Pumping Salt Water From Gas Wells

By ***R. L. COOK***

Panhandle Eastern Pipe Line Company

HISTORY

During the past 10 years operators in southwestern Kansas and the Oklahoma and Texas Panhandles have been confronted with the ever increasing problem of removing salt water from gas wells. The majority of these wells are low pressure, shallow gas wells and are located principally in the Hugoton and Greenwood gas fields.

The salt water problem in gas wells first became apparent during the early 1950's when the edge wells in the Hugoton Field were being drilled and completed. In order to keep the wells from "logging off" and curtailing gas production, small diameter tubing strings from 1 to 1-1/2 in. were installed inside the production casing. The gas was produced through the casing and the salt water was removed through the tubing intermittently either by manual blowing or by a time-cycle intermitter. When it was found that this method was not very efficient due to large volumes of gas being vented to the atmosphere to raise small amounts of salt water, gas lift valves were installed in the tubing strings. This system proved to be satisfactory and many operators began equipping their water problem wells with gas lift valves in 1954. Many wells are still utilizing this system today.

During the next several years special adaptions of the gas lift system were developed such as the bottomhole separator, the closed compressor lift system, plunger lifts, and the differential pressure controller. Some of these methods proved to be more efficient than the gas lift valves while other methods were discontinued. Developments are still being made in various gas lift systems with the most recent being the downhole intermitter and the subsurface liquid diverter. During the middle 1950's the Greenwood Field was being drilled and completed; however, it was found that many of these wells along with some of the Hugoton Field wells were producing substantially more salt water. As a result, more gas was wasted to the atmosphere to lift the water. During the latter part of 1959, Panhandle Eastern developed a test separator unit designed to test the water problem wells and determine the amount of gas vented to the air to lift the water. This water-lift ratio is expressed as the number of cubic feet of gas required to lift one bbl of salt water. From the testing program it was found that most gas lift systems were uneconomical when the wells produced in excess of 8 to 10 BPD due to the large amounts of gas vented to the atmosphere. It was in early 1960 that the first small beam-type pumping unit was installed and found to be very practical and successful in removing large quantities of salt water.

PUMPING UNIT OPERATIONS

In August 1960, Panhandle Eastern installed its first salt water pumping unit. Since that time 50 additional units have been installed in the Hugoton and Greenwood Field, but due to abandonment of several wells Panhandle today operates 47 shallow well pumping units. Panhandle also operates two deeper well pumping units, one at 4600 ft and the other at 6311 ft.

The results of the testing program mentioned above were significant on problem wells prior to the installation of pumping units. (See Attachments I and II at end of paper). The average Kansas Hugoton Field well required 116 MCF to lift 16 BWPD; the Oklahoma Hugoton Field average well required 91 MCFD to lift 14 BWPD; and the average Greenwood Field well used 100 MCFD to raise 9 BWPD. Based on average field prices, the value of gas required to lift one bbl of water would amount to \$0.80/bbl in Kansas Hugoton Field, \$0.72/bbl in Oklahoma Hugoton Field, and \$1.67/bbl in the Kansas Greenwood Field. Due to the excessive amount of salt water produced and the large amount of gas wasted, it was more economical to install the pumping units on the wells shown in Attachments I and II. Pumping unit operations also improved the ability of the well to produce gas, as can be seen in Attachment III.

PUMPING UNIT DESIGN

Figure 1 shows a schematic drawing of a typical small beam-type pumping unit with the subsurface pump, sucker rods, and the unit powered by either a gas engine or a small electric motor. The first units installed had a 24-in. polish rod stroke, a peak torque of 10,000 in.-lbs, and operated at between 11 and 15 strokes per minute. As more experience was gained in operating the units, it was determined that greater efficiency could be obtained by using a 30-in. polish rod stroke, a peak torque of 16,000 in.-lbs and still operate at between 11 and 15 strokes per minute. The amount of water that can be pumped is determined by the speed, the polish rod stroke, and the size of the subsurface pump.

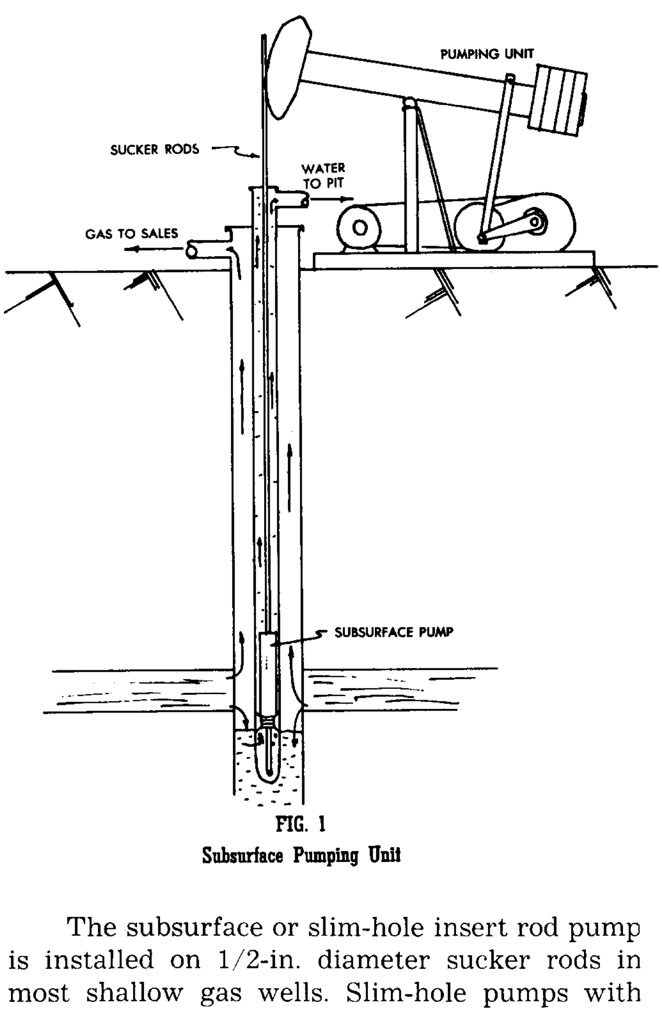


FIG. 1
Subsurface Pumping Unit

The subsurface or slim-hole insert rod pump is installed on 1/2-in. diameter sucker rods in most shallow gas wells. Slim-hole pumps with plunger diameters of 1 and 1-1/16 in. are commonly used in 1-1/4 and 1-1/2 in. diameter tubing strings, respectively. The largest bottomhole pump Panhandle has installed is 1-1/2 in. inside of 2-3/8 in. tubing. This installation is on a 4600 ft well and has a double taper sucker rod string of 5/8-in. and 3/4-in. The unit has a 48-in. polish rod stroke, operates at 12 strokes per minute and produces 30 bbl of heavy condensate and 75 bbl of salt water per day. Table I shows a comparison of the number of bbl of salt water that can be pumped per day (assuming a pump efficiency at 80 per cent) of the 24-in. with the 30-in. pumping units at various speeds and with different size insert rod pumps.

TABLE I

	24-in. Unit			30-in. Unit		
Speed (SPM)	1"	1-1/16"	1¼"	1"	1-1/16"	1¼"
10	22	25	35	28	31	44
12	27	30	42	34	38	52
14	31	35	49	39	44	61
16	36	40	56	45	50	70

As can be seen from the table above, a unit can be designed to handle most salt water problems in the low pressure, shallow gas wells.

Some wells do not produce the maximum amount of water all the time they are on production; therefore, to keep the well from "pumping off", a time clock is used to operate the unit periodically as required during the day. Attachment IV shows the calculations involved in designing a pumping unit for a Greenwood Field gas well. Attachment V shows the relationship between load ratio and the per cent of maximum recommended load in designing safe sucker rod load. In the calculations, the load ratio was 42.4 per cent and the maximum recommended load was 49.7 per cent. The plot of these two percentages on Graph 2 shows that the sucker rod design is well within the area of safe loading.

COSTS

In referring to Attachments I and II, the pump setting depths range from 2150 to 3250 ft and the installation costs vary from $2800 to $3650. The average pumping unit cost on a per foot basis for the average Kansas Hugoton Field well is $1.19, $1.14/ft for the Oklahoma Hugoton Field well, and $1.07/ft for the average Greenwood Field well. The average cost for all 47 wells is $1.11/ft. The costs shown do not include the tubing since it was already installed in the well either during completion or when the well first began producing salt water. The installation cost does include the pumping unit, sucker rods, subsurface pump, electric motor, pulling unit, and Company labor.

The prime mover for the pumping units is a 3-hp electric motor except on one shallow well and one deep well. Experience has shown that the electric power source is actually less expensive to install and requires less maintenance cost than a gas engine. The 3-hp electric motor system can be installed for approximately $300 less than a gas engine. The average electricity cost is approximately $12 per month. This would be about the same monthly cost as with a gas engine when maintenance and the value of the gas required to run the engine are included.

The direct operating expense for wells with pumping units is approximately $50 per month higher than wells without pumping units. However, this additional expense is offset by saving reservoir gas that was previously wasted in lifting the water and from the increase in the ability of the well to produce gas. (See Attachment III) Based on the analysis the average payout of a pumping unit has ranged from 12 to 18 months.

OTHER PUMPING UNITS

New developments in the beam-type pumping unit led to the gas-operated or pneumatic pumping unit. This method utilitzes wellhead gas, which operates through two volume tanks and raises a piston attached to the polish rod in an upper cylinder above the volume tanks. A schematic drawing of the pneumatic unit is shown in Fig. 2. The sensing valves regulate the upstroke and downstroke and the amount of gas used from the wellhead. As the piston is forced upward on each upstroke, the gas in the upper cylinder is vented to the atmosphere.

The experimental unit was first installed on one of the Company's Hugoton Field gas wells in June 1961. After many months of testing and revising, the unit proved to operate satisfactorily although it was required to exhaust some gas to the atmosphere which measured on the average of two MCF per bbl. The first production models were installed on two remote Greenwood Field Wells located in Morton County, Kansas, at a cost of $3300. (See Attachment II) One of

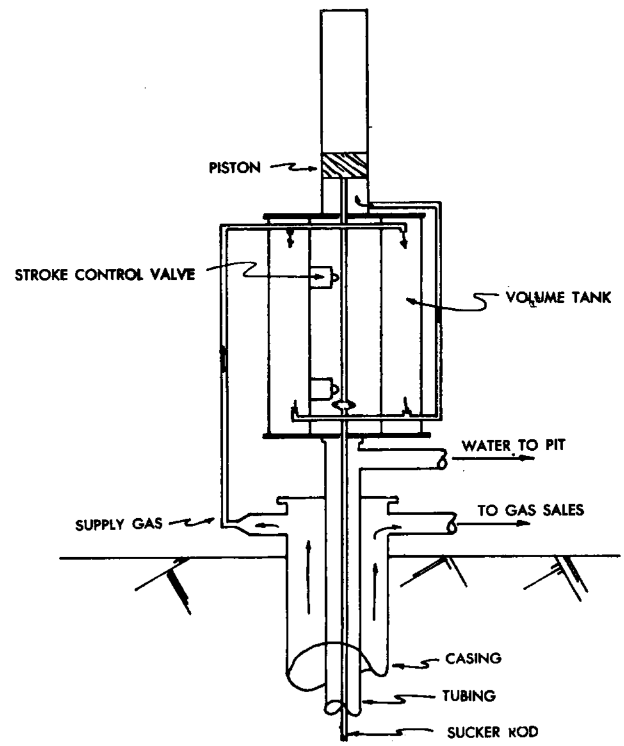


FIG. 2
Pneumatic Pumping Unit

the units was transferred to another Greenwood Field well during December 1966. Both units are operating satisfactorily. This unit is usually referred to as the TEC (Transferred Energy Concept) pumper and is manufactured by Continental Emsco.

The other pumping unit that was developed is known as the Johnston Gas Pumping Unit. This unit is similar to the TEC unit in that it operates from wellhead gas and uses a piston in reciprocating the sucker rods and subsurface pump. However, the main difference and advantage of the unit is that no gas is exhausted to the atmosphere but is returned to the sales line. The reason for this difference is that the Gas Pumping Unit is completely counterbalanced by the use of a small accumulator tank. The gas unit operates on a differential between casing working pressure and sales line pressure and, therefore, there must be a required differential before the gas is returned to the sales line. This differential is dependent on the size of subsurface pump, depth, and, of course, the sales line pressure.

The experimental unit was installed on a Company Hugoton Field well (See Attachment I) in September 1965. Operational-time tests are presently being conducted on this unit. The well has a 1-in. subsurface pump and requires a differential between casing and sales line pressure of 20 psi before the unit will exhaust the gas back into the sales line. If the differential is less than 20 lbs, the pumping unit ceases to operate. The unit operates very satisfactorily during the summer months, but is difficult to operate during the winter months due to "freezes" encountered in the unit. Experimentation and testing are continuing in order to solve this problem. Patents are pending on this unit at the present time.

CONCLUSION

The salt water problem is becoming greater each year and will continue as the reservoir pressure declines and more water encroaches near the wellbore. The investigation of water lift has resulted in several new methods in gas lift and in beam-type pumping units which has lead to gas-operated or pneumatic pumping units. The units which are powered by an electric motor have proven to be the most efficient and economical method of removing water from wells which prdouce in excess of 10 BPD. The two main advantages of the pumping unit are the elimination of gas vented to the atmosphere and the fact that the unit can be operated to abandonment pressure.

ATTACHMENT I

PUMPING UNIT DATA
SHALLOW GAS WELLS - KANSAS AND OKLAHOMA

	Tests Prior to Pumping Unit				Date	Pump	Installation	
	Production To Sales (MCFD)	Vent Gas (MCF)	Wtr. Prod. (BBLS)	Lift-Ratio (MCF/BBL)	Pumping Unit Installed	Setting Depth	Cost Ex. Tubing	
HUGOTON FIELD, KANSAS								
Well Name & No.								
Baker 1-33	255	75	8	9.4	Feb. '62	2,160	$3,000	
Barker 1-22	155	91	16	5.7	April '62	2,175	2,800	
Bush 1-25	115	68	11	6.2	March '62	2,700	3,000	
Eagley 1-2	220	120	9	13.3	April '62	2,250	2,800	
Garey 1-27	-	-	10	-	April '61	2,700	3,000	
Gerber 1-14*	1,200	-	25		Sept. '65	2,721	3,000	
Harmon 1-34	520	140	10	14	Feb. '62	2,230	2,900	
Harnden 1-34	-	-	18	-	April '61	2,725	2,900	
Kneller 1-4	690	210	11	19.1	Oct. '61	2,150	2,800	
Millemon 1-27	1,060	111	44	2.5	Feb. '65	2,704	3,000	
Total	4,215	815	162			24,515	$29,200	
Average	527	116	16	7.3		2,452	$2,920	$1.19/ft

*Gas-operated unit (Experimental)

	Production To Sales (MCFD)	Vent Gas (MCF)	Wtr. Prod. (BBLS)	Lift-Ratio (MCF/BBL)	Date Pumping Unit Installed	Pump Setting Depth	Installation Cost Ex. Tubing	
HUGOTON FIELD, OKLAHOMA								
Allen 1-21	97	43	6	7.2	Nov. '65	2,738	$2,800	
Ballew 1-24	333	112	12	9.3	June '61	2,675	3,000	
Easterwood 1-1	270	81	12	6.8	May '62	2,725	3,100	
Easterwood 1-14	-	-	10	-	March '61	2,650	2,835	
Gilmore 1-29	-	60	28	2.1	Nov. '61	2,610	3,300	
Keenan 1-36	545	70	10	7.0	Jan. '62	2,725	3,050	
Lennen 1-12	-	-	10	-	Dec. '60	2,550	3,600	
Loring 1-31	227	46	15	9.7	July '61	2,650	3,000	
Mathewson 1-22	-	-	12	-	Oct. '60	2,750	3,140	
McClelland 2-28	120	45	17	2.7	Aug. '62	2,708	2,950	
Miller 1-13	225	85	10	8.5	June '61	2,650	3,000	
Miller 1-14	195	173	29	6.0	July '61	2,700	3,100	
Reust 1-32	-	-	10	-	Aug. '61	2,700	3,000	
Smith 1-27	126	68	11	6.2	Aug. '61	2,700	3,000	
Smith 1-34	200	91	12	7.6	Sept. '61	2,725	2,925	
Tucker 1-1	182	115	12	9.6	May '62	2,450	3,000	
Total	2,520	1,089	216			42,706	48,800	
Average	229	91	14	6.5		2,669	3,050	$1.14/ft

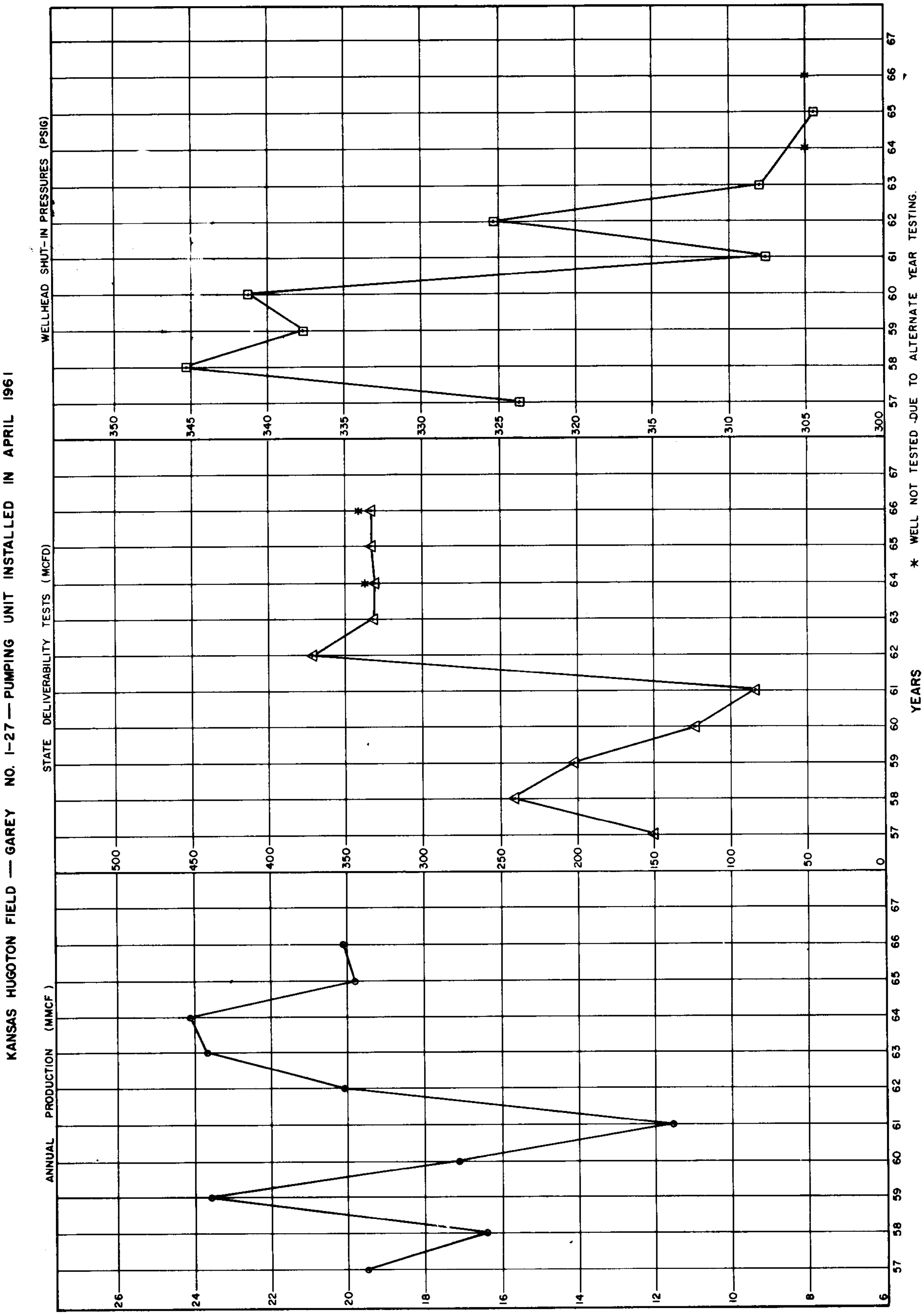
ATTACHMENT II

PUMPING UNIT DATA

GREENWOOD FIELD, KANSAS Well Name & No.	Tests Prior to Pumping Unit Production To Sales (MCFD)	Vent Gas (MCF)	Wtr. Prod. (BWPD)	Lift-Ratio (MCF/BBL)	Date Pumping Unit Installed	Pump Setting Depth	Installation Cost Ex. Tubing
American Life 1-10	2,000	168	10	16.8	Jan. '62	3,000	$3,100
Becker 1-9	-	103	5	20.6	Sept. '61	3,210	3,200
Berryman "B" 1-21	380	124	10	12.4	Jan. '62	2,900	3,600
Brown 1-13	343	114	8	14.5	Sept. '61	3,220	3,400
Friend 1-14*	900	105	5	21.1	Dec. '66	3,192	3,000
Interstate 1-1	-	190	8	23.8	Oct. '61	3,100	3,650
Interstate 1-11	315	100	12	8.3	Jan. '62	2,880	3,100
Interstate 1-20	2,983	36	9	4.0	Mar. '63	2,922	3,300
Kansas 1-23	-	-	10	-	May '66	2,964	2,900
Kansas 1-24*	650	99	6	16.5	July '62	2,816	3,300
Lewis "B" 1-17	2,125	126	6	21.0	Aug. '62	3,250	3,600
Linscott 2-33	507	43	8	5.4	Oct. '61	2,900	2,900
Moore "B" 1-2	770	44	8	5.5	Jan. '62	2,930	3,400
Moore "C" 1-2	270	74	10	7.4	April '62	3,250	3,450
Murphy 1-31	1,600	116	6	19.3	Dec. '63	3,217	3,500
Murphy 1-33	750	65	6	10.8	Jan. '64	3,144	3,400
Riley "B" 1-15	2,500	102	6	17.0	Dec. '61	2,950	3,200
Ruggles 1-13	530	147	9	16.3	Feb. '62	3,000	3,200
Ryman 1-32	168	44	15	2.9	May '61	3,100	3,000
Turner 1-19	208	67	18	3.7	Sept. '61	3,225	3,100
Wares 1-9	-	140	12	11.7	Aug. '61	3,050	3,100
Total	16,999	2,007	187			64,220	$68,400
Average	1,000	100	9	11.1		3,058	$3,257 $1.07/ft

*Pneumatic pumping unit

ATTACHMENT III



Kansas No. 1-23

CALCULATIONS

1-1/2" tbg., 1" pump, 1/2" sucker rods, 24" stroke, 12 SPM

1) W_r = (D) (R_w) = (2950) (0.68) = Wt. of rod string = 2006 lbs

2) L_1 = (D) ($R_{1\%}$) = (2950) (100%) = Length of rods = 2950 ft

L_2 = (D) ($R_{2\%}$) = ( ) ( ) = =

L_3 = (D) ($R_{3\%}$) = ( ) ( ) = =

3) F = (D) (W_f) = (2950) (0.256) = Wt. of fluid column = 755 lbs

4) $S_{tb} = 0.000\ 000\ 413\ (F)\ \left(\frac{1}{A_t}\right)\ (D)$ = Tubing stretch

$0.000\ 000\ 413\ (\ 755\ )\ \left(\frac{1}{0.800}\right)\ (\ 2950\ )$ = 1.2 in.

5) $S_r = 0.000\ 000\ 413\ (F)\ \left(\frac{L_1}{A_{r1}} + \frac{L_2}{A_{r2}} + \frac{L_3}{A_{r3}}\right)$ = Rod Stretch

$0.000\ 000\ 413\ (\ 755\ )\ \left(\frac{2950}{0.196} + \_\_\_ + \_\_\_\right)$ = 4.7 in.

6) $S_T = S_{tb} + S_r = 1.2 + 4.7 = 5.9''$ = Total stretch

7) $OT_{\text{Overtravel}} = 1.55\ (\frac{AF}{1.05} - 1.00)\ \left(\frac{D}{1000}\right)^2 = 1.55\ (\ 0.05\ )\ (\ 8.70\ )$ = 0.7 in.

8) $S_{p\ \text{Plunger stroke}} = S + OT - S_T = (\ 24\ ) + (\ 0.7\ ) - (\ 5.9\ )$ = 18.8 in.

9) Q = (S_p) (SPM) (PC @ 100%) = (18.8) (12) (0.117) = 26.4 bbls/day

Q = (S_p) (SPM) (PC @ 80%) = (18.8) (12) (0.094) = 21.2 bbls/day

10) PPRL = F = (AF) (W_r) = 755 + (1.05 x 2006) = 2861 lbs
Peak Polish Rod Load

11) MPRL = W_r (1.872 - AF) = (2006) (0.822) = 1649 lbs
Minimum Polish Rod Load

12) CB = $\frac{\text{PPRL + MPRL}}{2} = \frac{2861 + 1649}{2}$ = 2550 lbs
Counter balance

13) PT = (PPRL - CB) ($^S/2$) = (311) (12) = 3732 in.-lbs
Peak Torque

14) RS = $\frac{\text{PPRL}}{A_{rt}} = \frac{2861}{0.196}$ = 14,597 psi
Rod Stress

15) HP = (Attachments Nos. 10, 11, 12)

16) Motor Sheaver PD = $\frac{\text{(SPM) (Unit Gear Ratio)}}{\text{Motor RPM}}$ x (Unit Sheave P.D.) =

$\left(\frac{12 \times 30}{1160}\right)$ (18") = 5.6 in.

Load Ratio = $\frac{\text{PPRL - MPRL}}{\text{PPRL}}$ x 100

$= \frac{2861 - 1649}{2861} = \frac{1212}{2861}$

= 42.4%

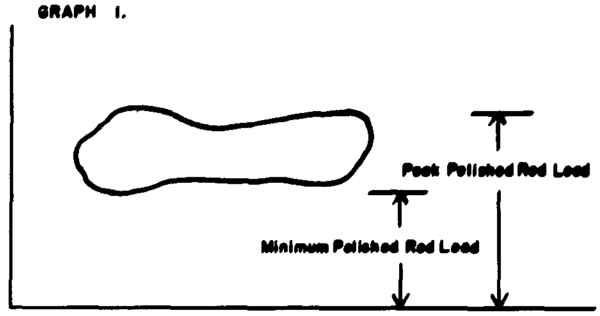
1/2" No. 1 Continental sucker rod has a maximum recommended load of 5,750 lbs.

PPRL = 2861 lbs

% of max. recommended load = $\frac{2861}{5750}$ = 49.7%

ATTACHMENT V

GRAPH 1.



HYPOTHETICAL DYNAMOMETER CARD

$$\text{Load Ratio} = \frac{\text{PPRL} - \text{MPRL}}{\text{PPRL}} \times 100$$

GRAPH 2.

Curve for Reduction of Maximum Allowable Load
Based on Load Ratio