Pressure Maintenance Program, North (Strawn) Field, Jones County, Texas

By WILLIAM H. LEACH, JR., *and* E. L. ANDERS, JR.
LeClair Operating Company, Inc.

ABSTRACT

This paper presents a discussion of the production history, reservoir performance, and operational problems encountered for the pressure maintenance program in the Strawn Sand Reservoir in the Truby, North (Strawn) Field of Jones County, Texas. Primary energy in the reservoir was supplied by solution gas with a partially effective water drive.

Water injection for pressure maintenance was commenced in May, 1957, about 5-1/2 yr after the field was discovered. Cambrian water has been used for injection, and its highly corrosive nature has created many operational problems. The injection program was designed so that all injection water enters the formation below the oil-water contact. The monoclinal structure of the field with sand pinchout updip has required that injection wells be changed periodically to follow the rising trend of the oil-water contact across the field. At the present time the field is about 3/4 swept out (areally) by injected water.

Oil recovery from the 1415 surface acre unit has already exceeded 2.4 million barrels of 44 percent of the oil originally in place. Cumulative injection to date exceeds four million barrels.

GENERAL DISCUSSION

The Truby, North (Strawn) Unit contains 1415 surface acres and comprises all but one well of the Truby, North (Strawn) Field, Jones County, Texas (Figure 1). Specifically the field is located approximately 5 mi southwest of Anson, Texas. The entire field produces from the Strawn Sand (series) of Pennsylvanian Age.

GEOLOGICAL DATA

The Strawn Sand occurs beneath the subject field at approximately 4600 ft subsurface. The sand is medium grain in texture and occurs structurally in the form of a monocline dipping from northeast to southwest (Figure 2). The structure is terminated by an original oil-water contact on its western extremity (occurring at approximately -2823 ft subsea) and by sand pinchouts on all other edges of the structure.

Sand development in this pay generally increases from both the east and west flanks toward locally high buildups occurring along the northeast and southwest longitudinal axis (Figure 3). The thickest pay section found in the field was 34 ft in Well No. 9-6. The sand comprises approximately 817 productive acres and has an average thickness across the field of 13.4 ft. Reservoir volume, therefore, is just slightly under 11,000 acre ft.

PROPERTIES OF THE RESERVOIR

From core analysis, electric log interpretation, crude oil analysis, and various laboratory tests, it has been determined that the Strawn Sand Reservoir has the following properties:

(1) Porosity: 12.1%
(2) Permeability: 68 millidarcies
(3) Connate water saturation: 23.5% of pore space
(4) Crude oil gravity: 40°, API at 60° F.
(5) Viscosity of crude oil at reservoir temperature: .7 Centipoises
(6) Reservoir temperature: 117 ° F.
(7) Original solution gas-oil ratio: 900 cu ft per bbl
(8) Formation volume factor (original): 1.45 bbl reservoir oil per bbl of stock tank oil.
(9) Original reservoir pressure: 1900 psig

Utilizing the above figures, it was determined that the Truby, North (Strawn) Reservoir contained originally approximately 5,425,000 bbl of oil or approximately 495 bbl per acre ft.

EARLY PRODUCTION HISTORY

The Truby, North (Strawn) Field was discovered in December 1951 with the completion of Woodley Petroleum Company and E. C. Johnston Company's N. A. Bagley, Well No. 1. Development of the field continued until early 1954. At that time a total of 39 wells had been drilled to the Strawn pay on a density pattern of approximately one well per 20 acres (Figure 1). The field reached its peak productive (monthly) status in January 1955, when approximately 44,000 bbl of oil was produced. However, during the years 1954, 1955, and early 1956, field production remained relatively flat at approximately 37,000 bbl per month (Figure 10). In May of 1956, the field began to decline significantly in production. This decline was accompanied by increases in water production in wells lying along the western edge of the field.

EARLY ENGINEERING STUDY AND RECOMMENDATIONS

In anticipation of the aforementioned production decline, the various operators in this field, in 1955, agreed that an engineering study of the property should be made. Such a study was prepared and submitted to the operators for their consideration late in 1955. The study concluded that the field recovery mechanism was basically a solution gas drive which was influenced to some extent by a limited water drive on the western edge of the field. Because of the presence of this limited water drive, it was the conclusion of the report that the recovery of the Truby, North (Strawn) Field could be materially benefited by a pressure maintenance program which would utilize water injected beneath the oil-water contact as the repressuring medium. It was reasoned that injection at this point would cause additional oil to be swept upstructure toward and against the sand pinchout of the field, and would thereby permit this oil to be recovered from the higher structural wells in the field while the lower wells would, of course, be sacrificed to the effects of the injection program. The field operators concurred with this proposal, and the entire field (with the exception of one well) was unitized, effective May 1, 1957.

It should be mentioned that, fortunately, a fairly accurate pressure history had been maintained on this field through its primary producing life. Four pressure surveys had been taken, and, utilizing these four surveys, it was possible to construct a reasonably accurate graph of reservoir pressure decline versus cumulative production (Figure 9). In addition it was possible to develop isobaric maps periodically for the Truby, North (Strawn) Field based on results of pressure surveys. Figure 4 is an isobaric map showing the pressure configuration of the field as of the earliest survey taken (July 1954). Figure 5 shows the pressure configuration of the field as of the last survey taken prior to the initiation of repressuring operations (November, 1956).

ADDITIONAL FACILITIES REQUIRED FOR REPRESSURING

In order to initiate repressuring operations in the Truby, North (Strawn) Unit, it was necessary to first produce an adequate supply of water. An existing dry hole (Well No. 3-2 on Figure 1) was therefore deepened to the Cambrian Sand formation and completed as a water supply well. The top of the Cambrian Sand was found at approximately 5660 ft subsurface. The well was cased with 7 in. casing to approximate 3258 ft subsurface and swedged down to 5-1/2 in. casing from 3258 ft to 5660 ft subsurface. The well was completed open hole from 5660 ft to 5850 ft (total depth). The well was stimulated with a treatment of 2,000 gal. of 15% acid followed by a frac treatment of 40,000 gal. of gelled salt water and 40,000 lb of sand. Following this treatment, it was found that the static fluid level in the well was 400 ft subsurface. Despite approximately 6 yr of usage, the fluid level in the well remains virtually unchanged as of this date. A submersible electric (65 hp) pump was installed in the water supply well on 3 in. tubing and set at approximately 1400 ft subsurface. Initial testing indicated that drawdown from the static fluid level for the requirements for this project (believed at that time to be approximately 5,000 BWPD) would not exceed 600 ft. At the present time, water requirements from this well approximate only 1500 BPD, and drawdown is less than 300 ft. It should be mentioned that the Cambrian Sand has always furnished a very adequate supply of water into the well bore of the water supply well.

In the initial installation of repressuring facilities of the Truby, North (Strawn) Unit, it was believed that a sizeable savings could be realized through the installation of a generating plant to furnish power for the electrical water supply well pump as opposed to purchasing that same power required from a local power concern. It was further reasoned that, if such a station were installed, and that, assuming adequate capacity were built into such an installation, the pumping units on the field which utilize electricity for their source of energy (approximately 1/2 of the pumping units then located on the project) could utilize the generated power rather than purchasing same. For this reason, therefore, a generating plant was built. This plant was composed of two 12-cylinder internal combustion gas engines, each powering a 250 KVA generator.

The injection station constructed for the Unit was composed of 2 horizontal triplex pumps with 5 in. stroke and 2-1/4 in. liners and plungers each. These 2 pumps were each powered by a single cylinder (13-1/4 in. X 16 in.) internal combustion engine. Cooling of these engines was accomplished by means of heat exchangers. The generating station engines were cooled through the installation of a horizontal fan type cooling tower.

Initially the injection program utilized 5 input wells (Nos. 3-1A, 4-2, 6-6, 8-6, and 11-3--Figure 1). Injection was accomplished down bare steel tubing, with hookwall packers. The injection system was composed of a 4-1/2 in. OD (used) drill pipe (main-line) to which was welded 2-3/8 in. OD line type laterals. The entire system was unlined, uncoated, and buried.

The injection system was closed throughout. Filtration was handled through two 7 ft X 5 ft rapid water filters located at the injection station. The injection water was not chemically treated. Back-washing of filters was done into an unlined surface pit with the residue water being permitted to evaporate. The water utilized for backwashing was unfiltered. Six 210 bbl steel (uncoated) tanks provided station water storage and charging of the injection (triplex) pumps was done by means of a centrifugal pump.

A consolidation of tank batteries was made with the resultant batteries being three units composed of eight 210 bbl tanks and a 4 ft X 20 ft pressure type heater treater each. Flowlines from producing wells were then relocated on an individual basis so that each tank battery was equipped with a header arrangement for the separate testing of each producing well.

There were no facilities installed to handle produced water. Therefore, all produced water initially was disposed of in evaporative pits at the tank batteries.

RESULTS OF THE INITIAL INJECTION PROGRAM

Unfortunately, the first 18 months of the injection program were not particularly successful from a financial standpoint. The decline trend of the project was arrested (Figure 10) and some repressuring was obviously done (Figure 9). However, a number of factors which developed during this 18 month period caused the economics of this property to be something less than desirable.

First, it was found that the Cambrian water was extremely corrosive, and therefore, the unlined injection system began to suffer adverse effects almost immediately. Not only had the lines and heat exchangers become corroded to the point of deterioration, but the downhole tubing and station filters and tanks as well suffered from corrosion attack. Secondly, it was found that the generating plant had only sufficient power to handle the water supply well pump and could not generate (economically) adequate excess to handle the power requirements of the pumping units on the field driven by electric motors. It was also realized at this same time that because the generating engines purchased were war surplus items, replacement parts for these models were not stock items and, therefore, required special order from the manufacturer. Thirdly, the unlined station pit and disposal pits at the three tank batteries were found to be seeping across caliche beds and possibly polluting some fresh water wells in the area. Fourth, and probably most detrimental, it was found that while the project as a whole had responded, generally speaking, to the injection program, local areas in the field were being prematurely watered out, probably as a result of injection rates in excess of the capacity of the sand to take water without causing channels. In the case of input well No. 11-3, this action is known to have caused the premature watering out of 4 producing wells. As a result of this excessive injection program, the field pressure configuration as of November 1, 1958 was as shown on Figure 6. If this figure is compared to Figure 2, the structure map of the project, it is apparent that the repressuring program as of that date was not generally following the structural feature of the Unit as desired.

REMEDIAL STEPS TAKEN

On November 1, 1958, LeClair Operating Co., Inc. was commissioned to take over the operation of the Truby, North (Strawn) Unit. A pressure survey was immediately run to determine the conditions in the reservoir. The results of that survey, as previously mentioned, are depicted in Figure 6. Based on the results of this survey, a complete engineering reexamination of the project was undertaken. The physical equipment of the Unit was next examined and it was finally and reluctantly agreed that it would be necessary to shut down the injection facilities in this project for a period of time while certain much needed remedial steps were taken.

All of the storage and filtering facilities at the injection station were removed and sold for salvage. New internally plastic coated 7 ft X 5 ft rapid water filters were installed, and two 500 bbl redwood tanks were built on location for water storage. The station earthen pit was filled and a lined pit constructed for backwash purposes. The heat exchangers were removed and discarded and the cooling tower repiped to service the injection station engines also.

Begun was a chemical injection program utilizing a filming amine chemical injected in "batch" doses into the supply well. Input well No. 11-3 and producing well No. 9-5 were both squeeze cemented, and temporarily abandoned. In addition, producing wells 11-1 and 11-2 (which were also watered out) were temporarily abandoned. Well No. 8-4 was put into service as an injection well replacing well No. 11-3. Input well No. 3-1A was taken out of service as an injection well because of the deteriorated condition of its downhole equipment and also because of its questionable worth to the injection program. (In this regard, it was believed that injection should be taking place nearer the current oil-water contact). Well No. 4-2 was taken out of service as an injection well and well No. 6-1 converted to input service in its place. This move was made because of the thicker sand section in 6-1, and its proximity to the then current oil-water contact because this well had also been prematurely watered out prior to the change of operators.

It was decided to pull tubing in the 2 remaining input wells, 6-6 and 8-6, and replace that tubing with plastic coated tubing. Unfortunately, in the case of both wells, the tubing was found to be in such a deteriorated condition that costly fishing jobs were involved before the entire string of tubing and the hookwall packer could be removed. In the case of well No. 8-6, it was never possible to remove all the tubing and packer from the well, and it was necessary to abandon this well and replace it with well No. 8-3.

The project following revision was equipped with 4 water input wells (6-1, 6-6, 8-3, 8-4). All the wells were equipped with plastic lined tubing and permanent packers set so as to eliminate packer removal difficulties.

The (bare steel) injection system was replaced with a cement lined 3-1/2 in. OD main and 2-3/8 in. OD laterals. The main line was laid along the shoulder of the county road right-of-way and only buried where access roads, etc., dictated (Figure 1). All the laterals were buried because of their crossing cultivated fields. None of the buried lines were wrapped. The previous injection system was left in place (buried) because of some serious doubts that it could be recovered in sufficient quantity to pay for the removal costs.

A return water system was also installed (Figure 1). Like the injection system, the main line of this facility was also laid along the county road right-of-way. This system was composed of 4-1/2 in. OD (second hand) drill pipe (main) and used 2-3/8 in. OD tubing for laterals to batteries (Figure 1). Neither size was coated or lined. This line operates under heater treater pressure only. Because of this low pressure condition and of the fact that only relatively low volumes of water would be handled, it was reasoned that this system could survive without coating. To date this assumption has been valid.

On January 16, 1959, a pressure survey was run on the field to determine how much bottom hole pressure had been lost as a result of producing the field during that period of time when the injection facilities were shut down for revision. It was noted that on a volumetrically weighted average basis, bottom hole pressure had declined from 972 psi prior to the shut down to 755 psi following shut down. The injection program was begun again, this time utilizing injection rates of only approximately 450 bbl per injection well per day, or approximately 1800 bbl for the unit per day.

PROJECT PERFORMANCE SINCE JANUARY 1, 1959

As noted by Figures 9, 10, and 11, the performance of the Truby, North (Strawn) Unit since January 1, 1959 has been most satisfactory. Production has averaged 15,000 bbl per month for approximately 4 yr. In this regard it should be pointed out that during 1959 a period of voluntary curtailment was experienced while the operator made various studies to determine if the field was showing any detrimental effect from possibly excessive withdrawals.

Bottom hole pressure has continued to increase (Figure 9 and Figure 7) according to expectations and predictions. Moreover, the pressure configuration of the project at the present time (Figure 7) more closely follows the structural trend of the reservoir (Figure 2) as desired.

Only recently the project has shown some production decline as is undoubtedly to be anticipated. Figure 8 indicates that approximately 3/4 of the areal extent of the project has been watered out completely because of the injection program, or is now very significantly water productive.

As of February 1, 1963, the Truby, North (Strawn) Unit had recovered 2,430,000 bbl of oil, or approximately 45% of the oil originally in place. Obviously, this figure reflects recovery both prior to and following water injection. Such is necessary, however, for this is a pressure maintenance project and not a secondary recovery project; and therefore there is no point at which the production from primary means can actually be separated from the production brought about by repressuring. This production figure has been accomplished through the injection of 3,962,000 bbl of water. Approximately 591,000 bbl of water have been produced through the life of the field. In addition, 2,782,000 MCF of gas have been produced and, except for field needs, sold through February 1, 1963. Injection to February 1, 1963 represents 0.384 pore volumes. It is anticipated that project reserves as of the same date are approximately 200,000 bbl and that the project has an anticipated future life of 2 yr.

Bottom hole pressure surveys have been conducted on a semi-annual basis since January 1, 1959 in order to keep close surveillance over how adequately the injection program is maintaining pressure of the reservoir. The results of these surveys are plotted graphically on Figure 9 (currently the weighted average field pressure is 1076 psig). In addition, the operator has constructed an isobaric map of each survey and furnished owners with a copy of same as a part of their regular monthly reports on those months when the surveys have been run.

OPERATIONAL PROCEDURES AND PROBLEMS SINCE JANUARY 1, 1959

The project, at the present time, has been reduced to a total of 12 producing wells. As wells become 100% water productive and no longer serviceable to the Unit, they are plugged out and the proceeds recovered from their salvage are distributed equitably among working interest owners. At the present time, injection is still being maintained on that basis of approximately 450 bbl per well per day. As of this writing, this field is producing approximately 300 BOPD and a very nearly equal volume of water. Because the reservoir is conceded to be a closed structure on all but its west side, it must be concluded that in excess of 1/2 of the water injected is returned to the aquifer on the west.

The Unit has not been without its operating problems since January 1, 1959. However, probably in excess of 70% of all problems have been as a result of corrosion caused by the Cambrian injection water. This condition has twice necessitated that entire strings of tubing, even though coated, be replaced. Certain of this removal has entailed fishing operations. The operator has experimented with various kinds and has concluded that probably a plastic coating on new tubing is most satisfactory for service in this particular water. At the present time, 2 of the unit input wells are equipped with cement lined tubing while 2 are equipped with plastic lined tubing (1 of these being plastic lined new and the other used tubing). It is the operator's feeling that cement lined tubing is very adequate as long as no occasion arises wherein it is necessary to remove this tubing from the well. The inherent handling and collar protection problems of cement lined tubing have made it undesirable for service in this project if it is necessary to pull the tubing string with any regularity. Plastic lining on used tubing has not proved satisfactory in this project because of the problem (which very nearly defies solution) of adequate cleaning of the pipe prior to lining

Replacement of buried cement lined laterals has caused the second most expensive operational problem. It was first believed that failures in these laterals were caused by corrosion attack from internal sources, despite cement lining. Further investigation, however, revealed that a soil condition was attacking the exterior of the lines and corroding them to a point of failure. It has, therefore, been necessary to replace several laterals. All replacement lines are, of course, cement lined, then doped, wrapped (plastic tape) and wrapped again. This protection method has proved adequate.

Despite plastic coating it has been necessary to replace one of the station filters installed in late 1958, and it now appears that probably a second filter will require replacement shortly.

ECONOMICS

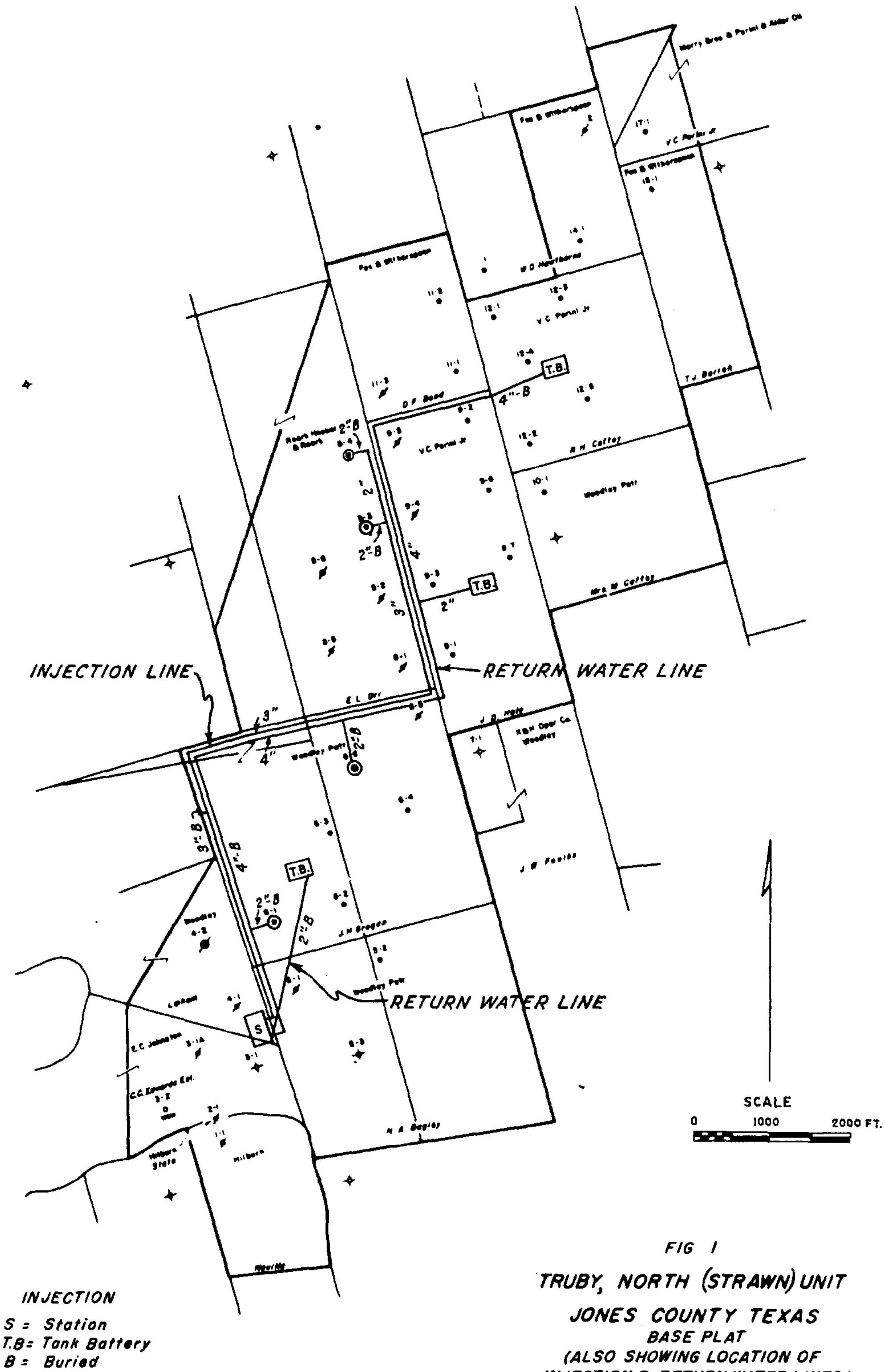
The operator is not, of course, able to furnish economics for the period prior to January 1, 1959. However, the following is a breakdown of the economics of this project pertinent to the working interest owners for the four years of LeClair operation:

Year	NWI Profit	Lifting Costs (NWI Bbl Oil)	Lifting Costs (Total Bbl Fluid)*	Lifting Costs Per well per mo.
1959	$333,040.59	$0.67	$0.47	$275.93
1960	332,184.54	0.80	0.49	279.62
1961	342,321.45	0.40	0.23	206.21
1962	335,959.92	0.54	0.30	348.25**

** Tubing replacements
* NWI oil and all water

CONCLUSION

In conclusion it can only be stated that the operator considers this program to have been extremely effective and quite profitable to working interest owners. The 1958 plant revision provided a solution for a great number of potential problems. Therefore, sizable savings on operating costs were realized as a result of this action. A properly engineered injection program has kept production at a maximum and caused reservoir pressure to continue to increase. Although the project has now declined, the operator feels that with reduced overhead as a result of fewer wells, the per barrel profit of the project can be maintained. The operator will be pleased to answer any questions or discuss any phase of this program with any interested person.



INJECTION
S = Station
T.B= Tank Battery
B = Buried

FIG I
TRUBY, NORTH (STRAWN) UNIT
JONES COUNTY TEXAS
BASE PLAT
(ALSO SHOWING LOCATION OF
INJECTION & RETURN WATER LINES)

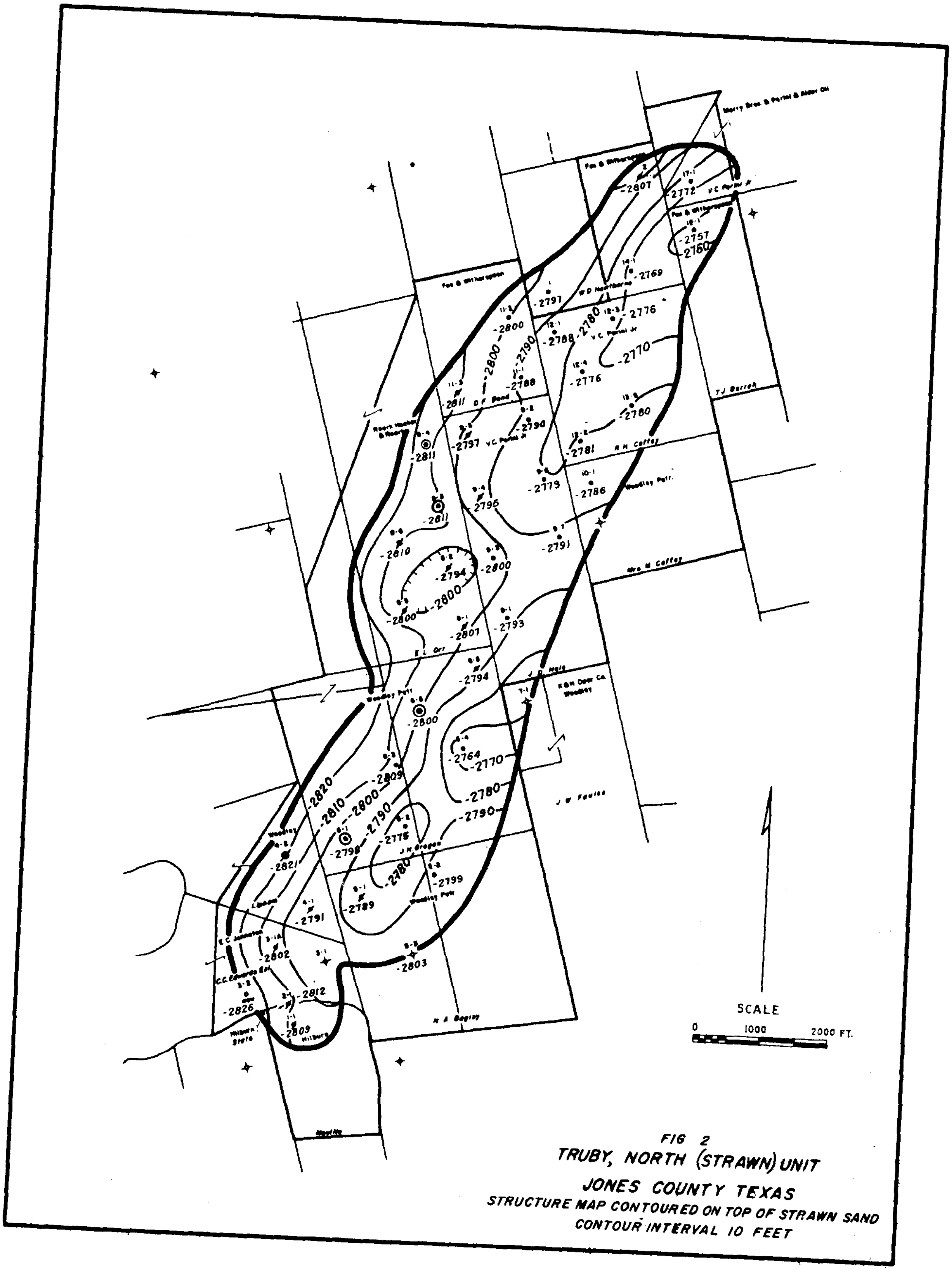


FIG 2
TRUBY, NORTH (STRAWN) UNIT
JONES COUNTY TEXAS
STRUCTURE MAP CONTOURED ON TOP OF STRAWN SAND
CONTOUR INTERVAL 10 FEET

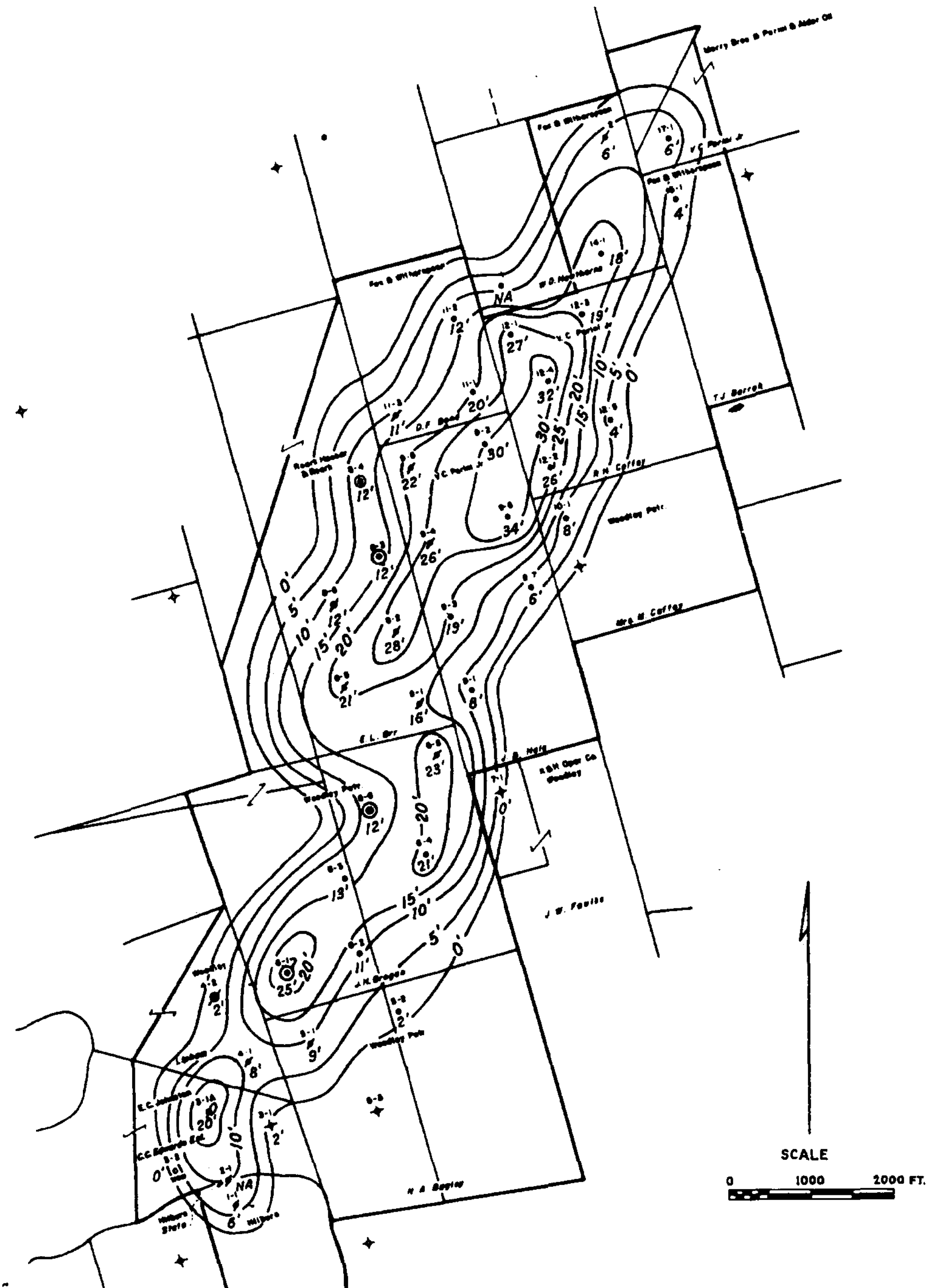


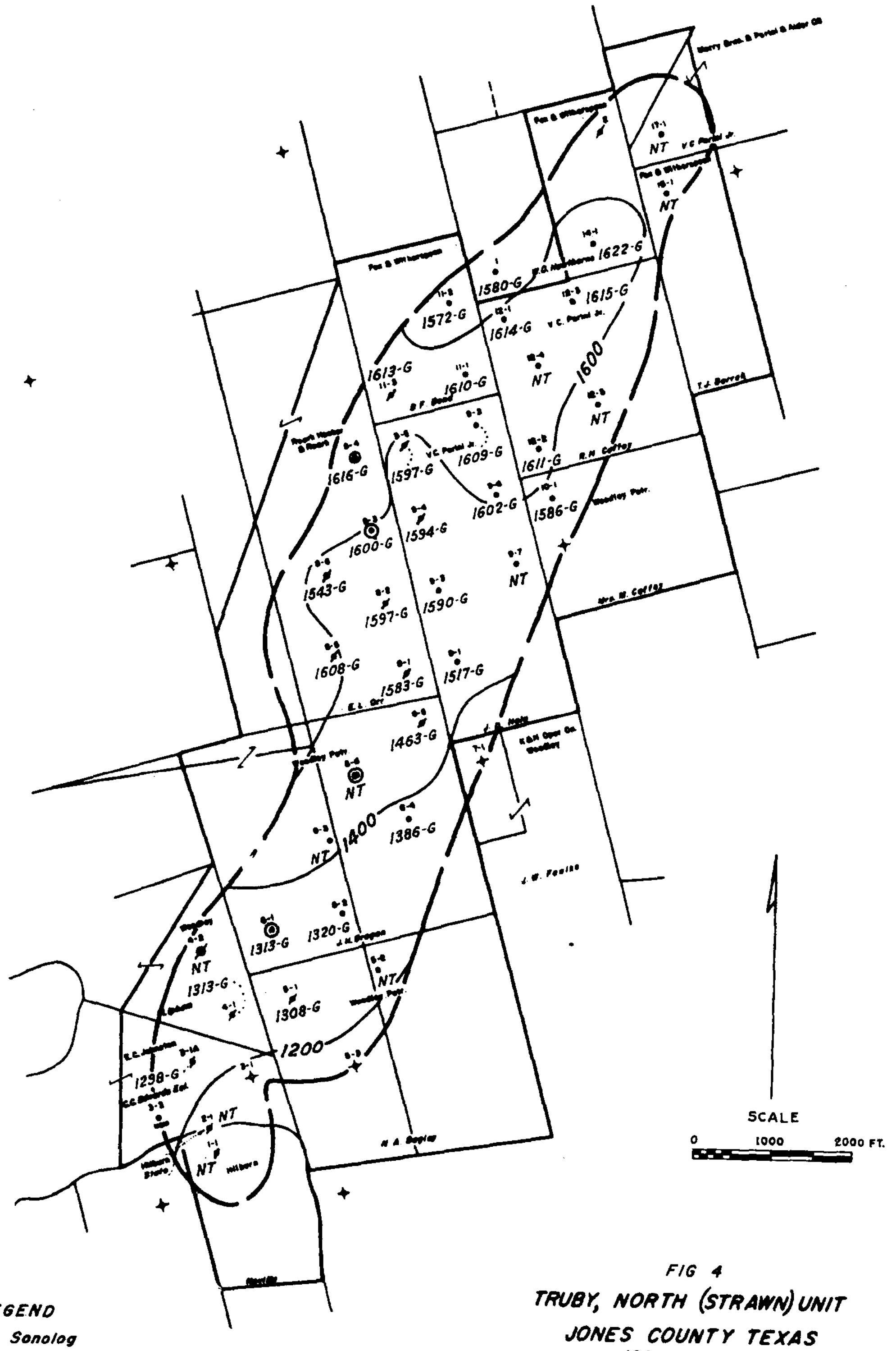
FIG 3

TRUBY, NORTH (STRAWN) UNIT

JONES COUNTY TEXAS

NET SAND ISOPACHOUS MAP

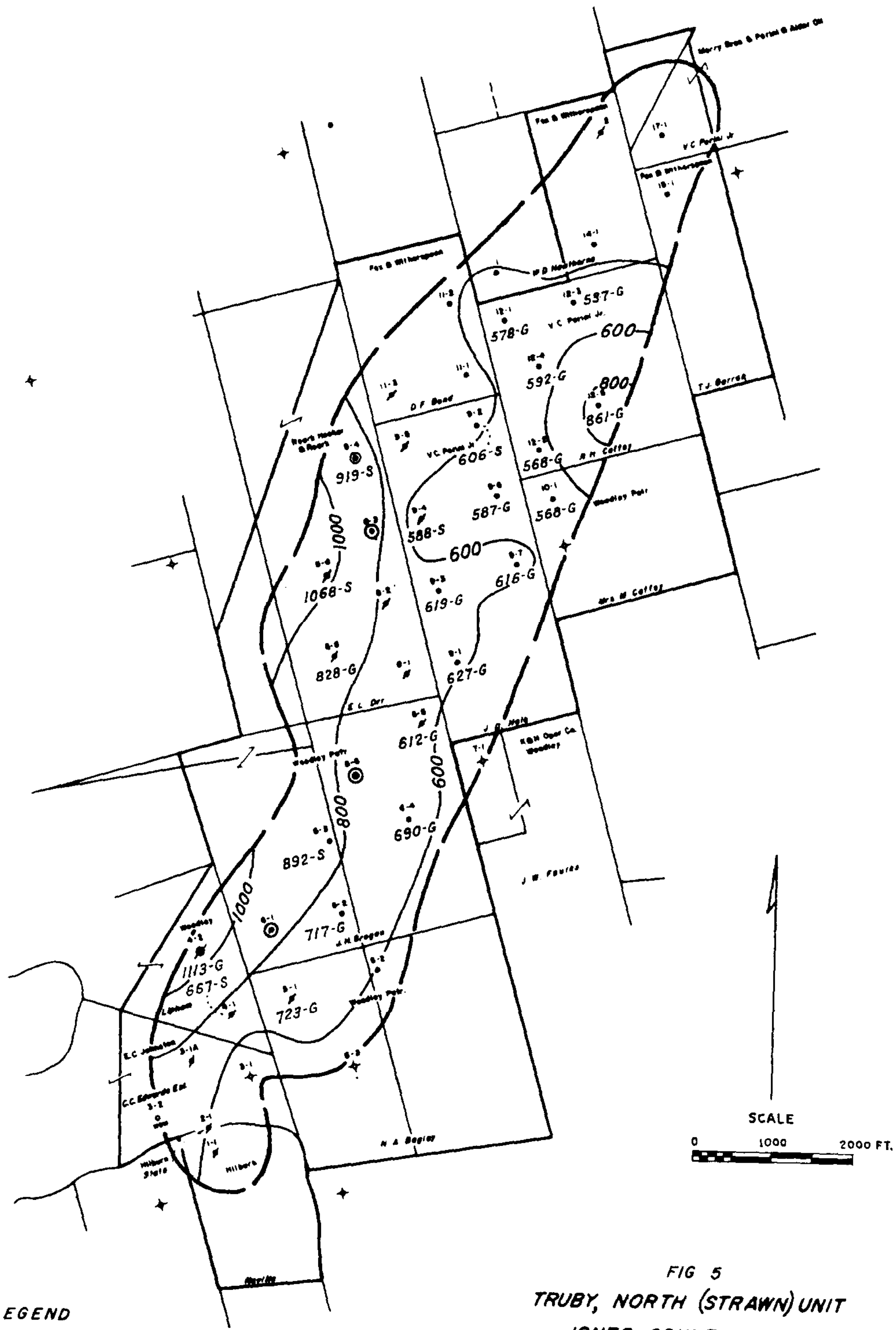
CONTOUR INTERVAL 5 FEET



LEGEND

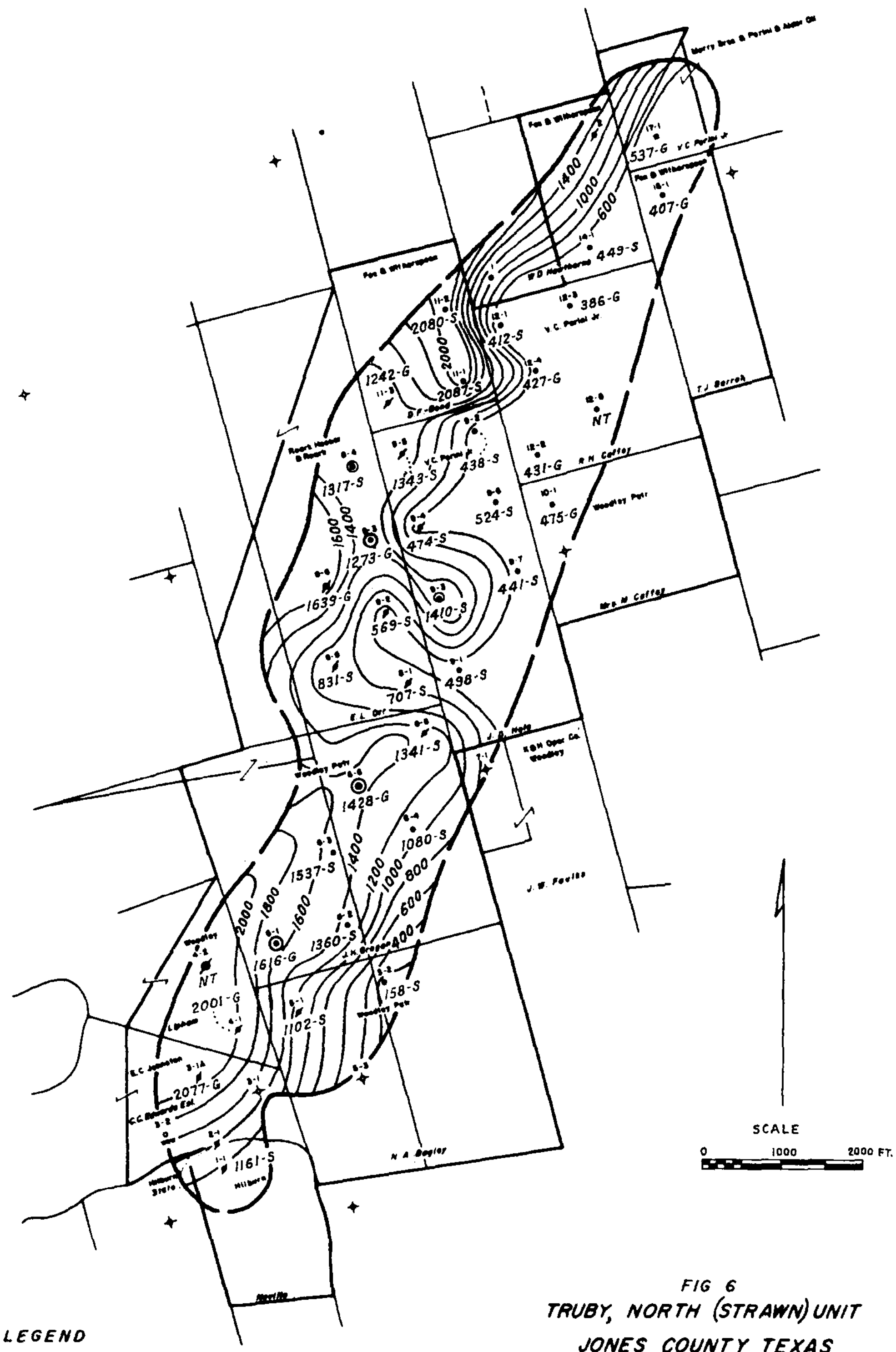
S = Sonolog
G = Gauge
NT = Not Tested

FIG 4
TRUBY, NORTH (STRAWN) UNIT
JONES COUNTY TEXAS
ISOBARIC MAP
BHP SURVEY, JULY 1954
CONTOUR INTERVAL 200 PSI



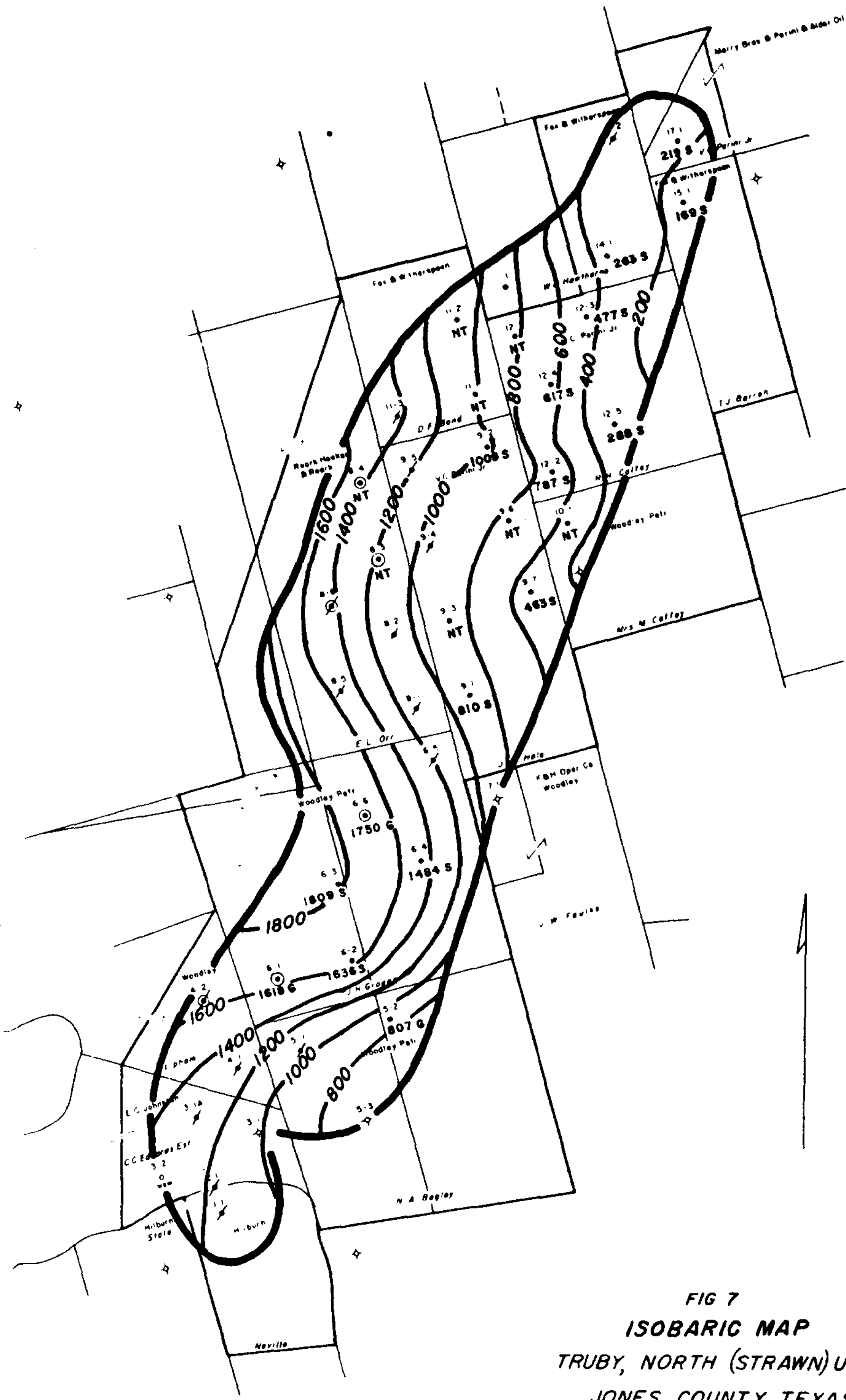
LEGEND
S = Sonolog
G = Gauge
NT = Not Tested

FIG 5
TRUBY, NORTH (STRAWN) UNIT
JONES COUNTY TEXAS
ISOBARIC MAP
BHP SURVEY, NOVEMBER 1956
CONTOUR INTERVAL 200 PSI



LEGEND
S = Sonolog
G = Gauge
NT Not Tested

FIG 6
TRUBY, NORTH (STRAWN) UNIT
JONES COUNTY TEXAS
ISOBARIC MAP
BHP SURVEY, NOVEMBER 1958
CONTOUR INTERVAL 200 PSI



S= Sonoloq
G= Guage
NT= Not Tested

FIG 7

ISOBARIC MAP

TRUBY, NORTH (STRAWN) UNIT

JONES COUNTY TEXAS

BHP Survey, January 17, 1963

Contour Interval 200 PSI

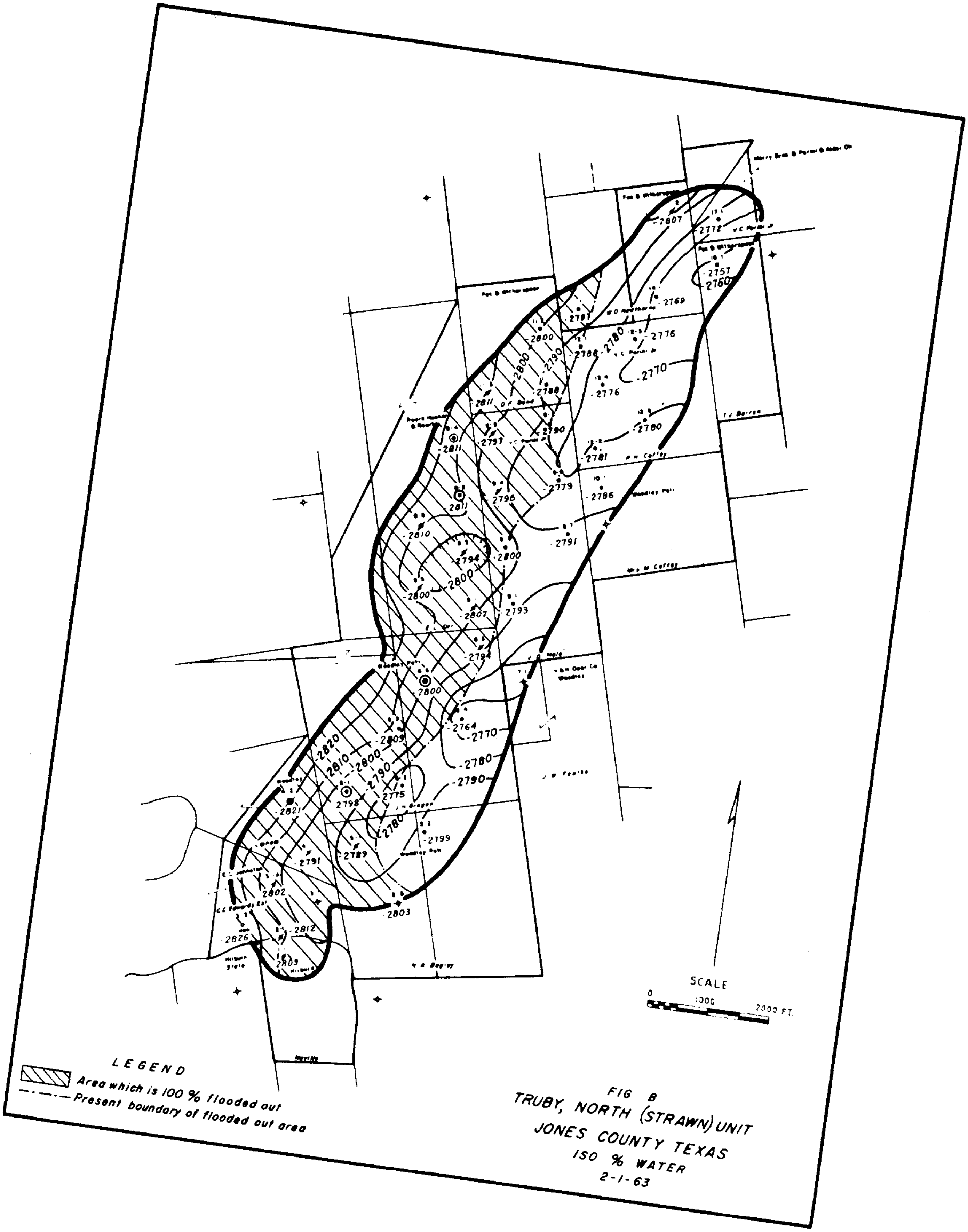
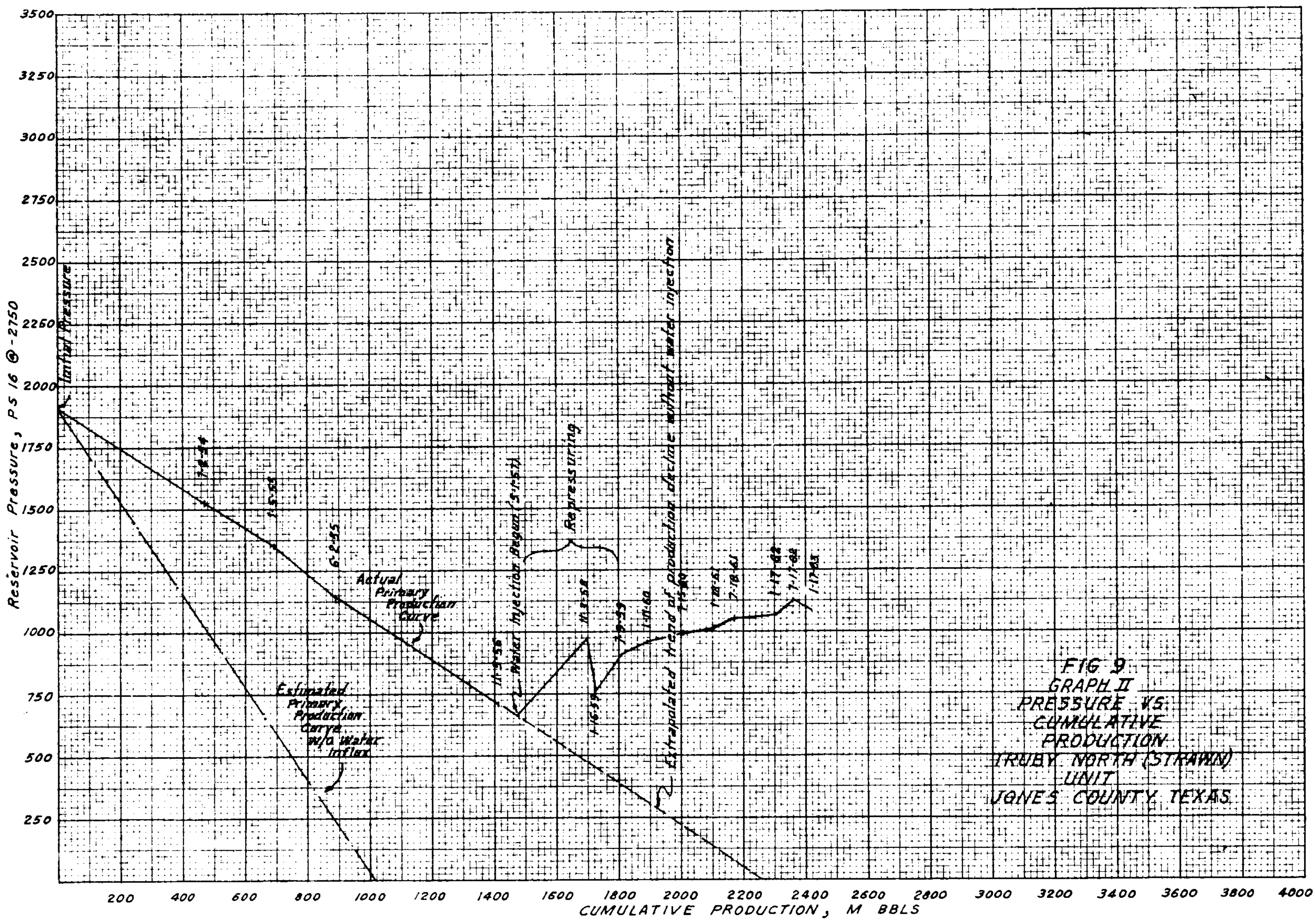


FIG 8
TRUBY, NORTH (STRAWN) UNIT
JONES COUNTY TEXAS
ISO % WATER
2-1-63



Reservoir Pressure, PS 16 @ -2750
3500
3250
3000
2750
2500
2250
2000
1750
1500
1250
1000
750
500
250
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
3000
3200
3400
3600
3800
4000
CUMULATIVE PRODUCTION, M BBLS
Initial Pressure
Actual Primary Production Curve
Estimated Primary Production Curve w/o Water Influx
Water Injection Begun (5-1-57)
Repressuring
Extrapolated trend of production decline without water injection
6-2-55
11-9-56
11-5-58
1-16-59
7-9-59
1-11-60
1-18-61
7-18-61
1-17-62
7-17-62
1-17-63
FIG 9
GRAPH II
PRESSURE VS.
CUMULATIVE
PRODUCTION
TRUBY NORTH (STRAWN)
UNIT
JONES COUNTY, TEXAS

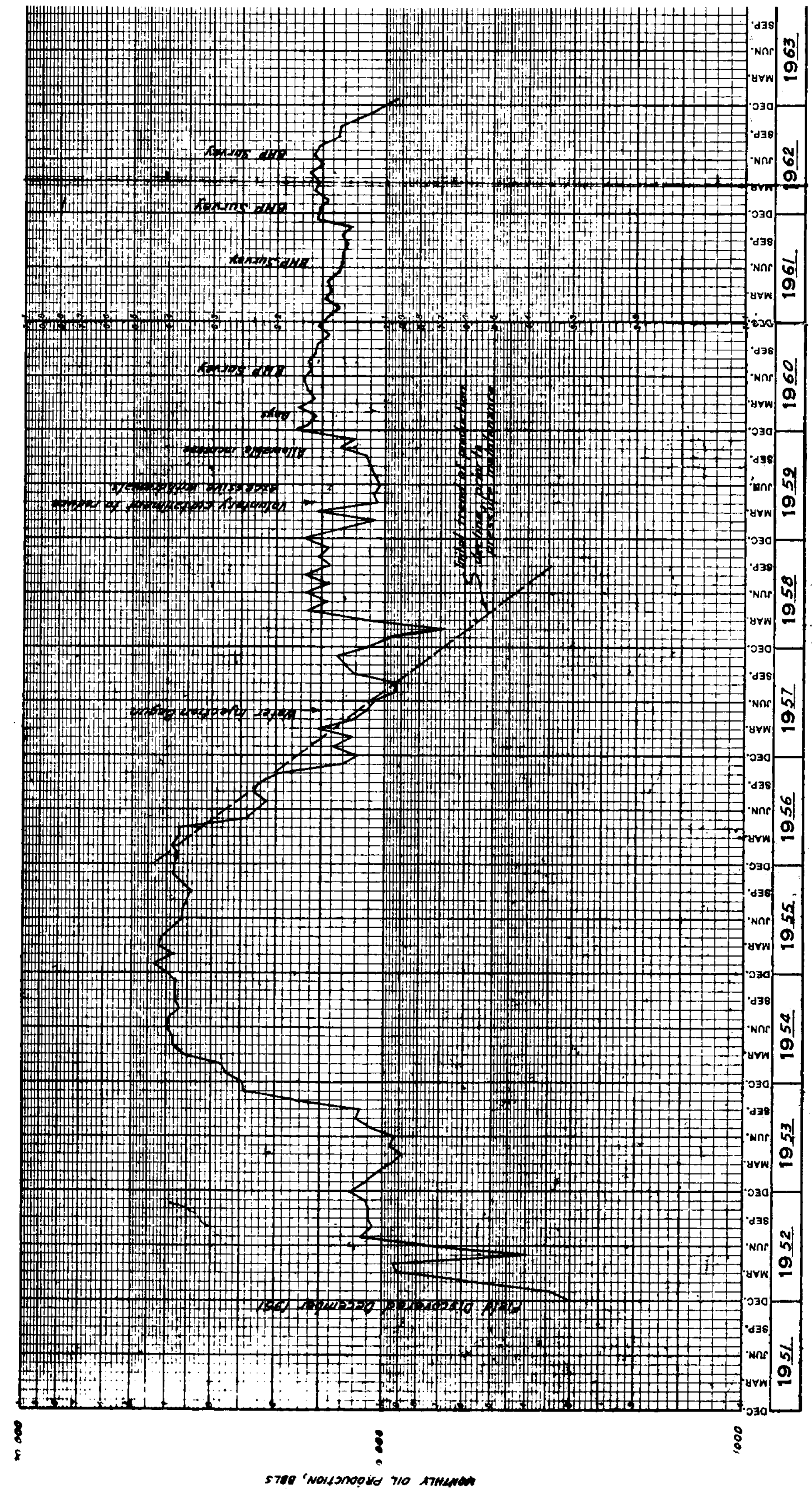
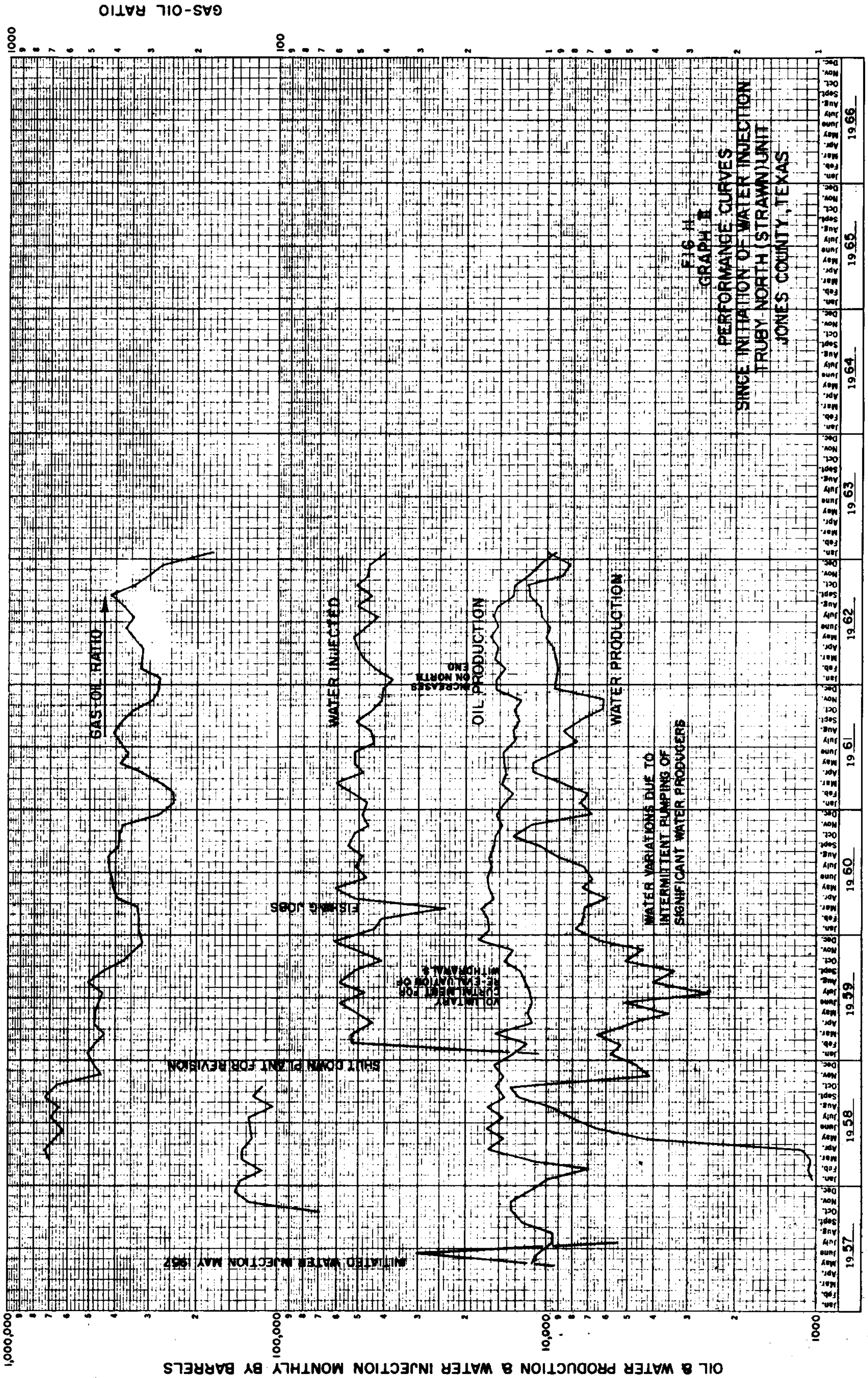


FIG 10 GRAPH I

PRODUCTION DECLINE CURVE
TRUBY NORTH (STRAWN) UNIT, JONES CO. TEX.


GAS-OIL RATIO
OIL & WATER PRODUCTION & WATER INJECTION MONTHLY BY BARRELS
FIG. H
GRAPH II
PERFORMANCE CURVES
SINCE INITIATION OF WATER INJECTION
TRUBY NORTH (STRAWN) UNIT
JONES COUNTY, TEXAS
GAS-OIL RATIO
WATER INJECTED
OIL PRODUCTION
WATER PRODUCTION
INCREASES ON NORTH END
WATER VARIATIONS DUE TO INTERMITTENT PUMPING OF SIGNIFICANT WATER PRODUCERS
FISHING JOBS
VOLUNTARY CURTAILMENT FOR RE-EVALUATION OF WITHDRAWALS
SHUT DOWN PLANT FOR REVISION
INITIATED WATER INJECTION MAY 1957
1957
1958
1959
1960
1961
1962
1963
1964
1965
1966