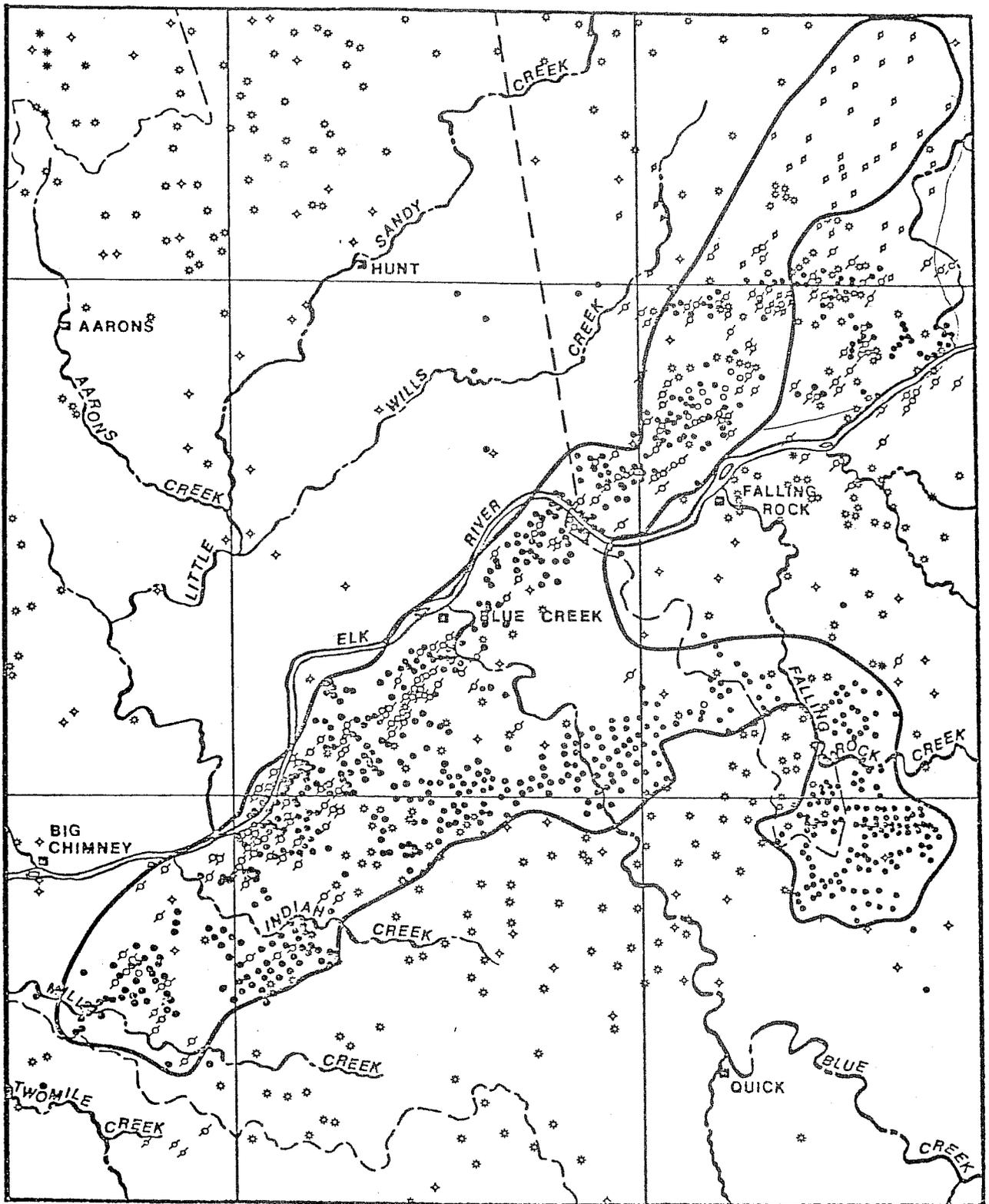
FORMATION NAME(s)	Big Injun	Squaw	Weir
AVE DEPTH(s)	1870	1885	2000
AVE THICKNESS(es) Net/Gross	35'	12/16-180	10/64
API GRAVITY/VISCOSITY	51.8°/36 sec. ² 23 cp @ 100°F	(42°)	(45°) 3 C.Stokes
AVE k	20 md	7 md - 12 md	
So-CURRENT	52 approximately?		
AVE φ	21%	approximately 10%	15%
SALINITY OF CONN. H ₂ O			
GAS CAP			Yes
DRIVE TYPE	Gravity-water level 125-275'		Gas Cap Exp?
SUCCESSFUL SECONDARY RECOVERY?			Gas inject. 1925? * Waterflood unsuccessful
SIZE (NUMBER OF ACRES)		7,000 ac.	7,200 ac.

TYPE OF TRAP? Stratigraphic shale content increase from 10% to 25% (Big Injun)
 Stratigraphic - Weir down dip from gas.

TYPE OF DEPOSIT : Weir - Coarse grained and pebbly sandstone.
 Several layers in southern portion of field.

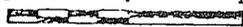
ADDITIONAL INFORMATION: 8-10 Big Injun wells drilled in the 1920's.
 some still producing in 1967 - (3 or 4)
 78 wells drilled since spring of 1967 to 1969- Big Injun
 1959 Production 75,000 barrels year
 1959 cumulative 17,000,000 barrels
 Weir IP maximum 40 BOPO - Squaw 100 BOPO
 Reservoir temperature about 75 F
 *Many Secondary Recovery projects attempted, some successfully but
 no large scale Secondary Recovery Program.
 Oil production to 1963 - 18,853,000 includes Poter's Branch Field

REFERENCES:
 Bureau of Mines #607 (1963)
 Oil and Gas Journal, October 20, 1969, Page 124-126
 Frank D. Smith proposal
 Driller's and Mechanical Logs
 Oil and Gas Report - Southern West Virginia Bulletin #17 (1959)
 *IOCC Reports 1951-1960 - See Table 9 for details, also Figures
 8 and 9



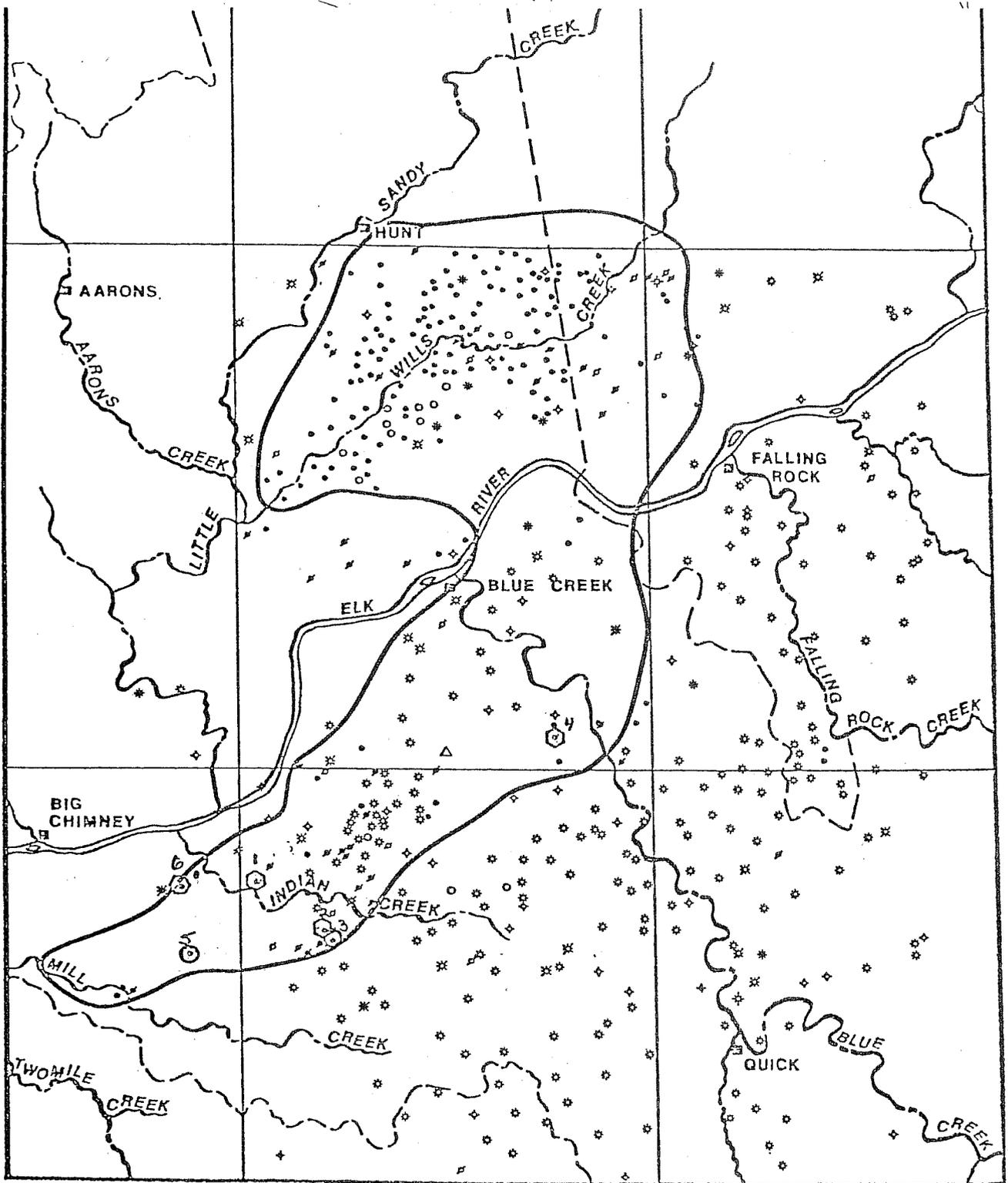
Graphic Scale

0 1 2 miles



BLUE CREEK FIELD
 LOCATION OF WELLS
 KNOWN IN 1960 FROM
 WEST VIRGINIA OIL AND
 GAS REPORT MAP
 KANAWHA CO.

Figure 1



Graphic Scale

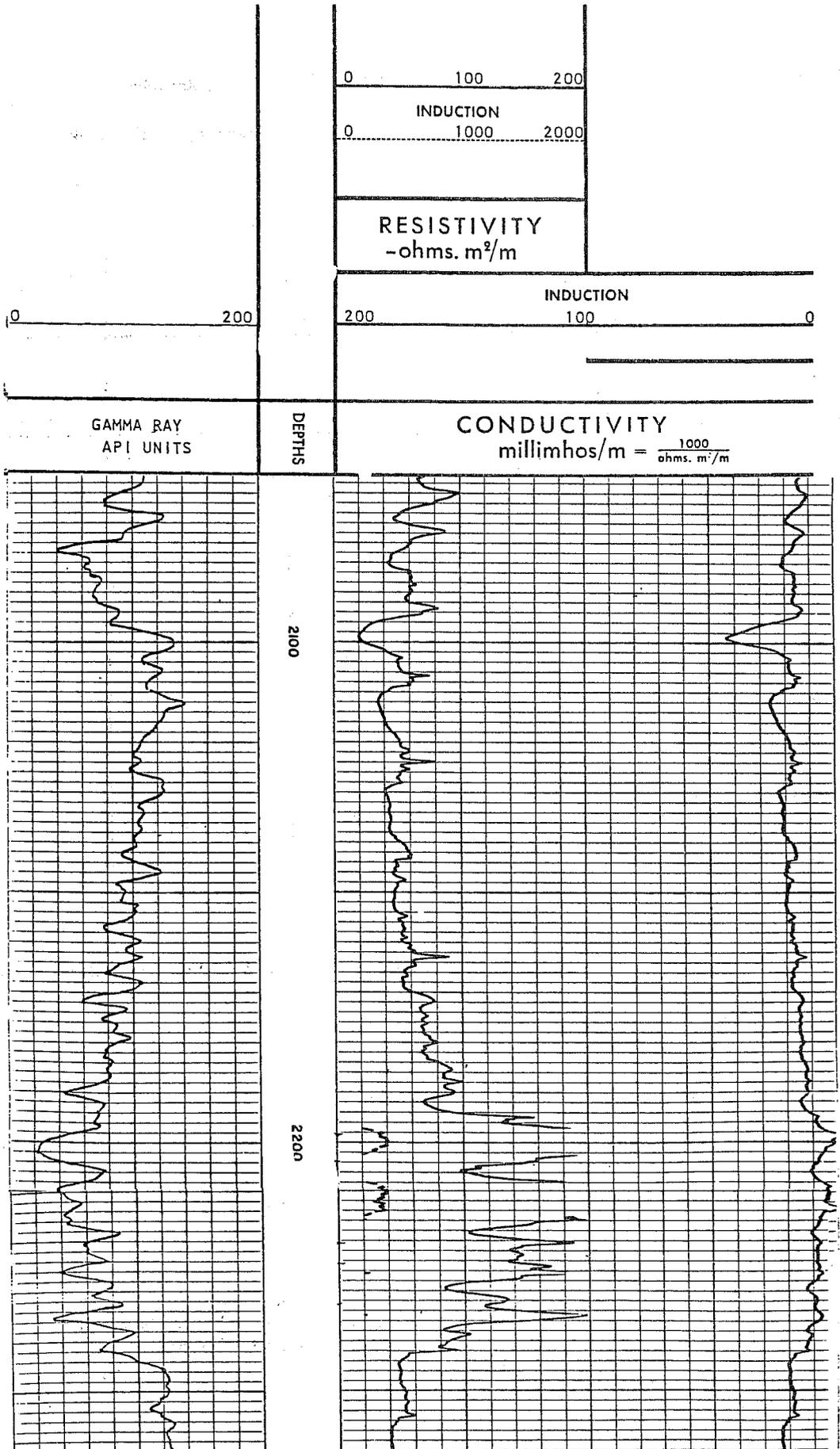
0 1 2 miles

- = Location of Induction Log
- = Location of Driller's Log

BLUE CREEK FIELD
 LOCATION OF ALL WELLS
 DRILLED OR PLUGGED SINCE 1929
 MAP FROM WEST VIRGINIA
 MINES DEPARTMENT OIL & GAS
 DIVISION (1978)

Figure 2

BLUE CREEK FIELD



GRUY FEDERAL, INC.

FIELD NAME - Cabin Creek CO. (s) - Boone, Kanawha
 LOCATION - DIST. - Sherman, Cabin Creek
 PRINCIPAL OPERATOR - Abandoned

FORMATION NAME(s)	Berea			
AVE DEPTH(s)	2800			
AVE THICKNESS(es)	20/35-44 45.8 2.36			
API GRAVITY/VISCOSITY	47° 8°/3.3 cp @ 100°			
AVE k	70			
SATURATIONS	Sw-40 orig			
AVE φ	(7-20) = 16%			
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?	Gas 1930 Successful* Gas 1932 Successful* Water 1937 Successful*			
SIZE (NUMBER OF ACRES)	4,480			

TYPE OF TRAP? Perm barrier on monocline

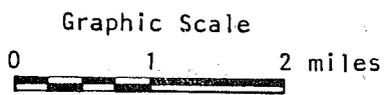
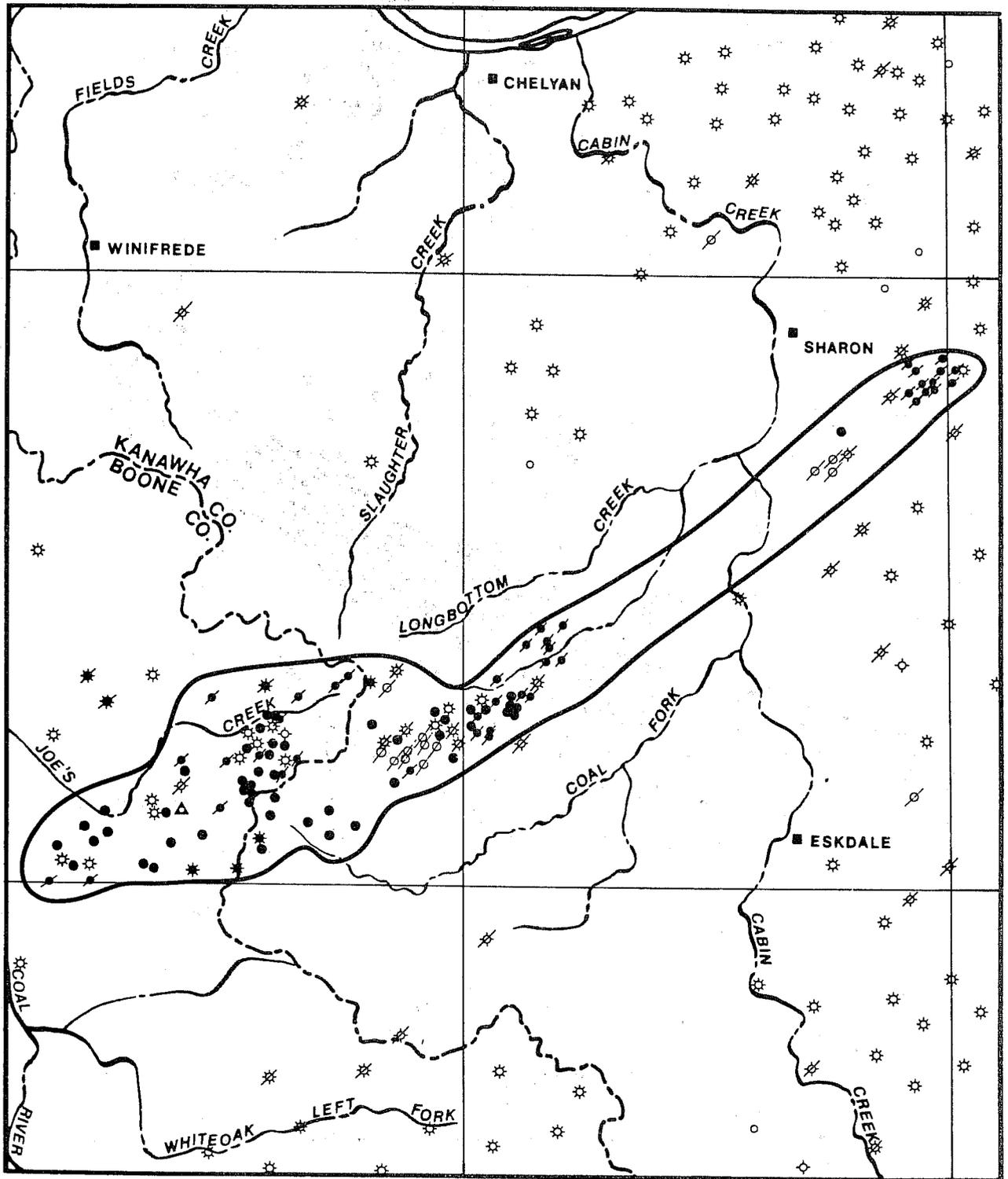
TYPE OF DEPOSIT : The Berea Sand ranges from a clear, white, hard quartzite to a fine grain pebbly quartz sandstone.

ADDITIONAL INFORMATION: Reservoir temp 85°
 Disc 1914
 So orig est 365 B/AF
 Ave well spacing 650'
 1963 Estimates- Orig BO - 32,704,000 b
 Prod - 11,077,000 b
 Left - 21,677,000 b

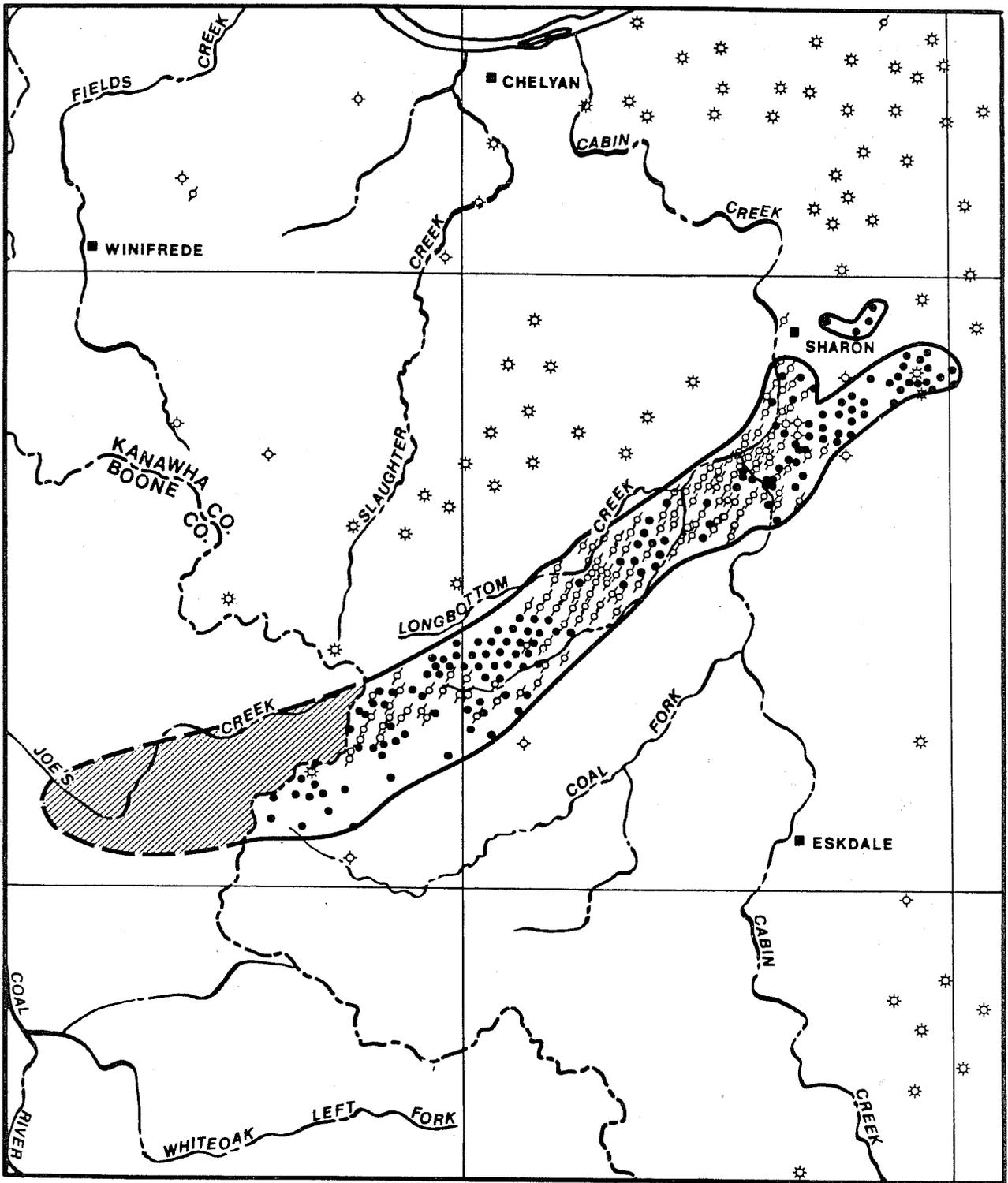
REFERENCES:

Bureau of Mines #607
 Wasson and Wasson-Bulletin AAPG Volume I #7, page 2, 1927
 Pages 705-719, also Chap in Structure of Type American
 Oil Fields, AAPG 1929, Volume I, pages 462-475

IOCC Reports Secondary Recovery 1951, 1954, 1957, 1960
 **See Table 7 for details
 *See Table 6a for details



CABIN CREEK FIELD
 LOCATION OF ALL WELLS
 DRILLED OR PLUGGED SINCE 1929
 MAP FROM WEST VIRGINIA
 MINES DEPARTMENT OIL & GAS
 DIVISION (1978)



Graphic Scale



CABIN CREEK FIELD
 LOCATION OF WELLS
 KNOWN IN 1958 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 KANAWHA COUNTY

GRUY FEDERAL, INC.

FIELD NAME - Cameron - Gardner

CO.(s) - Marshall, Wetzel

LOCATION -

DIST. - Liberty, Meade, Cameron, Proctor

PRINCIPAL OPERATOR -

FORMATION NAME(s)

Gordon

AVE DEPTH(s)

2808

AVE THICKNESS(es)

5/10-50

API GRAVITY/VISCOSITY

45°

AVE k

So-CURRENT

AVE φ

11%

SALINITY OF CONN.
H₂O

GAS CAP

DRIVE TYPE

SUCCESSFULL SECONDARY
RECOVERY?

Current gas
inj. program

SIZE (NUMBER OF ACRES)

6,989 (8340)

TYPE OF TRAP?

(Stratigraphic) Perm barrier

TYPE OF DEPOSIT :

The Gordon Sand is a tightly cemented S.S. containing small pebbles.

ADDITIONAL INFORMATION:

Disc. 1899

Ave well spacing 700 feet

Maximum IP = 400 BOPO

So orig est 720 B/AF

Res temp 85°

ISP - 1,300 psi

Initial gas oil ratio 530

1963 Est. - Orig BO - 25,160,000 b

Prod - 5,975,000 b 4,900,000 b (1955)

Left - 19,185,000 b

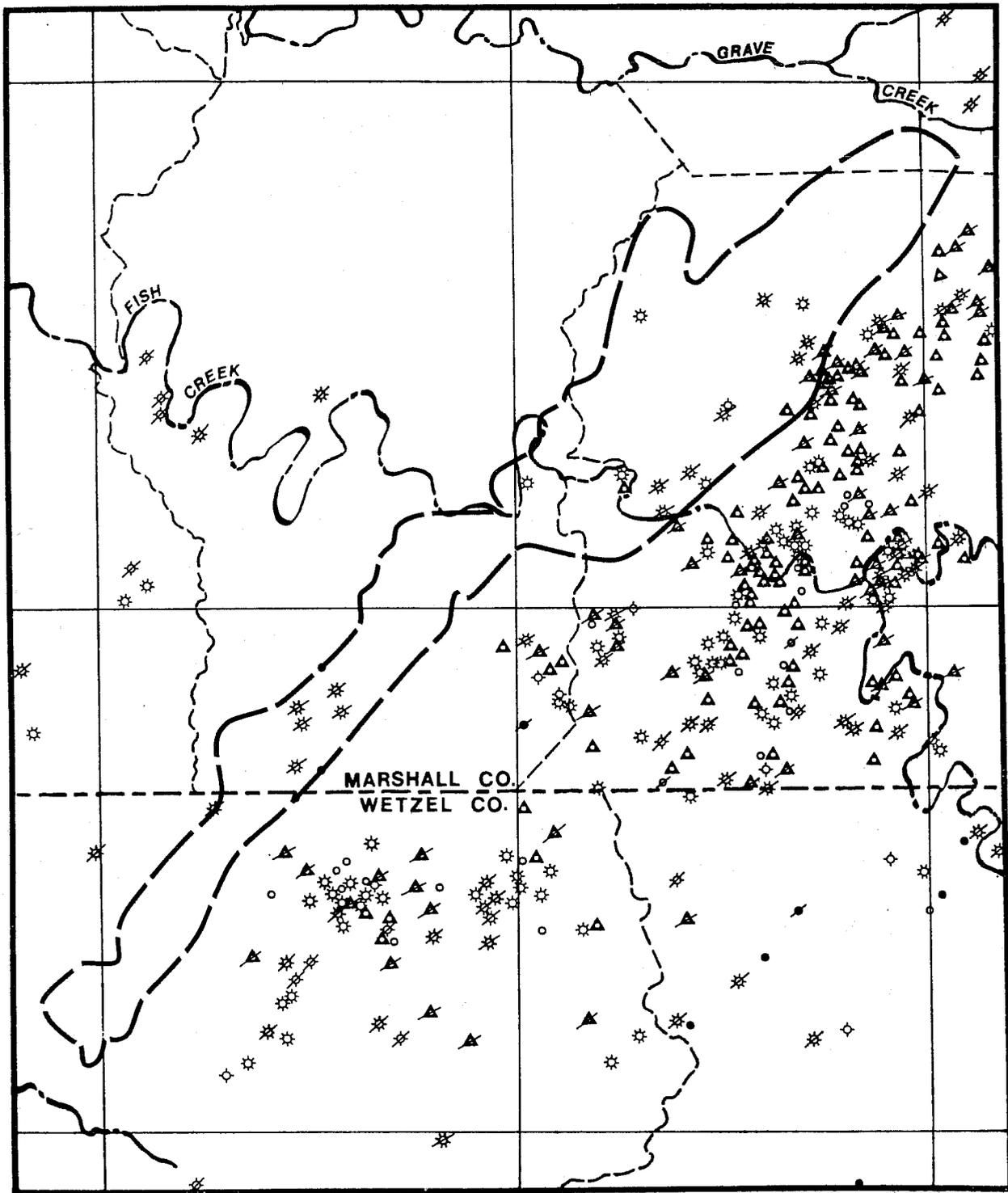
Prod (1955) 12,000 BO/yr from 150 wells

REFERENCES:

Bureau of Mines #607 (1963)

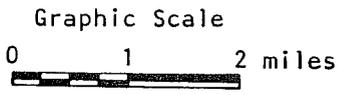
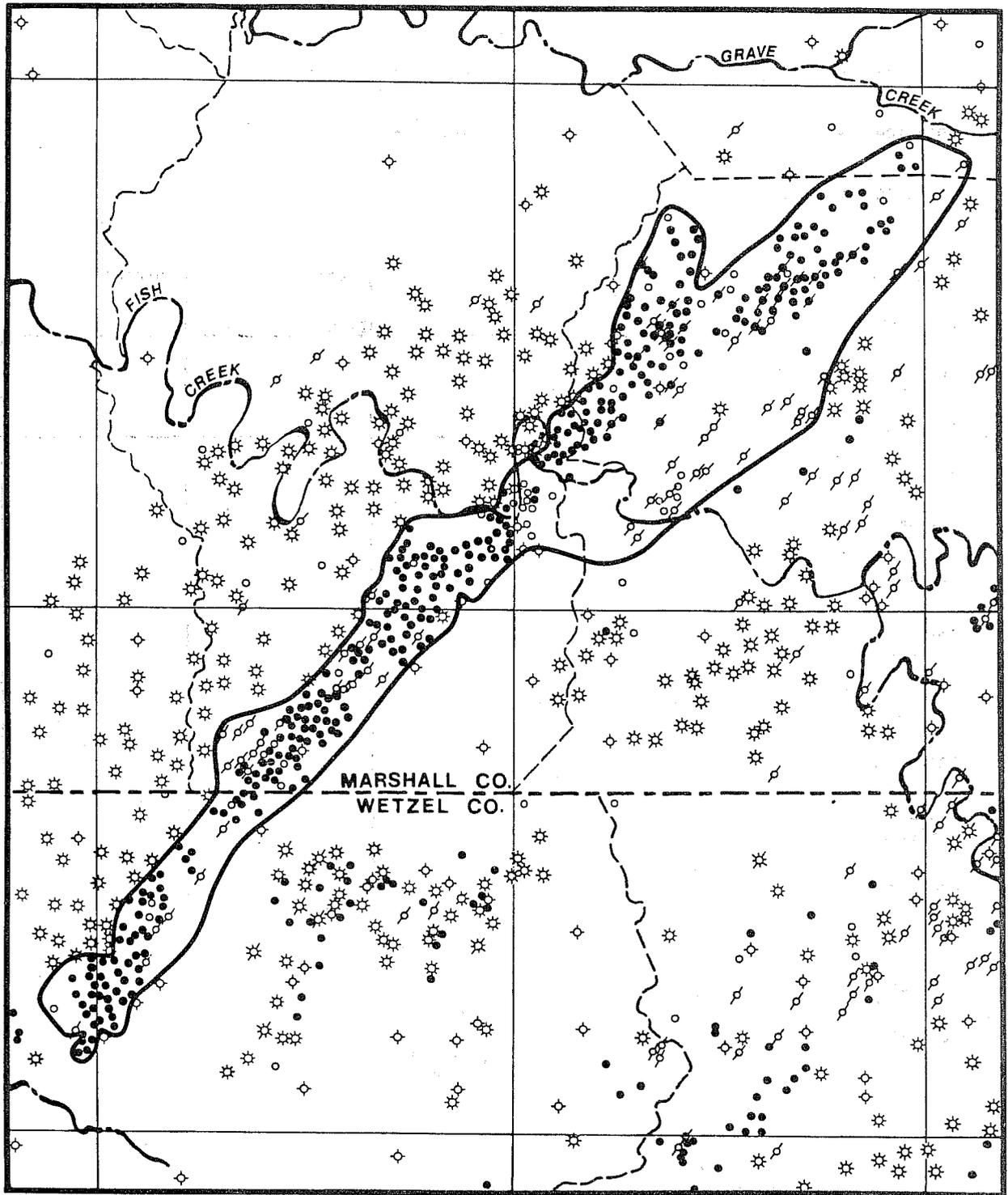
West Virginia Oil and Gas Map Booklet (1977)

Oil and Gas Report (1955)



Graphic Scale
0 1 2 miles

CAMERON GARDNER FIELD
LOCATION OF ALL WELLS
DRILLED OR PLUGGED SINCE 1929
MAP FROM WEST VIRGINIA
MINES DEPARTMENT OIL & GAS
DIVISION (1978)



CAMERON GARDNER FIELD
 LOCATIONS OF WELLS
 KNOWN IN 1955 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 MARSHAL FYLER & WETZEL CO.'S

GRUY FEDERAL, INC.

FIELD NAME - Cairo

CO.(s) - Ritchie

LOCATION - Ritchie

DIST. -

PRINCIPAL OPERATOR -

FORMATION NAME(s)	Salt	Big Injun	Squaw	Keener?
AVE DEPTH(s)	1650	2150	2300	
AVE THICKNESS(es)				
API GRAVITY/VISCOSITY	45.2			
AVE k				
So-CURRENT				
AVE ϕ				
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?				
SIZE (NUMBER OF ACRES)				

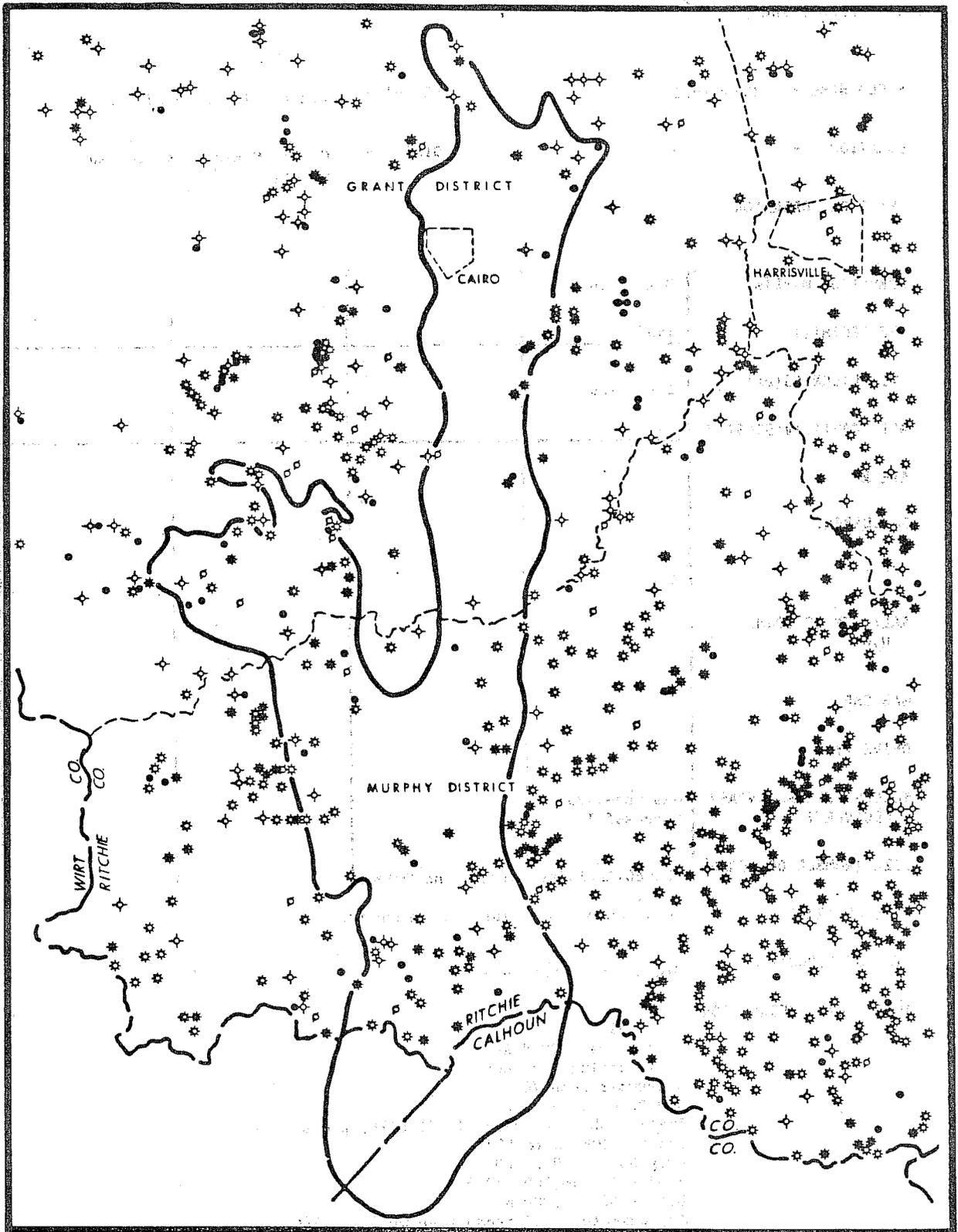
TYPE OF TRAP?

TYPE OF DEPOSIT :

ADDITIONAL INFORMATION: 1963 estimate orig BO - 119,112,000 b
prod ~ 28,273,000 b
left - 89,762,000 b

REFERENCES:

Bureau of Mines #607
Oil & Gas Map of West Virginia 1976



CAIRO FIELD
 LOCATION OF WELLS
 KNOWN IN 1966 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 RITCHIE, WIRT, AND CALHOUN COUNTIES

GRUY FEDERAL, INC.

FIELD NAME - Centerpoint

CO.(s) - Wetzell, Tyler, Doddridge

LOCATION -

DIST. - Green, McElroy, McClellan, Grant, West

PRINCIPAL OPERATOR -

FORMATION NAME(s)	Big Injun			
AVE DEPTH(s)	1965			
AVE THICKNESS(es)	10/70-178			
API GRAVITY/VISCOSITY	45 ^o			
AVE k				
So-CURRENT				
AVE φ	17%			
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?	Gas Inj-1929 Successful			
SIZE (NUMBER OF ACRES)	12,980(includes Shirley and Swiger)			

TYPE OF TRAP? Combination; Syncline and perm barrier

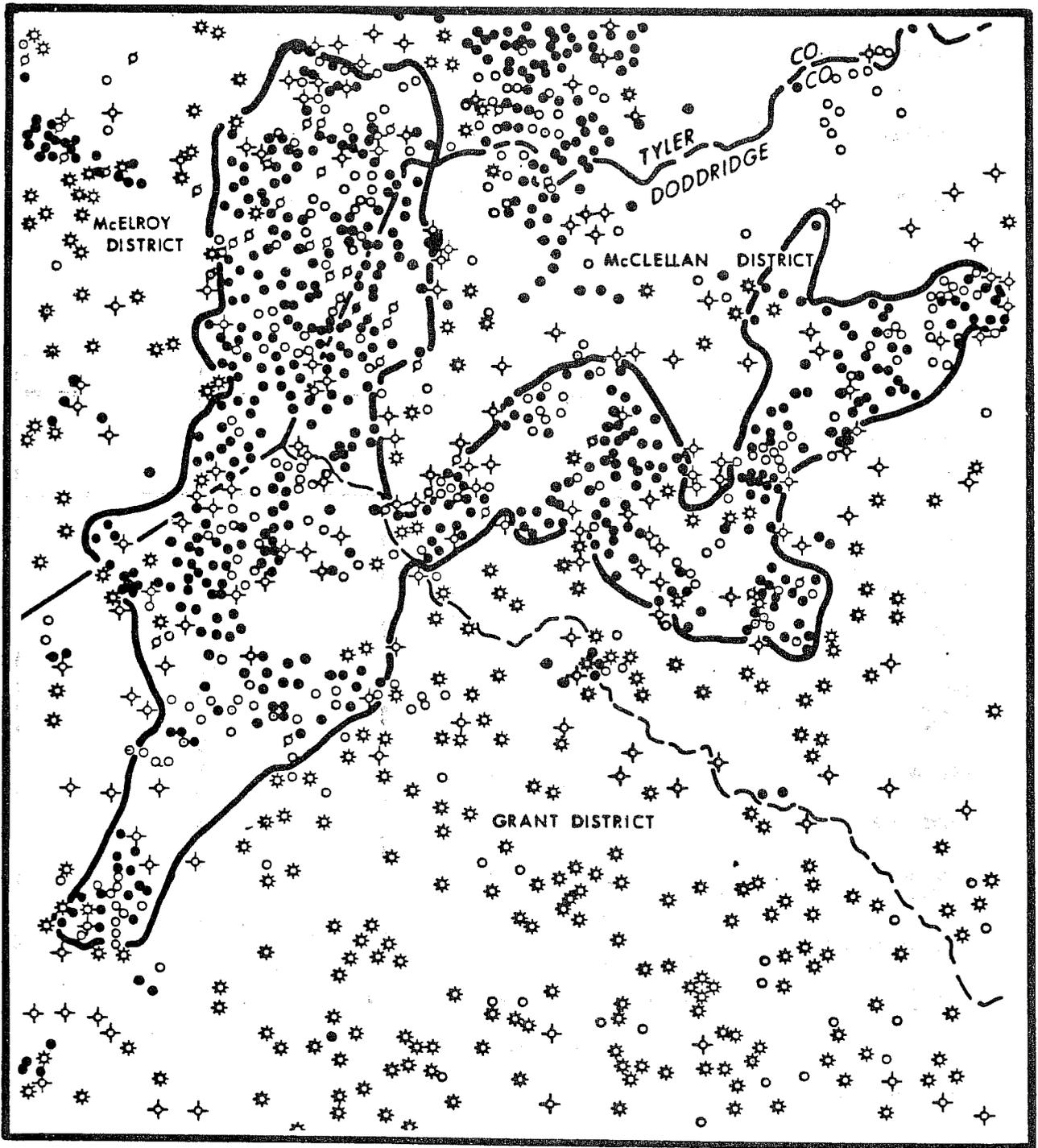
TYPE OF DEPOSIT : Big Injun - Friable S.S.

ADDITIONAL INFORMATION:

Disc 1892
 So orig est 400 B/AF
 Well spacing 700 feet
 Reservoir temp 76^o
 300 BOPO largest IP
 Initial shut in reservoir (IWHSIP) pressure 950 psi
 Initial GOR ratio 420
 Orig BO - 51,920,000
 Prod - 11,646,000-(1973)
 Left - 40,274,000 b
 Approximately 325 productive wells in 1963
 Continuous with Jacksonburg-Stringtown to the north.

REFERENCES:

Bureau of Mines #607 (1963)
 West Virginia Oil and Gas Map(1976)
 Oil and Gas Report Bulletin 12 (1955)



CENTERPOINT
 LOCATION OF WELLS
 KNOWN IN 1955 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 TYLER AND DODDRIDGE COUNTIES

GRUY FEDERAL, INC.

FIELD NAME - Granny's Creek (Stockley) CO. (s) - Clay, Roane

LOCATION - DIST. - Henry, Geary

PRINCIPAL OPERATOR - Columbia Gas Transmission Corp.

FORMATION NAME(s)	Big Injun			
AVE DEPTH(s)	2100			
AVE THICKNESS(es)	20/40			
API GRAVITY/VISCOSITY	45°-46° 45.4°			
AVE k	2.1 to 200 md.			
So-CURRENT	30-35% in watered out portion			
AVE φ	17-20%			
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?	Gas Inj. 1943 successful * Water flood successful ** 350 Acre (1963)			
SIZE (NUMBER OF ACRES)	2,803			

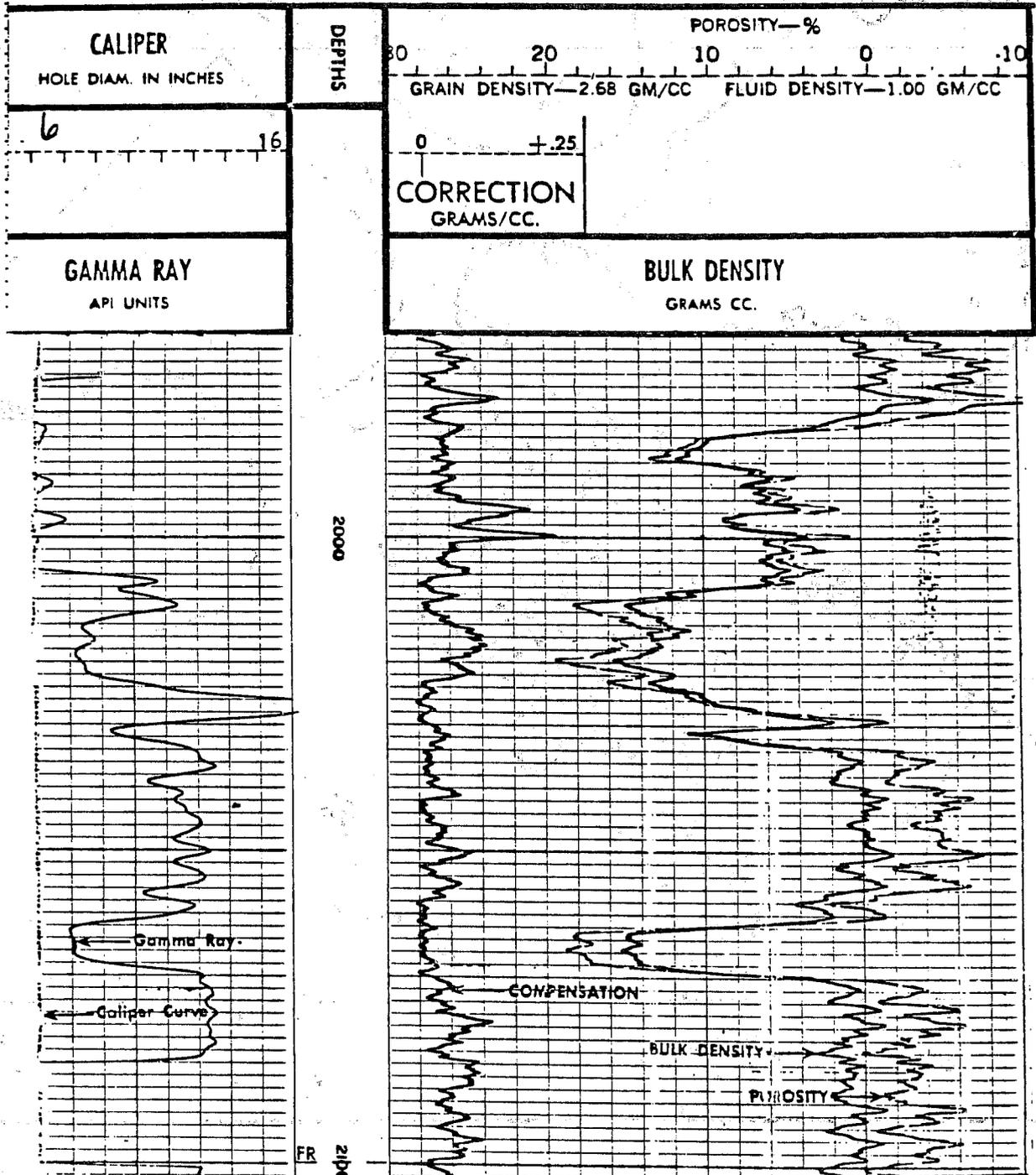
TYPE OF TRAP? Combination (Syncline and perm barrier)

TYPE OF DEPOSIT : Big Injun - tight friable sandstone.

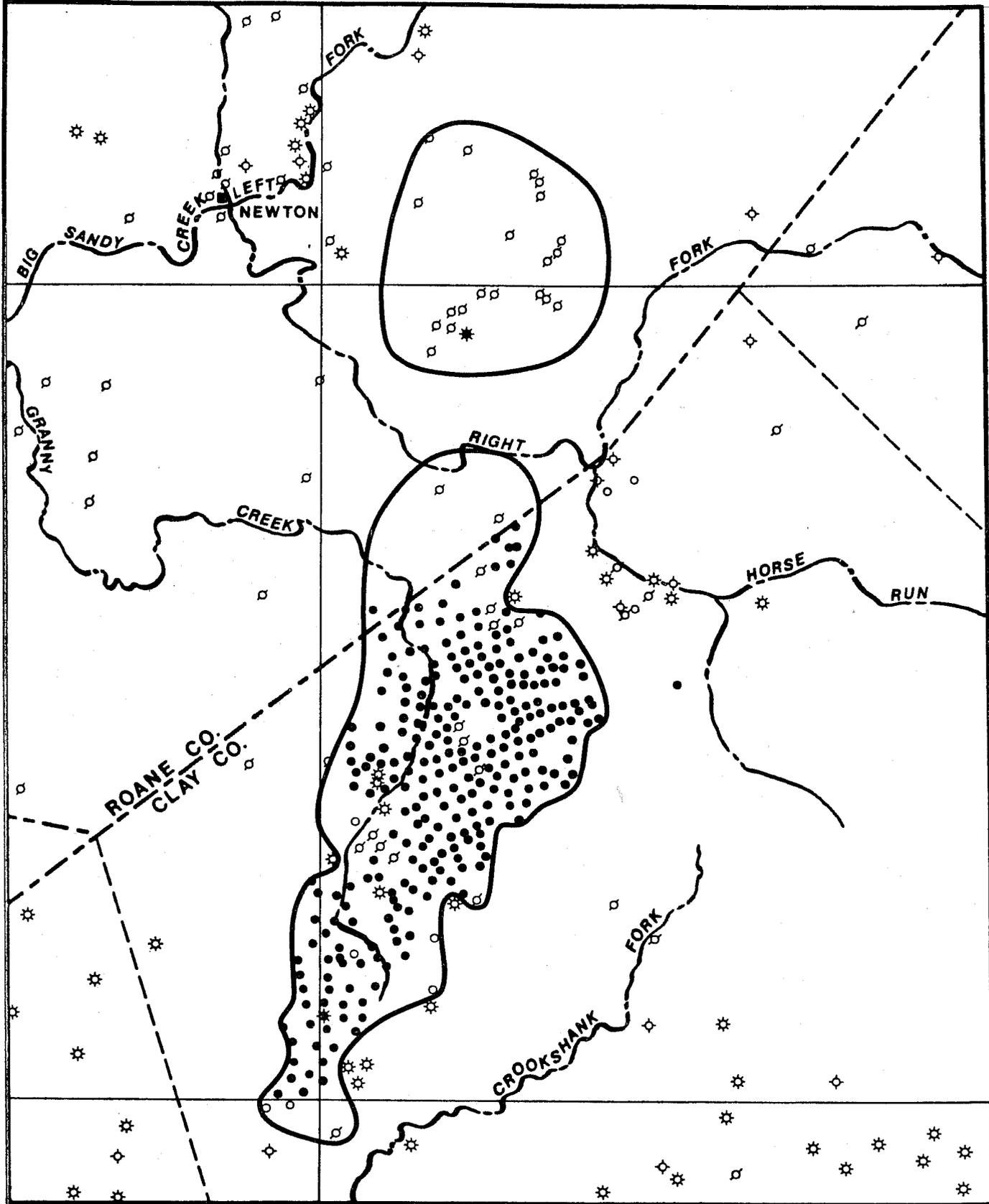
ADDITIONAL INFORMATION: Disc. 1925
 So orig est 300 B/AF
 Avg. well spacing - 500 feet
 Max initial oil prod - 50 bpd
 Res temp 77°
 1963 Estimate Orig BO - 16,818,000 b
 Prod - 6,466,000 b
 Left - 10,352,000 b
 From Conner - Oil banks in front of waterflood water, however, water does not
 bank in front of CO₂. Have had some parrifin build up problems.

REFERENCES:
 Bureau of Mines #607
 Conner W.D. ERDA Publication and BERC 76/3
 Unpublished Report - Royal Watts
 IOCC Report 1951, 1957
 *See Table 6
 **See Table 8

GRANNY'S CREEK FIELD



GRANNY'S CREEK FIELD
 DEPTH IN FEET
 0 10 20 30 40 50 60 70 80 90 100 110 120 130 140 150 160 170 180 190 200 210 220 230 240 250 260 270 280 290 300 310 320 330 340 350 360 370 380 390 400 410 420 430 440 450 460 470 480 490 500 510 520 530 540 550 560 570 580 590 600 610 620 630 640 650 660 670 680 690 700 710 720 730 740 750 760 770 780 790 800 810 820 830 840 850 860 870 880 890 900 910 920 930 940 950 960 970 980 990 1000



GRANNY'S CREEK FIELD
 LOCATION OF WELLS
 FROM WEST VIRGINIA
 MINES DEPARTMENT OIL & GAS
 DIVISION AND OTHER SOURCES (1978)

GRUY FEDERAL, INC.

FIELD NAME - Greenwood

CO.(s) - Doddridge Ritchie

LOCATION -

DIST. - Central, Southwest, Union

PRINCIPAL OPERATOR -

Old part of field now abandoned

FORMATION NAME(s)	Big Injun-2000	Salt Sand		
AVE DEPTH(s)	1862			
AVE THICKNESS(es)	8/15-120			
API GRAVITY/VISCOSITY	44.5 °			
AVE k				
So-CURRENT				
AVE φ	6%			
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?	None			
SIZE (NUMBER OF ACRES)	2500	2253		

TYPE OF TRAP? Stratigraphic permeability barrier

TYPE OF DEPOSIT : Sandstone

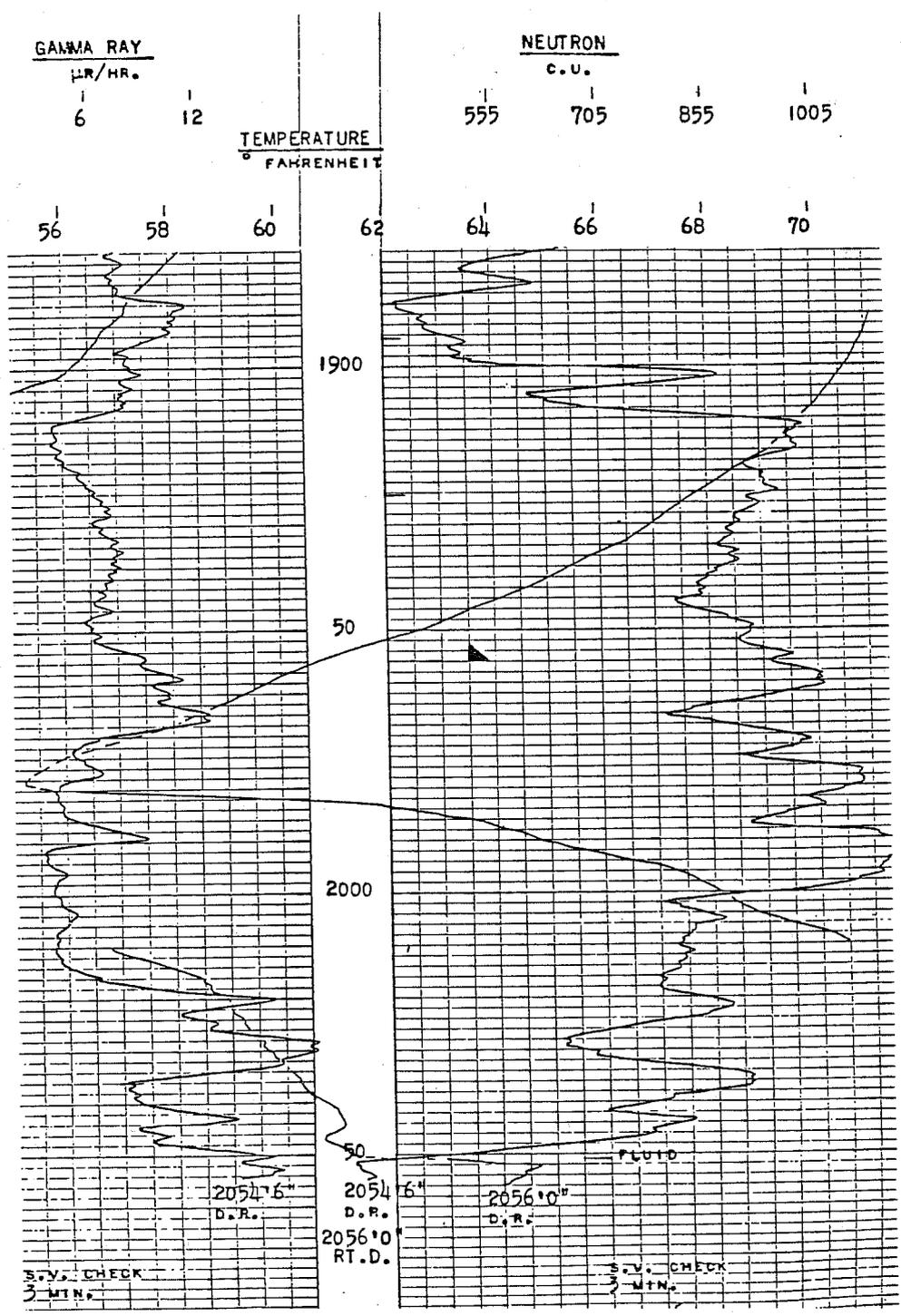
ADDITIONAL INFORMATION:

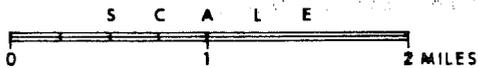
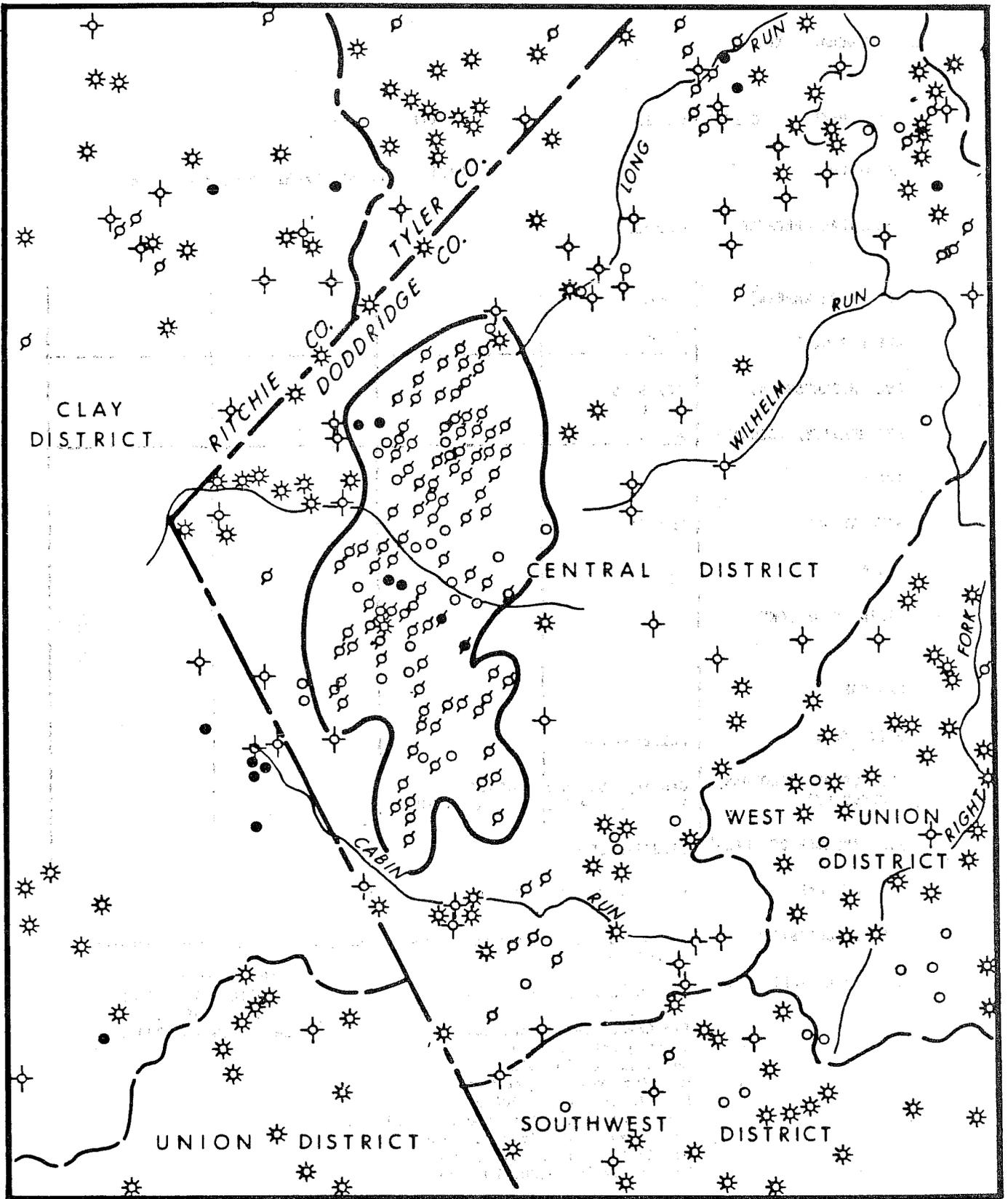
Water produced from Big Injun
So orig at 750 B/AF
Maximum IP 10 BOPO
Majority of field abandoned in 1963
Disc 1920
1963 Estimates- Orig,BO - 13,518,000 b
Prod - 2,682,000 b
Left - 10,836,000 b
Field extended to north and east by drilling in
1963-67-additional drilling in 1970's

REFERENCES:

Bureau of Mines #607
West Virginia Oil and Gas Map 1976

GREENWOOD FIELD





GREENWOOD FIELD
 LOCATION OF WELLS
 KNOWN IN 1959 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 DODDRIDGE AND RITCHIE COUNTIES

GRUY FEDERAL, INC.

FIELD NAME - Griffithsville

CO. (s) - Lincoln

LOCATION -

DIST. - Duval, Washington, and Union

PRINCIPAL OPERATOR - Pennzoil

FORMATION NAME(s)	Berea			
AVE DEPTH(s)	2354			
AVE THICKNESS(es)	10/18-26 14/18			
API GRAVITY/VISCOSITY	43°/3.1			
AVE k				
SATURATIONS	So = 80%			
AVE φ	11.1			
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE	Solution gas			
SUCCESSFULL SECONDARY RECOVERY?	Gas inj 1926-Successful* Water inj 1945-1953 Successful**			
SIZE (NUMBER OF ACRES)	12,877-15,500			

TYPE OF TRAP? Syncline and perm barrier

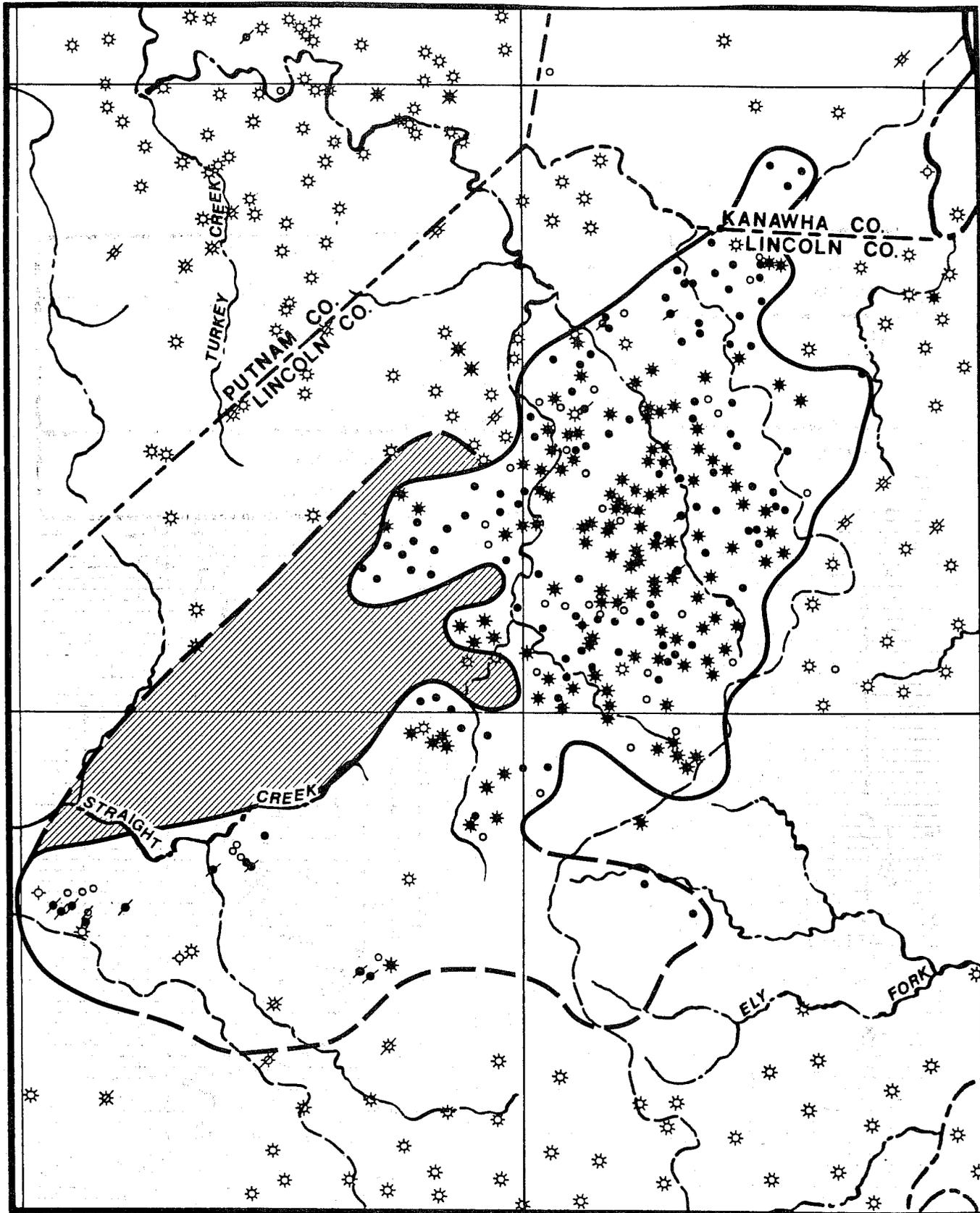
TYPE OF DEPOSIT : The Berea sand is a white, fine grained, closely cemented sandstone. Dolomitic

ADDITIONAL INFORMATION:

Salt Sand source of Brine. Disc. 1907 Big Creek Development Co. So orig est 575 B/AF Ave well spacing 550' 78° F Reservoir temperature Rec. in 1927 est 1,400 B/A Practically no water production with oil. Orig press 997 initial GOR 490 Max initial oil prod. 75 bpd Recoveries 1000-3000 BO/Acre	1963 Estimate Orig BO - 74,043,000 b Prod - 14,790,000 b Left - 59,253,000 b
--	---

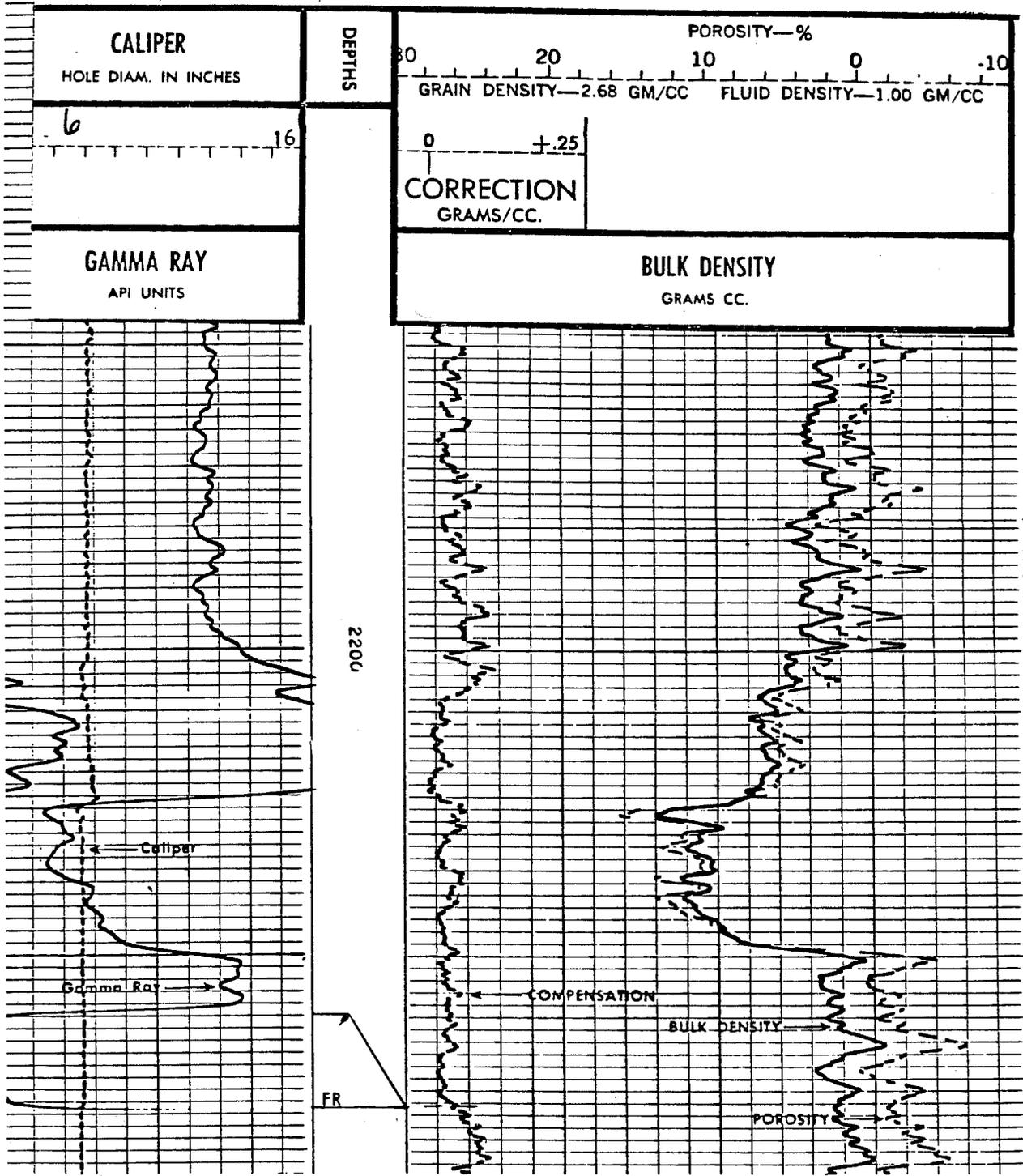
REFERENCES:

- P. F. Beeler 1977
- Bureau of Mines #607
- Davis and Stephenson, Structure Typical American Oil Fields, 1929, Volume II
- Howard Johnston
- IOCC Report Secondary 1951
- *See Table 6a for details
- **See Table 7 for detail



GRIFFITHSVILLE FIELD
LOCATION OF ALL WELLS
DRILLED OR PLUGGED SINCE 1929
MAP FROM WEST VIRGINIA
MINES DEPARTMENT OIL & GAS
DIVISION (1978)

GRIFFITHSVILLE FIELD



GRUY FEDERAL, INC.

FIELD NAME - Jacksonburg - Stringtown

CO. (s) - Wetzel, Tyler, Doddridge

LOCATION -

DIST. - Grant, Greer, McElroy,
McClellan

PRINCIPAL OPERATOR -

FORMATION NAME(s)	Gordon	Big Injun		
AVE DEPTH(s)	2825	2100		
AVE THICKNESS(es)	4-5/10-35	8/40		
API GRAVITY/VISCOSITY	41.7 ^o / 4.5 @ 100 ^o			
AVE k	300			
SATURATION	Sw = 20% orig			
AVE ϕ	12.5 /10			
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?	Gas Inj. 1936 - Gas inj 1950 ** Gas Injection(1950) Successful**			
SIZE (NUMBER OF ACRES)	15,386 (7,852)			
TYPE OF TRAP?	(Syncline and perm barrier)			
TYPE OF DEPOSIT :	Conglom. sandstone			

ADDITIONAL INFORMATION:

So orig est 1277 B/AF
Disc 1895
Av well SP 750 feet
WHISIP = 1,200#
Reservoir temp 82^o - 84^o
Orig est 1437 B/AF
Orig BO - 88,469,000
Prod - 20,458,000
Left - 68,011,000
Continuous to south with Shirley Field
No recent drilling

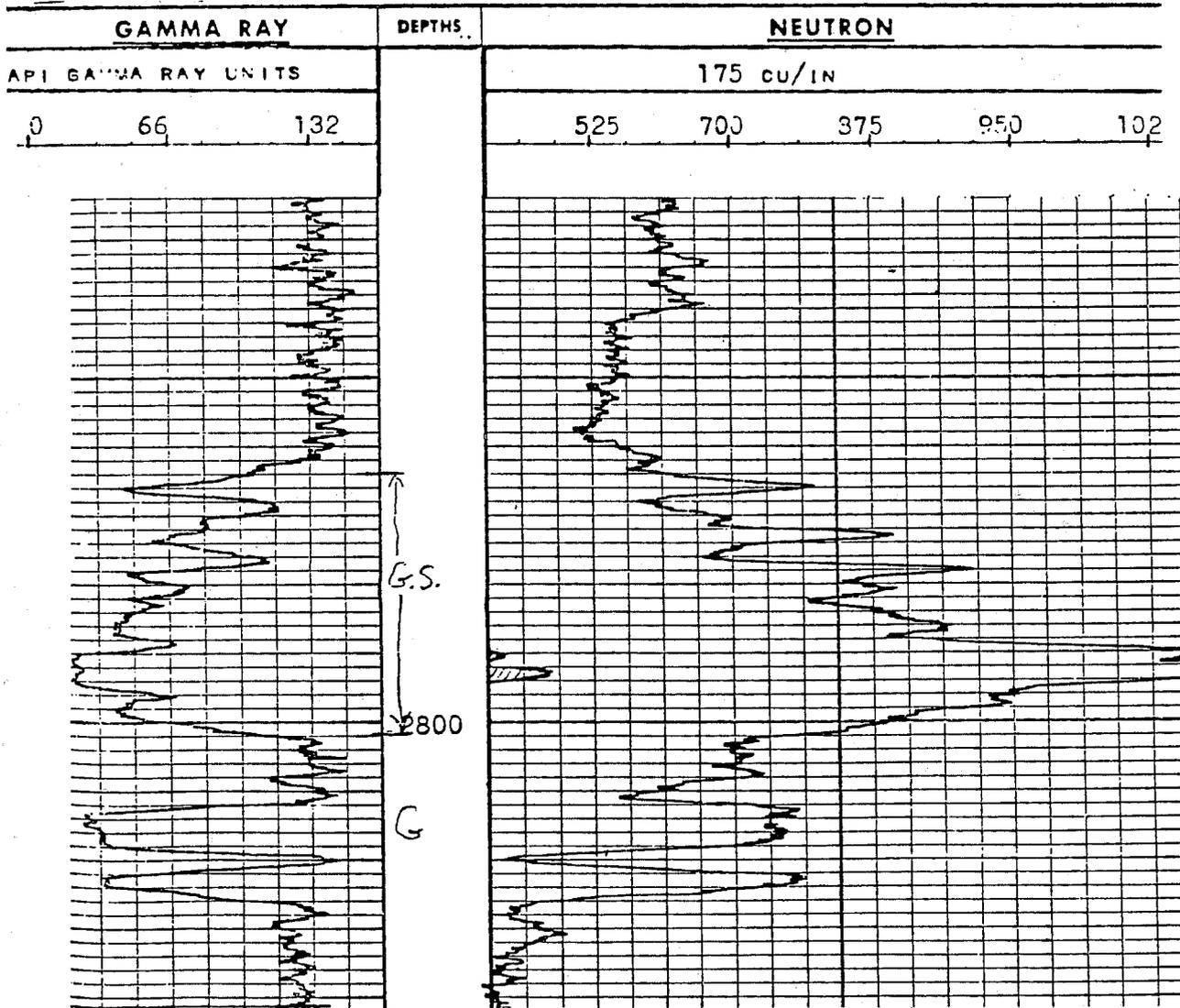
637 Max number of wells
1950 (217 wells)
Recovery 1,370-1546 BOP Acre

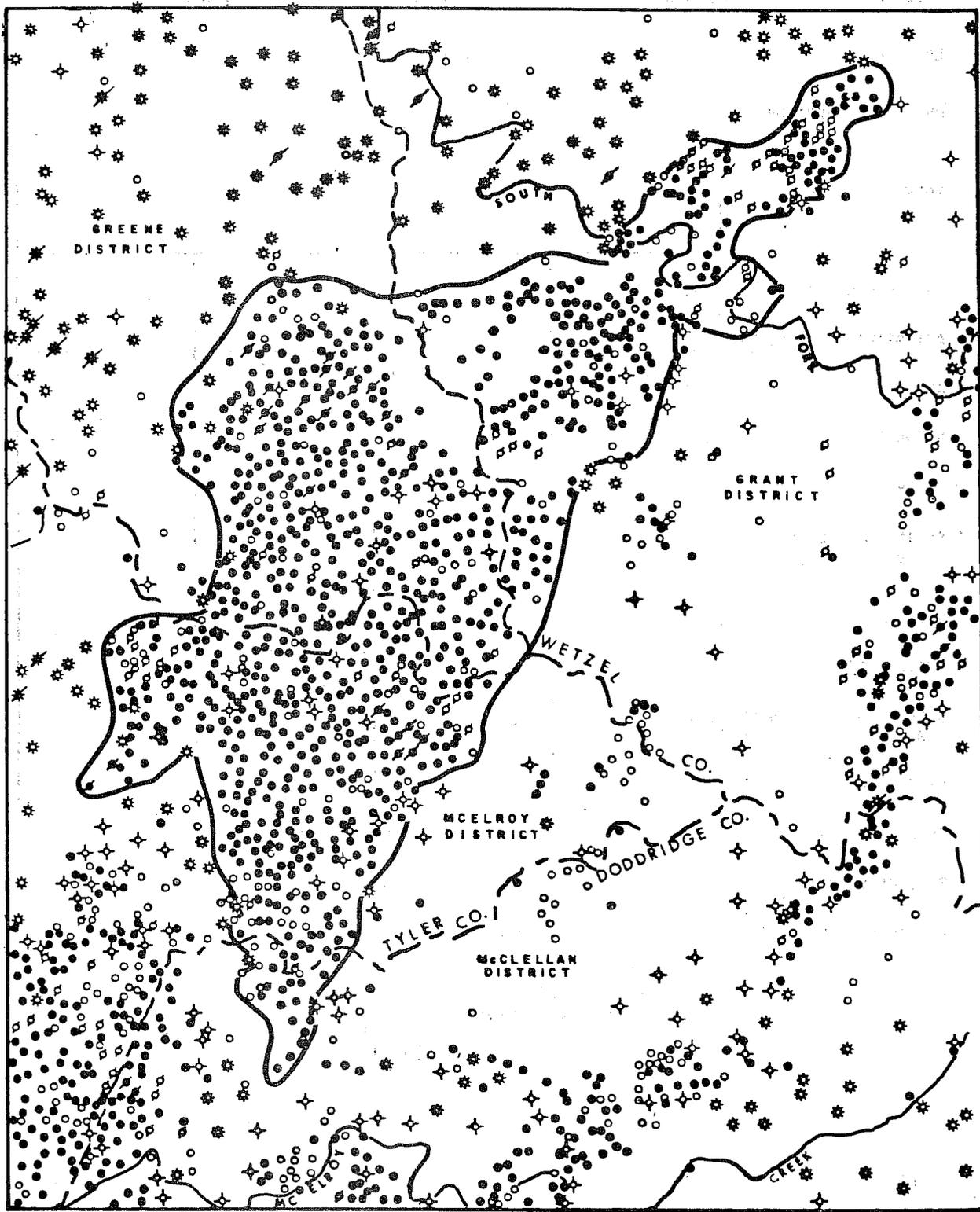
2 Prod 21,000 BO/year from
250 wells (1955)

REFERENCES:

Bureau of Mines #607 (1963)
West Virginia Oil and Gas Map (1976)
West Virginia Oil and Gas Map Booklet (1977)
Oil and Gas Report Bulletin 12 (1955)
IOCC Secondary Recovery 1951, 1954, 1955, 1960
*See Table 5 for detail
*See Figure x and discussion in Section 1 for detail.
**Table 6 for details

JACKSONBURG-STRINGTOWN FIELD





JACKSONBURG-STRINGTOWN FIELD
 LOCATION OF WELLS
 KNOWN IN 1955 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 WETZEL, TYLER, AND DODDRIDGE CO.'S

FIELD NAME - Kidwell-Elk Fork

CO.(s) - Lincoln, Ellsworth

LOCATION - Tyler

DIST. -

PRINCIPAL OPERATOR -

FORMATION NAME(s)	Keener			
AVE DEPTH(s)	1615-1938			
AVE THICKNESS(es)	8/15-31			
API GRAVITY/VISCOSITY				
AVE k	260			
SATURATIONS	Sw = 44 orig			
AVE ϕ	18.6			
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?	gas-1934, successful *			
SIZE (NUMBER OF ACRES)	4282			

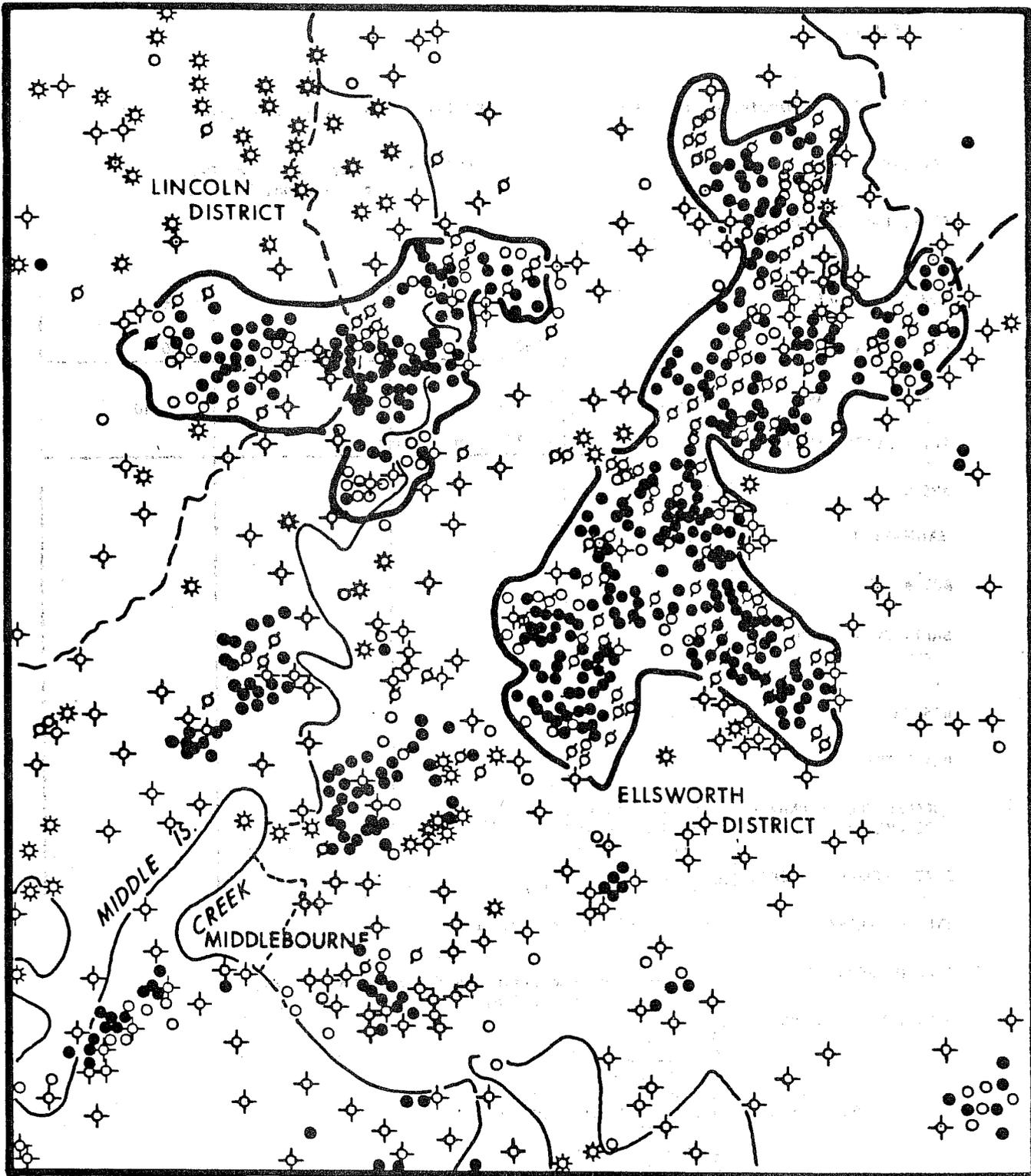
TYPE OF TRAP?

TYPE OF DEPOSIT : Keener-fine grain tightly cemented

ADDITIONAL INFORMATION: Max - initial oil prod 2,000 bpd
 Avg spacing - 500 ft.
 Disc - 1897
 Orig est. = 750 b/af
 73.5 reservoir temperature
 1963 Estimates - orig BO 25,692,000 b
 prod 6,775,000 b
 left 18,937,000 b

REFERENCES: Bureau of Mines Bulletin 607,1973
 IOCC Report Secondary Recovery 195

*See Table 6 for details



KIDWELL-ELKFORK FIELD
 LOCATION OF WELLS
 KNOWN IN 1955 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 TYLER COUNTY

GRUY FEDERAL, INC.

FIELD NAME - Mannington (Mt. Morris) CO.(s) - Monongalia, Marion

LOCATION - DIST. - Clay, Cass, Paw Paw, Mannington, Lincoln

PRINCIPAL OPERATOR - Largely abandoned

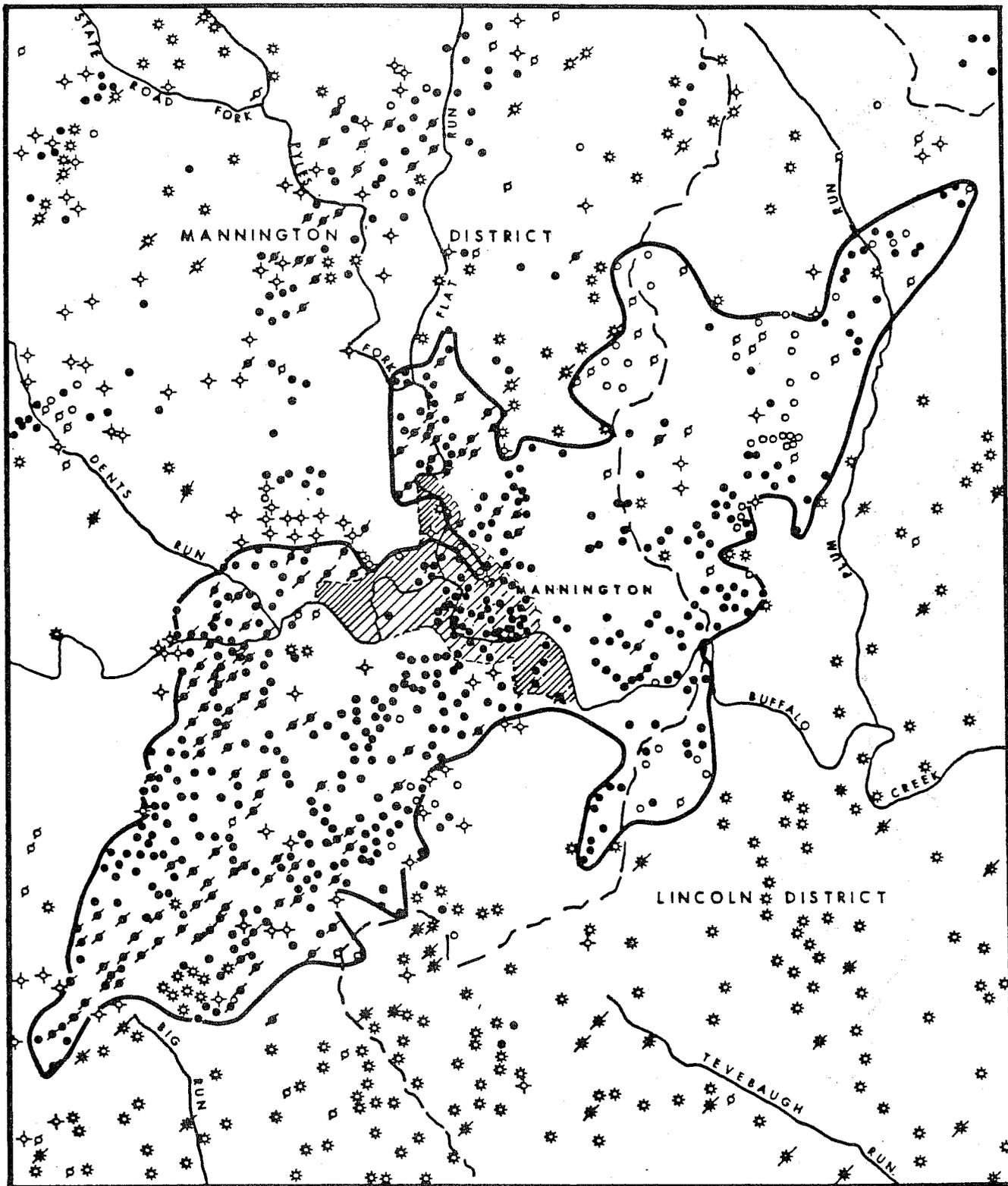
FORMATION NAME(s)	Big Injun	Gordon	Fifth
AVE DEPTH(s)	2002	2880	2960
AVE THICKNESS(es)	18/112-181	5/15-43	7/10-40
API GRAVITY/VISCOSITY	39.9/9.02	42.3/4.9 cp @ 100°F	
AVE k	62		
SATURATIONS	58.4% original So		
AVE φ	10		
SALINITY OF CONN. H ₂ O			
GAS CAP			
DRIVE TYPE			
SUCCESSFULL SECONDARY RECOVERY?	(Gas Inj. started 1925-Successful) Still being done	* Underway	
SIZE (NUMBER OF ACRES)	≈ 4,000	12,000	

TYPE OF TRAP? Stratigraphic (perm barrier)

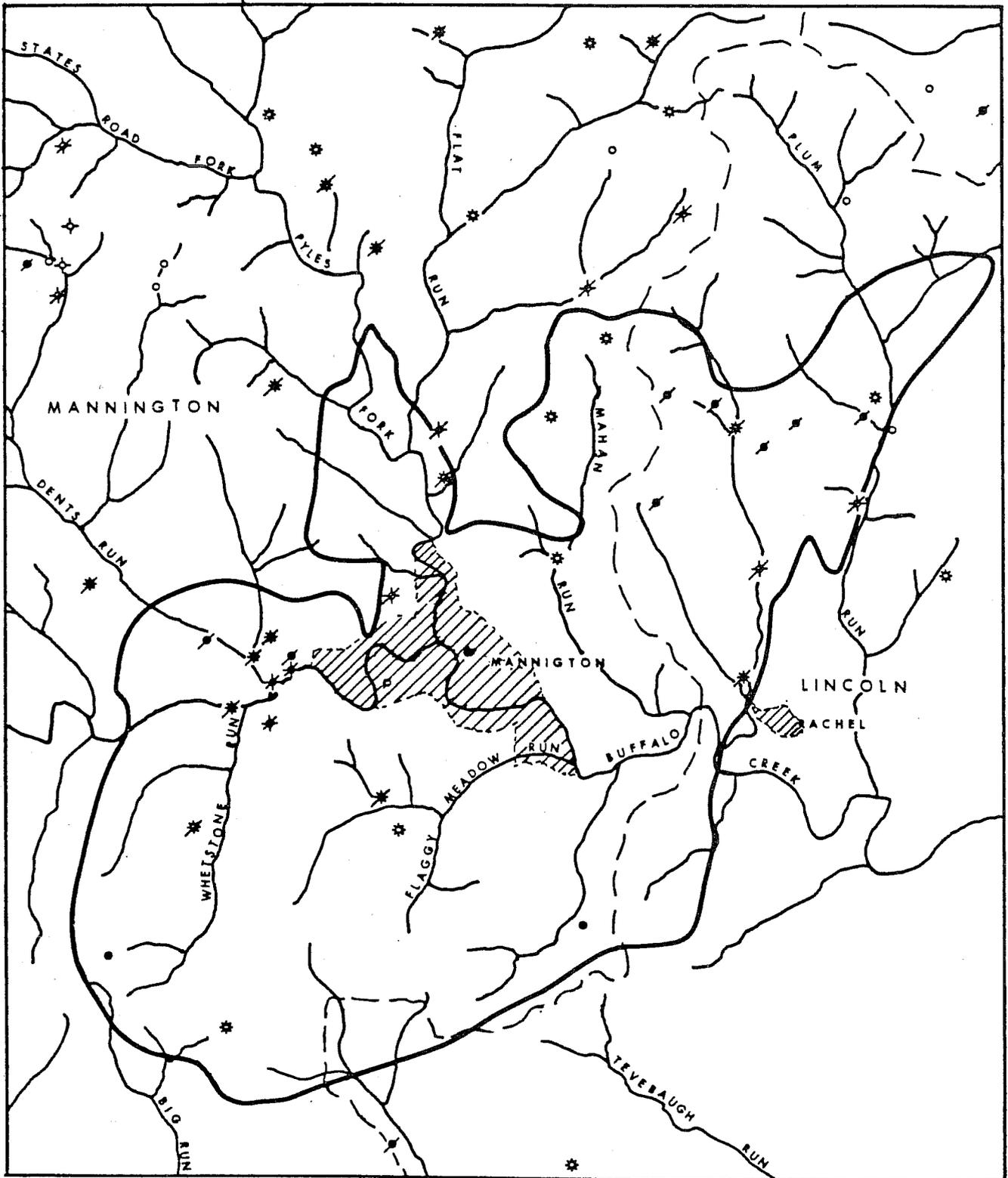
TYPE OF DEPOSIT : Big Injun-fine-med grain S.S.; Gordon-Cong. S.S.; Fifth-med-crs. grain S.S.

ADDITIONAL INFORMATION:
 Disc. 1896
 So orig 504 B/AF
 Max IP 50 BOPO
 Ave well Sp 700 feet
 1963 Estimates- Orig BO - 127,617,000
 Prod - 32,017,000
 Left - 95,600,000
 Reservoir Temp 74°
 168 wells 1950 producing approximately 751 wells in total field
 *Significant water production

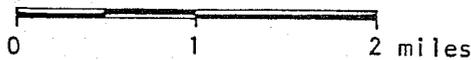
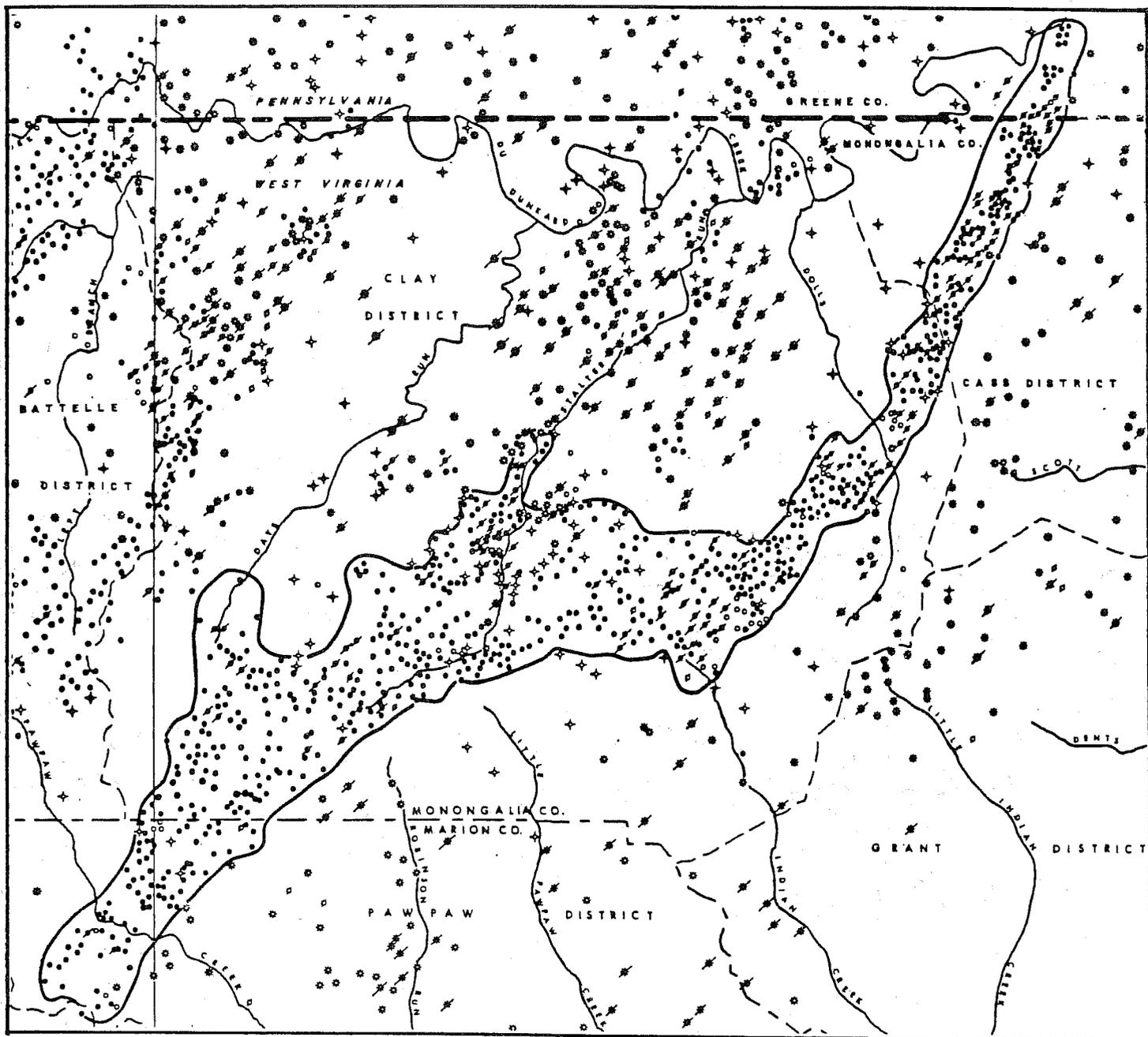
REFERENCES: Bureau of Mines #607
 West Virginia Oil and Gas Map 1976
 West Virginia Oil and Gas Map Bulletin
 IOCC Report Secondary Recovery 1951
 *See Table 6 for details



MANNINGTON FIELD
 LOCATION OF WELLS
 KNOWN IN 1958 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 MARION CO.



MANNINGTON FIELD
 LOCATION OF ALL WELLS
 DRILLED OR PLUGGED SINCE 1929
 MAP FROM WEST VIRGINIA
 MINES DEPARTMENT OIL & GAS
 DIVISION (1978)



MT. MORRIS FIELD
 LOCATION OF WELLS
 KNOWN IN 1958 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 GREENE, MONONGALIA, AND MARION COUNTIES

GRUY FEDERAL, INC.

FIELD NAME - Pine Grove, Camp Run

CO. (s) - Wetzel

LOCATION -

DIST. - Grant, Center, Green

PRINCIPAL OPERATOR -

FORMATION NAME(s)	Gordon Stray	Gordon		
AVE DEPTH(s)	2528	3012		
AVE THICKNESS(es)	/20-40	5/10-70		
API GRAVITY/VISCOSITY				
AVE k				
So-CURRENT				
AVE ϕ				
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?				Gas Inj. started before 1942. Reported as successful. Gas 1951*
SIZE (NUMBER OF ACRES)		5,485		

TYPE OF TRAP? Stratigraphic (perm barrier)

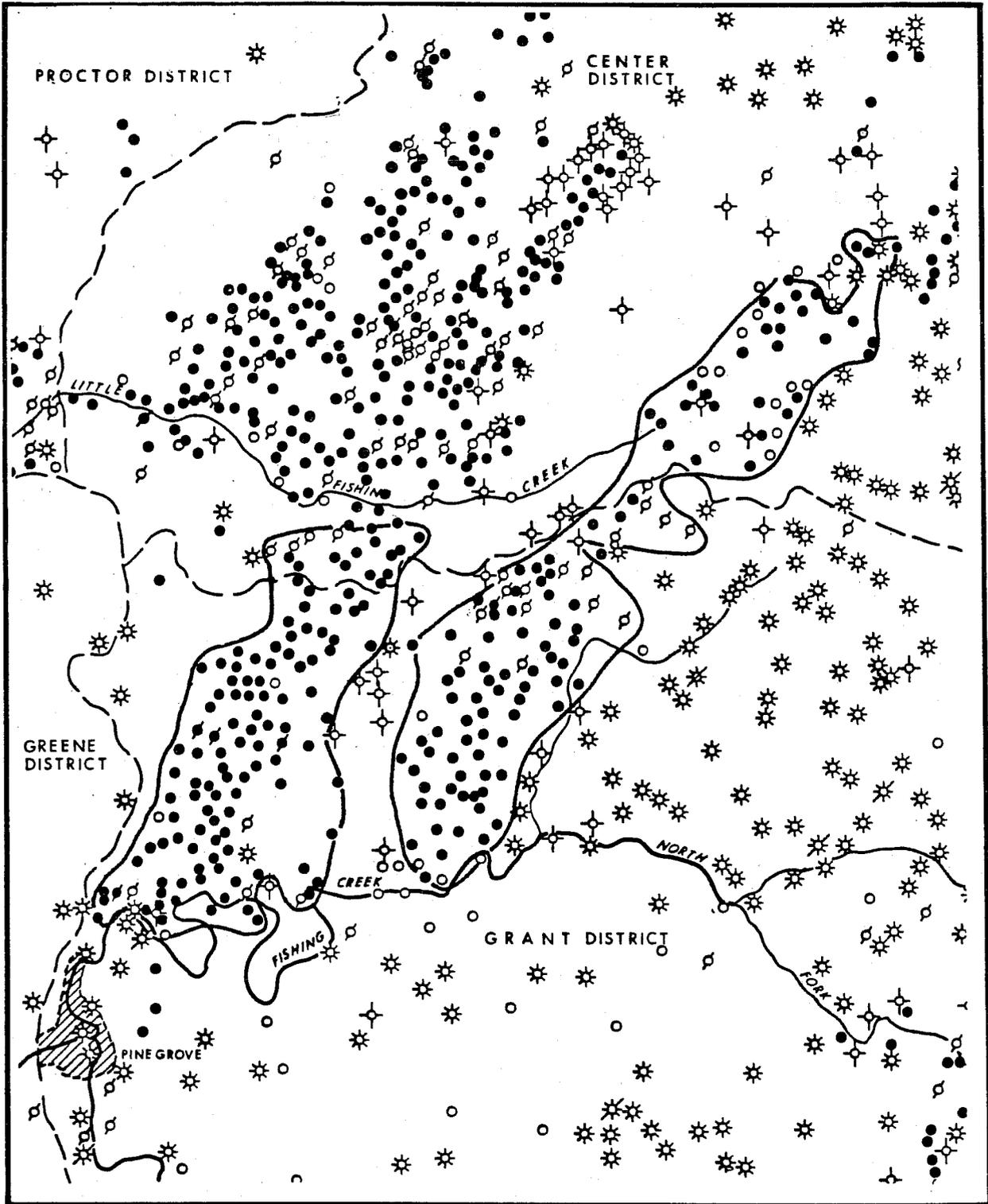
TYPE OF DEPOSIT : Gordon-Conglom S.S.

ADDITIONAL INFORMATION:

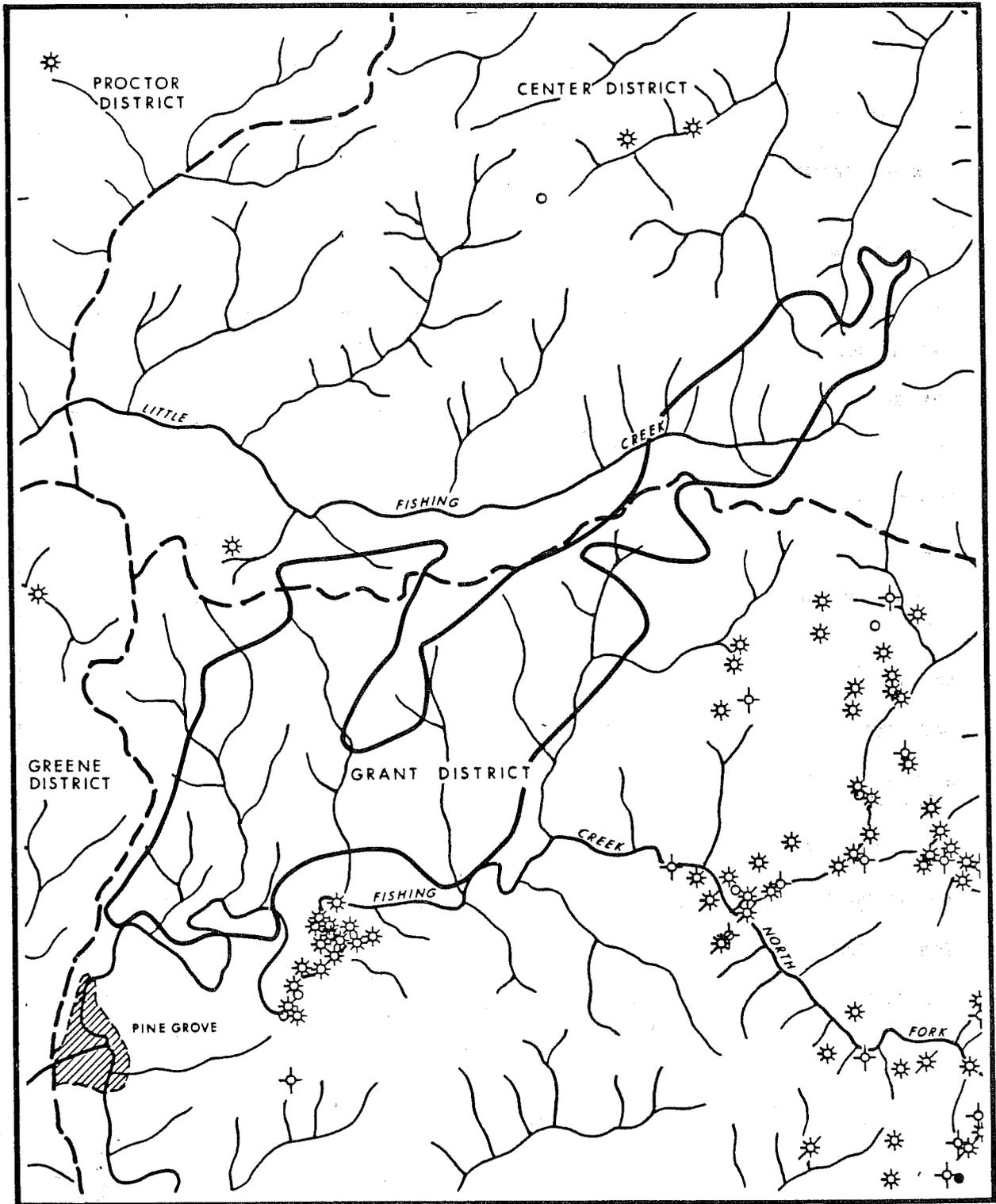
Disc 1899
 1200 B/AF orig So est
 150 producing wells in 1963
 Ave well spacing 700 feet
 Maximum initial oil prod - 50 bpd
 1963 Estimate- Orig BO - 32,910,000
 Prod - 1,575,000
 Left - 31,335,000
 Inactive
 Production (1955) 13,000 BO/yr from 150 wells

REFERENCES:

Bureau of Mines #607
 West Virginia Oil and Gas Map 1976
 Oil & Gas Report Bulletin 12 (1955)
 IOCC Secondary Recovery 1951-1960
 *See Table 5 for details



PINE GROVE FIELD
 LOCATION OF WELLS
 KNOWN IN 1958 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 WETZEL COUNTY



PINE GROVE FIELD
 LOCATION OF ALL WELLS
 DRILLED OR PLUGGED SINCE 1929
 MAP FROM WEST VIRGINIA
 MINES DEPARTMENT OIL & GAS
 DIVISION (1978)

GRUY FEDERAL, INC.

FIELD NAME - Porto Rico, Stout

CO.(s) - Doddridge

LOCATION -

DIST. - Southwest, Cove, New Milton,
West Union

PRINCIPAL OPERATOR -

Largely Abandoned

FORMATION NAME(s)	Gordon	First Cow Run		
AVE DEPTH(s)	2512			
AVE THICKNESS(es)	4/5-20			
API GRAVITY/VISCOSITY				
AVE k				
SO-CURRENT				
AVE ϕ				
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?				
SIZE (NUMBER OF ACRES)	5,587			

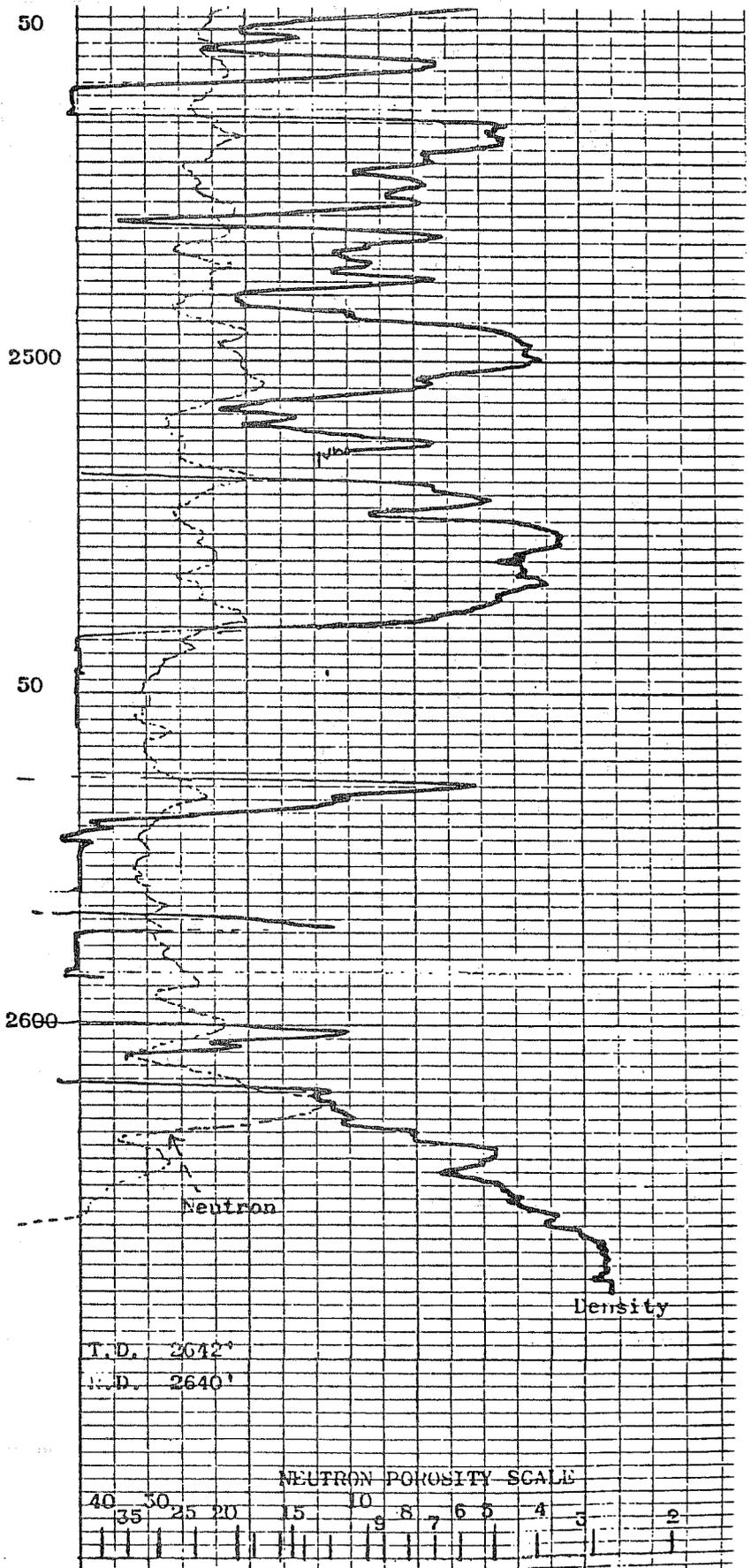
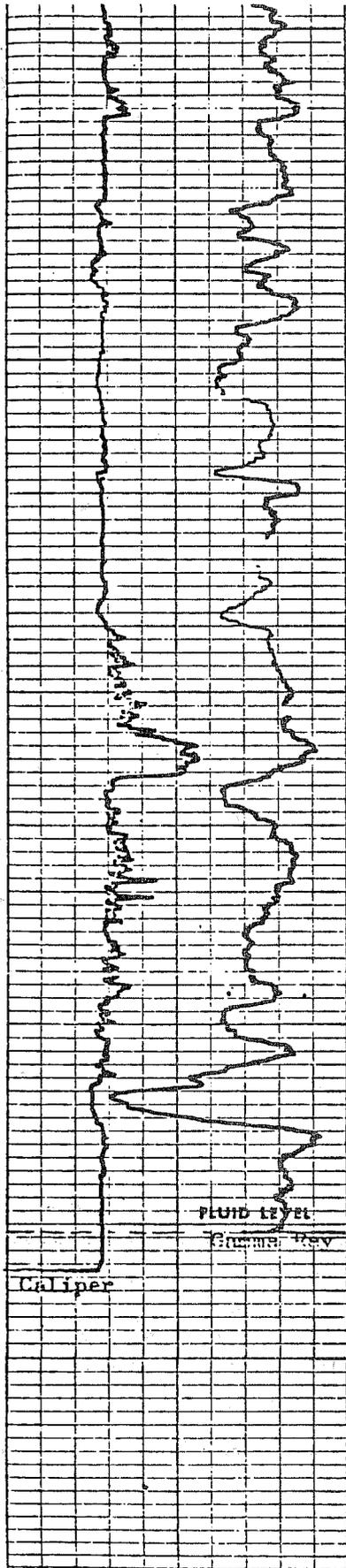
TYPE OF TRAP? Combination (Syncline - perm barrier)

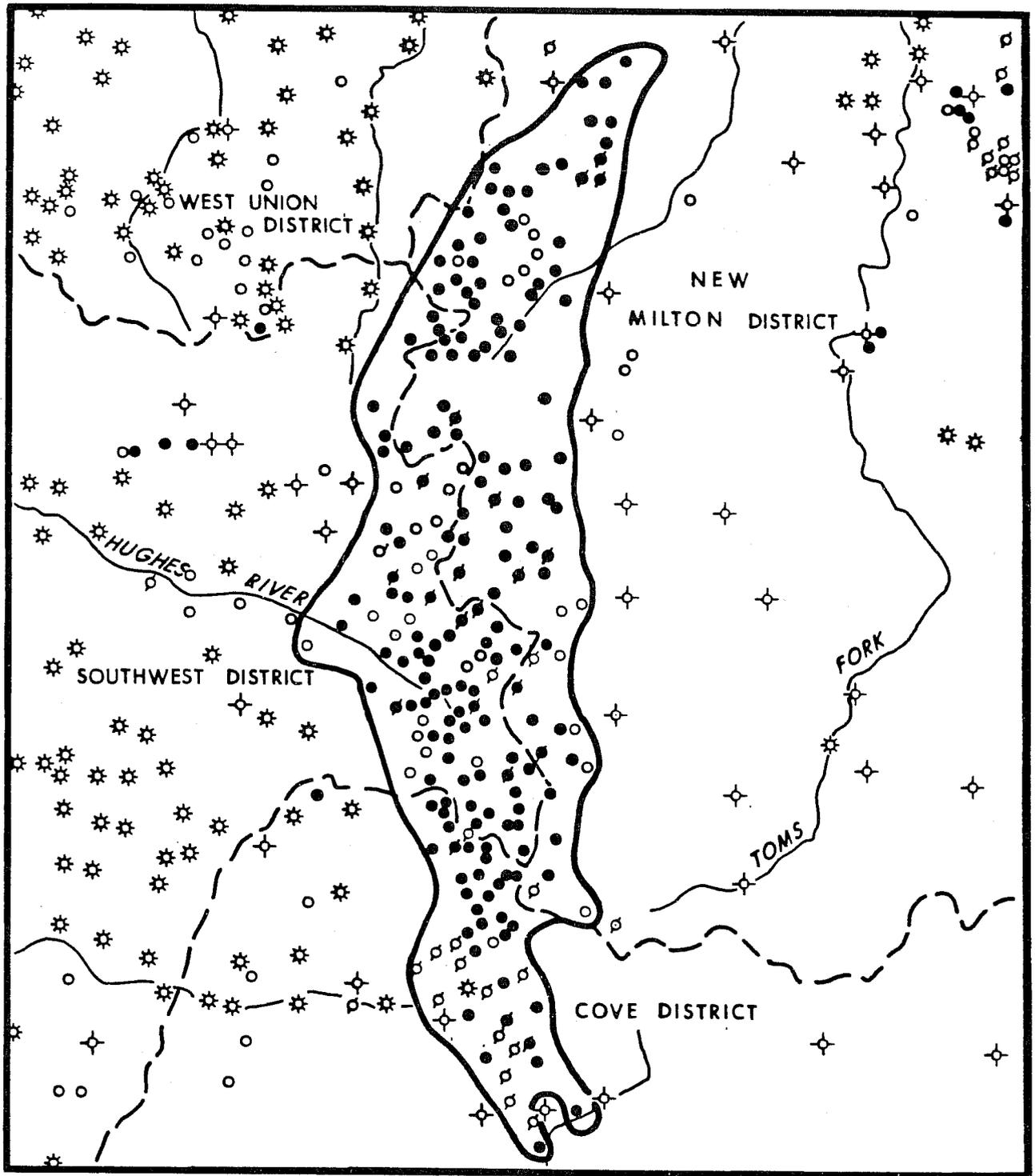
TYPE OF DEPOSIT : Sandstone, West - thin; East - thicker

ADDITIONAL INFORMATION: Abandoned about 1950 (largely)
Renewed activity in 1971
Ave well spacing 750 feet
Disc 1899
Maximum IP 200 BOPO
So orig est 1625 B/AF
1963 Estimate- Orig BO - 36,315,000
Prod - 6,791,000
Left - 29,524,000
Merges with New Milton (north) to northeast

REFERENCES: Bureau of Mines #607
West Virginia Oil and Gas Map 1977

PORTO RICO FIELD





PORTO RICO FIELD
 LOCATION OF WELLS
 KNOWN IN 1959 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 DODDRIDGE CO.

GRUY FEDERAL, INC.

FIELD NAME - Salam Wallace (Zinnia) CO.(s) - Doddridge, Harrison, Marion
 LOCATION - DIST. - Greenbriar, Grant, McClellan,
 PRINCIPAL OPERATOR - Eagle, Sardis, Ten Mile,
 Mannington, Marion, Grant

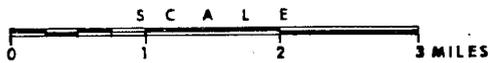
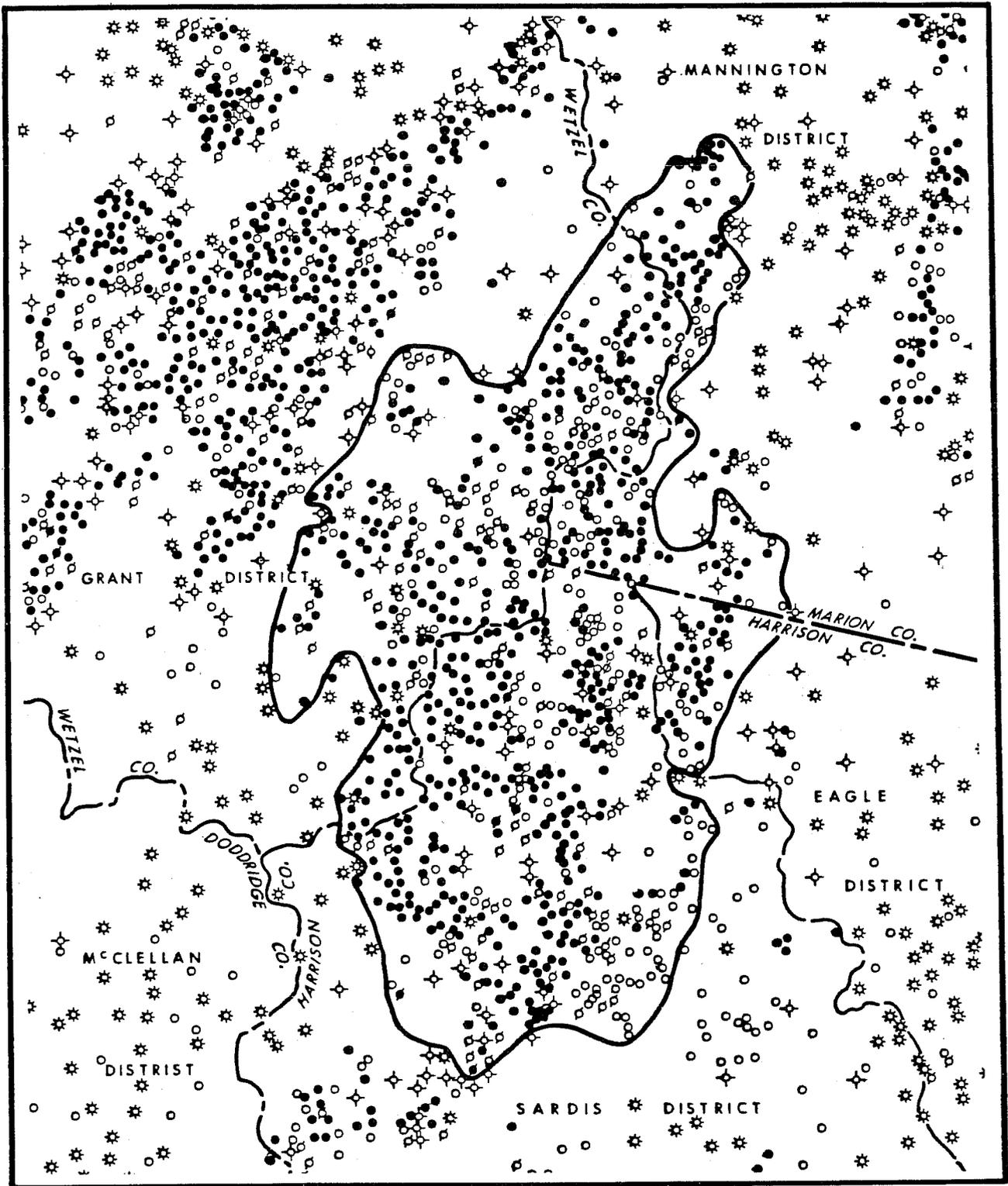
FORMATION NAME(s)	Gordon			
AVE DEPTH(s)	2825			
AVE THICKNESS(es)	8/5-50			
API GRAVITY/VISCOSITY				
AVE k				
So-CURRENT				
AVE ϕ				
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFUL SECONDARY RECOVERY?	Gas Inj 1936 Successful			
SIZE (NUMBER OF ACRES)	41,800			

TYPE OF TRAP? Combination (Syncline - perm barrier)

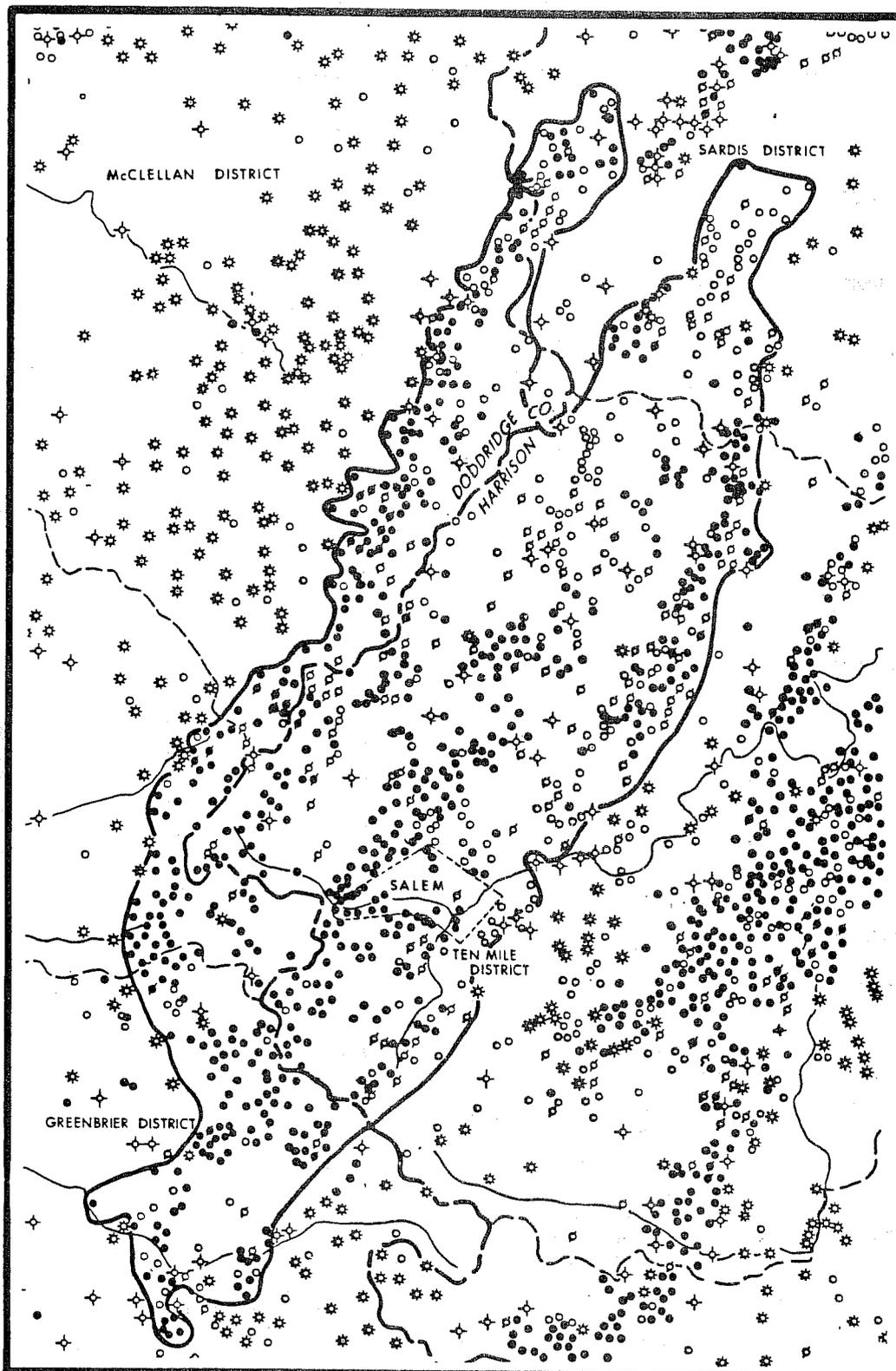
TYPE OF DEPOSIT : Gordon - hard conglomeratic sandstone

ADDITIONAL INFORMATION:
 Disc 1899
 Ave well spacing 800 feet
 So orig 725 est
 Max IP 1400 BOPO
 Orig BO - 242,440,000 b
 Prod. - 41,162,000 b
 Left - 201,278,000 b
 Little drilling activity since 1966

REFERENCES:
 Bureau of Mines #607
 West Virginia Oil and Gas Map 1976



NORTH PORTION
SALEM-WALLACE FIELD
LOCATION OF WELLS
KNOWN IN 1955 - FROM WEST
VIRGINIA OIL AND GAS REPORT MAP
DODDRIDGE AND HARRISON COUNTIES



SOUTH PORTION
 SALEM-WALLACE FIELD
 LOCATION OF WELLS
 KNOWN IN 1955 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 DODDRIDGE AND HARRISON COUNTIES

FIELD NAME - Steel Run

CO.(s) - Wetzel

LOCATION -

DIST. - Center, Proctor, Green

PRINCIPAL OPERATOR -

FORMATION NAME(s)	Gordon Stray	Gordon		
AVE DEPTH(s)	3012	2988		
AVE THICKNESS(es)	5/10-40	5/15-28		
API GRAVITY/VISCOSITY				
AVE k				
So-CURRENT				
AVE ϕ				
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?				
SIZE (NUMBER OF ACRES)	4,050			

TYPE OF TRAP? Combination (Syncline and perm barrier)

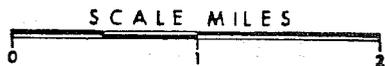
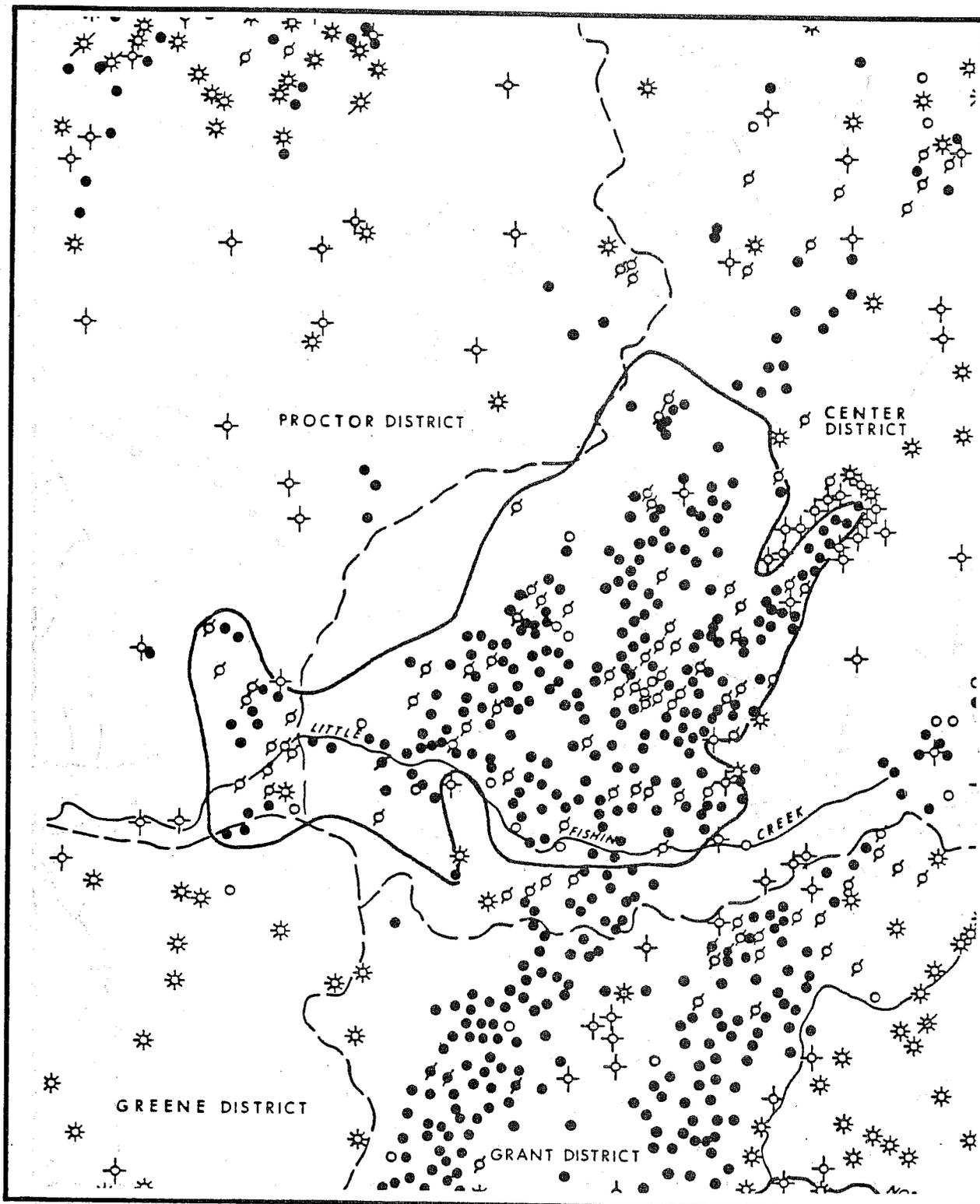
TYPE OF DEPOSIT : Gordon Stray - loosely cemented cong. S,S.
Gordon Sd - tightly cemented cong. S,S.

ADDITIONAL INFORMATION:

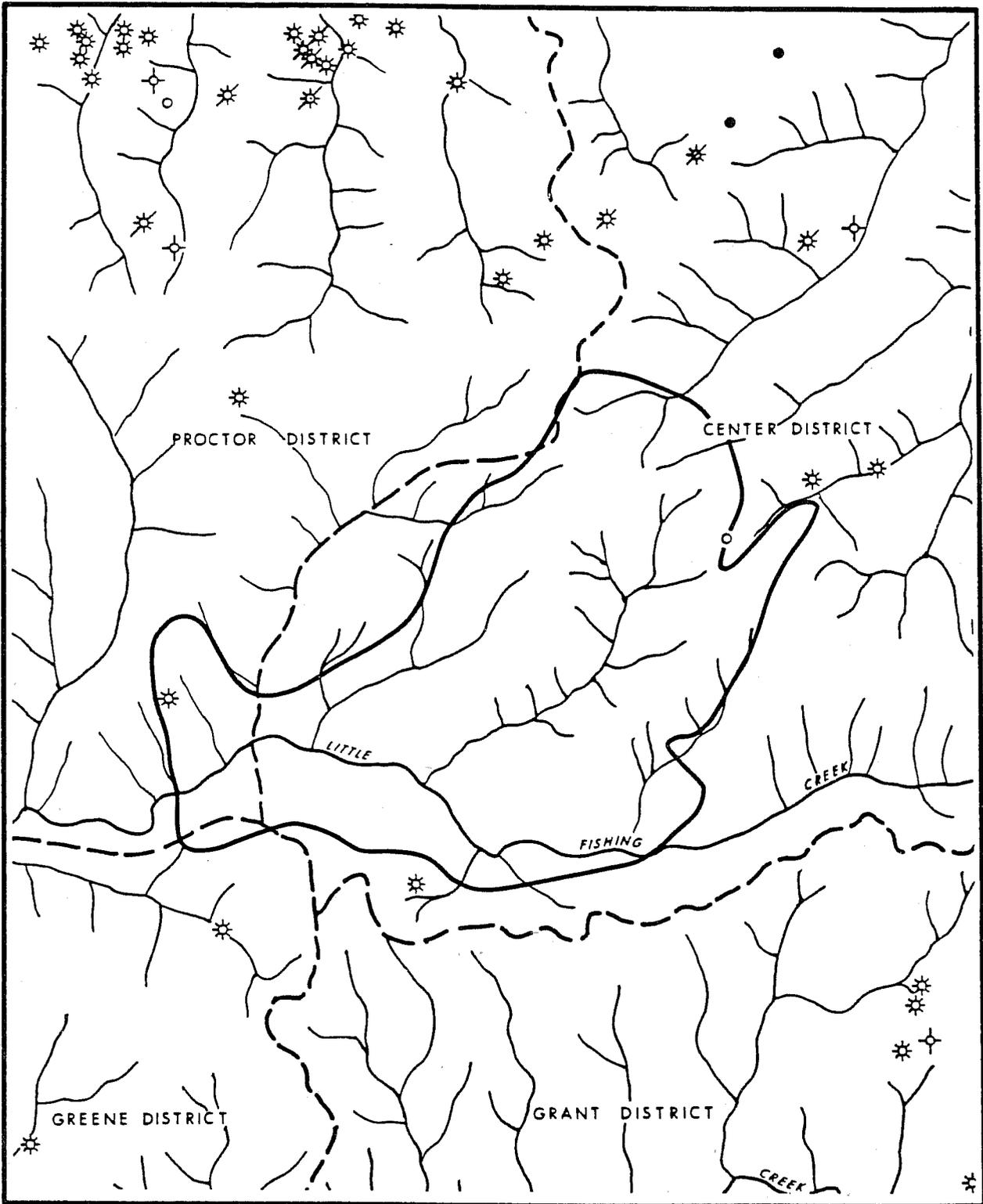
100 wells in field in 1963
 Max IP 500 BOPO
 So orig est 1315
 Disc 1902
 Ave wells spacing 850 feet
 Extend to Pine Grove and Camp Run Field
 1963 Estimates- Orig BO - 26,629,000 b
 Prod - 3,970,000 b 3,900,000 (1955)
 Left - 22,659,000 b
 Continuous with Silver Hill to North and Pine Grove, Camp Run
 to South.
 Prod (1955) 5,500 BO/year from 100 wells

REFERENCES:

Bureau of Mines #607 (1963)
 West Virginia Oil and Gas Map (1976)
 Oil and Gas Report Bulletin 12 (1955)



STEEL RUN FIELD
 LOCATION OF WELLS
 KNOWN IN 1958 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 WETZEL COUNTY



STEEL RUN FIELD
 LOCATION OF ALL WELLS
 DRILLED OR PLUGGED SINCE 1929
 MAP FROM WEST VIRGINIA
 MINES DEPARTMENT OIL & GAS
 DIVISION (1978)

GRUY FEDERAL, INC.

FIELD NAME - Rouzer

CO.(s) - Union

LOCATION - Clay

DIST. -

PRINCIPAL OPERATOR -

FORMATION NAME(s)	Big Injun			
AVE DEPTH(s)	1868			
AVE THICKNESS(es)	30/20-63			
API GRAVITY/VISCOSITY				
AVE k				
So-CURRENT				
AVE ϕ				
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?				
SIZE (NUMBER OF ACRES)	*3200			

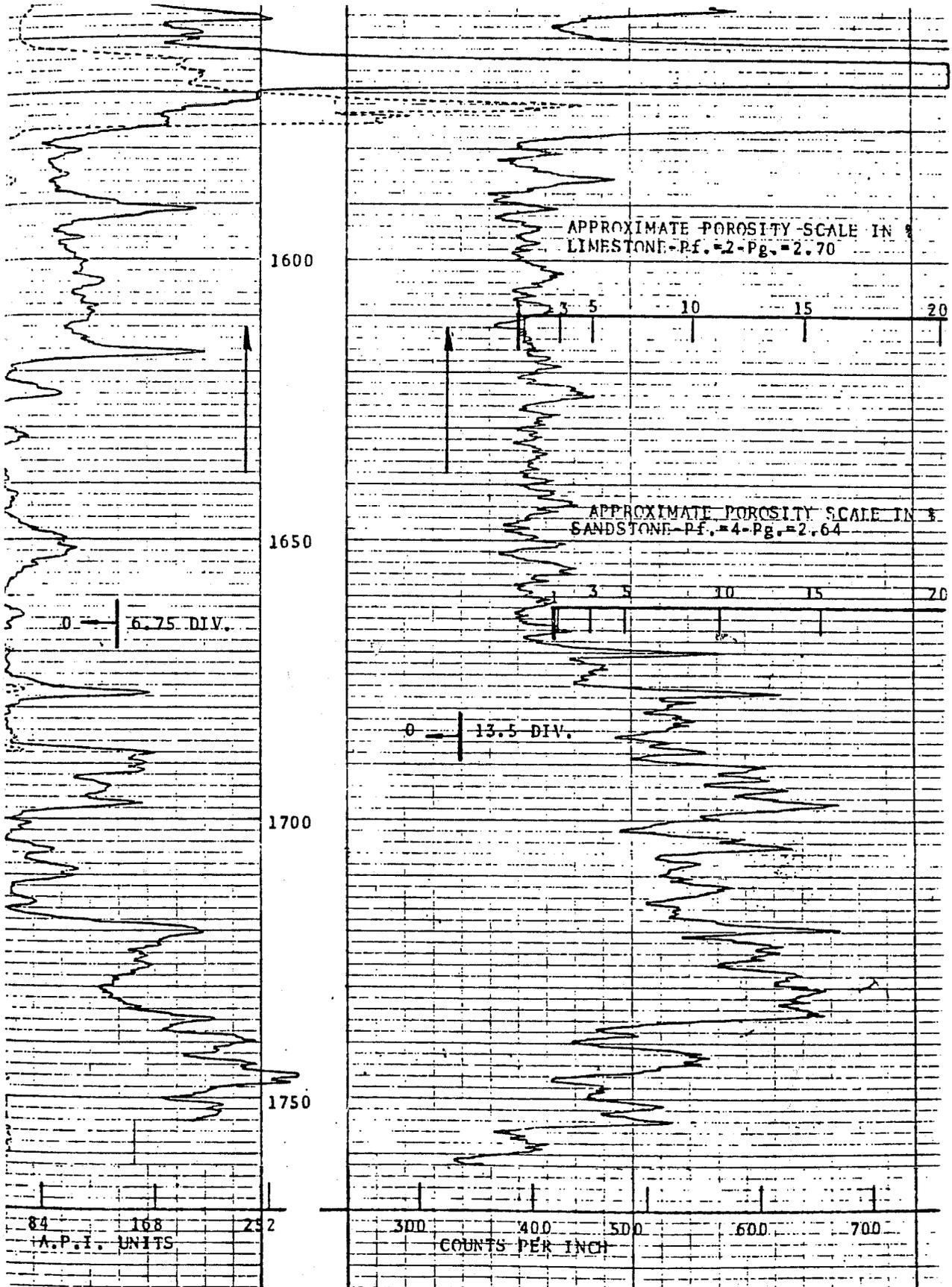
TYPE OF TRAP? Combination (Syncline & Perm Barrier)

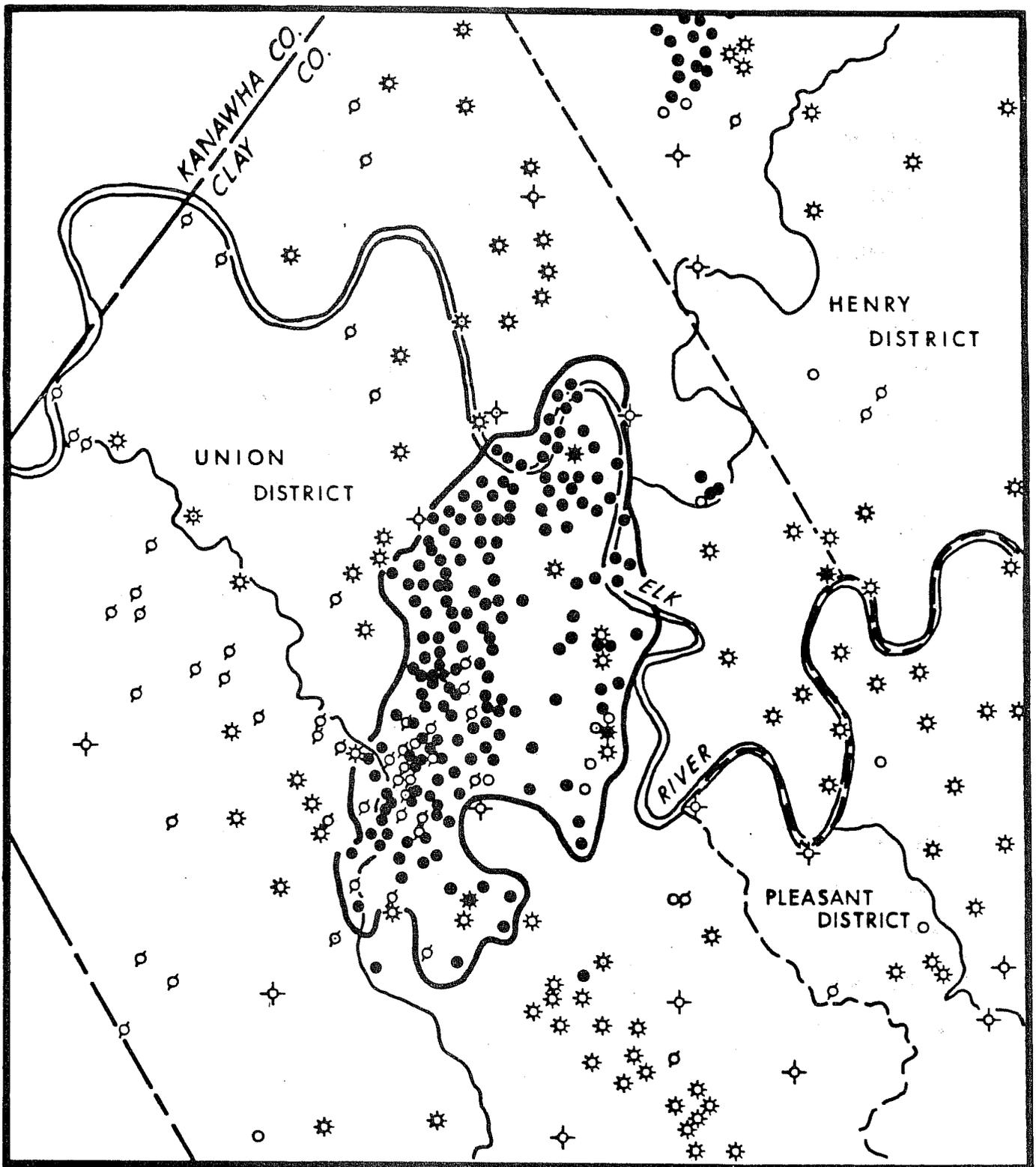
TYPE OF DEPOSIT : Big Injun - white to grey, friable; sandstone

ADDITIONAL INFORMATION: Disc 1912
 Ave well spacing 600'
 So orig 200 B/AF
 100 BDPD Max IP
 1963 Estimates/ orig BO 14,898,000 b
 prod 3,951,000 b
 left 10,947,000 b

REFERENCES: Bureau of Mines #607
 *West Virginia Oil & Gas Map 1976

ROUZER FIELD





ROUZER FIELD
 LOCATION OF WELLS
 KNOWN IN 1964 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 CLAY COUNTY

GRUY FEDERAL, INC.

FIELD NAME - Sistersville

CO.(s) - Lincoln, Union

LOCATION - Tyler

DIST. -

PRINCIPAL OPERATOR -

Probably Abandoned

FORMATION NAME(s)	Big Injun			
AVE DEPTH(s)	1554			
AVE THICKNESS(es)	10/75-118			
API GRAVITY/VISCOSITY	46.3			
AVE k				
So-CURRENT				
AVE ϕ	16			
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?	Gas - 1933 - Successful			
SIZE (NUMBER OF ACRES)	6554			

TYPE OF TRAP? Permeability Barrier and Anticlin

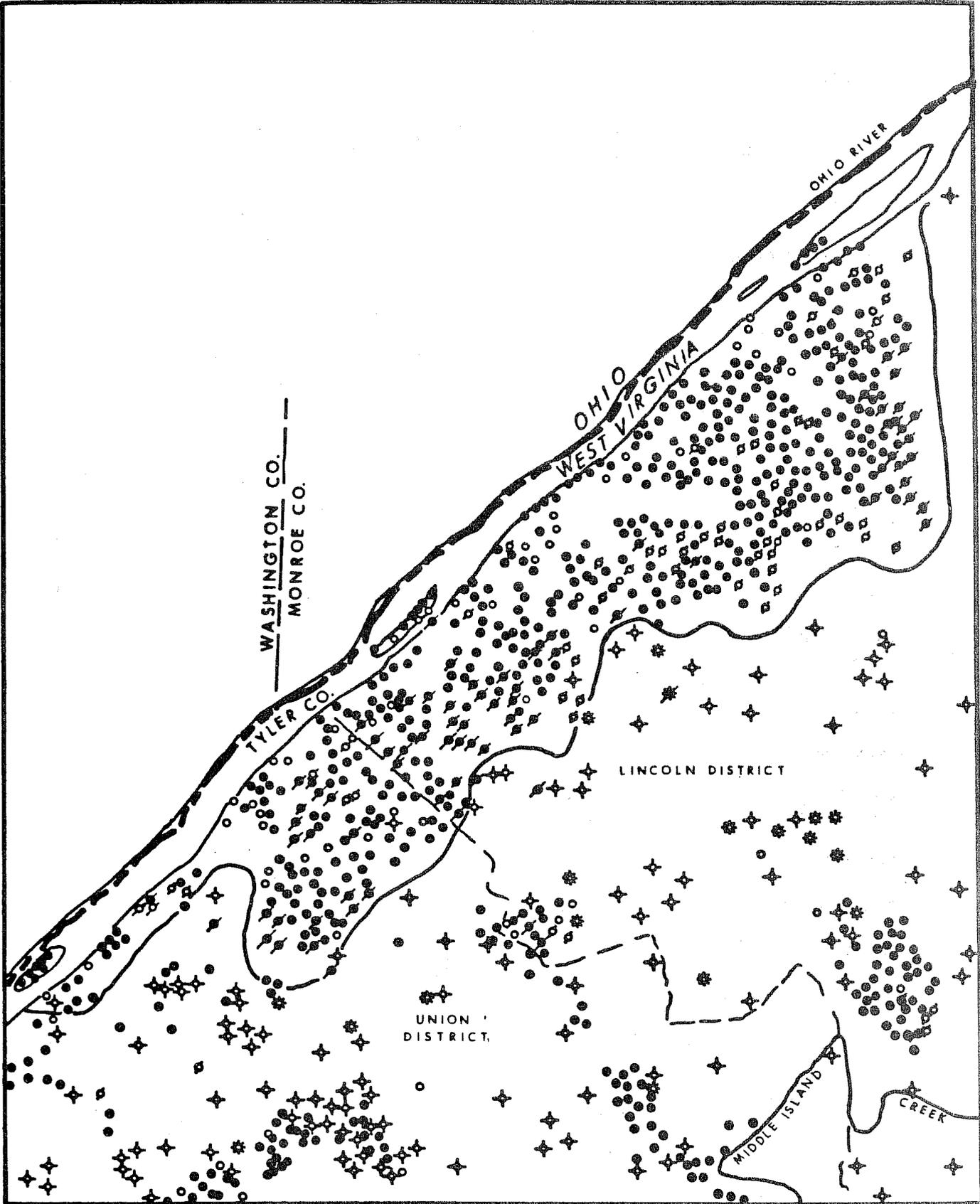
TYPE OF DEPOSIT : Very coarse

ADDITIONAL INFORMATION:

Disc 1890
 Well spacing - 400 feet
 Max initial oil prod. 1,100 bpd
 Res temp 73°
 Init est. 900 b/af
 Water produced with oil
 Orig BO - 58,986,000 b
 Prod - 14,633,000 b
 Left - 45,353,000 b
 Prod - 2,000 BO/year 1955 from 250 wells

REFERENCES:

Bureau of Mines Bulletin 607, 1963
 Oil and Gas Fields of West Virginia 1977
 Oil and Gas Report BULLETIN #12 (1955)



SISTERSVILLE FIELD
 LOCATION OF WELLS
 KNOWN IN 1955 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 TYLER COUNTY

GRUY FEDERAL, INC.

FIELD NAME - Tariff - (Tallman)

CO. (s) - Roane

LOCATION -

DIST. - Geary, Smithfield

PRINCIPAL OPERATOR -

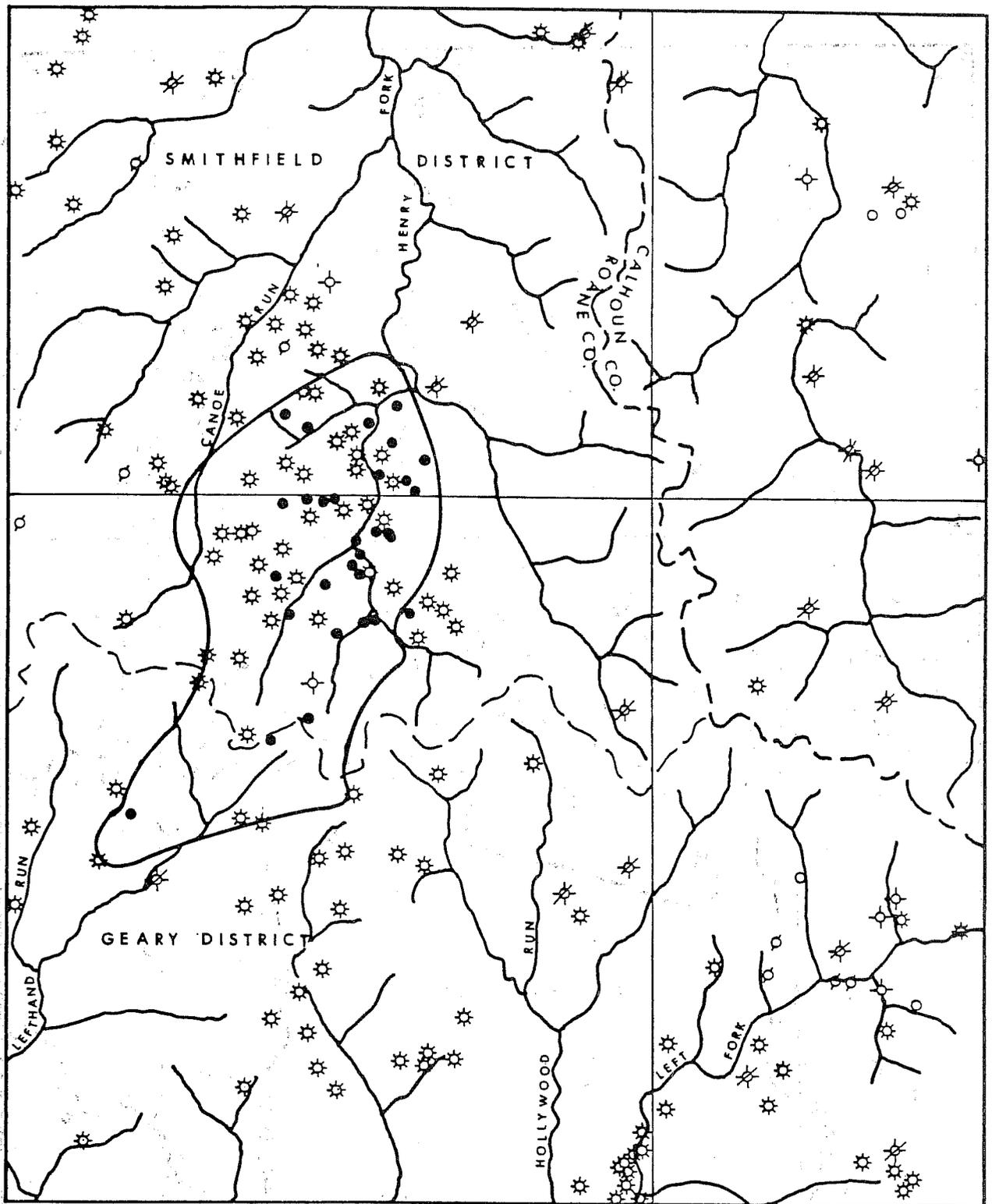
FORMATION NAME(s)	Big Injun			
AVE DEPTH(s)	2012			
AVE THICKNESS(es)	12/24-67			
API GRAVITY/VISCOSITY	47°			
AVE k				
So-CURRENT				
AVE φ	17%			
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?	Gas Inj before 1940* - Gas Inj 1951 **			
SIZE (NUMBER OF ACRES)	2,938			

TYPE OF TRAP? Combination - (syncline and perm barrier)

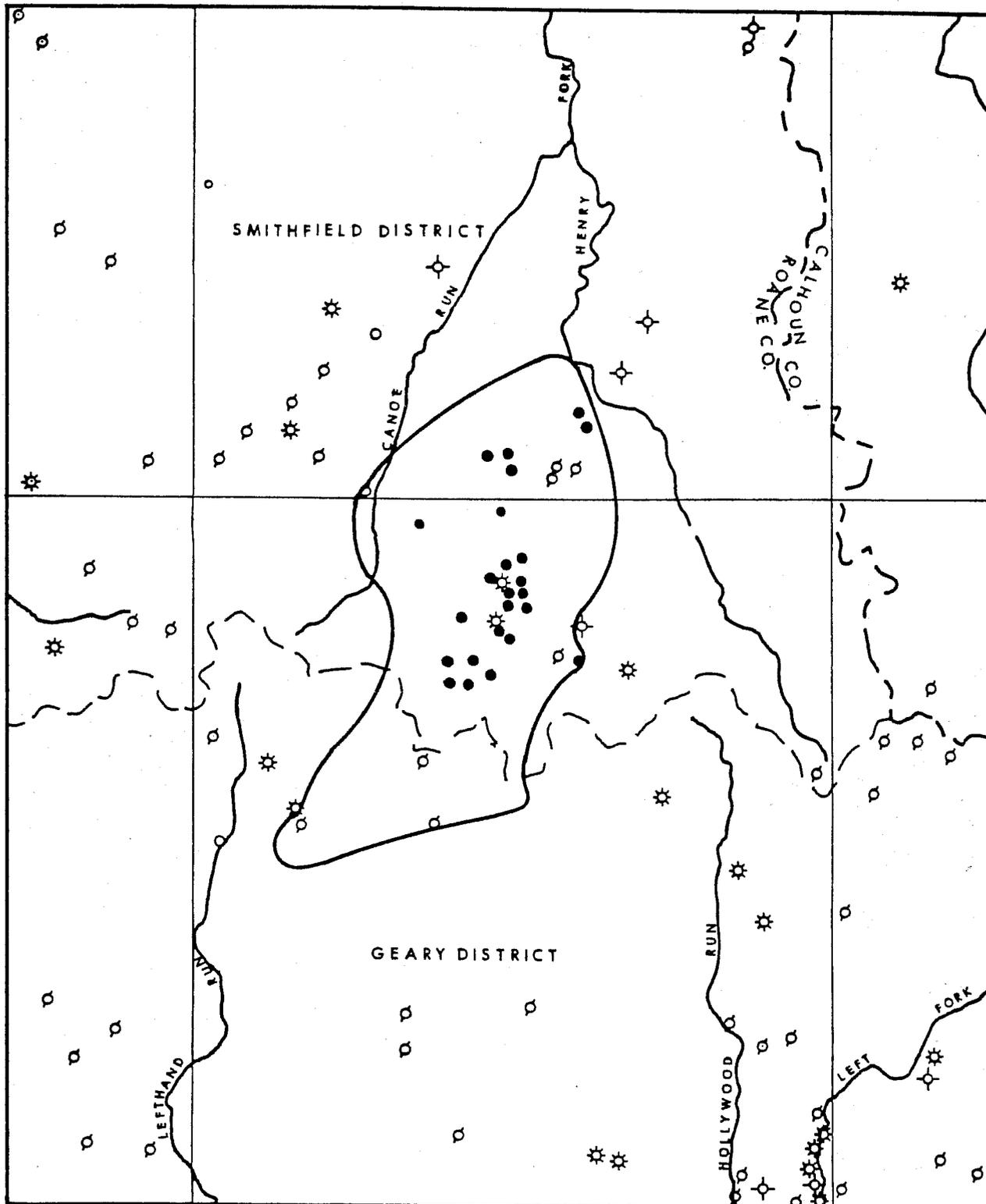
TYPE OF DEPOSIT : Big Injun - friable and well cemented

ADDITIONAL INFORMATION: Max IP 150 BOPO
 Disc 1909
 So orig est 392 B/AF
 Reservoir temperature 73°
 IGOR 390
 WHISIP 870#
 1963 estimates- Orig BO - 13,809,000 b
 Prod - 3,170,000 b
 Left - 10,639,000 b
 Field extended in early 60's and again in early 70's.

REFERENCES: Bureau of Mines #607
 West Virginia Oil and Gas Map 1976 and 1977
 IOCC Secondary Recovery 1951
 **See Table 6 for details



TARIFF FIELD
 LOCATION OF ALL WELLS
 DRILLED OR PLUGGED SINCE 1929
 MAP FROM WEST VIRGINIA
 MINES DEPARTMENT OIL & GAS
 DIVISION (1978)



TARIFF FIELD
 LOCATION OF WELLS
 KNOWN IN 1958 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 ROANE COUNTY

FIELD NAME - Walton, (Rock Creek-Johnsons Creek) CO. (s) - Roane
 LOCATION - DIST. - Smithfield, Walton, Harper
 PRINCIPAL OPERATOR -

FORMATION NAME(s)	Big Injun			
AVE DEPTH(s)	2050			
AVE THICKNESS(es)	21'			
API GRAVITY/VISCOSITY	43.5/3.2 cp @ 73°F			
AVE k	14 15-20			
SATURATIONS	Sw=52% orig So=35-46			
AVE φ	21.7			
SALINITY OF CONN. H ₂ O	High			
GAS CAP				
DRIVE TYPE	Solution Gas			
SUCCESSFULL SECONDARY RECOVERY?	Gas 1937 Successful * Wtr. 1954-Unsuccessful Steam 1970-Unsuccessful			
SIZE (NUMBER OF ACRES)	11,200			

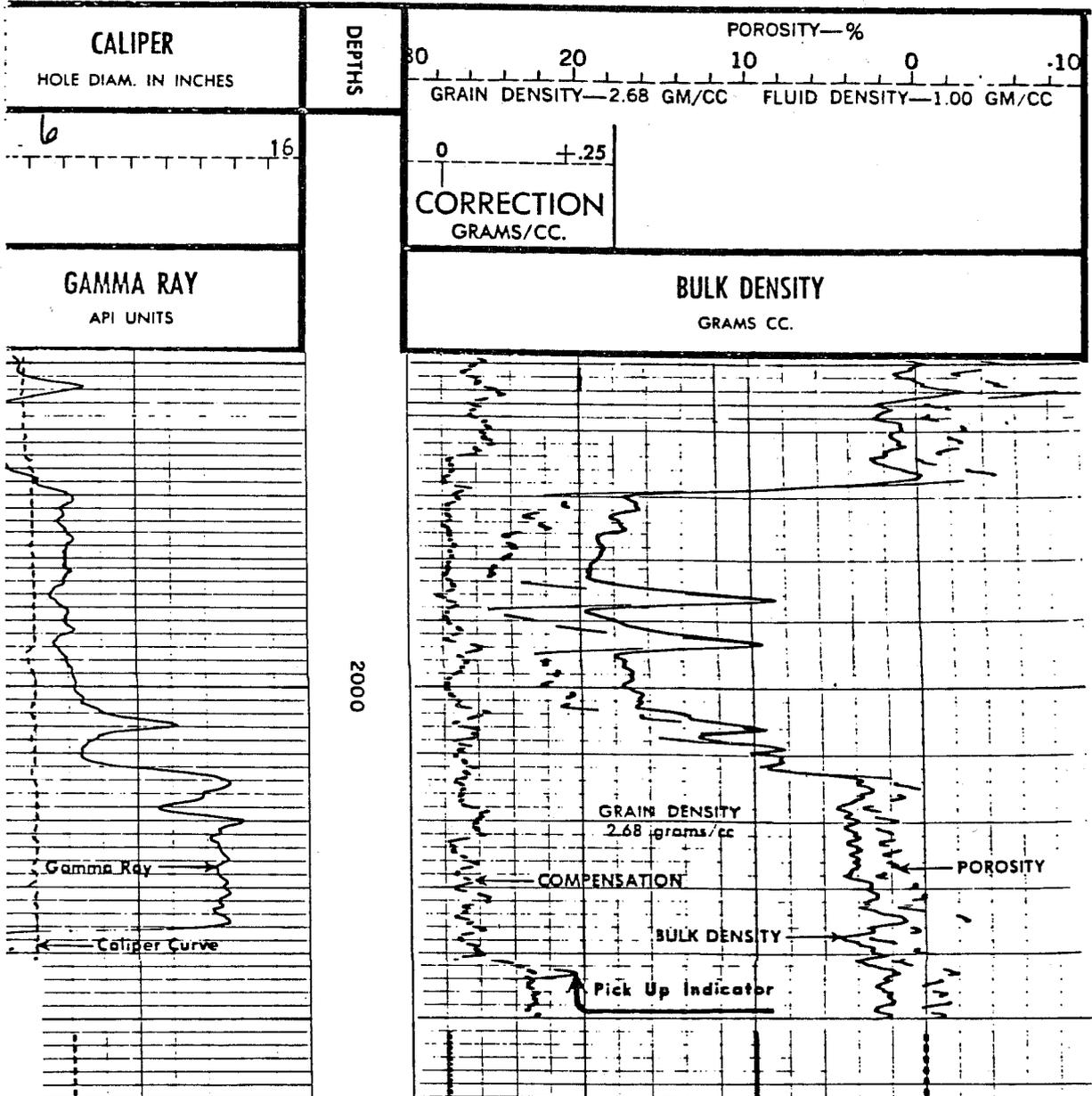
TYPE OF TRAP? Combination (Anticline - perm barrier)

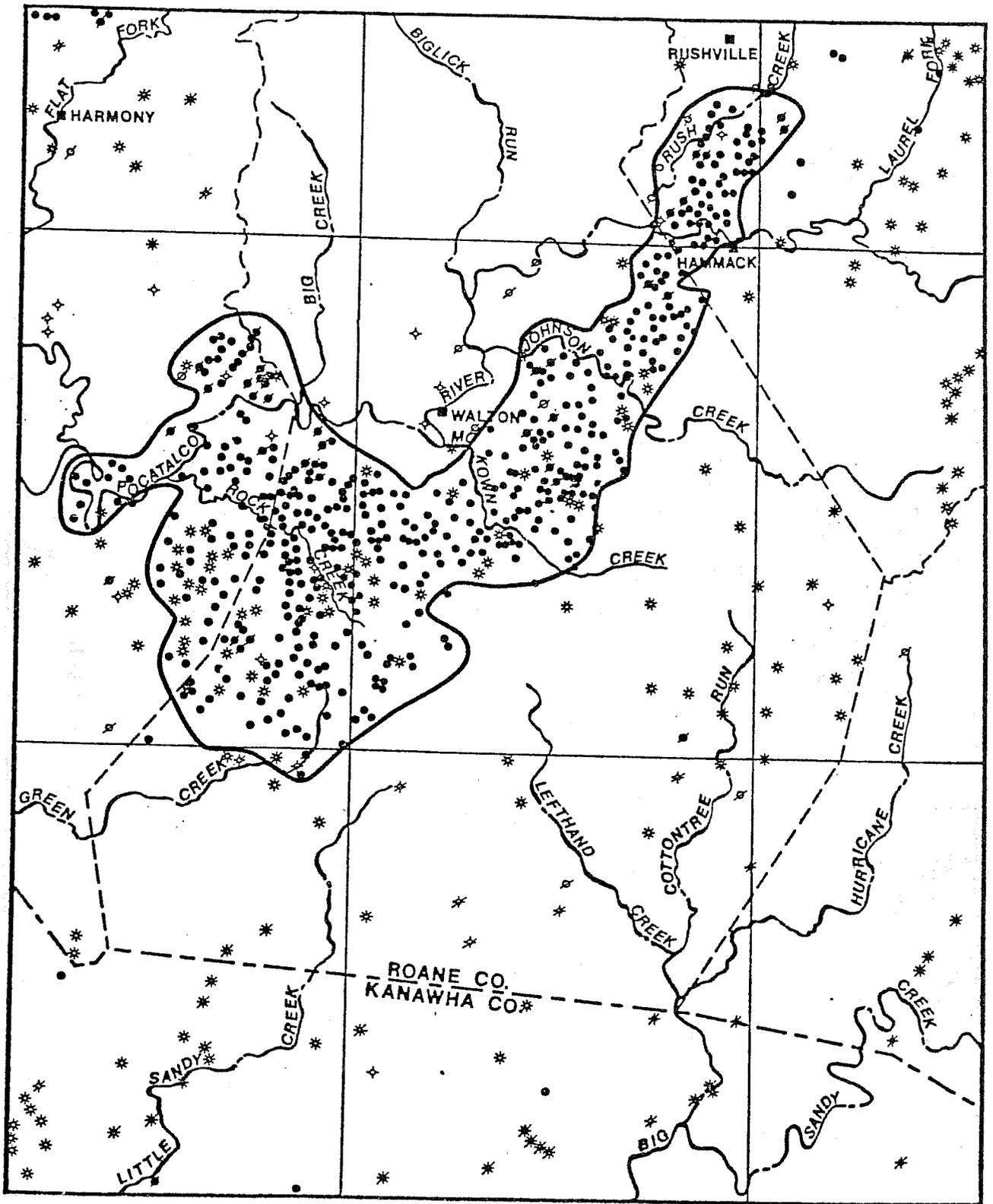
TYPE OF DEPOSIT: Big Injun - hard friable S.S.

ADDITIONAL INFORMATION:
 9,000 acres to 1966 between 1966-69 300 wells drilled on 5,500 acres @ 18 acre spacing.
 Steamflood attempted in 1970.
 217 Wells in 1950
 Reservoir temp 73° 75°
 1963 Estimates-Orig BO - 54,165,000 b
 Prod - 18,097,000 b
 Left - 36,068,000 b
 Very active drilling - 1970's

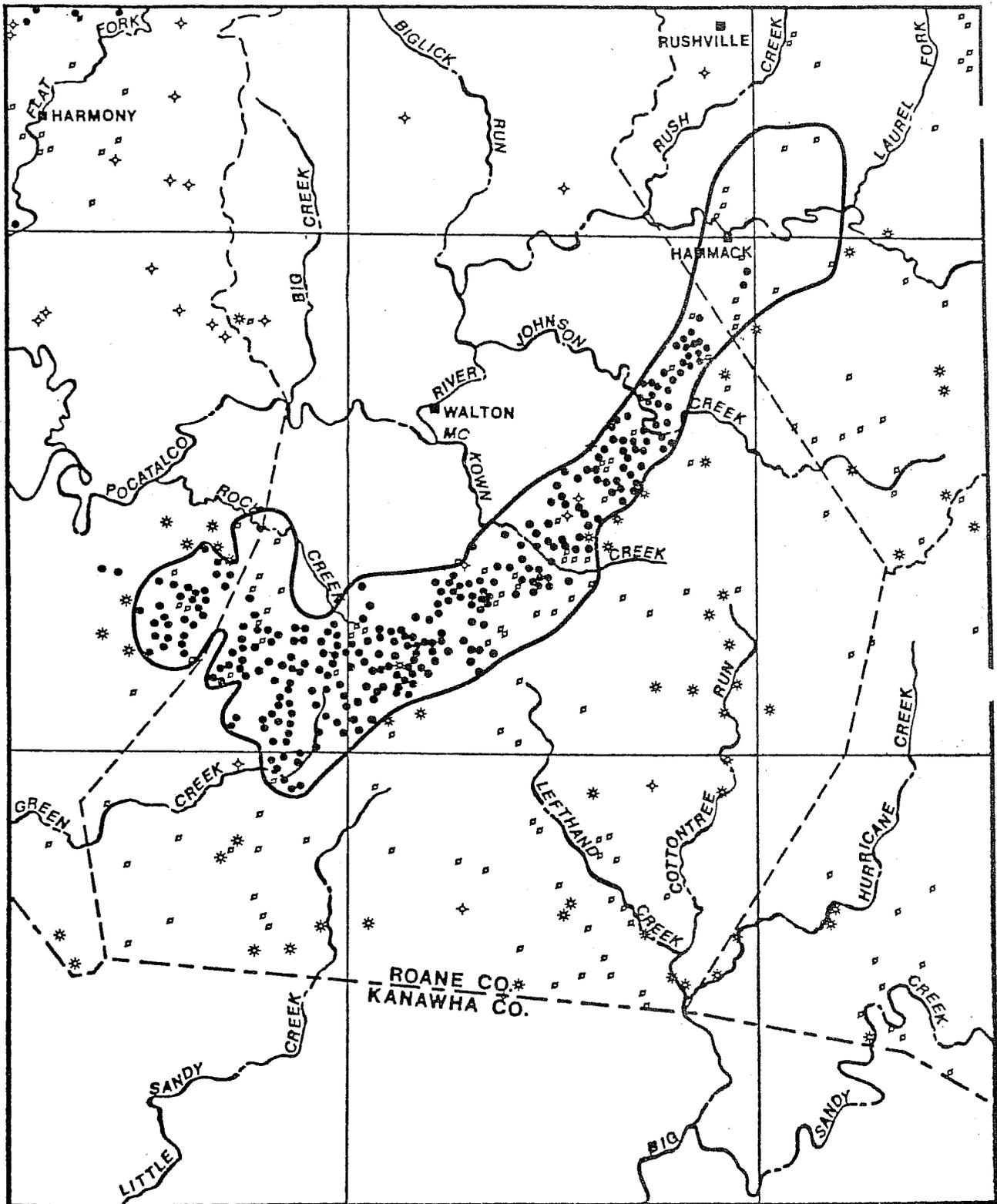
REFERENCES:
 Bureau of Mines #607
 ERDA Publications
 Oil and Gas Journal October 20, 1969
 West Virginia Oil and Gas Map
 IOCC Reports Secondary Recovery 1951
 *Table 6 for details

WALTON - ROCK CREEK FIELD





WALTON - (ROCK CREEK) FIELD
 LOCATION OF ALL WELLS
 DRILLED OR PLUGGED SINCE 1929
 MAP FROM WEST VIRGINIA
 MINES DEPARTMENT-OIL AND GAS
 DIVISION - 1978



WALTON - (ROCK CREEK) FIELD
 LOCATION OF WELLS
 KNOWN IN 1958 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 WIRT, ROANE, AND CALHOUN COUNTIES

FIELD NAME - Wolf-Summit-Big Isaacs

CO.(s) - Doddridge, Harrison, Lewis

LOCATION -

DIST. - Greenbriar, Sardis, Union,
Ten Mile, Freeman's Creek

PRINCIPAL OPERATOR -

FORMATION NAME(s)	Gordon Stray	Gordon	Fifth 2900	
AVE DEPTH(s)	1900-2850	1986-3165	2100-3205	
AVE THICKNESS(es)			6/7	
API GRAVITY/VISCOSITY			41.7/4.64	
AVE k			130	
SATURATIONS			So=43.9% orig? Sw=12% orig	
AVE ϕ			20%	
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFUL SECONDARY RECOVERY?			Gas -1926 * No records	
SIZE (NUMBER OF ACRES)			17,229	

TYPE OF TRAP?

Combination (Syncline and perm barrier)

TYPE OF DEPOSIT :

Fifth - coarse grained, well-cemented S.S.

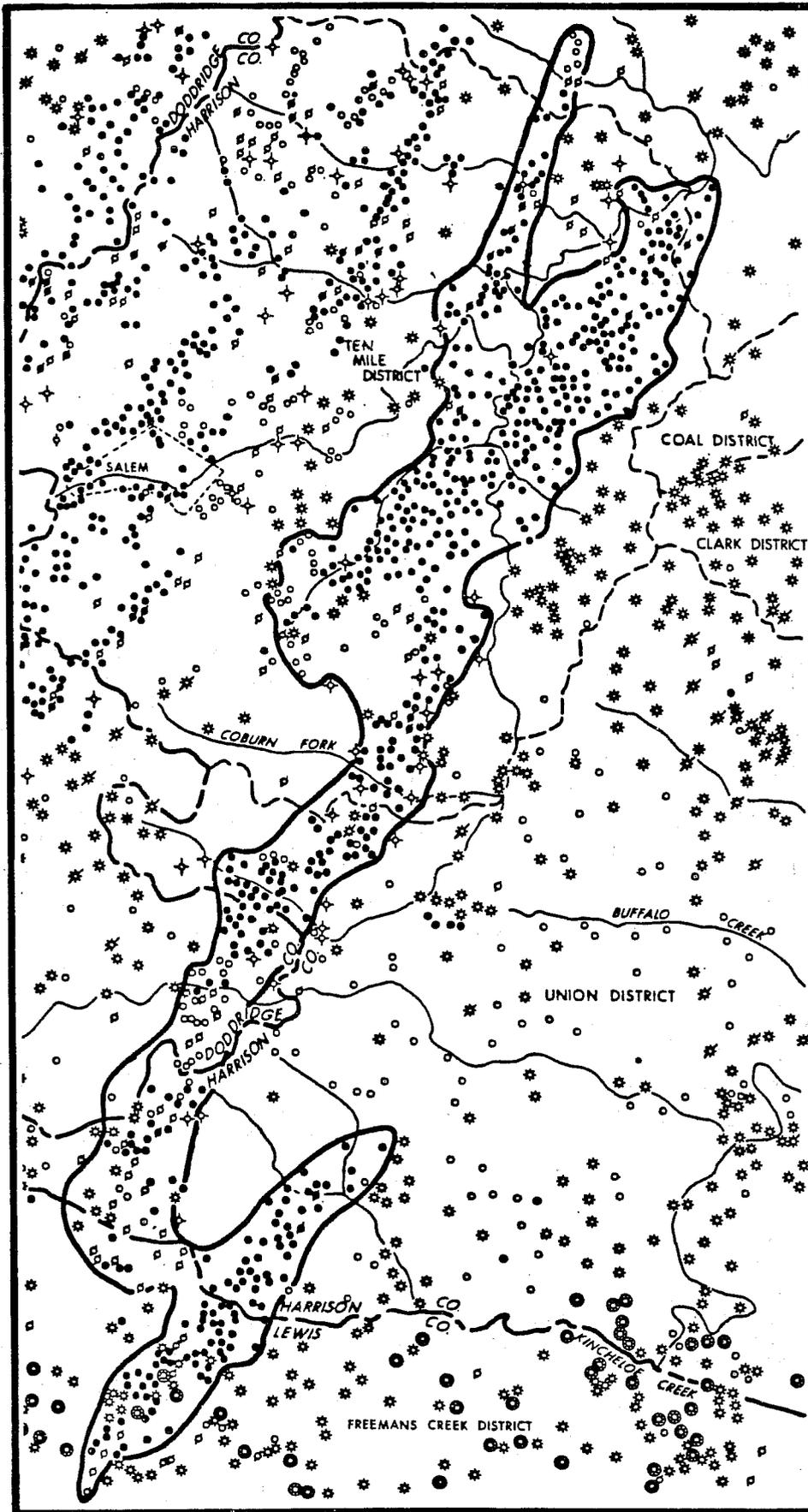
ADDITIONAL INFORMATION:

Disc 1896
Res temp 85.5

No recent activity
Prod with Big Isaacs, and Rockcamp Run, 12,629,000
218 Well 1950

REFERENCES:

Bureau of Mines #607
West Virginia Oil and Gas Map 1976
IOCC Secondary Recovery 1951
*See Table 5 for details



WOLF SUMMIT - BIG ISAAC
FIELD
LOCATION OF WELLS KNOWN
IN 1959 - FROM WEST
VIRGINIA OIL AND GAS
REPORT MAP
DODDRIDGE, HARRISON, AND
LEWIS CO.'S

FIELD NAME - Yellow Creek (Big Springs) CO.(s) - Calhoun, Ritchie, Gilmer
 LOCATION - DIST. - Sheridan, Center, Murphy and Dekalb

PRINCIPAL OPERATOR -

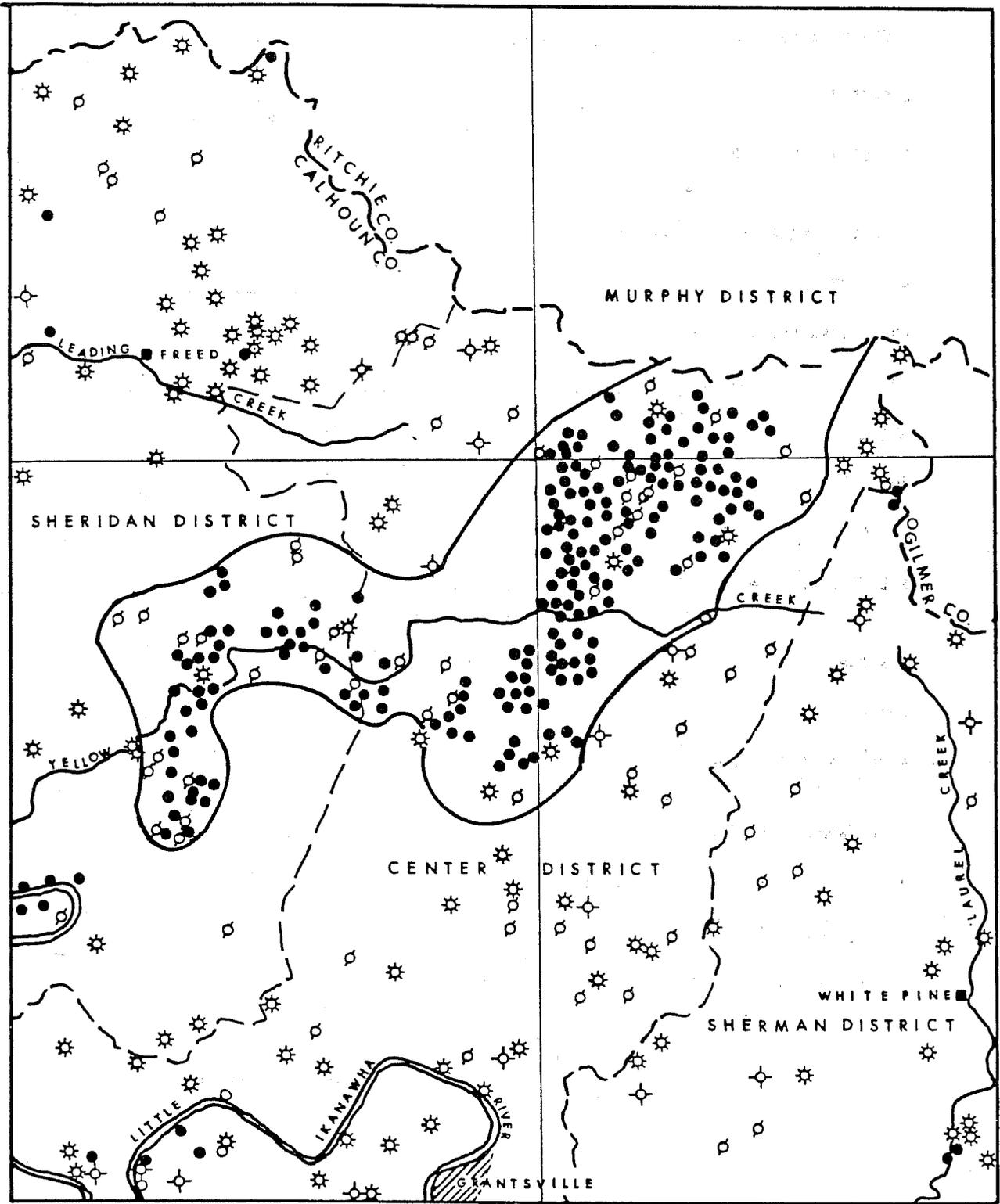
FORMATION NAME(s)	Berea	Big Injun	Maxton	
AVE DEPTH(s)	2268			
AVE THICKNESS(es)	8/27-34			
API GRAVITY/VISCOSITY				
AVE k				
So-CURRENT				
AVE φ				
SALINITY OF CONN. H ₂ O				
GAS CAP				
DRIVE TYPE				
SUCCESSFULL SECONDARY RECOVERY?				
SIZE (NUMBER OF ACRES)	4812			

TYPE OF TRAP? Stratigraphic (perm barrier)

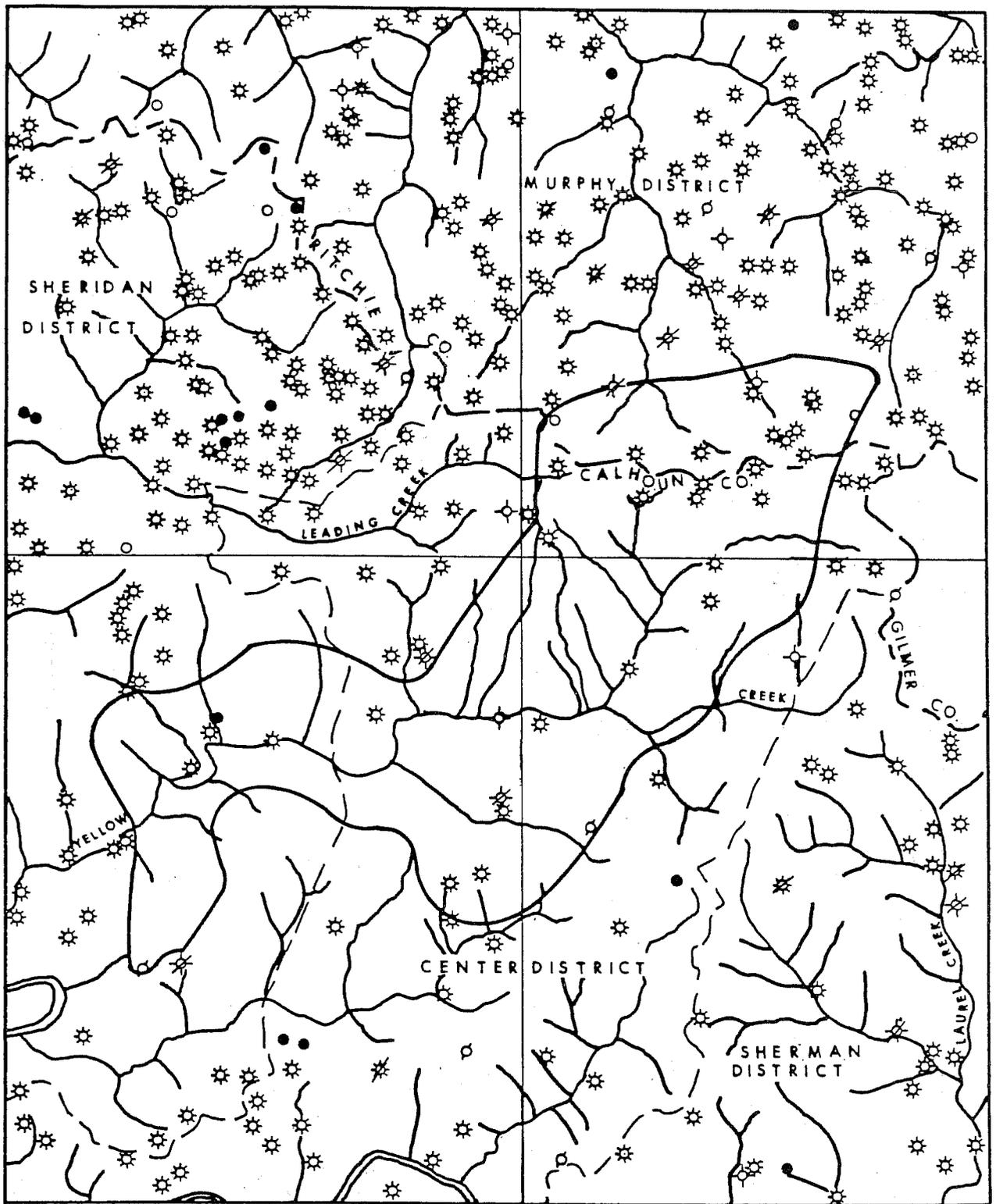
TYPE OF DEPOSIT : Sandstone

ADDITIONAL INFORMATION: Maximum IP - 200 BOPO
 Disc 1904
 Well spacing est. 650
 So orig 563 B/AF
 Orig - BO 21,654,000 b
 Prod - 6,165,000 b - includes Bellsford, Lyncamp and Thursday Fields
 Left - 15,489,000 b
 Prod to 1963

REFERENCES: Bureau of Mines #607
 West Virginia Oil and Gas Map 1976



YELLOW CREEK FIELD
 LOCATION OF WELLS
 KNOWN IN 1958 - FROM WEST
 VIRGINIA OIL AND GAS REPORT MAP
 CALHOUN COUNTY



YELLOW CREEK FIELD
 LOCATION OF ALL WELLS
 DRILLED OR PLUGGED SINCE 1929
 MAP FROM WEST VIRGINIA
 MINES DEPARTMENT OIL & GAS
 DIVISION (1978)

RECORD 00001

OIL ANALYSES FOR 27 WEST VIRGINIA FIELDS

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - TYLER
 FIELD NAME - BENS RUN
 PRODUCING FORMATION NAME - MAXTON, MAUCH CHUNK
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 SERIES - CHESTER
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 01903
 SANDSTONE
 AGENCY SAMPLE NO - B33154
 SPECIFIC GRAVITY - 0.791
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 VISCOSITY SUS AT 100 DEGREES F. - 036
 PERCENT OF CRUDE - 18.2
 VOLUME PERCENT FRACTION 2 - 6.0
 VOLUME PERCENT FRACTION 3 - 6.1
 VOLUME PERCENT FRACTION 4 - 7.6
 VOLUME PERCENT FRACTION 5 - 6.3
 VOLUME PERCENT FRACTION 6 - 6.2
 VOLUME PERCENT FRACTION 7 - 5.1
 VOLUME PERCENT FRACTION 8 - 5.3
 VOLUME PERCENT FRACTION 9 - 5.6
 VOLUME PERCENT FRACTION 10 - 6.4
 VOLUME PERCENT FRACTION 11 - 4.4
 VOLUME PERCENT FRACTION 12 - 5.8
 VOLUME PERCENT FRACTION 13 - 5.0
 VOLUME PERCENT FRACTION 14 - 4.8
 VOLUME PERCENT FRACTION 15 - 5.1
 SPECIFIC GRAVITY FRACTION 2 - 0.645
 SPECIFIC GRAVITY FRACTION 3 - 0.687
 SPECIFIC GRAVITY FRACTION 4 - 0.721
 SPECIFIC GRAVITY FRACTION 5 - 0.741
 SPECIFIC GRAVITY FRACTION 6 - 0.756
 SPECIFIC GRAVITY FRACTION 7 - 0.769
 SPECIFIC GRAVITY FRACTION 8 - 0.779
 SPECIFIC GRAVITY FRACTION 9 - 0.791
 SPECIFIC GRAVITY FRACTION 10 - 0.806
 SPECIFIC GRAVITY FRACTION 11 - 0.827
 SPECIFIC GRAVITY FRACTION 12 - 0.831
 SPECIFIC GRAVITY FRACTION 13 - 0.840
 SPECIFIC GRAVITY FRACTION 14 - 0.846
 SPECIFIC GRAVITY FRACTION 15 - 0.853
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 41
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 055
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 072
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 105
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 20
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 40
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 055
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 070
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - TYLER
 FIELD NAME - BENS RUN
 PRODUCING FORMATION NAME - COW RUN, CONEMAUGH
 ERA - PALEOZOIC
 SYSTEM - PENNSYLVANIAN
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 00624
 SANDSTONE
 AGENCY SAMPLE NO - B33155
 SPECIFIC GRAVITY - 0.756
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.0
 VISCOSITY SUS AT 100 DEGREES F. - LESS THAN 32
 PERCENT OF CRUDE - 1.7
 VOLUME PERCENT FRACTION 1 - 6.3
 VOLUME PERCENT FRACTION 2 - 5.7
 VOLUME PERCENT FRACTION 3 - 6.6
 VOLUME PERCENT FRACTION 4 - 9.6
 VOLUME PERCENT FRACTION 5 - 8.3
 VOLUME PERCENT FRACTION 6 - 8.0
 VOLUME PERCENT FRACTION 7 - 8.1
 VOLUME PERCENT FRACTION 8 - 7.5
 VOLUME PERCENT FRACTION 9 - 7.9
 VOLUME PERCENT FRACTION 10 - 7.7
 VOLUME PERCENT FRACTION 11 - 5.3
 VOLUME PERCENT FRACTION 12 - 6.3
 VOLUME PERCENT FRACTION 13 - 3.7
 VOLUME PERCENT FRACTION 14 - 3.2
 VOLUME PERCENT FRACTION 15 - 2.3
 SPECIFIC GRAVITY FRACTION 2 - 0.649
 SPECIFIC GRAVITY FRACTION 3 - 0.685
 SPECIFIC GRAVITY FRACTION 4 - 0.714
 SPECIFIC GRAVITY FRACTION 5 - 0.732
 SPECIFIC GRAVITY FRACTION 6 - 0.748
 SPECIFIC GRAVITY FRACTION 7 - 0.764
 SPECIFIC GRAVITY FRACTION 8 - 0.777
 SPECIFIC GRAVITY FRACTION 9 - 0.788
 SPECIFIC GRAVITY FRACTION 10 - 0.801
 SPECIFIC GRAVITY FRACTION 11 - 0.821
 SPECIFIC GRAVITY FRACTION 12 - 0.827
 SPECIFIC GRAVITY FRACTION 13 - 0.837
 SPECIFIC GRAVITY FRACTION 14 - 0.845
 SPECIFIC GRAVITY FRACTION 15 - 0.859
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 056
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 077
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 135
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 40
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 055
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 070
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 085

RECORD 00003

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - KANAWHA
 FIELD NAME - BLUE CREEK
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00430
 SPECIFIC GRAVITY - 0.810
 SULFUR (WEIGHT PERCENT) - 0.11
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 PERCENT OF CRUDE - 15.9
 VOLUME PERCENT FRACTION 1 - 3.3
 VOLUME PERCENT FRACTION 2 - 3.7
 VOLUME PERCENT FRACTION 3 - 3.9
 VOLUME PERCENT FRACTION 4 - 8.2
 VOLUME PERCENT FRACTION 5 - 6.8
 VOLUME PERCENT FRACTION 6 - 6.5
 VOLUME PERCENT FRACTION 7 - 5.8
 VOLUME PERCENT FRACTION 8 - 5.6
 VOLUME PERCENT FRACTION 9 - 6.0
 VOLUME PERCENT FRACTION 10 - 6.4
 VOLUME PERCENT FRACTION 11 - 4.6
 VOLUME PERCENT FRACTION 12 - 4.6
 VOLUME PERCENT FRACTION 13 - 4.5
 VOLUME PERCENT FRACTION 14 - 4.6
 VOLUME PERCENT FRACTION 15 - 4.6
 SPECIFIC GRAVITY FRACTION 2 - 0.655
 SPECIFIC GRAVITY FRACTION 3 - 0.707
 SPECIFIC GRAVITY FRACTION 4 - 0.729
 SPECIFIC GRAVITY FRACTION 5 - 0.747
 SPECIFIC GRAVITY FRACTION 6 - 0.760
 SPECIFIC GRAVITY FRACTION 7 - 0.772
 SPECIFIC GRAVITY FRACTION 8 - 0.783
 SPECIFIC GRAVITY FRACTION 9 - 0.795
 SPECIFIC GRAVITY FRACTION 10 - 0.810
 SPECIFIC GRAVITY FRACTION 11 - 0.828
 SPECIFIC GRAVITY FRACTION 12 - 0.830
 SPECIFIC GRAVITY FRACTION 13 - 0.844
 SPECIFIC GRAVITY FRACTION 14 - 0.854
 SPECIFIC GRAVITY FRACTION 15 - 0.862
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 33
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 065
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 075
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 111
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 23
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 46
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 064
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 079
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 095

RECORD 00004

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - RITCHIE
 FIELD NAME - BONDS CREEK
 PRODUCING FORMATION NAME - GORDON, CATSKILL
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02582
 SANDSTONE
 AGENCY SAMPLE NO - B63274
 SPECIFIC GRAVITY - 0.715
 SULFUR (WEIGHT PERCENT) - 0.07
 NITROGEN (WEIGHT PERCENT) - 0.002
 POUR POINT (DEGREE F.) - LESS THAN 5
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.0
 VISCOSITY SUS AT 100 DEGREES F. - 032
 PERCENT OF CRUDE - 11.6
 VOLUME PERCENT FRACTION 1 - 14.7
 VOLUME PERCENT FRACTION 2 - 12.3
 VOLUME PERCENT FRACTION 3 - 13.8
 VOLUME PERCENT FRACTION 4 - 13.2
 VOLUME PERCENT FRACTION 5 - 7.9
 VOLUME PERCENT FRACTION 6 - 6.4
 VOLUME PERCENT FRACTION 7 - 4.3
 VOLUME PERCENT FRACTION 8 - 2.7
 VOLUME PERCENT FRACTION 9 - 2.4
 VOLUME PERCENT FRACTION 10 - 2.6
 SPECIFIC GRAVITY FRACTION 2 - 0.656
 SPECIFIC GRAVITY FRACTION 3 - 0.693
 SPECIFIC GRAVITY FRACTION 4 - 0.719
 SPECIFIC GRAVITY FRACTION 5 - 0.739
 SPECIFIC GRAVITY FRACTION 6 - 0.752
 SPECIFIC GRAVITY FRACTION 7 - 0.766
 SPECIFIC GRAVITY FRACTION 8 - 0.777
 SPECIFIC GRAVITY FRACTION 9 - 0.790
 SPECIFIC GRAVITY FRACTION 10 - 0.802

RECORD 00005

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - WETZEL
 FIELD NAME - BURTON
 PRODUCING FORMATION NAME - MAXTON MAUCH CHUNK
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 SERIES - CHESTER
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02027
 SANDSTONE
 AGENCY SAMPLE NO - B33151
 SPECIFIC GRAVITY - 0.812
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.1
 VISCOSITY SUS AT 100 DEGREES F. - 042
 PERCENT OF CRUDE - 21.9
 VOLUME PERCENT FRACTION 3 - 2.6
 VOLUME PERCENT FRACTION 4 - 4.3
 VOLUME PERCENT FRACTION 5 - 4.8
 VOLUME PERCENT FRACTION 6 - 5.3
 VOLUME PERCENT FRACTION 7 - 5.0
 VOLUME PERCENT FRACTION 8 - 5.5
 VOLUME PERCENT FRACTION 9 - 6.7
 VOLUME PERCENT FRACTION 10 - 7.6
 VOLUME PERCENT FRACTION 11 - 6.4
 VOLUME PERCENT FRACTION 12 - 7.5
 VOLUME PERCENT FRACTION 13 - 7.1
 VOLUME PERCENT FRACTION 14 - 6.5
 VOLUME PERCENT FRACTION 15 - 8.2
 SPECIFIC GRAVITY FRACTION 3 - 0.687
 SPECIFIC GRAVITY FRACTION 4 - 0.715
 SPECIFIC GRAVITY FRACTION 5 - 0.734
 SPECIFIC GRAVITY FRACTION 6 - 0.749
 SPECIFIC GRAVITY FRACTION 7 - 0.762
 SPECIFIC GRAVITY FRACTION 8 - 0.774
 SPECIFIC GRAVITY FRACTION 9 - 0.787
 SPECIFIC GRAVITY FRACTION 10 - 0.800
 SPECIFIC GRAVITY FRACTION 11 - 0.821
 SPECIFIC GRAVITY FRACTION 12 - 0.829
 SPECIFIC GRAVITY FRACTION 13 - 0.836
 SPECIFIC GRAVITY FRACTION 14 - 0.842
 SPECIFIC GRAVITY FRACTION 15 - 0.849
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 055
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 070
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 100
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 45
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 065
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 080
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 095

RECORD 00006

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - WETZEL
 FIELD NAME - BURTON
 PRODUCING FORMATION NAME - CATSKILL
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 03274
 SANDSTONE
 AGENCY SAMPLE NO - B33152
 SPECIFIC GRAVITY - 0.813
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.3
 VISCOSITY SUS AT 100 DEGREES F. - 042
 PERCENT OF CRUDE - 17.4
 VOLUME PERCENT FRACTION 3 - 4.1
 VOLUME PERCENT FRACTION 4 - 5.4
 VOLUME PERCENT FRACTION 5 - 6.9
 VOLUME PERCENT FRACTION 6 - 6.0
 VOLUME PERCENT FRACTION 7 - 5.7
 VOLUME PERCENT FRACTION 8 - 5.5
 VOLUME PERCENT FRACTION 9 - 6.1
 VOLUME PERCENT FRACTION 10 - 7.3
 VOLUME PERCENT FRACTION 11 - 9.3
 VOLUME PERCENT FRACTION 12 - 5.4
 VOLUME PERCENT FRACTION 13 - 6.7
 VOLUME PERCENT FRACTION 14 - 6.8
 VOLUME PERCENT FRACTION 15 - 7.0
 SPECIFIC GRAVITY FRACTION 3 - 0.680
 SPECIFIC GRAVITY FRACTION 4 - 0.718
 SPECIFIC GRAVITY FRACTION 5 - 0.742
 SPECIFIC GRAVITY FRACTION 6 - 0.758
 SPECIFIC GRAVITY FRACTION 7 - 0.770
 SPECIFIC GRAVITY FRACTION 8 - 0.780
 SPECIFIC GRAVITY FRACTION 9 - 0.791
 SPECIFIC GRAVITY FRACTION 10 - 0.804
 SPECIFIC GRAVITY FRACTION 11 - 0.828
 SPECIFIC GRAVITY FRACTION 12 - 0.837
 SPECIFIC GRAVITY FRACTION 13 - 0.844
 SPECIFIC GRAVITY FRACTION 14 - 0.854
 SPECIFIC GRAVITY FRACTION 15 - 0.864
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 42
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 50
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 065
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 099
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 170
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 45
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 065
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 085
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 095

RECORD 00007

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - KANAWHA
 FIELD NAME - CABIN CREEK
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00428
 SPECIFIC GRAVITY - 0.797
 SULFUR (WEIGHT PERCENT) - 0.19
 POUR POINT (DEGREE F.) - LESS THAN 5
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 PERCENT OF CRUDE - 14.4
 VOLUME PERCENT FRACTION 1 - 3.2
 VOLUME PERCENT FRACTION 2 - 3.2
 VOLUME PERCENT FRACTION 3 - 5.8
 VOLUME PERCENT FRACTION 4 - 6.7
 VOLUME PERCENT FRACTION 5 - 7.1
 VOLUME PERCENT FRACTION 6 - 7.6
 VOLUME PERCENT FRACTION 7 - 6.9
 VOLUME PERCENT FRACTION 8 - 6.3
 VOLUME PERCENT FRACTION 9 - 7.0
 VOLUME PERCENT FRACTION 10 - 7.7
 VOLUME PERCENT FRACTION 11 - 3.3
 VOLUME PERCENT FRACTION 12 - 4.7
 VOLUME PERCENT FRACTION 13 - 4.7
 VOLUME PERCENT FRACTION 14 - 4.2
 VOLUME PERCENT FRACTION 15 - 4.2
 SPECIFIC GRAVITY FRACTION 2 - 0.662
 SPECIFIC GRAVITY FRACTION 3 - 0.703
 SPECIFIC GRAVITY FRACTION 4 - 0.727
 SPECIFIC GRAVITY FRACTION 5 - 0.744
 SPECIFIC GRAVITY FRACTION 6 - 0.761
 SPECIFIC GRAVITY FRACTION 7 - 0.773
 SPECIFIC GRAVITY FRACTION 8 - 0.783
 SPECIFIC GRAVITY FRACTION 9 - 0.798
 SPECIFIC GRAVITY FRACTION 10 - 0.809
 SPECIFIC GRAVITY FRACTION 11 - 0.825
 SPECIFIC GRAVITY FRACTION 12 - 0.829
 SPECIFIC GRAVITY FRACTION 13 - 0.840
 SPECIFIC GRAVITY FRACTION 14 - 0.849
 SPECIFIC GRAVITY FRACTION 15 - 0.856
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 38
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 055
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 071
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 112
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 43
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 054
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 079
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 093

RECORD 00008

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - BOONE
 FIELD NAME - CABIN CREEK
 PRODUCING FORMATION NAME - BEREA
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02712
 SANDSTONE
 AGENCY SAMPLE NO - B23374
 SPECIFIC GRAVITY - 0.768
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 VISCOSITY SUS AT 100 DEGREES F. - 037
 PERCENT OF CRUDE - 14.9
 VOLUME PERCENT FRACTION 1 - 1.7
 VOLUME PERCENT FRACTION 2 - 3.9
 VOLUME PERCENT FRACTION 3 - 5.9
 VOLUME PERCENT FRACTION 4 - 9.2
 VOLUME PERCENT FRACTION 5 - 7.3
 VOLUME PERCENT FRACTION 6 - 6.1
 VOLUME PERCENT FRACTION 7 - 6.5
 VOLUME PERCENT FRACTION 8 - 6.2
 VOLUME PERCENT FRACTION 9 - 5.6
 VOLUME PERCENT FRACTION 10 - 5.5
 VOLUME PERCENT FRACTION 11 - 5.1
 VOLUME PERCENT FRACTION 12 - 4.6
 VOLUME PERCENT FRACTION 13 - 5.2
 VOLUME PERCENT FRACTION 14 - 4.0
 VOLUME PERCENT FRACTION 15 - 5.0
 SPECIFIC GRAVITY FRACTION 2 - 0.667
 SPECIFIC GRAVITY FRACTION 3 - 0.699
 SPECIFIC GRAVITY FRACTION 4 - 0.726
 SPECIFIC GRAVITY FRACTION 5 - 0.745
 SPECIFIC GRAVITY FRACTION 6 - 0.759
 SPECIFIC GRAVITY FRACTION 7 - 0.772
 SPECIFIC GRAVITY FRACTION 8 - 0.782
 SPECIFIC GRAVITY FRACTION 9 - 0.794
 SPECIFIC GRAVITY FRACTION 10 - 0.808
 SPECIFIC GRAVITY FRACTION 11 - 0.830
 SPECIFIC GRAVITY FRACTION 12 - 0.835
 SPECIFIC GRAVITY FRACTION 13 - 0.844
 SPECIFIC GRAVITY FRACTION 14 - 0.856
 SPECIFIC GRAVITY FRACTION 15 - 0.866
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 42
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 47
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 061
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 110
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 130
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 20
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 35
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 050
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 070
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 085

RECORD 00009

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - BOONE
 FIELD NAME - CABIN CREEK
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B26569
 SPECIFIC GRAVITY - 0.792
 SULFUR (WEIGHT PERCENT) - 0.10
 POUR POINT (DEGREE F.) - LESS THAN 5
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.3
 VISCOSITY SUS AT 100 DEGREES F. - 039
 PERCENT OF CRUDE - 15.9

VOLUME PERCENT FRACTION 2	-	4.9
VOLUME PERCENT FRACTION 3	-	6.5
VOLUME PERCENT FRACTION 4	-	7.4
VOLUME PERCENT FRACTION 5	-	7.6
VOLUME PERCENT FRACTION 6	-	6.9
VOLUME PERCENT FRACTION 7	-	6.2
VOLUME PERCENT FRACTION 8	-	6.2
VOLUME PERCENT FRACTION 9	-	5.9
VOLUME PERCENT FRACTION 10	-	6.5
VOLUME PERCENT FRACTION 11	-	4.6
VOLUME PERCENT FRACTION 12	-	5.8
VOLUME PERCENT FRACTION 13	-	5.1
VOLUME PERCENT FRACTION 14	-	3.5
VOLUME PERCENT FRACTION 15	-	5.1
SPECIFIC GRAVITY FRACTION 2	-	0.655
SPECIFIC GRAVITY FRACTION 3	-	0.695
SPECIFIC GRAVITY FRACTION 4	-	0.724
SPECIFIC GRAVITY FRACTION 5	-	0.747
SPECIFIC GRAVITY FRACTION 6	-	0.759
SPECIFIC GRAVITY FRACTION 7	-	0.772
SPECIFIC GRAVITY FRACTION 8	-	0.784
SPECIFIC GRAVITY FRACTION 9	-	0.795
SPECIFIC GRAVITY FRACTION 10	-	0.809
SPECIFIC GRAVITY FRACTION 11	-	0.833
SPECIFIC GRAVITY FRACTION 12	-	0.836
SPECIFIC GRAVITY FRACTION 13	-	0.849
SPECIFIC GRAVITY FRACTION 14	-	0.866
SPECIFIC GRAVITY FRACTION 15	-	0.879
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11	-	40
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12	-	46
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13	-	058
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14	-	081
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15	-	125
CLOUD POINT DEGREES F. FOR FRACTION 11	-	30
CLOUD POINT DEGREES F. FOR FRACTION 12	-	55
CLOUD POINT DEGREES F. FOR FRACTION 13	-	070
CLOUD POINT DEGREES F. FOR FRACTION 14	-	085
CLOUD POINT DEGREES F. FOR FRACTION 15	-	090

RECORD 00010

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - BOONE
 FIELD NAME - CABIN CREEK
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B27191
 SPECIFIC GRAVITY - 0.840
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.3
 VISCOSITY SUS AT 100 DEGREES F. - 071
 PERCENT OF CRUDE - 29.8
 VOLUME PERCENT FRACTION 7 - 2.1
 VOLUME PERCENT FRACTION 8 - 7.0
 VOLUME PERCENT FRACTION 9 - 9.3
 VOLUME PERCENT FRACTION 10 - 10.7
 VOLUME PERCENT FRACTION 11 - 8.3
 VOLUME PERCENT FRACTION 12 - 7.8
 VOLUME PERCENT FRACTION 13 - 9.5
 VOLUME PERCENT FRACTION 14 - 5.9
 VOLUME PERCENT FRACTION 15 - 7.6
 SPECIFIC GRAVITY FRACTION 7 - 0.778
 SPECIFIC GRAVITY FRACTION 8 - 0.780
 SPECIFIC GRAVITY FRACTION 9 - 0.794
 SPECIFIC GRAVITY FRACTION 10 - 0.807
 SPECIFIC GRAVITY FRACTION 11 - 0.834
 SPECIFIC GRAVITY FRACTION 12 - 0.836
 SPECIFIC GRAVITY FRACTION 13 - 0.848
 SPECIFIC GRAVITY FRACTION 14 - 0.856
 SPECIFIC GRAVITY FRACTION 15 - 0.863
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 42
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 46
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 057
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 077
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 115
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 10
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 045
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 060
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 075

RECORD 00011

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - BOONE
 FIELD NAME - CABIN CREEK
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B27192
 SPECIFIC GRAVITY - 0.831
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 VISCOSITY SUS AT 100 DEGREES F. - 050
 PERCENT OF CRUDE - 17.5
 VOLUME PERCENT FRACTION 3 - 1.9
 VOLUME PERCENT FRACTION 4 - 0.0
 VOLUME PERCENT FRACTION 5 - 0.0
 VOLUME PERCENT FRACTION 6 - 0.0
 VOLUME PERCENT FRACTION 7 - 3.4
 VOLUME PERCENT FRACTION 8 - 7.9
 VOLUME PERCENT FRACTION 9 - 10.9
 VOLUME PERCENT FRACTION 10 - 11.6
 VOLUME PERCENT FRACTION 11 - 12.3
 VOLUME PERCENT FRACTION 12 - 13.4
 VOLUME PERCENT FRACTION 13 - 6.3
 VOLUME PERCENT FRACTION 14 - 7.5
 VOLUME PERCENT FRACTION 15 - 5.4
 SPECIFIC GRAVITY FRACTION 8 - 0.781
 SPECIFIC GRAVITY FRACTION 9 - 0.792
 SPECIFIC GRAVITY FRACTION 10 - 0.806
 SPECIFIC GRAVITY FRACTION 11 - 0.830
 SPECIFIC GRAVITY FRACTION 12 - 0.838
 SPECIFIC GRAVITY FRACTION 13 - 0.857
 SPECIFIC GRAVITY FRACTION 14 - 0.864
 SPECIFIC GRAVITY FRACTION 15 - 0.872
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 41
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 48
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 068
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 100
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 170
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 10
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 30
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 050
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 050
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 050

RECORD 00012

CONTINENT - NORTH AMERICA
COUNTRY - U.S.A.
STATE - WEST VIRGINIA
COUNTY - BOONE
FIELD NAME - CABIN CREEK
GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
GEOLOGICAL BASIN CODE - 160
AGENCY SAMPLE NO - B27193
SPECIFIC GRAVITY - 0.795
VISCOSITY SUS AT 100 DEGREES F. - 034
PERCENT OF CRUDE - 8.0
VOLUME PERCENT FRACTION 3 - 5.3
VOLUME PERCENT FRACTION 4 - 0.0
VOLUME PERCENT FRACTION 5 - 0.0
VOLUME PERCENT FRACTION 6 - 2.8
VOLUME PERCENT FRACTION 7 - 12.7
VOLUME PERCENT FRACTION 8 - 25.7
VOLUME PERCENT FRACTION 9 - 25.5
VOLUME PERCENT FRACTION 10 - 18.2
SPECIFIC GRAVITY FRACTION 7 - 0.780
SPECIFIC GRAVITY FRACTION 8 - 0.784
SPECIFIC GRAVITY FRACTION 9 - 0.796
SPECIFIC GRAVITY FRACTION 10 - 0.808

RECORD 00013

CONTINENT - NORTH AMERICA
COUNTRY - U.S.A.
STATE - WEST VIRGINIA
COUNTY - BOONE
FIELD NAME - CABIN CREEK
GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
GEOLOGICAL BASIN CODE - 160
AGENCY SAMPLE NO - B27194
SPECIFIC GRAVITY - 0.825
VISCOSITY SUS AT 100 DEGREES F. - 045
PERCENT OF CRUDE - 2.0
VOLUME PERCENT FRACTION 9 - 5.5
VOLUME PERCENT FRACTION 10 - 20.2
VOLUME PERCENT FRACTION 11 - 22.5
VOLUME PERCENT FRACTION 12 - 28.8
VOLUME PERCENT FRACTION 13 - 14.1
VOLUME PERCENT FRACTION 14 - 6.7
SPECIFIC GRAVITY FRACTION 9 - 0.801
SPECIFIC GRAVITY FRACTION 10 - 0.811
SPECIFIC GRAVITY FRACTION 11 - 0.831
SPECIFIC GRAVITY FRACTION 12 - 0.832
SPECIFIC GRAVITY FRACTION 13 - 0.844
SPECIFIC GRAVITY FRACTION 14 - 0.859
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 057
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 075
CLOUD POINT DEGREES F. FOR FRACTION 11 - 10
CLOUD POINT DEGREES F. FOR FRACTION 12 - 30
CLOUD POINT DEGREES F. FOR FRACTION 13 - 045
CLOUD POINT DEGREES F. FOR FRACTION 14 - 050

RECORD 00014

CONTINENT - NORTH AMERICA
COUNTRY - U.S.A.
STATE - WEST VIRGINIA
COUNTY - BOONE
FIELD NAME - CABIN CREEK
GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
GEOLOGICAL BASIN CODE - 160
AGENCY SAMPLE NO - B27195
SPECIFIC GRAVITY - 0.875
CARBON RESIDUE (PERCENT OF CRUDE) - 0.7
VISCOSITY SUS AT 100 DEGREES F. - 340
PERCENT OF CRUDE - 55.1
VOLUME PERCENT FRACTION 13 - 9.2
VOLUME PERCENT FRACTION 14 - 16.2
VOLUME PERCENT FRACTION 15 - 19.3
SPECIFIC GRAVITY FRACTION 13 - 0.853
SPECIFIC GRAVITY FRACTION 14 - 0.860
SPECIFIC GRAVITY FRACTION 15 - 0.868
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 061
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 081
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 125
CLOUD POINT DEGREES F. FOR FRACTION 13 - 040
CLOUD POINT DEGREES F. FOR FRACTION 14 - 045
CLOUD POINT DEGREES F. FOR FRACTION 15 - 045

RECORD 00015

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - BOONE
 FIELD NAME - CABIN CREEK
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B27684
 SPECIFIC GRAVITY - 0.826
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 VISCOSITY SUS AT 100 DEGREES F. - 048
 PERCENT OF CRUDE - 24.4
 VOLUME PERCENT FRACTION 5 - 1.7
 VOLUME PERCENT FRACTION 6 - 7.7
 VOLUME PERCENT FRACTION 7 - 8.7
 VOLUME PERCENT FRACTION 8 - 8.5
 VOLUME PERCENT FRACTION 9 - 7.9
 VOLUME PERCENT FRACTION 10 - 9.0
 VOLUME PERCENT FRACTION 11 - 5.2
 VOLUME PERCENT FRACTION 12 - 7.9
 VOLUME PERCENT FRACTION 13 - 6.8
 VOLUME PERCENT FRACTION 14 - 5.8
 VOLUME PERCENT FRACTION 15 - 6.3
 SPECIFIC GRAVITY FRACTION 5 - 0.755
 SPECIFIC GRAVITY FRACTION 6 - 0.760
 SPECIFIC GRAVITY FRACTION 7 - 0.770
 SPECIFIC GRAVITY FRACTION 8 - 0.781
 SPECIFIC GRAVITY FRACTION 9 - 0.793
 SPECIFIC GRAVITY FRACTION 10 - 0.807
 SPECIFIC GRAVITY FRACTION 11 - 0.830
 SPECIFIC GRAVITY FRACTION 12 - 0.831
 SPECIFIC GRAVITY FRACTION 13 - 0.845
 SPECIFIC GRAVITY FRACTION 14 - 0.855
 SPECIFIC GRAVITY FRACTION 15 - 0.868
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 056
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 075
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 120
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 15
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 30
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 050
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 065
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 080

RECORD 00016

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - BOONE
 FIELD NAME - CABIN CREEK
 PRODUCING FORMATION NAME - BEREA
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 03280

SANDSTONE

AGENCY SAMPLE NO - B44128
 SPECIFIC GRAVITY - 0.808
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 VISCOSITY SUS AT 100 DEGREES F. - 040
 PERCENT OF CRUDE - 17.9

VOLUME PERCENT FRACTION 2	-	0.9
VOLUME PERCENT FRACTION 3	-	3.8
VOLUME PERCENT FRACTION 4	-	7.8
VOLUME PERCENT FRACTION 5	-	7.5
VOLUME PERCENT FRACTION 6	-	7.8
VOLUME PERCENT FRACTION 7	-	6.9
VOLUME PERCENT FRACTION 8	-	6.8
VOLUME PERCENT FRACTION 9	-	6.6
VOLUME PERCENT FRACTION 10	-	7.8
VOLUME PERCENT FRACTION 11	-	4.7
VOLUME PERCENT FRACTION 12	-	6.2
VOLUME PERCENT FRACTION 13	-	5.2
VOLUME PERCENT FRACTION 14	-	4.9
VOLUME PERCENT FRACTION 15	-	5.0

SPECIFIC GRAVITY FRACTION 3	-	0.696
SPECIFIC GRAVITY FRACTION 4	-	0.727
SPECIFIC GRAVITY FRACTION 5	-	0.745
SPECIFIC GRAVITY FRACTION 6	-	0.761
SPECIFIC GRAVITY FRACTION 7	-	0.773
SPECIFIC GRAVITY FRACTION 8	-	0.783
SPECIFIC GRAVITY FRACTION 9	-	0.795
SPECIFIC GRAVITY FRACTION 10	-	0.809
SPECIFIC GRAVITY FRACTION 11	-	0.826
SPECIFIC GRAVITY FRACTION 12	-	0.836
SPECIFIC GRAVITY FRACTION 13	-	0.842
SPECIFIC GRAVITY FRACTION 14	-	0.851
SPECIFIC GRAVITY FRACTION 15	-	0.864

VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11	-	40
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12	-	45
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13	-	055
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14	-	080
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15	-	125

CLOUD POINT DEGREES F. FOR FRACTION 11	-	15
CLOUD POINT DEGREES F. FOR FRACTION 12	-	30
CLOUD POINT DEGREES F. FOR FRACTION 13	-	045
CLOUD POINT DEGREES F. FOR FRACTION 14	-	065
CLOUD POINT DEGREES F. FOR FRACTION 15	-	080

RECORD 00017

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - RITCHIE
 FIELD NAME - CAIRO
 PRODUCING FORMATION NAME - CONQUENESSING
 ERA - PALEOZOIC
 SYSTEM - PENNSYLVANIAN
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160

OTHER SALT

AGENCY SAMPLE NO - B33156

SPECIFIC GRAVITY - 0.801

SULFUR (WEIGHT PERCENT) - LESS THAN 0.10

CARBON RESIDUE (PERCENT OF CRUDE) - 0.3

VISCOSITY SUS AT 100 DEGREES F. - 037

PERCENT OF CRUDE - 20.2

VOLUME PERCENT FRACTION 2 - 4.2

VOLUME PERCENT FRACTION 3 - 5.3

VOLUME PERCENT FRACTION 4 - 7.9

VOLUME PERCENT FRACTION 5 - 6.9

VOLUME PERCENT FRACTION 6 - 6.3

VOLUME PERCENT FRACTION 7 - 5.6

VOLUME PERCENT FRACTION 8 - 5.1

VOLUME PERCENT FRACTION 9 - 5.5

VOLUME PERCENT FRACTION 10 - 6.5

VOLUME PERCENT FRACTION 11 - 4.7

VOLUME PERCENT FRACTION 12 - 5.8

VOLUME PERCENT FRACTION 13 - 5.3

VOLUME PERCENT FRACTION 14 - 4.5

VOLUME PERCENT FRACTION 15 - 5.4

SPECIFIC GRAVITY FRACTION 2 - 0.658

SPECIFIC GRAVITY FRACTION 3 - 0.691

SPECIFIC GRAVITY FRACTION 4 - 0.724

SPECIFIC GRAVITY FRACTION 5 - 0.744

SPECIFIC GRAVITY FRACTION 6 - 0.760

SPECIFIC GRAVITY FRACTION 7 - 0.772

SPECIFIC GRAVITY FRACTION 8 - 0.782

SPECIFIC GRAVITY FRACTION 9 - 0.794

SPECIFIC GRAVITY FRACTION 10 - 0.808

SPECIFIC GRAVITY FRACTION 11 - 0.830

SPECIFIC GRAVITY FRACTION 12 - 0.834

SPECIFIC GRAVITY FRACTION 13 - 0.843

SPECIFIC GRAVITY FRACTION 14 - 0.850

SPECIFIC GRAVITY FRACTION 15 - 0.858

VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40

VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45

VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 055

VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 072

VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 105

CLOUD POINT DEGREES F. FOR FRACTION 11 - 20

CLOUD POINT DEGREES F. FOR FRACTION 12 - 40

CLOUD POINT DEGREES F. FOR FRACTION 13 - 055

CLOUD POINT DEGREES F. FOR FRACTION 14 - 070

CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

RECORD 00018

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - MONONGALIA
 FIELD NAME - CLAY
 PRODUCING FORMATION NAME - BIG INJUN, POCONO
 ERA - PALEOZOIC
 SYSTEM - MISSISSIPPIAN
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02209
 SANDSTONE
 AGENCY SAMPLE NO - B26346
 SPECIFIC GRAVITY - 0.796
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 VISCOSITY SUS AT 100 DEGREES F. - 037
 PERCENT OF CRUDE - 14.3
 VOLUME PERCENT FRACTION 2 - 3.7
 VOLUME PERCENT FRACTION 3 - 4.7
 VOLUME PERCENT FRACTION 4 - 8.5
 VOLUME PERCENT FRACTION 5 - 8.1
 VOLUME PERCENT FRACTION 6 - 6.0
 VOLUME PERCENT FRACTION 7 - 6.2
 VOLUME PERCENT FRACTION 8 - 8.7
 VOLUME PERCENT FRACTION 9 - 6.5
 VOLUME PERCENT FRACTION 10 - 7.3
 VOLUME PERCENT FRACTION 11 - 4.2
 VOLUME PERCENT FRACTION 12 - 6.4
 VOLUME PERCENT FRACTION 13 - 5.4
 VOLUME PERCENT FRACTION 14 - 4.7
 VOLUME PERCENT FRACTION 15 - 5.2
 SPECIFIC GRAVITY FRACTION 2 - 0.666
 SPECIFIC GRAVITY FRACTION 3 - 0.694
 SPECIFIC GRAVITY FRACTION 4 - 0.723
 SPECIFIC GRAVITY FRACTION 5 - 0.743
 SPECIFIC GRAVITY FRACTION 6 - 0.756
 SPECIFIC GRAVITY FRACTION 7 - 0.767
 SPECIFIC GRAVITY FRACTION 8 - 0.779
 SPECIFIC GRAVITY FRACTION 9 - 0.791
 SPECIFIC GRAVITY FRACTION 10 - 0.805
 SPECIFIC GRAVITY FRACTION 11 - 0.827
 SPECIFIC GRAVITY FRACTION 12 - 0.831
 SPECIFIC GRAVITY FRACTION 13 - 0.846
 SPECIFIC GRAVITY FRACTION 14 - 0.855
 SPECIFIC GRAVITY FRACTION 15 - 0.864
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 44
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 054
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 071
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 105
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 30
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 50
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 065
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 080
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 095

RECORD 00019

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - LEWIS
 FIELD NAME - FINK
 PRODUCING FORMATION NAME - GANTZ
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02030
 SANDSTONE
 AGENCY SAMPLE NO - B64141
 SPECIFIC GRAVITY - 0.822
 SULFUR (WEIGHT PERCENT) - 0.07
 NITROGEN (WEIGHT PERCENT) - 0.008
 POUR POINT (DEGREE F.) - LESS THAN 5
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.6
 VISCOSITY SUS AT 100 DEGREES F. - 043
 PERCENT OF CRUDE - 36.2
 VOLUME PERCENT FRACTION 1 - 1.3
 VOLUME PERCENT FRACTION 2 - 3.3
 VOLUME PERCENT FRACTION 3 - 3.4
 VOLUME PERCENT FRACTION 4 - 4.5
 VOLUME PERCENT FRACTION 5 - 4.4
 VOLUME PERCENT FRACTION 6 - 5.0
 VOLUME PERCENT FRACTION 7 - 4.5
 VOLUME PERCENT FRACTION 8 - 4.0
 VOLUME PERCENT FRACTION 9 - 4.0
 VOLUME PERCENT FRACTION 10 - 4.7
 VOLUME PERCENT FRACTION 11 - 3.5
 VOLUME PERCENT FRACTION 12 - 6.3
 VOLUME PERCENT FRACTION 13 - 5.7
 VOLUME PERCENT FRACTION 14 - 6.6
 SPECIFIC GRAVITY FRACTION 2 - 0.684
 SPECIFIC GRAVITY FRACTION 3 - 0.715
 SPECIFIC GRAVITY FRACTION 4 - 0.733
 SPECIFIC GRAVITY FRACTION 5 - 0.749
 SPECIFIC GRAVITY FRACTION 6 - 0.764
 SPECIFIC GRAVITY FRACTION 7 - 0.778
 SPECIFIC GRAVITY FRACTION 8 - 0.790
 SPECIFIC GRAVITY FRACTION 9 - 0.801
 SPECIFIC GRAVITY FRACTION 10 - 0.813
 SPECIFIC GRAVITY FRACTION 11 - 0.825
 SPECIFIC GRAVITY FRACTION 12 - 0.830
 SPECIFIC GRAVITY FRACTION 13 - 0.839
 SPECIFIC GRAVITY FRACTION 14 - 0.850
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 41
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 47
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 060
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 082
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 40
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 070
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 080

RECORD 00020

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - LEWIS
 FIELD NAME - FINK
 PRODUCING FORMATION NAME - GANTZ
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02235
 SANDSTONE
 AGENCY SAMPLE NO - B64142
 SPECIFIC GRAVITY - 0.829
 SULFUR (WEIGHT PERCENT) - 0.07
 NITROGEN (WEIGHT PERCENT) - 0.009
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.8
 VISCOSITY SUS AT 100 DEGREES F. - 049
 PERCENT OF CRUDE - 28.4
 VOLUME PERCENT FRACTION 2 - 1.3
 VOLUME PERCENT FRACTION 3 - 2.3
 VOLUME PERCENT FRACTION 4 - 4.1
 VOLUME PERCENT FRACTION 5 - 4.6
 VOLUME PERCENT FRACTION 6 - 4.7
 VOLUME PERCENT FRACTION 7 - 5.0
 VOLUME PERCENT FRACTION 8 - 5.8
 VOLUME PERCENT FRACTION 9 - 5.9
 VOLUME PERCENT FRACTION 10 - 5.2
 VOLUME PERCENT FRACTION 11 - 5.8
 VOLUME PERCENT FRACTION 12 - 6.8
 VOLUME PERCENT FRACTION 13 - 6.9
 VOLUME PERCENT FRACTION 14 - 5.3
 VOLUME PERCENT FRACTION 15 - 6.7
 SPECIFIC GRAVITY FRACTION 2 - 0.660
 SPECIFIC GRAVITY FRACTION 3 - 0.699
 SPECIFIC GRAVITY FRACTION 4 - 0.727
 SPECIFIC GRAVITY FRACTION 5 - 0.745
 SPECIFIC GRAVITY FRACTION 6 - 0.761
 SPECIFIC GRAVITY FRACTION 7 - 0.773
 SPECIFIC GRAVITY FRACTION 8 - 0.786
 SPECIFIC GRAVITY FRACTION 9 - 0.799
 SPECIFIC GRAVITY FRACTION 10 - 0.811
 SPECIFIC GRAVITY FRACTION 11 - 0.833
 SPECIFIC GRAVITY FRACTION 12 - 0.840
 SPECIFIC GRAVITY FRACTION 13 - 0.845
 SPECIFIC GRAVITY FRACTION 14 - 0.856
 SPECIFIC GRAVITY FRACTION 15 - 0.862
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 48
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 060
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 082
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 135
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 40
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 065
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 080
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 100

RECORD 00021

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - DODDRIDGE
 FIELD NAME - FLINT
 PRODUCING FORMATION NAME - GORDON, CATSKILL
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02581

SANDSTONE

AGENCY SAMPLE NO - B33158
 SPECIFIC GRAVITY - 0.817
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.3
 VISCOSITY SUS AT 100 DEGREES F. - 044
 PERCENT OF CRUDE - 23.8

VOLUME PERCENT FRACTION 3 -	5.2
VOLUME PERCENT FRACTION 4 -	2.5
VOLUME PERCENT FRACTION 5 -	3.9
VOLUME PERCENT FRACTION 6 -	4.9
VOLUME PERCENT FRACTION 7 -	6.4
VOLUME PERCENT FRACTION 8 -	6.3
VOLUME PERCENT FRACTION 9 -	6.6
VOLUME PERCENT FRACTION 10 -	8.4
VOLUME PERCENT FRACTION 11 -	4.9
VOLUME PERCENT FRACTION 12 -	6.9
VOLUME PERCENT FRACTION 13 -	7.1
VOLUME PERCENT FRACTION 14 -	6.0
VOLUME PERCENT FRACTION 15 -	5.9

SPECIFIC GRAVITY FRACTION 3 -	0.662
SPECIFIC GRAVITY FRACTION 4 -	0.706
SPECIFIC GRAVITY FRACTION 5 -	0.734
SPECIFIC GRAVITY FRACTION 6 -	0.755
SPECIFIC GRAVITY FRACTION 7 -	0.770
SPECIFIC GRAVITY FRACTION 8 -	0.782
SPECIFIC GRAVITY FRACTION 9 -	0.793
SPECIFIC GRAVITY FRACTION 10 -	0.805
SPECIFIC GRAVITY FRACTION 11 -	0.829
SPECIFIC GRAVITY FRACTION 12 -	0.834
SPECIFIC GRAVITY FRACTION 13 -	0.844
SPECIFIC GRAVITY FRACTION 14 -	0.853
SPECIFIC GRAVITY FRACTION 15 -	0.860

VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 -	41
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 -	46
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 -	058
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 -	085
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 -	140

CLOUD POINT DEGREES F. FOR FRACTION 11 -	20
CLOUD POINT DEGREES F. FOR FRACTION 12 -	40
CLOUD POINT DEGREES F. FOR FRACTION 13 -	055
CLOUD POINT DEGREES F. FOR FRACTION 14 -	075
CLOUD POINT DEGREES F. FOR FRACTION 15 -	090

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - LINCOLN
 FIELD NAME - FREEMAN
 PRODUCING FORMATION NAME - BEREA
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02237
 SANDSTONE
 AGENCY SAMPLE NO - B23376
 SPECIFIC GRAVITY - 0.836
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.6
 VISCOSITY SUS AT 100 DEGREES F. - 050
 PERCENT OF CRUDE - 27.9
 VOLUME PERCENT FRACTION 3 - 1.9
 VOLUME PERCENT FRACTION 4 - 4.0
 VOLUME PERCENT FRACTION 5 - 6.3
 VOLUME PERCENT FRACTION 6 - 6.7
 VOLUME PERCENT FRACTION 7 - 6.0
 VOLUME PERCENT FRACTION 8 - 6.0
 VOLUME PERCENT FRACTION 9 - 6.0
 VOLUME PERCENT FRACTION 10 - 6.0
 VOLUME PERCENT FRACTION 11 - 5.0
 VOLUME PERCENT FRACTION 12 - 5.7
 VOLUME PERCENT FRACTION 13 - 6.5
 VOLUME PERCENT FRACTION 14 - 6.0
 VOLUME PERCENT FRACTION 15 - 6.0
 SPECIFIC GRAVITY FRACTION 4 - 0.728
 SPECIFIC GRAVITY FRACTION 5 - 0.747
 SPECIFIC GRAVITY FRACTION 6 - 0.762
 SPECIFIC GRAVITY FRACTION 7 - 0.774
 SPECIFIC GRAVITY FRACTION 8 - 0.787
 SPECIFIC GRAVITY FRACTION 9 - 0.800
 SPECIFIC GRAVITY FRACTION 10 - 0.813
 SPECIFIC GRAVITY FRACTION 11 - 0.836
 SPECIFIC GRAVITY FRACTION 12 - 0.840
 SPECIFIC GRAVITY FRACTION 13 - 0.844
 SPECIFIC GRAVITY FRACTION 14 - 0.864
 SPECIFIC GRAVITY FRACTION 15 - 0.871
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 41
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 46
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 060
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 087
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 135
 CLOUD POINT DEGREES F. FOR FRACTION 11 - LESS THAN 5
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 30
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 045
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 065
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 085

RECORD 00023

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - HANCOCK
 FIELD NAME - HANCOCK COUNTY
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00422
 SPECIFIC GRAVITY - 0.783
 SULFUR (WEIGHT PERCENT) - 0.84
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 PERCENT OF CRUDE - 16.6
 VOLUME PERCENT FRACTION 1 - 6.0
 VOLUME PERCENT FRACTION 2 - 5.1
 VOLUME PERCENT FRACTION 3 - 7.0
 VOLUME PERCENT FRACTION 4 - 9.0
 VOLUME PERCENT FRACTION 5 - 7.0
 VOLUME PERCENT FRACTION 6 - 6.2
 VOLUME PERCENT FRACTION 7 - 5.7
 VOLUME PERCENT FRACTION 8 - 5.6
 VOLUME PERCENT FRACTION 9 - 5.3
 VOLUME PERCENT FRACTION 10 - 5.6
 VOLUME PERCENT FRACTION 11 - 4.1
 VOLUME PERCENT FRACTION 12 - 4.3
 VOLUME PERCENT FRACTION 13 - 4.4
 VOLUME PERCENT FRACTION 14 - 3.9
 VOLUME PERCENT FRACTION 15 - 4.3
 SPECIFIC GRAVITY FRACTION 2 - 0.664
 SPECIFIC GRAVITY FRACTION 3 - 0.703
 SPECIFIC GRAVITY FRACTION 4 - 0.728
 SPECIFIC GRAVITY FRACTION 5 - 0.746
 SPECIFIC GRAVITY FRACTION 6 - 0.760
 SPECIFIC GRAVITY FRACTION 7 - 0.772
 SPECIFIC GRAVITY FRACTION 8 - 0.783
 SPECIFIC GRAVITY FRACTION 9 - 0.794
 SPECIFIC GRAVITY FRACTION 10 - 0.806
 SPECIFIC GRAVITY FRACTION 11 - 0.835
 SPECIFIC GRAVITY FRACTION 12 - 0.842
 SPECIFIC GRAVITY FRACTION 13 - 0.846
 SPECIFIC GRAVITY FRACTION 14 - 0.850
 SPECIFIC GRAVITY FRACTION 15 - 0.858
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 43
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 060
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 075
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 107
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 18
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 37
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 063
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 073
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

RECORD 00024

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - HARRISON
 FIELD NAME - HARRISON COUNTY
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00418
 SPECIFIC GRAVITY - 0.808
 SULFUR (WEIGHT PERCENT) - 0.20
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.5
 PERCENT OF CRUDE - 23.9
 VOLUME PERCENT FRACTION 1 - 1.2
 VOLUME PERCENT FRACTION 2 - 2.1
 VOLUME PERCENT FRACTION 3 - 3.3
 VOLUME PERCENT FRACTION 4 - 5.7
 VOLUME PERCENT FRACTION 5 - 5.0
 VOLUME PERCENT FRACTION 6 - 6.2
 VOLUME PERCENT FRACTION 7 - 6.0
 VOLUME PERCENT FRACTION 8 - 5.2
 VOLUME PERCENT FRACTION 9 - 6.3
 VOLUME PERCENT FRACTION 10 - 7.4
 VOLUME PERCENT FRACTION 11 - 4.2
 VOLUME PERCENT FRACTION 12 - 4.8
 VOLUME PERCENT FRACTION 13 - 5.5
 VOLUME PERCENT FRACTION 14 - 6.0
 VOLUME PERCENT FRACTION 15 - 7.2
 SPECIFIC GRAVITY FRACTION 2 - 0.668
 SPECIFIC GRAVITY FRACTION 3 - 0.720
 SPECIFIC GRAVITY FRACTION 4 - 0.732
 SPECIFIC GRAVITY FRACTION 5 - 0.750
 SPECIFIC GRAVITY FRACTION 6 - 0.762
 SPECIFIC GRAVITY FRACTION 7 - 0.770
 SPECIFIC GRAVITY FRACTION 8 - 0.782
 SPECIFIC GRAVITY FRACTION 9 - 0.795
 SPECIFIC GRAVITY FRACTION 10 - 0.805
 SPECIFIC GRAVITY FRACTION 11 - 0.820
 SPECIFIC GRAVITY FRACTION 12 - 0.825
 SPECIFIC GRAVITY FRACTION 13 - 0.830
 SPECIFIC GRAVITY FRACTION 14 - 0.849
 SPECIFIC GRAVITY FRACTION 15 - 0.859
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 056
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 076
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 108
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 43
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 061
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 075
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

RECORD 00025

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - HARRISON
 FIELD NAME - HARRISON COUNTY
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00419
 SPECIFIC GRAVITY - 0.800
 SULFUR (WEIGHT PERCENT) - 0.27
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.5
 PERCENT OF CRUDE - 20.3
 VOLUME PERCENT FRACTION 1 - 0.7
 VOLUME PERCENT FRACTION 2 - 2.2
 VOLUME PERCENT FRACTION 3 - 4.7
 VOLUME PERCENT FRACTION 4 - 6.8
 VOLUME PERCENT FRACTION 5 - 5.8
 VOLUME PERCENT FRACTION 6 - 6.8
 VOLUME PERCENT FRACTION 7 - 6.4
 VOLUME PERCENT FRACTION 8 - 5.7
 VOLUME PERCENT FRACTION 9 - 6.5
 VOLUME PERCENT FRACTION 10 - 8.2
 VOLUME PERCENT FRACTION 11 - 3.4
 VOLUME PERCENT FRACTION 12 - 6.4
 VOLUME PERCENT FRACTION 13 - 6.1
 VOLUME PERCENT FRACTION 14 - 6.0
 VOLUME PERCENT FRACTION 15 - 4.0
 SPECIFIC GRAVITY FRACTION 3 - 0.690
 SPECIFIC GRAVITY FRACTION 4 - 0.725
 SPECIFIC GRAVITY FRACTION 5 - 0.742
 SPECIFIC GRAVITY FRACTION 6 - 0.757
 SPECIFIC GRAVITY FRACTION 7 - 0.770
 SPECIFIC GRAVITY FRACTION 8 - 0.782
 SPECIFIC GRAVITY FRACTION 9 - 0.795
 SPECIFIC GRAVITY FRACTION 10 - 0.805
 SPECIFIC GRAVITY FRACTION 11 - 0.820
 SPECIFIC GRAVITY FRACTION 12 - 0.825
 SPECIFIC GRAVITY FRACTION 13 - 0.828
 SPECIFIC GRAVITY FRACTION 14 - 0.859
 SPECIFIC GRAVITY FRACTION 15 - 0.864
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 058
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 079
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 114
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 23
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 41
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 059
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 075
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - KANAWHA
 FIELD NAME - KELLY CREEK
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00429
 SPECIFIC GRAVITY - 0.799
 SULFUR (WEIGHT PERCENT) - 0.11
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 PERCENT OF CRUDE - 14.8
 VOLUME PERCENT FRACTION 1 - 2.7
 VOLUME PERCENT FRACTION 2 - 3.1
 VOLUME PERCENT FRACTION 3 - 6.7
 VOLUME PERCENT FRACTION 4 - 8.4
 VOLUME PERCENT FRACTION 5 - 6.3
 VOLUME PERCENT FRACTION 6 - 6.7
 VOLUME PERCENT FRACTION 7 - 5.7
 VOLUME PERCENT FRACTION 8 - 5.7
 VOLUME PERCENT FRACTION 9 - 6.3
 VOLUME PERCENT FRACTION 10 - 6.4
 VOLUME PERCENT FRACTION 11 - 5.0
 VOLUME PERCENT FRACTION 12 - 4.9
 VOLUME PERCENT FRACTION 13 - 4.9
 VOLUME PERCENT FRACTION 14 - 4.9
 VOLUME PERCENT FRACTION 15 - 4.5
 SPECIFIC GRAVITY FRACTION 2 - 0.670
 SPECIFIC GRAVITY FRACTION 3 - 0.700
 SPECIFIC GRAVITY FRACTION 4 - 0.730
 SPECIFIC GRAVITY FRACTION 5 - 0.748
 SPECIFIC GRAVITY FRACTION 6 - 0.762
 SPECIFIC GRAVITY FRACTION 7 - 0.775
 SPECIFIC GRAVITY FRACTION 8 - 0.785
 SPECIFIC GRAVITY FRACTION 9 - 0.796
 SPECIFIC GRAVITY FRACTION 10 - 0.811
 SPECIFIC GRAVITY FRACTION 11 - 0.826
 SPECIFIC GRAVITY FRACTION 12 - 0.833
 SPECIFIC GRAVITY FRACTION 13 - 0.841
 SPECIFIC GRAVITY FRACTION 14 - 0.852
 SPECIFIC GRAVITY FRACTION 15 - 0.859
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 35
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 057
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 075
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 122
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 21
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 46
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 059
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 077
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 091

RECORD 00027

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - KANAWHA
 FIELD NAME - KELLY CREEK
 PRODUCING FORMATION NAME - WEIR, CUYAHOGA
 ERA - PALEOZOIC
 SYSTEM - MISSISSIPPIAN
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 01755

SANDSTONE

AGENCY SAMPLE NO - B23375
 SPECIFIC GRAVITY - 0.772
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.1
 VISCOSITY SUS AT 100 DEGREES F. - 036

PERCENT OF CRUDE - 16.4

VOLUME PERCENT FRACTION 1	-	1.4
VOLUME PERCENT FRACTION 2	-	3.6
VOLUME PERCENT FRACTION 3	-	6.3
VOLUME PERCENT FRACTION 4	-	9.4
VOLUME PERCENT FRACTION 5	-	7.6
VOLUME PERCENT FRACTION 6	-	6.2
VOLUME PERCENT FRACTION 7	-	5.1
VOLUME PERCENT FRACTION 8	-	5.3
VOLUME PERCENT FRACTION 9	-	5.9
VOLUME PERCENT FRACTION 10	-	6.4
VOLUME PERCENT FRACTION 11	-	3.6
VOLUME PERCENT FRACTION 12	-	6.3
VOLUME PERCENT FRACTION 13	-	4.3
VOLUME PERCENT FRACTION 14	-	3.9
VOLUME PERCENT FRACTION 15	-	5.4

SPECIFIC GRAVITY FRACTION 2	-	0.675
SPECIFIC GRAVITY FRACTION 3	-	0.698
SPECIFIC GRAVITY FRACTION 4	-	0.727
SPECIFIC GRAVITY FRACTION 5	-	0.744
SPECIFIC GRAVITY FRACTION 6	-	0.759
SPECIFIC GRAVITY FRACTION 7	-	0.772
SPECIFIC GRAVITY FRACTION 8	-	0.783
SPECIFIC GRAVITY FRACTION 9	-	0.795
SPECIFIC GRAVITY FRACTION 10	-	0.809
SPECIFIC GRAVITY FRACTION 11	-	0.831
SPECIFIC GRAVITY FRACTION 12	-	0.835
SPECIFIC GRAVITY FRACTION 13	-	0.845
SPECIFIC GRAVITY FRACTION 14	-	0.854
SPECIFIC GRAVITY FRACTION 15	-	0.863

VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11	-	41
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12	-	46
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13	-	059
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14	-	077
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15	-	110

CLOUD POINT DEGREES F. FOR FRACTION 11	-	20
CLOUD POINT DEGREES F. FOR FRACTION 12	-	35
CLOUD POINT DEGREES F. FOR FRACTION 13	-	060
CLOUD POINT DEGREES F. FOR FRACTION 14	-	070
CLOUD POINT DEGREES F. FOR FRACTION 15	-	090

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - RITCHIE
 FIELD NAME - LOST RUN
 PRODUCING FORMATION NAME - BIG INJUN, POCONO
 ERA - PALEOZOIC
 SYSTEM - MISSISSIPPIAN
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 01945
 SANDSTONE
 AGENCY SAMPLE NO - B33157
 SPECIFIC GRAVITY - 0.781
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 POUR POINT (DEGREE F.) - LESS THAN 5
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 VISCOSITY SUS AT 100 DEGREES F. - 034
 PERCENT OF CRUDE - 14.7
 VOLUME PERCENT FRACTION 1 - 4.6
 VOLUME PERCENT FRACTION 2 - 4.5
 VOLUME PERCENT FRACTION 3 - 7.0
 VOLUME PERCENT FRACTION 4 - 9.1
 VOLUME PERCENT FRACTION 5 - 7.5
 VOLUME PERCENT FRACTION 6 - 7.0
 VOLUME PERCENT FRACTION 7 - 5.5
 VOLUME PERCENT FRACTION 8 - 5.3
 VOLUME PERCENT FRACTION 9 - 5.6
 VOLUME PERCENT FRACTION 10 - 6.8
 VOLUME PERCENT FRACTION 11 - 3.6
 VOLUME PERCENT FRACTION 12 - 5.1
 VOLUME PERCENT FRACTION 13 - 4.5
 VOLUME PERCENT FRACTION 14 - 3.9
 VOLUME PERCENT FRACTION 15 - 4.4
 SPECIFIC GRAVITY FRACTION 2 - 0.656
 SPECIFIC GRAVITY FRACTION 3 - 0.692
 SPECIFIC GRAVITY FRACTION 4 - 0.724
 SPECIFIC GRAVITY FRACTION 5 - 0.743
 SPECIFIC GRAVITY FRACTION 6 - 0.758
 SPECIFIC GRAVITY FRACTION 7 - 0.770
 SPECIFIC GRAVITY FRACTION 8 - 0.780
 SPECIFIC GRAVITY FRACTION 9 - 0.791
 SPECIFIC GRAVITY FRACTION 10 - 0.803
 SPECIFIC GRAVITY FRACTION 11 - 0.826
 SPECIFIC GRAVITY FRACTION 12 - 0.832
 SPECIFIC GRAVITY FRACTION 13 - 0.839
 SPECIFIC GRAVITY FRACTION 14 - 0.845
 SPECIFIC GRAVITY FRACTION 15 - 0.853
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 41
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 46
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 055
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 074
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 110
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 20
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 40
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 055
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 070
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - MARION
 FIELD NAME - MANNINGTON
 PRODUCING FORMATION NAME - BIG INJUN, POCONO
 ERA - PALEOZOIC
 SYSTEM - MISSISSIPPIAN
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 01850
 SANDSTONE
 AGENCY SAMPLE NO - B33149
 SPECIFIC GRAVITY - 0.806
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.3
 VISCOSITY SUS AT 100 DEGREES F. - 040
 PERCENT OF CRUDE - 16.6
 VOLUME PERCENT FRACTION 2 - 2.1
 VOLUME PERCENT FRACTION 3 - 3.2
 VOLUME PERCENT FRACTION 4 - 6.1
 VOLUME PERCENT FRACTION 5 - 7.1
 VOLUME PERCENT FRACTION 6 - 6.9
 VOLUME PERCENT FRACTION 7 - 6.7
 VOLUME PERCENT FRACTION 8 - 6.3
 VOLUME PERCENT FRACTION 9 - 6.5
 VOLUME PERCENT FRACTION 10 - 7.9
 VOLUME PERCENT FRACTION 11 - 5.1
 VOLUME PERCENT FRACTION 12 - 7.0
 VOLUME PERCENT FRACTION 13 - 6.5
 VOLUME PERCENT FRACTION 14 - 5.5
 VOLUME PERCENT FRACTION 15 - 6.3
 SPECIFIC GRAVITY FRACTION 2 - 0.683
 SPECIFIC GRAVITY FRACTION 3 - 0.683
 SPECIFIC GRAVITY FRACTION 4 - 0.719
 SPECIFIC GRAVITY FRACTION 5 - 0.739
 SPECIFIC GRAVITY FRACTION 6 - 0.755
 SPECIFIC GRAVITY FRACTION 7 - 0.768
 SPECIFIC GRAVITY FRACTION 8 - 0.778
 SPECIFIC GRAVITY FRACTION 9 - 0.790
 SPECIFIC GRAVITY FRACTION 10 - 0.804
 SPECIFIC GRAVITY FRACTION 11 - 0.824
 SPECIFIC GRAVITY FRACTION 12 - 0.829
 SPECIFIC GRAVITY FRACTION 13 - 0.839
 SPECIFIC GRAVITY FRACTION 14 - 0.849
 SPECIFIC GRAVITY FRACTION 15 - 0.859
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 41
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 46
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 058
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 087
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 140
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 45
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 065
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 080
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 095

RECORD 00030

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - MARION
 FIELD NAME - MANNINGTON
 PRODUCING FORMATION NAME - GORDON, CATSKILL
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02590
 SANDSTONE
 AGENCY SAMPLE NO - B33150
 SPECIFIC GRAVITY - 0.814
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.5
 VISCOSITY SUS AT 100 DEGREES F. - 046
 PERCENT OF CRUDE - 26.2
 VOLUME PERCENT FRACTION 2 - 1.7
 VOLUME PERCENT FRACTION 3 - 2.8
 VOLUME PERCENT FRACTION 4 - 4.8
 VOLUME PERCENT FRACTION 5 - 4.9
 VOLUME PERCENT FRACTION 6 - 5.5
 VOLUME PERCENT FRACTION 7 - 4.9
 VOLUME PERCENT FRACTION 8 - 5.3
 VOLUME PERCENT FRACTION 9 - 5.6
 VOLUME PERCENT FRACTION 10 - 6.7
 VOLUME PERCENT FRACTION 11 - 4.7
 VOLUME PERCENT FRACTION 12 - 6.6
 VOLUME PERCENT FRACTION 13 - 8.1
 VOLUME PERCENT FRACTION 14 - 4.3
 VOLUME PERCENT FRACTION 15 - 6.7
 SPECIFIC GRAVITY FRACTION 2 - 0.674
 SPECIFIC GRAVITY FRACTION 3 - 0.674
 SPECIFIC GRAVITY FRACTION 4 - 0.713
 SPECIFIC GRAVITY FRACTION 5 - 0.735
 SPECIFIC GRAVITY FRACTION 6 - 0.752
 SPECIFIC GRAVITY FRACTION 7 - 0.766
 SPECIFIC GRAVITY FRACTION 8 - 0.777
 SPECIFIC GRAVITY FRACTION 9 - 0.790
 SPECIFIC GRAVITY FRACTION 10 - 0.802
 SPECIFIC GRAVITY FRACTION 11 - 0.823
 SPECIFIC GRAVITY FRACTION 12 - 0.830
 SPECIFIC GRAVITY FRACTION 13 - 0.839
 SPECIFIC GRAVITY FRACTION 14 - 0.848
 SPECIFIC GRAVITY FRACTION 15 - 0.855
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 056
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 080
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 115
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 45
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 060
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 075
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

RECORD 00031

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - WOOD
 FIELD NAME - NOT KNOWN
 PRODUCING FORMATION NAME - COW RUN, CONEMAUGH
 ERA - PALEOZOIC
 SYSTEM - PENNSYLVANIAN
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 00910
 SANDSTONE
 AGENCY SAMPLE NO - B23325
 SPECIFIC GRAVITY - 0.795
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.4
 VISCOSITY SUS AT 100 DEGREES F. - 037
 PERCENT OF CRUDE - 18.1
 VOLUME PERCENT FRACTION 1 - 4.0
 VOLUME PERCENT FRACTION 2 - 3.4
 VOLUME PERCENT FRACTION 3 - 5.1
 VOLUME PERCENT FRACTION 4 - 7.5
 VOLUME PERCENT FRACTION 5 - 7.2
 VOLUME PERCENT FRACTION 6 - 5.6
 VOLUME PERCENT FRACTION 7 - 5.3
 VOLUME PERCENT FRACTION 8 - 6.0
 VOLUME PERCENT FRACTION 9 - 7.4
 VOLUME PERCENT FRACTION 10 - 4.3
 VOLUME PERCENT FRACTION 11 - 6.1
 VOLUME PERCENT FRACTION 12 - 4.3
 VOLUME PERCENT FRACTION 13 - 4.9
 VOLUME PERCENT FRACTION 14 - 5.0
 VOLUME PERCENT FRACTION 15 - 5.6
 SPECIFIC GRAVITY FRACTION 2 - 0.657
 SPECIFIC GRAVITY FRACTION 3 - 0.692
 SPECIFIC GRAVITY FRACTION 4 - 0.722
 SPECIFIC GRAVITY FRACTION 5 - 0.742
 SPECIFIC GRAVITY FRACTION 6 - 0.758
 SPECIFIC GRAVITY FRACTION 7 - 0.769
 SPECIFIC GRAVITY FRACTION 8 - 0.780
 SPECIFIC GRAVITY FRACTION 9 - 0.793
 SPECIFIC GRAVITY FRACTION 10 - 0.808
 SPECIFIC GRAVITY FRACTION 11 - 0.833
 SPECIFIC GRAVITY FRACTION 12 - 0.836
 SPECIFIC GRAVITY FRACTION 13 - 0.846
 SPECIFIC GRAVITY FRACTION 14 - 0.859
 SPECIFIC GRAVITY FRACTION 15 - 0.866
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 42
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 058
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 080
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 120
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 20
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 40
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 060
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 080
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

RECORD 00032

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - WOOD
 FIELD NAME - NOT KNOWN
 PRODUCING FORMATION NAME - COW RUN, CONEMAUGH
 ERA - PALEOZOIC
 SYSTEM - PENNSYLVANIAN
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 01040
 SANDSTONE
 AGENCY SAMPLE NO - B23326
 SPECIFIC GRAVITY - 0.799
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.6
 VISCOSITY SUS AT 100 DEGREES F. - 039
 PERCENT OF CRUDE - 17.1

VOLUME PERCENT FRACTION 2 -	5.2
VOLUME PERCENT FRACTION 3 -	4.0
VOLUME PERCENT FRACTION 4 -	7.4
VOLUME PERCENT FRACTION 5 -	6.2
VOLUME PERCENT FRACTION 6 -	5.5
VOLUME PERCENT FRACTION 7 -	6.0
VOLUME PERCENT FRACTION 8 -	6.1
VOLUME PERCENT FRACTION 9 -	6.2
VOLUME PERCENT FRACTION 10 -	6.7
VOLUME PERCENT FRACTION 11 -	6.3
VOLUME PERCENT FRACTION 12 -	6.7
VOLUME PERCENT FRACTION 13 -	5.7
VOLUME PERCENT FRACTION 14 -	3.5
VOLUME PERCENT FRACTION 15 -	5.5
SPECIFIC GRAVITY FRACTION 2 -	0.667
SPECIFIC GRAVITY FRACTION 3 -	0.684
SPECIFIC GRAVITY FRACTION 4 -	0.710
SPECIFIC GRAVITY FRACTION 5 -	0.734
SPECIFIC GRAVITY FRACTION 6 -	0.751
SPECIFIC GRAVITY FRACTION 7 -	0.769
SPECIFIC GRAVITY FRACTION 8 -	0.779
SPECIFIC GRAVITY FRACTION 9 -	0.792
SPECIFIC GRAVITY FRACTION 10 -	0.806
SPECIFIC GRAVITY FRACTION 11 -	0.836
SPECIFIC GRAVITY FRACTION 12 -	0.839
SPECIFIC GRAVITY FRACTION 13 -	0.857
SPECIFIC GRAVITY FRACTION 14 -	0.861
SPECIFIC GRAVITY FRACTION 15 -	0.871
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 -	42
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 -	48
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 -	064
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 -	093
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 -	135
CLOUD POINT DEGREES F. FOR FRACTION 11 -	25
CLOUD POINT DEGREES F. FOR FRACTION 12 -	40
CLOUD POINT DEGREES F. FOR FRACTION 13 -	065
CLOUD POINT DEGREES F. FOR FRACTION 14 -	080
CLOUD POINT DEGREES F. FOR FRACTION 15 -	090

RECORD 00033

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - MARSHALL
 FIELD NAME - NOT KNOWN
 PRODUCING FORMATION NAME - BIG INJUN, POCONO
 ERA - PALEOZOIC
 SYSTEM - MISSISSIPPIAN
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 01778

SANDSTONE

AGENCY SAMPLE NO - B23388
 SPECIFIC GRAVITY - 0.768
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.0
 VISCOSITY SUS AT 100 DEGREES F. - 033
 PERCENT OF CRUDE - 11.2

VOLUME PERCENT FRACTION 1	-	4.4
VOLUME PERCENT FRACTION 2	-	5.1
VOLUME PERCENT FRACTION 3	-	6.4
VOLUME PERCENT FRACTION 4	-	9.9
VOLUME PERCENT FRACTION 5	-	8.1
VOLUME PERCENT FRACTION 6	-	8.6
VOLUME PERCENT FRACTION 7	-	4.9
VOLUME PERCENT FRACTION 8	-	4.8
VOLUME PERCENT FRACTION 9	-	5.8
VOLUME PERCENT FRACTION 10	-	5.5
VOLUME PERCENT FRACTION 11	-	4.8
VOLUME PERCENT FRACTION 12	-	4.3
VOLUME PERCENT FRACTION 13	-	4.3
VOLUME PERCENT FRACTION 14	-	4.0
VOLUME PERCENT FRACTION 15	-	4.5

SPECIFIC GRAVITY FRACTION 2	-	0.667
SPECIFIC GRAVITY FRACTION 3	-	0.690
SPECIFIC GRAVITY FRACTION 4	-	0.719
SPECIFIC GRAVITY FRACTION 5	-	0.738
SPECIFIC GRAVITY FRACTION 6	-	0.754
SPECIFIC GRAVITY FRACTION 7	-	0.769
SPECIFIC GRAVITY FRACTION 8	-	0.779
SPECIFIC GRAVITY FRACTION 9	-	0.788
SPECIFIC GRAVITY FRACTION 10	-	0.800
SPECIFIC GRAVITY FRACTION 11	-	0.827
SPECIFIC GRAVITY FRACTION 12	-	0.831
SPECIFIC GRAVITY FRACTION 13	-	0.842
SPECIFIC GRAVITY FRACTION 14	-	0.850
SPECIFIC GRAVITY FRACTION 15	-	0.859

VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11	-	40
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12	-	46
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13	-	060
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14	-	075
VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15	-	115

CLOUD POINT DEGREES F. FOR FRACTION 11	-	15
CLOUD POINT DEGREES F. FOR FRACTION 12	-	35
CLOUD POINT DEGREES F. FOR FRACTION 13	-	050
CLOUD POINT DEGREES F. FOR FRACTION 14	-	075
CLOUD POINT DEGREES F. FOR FRACTION 15	-	090

RECORD 00034

CONTINENT -- NORTH AMERICA
 COUNTRY -- U.S.A.
 STATE -- WEST VIRGINIA
 COUNTY -- MARSHALL
 FIELD NAME -- NOT KNOWN
 PRODUCING FORMATION NAME -- COW RUN, CONEMAUGH
 ERA -- PALEOZOIC
 SYSTEM -- PENNSYLVANIAN
 GEOLOGICAL BASIN NAME -- APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE -- 160
 DEPTH TO TOP (FT.) -- 00953
 SANDSTONE
 AGENCY SAMPLE NO -- B23389
 SPECIFIC GRAVITY -- 0.780
 SULFUR (WEIGHT PERCENT) -- LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) -- 0.2
 VISCOSITY SUS AT 100 DEGREES F. -- 033
 PERCENT OF CRUDE -- 3.3
 VOLUME PERCENT FRACTION 2 -- 2.1
 VOLUME PERCENT FRACTION 3 -- 4.0
 VOLUME PERCENT FRACTION 4 -- 7.0
 VOLUME PERCENT FRACTION 5 -- 9.8
 VOLUME PERCENT FRACTION 6 -- 9.2
 VOLUME PERCENT FRACTION 7 -- 8.7
 VOLUME PERCENT FRACTION 8 -- 9.3
 VOLUME PERCENT FRACTION 9 -- 10.0
 VOLUME PERCENT FRACTION 10 -- 9.2
 VOLUME PERCENT FRACTION 11 -- 7.5
 VOLUME PERCENT FRACTION 12 -- 7.3
 VOLUME PERCENT FRACTION 13 -- 5.3
 VOLUME PERCENT FRACTION 14 -- 4.9
 VOLUME PERCENT FRACTION 15 -- 2.4
 SPECIFIC GRAVITY FRACTION 2 -- 0.677
 SPECIFIC GRAVITY FRACTION 3 -- 0.690
 SPECIFIC GRAVITY FRACTION 4 -- 0.714
 SPECIFIC GRAVITY FRACTION 5 -- 0.732
 SPECIFIC GRAVITY FRACTION 6 -- 0.748
 SPECIFIC GRAVITY FRACTION 7 -- 0.762
 SPECIFIC GRAVITY FRACTION 8 -- 0.774
 SPECIFIC GRAVITY FRACTION 9 -- 0.785
 SPECIFIC GRAVITY FRACTION 10 -- 0.797
 SPECIFIC GRAVITY FRACTION 11 -- 0.823
 SPECIFIC GRAVITY FRACTION 12 -- 0.826
 SPECIFIC GRAVITY FRACTION 13 -- 0.839
 SPECIFIC GRAVITY FRACTION 14 -- 0.851
 SPECIFIC GRAVITY FRACTION 15 -- 0.865
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 -- 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 -- 46
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 -- 058
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 -- 087
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 -- 145
 CLOUD POINT DEGREES F. FOR FRACTION 11 -- 30
 CLOUD POINT DEGREES F. FOR FRACTION 12 -- 40
 CLOUD POINT DEGREES F. FOR FRACTION 13 -- 060
 CLOUD POINT DEGREES F. FOR FRACTION 14 -- 080
 CLOUD POINT DEGREES F. FOR FRACTION 15 -- 090

RECORD 00035

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - HARRISON
 FIELD NAME - SHINNSTON
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02640
 SANDSTONE
 AGENCY SAMPLE NO - B33159
 SPECIFIC GRAVITY - 0.826
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.3
 VISCOSITY SUS AT 100 DEGREES F. - 049
 PERCENT OF CRUDE - 27.9
 VOLUME PERCENT FRACTION 3 - 0.9
 VOLUME PERCENT FRACTION 4 - 3.9
 VOLUME PERCENT FRACTION 5 - 4.7
 VOLUME PERCENT FRACTION 6 - 4.7
 VOLUME PERCENT FRACTION 7 - 4.8
 VOLUME PERCENT FRACTION 8 - 5.3
 VOLUME PERCENT FRACTION 9 - 6.0
 VOLUME PERCENT FRACTION 10 - 7.0
 VOLUME PERCENT FRACTION 11 - 5.0
 VOLUME PERCENT FRACTION 12 - 7.7
 VOLUME PERCENT FRACTION 13 - 6.9
 VOLUME PERCENT FRACTION 14 - 7.2
 VOLUME PERCENT FRACTION 15 - 7.3
 SPECIFIC GRAVITY FRACTION 3 - 0.711
 SPECIFIC GRAVITY FRACTION 4 - 0.723
 SPECIFIC GRAVITY FRACTION 5 - 0.742
 SPECIFIC GRAVITY FRACTION 6 - 0.758
 SPECIFIC GRAVITY FRACTION 7 - 0.770
 SPECIFIC GRAVITY FRACTION 8 - 0.780
 SPECIFIC GRAVITY FRACTION 9 - 0.793
 SPECIFIC GRAVITY FRACTION 10 - 0.806
 SPECIFIC GRAVITY FRACTION 11 - 0.826
 SPECIFIC GRAVITY FRACTION 12 - 0.831
 SPECIFIC GRAVITY FRACTION 13 - 0.839
 SPECIFIC GRAVITY FRACTION 14 - 0.846
 SPECIFIC GRAVITY FRACTION 15 - 0.853
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 41
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 47
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 057
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 074
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 105
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 45
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 060
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 075
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - ROANE
 FIELD NAME - SPENCER
 PRODUCING FORMATION NAME - BEREA
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02539
 SANDSTONE
 AGENCY SAMPLE NO - B26344
 SPECIFIC GRAVITY - 0.814
 SULFUR (WEIGHT PERCENT) - 0.12
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.3
 VISCOSITY SUS AT 100 DEGREES F. - 041
 PERCENT OF CRUDE - 24.7
 VOLUME PERCENT FRACTION 1 - 0.9
 VOLUME PERCENT FRACTION 2 - 2.7
 VOLUME PERCENT FRACTION 3 - 3.7
 VOLUME PERCENT FRACTION 4 - 6.1
 VOLUME PERCENT FRACTION 5 - 5.5
 VOLUME PERCENT FRACTION 6 - 5.3
 VOLUME PERCENT FRACTION 7 - 5.9
 VOLUME PERCENT FRACTION 8 - 5.7
 VOLUME PERCENT FRACTION 9 - 5.6
 VOLUME PERCENT FRACTION 10 - 6.5
 VOLUME PERCENT FRACTION 11 - 3.3
 VOLUME PERCENT FRACTION 12 - 6.3
 VOLUME PERCENT FRACTION 13 - 6.1
 VOLUME PERCENT FRACTION 14 - 5.1
 VOLUME PERCENT FRACTION 15 - 6.0
 SPECIFIC GRAVITY FRACTION 2 - 0.667
 SPECIFIC GRAVITY FRACTION 3 - 0.697
 SPECIFIC GRAVITY FRACTION 4 - 0.725
 SPECIFIC GRAVITY FRACTION 5 - 0.745
 SPECIFIC GRAVITY FRACTION 6 - 0.760
 SPECIFIC GRAVITY FRACTION 7 - 0.772
 SPECIFIC GRAVITY FRACTION 8 - 0.784
 SPECIFIC GRAVITY FRACTION 9 - 0.794
 SPECIFIC GRAVITY FRACTION 10 - 0.808
 SPECIFIC GRAVITY FRACTION 11 - 0.835
 SPECIFIC GRAVITY FRACTION 12 - 0.836
 SPECIFIC GRAVITY FRACTION 13 - 0.848
 SPECIFIC GRAVITY FRACTION 14 - 0.860
 SPECIFIC GRAVITY FRACTION 15 - 0.868
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 055
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 080
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 115
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 30
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 40
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 060
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 075
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

RECORD 00037

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - ROANE
 FIELD NAME - SPENCER
 PRODUCING FORMATION NAME - BEREA
 ERA - PALEOZOIC
 SYSTEM - PALEOZOIC
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 DEPTH TO TOP (FT.) - 02784
 SANDSTONE
 AGENCY SAMPLE NO - B43127
 SPECIFIC GRAVITY - 0.795
 SULFUR (WEIGHT PERCENT) - LESS THAN 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.4
 VISCOSITY SUS AT 100 DEGREES F. - 039
 PERCENT OF CRUDE - 22.0
 VOLUME PERCENT FRACTION 1 - 3.8
 VOLUME PERCENT FRACTION 2 - 3.5
 VOLUME PERCENT FRACTION 3 - 5.3
 VOLUME PERCENT FRACTION 4 - 6.7
 VOLUME PERCENT FRACTION 5 - 6.1
 VOLUME PERCENT FRACTION 6 - 5.5
 VOLUME PERCENT FRACTION 7 - 4.8
 VOLUME PERCENT FRACTION 8 - 4.9
 VOLUME PERCENT FRACTION 9 - 4.8
 VOLUME PERCENT FRACTION 10 - 6.3
 VOLUME PERCENT FRACTION 11 - 2.7
 VOLUME PERCENT FRACTION 12 - 5.5
 VOLUME PERCENT FRACTION 13 - 5.1
 VOLUME PERCENT FRACTION 14 - 4.7
 VOLUME PERCENT FRACTION 15 - 5.2
 SPECIFIC GRAVITY FRACTION 2 - 0.662
 SPECIFIC GRAVITY FRACTION 3 - 0.687
 SPECIFIC GRAVITY FRACTION 4 - 0.730
 SPECIFIC GRAVITY FRACTION 5 - 0.749
 SPECIFIC GRAVITY FRACTION 6 - 0.764
 SPECIFIC GRAVITY FRACTION 7 - 0.777
 SPECIFIC GRAVITY FRACTION 8 - 0.787
 SPECIFIC GRAVITY FRACTION 9 - 0.798
 SPECIFIC GRAVITY FRACTION 10 - 0.810
 SPECIFIC GRAVITY FRACTION 11 - 0.828
 SPECIFIC GRAVITY FRACTION 12 - 0.834
 SPECIFIC GRAVITY FRACTION 13 - 0.842
 SPECIFIC GRAVITY FRACTION 14 - 0.850
 SPECIFIC GRAVITY FRACTION 15 - 0.859
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 053
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 070
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 105
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 15
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 30
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 050
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 065
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 080

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - RITCHIE
 FIELD NAME - WEST VIRGINIA, NW COMP.
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00416
 SPECIFIC GRAVITY - 0.805
 SULFUR (WEIGHT PERCENT) - 0.28
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.4
 PERCENT OF CRUDE - 19.9
 VOLUME PERCENT FRACTION 1 - 2.3
 VOLUME PERCENT FRACTION 2 - 2.6
 VOLUME PERCENT FRACTION 3 - 5.7
 VOLUME PERCENT FRACTION 4 - 7.7
 VOLUME PERCENT FRACTION 5 - 7.0
 VOLUME PERCENT FRACTION 6 - 7.0
 VOLUME PERCENT FRACTION 7 - 6.0
 VOLUME PERCENT FRACTION 8 - 5.8
 VOLUME PERCENT FRACTION 9 - 5.2
 VOLUME PERCENT FRACTION 10 - 7.0
 VOLUME PERCENT FRACTION 11 - 4.5
 VOLUME PERCENT FRACTION 12 - 4.8
 VOLUME PERCENT FRACTION 13 - 4.7
 VOLUME PERCENT FRACTION 14 - 4.6
 VOLUME PERCENT FRACTION 15 - 5.2
 SPECIFIC GRAVITY FRACTION 2 - 0.660
 SPECIFIC GRAVITY FRACTION 5 - 0.745
 SPECIFIC GRAVITY FRACTION 6 - 0.760
 SPECIFIC GRAVITY FRACTION 7 - 0.778
 SPECIFIC GRAVITY FRACTION 8 - 0.796
 SPECIFIC GRAVITY FRACTION 9 - 0.805
 SPECIFIC GRAVITY FRACTION 10 - 0.810
 SPECIFIC GRAVITY FRACTION 12 - 0.815
 SPECIFIC GRAVITY FRACTION 13 - 0.835
 SPECIFIC GRAVITY FRACTION 14 - 0.845
 SPECIFIC GRAVITY FRACTION 15 - 0.872
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 063
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 101
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 113
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 10
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 46
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 063
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 075
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

RECORD 00039

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - RITCHIE
 FIELD NAME - WEST VIRGINIA, NW COMP.
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00417
 SPECIFIC GRAVITY - 0.806
 SULFUR (WEIGHT PERCENT) - 0.24
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.5
 PERCENT OF CRUDE - 19.8
 VOLUME PERCENT FRACTION 1 - 2.6
 VOLUME PERCENT FRACTION 2 - 2.9
 VOLUME PERCENT FRACTION 3 - 5.0
 VOLUME PERCENT FRACTION 4 - 7.9
 VOLUME PERCENT FRACTION 5 - 6.9
 VOLUME PERCENT FRACTION 6 - 7.0
 VOLUME PERCENT FRACTION 7 - 5.4
 VOLUME PERCENT FRACTION 8 - 5.6
 VOLUME PERCENT FRACTION 9 - 5.6
 VOLUME PERCENT FRACTION 10 - 6.5
 VOLUME PERCENT FRACTION 11 - 3.6
 VOLUME PERCENT FRACTION 12 - 5.6
 VOLUME PERCENT FRACTION 13 - 4.8
 VOLUME PERCENT FRACTION 14 - 4.8
 VOLUME PERCENT FRACTION 15 - 6.0
 SPECIFIC GRAVITY FRACTION 2 - 0.673
 SPECIFIC GRAVITY FRACTION 3 - 0.709
 SPECIFIC GRAVITY FRACTION 4 - 0.731
 SPECIFIC GRAVITY FRACTION 5 - 0.748
 SPECIFIC GRAVITY FRACTION 6 - 0.763
 SPECIFIC GRAVITY FRACTION 7 - 0.776
 SPECIFIC GRAVITY FRACTION 8 - 0.787
 SPECIFIC GRAVITY FRACTION 9 - 0.801
 SPECIFIC GRAVITY FRACTION 10 - 0.812
 SPECIFIC GRAVITY FRACTION 11 - 0.825
 SPECIFIC GRAVITY FRACTION 12 - 0.831
 SPECIFIC GRAVITY FRACTION 13 - 0.841
 SPECIFIC GRAVITY FRACTION 14 - 0.849
 SPECIFIC GRAVITY FRACTION 15 - 0.848
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 41
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 46
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 056
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 075
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 076
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 16
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 34
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 055
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 070
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 082

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - RITCHIE
 FIELD NAME - WEST VIRGINIA, NW COMP.
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00420
 SPECIFIC GRAVITY - 0.805
 SULFUR (WEIGHT PERCENT) - 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.4
 PERCENT OF CRUDE - 21.5
 VOLUME PERCENT FRACTION 1 - 0.7
 VOLUME PERCENT FRACTION 2 - 2.1
 VOLUME PERCENT FRACTION 3 - 4.0
 VOLUME PERCENT FRACTION 4 - 6.2
 VOLUME PERCENT FRACTION 5 - 6.4
 VOLUME PERCENT FRACTION 6 - 6.0
 VOLUME PERCENT FRACTION 7 - 5.9
 VOLUME PERCENT FRACTION 8 - 5.9
 VOLUME PERCENT FRACTION 9 - 5.9
 VOLUME PERCENT FRACTION 10 - 6.7
 VOLUME PERCENT FRACTION 11 - 6.3
 VOLUME PERCENT FRACTION 12 - 5.8
 VOLUME PERCENT FRACTION 13 - 6.2
 VOLUME PERCENT FRACTION 14 - 4.8
 VOLUME PERCENT FRACTION 15 - 5.6
 SPECIFIC GRAVITY FRACTION 2 - 0.660
 SPECIFIC GRAVITY FRACTION 3 - 0.703
 SPECIFIC GRAVITY FRACTION 4 - 0.730
 SPECIFIC GRAVITY FRACTION 5 - 0.747
 SPECIFIC GRAVITY FRACTION 6 - 0.762
 SPECIFIC GRAVITY FRACTION 7 - 0.777
 SPECIFIC GRAVITY FRACTION 8 - 0.788
 SPECIFIC GRAVITY FRACTION 9 - 0.799
 SPECIFIC GRAVITY FRACTION 10 - 0.810
 SPECIFIC GRAVITY FRACTION 11 - 0.820
 SPECIFIC GRAVITY FRACTION 12 - 0.830
 SPECIFIC GRAVITY FRACTION 13 - 0.838
 SPECIFIC GRAVITY FRACTION 14 - 0.852
 SPECIFIC GRAVITY FRACTION 15 - 0.856
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 33
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 45
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 057
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 093
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 109
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 25
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 50
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 063
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 077
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 091

RECORD 00041

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - TYLER
 FIELD NAME - WEST VIRGINIA, NW COMP.
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00423
 SPECIFIC GRAVITY - 0.808
 SULFUR (WEIGHT PERCENT) - 0.10
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.6
 PERCENT OF CRUDE - 21.1
 VOLUME PERCENT FRACTION 1 - 1.8
 VOLUME PERCENT FRACTION 2 - 2.1
 VOLUME PERCENT FRACTION 3 - 4.8
 VOLUME PERCENT FRACTION 4 - 6.6
 VOLUME PERCENT FRACTION 5 - 6.0
 VOLUME PERCENT FRACTION 6 - 6.4
 VOLUME PERCENT FRACTION 7 - 6.3
 VOLUME PERCENT FRACTION 8 - 5.7
 VOLUME PERCENT FRACTION 9 - 6.6
 VOLUME PERCENT FRACTION 10 - 7.1
 VOLUME PERCENT FRACTION 11 - 3.6
 VOLUME PERCENT FRACTION 12 - 6.3
 VOLUME PERCENT FRACTION 13 - 5.7
 VOLUME PERCENT FRACTION 14 - 4.6
 VOLUME PERCENT FRACTION 15 - 5.3
 SPECIFIC GRAVITY FRACTION 2 - 0.677
 SPECIFIC GRAVITY FRACTION 3 - 0.716
 SPECIFIC GRAVITY FRACTION 4 - 0.740
 SPECIFIC GRAVITY FRACTION 5 - 0.759
 SPECIFIC GRAVITY FRACTION 6 - 0.775
 SPECIFIC GRAVITY FRACTION 7 - 0.787
 SPECIFIC GRAVITY FRACTION 8 - 0.798
 SPECIFIC GRAVITY FRACTION 9 - 0.809
 SPECIFIC GRAVITY FRACTION 10 - 0.820
 SPECIFIC GRAVITY FRACTION 11 - 0.825
 SPECIFIC GRAVITY FRACTION 12 - 0.830
 SPECIFIC GRAVITY FRACTION 13 - 0.840
 SPECIFIC GRAVITY FRACTION 14 - 0.848
 SPECIFIC GRAVITY FRACTION 15 - 0.857
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 11 - 40
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 44
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 054
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 072
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 104
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 37
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 055
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 072
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 086

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - TYLER
 FIELD NAME - WEST VIRGINIA, NW COMP.
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00424
 SPECIFIC GRAVITY - 0.803
 SULFUR (WEIGHT PERCENT) - 0.09
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 PERCENT OF CRUDE - 19.5
 VOLUME PERCENT FRACTION 1 - 2.2
 VOLUME PERCENT FRACTION 2 - 2.3
 VOLUME PERCENT FRACTION 3 - 4.7
 VOLUME PERCENT FRACTION 4 - 7.2
 VOLUME PERCENT FRACTION 5 - 7.1
 VOLUME PERCENT FRACTION 6 - 6.7
 VOLUME PERCENT FRACTION 7 - 6.9
 VOLUME PERCENT FRACTION 8 - 5.9
 VOLUME PERCENT FRACTION 9 - 6.1
 VOLUME PERCENT FRACTION 10 - 6.7
 VOLUME PERCENT FRACTION 11 - 4.4
 VOLUME PERCENT FRACTION 12 - 5.7
 VOLUME PERCENT FRACTION 13 - 5.2
 VOLUME PERCENT FRACTION 14 - 4.6
 VOLUME PERCENT FRACTION 15 - 4.8
 SPECIFIC GRAVITY FRACTION 2 - 0.670
 SPECIFIC GRAVITY FRACTION 3 - 0.692
 SPECIFIC GRAVITY FRACTION 4 - 0.733
 SPECIFIC GRAVITY FRACTION 5 - 0.750
 SPECIFIC GRAVITY FRACTION 6 - 0.765
 SPECIFIC GRAVITY FRACTION 7 - 0.775
 SPECIFIC GRAVITY FRACTION 8 - 0.787
 SPECIFIC GRAVITY FRACTION 9 - 0.796
 SPECIFIC GRAVITY FRACTION 10 - 0.810
 SPECIFIC GRAVITY FRACTION 11 - 0.823
 SPECIFIC GRAVITY FRACTION 12 - 0.830
 SPECIFIC GRAVITY FRACTION 13 - 0.838
 SPECIFIC GRAVITY FRACTION 14 - 0.841
 SPECIFIC GRAVITY FRACTION 15 - 0.852
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 39
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 055
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 075
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 102
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 18
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 50
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 066
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 075
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 083

RECORD 00043

CONTINENT - NORTH AMERICA
 COUNTRY - U.S.A.
 STATE - WEST VIRGINIA
 COUNTY - TYLER
 FIELD NAME - WEST VIRGINIA, NW COMP.
 GEOLOGICAL BASIN NAME - APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE - 160
 AGENCY SAMPLE NO - B00425
 SPECIFIC GRAVITY - 0.804
 SULFUR (WEIGHT PERCENT) - 0.09
 POUR POINT (DEGREE F.) - LESS THAN 5
 CARBON RESIDUE (PERCENT OF CRUDE) - 0.2
 PERCENT OF CRUDE - 16.8
 VOLUME PERCENT FRACTION 2 - 1.2
 VOLUME PERCENT FRACTION 3 - 3.8
 VOLUME PERCENT FRACTION 4 - 8.8
 VOLUME PERCENT FRACTION 5 - 7.9
 VOLUME PERCENT FRACTION 6 - 7.7
 VOLUME PERCENT FRACTION 7 - 6.4
 VOLUME PERCENT FRACTION 8 - 7.9
 VOLUME PERCENT FRACTION 9 - 5.9
 VOLUME PERCENT FRACTION 10 - 7.0
 VOLUME PERCENT FRACTION 11 - 4.9
 VOLUME PERCENT FRACTION 12 - 5.7
 VOLUME PERCENT FRACTION 13 - 5.8
 VOLUME PERCENT FRACTION 14 - 5.4
 VOLUME PERCENT FRACTION 15 - 4.8
 SPECIFIC GRAVITY FRACTION 3 - 0.700
 SPECIFIC GRAVITY FRACTION 4 - 0.728
 SPECIFIC GRAVITY FRACTION 5 - 0.747
 SPECIFIC GRAVITY FRACTION 6 - 0.765
 SPECIFIC GRAVITY FRACTION 7 - 0.772
 SPECIFIC GRAVITY FRACTION 8 - 0.785
 SPECIFIC GRAVITY FRACTION 9 - 0.796
 SPECIFIC GRAVITY FRACTION 10 - 0.806
 SPECIFIC GRAVITY FRACTION 11 - 0.820
 SPECIFIC GRAVITY FRACTION 12 - 0.828
 SPECIFIC GRAVITY FRACTION 13 - 0.836
 SPECIFIC GRAVITY FRACTION 14 - 0.853
 SPECIFIC GRAVITY FRACTION 15 - 0.862
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 - 37
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 - 057
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 - 076
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 - 107
 CLOUD POINT DEGREES F. FOR FRACTION 11 - 18
 CLOUD POINT DEGREES F. FOR FRACTION 12 - 43
 CLOUD POINT DEGREES F. FOR FRACTION 13 - 059
 CLOUD POINT DEGREES F. FOR FRACTION 14 - 075
 CLOUD POINT DEGREES F. FOR FRACTION 15 - 090

CONTINENT -- NORTH AMERICA
 COUNTRY -- U.S.A.
 STATE -- WEST VIRGINIA
 COUNTY -- WETZEL
 FIELD NAME -- WETZEL COUNTY
 GEOLOGICAL BASIN NAME -- APPALACHIAN BASIN
 GEOLOGICAL BASIN CODE -- 160
 AGENCY SAMPLE NO -- B00421
 SPECIFIC GRAVITY -- 0.804
 SULFUR (WEIGHT PERCENT) -- 0.11
 CARBON RESIDUE (PERCENT OF CRUDE) -- 0.4
 PERCENT OF CRUDE -- 20.5
 VOLUME PERCENT FRACTION 1 -- 1.1
 VOLUME PERCENT FRACTION 2 -- 2.5
 VOLUME PERCENT FRACTION 3 -- 4.8
 VOLUME PERCENT FRACTION 4 -- 6.7
 VOLUME PERCENT FRACTION 5 -- 6.5
 VOLUME PERCENT FRACTION 6 -- 6.8
 VOLUME PERCENT FRACTION 7 -- 6.2
 VOLUME PERCENT FRACTION 8 -- 6.1
 VOLUME PERCENT FRACTION 9 -- 6.2
 VOLUME PERCENT FRACTION 10 -- 6.8
 VOLUME PERCENT FRACTION 11 -- 5.2
 VOLUME PERCENT FRACTION 12 -- 5.5
 VOLUME PERCENT FRACTION 13 -- 5.3
 VOLUME PERCENT FRACTION 14 -- 4.7
 VOLUME PERCENT FRACTION 15 -- 5.1
 SPECIFIC GRAVITY FRACTION 2 -- 0.655
 SPECIFIC GRAVITY FRACTION 3 -- 0.704
 SPECIFIC GRAVITY FRACTION 4 -- 0.723
 SPECIFIC GRAVITY FRACTION 5 -- 0.739
 SPECIFIC GRAVITY FRACTION 6 -- 0.753
 SPECIFIC GRAVITY FRACTION 7 -- 0.777
 SPECIFIC GRAVITY FRACTION 8 -- 0.787
 SPECIFIC GRAVITY FRACTION 9 -- 0.796
 SPECIFIC GRAVITY FRACTION 10 -- 0.809
 SPECIFIC GRAVITY FRACTION 11 -- 0.823
 SPECIFIC GRAVITY FRACTION 12 -- 0.830
 SPECIFIC GRAVITY FRACTION 13 -- 0.840
 SPECIFIC GRAVITY FRACTION 14 -- 0.852
 SPECIFIC GRAVITY FRACTION 15 -- 0.862
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 12 -- 44
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 13 -- 058
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 14 -- 083
 VISCOSITY SUS AT 100 DEGREES F. FOR FRACTION 15 -- 109
 CLOUD POINT DEGREES F. FOR FRACTION 11 -- 21
 CLOUD POINT DEGREES F. FOR FRACTION 12 -- 43
 CLOUD POINT DEGREES F. FOR FRACTION 13 -- 061
 CLOUD POINT DEGREES F. FOR FRACTION 14 -- 075

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