Engineering And Operating Problems In Waterflooding A Sand Reservoir At 6400 Feet

By DONALD T. MAY
Ryder Scott Co., Petroleum Engineers

INTRODUCTION

The Sadler, West (Penn.) Field is located in Western Grayson County, Texas, and about 3 mi. north of Whitesboro, Texas. The Huff sand reservoir, which is under waterflood, is at an average depth of 6,400 ft and areally covers about 1,550 productive acres. The map in Figure 1 shows the developed area.

Waterfloods in shallow sands to depths of 3,000 ft were started prior to 1930. Operators started waterflooding reservoirs at greater depths within the last 10 years. It has been found that many operating conditions which adversely affected shallow waterflood production likewise affect deep floods.

In order to compare waterflooding of this deeper reservoir with that of shallow reservoirs, the production history of the field and certain reservoir properties are reviewed.

PRIMARY PRODUCTION HISTORY

The curve in Figure 2 shows the primary development, production and injection history from early in 1954 through the first quarter of 1960. It will be noted that the rate of oil production increased during the first 2 yr as new wells were drilled. Most of the leases have made their allowable from inception until early in 1957 which accounts for the flatness of the oil production curve during 1956. The entire productive area had been drilled by November, 1956, and early in 1957 the oil production rate started declining and continued through 1958 and 1959 in a manner common to a solution gas drive reservoir.

PRIMARY PRODUCING MECHANISM

The decline in oil production without any water production during the years 1957, 1958 and 1959 is typical in a reservoir where solution gas is essentially the only energy driving oil to production. From reservoir studies it was found that the dry holes, which are shown along the east side of the developed area of the reservoir, were due to the Huff sand being structurally low and below the oil-water contact ranging between 5,760 and 5,766 ft sub-sea.

The primary production history of a producer just outside of the unitized area supported the fact that solution gas was the primary producing mechanism and that the water below the oil-water contact was not effective in driving oil. The well in reference is located about 800 ft southeast of Unit well No. 1 in the southeast corner of the field. At this well the base of the Huff sand is at the oil-water contact. Figure 3 is a curve showing the production history from the time the well was completed in March, 1954, until abandonment in December, 1955. The initial potential of this well was reported at 149 BOPD and no water with a gas-oil ratio of 400. It produced from 65 to 80 BOPD for about 4 months, after which time its oil production rate declined rapidly. Within 1 month after completion of this well its rate of water production was about 20 BPD and remained at this average rate through 1954. At the end of the year 1954 the rate of water production started declining rapidly at a rate parelleling the oil decline. If water had been a driving mechanism the rate of water production would have increased during 1955 rather than decline with the oil production.

RESERVOIR PROPERTIES INFLUENCING FLOOD PLAN CHOSEN

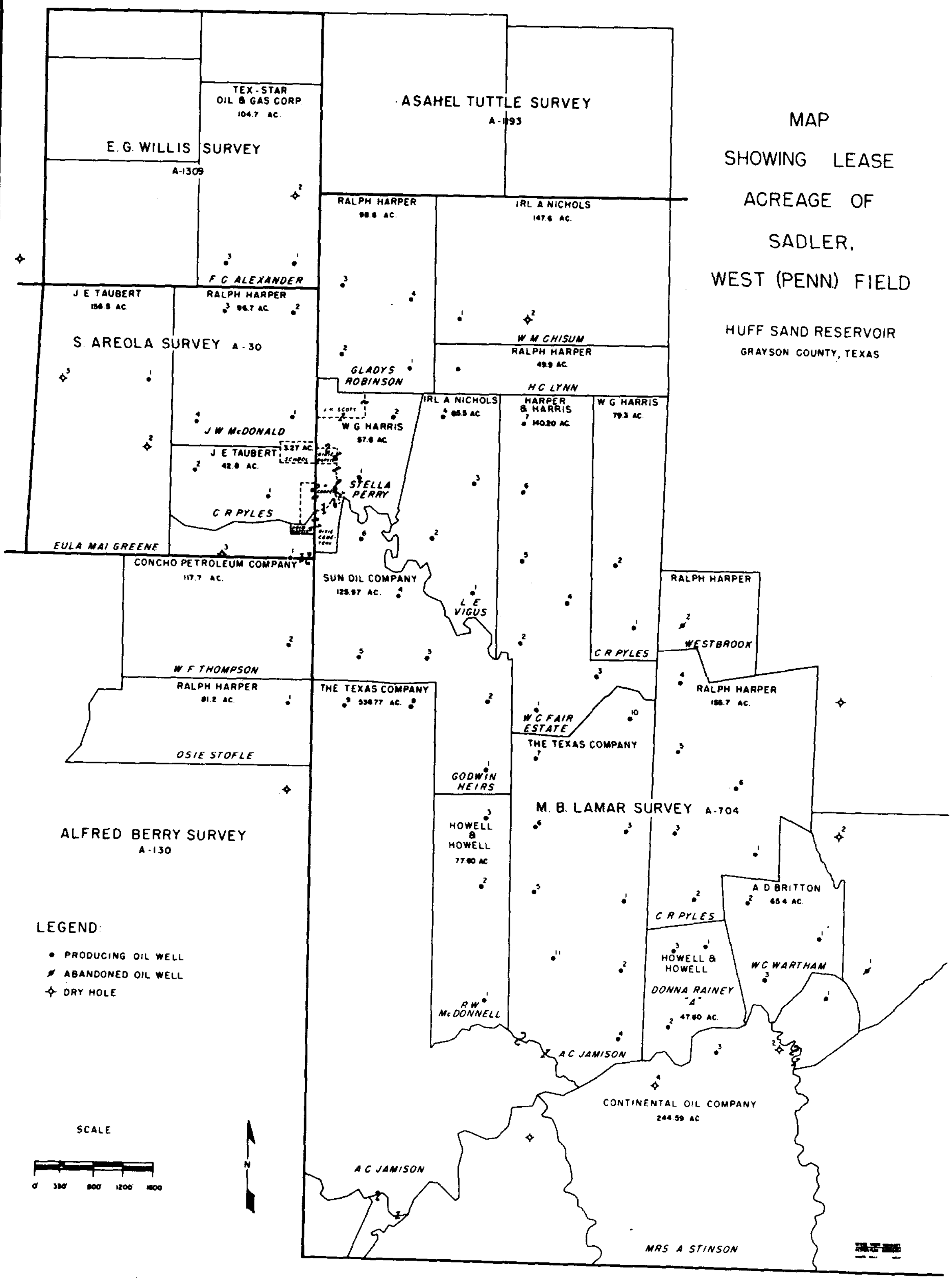
Figure 4 shows the structure of the reservoir and was determined from contours on the base of the "Q" limestone which is found from 10 to 30 ft above the top of the Huff sand. The structure shows a simple monocline which dips N-50°-E- at a rate of approximately 140 ft per mile. Accumulation of oil in the Huff sand apparently is the result of a porosity 'pinchout' on the up-dip side of the structure, while on the down-dip side, a transition from oil to water defines the limits of the field.

To show how the sand thickness is distributed throughout the field an ispoach of estimated net waterflood pay is presented in Figure 5. The reservoir has a total of 18,881 Ac Ft and covers 1,550 acres which gives an average sand thickness near 12 ft.

In waterflooding there are generally 3 water injection plans which have been used widely. These are the line drive, the peripheral and the 5 spot pattern or its modification. The following presents material for choosing a 5 spot pattern for waterflooding the Huff sand reservoir.

Firstly, small core samples revealed that sand was bedded so that the effective vertical permeability would be very low compared to the horizontal permeability.

Secondly, cross sectional studies indicated that the sand reservoir was a series of ancient offshore bars which were deposited simultaneously and in series. Thus, it comprises a number of sand lenses separated by thin shale breaks and some limey streaks. The thin shale and/or limebreaks are not continuous across the field or through the length of the field which is evidence that the reservoir rock is not a blanket type deposition. Figure 6 shows the wells included in the two cross sections AB and CD. Figure 7 shows an interpretation of the manner in which the



MAP
SHOWING LEASE
ACREAGE OF
SADLER,
WEST (PENN) FIELD
HUFF SAND RESERVOIR
GRAYSON COUNTY, TEXAS
ASAHEL TUTTLE SURVEY
E. G. WILLIS SURVEY
A-1309
TEX-STAR OIL & GAS CORP
104.7 AC.
RALPH HARPER
IRL A NICHOLS
F C ALEXANDER
J E TAUBERT
156.5 AC.
RALPH HARPER
S. AREOLA SURVEY A-30
W M CHISUM
RALPH HARPER
49.9 AC.
GLADYS ROBINSON
H C LYNN
IRL A NICHOLS
HARPER & HARRIS
140.20 AC.
W G HARRIS
79.3 AC.
W G HARRIS
87.6 AC.
J W McDONALD
J E TAUBERT
42.8 AC.
STELLA PERRY
C R PYLES
EULA MAI GREENE
CONCHO PETROLEUM COMPANY
117.7 AC.
SUN OIL COMPANY
125.97 AC.
L E VIGUS
RALPH HARPER
WESTBROOK
C R PYLES
W F THOMPSON
RALPH HARPER
81.2 AC.
THE TEXAS COMPANY
536.77 AC.
RALPH HARPER
136.7 AC.
W C FAIR ESTATE
THE TEXAS COMPANY
OSIE STOFLE
GODWIN HEIRS
M. B. LAMAR SURVEY A-704
HOWELL & HOWELL
77.60 AC
ALFRED BERRY SURVEY
A-130
A D BRITTON
65.4 AC.
C R PYLES
LEGEND:
PRODUCING OIL WELL
ABANDONED OIL WELL
DRY HOLE
HOWELL & HOWELL
W C WARTHAM
DONNA RAINEY "A"
47.60 AC.
R W McDONNELL
A C JAMISON
CONTINENTAL OIL COMPANY
244.59 AC
SCALE
0 330' 800' 1200' 1600'
N
A C JAMISON
MRS A STINSON

FIGURE I

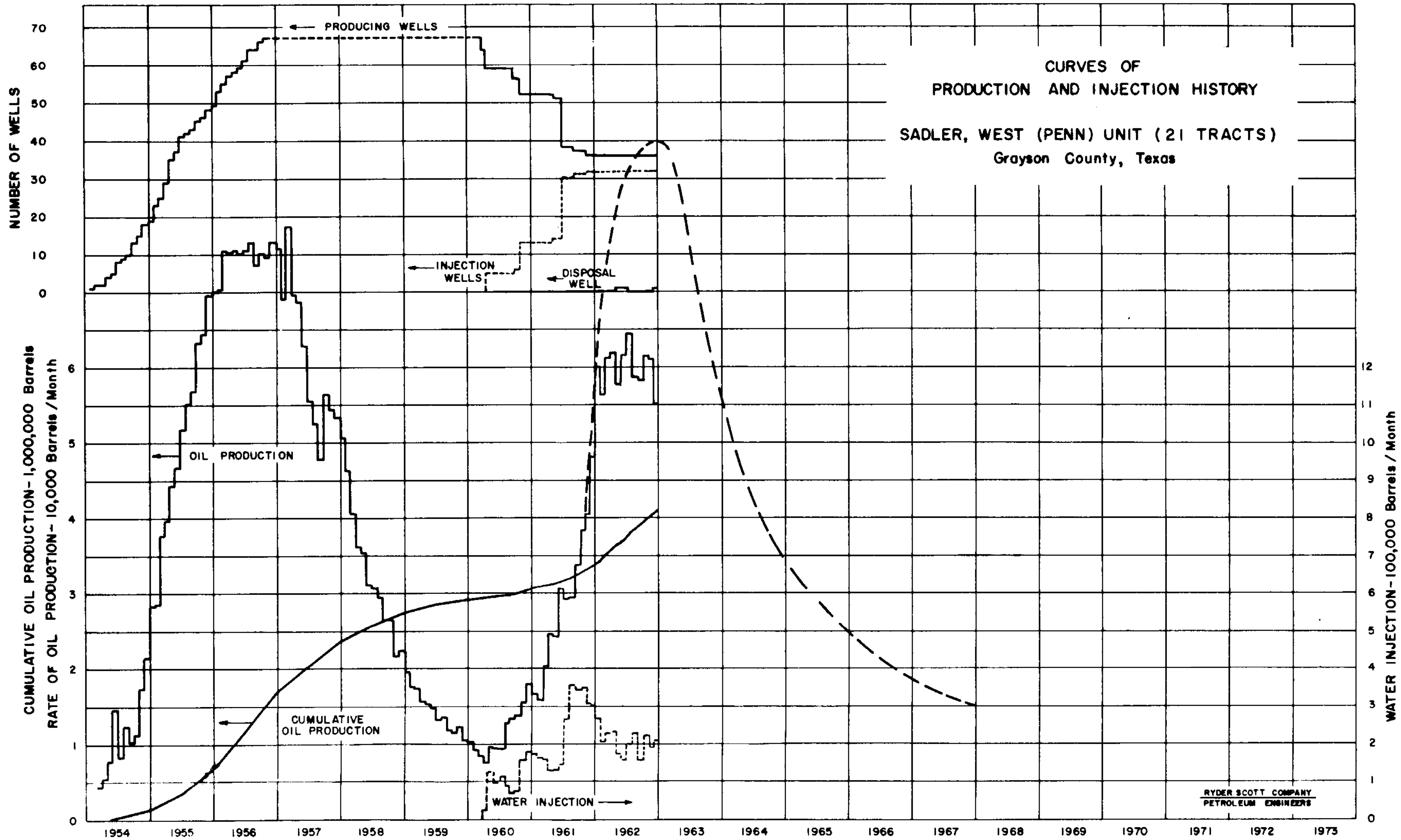

CURVES OF
PRODUCTION AND INJECTION HISTORY
SADLER, WEST (PENN) UNIT (21 TRACTS)
Grayson County, Texas
PRODUCING WELLS
INJECTION WELLS
DISPOSAL WELL
OIL PRODUCTION
CUMULATIVE OIL PRODUCTION
WATER INJECTION
NUMBER OF WELLS
CUMULATIVE OIL PRODUCTION-1,000,000 Barrels
RATE OF OIL PRODUCTION-10,000 Barrels/Month
WATER INJECTION-100,000 Barrels/Month
1954 1955 1956 1957 1958 1959 1960 1961 1962 1963 1964 1965 1966 1967 1968 1969 1970 1971 1972 1973
RYDER SCOTT COMPANY
PETROLEUM ENGINEERS

FIGURE 2

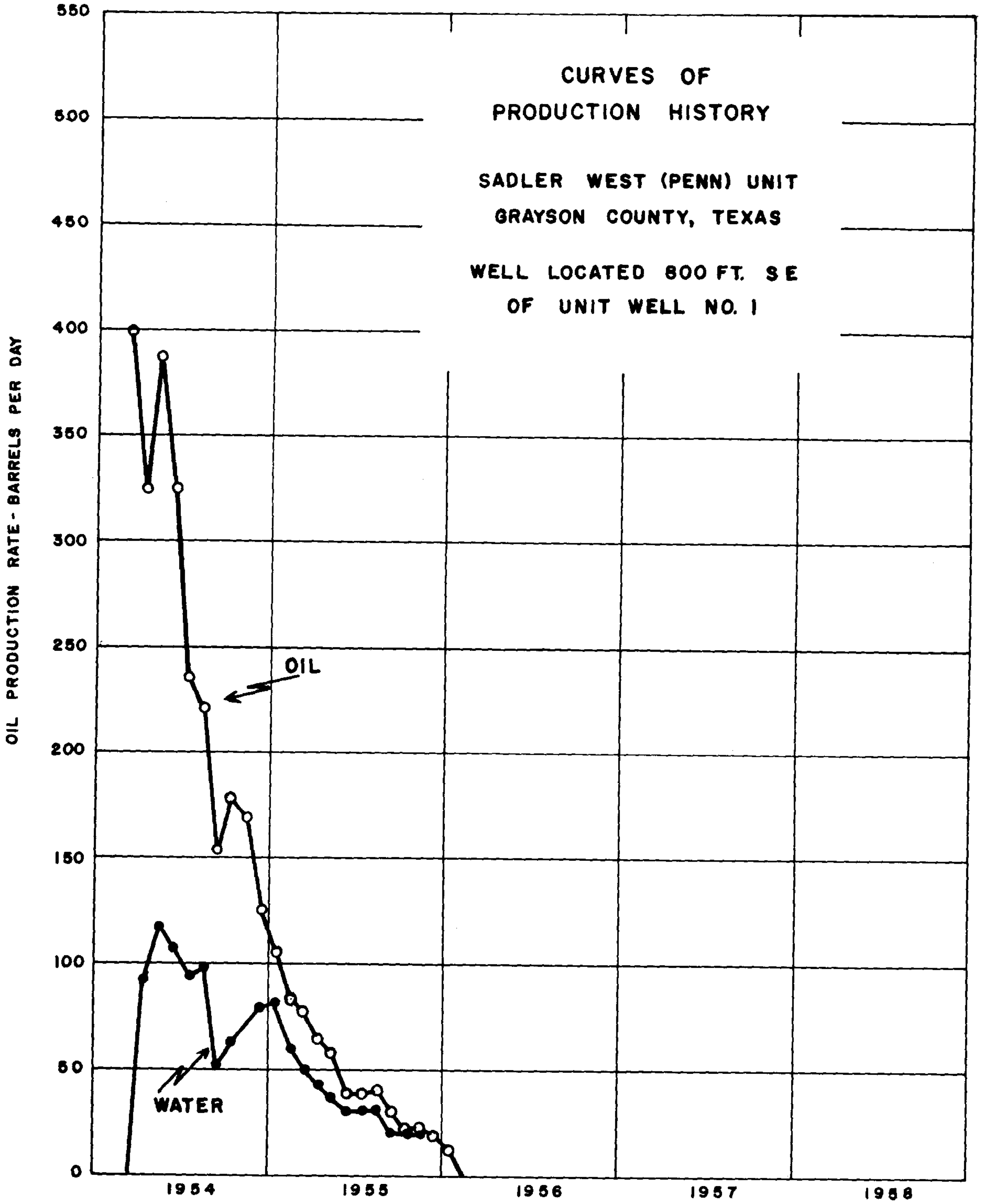

CURVES OF
PRODUCTION HISTORY
SADLER WEST (PENN) UNIT
GRAYSON COUNTY, TEXAS
WELL LOCATED 800 FT. SE
OF UNIT WELL NO. 1
OIL PRODUCTION RATE - BARRELS PER DAY
550
500
450
400
350
300
250
200
150
100
50
0
OIL
WATER
1954
1955
1956
1957
1958

FIGURE 3

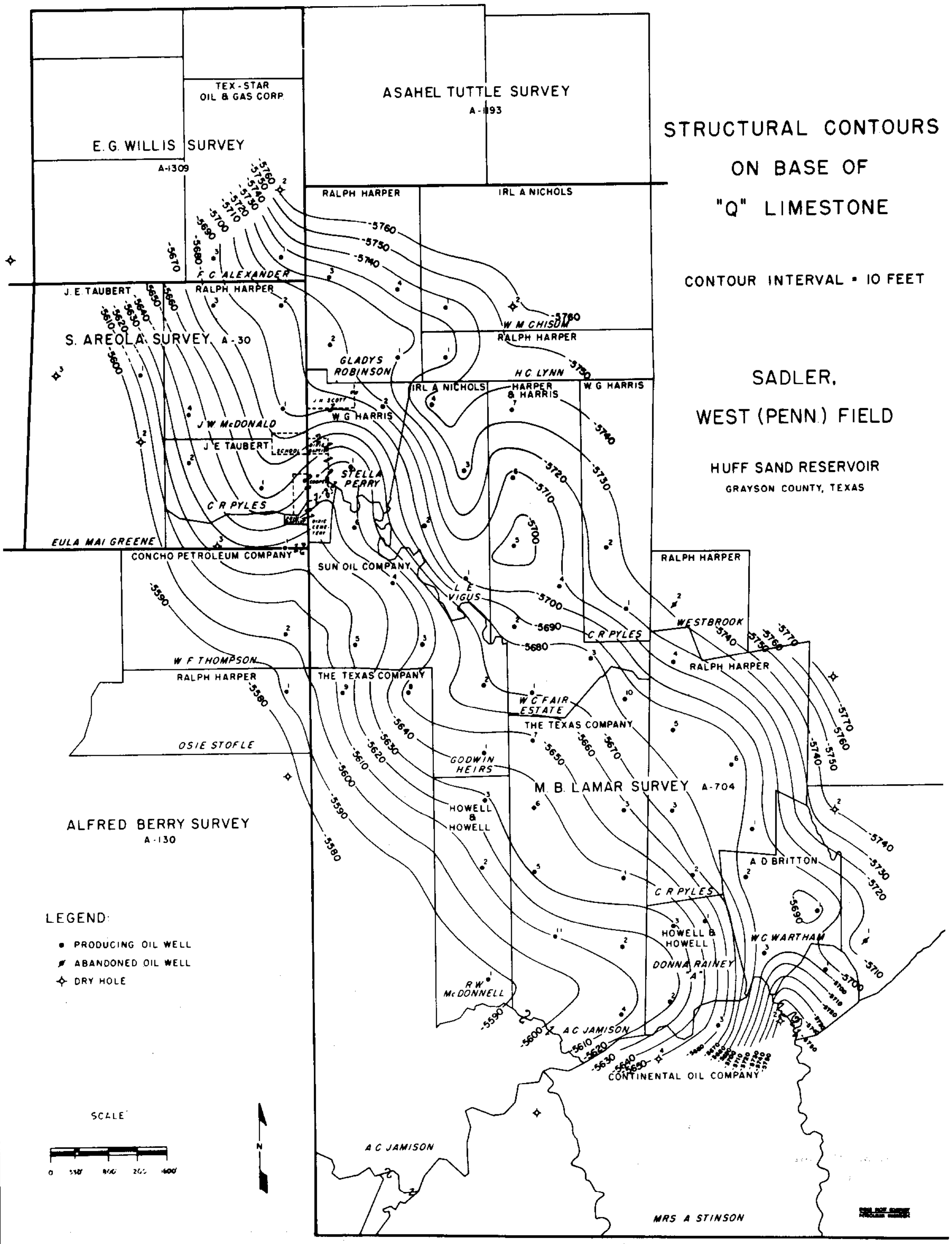

STRUCTURAL CONTOURS
ON BASE OF
"Q" LIMESTONE
CONTOUR INTERVAL = 10 FEET
SADLER,
WEST (PENN.) FIELD
HUFF SAND RESERVOIR
GRAYSON COUNTY, TEXAS
ASAHEL TUTTLE SURVEY
E. G. WILLIS SURVEY
A-1309
TEX-STAR OIL & GAS CORP
RALPH HARPER
IRL A NICHOLS
F C ALEXANDER
J. E TAUBERT
S. AREOLA SURVEY A-30
W M CHISUM
GLADYS ROBINSON
H C LYNN
HARPER & HARRIS
W G HARRIS
J W McDONALD
STELLA PERRY
C R PYLES
EULA MAI GREENE
CONCHO PETROLEUM COMPANY
SUN OIL COMPANY
L E VIGUS
WESTBROOK
W F THOMPSON
THE TEXAS COMPANY
W C FAIR ESTATE
OSIE STOFLE
GODWIN HEIRS
M. B. LAMAR SURVEY A-704
HOWELL & HOWELL
ALFRED BERRY SURVEY
A-130
A D BRITTON
W C WARTHAM
DONNA RAINEY "A"
R W McDONNELL
A C JAMISON
CONTINENTAL OIL COMPANY
MRS A STINSON
LEGEND
PRODUCING OIL WELL
ABANDONED OIL WELL
DRY HOLE
SCALE
N

FIGURE 4

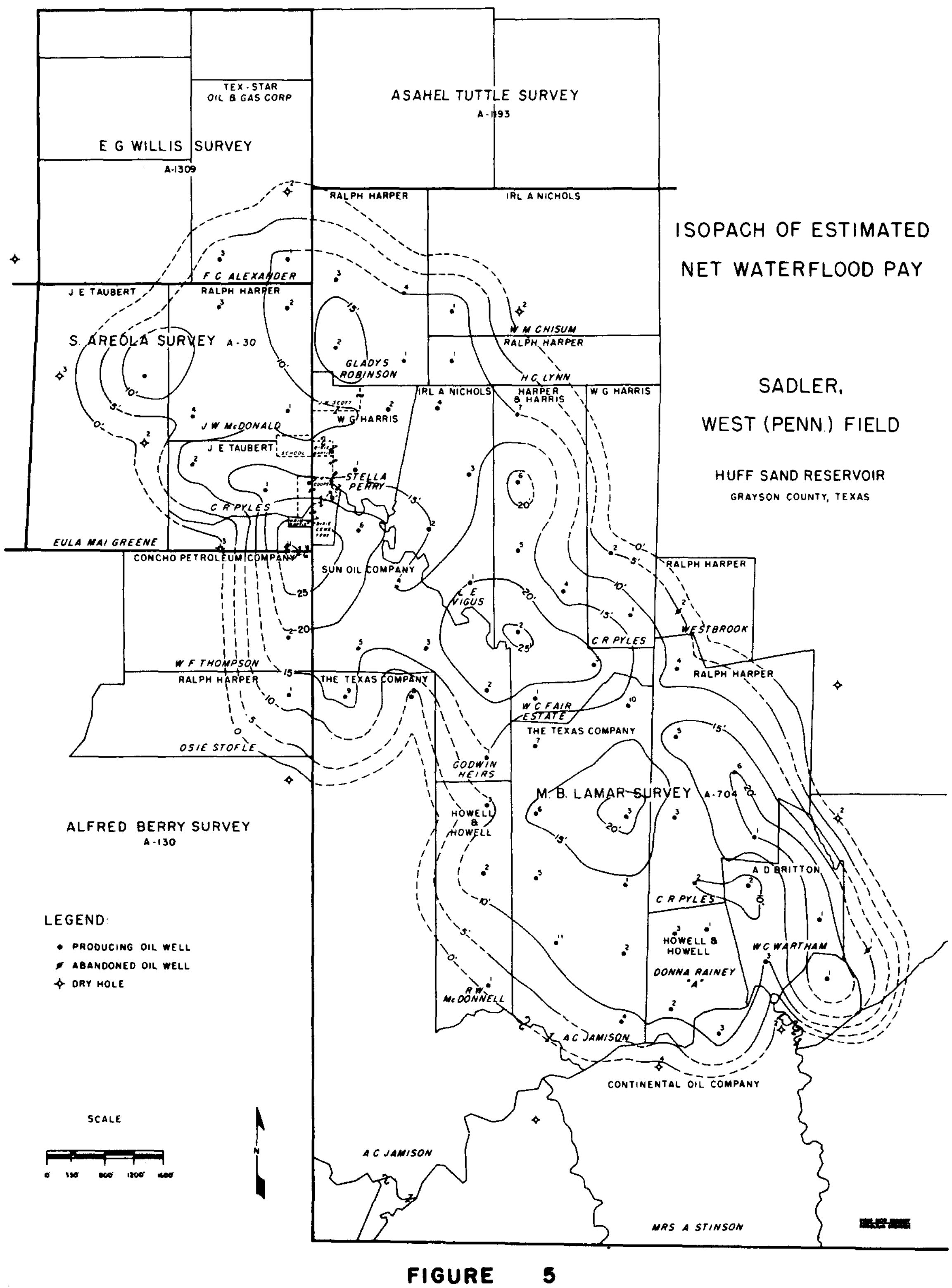

ISOPACH OF ESTIMATED
NET WATERFLOOD PAY
SADLER,
WEST (PENN.) FIELD
HUFF SAND RESERVOIR
GRAYSON COUNTY, TEXAS
ASAHEL TUTTLE SURVEY
A-1193
TEX-STAR
OIL & GAS CORP
E G WILLIS SURVEY
A-1309
RALPH HARPER
IRL A NICHOLS
F C ALEXANDER
J E TAUBERT
S. AREOLA SURVEY A-30
W M CHISUM
GLADYS ROBINSON
H G LYNN
HARPER & HARRIS
W G HARRIS
J W McDONALD
STELLA PERRY
C R PYLES
EULA MAI GREENE
CONCHO PETROLEUM COMPANY
SUN OIL COMPANY
L E VIGUS
WESTBROOK
W F THOMPSON
THE TEXAS COMPANY
W C FAIR ESTATE
OSIE STOFLE
GODWIN HEIRS
M. B. LAMAR SURVEY A-704
HOWELL & HOWELL
A D BRITTON
ALFRED BERRY SURVEY
A-130
W C WARTHAM
DONNA RAINEY "A"
R W McDONNELL
A C JAMISON
CONTINENTAL OIL COMPANY
MRS A STINSON
LEGEND:
PRODUCING OIL WELL
ABANDONED OIL WELL
DRY HOLE
SCALE
0 150' 800' 1200' 1600'
N

FIGURE 5

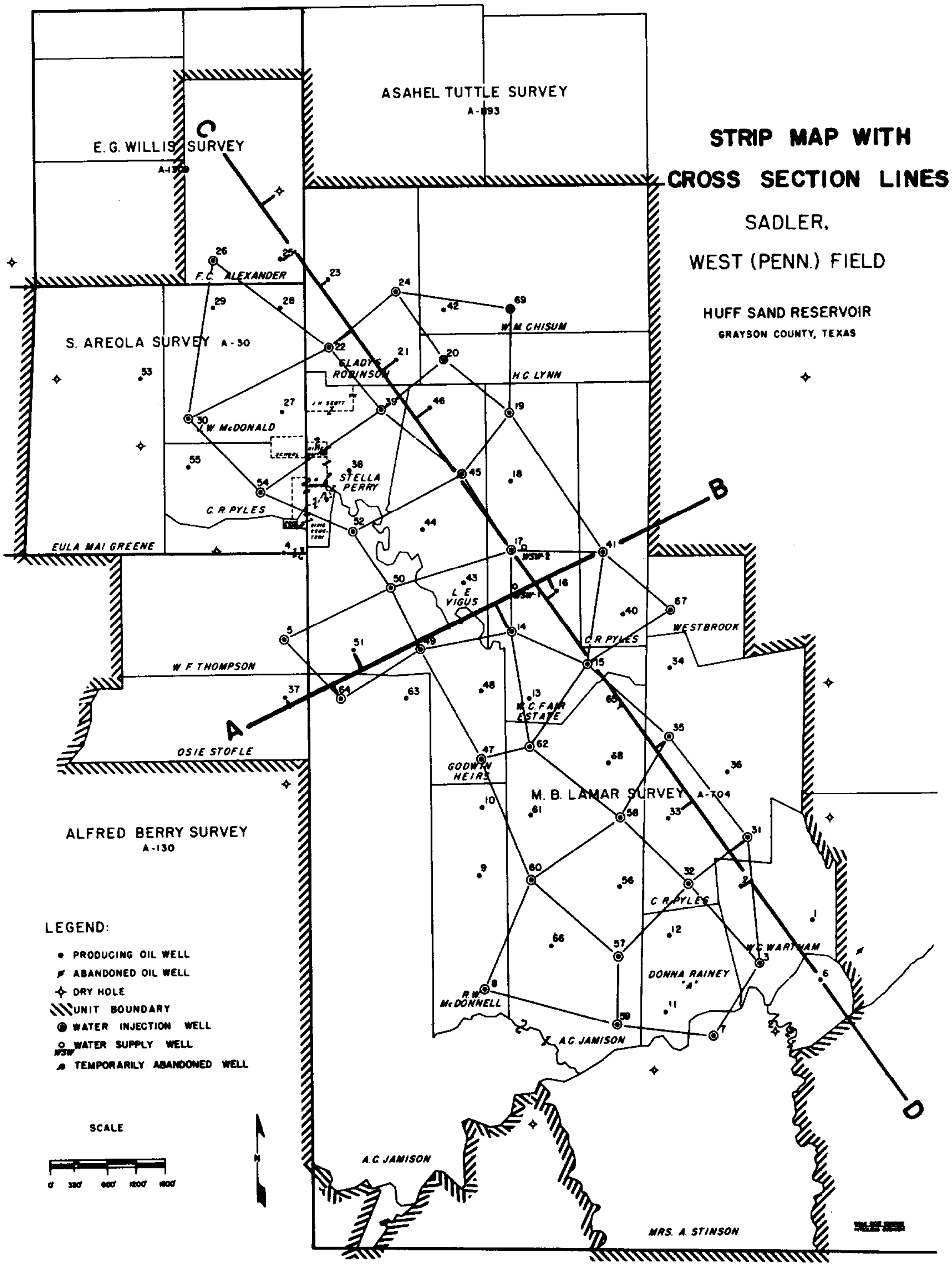

STRIP MAP WITH
CROSS SECTION LINES
SADLER,
WEST (PENN.) FIELD
HUFF SAND RESERVOIR
GRAYSON COUNTY, TEXAS
ASAHEL TUTTLE SURVEY
E. G. WILLIS SURVEY
S. AREOLA SURVEY A-30
ALFRED BERRY SURVEY
A-130
M. B. LAMAR SURVEY A-704
F. C. ALEXANDER
GLADYS ROBINSON
W. M. CHISUM
H C LYNN
J. W. McDONALD
STELLA PERRY
C R PYLES
EULA MAI GREENE
L. E. VIGUS
W F THOMPSON
OSIE STOFLE
WESTBROOK
W. C. FAIR ESTATE
GODWIN HEIRS
DONNA RAINEY "A"
W C WARTHAM
R W McDONNELL
A C JAMISON
MRS. A. STINSON
LEGEND:
PRODUCING OIL WELL
ABANDONED OIL WELL
DRY HOLE
UNIT BOUNDARY
WATER INJECTION WELL
WATER SUPPLY WELL
TEMPORARILY ABANDONED WELL
SCALE
N

FIGURE 6

STRIP MAP
&
CROSS SECTION A-B & C-D

HORIZONTAL SCALE 1" = 400'
VERTICAL SCALE 5" = 100'

SADLER WEST (PENN) FIELD
GRAYSON COUNTY, TEXAS

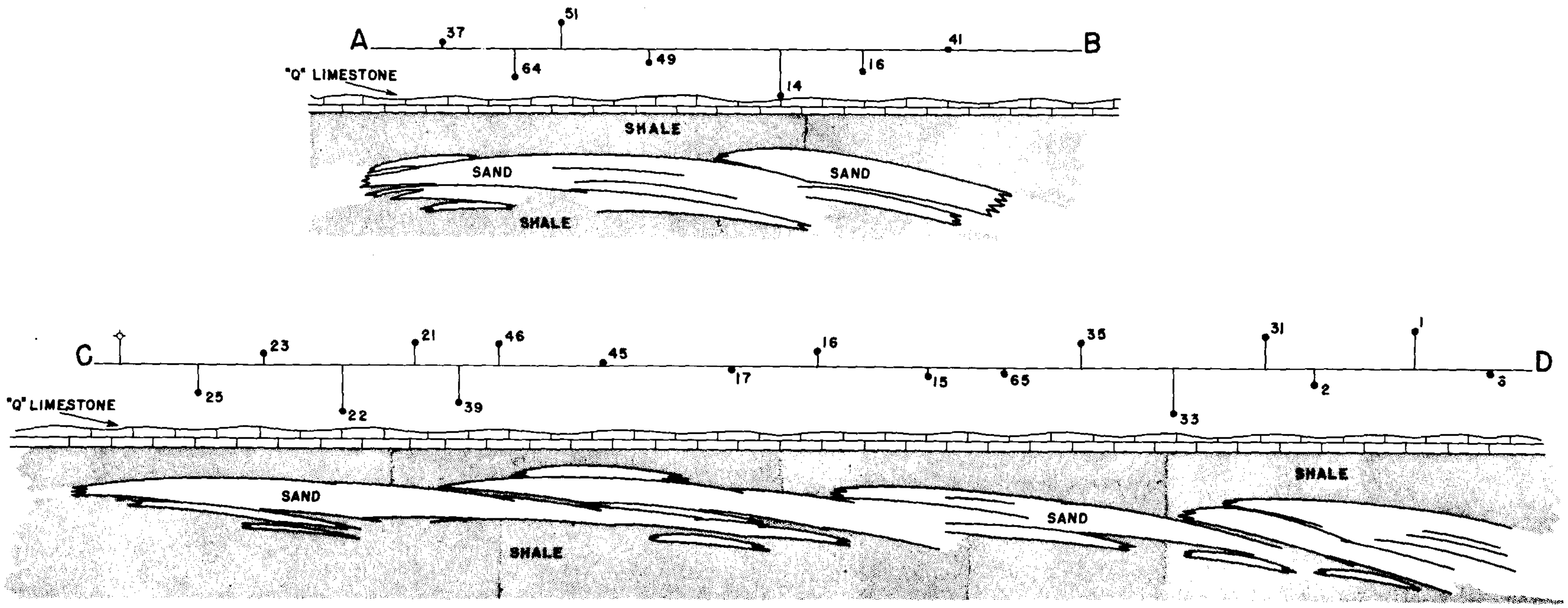


FIGURE 7

sand bars are laid down as correlated from electrical logs. It is readily apparent that a number of the smaller sand bars are intercepted by only 3 or 4 wells. Such bar areas would not be flooded where a line drive or peripherial plan of injecting water was adopted. Also, the end areas of many of the larger bars would remain unswept because they would not be intercepted with sufficient producers and injectors. The shale barriers between bars would effectively stop any fluid movement across them during the flood life of the reservoir. In order to intercept the greatest number of sand bars, a 5 spot pattern was devised so that fluid movement from injector to the producer would be obstructed the least by silty or shale layers which are effectively impermeable.

Figure 8 shows the 5 spot pattern plan wherein producing wells were converted to intakes to avoid drilling new wells in order to keep the development cost at a minimum.

PILOT FLOOD

Before most floods are developed on a full scale, a pilot is installed in order to determine if the reservoir shows reponse as figured by the engineers. In this flood, Unit wells Nos. 14, 15, 17, 41 and 67 were chosen for the pilot operation. Before water injection started on April 25, 1960, it was pointed out to the operator that well No. 16 may experience two peak rates of oil production if the conclusion was correct about the reservoir being made up of a number of individual sand bars. The producer well No. 16 showed that it served 2 distinct sand bars, one intercepted by well No. 14 and the other one intercepted by wells Nos. 15, 17 and 41. The production curve in Figure 13 shows the 2 peaks for well No. 16. This gave support to the conclusion about the reservoir being made up of a number of sand bars. Thus the performance of the pilot gave support to the choice made in the waterflood pattern plan.

NEXT STATES OF EXPANSION

The pilot was in operation about six months which was just sufficient time to study the performance and decide on the expansion. In November, 1960, the next group of 8 producing wells No. 19, 35, 45, 47, 49, 50, 52 and 62 which encircled the pilot area, were converted to intakes. In July, 1961, the remaining 18 producers, which were needed as intakes to place the entire reservoir under flood, were converted as shown in Figure 8.

THE INJECTION SYSTEM

Since fresh water did not adversely affect the Huff sand it was decided to use the Trinity water as a supply, for it was shallow and would furnish somewhat in excess of 10,000 BWPD per well by lifting with a turbine pump set at a depth of about 350 ft. Since the fresh water was not compatable with the connate water in the Huff sand reservoir, it was figured to be more economical to use a dual injection system in order to inject fresh water and produced saline water separately and simultaneously into the reservoir. The other plan, which was figured in the comparison, would have required a treating and filtering system wherein the two waters would be mixed at the surface before being injected.

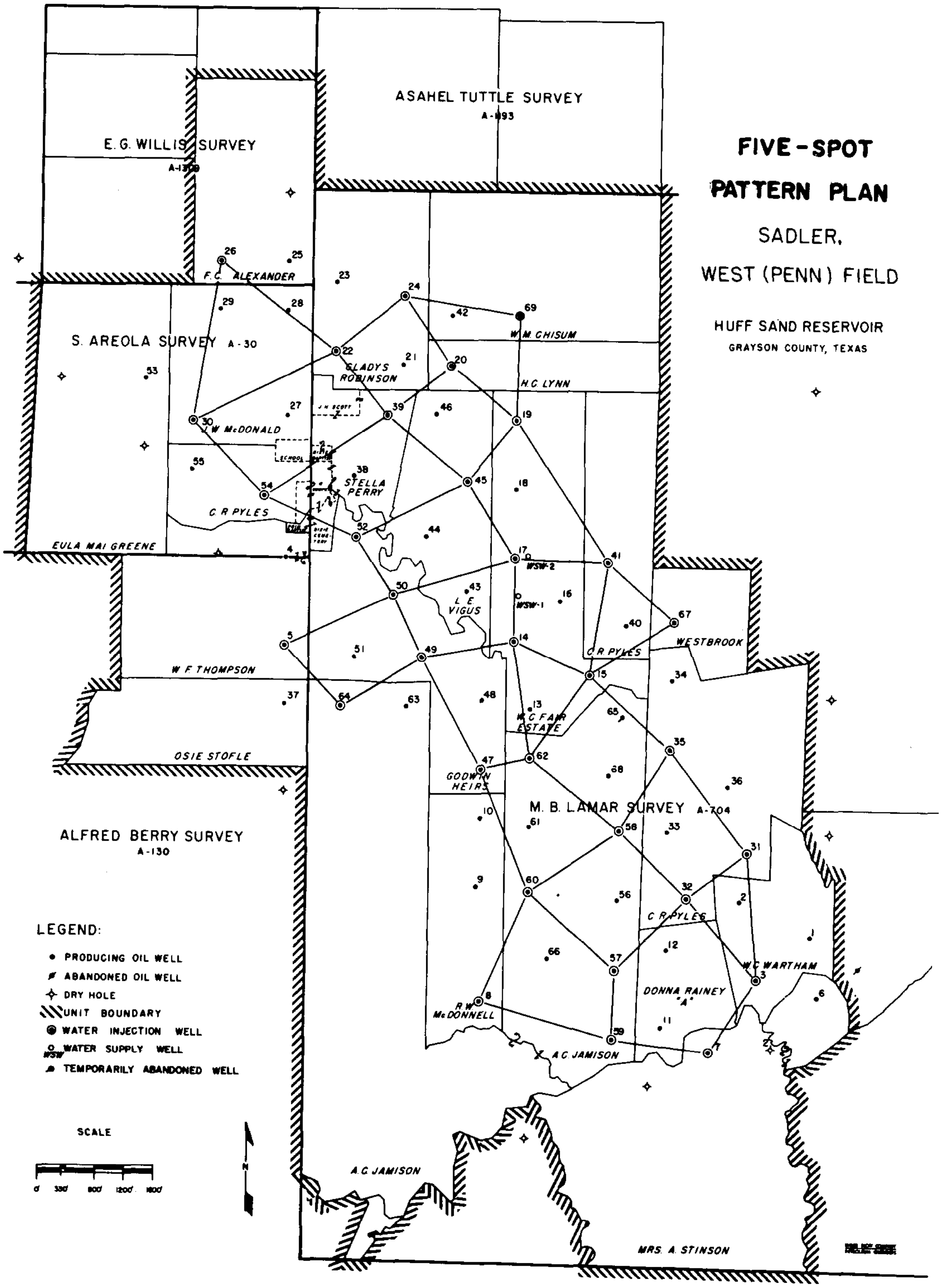
Figure 9 is a sketch plan to show the pipe and valve combinations of the intake manifold and pressured water discharge header so that either fresh or salt water can be delivered to any one of the 5 pressure pumps and delivered to the respective header carrying either of the 2 waters.

Figure 10 shows the water distribution system with a dual trunk line from the plant to the southeast area of the field. This dual trunk line will permit injecting either fresh or salt water at any time independently into any lateral line serving one or more water intake wells. As done in many floods, a centrifugal pump was used to deliver water to the injection wells serving all the field outside the pilot area. The centrifugal pump delivers a large volume of water to the intakes to accelerate the filling up of the reservoir and thereby avoid large initial capital outlay. As soon as the intakes begin to show pressure at the wellhead, the pressure pumps are installed as they will be required to deliver water at sufficient pressure to maintain satisfactory injection rates.

THE GATHERING SYSTEM

As will be noted on any map figure the unitized area comprises 21 different leases. During the pilot flood operation and for sometime after the first stage of expansion the tank batteries and gathering lines for the separate leases were utilized. At the time of the second stage of expansion, which placed the entire field under flood, the oil storage tanks were grouped into 6 separate batteries, which had proper sized heater-treaters, from which the gauger delivered the produced oil to the pipe line. Near the middle of 1960 the produced water reached a significant volume and at this time a separate injection system to handle produced water was utilized. Centrifugal pumps were installed to drive the produced water from the respective tank batteries to the main produced water storage at the pressure plant.

At the beginning of 1962 a centralized oil and water gathering system was agreed upon. The lines of the gathering system which delivers all the produced oil and water to the storage tanks located near the pressure plant, are shown in Figure 11. It was decided to eliminate heater-treaters for aiding in the separation of oil and water. Treating and storage vessels were installed which would permit separating the oil and water without employing heat as done with a heat-treater. The treating and storage vessel system is diagrammed in Figure 12. The line of flow through the vessels is shown by arrows starting at the lift of the system and ending on the right. The oil and water from the field gathering system enters the 24 in. diameter header, raises through .the 10 in. pipe emptying into a four foot diameter flume. The flume discharges into the 4,000 bbl gun barrel with a spreader which facilitates the separation of oil and water. Most of the water is removed in the first gun barrel. The remaining water in the oil is removed by the time it has passed through the second or the 1,750 bbl gun barrel. From this point it empties into 2 high 1,000 bbl storage tanks and finally into the high 500 bbl surge tank which delivers market oil to the LACT unit connected to the pipe line. The installation cost and the operating cost of a centralized heater-treater system as compared to a gun barrel system which is designated by the plan as shown in Figure 13 for handling 3,000 BOPD plus 6,000 BWPD is as follows:



FIVE-SPOT PATTERN PLAN
SADLER, WEST (PENN) FIELD
HUFF SAND RESERVOIR
GRAYSON COUNTY, TEXAS
ASAHEL TUTTLE SURVEY
E. G. WILLIS SURVEY
S. AREOLA SURVEY A-30
ALFRED BERRY SURVEY
A-130
M. B. LAMAR SURVEY A-704
F. C. ALEXANDER
GLADYS ROBINSON
W. M. CHISUM
H. C. LYNN
J. W. McDONALD
STELLA PERRY
C. R. PYLES
EULA MAI GREENE
L. E. VIGUS
W. F. THOMPSON
WESTBROOK
OSIE STOFLE
W. C. FARR ESTATE
GODWIN HEIRS
DONNA RAINEY "A"
W. C. WARTHAM
R. W. McDONNELL
A. C. JAMISON
MRS. A. STINSON
LEGEND:
PRODUCING OIL WELL
ABANDONED OIL WELL
DRY HOLE
UNIT BOUNDARY
WATER INJECTION WELL
WATER SUPPLY WELL
TEMPORARILY ABANDONED WELL
SCALE

FIGURE 8

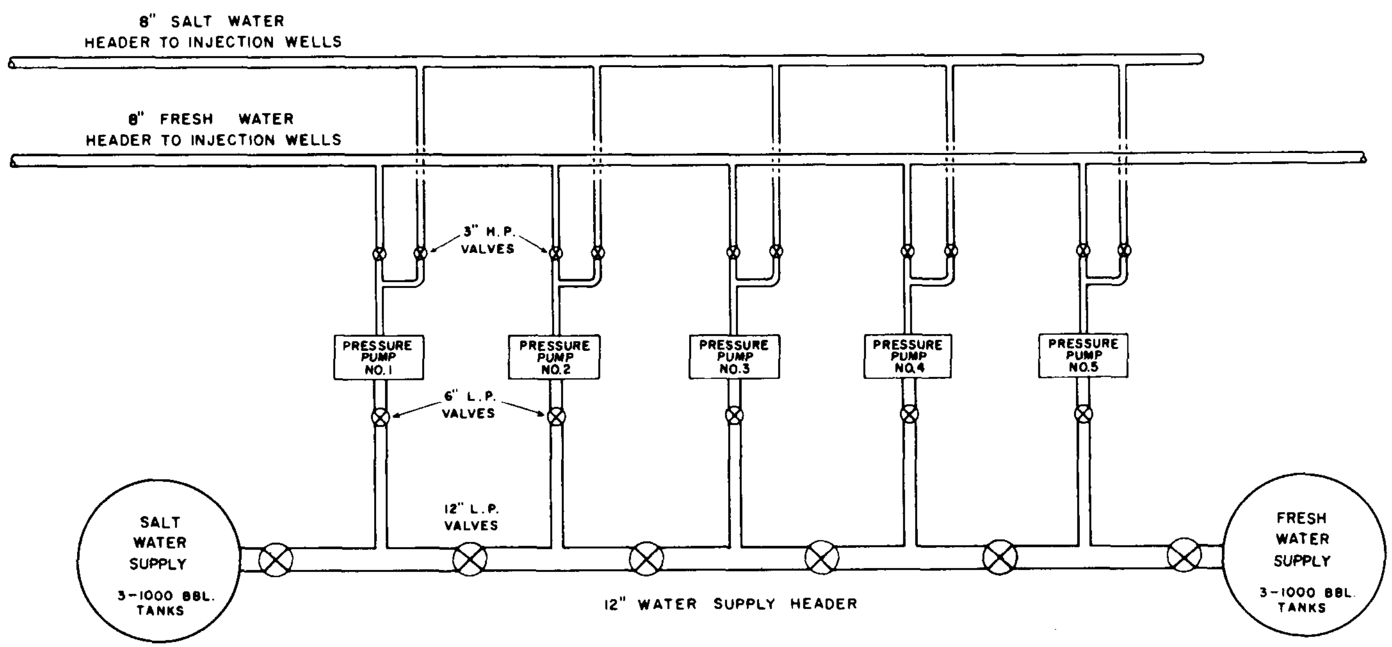


FIGURE 9

SKETCH PLAN FOR WATER PLANT

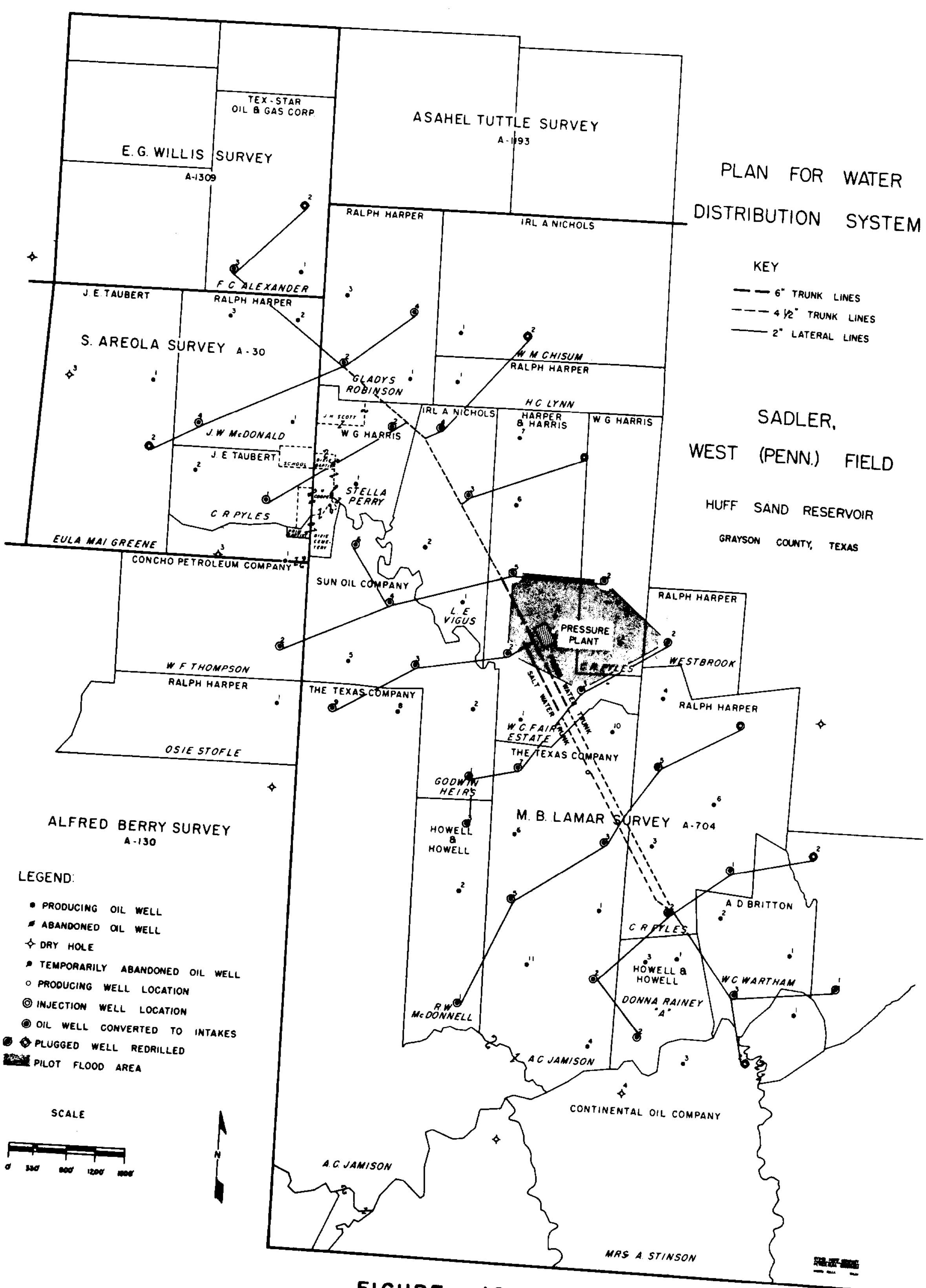

PLAN FOR WATER DISTRIBUTION SYSTEM
KEY
6" TRUNK LINES
4 ½" TRUNK LINES
2" LATERAL LINES
SADLER, WEST (PENN.) FIELD
HUFF SAND RESERVOIR
GRAYSON COUNTY, TEXAS
E. G. WILLIS SURVEY
A-1309
TEX-STAR OIL & GAS CORP.
ASAHEL TUTTLE SURVEY
A-1193
RALPH HARPER
IRL A NICHOLS
F C ALEXANDER
J E TAUBERT
S. AREOLA SURVEY A-30
W M CHISUM
GLADYS ROBINSON
IRL A NICHOLS
H C LYNN
HARPER & HARRIS
W G HARRIS
J W McDONALD
J E TAUBERT
STELLA PERRY
C R PYLES
EULA MAI GREENE
CONCHO PETROLEUM COMPANY
SUN OIL COMPANY
L E VIGUS
PRESSURE PLANT
WESTBROOK
W F THOMPSON
THE TEXAS COMPANY
SALT WATER TRUNK
W C FAIR ESTATE
OSIE STOFLE
GODWIN HEIRS
HOWELL & HOWELL
M. B. LAMAR SURVEY A-704
ALFRED BERRY SURVEY
A-130
A D BRITTON
C R PYLES
DONNA RAINEY "A"
W C WARTHAM
R W McDONNELL
A C JAMISON
CONTINENTAL OIL COMPANY
MRS A STINSON
LEGEND:
PRODUCING OIL WELL
ABANDONED OIL WELL
DRY HOLE
TEMPORARILY ABANDONED OIL WELL
PRODUCING WELL LOCATION
INJECTION WELL LOCATION
OIL WELL CONVERTED TO INTAKES
PLUGGED WELL REDRILLED
PILOT FLOOD AREA
SCALE
0 300' 600' 1200' 1800'
N

FIGURE 10

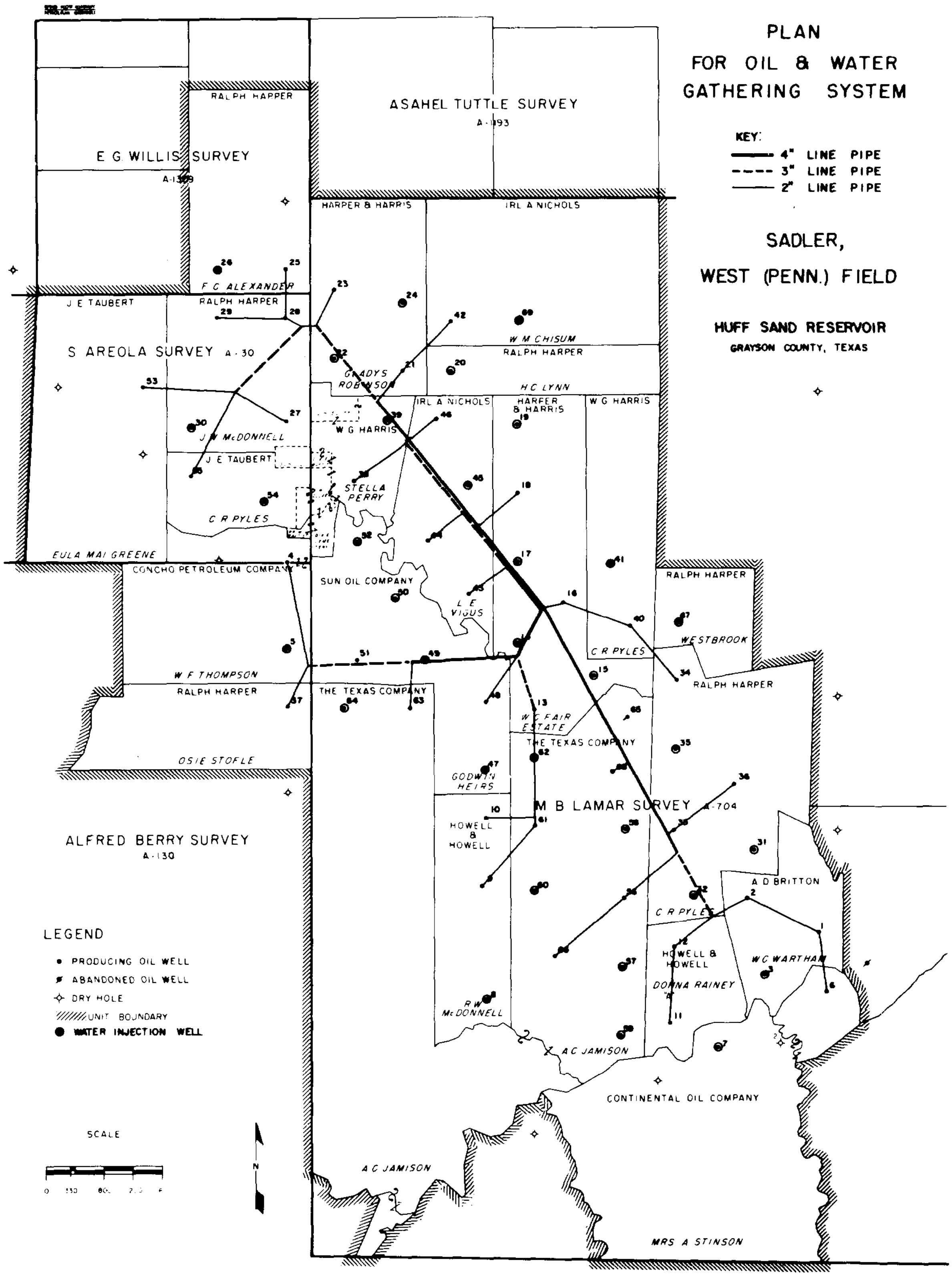
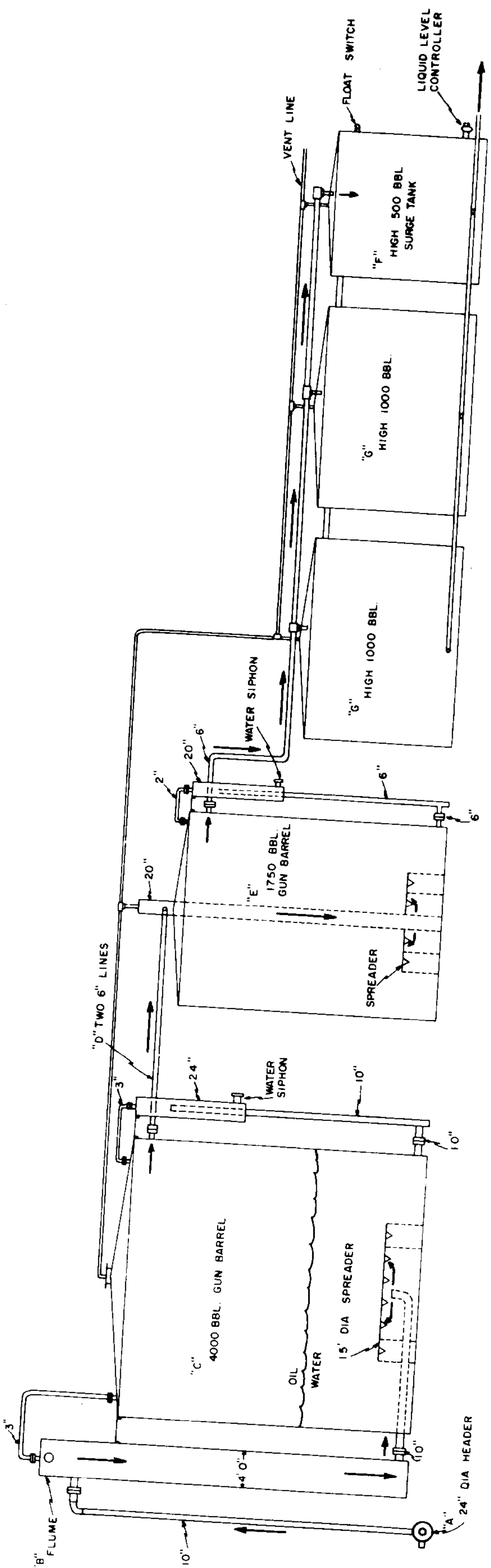

PLAN
FOR OIL & WATER
GATHERING SYSTEM
KEY:
4" LINE PIPE
3" LINE PIPE
2" LINE PIPE
SADLER,
WEST (PENN.) FIELD
HUFF SAND RESERVOIR
GRAYSON COUNTY, TEXAS
ASAHEL TUTTLE SURVEY
E G WILLIS SURVEY
S AREOLA SURVEY
M B LAMAR SURVEY
ALFRED BERRY SURVEY
LEGEND
PRODUCING OIL WELL
ABANDONED OIL WELL
DRY HOLE
UNIT BOUNDARY
WATER INJECTION WELL
SCALE

FIGURE 11



TREATING AND STORAGE VESSELS
FIGURE 12

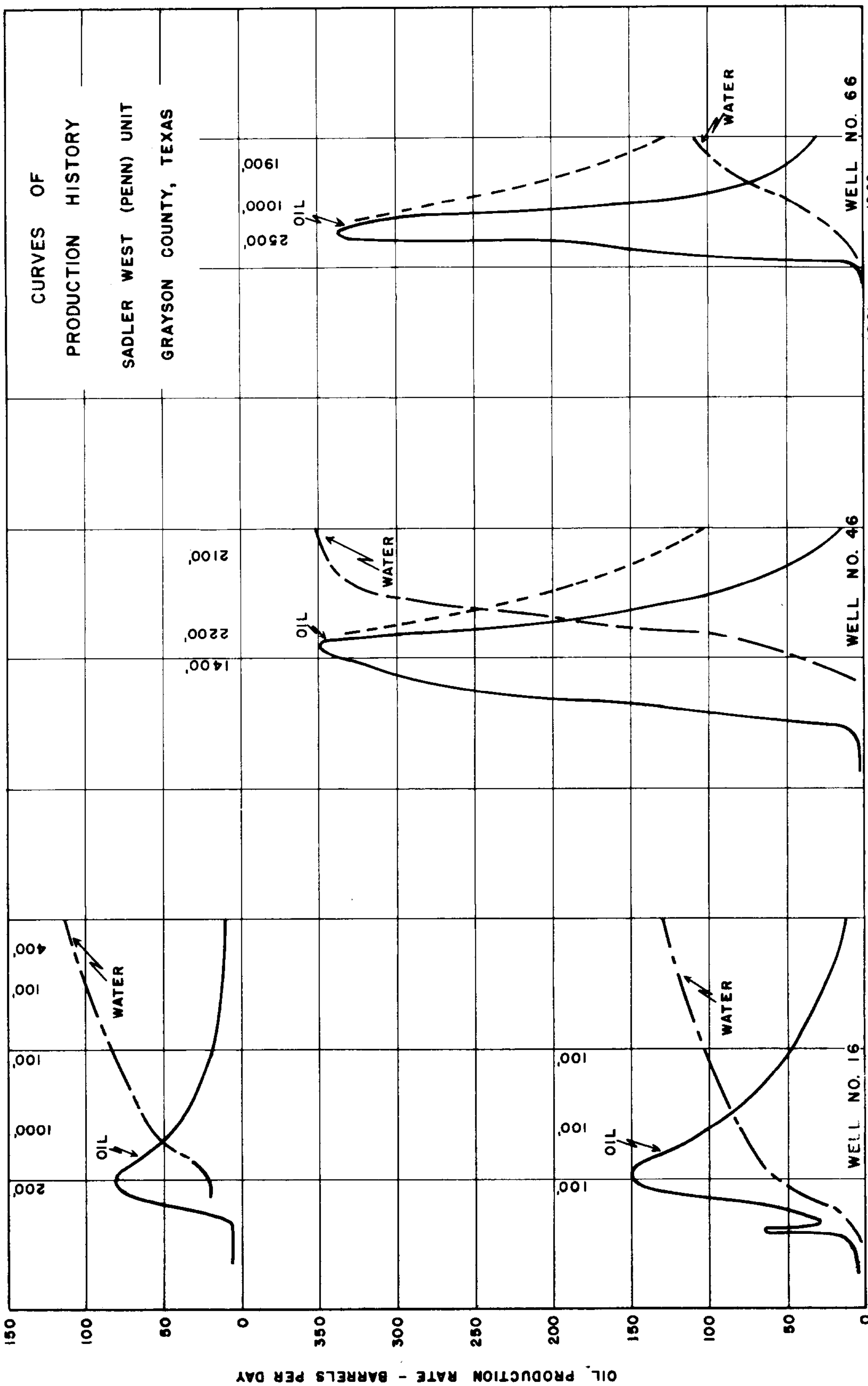

CURVES OF
PRODUCTION HISTORY
SADLER WEST (PENN) UNIT
GRAYSON COUNTY, TEXAS
OIL PRODUCTION RATE - BARRELS PER DAY
WELL NO. 16
WELL NO. 46
WELL NO. 66
OIL
WATER
1960
1961
1962
200'
1000'
100'
400'
1400'
2200'
2100'
2500'
1900'

FIGURE 13

	Water Knock-out and Heater-Treater	Gun Barrel (cold separation)
Cost of entire system (installed)	$21,800.00	$33,300.00
Cost of chemicals ($ per month)	$ 1,300.00	$ 1,050.00
Cost of Fuel* ($ per month)	$ 950.00	$ -0-

*Purchased fuel since the gas production ceases after the flood has passed its peak.

The secret of separating oil and water without the aid of heat is the large capacity of the gun barrels allowing retention time for the separation of the 2 fluids. As noted in Figure 12 the 2 high 1,000 bbl storage tanks also give further retention time to remove traces of water which may not have been separated by the second gun barrel (1,750 bbl capacity). By comparing the cost in the foregoing table it is apparent that the cold separation system is more economical.

A test should be made to determine if a chemical will work properly to cause cold separation of the oil and water before designing such a system. Allow 24 hr of retention time for a barrel of oil in the gun barrel when designing the capacities needed.

WATER FLOOD PERFORMANCE

Figure 2 also shows the history of oil production and water injection. The number of producing wells and the time they were converted into intakes is shown on the graph. Also plotted is extrapolated rate of oil production which was figured in October, 1961. This extrapolated curve was based on the performance of already stimulated wells in and around the pilot area.

In November, 1960, it was noted that the conventional beam unit at well No. 16 was lifting considerably more fluid than the actual capacity of the unit. Thus it was apparent that this well would have to have a head of fluid in the hole. The measurement showed a fluid column standing 2,700 ft above the top of the sand with the well making 97 BOPD and 37 BWPD and its pumping unit was rated to lift 120 BOPD.

By the time the entire field was under waterflood, every producing well was equipped with the conventional beam type unit having a 160,000 or 220,000 lb peak torque gear-box rating with a 54 in. and 64 in. stroke respectively. The small unit was rated to lift 120 BOPD and the larger unit was rated to lift 180 BOPD from a depth of 6,400 ft.

When several of the larger capacity producers began to approach a peak rate of oil production, it was found that the pump and unit were lifting about twice their rated capacity. That is, the well was making more than 300 BOPD with a pumping unit rated to lift 180 BOPD. There would have to be a high column of oil standing above the sub-surface pump in the well in order for such volumes of oil to be pumped. Fluid level measurements revealed that at a number of wells the column of fluid was standing at levels from 2,500 ft to more than 4,000 ft above the sub-surface pump set at the top of the perforated casing opposite the sand.

In most 5 spot pattern floods, where the water is injected under pressure balance, a water cut in the production starts soon after the peak rate of oil production has been reached. Therefore, the operator must install proper lifting equipment to avoid getting high fluid levels in the wells at the time the water-cut starts showing at the producing wells to avoid, as much as possible, damage at the sandface in the producing wells which can cause loss in ultimate waterflood oil production. The first step taken in this flood was to hold a constant operating pressure at the plant and allow a decline in the water injection rate. In Figure 2 it will be noted that the water injection rate was allowed to decline from 350,000 B/M in October, 1961, to about 250,000 B/M in March, 1962 and to 160,000 B/M in June, 1962. By adopting this plan it was felt that the least damage would occur at the producers while time was allowed for the operator to get approval from the working interest owners in the unit to install larger beam type units or a hydraulic system to lift the oil and water. On February 2, 1962, an operator's meeting was held and it was decided that the economics of the flood should be compared wherein a total of 6,000 BWPD is injected as compared to 12,000 BWPD. At a 6,000 BWPD injection a number of the present beam units would not have to be replaced by larger units while several would have to be replaced with 12,000 BWPD being injected. The comparison of the development costs is shown in the following table:

	Type of Lift: Beam	Type of Lift: Hydraulic
Injecting 12,000 BWPD - Flood Life of Seven Years		
Income From Net Oil	$8,132,500	$8,132,500
Estimated Costs		
Development	$ 376,000	$ 175,000
Operating	$1,680,000	$1,596,000
Future Cash Realization (not discounted)	$6,076,400	$6,361,200
Injecting 6,000 BWPD - Flood Life of Nine Years		
Income From Net Oil	$6,954,500	$6,954,500
Estimated Costs		
Development	$ 187,000	$ 91,800
Operating	$1,890,000	$1,782,000
Future Cash Realization (not discounted)	$4,877,500	$5,080,700

From the figures in the foregoing table it is indicated that it is better to inject water at the higher rate (12,000 BWPD) and to install the hydraulic lift system. At the higher rate of water injection a hydraulic lift system in place of a beam type lift system could increase the income from the flood $284,800.00. In view of these differences it was decided that a hydraulic lift system to handle 3 producers would be installed to determine if such an installation would work satisfactorily. The 3 well system was installed and in operation during May, 1962, on wells Nos. 16, 43 and 48. During the following 3 months the hydraulic lifting at these 3 wells worked very satisfactorily and it was concluded that it excelled the beam type unit for lifting large volumes of fluids from this reservoir at 6,400 ft. Consequently, 6 more wells (Nos. 4, 21, 37, 38, 51 and 56) were converted to a hydraulic lift and in operation on this system in September, 1962. All nine wells on the hydraulic system could be pumped so that all the fluid coming into each well could be lifted completely. The fluid level at these wells while on a beam type unit were as follows:

Well No.	Fluid Level Feet Above Sand
4	4,300
16	100
21	3,200
37	5,800
38	3,400
43	3,500
48	700
51	5,200
56	1,700

As will be noted by the production curve in Figure 2 the gain in oil production in June and July, 1962, did not improve much compared to the April oil production. The lower rate during May was due to oil used in filling up the power oil system with crude oil used in the operation of the hydraulic system. Also the gain in oil production was very slight after placing the other six wells on the hydraulic lift system in September, 1962. The BOPM produced expressed as a daily average is as follows:

Month	Production		Gain
	B/M	B/D	B/D
Sept.	58,470	1,949	
Oct.	61,589	1,987	38
Nov.	61,019	2,034	47

A much larger gain in oil production was expected since the hydraulic system was lifting all the fluid production daily. Since an appreciable gain did not occur an investigation was made to see if there was some reason for such performance.

DETERMINATION OF RESERVOIR DAMAGE

The injector or the producer is usually the source of trouble in a waterflood.

The Injector. After the reservoir is filled up, the ratio of produced fluid to injected water should approach the whole number one (1.00) when the producer reaches its peak rate of fluid production provided the injection well is taking water satisfactorily at that time. This ratio was good as shown for a few wells selected at random.

Producer Well No.	Date of Peak Produced Rate	Produced Fluid / Injected Water
27	9/62	0.93
48	5/61	0.72
56	5/62	0.83
61	9/62	0.91

This data indicates that very little trouble, if any was encountered at the injection well.

The Producer. Frequent production tests or individual well tests were taken at all the producers. Production test curves frequently indicate if trouble or damage occurred at the producing wells. Curves of production from wells Nos. 16, 40, 46, and 66 are presented in Figure 13. The number over the curve is the measured fluid level above the top of the sand in the respective month the measurement was taken. The solid line curve is plotted from actual production tests and the dashed line curve on wells Nos. 46 and 66 is the estimated production trend for the wells based on the average production decline experienced at the 2 pilot producer wells Nos. 16 and 40 where water was started into their offset intakes at the same time and water injection has continued from inception of the flood.

It will be noted that wells Nos. 16 and 40 never had a significant head of fluid standing in the hole before or during the time of peak rate of oil production. The production curves for these two wells appear normal for any sand being flooded by the 5 spot pattern.

At wells Nos. 46 and 66 there was a high fluid column during the peak oil producing period. At this time the rate of oil production started showing an abnormally fast decline compared to wells Nos. 16 and 40. As stated before, the dashed lined curve is the estimated production rate at wells Nos. 46 and 66 assuming that their decline to be similiar to that of wells Nos. 16 and 40. From the comparison of the above curves and the performance of other 5 spot floods, it is indicated that the column of fluid in wells Nos. 46 and 66 caused damage at the producer which will either retard the rate of oil production or permanently trap oil from production. The latter conditions have occurred in other floods and it is normal to expect such happening in this flood. In any event, it has been recommended that certain producing wells be sandfraced. If there is damage to the sand at the producing well then the sandfrac treatment should overcome the damage to some extent. Since there are a number of producers which have indication of damage as at wells Nos. 46 and 66, it may require an extensive fracing program at producing wells to get the waterflood oil reserves believed to be in place before the operation reaches an economic limit.

HYDRAULIC VS. BEAM TYPE PUMPING UNIT

In view of the possible well damage due to high fluid columns in producing wells, it cannot be said at this time whether the hydraulic lift system will aid in producing more oil from this flood. In order to furnish such an answer it would have been necessary to have had the hydraulic system in operation at 2 or 3 high volume producers before a head of fluid developed as happened in wells Nos. 46 and 66. It is felt that a sandfrac treatment will show whether producers like wells Nos. 46 and 66 have been damaged by high fluid columns having stood in them. Such remedial work will likely be carried out in the near future and more data will be available to evaluate between the hydraulic system and the beam type unit.

The writer is of the opinion that for this particular reservoir the hydraulic system is superior to the beam type unit. Several advantages of the hydraulic system are as follows:

(1) The original cost of the hydraulic system is somewhat less. The following costs covers complete installation except the tubing which is used in the producer whether on hydraulic or beam type lift. The comparative costs on an individual well basis is as

follows:

Pumping Units		Hydraulics*	
300 BFPD	500 BFPD	300 BFPD	500 BFPD
$16,000	$24,800	$10,800	$13,700

* Figured from a 3-well system.

(2) The well pulling costs, pump repair cost and miscellaneous repair and equipment costs averages less on an individual well basis. The comparative costs on an individual well basis for a period of 1 yr are as follows:

Pumping Units		Hydraulics	
300 BFPD	500 BFPD	300 BFPD	500 BFPD
$ 2,800	$ 3,700	$ 1,000	$1,500

A large portion of the cost for work on pumping units is well pulling.

(3) The hydraulic system is very flexible so that the horsepower requirement can be distributed to the wells where it is needed. The horsepower is distributed by the amount required to lift the daily fluid production from each producer. On a beam type unit it is easy to over or under estimate the productive capacity of a well in a waterflood. If the pump unit is over designed then there is capital investment tied up in unusable horsepower which is not necessary. If the pump unit is under designed then there will be a loss in oil production as it will not be lifted during the economic life of the flood.

(4) The hydraulic lift, which is equipped with a free sub-surface pump at the well, requires very little down time to repair the down-hole pump. Here the high pressure power oil system is used to circulate the production unit to the surface. At 6,400 ft it requires about 3 hr to round trip the sub-surface pump while it takes in excess of 8 hr to exchange the pump on a beam type unit. In most waterfloods the down time at a producing well should be kept at the very minimum.

(5) The work load of the pumper is reduced as a daily trip to each producer is eliminated as all wells can be checked at the central station at the time the pressure pump and engine are checked.

SUMMARY

This paper reviewed the history of production and various properties of the Huff sand reservoir to show why a certain flood plan was adopted. It has been found that the field operating personnel do a better job if such fundamentals are explained. Any installation or type of operation, with which the field man is not familiar, should be explained also to develop a thinker rather than one who merely follows a mechanical routine each day.

It is hoped that the installations discussed will present ideas which may be of use in floods which are in operation or which are in the planning stage.

The waterflood performance indicated that lifting produced fluids to the surface from a depth of 6,400 ft has been a major problem. The method of hydraulic lifting has been improved and more widely accepted in recent years. It is believed that it will be used extensively where large volumes of fluid have to be lifted from deeper formations.

It was installed on a trial basis in this flood and found to be more economical for lifting the large volumes of oil and water. However, it is indicated that the hydraulic system was not installed soon enough on the high capacity producers to eliminate the damage apparently caused by high fluid levels standing in the producing wells. It is hoped that the proposed sandfrac treatment at the producers, which show indications of damage, will aid their oil producing rate. If this occurs then the hydraulic lift system will prove its worth in this flood as it can be expanded to lift large volumes of fluid resulting from a higher injection rate which shows to be the more profitable plan of operation.