Designed Beam Pumping*

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INTRODUCTION

Since 1961, Continental Oil Company has been presenting beam pumping short courses to assist both technical and nontechnical employees in learning and applying the basic principles of sucker rod pumping. With the publication of API RP11L, the basic principles used prior to 1967 were modified to include improvements in design criteria advocated in API RP11L.

This paper presents the controlling features of a beam pumping system and discusses the design procedure of each segment in a step-by-step fashion. Numerous symbols have been used throughout the paper, and a composite nomenclature has been included at the end for the convenience of the reader in following the calculations. Exhibits, figures and tables mentioned in the paper are listed and presented at the end.

References which support the development of some of the controlling factors will also be found at the end of the paper.

In order to simulate field calculating conditions, a slide rule was used for appropriate mathematical calculations. Numbers have been rounded to simplify calculations. However, the resulting values are representative for the particular calculation for which they were used. The authors feel that the use of the slide rule is sufficiently accurate for design purposes. The method presented is recommended for any well which is determined to be a suitable candidate for this type of artificial lift.

CONTROLLING FACTORS

The controlling factors considered in this optimum design are:

1. The producing bottomhole pressure
2. The shutin bottomhole pressure
3. The desired liquid production
4. The various components of the conventional beam pumping system
5. The optimum vibration of the entire system.

These factors will be presented and discussed using the solutions to five problems as the communication vehicles.

OPTIMUM DESIGN PROCEDURE

To demonstrate the design technique advocated in this paper, five problems will be solved using the assumed data which follows:

1. A well is being pumped with a test unit at a rate of 46 bbl of 36° API oil and 77 bbl of 1.05 specific gravity salt water per day.
2. The sour gas volume which is produced up the annulus between the 5-1/2-in., 17 lb/ft, OD casing and the 2-3/8-in. OD tubing is 30 MCFPD.
3. The specific gravity of the gas is 0.80.
4. The producing casing pressure is 55 psig.
5. The producing fluid level is 3000 ft from the surface.
6. The shutin fluid level is at 1800 ft, with a casing pressure of 40 psig.
7. The plugged back well depth is 5200 ft.
8. The perforated interval is from 4990 to 5010 ft.
9. The pump is set at 3500 ft.

PROBLEMS

Problem One

Determine the producing bottomhole pressure.

Problem Two

Determine the shutin bottomhole pressure.

Problem Three

Develop the desired liquid production by determining the well liquid capacity at a reduced producing bottomhole pressure of 135 psig, or 150 psia.

Problem Four

Determine the conventional beam pumping equipment required to produce the 166 BFPD found in solving Problem Two.

Problem Five

Discussion of optimum vibration analysis

PROBLEM ONE - DETERMINE THE PRODUCING BOTTOMHOLE PRESSURE

1. A producing sketch of the well was prepared (Exhibit 1).
2. Figure 1 indicates that the pressure should be calculated at the pump intake and at the midpoint of the perforations because the area of the flow conduit changes.
3. Pressure at first pressure point, pump intake, P_x:
   $P_x = (P_c + P_{ab})/C_g + (D_x - FL) \times S.G. \times 0.433 \times F_x$

Where:

P_c = Casing Pressure, psig
P_{ab} = Atmospheric Pressure, psia
D_x = Depth from Surface to Pressure Point, feet
FL = Distance from Surface to Fluid Level, feet
S.G. = Specific Gravity of Annulus Liquid
C_g = Gas Gradient Correction Factor From Fig. 2
F_x = Liquid Gradient Correction Factor From Fig. 1
S.G. = 141.5/(131.5 + 36° API) = 141.5/167.5 = 0.85
a = Area of Casing-Tubing Annulus = $(4.892^2 - 2.375^2)\pi/4$ = (23.93 - 5.64) 0.7854 = 18.29 × 0.7854 = 14.37 in.^{2}

Let:

$F_{x1} = 1.0$
$P_{x1} = (55 + 14.7)/0.92 + (3500 - 3000) \times 0.85 \times 0.433 \times 1.0$
$P_{x1} = 75.8 + 184 = 259.8$ psia

$Q/aP^{0.4} = 30/(14.37 \times 9.2) = 0.227$
$F_{x2} = 0.65$
$P_{x2} = 75.8 + 184 \times 0.65 = 75.8 + 119.5 = 195.3$ psia

$Q/aP^{0.4} = 30/(14.37 \times 8.23) = 0.254$
$F_{x3} = 0.63$
$P_{x3} = 75.8 + 184 \times 0.63 = 75.8 + 116 = 191.8$ psia, <u>WHICH IS THE PRESSURE AT THE PUMP INTAKE</u>

<u>NOTE:</u> The preceding procedure should be repeated until two successive trial answers are within the limits of the accuracy desired. Normally the last P_x should be within five percent of the previously calculated P_x.

4. Pressure at perforations midpoint = 191.8 + (5000 - 3500) × S.G. × 0.433 × F
   S.G. oil-water mixture = S.G. oil × oil frac. + S.G. water × water frac.
   = 0.85 × 0.374 + 1.05 × 0.626
   = 0.318 + 0.658 = 0.976

Let:

$F_{x1} = 1.0$
$P_{x1} = 191.8 + 1500 \times 0.976 \times 0.433 \times 1.0 = 191.8 + 634 = 825.8$

$Q/aP^{0.4} = 30/(18.8 \times 14.6) = 0.1093$
$F_{x2} = 0.77$
$P_{x2} = 191.8 + 634 \times 0.77 = 191.8 + 488 = 679.8$ psia

$Q/aP^{0.4} = 30/(18.8 \times 13.5) = 0.1183$
$F_{x3} = 0.75$
$P_{x3} = 191.8 + 634 \times 0.75 = 191.8 + 475 = 666.8$, or rounded to 667 psia

This is the pressure at the midpoint of the perforations, <u>WHICH IS THE PRODUCING BOTTOMHOLE PRESSURE.</u>

<u>NOTE:</u> Producing BHP would have been estimated to be 259.8 + 634 = 893.8, or rounded to 894 psia, if the effect of gas bubbling through the column had not been considered.

PROBLEM TWO - DETERMINE THE SHUTIN BOTTOMHOLE PRESSURE

1. A shutin sketch of the well was prepared (Exhibit 2).
2. Shutin bottomhole pressure, $\overline{P}_r$:
   $\overline{P}_r = (P_c + P_{ab})/C_g$ + oil column pressure + mixed column pressure
   $= (40 + 14.7)/0.952 + 500 \times 0.85 \times 0.433 + 2700 \times 0.976 \times 0.433$
   $= 57.5 + 184 + 1139$
   = 1380.5, or rounded to 1381 psia, <u>WHICH IS THE SHUTIN BOTTOMHOLE PRESSURE.</u>

PROBLEM THREE - DEVELOP THE DESIRED LIQUID PRODUCTION BY DETERMINING THE WELL LIQUID CAPACITY AT A REDUCED PRODUCING BOTTOMHOLE PRESSURE OF 135 PSIG, OR 150 PSIA

Using Vogel's Curve, Fig. 3, find the capacity at a producing BHP of 150 psia.

1. $P_{wf}/\bar{P}_r = 667/1381 = 0.483$
2. From Curve, $\dfrac{q_o @ 667 \text{ psia}}{q_{o(max.)}} = 0.72$
3. If $P_{wf} = 135 + 14.7 = 149.7$, or rounded to 150,

   $P_{wf}/\bar{P}_r = \dfrac{150}{1381} = 0.1086$
4. And, from Vogel's Curve, Fig. 3,

   $\dfrac{q_o @ 150 \text{ psia}}{q_{o(max.)}} = 0.97$
5. $q_o @ 150 \text{ psia} = \dfrac{q_o @ 667 \text{ psia}}{q_o @ 667 \text{ psia}/q_{o(max.)}} \times \dfrac{q_o @ 150 \text{ psia}}{q_{o(max.)}}$
6. q_o, capacity at 150 psia producing BHP

   = (123 BFPD/0.72) 0.97

   = 166 BFPD

PROBLEM FOUR - DETERMINE THE CONVENTIONAL BEAM PUMPING EQUIPMENT REQUIRED TO PRODUCE THE 166 BFPD FOUND BY SOLVING PROBLEM THREE

General Assumptions

1. Assume pump volumetric efficiency will be 70 percent.

   Pump Displacement, PD, required = 166/0.70 = 237 BFPD
2. Assume that the pump intake can be placed below the perforated interval at approximately 5050 feet.
3. Table 1 indicates that a 1.50-in. pump should be tried.
4. The dimensionless pumping speed, N/N_o', should not exceed 0.35 because the unit will be difficult to counterbalance.
5. The dimensionless pumping load, F_o/Sk_r, should not exceed 0.50 because the unit will be difficult to counterbalance.
6. The pumping speed squared multiplied by the stroke length in inches should not exceed 21,150; or the Mills' Acceleration Factor, c, should not exceed 0.3 ($c = SN^2/70{,}500$, where S = polished rod stroke length and N = strokes per minute). Note that $0.3 \times 70{,}500 = 21{,}150$. Experience has shown that equipping and operating installations with an acceleration factor greater than 0.3 results in excessive subsurface failures. Experience also shows that an acceleration factor of less than 0.225 results in an excessive expenditure for the pumping unit equipment. Figure 4 is a nomograph that considers these dimensionless pumping speeds and acceleration factor limitations.
7. API Class D sucker rods should not be used in sour gas environments because hydrogen sulfide will cause premature failure of these rods. API Class C rods can be used if an effective corrosion inhibitor is available.
8. Allowable rod stress decreases as load range increases. Rod strings that contain slim-hole couplings should be derated. Recommended allowable stresses and slim-hole derating factors are given on Fig. 5.
9. The tubing will be anchored. This will increase the net plunger travel about 10 percent on this installation. Tubing anchors should not be run in areas where scale or sand will stick the anchor.
10. Net plunger travel, S_p, should be approximately equal to 80 percent of the polished rod stroke length.
11. A sufficient length of centralized sinker bars should be included in the design to provide weight on the downstroke to aid in opening the traveling valve. This will reduce the buckling of the sucker rod string and aid in preventing premature failure of the pump pull rod.

Calculations

1. Determine pump displacement, PD, and associated numbers of strokes per minute, N:

   $PD = 0.1166\ S_p N D^2$

   $S_p = 0.8 \times S$

   $PD = 0.1166 \times 0.8 \times SND^2$

   $PD = 0.09328\ SND^2$

   PD also equals 237 BFPD

   $SND^2 = \dfrac{237}{0.09328} = 2541$

   $SN = \dfrac{2541}{D^2} = \dfrac{2541}{(1.5)^2} = 1130$

   $N = \dfrac{1130}{S}$
2. Assume values for S:

S*	N	c	N/N_o**
42	26.9	0.432	0.555
48	23.6	0.376	0.486
54	20.9	0.337	0.431
64	17.7	0.285	0.365
74	15.3	0.245	0.315
86	13.15	0.210	0.271

*Values of S selected from "API Specification for Pumping Units," API Standard 11E, Pages 6 and 7, Table 2.

$$^{**}N/N_o = \frac{NL}{245{,}000} = \frac{N \times 5050}{245{,}000} = 0.0206\ N$$

3. Select the S and N that have the smallest S and an acceleration factor of less than 0.30:
   This is a 64-in. stroke length at 17.7 SPM. Note that the dimensionless pumping speed, N/N_o, is greater than 0.35. A tapered rod string will probably be selected. This will result in the dimensionless pumping speed decreasing to approximately 0.33 since N/N_o must be divided by the frequency factor, F_c, which is larger than 1.0. This can be seen in Table 1, API RP11L.
4. Select a rod string:
   A study of Fig. 2, API RP11L, indicates that to maintain an S_p/S of 0.80 with an N/N_o' of 0.33, F_o/Sk_r, the dimensionless rod stretch must be about 0.37.
   NOTE: S.G. = 0.976 (Assume G = 1.0 since some oil will bypass water in the tubing)
   $F_o = 0.340 \times G \times D^2 \times H$
   $G = 1.0$
   $D^2 = (1.50)^2 = 2.25$
   $H = 5050$ ft (Assume lift depth, H, equals pump setting depth, L, for design purposes)
   $F_o = 0.340 \times 1.0 \times 2.25 \times 5050 = 3860$ lb
   $F_o/Sk_r = 0.37 = 3860/Sk_r$
   $Sk_r = 3860/0.37 = 10{,}170$ lb
   $k_r = 10{,}170/S = 10{,}170/64 = 159$
   $1/k_r = E_rL$
   $1/159 = E_r \times 5050$
   $E_r = 1/(159 \times 5050) = 1.246 \times 10^{-6}$ in./lb-ft

From Table 1, API RP11L, select a rod string for a 1.5-in. pump that will stretch less than 1.246×10^{-6} in./lb-ft. This string is a 65, which has a W_r of 1.33 lb/ft, an E_r of 1.119×10^{-6} in./lb-ft, and an F_c of 1.103.

NOTE: If a 64 string had met the E_r requirements, it would not have been selected because 1/2-in. rods are easily damaged.

5. Check calculated rod stress against allowable stress:

   a. $W = W_rL = 1.33 \times 5050 = 6720$ lb
   $W_{rf} = W(1 - 0.128 \times G) = 6720\,(1 - 0.128 \times 1.0) = 5860$ lb
   $F_o = 3860$ lb
   $1/k_r = E_r \times L = 1.119 \times 10^{-6} \times 5050 = 5650 \times 10^{-6}$
   $Sk_r = S/(1/k_r) = 64/(5650 \times 10^{-6}) = 11{,}330$ lb
   $F_o/Sk_r = 3{,}860/11{,}330 = 0.34$ (This is satisfactory as it is less than 0.5)
   b. $N/N_o = 17.7 \times 5050/245{,}000 = 0.367$
   $N/N_o' = (N/N_o)/F_c = 0.367/1.103 = 0.331$
   c. Using F_o/Sk_r of 0.34 and N/N_o of 0.367, determine F_1/Sk_r from Fig. 3, API RP11L and F_2/Sk_r from Fig. 4, API RP11L.
   $F_1/Sk_r = 0.61$
   $F_2/Sk_r = 0.255$
   d. $PPRL = W_{rf} + (F_1/Sk_r \times Sk_r) = 5860 + (0.61 \times 11{,}330)$
   $= 5860 + 6920 = 12{,}780$ lb
   e. $MPRL = W_{rf} - (F_2/Sk_r \times Sk_r) = 5860 - (0.255 \times 11{,}330)$
   $= 5860 - 2890 = 2970$ lb
   f. $(PPRL - MPRL)/PPRL \times 100 = (12{,}780 - 2970)/12{,}780 \times 100$
   $= (9810/12{,}780) \times 100 = 76.8\%$
   g. Calculated rod stress = PPRL/Area of Top Rod
   $= 12{,}780/0.442 = 29{,}000$ lb/in.^{2}
   h. Allowable rod stress, from Fig. 5, Curve for API Class C Rods
   $= 28{,}600$ lb/in.^{2}
   i. Overload $= 29{,}000 - 28{,}600 = 400$ lb/in.^{2}
   j. Percent Overload $= (400/28{,}600) \times 100 = 1.4\%$

NOTE: Recall that the specific gravity of the fluid column was assumed to be slightly higher than that calculated. Also recall that the fluid level in the annulus was assumed to be at the pump intake for design purposes. It will also be possible to reduce the pumping speed in the final design because E_r is less than the calculated required value. It is therefore believed that the 65 rod string will be satisfactory and will not be overloaded in the final design.

6. Check to see if the pump can be pulled:
   The critical point will be the top rod in the bottom section. The fluid load that must be lifted to unseat the pump is related to the internal diameter of the seating nipple. The 65-rod string and the 1.5-in. pump indicate that 2-3/8-in. OD tubing can be used. Seating nipple data can be found in "API Specification for Subsurface Pumps and Fittings," API Std. 11 AX, Pages 38 and 39.

Calculations:
   a. ID of seating nipple = 1.78 in.
   $F_o = 0.340 \times G \times D^2 \times H = 0.340 \times 1.0 \times 1.78^2 \times 5050 = 5440$ lb

b. Weight 5/8-in. rods in air = 1.135 lb/ft
Fraction of 5/8-in. rods in the string = 0.608 (Table 1, API RP11L)
Feet of 5/8-in. rods = 0.608 × 5050 = 3070 ft
$W = 1.135 \times 3070 = 3480$ lb
$W_{rf} = 3480 \times 0.872 = 3020$ lb

c. Additional buoyancy = Area of 5/8-in. rod × feet of 3/4-in. rods × 0.433 lb/in.^{2}-ft
= 0.307 in.^{2} × (5050 − 3070) ft × 0.433 lb/in ^{2}-ft
=263 lb

d. Load on top 5/8-in. rod while unseating pump, assuming no friction = $F_o + W_{rf}$ − buoyancy effect of the cross sectional area of the 5/8-in. rods on the 3/4 in. rods
= 5440 + 3020 − 263 = 8197 lb

e. Calculated stress = 8197/0.307 = 26,700 lb/in.^{2}

f. Allowable stress = yield strength × 0.8
Yield strength equals 60,000 lb/in.^{2} minimum (from suppliers' literature). 0.8 supplies a minimum safety factor. Sand or scale deposits around the pump seat can drastically increase the force required to unseat the pump and does result in stripping jobs. Maximum allowable stress = 60,000 × 0.8 = 48,000 lb/in.^{2}

NOTE: If a 64 rod string had been used, the calculated stress required to unseat the pump would have been increased to 29,300 lb/in.^{2} This becomes a major problem in deep wells where small pumps and large seating nipples are run in conjunction with small rods. It is concluded that the pump can be pulled if sand or scale does not interfere.

7. Redetermine Pumping Speed:
 a. $PD = 0.1166\ S(S_p/S)D^2N$;
  $(S_p/S)\ N = PD/(0.1166 \times S \times D^2)$
  $(S_p/S)N = 237/(0.1166 \times 64 \times 2.25) = 237/16.8 = 14.13$
 b. $F_c = 1.103$ (From Step 4)
 c. $F_o/Sk_r = 0.34$ (From Step 5)
 d. Refine N so resulting $(S_p/S)N$ will equal 14.13.

Assume N	Calculate N/No'*	Find Sp/S From API RP11L Fig. 2	Resulting (Sp/S)N
17.7	0.331	0.81	14.35
17.6	0.329	0.81	14.26
17.5	0.327	0.80	14.00
17.55	0.328	0.805	14.13

Pumping speed should be 17.55 SPM, since 0.805 x 17.55 = 14.13

$$* \ N/N_o' = \frac{N}{N_o \times F_c} = \frac{NL}{245{,}000 \times 1.103} = \left(\frac{5050}{245{,}000 \times 1.103}\right) N = 0.0187N$$

8. Fill out an API RP11L Calculation Sheet: The completed calculation sheet is Fig. 6.

Selection of Surface Equipment

1. Figure 7 indicates a 160 unit would be too small, because:
 a. Torque at polished rod = 149,500 in.-lb (Line 25, Fig. 6)
 b. API gear box torque rating = 160,000 in.-lb
 c. 149,500/160,000 = 0.934
 d. From Fig. 7, maximum possible efficiency factor, assuming a new unit = 0.875
 e. Minimum gear box required = 149,500/0.875 = 171,000 in.-lb.

 A unit with a 228,000 in.-lb gear box should be selected.
 The efficiency factor from Fig. 7 will be approximately 0.83, and the gear box torque will be approximately 149,500/0.83 = 180,000 in./lb.
2. Beam capacity should exceed PPRL by a minimum of 20 percent. Therefore, minimum beam rating or structural capacity should be 12,660 × 1.20 = 15,200 lb.
 From API Std. 11E, the nearest API capacity is 17,300 lb and will be sufficient.
3. Maximum stroke length should also be greater than design stroke length by 10 to 20 percent. Maximum stroke length should exceed or equal 64 × 1.10 or 70.5 in. Select a unit with a 74-in. maximum stroke.
4. Counterbalance ordered should exceed CBE by approximately 10 percent. Order 8250 × 1.10 = 9100 lb of effective counterbalance at the polished rod at the 90° crack angle position.
5. Primemover Selection: Figure 8 is used in conjunction with the polished rod horsepower obtained from the design calculation sheet to estimate the primemover brake horsepower requirements as follows:
 a. (4960 × PRHP)/Gear box rating = (4960 × 12.1)/228,000 = 0.264

b. From Fig. 8, assuming a new unit, efficiency = 0.63.
c. Brake horsepower required = 12.1 PRHP/0.63 Eff. = 19.2 BHP

Assuming a NEMA Class D electric motor and a cyclic load factor of 0.75, order a 25-HP motor (19.2/0.75 = 25.6).

6. V-Belt Drive Selection: The standard sheave for a pumping unit gear box is seldom the optimum sheave for a specific installation. It is desirable that the unit be able to operate at speeds well below and well above present initial design speeds. Factors that must be considered in the selection are:
   a. Minimum recommended pitch diameters of sheaves: This is given in Table 3.1, "API Specification for Oil-Field V-Belting," API Std. 1B, Page 6.
   b. Maximum allowable velocity of V-Belts: The recommended maximum design velocity is 5000 ft/min. Supplement 1 to API Std. 1B, March, 1965, allows maximum velocities to 6000 ft/min. without special sheaves, but pages 8-81 of "Standard Handbook For Mechanical Engineers" by Baumeister and Marks state that belt speeds over 5000 ft/min. may require special materials or construction as well as balancing.
   c. Sheaves generally listed in manufacturers' catalogs should be selected. These and sheaves available from some manufacturers are listed in Table A.1, API Std. 1B.
   d. The basic V-Belt drive formula is:
      SPM = RPM (PMPD/GBPD) (1/GBSR)
      Where:
      SPM = polished rod strokes per minute
      RPM = average revolutions per minute of primemover drive shaft
      PMPD = primemover sheave pitch diameter, inches
      GBPD = gear box sheave pitch diameter, inches
      GBSR = gear box speed reduction
   e. One manufacturer's 228 double reduction gear boxes have speed reductions of 28.45 and can be ordered with 24.6, 29.6, or 41-in. pitch diameter sheaves grooved for either five C-section or four D-section V-Belts. The 24.6-in. pitch diameter sheave is standard.

      With a 1120 RPM primemover, these sheaves will allow minimum strokes per minute of 14.5, 12 and 8.6 respectively with a 9-in. pitch diameter C-section primemover sheave, and minimum strokes per minute of 20.8, 17.3 and 12.5 respectively with a 13-in. pitch diameter D-section primemover sheave.
   f. A belt speed of 5000 ft/min. will result if a 14.2-in. sheave is placed on the 1120 RPM primemover. A standard 14-in. pitch diameter primemover sheave is the largest sheave that would be recommended. This would result in maximum SPM of 22.4, 18.6 and 13.4 respectively. The 41-in. unit sheave can be eliminated because the maximum allowable speed of 13.4 SPM is below the design speed of 17.55 SPM. All of the D-section sheaves can be eliminated because the minimum allowable speeds are excessive. This leaves the 24.6 and 29.6 C-section sheaves. The 29.6-in. sheave should be selected because the minimum speed can be 12 instead of 14.5 SPM.
   g. With a 29.6-in. pitch diameter gear box sheave, the initial design primemover sheave will be:
      SPM = RPM (PMPD/GBPD) (1/GBSR)
      PMPD = (SPM × GBPD × GBSR)/RPM = (17.55 × 29.6 × 28.45)/1120 = 13.2 in.
      Select 13.0 in. since this size is generally available.

      Calculations made above indicate the maximum primemover sheave will have a pitch diameter of 14 in.; this will result in approximately 18.6 SPM.
   h. API Std. 1B gives a step-by-step procedure for calculating the horsepower that can be transmitted by one V-Belt. This procedure is too involved for normal field usage, so simplifying assumptions were made, and Figs. 9 and 9A were developed. Simplifying assumptions were:
      (1) The average RPM of the primemover is 1120.
      (2) The speed ratio (pitch diameter of larger sheave divided by pitch diameter of smaller sheave) is greater than 2.0.
      (3) The center distance is equal to the sum of the sheave pitch diameters.
   i. V-Belt-drive design horsepower can be determined using either of two formulas supplied in API Std. 1B.
      (1) The recommended formula is:
          Design HP = crank shaft torque in in-lb × SPM/70,000
      (2) The other formula is:
          Design HP = average HP transmitted

× service correction factor

(3) For the initial installation, the V-Belt-drive design HP will be:
171,000 in.-lb × 17.55 SPM/70,000 = 42.9

(4) Maximum V-Belt drive design HP will be:
228,000 in.-lb × 18.6/70,000 = 60.7

(5) The horsepower that can be transmitted with one C-section V-Belt is then determined from Figs. 9 or 9A and is:
Initial installation (13-in. pitch diameter sheave): Horsepower per C-section belt = 17.2
Maximum installation (14-in. pitch diameter sheave): Horsepower per C-section belt = 18.7

(6) The minimum number of belts required:
Initial installation = design HP/HP per belt = 42.9/17.2 = 2.49, or 3 belts
Maximum installation = 60.7/18.7 = 3.26, or 4 belts
NOTE: Neither design calls for a sufficient number of belts to fill the five C-section grooves in the gear box sheave. Therefore, a four-groove sheave should be selected.

Selection of Subsurface Equipment

1. Gas Anchor:
   a. The pump intake will be below the casing perforations, so a natural gas anchor can be selected.
   b. Two-in. nominal tubing can be used with the 1.5-in. pump and the 65-rod string selected earlier in the solution to Problem Four.
   c. The net area of the annulus between the 5-1/2-in. OD, 17-lb casing and the 2-3/8-in. OD tubing = $(4.892^2 - 2.375^2)\ 0.7854 = (24 - 5.64)\ 0.7854 = 14.4$ in.^{2}
   d. Natural gas anchor capacity, BLPD = V × A/0.00935, where:
      V = Downward fluid velocity in a gas anchor which will allow large gas bubbles to flow upward. This is assumed to be 0.5 ft/sec but can be less if the produced fluids tend to foam or are viscous.

      A = Area of downcomer, square inches

      $$0.00935 = \text{Constant} = \frac{9702 \text{ in.}^3/\text{bbl}}{12 \text{ in./ft} \times 86{,}400 \text{ sec/day}}$$

      NGA Capacity = 0.5 ft/sec × 14.4 in.^{2}/ 0.00935 = 770 BLPD

      This is far above the required capacity of 237 BLPD and should prove very satisfactory.
   e. Note that a poor boy gas anchor, utilizing 2-3/8-in. OD tubing and a 1-in. nominal line pipe dip-tube would have had a capacity of 0.5 × 1.76/0.00935 = 94 BLPD.
   f. Select a natural gas anchor that utilizes the full ID area of 5-1/2-in. OD, 17-lb casing minus the OD area of 2-3/8-in. OD tubing.

2. Subsurface Pump: A study of API Std. 11AX, "API Specification for Subsurface Pumps and Fittings," March 1971, indicates that a thin-wall barrel rod pump can be selected for this installation. This pump is available with a stationary barrel and either a top or bottom anchor. It is also available with a traveling barrel and bottom anchor. The stationary barrel top anchor would be the most expensive, and the traveling barrel bottom anchor would be the least expensive. There should be less gas breaking out of solution with the top anchor pump, and volumetric efficiency should be higher, providing that the tubing perforations are opposite the pump intake if a natural gas anchor is utilized.

If the pump is allowed to pound fluid, bottom hold-down pumps should prove more satisfactory. If scale build-up in the pump will be a problem, a thin-wall barrel rod pump should not be run because it cannot be built to stroke through. If this condition exists, and the designer changes out the 2-3/8-in. OD tubing for 2-7/8-in., a stroke-through tubing pump should be considered. If sand is produced with the fluid, the top hold-down pump equipped with a sand check should be considered. Incidently, the sand check theoretically turns this pump into a two-stage pump, enabling the pump to operate at a higher volumetric efficiency when pumping viscous liquids or gas-liquid mixtures if the pump is constructed and spaced out to give a high compression ratio at the top and bottom of the stroke.

Assuming that sand or scale is not a problem, and further assuming that the pump will not be allowed to pound fluid, select the stationary thin-wall barrel top anchor rod pump. The API RP11L calculation sheet indicates the plunger stroke length will be approximately 51.5 in. Several factors can make the plunger stroke greater than that calculated. These include an effective operating fluid level above the pump intake, an operating speed greater than that calculated, a load on the gross plunger area less than calculated, and a polished rod stroke length greater than that used in the calculations. Any or all of these conditions will exist in a typical installation at some time. Therefore, the plunger should be able to travel a greater distance than is indicated by the design calculation. These conditions will also cause the plunger to operate in a different portion of the barrel. It is therefore recommended that a plunger travel of at least 60 in. be considered in the solution to Problem Four. The plunger length should be approximately one foot per 1000 ft of pump setting depth, so a five-foot plunger should be selected.

Shorter plungers are sometimes used in some low viscosity fluids, and shorter plungers are usually used in very viscous fluids. The use of plungers shorter than one foot per 1000 ft of pump setting depth in low viscosity fluids cannot be recommended because it is believed that this drastically reduces pump life. In addition, dynamometer surveys on some wells equipped with short plungers indicate that the plunger is "chattering" in the barrel. This should further reduce pump life and may decrease pumping unit, sucker rod and tubing life.

The barrel length will have to exceed the plunger stroke plus the plunger length plus the length of the plunger fittings. API Std. 11AX indicates that the length of the plunger fittings is 10-1/8-in. A minimum barrel length of 60 in. + 60 in. + 10-1/8-in. = 130-1/8-in. = 10 ft 10-1/8-in., or rounded off to 12 ft since it is the shortest usable standard length. The API designation of the pump selected is: 20-150 RWAC 12-5-0.

3. Sinker Bars:

GIVEN:

Sinker bar factor = 0.40 in.^{2} (Table 2)

G = 1.0

L = 5050 ft

ASSUME:

Twenty percent of the theoretical weight is required.

SOLUTION:

Theoretical weight = 0.40 in.^{2} × 5050 ft × 0.433 lb/in.^{2}-ft × 1.0 = 875 lb

Actual weight required = 0.20 × 875 = 175 lb

The largest slim-hole rod coupling that can be run in the 2-3/8-in. OD tubing is a 7/8-in. slim-hole coupling, which has an OD of 1-5/8-in. (Table 4.2, API Std. 11B). The nominal diameter of the pin on a 7/8-in. rod is 1-3/16 in. (Table 3.1, API Std. 11B). The largest polished rods that can be run as sinker bars can also use 7/8-in. slim-hole couplings. These are 1-1/4-in. rods, which also have a pin diameter of 1-3/16 in. (Table 2.1, API Std. 11D).

Weight of 1-1/4-in. polished rods in 1.0 specific gravity fluid = [490 lb/ft^3/144 in.^{2}/ft^2] (1.25)^2 (0.7854) [1 - (62.4 lb/ft^3/490 lb/ft^3)] =
3.4 lb/in.^{2}/ft × 1.227 in.^{2} × 0.872 = 3.63 lb/ft

Feet of 1-1/4-in. sinker bars required = 175 lb/ 3.63 lb/ft = 48.2 ft = three 16-ft, two 22-ft and one 11-ft, or five 11-ft polished rods (Table 2.1, API Std. 11D gives standard polished rod lengths). This length of 1-1/4-in. polished rods (over 36.1 ft) will tend to buckle and therefore should be centralized (See Fig. 10).

4. Rod String: Earlier, a 65 API Class C sucker rod string was selected. The rod string length is equal to the pump setting depth, minus the sinker bar length, minus the pump length, minus a portion of polished rod length. From Table 1, API RP11L find:

ROD SIZE	PERCENT	FEET	ORDER*
3/4" (6/8" = 6)	39.2	1980	2025′
5/8" (5/8" = 5)	60.8	3070	3075′

*Table 3.1, API Std. 11B gives pony rod lengths.

An adequate supply of the larger rod subs should be ordered for use in spacing out the pump. A sub and a centralizer will also be required above the pump. The size of this sub will be determined by the type pump run. It should be as large as is practical in order to transmit the weight of the sinker bars to the pump pull rod without buckling the sucker rod sub on the downstroke.

Each time the rod string is pulled after initial installation, a rod sub approximately equal to S (polished rod stroke length) should be added to the string above the sinker bars, and a sub of equal length should be removed from the top of the string to change rod box tubing wear area. This procedure should be reversed when the total length of subs above the sinker bars equals or exceeds 25 ft. Sinker bar centralizer on tubing wear area should also be moved when the pump is serviced. A coupling and short sub should be placed on top of the polished rod to facilitate servicing and to protect the polished rod threads so that the polished rod can be reversed. This coupling will also keep the polished rod from slipping through the carrier bar if the polished rod clamp is loosened or slips.

a. Pump setting depth = approximately 5050 ft (should be greater than distance to bottom of perforations, which are at 5010 ft + a minimum of 15 ft to remain out of turbulence at perforations).
b. Sinker bar length = approximately 48 ft
c. Pump length = plunger stroke length, S_p, where S_p = 51.5 in. + plunger length, which is 1 ft/1000 ft of pump setting depth, or 6 ft maximum, or 5 ft for this installation, plus the length of the fittings. Estimated minimum total length is 12 ft.
d. Portion of polished rod length = $S_p \times 2$ = $51.5 \times 2/12$ = 8.6 ft, or rounded to 9 ft.
e. Rod string length = 5050 − 48 − 12 − 9 = 4981 ft.

5. Tubing Anchor: A tension anchor is recommended. It should be placed in the tubing string at least 15 ft above the top of the casing perforations, which are at 4990 ft, but well below the operating fluid level, which should be above 4900 ft.

6. Polished Rod: Table 2.1, API Std. 11D, "API Specification for Miscellaneous Production Equipment," indicates that a 1-1/8-in. polished rod should be used with 3/4-in. rods. Length should be at least twice, and preferably three times the pumping unit maximum stroke of 74 in., or 2 to 3 $\times$ 74/12 = 12.35 to 18.5 ft. Select a 16 or 22-ft 1-1/8-in. polished rod. The minimum polished rod length should equal the maximum polished rod stroke length, plus two times the length of stuffing box packing, plus the distance from the top of stuffing box to the top of polished rod clamp at bottom of stroke, plus the dynamometer mounting space above clamp (in some cases), plus the rod stretch. If the polished rod is spaced properly on the initial installation, it can be reversed when it becomes worn. A polished rod is excessively worn when the diameter has been reduced more than 1/32 in. This actually depends on the capabilities of the stuffing box and polished rod velocity. Pits will destroy the packing. In many areas, common steel polished rods are purchased and a liner is installed to combat wear and corrosion. A 1-3/8-in. OD liner would be used with the 1-1/8-in. polished rod (Table 2.2, API Std. 11D).

PROBLEM FIVE - DISCUSSION OF OPTIMUM VIBRATION ANALYSIS

Figure 11 is a composite of dynamometer cards generated by Sucker Rod Pumping Research, Inc. using an electronic analog simulator. The controlling nondimensional parameters were N/N_o' and F_o/Sk_r. This work was released to the American Petroleum Institute, Division of Production, and was published in API BUL 11L2 in December, 1969.

The horizontal reference lines which traverse each card represent W_{rf}, the weight of the sucker rod string in fluid. The distance from W_{rf} to the PPRL represents the value F_1/Sk_r, and the distance from W_{rf} to the MPRL is F_2/Sk_r. Making allowance for some shrinkage in the reproduction process, the vertical scale for the values of F_1/Sk_r and F_2/Sk_r in Fig. 11 is one inch equals 1.0.

Each card represents a condition in which the tubing is anchored at the pump. Also, the dynamometer cards were generated using an assumption that the pump completely fills with fluid, and there is no fluid or gas pound present. This makes it possible to consider these cards as representative of very "healthy" pumping conditions.

The use of this figure makes it possible to forecast the shape of a dynamometer card when the pumping design conforms to those conditions presented in API RP11L and which are recommended in this paper. The authors have found that field-generated dynamometer cards from properly designed wells correspond very favorably to the cards in this figure, even to the apparent anomalies.

To use Fig. 11, the two controlling parameters, N/N_o' and F_o/Sk_r, must be known. The representative dynamometer card can be found at a position where the abscissa value and the ordinate value intersect. It may be necessary to interpolate between four of the cards using intermediate values of N/N_o' and F_o/Sk_r to determine the shape of the card.

From field experience feedback and practical considerations, the maximum values which can normally be tolerated on Fig. 11 are N/N_o' = 0.35 and F_o/Sk_r = 0.5. Values in excess of these can be associated with conditions in which the pumping system needs considerable improvement in design.

The dynamometer card which will most closely correspond to the solution to Problem Four is:

where:

$N/N_o' = 0.33$
$F_o/Sk_r = 0.34$
$F_1/Sk_r = 0.60$
$F_2/Sk_r = 0.25$

This particular card has a high load range.

NOTE: Unless a sucker rod string has been designed properly, frequent rod breaks may be experienced. If this should occur, the situation can be corrected by installing a properly designed sucker rod string, or by using the existing sucker rod string, unless it is already fatigued, and operating the system at lower values of N/N_o' and/or F_o/Sk_r.

It must be realized that the area of the card is associated with hydraulic horsepower, which in turn represents the volume of fluid being lifted. In varying the controlling parameters, it is quite possible that the hydraulic horsepower will also be varied. A loss in production may be the price paid for correcting the parted rods problem by decreasing the N/N_o' and/or F_o/Sk_r.

A most important consideration in varying the controlling parameters is to make certain that the well is properly counterbalanced, or with lower values of N/N_o' and F_o/Sk_r, negative torque can be experienced in the faster portion of the stroke. That condition cannot be tolerated by the pumping system.

Skillful use of Fig. 11 provides a much more accurate tool in analyzing dynamometer cards than by using card orders. The use of the figure is highly recommended as a diagnostic tool.

SUMMARY OF DESIGN

1. Well Capacity @ 135 psig = 166 BFPD
2. Calculated Pump Displacement Needed = 237 BFPD (Assuming 70% Vol. Eff.)
3. Sucker Rod String and Associated Components
   a. API Class C, Size 65 sucker rods
   b. Sinker Bars
      Install 48 ft of 1-1/4-in. sinker bars (polished rods) using a combination of either three 16-ft rods, two 22-ft and one 11-ft rods, or five 11-ft rods.
4. Subsurface Pump and Associated Components
   a. Install a pump with an API designation of 20-150 RWAC 12-5-0.
   b. Install 2-3/8-in. OD tubing.
   c. Install a 1.78-in. ID seating nipple.
   d. Tubing to be anchored using a tension-type anchor placed 15 ft above the top of the casing perforations.
   e. Install a natural gas anchor using 2-3/8-in. OD tubing.
5. Polished Rod
   Install either a 16-ft or a 22-ft 1-1/8-in. polished rod with a 1-3/8-in. OD polished rod liner, if a liner is required.
6. Pumping Unit
   a. A 228,000 in.-lb gear box should be selected.
   b. Beam rating or structural capacity should be 17,300 lb.
   c. Maximum stroke length should be 74 in.
   d. Order 9100 lb of effective counter balance measured at the polished rod at the 90° crank angle position.
7. Primemover System
   a. Install a 25-horsepower NEMA Class D, 1120 RPM electric motor.
   b. Install a 29.6-in. pitch diameter C-section gear box sheave, grooved for five belts.
   c. Install a 13.0-in. pitch diameter C-section primemover sheave, grooved for four belts.
   d. Install three C-section V-Belts.
8. Recommended Initial Operating Conditions
   a. Select a 64-in. stroke length.
   b. Operate the unit at approximately 17.55 SPM.

CONCLUSION

It is now possible to size beam pumping equipment much more accurately on initial installations and to determine that such equipment is also sized correctly on existing installations. The method presented in this paper for designing optimum beam pumping equipment for suitable wells is highly recommended and is believed to be much better than the methods formerly used.

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Special acknowledgment is made to Mr. M. H. Halderson, Phillips Petroleum Company, for his efforts during 1969 in making it possible for the authors to publish a composite of selected analog computer dynamometer cards conceived by Sucker Rod Pumping Research, Inc.

The authors are grateful to Shell Oil Company for permission to reproduce the previously unpublished Fig. 1.

Acknowledgment is made to the American Petroleum Institute, Division of Production, for permission to reproduce several figures and tables from its recommended practices and standards.

The authors also express appreciation to the Society of Petroleum Engineers of AIME for permission to use the Inflow Performance Relationship Curve from the 1968 *Transactions,* and to ARMCO Steel Corporation for permission to reproduce Page A-99 from its "Oil Country Tubular Products Engineering Data."

Lastly, the authors are grateful to Mrs. Ruth Webb, also an employee of Continental Oil Company, who scrupulously assisted in the preparation of the manuscript.

NOMENCLATURE AND DEFINITIONS

- a Cross section area of casing-tubing annulus, square inches
- A Area of downcomer, square inches
- AF Acceleration factor
- c Acceleration factor, $\frac{SN^2}{70{,}500}$
- CBE Counterbalance effect measured at the polished rod at the 90° crank angle, pounds
- C_g Gas gradient correction factor (Fig. 2)
- D Pump plunger diameter, inches
- D_x Depth from the surface to the pressure point under consideration, feet
- E_r Elastic constant of sucker rod string, inches per pound foot
- E_t Elastic constant for tubing string, inches per pound foot
- F_c Frequency factor, a constant of proportionality which depends on the sucker rod string and the speed of sound in steel
- FL Distance from the surface to the fluid level, feet
- F_x Liquid gradient correction factor (Fig. 1)
- F_o Static fluid load, in pounds per foot, on the gross plunger area multiplied by H, the net lift in feet, pounds
- F_1 Fluid load on the gross plunger area plus maximum upstroke dynamic effects, pounds
- F_2 Dynamic effects on the downstroke, pounds
- F_3 Polished rod horsepower factor
- $\frac{F_o}{Sk_r}$ Dimensionless sucker rod stretch
- G Specific gravity of produced fluid
- GBPD Gearbox sheave pitch diameter, inches
- GBSR Gearbox speed reduction factor
- H Net lift, approximated by the distance from the surface to the operating fluid level in the tubing-casing annulus, feet
- k_r Spring constant of the total sucker rod string, and represents the load in pounds required to stretch the total sucker rod string one inch
- $\frac{1}{k_r}$ Elastic constant for the total sucker rod string, inches per pound, also equals $E_r \times L$
- k_t Spring constant of the unanchored portion of the tubing, and represents the load in pounds required to stretch the unanchored portion of the tubing (between the anchor and the standing valve) one inch
- $\frac{1}{k_t}$ Elastic constant for the unanchored portion of the tubing string, inches per pound, measured from the standing value to the tubing anchor; also equals $E_t \times L_{ua}$
- L Length of the sucker rod string, feet
- MPRL Minimum load at the polished rod during the pumping cycle, pounds
- N Pumping speed, strokes per minute
- N_o Natural frequency of a nontapered sucker rod string, strokes per minute
- N_o' Natural frequency of a tapered sucker rod string, strokes per minute
- $\frac{N}{N_o}$ Dimensionless pumping speed factor for nontapered sucker rod string, also equals $(NL) \div 245{,}000$
- $\frac{N}{N_o'}$ Dimensionless pumping speed factor for tapered sucker rod string, also equals $(N/N_o) \div F_c$
- P_{ab} Atmospheric pressure, psia
- PBHP Producing bottomhole pressure, psia
- P_c Casing pressure, psig
- PD Bottomhole pump displacement assuming 100% volumetric efficiency, barrels per day, also equals $0.1166 \times S_p \times N \times D^2$
- PMPD Primemover sheave pitch diameter, inches

PPRL Peak load at the polished rod during the pumping cycle, pounds

$\bar{P}_r$ Reservoir pressure, psia

PRHP Horsepower at the polished rod

PT Peak torque, inch-pounds

P_{wf} Bottomhole pressure, psia

P_x Pressure at the pressure point (D_x) under consideration, psia

q_o Liquid producing rate at some value less than maximum, bbls. per day

q_o(max.) Maximum producing rate at 100% drawdown pressure rate with reservoir pressure at maximum, barrels per day

$\frac{q_o}{q_o \text{ max.}}$ Producing rate as a fraction of maximum producing rate

$\frac{Q}{aP^{0.4}}$ Ordinate from Fig. 1 where Q = MSCF/D, a = in.^{2}, and P = psi

RPM Revolutions per minute

S Polished rod stroke length, inches

S.G. Specific gravity of fluid in tubing-casing annulus

Sk_r Pounds of static load necessary to stretch the total sucker rod string an amount equal to the polished rod stroke length, also equals $S \div (1/k_r)$

S_p Bottomhole pump stroke, inches; S_p also equals $(\frac{S_p}{S} \times S) - (F_o \times \frac{1}{k_t})$ when the tubing is not anchored. If the tubing is anchored at the pump, the $(F_o \times \frac{1}{k_t})$ term becomes zero.

SPM Pumping speed, strokes per minute

$\frac{S_p}{S}$ Dimensionless plunger stroke factor

SV Standing valve

T_a Torque adjustment for peak torque for values of W_{rf}/Sk_r other than 0.3

V Downward fluid velocity in a gas anchor, feet per second

W Total weight of the sucker rod string in air, pounds

W_r Weight of sucker rod string in air, pounds per foot

W_{rf} Total weight of the sucker rod string in well fluid, pounds

$\frac{W_{rf}}{Sk_r}$ Weight of the sucker rod string in well fluid compared to the weight necessary to stretch the sucker rod string one polished rod stroke length, dimensionless

0.128 Weight of a cubic foot of fresh water, 62.4 pounds, divided by the weight of a cubic foot of steel, 489 pounds

0.34 Weight of a column of fresh water in a cylinder having a diameter of one inch and a height of one foot, pounds; also equals $0.433 \times 3.1416 \div 4$

0.433 Weight of a column of fresh water having a volume defined by a cross sectional area of one square inch and a height of one foot, pounds.

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EXHIBITS, FIGURES AND TABLES

API FIGURES AND TABLES

Reproduced by Permision - API Designations and Publication Titles Given

"API Specification for Oil-Field V-Belting," API Std. 1B

Table 3.1 Groove Dimensions for V-Belt Sheaves

Table A.1 V-Belt Sheave Sizes Generally Listed in Manufacturers Catalog

"API Specification for Subsurface Pumps and Fittings," API Std. 11AX

SECTION II Pump Designation
N11 Nipple, Seating, Cup Type (Rod Pump)
N12 Nipple, Seating, Mechanical Bottom Lock
N13 Nipple, Seating, 2 Cup Type (Tubing Pump)
N14 Nipple, Seating, Mechanical Top Lock

"API Specification for Sucker Rods," API Std. 11B

Table 3.1 General Dimensions and Tolerances for Sucker Rods and Pony Rods

Table 4.2 Slimhole Coupling and Subcouplings

"API Specification for Miscellaneous Production Equipment," API Std. 11D

Table 2.1 Polished Rod Specifications

Table 2.2 Polished Rod Liners Specifications

"API Specification for Pumping Units," API Std. 11E

Table 2 Pumping Unit Size Ratings

"API Recommended Practice for Design Calculations for Sucker Rod Pumping Systems (Conventional Units)," API RP11L

Table 1 Rod and Pump Data
Table 2 Tubing Data
Table 3 Sucker Rod Data
Figure 2 $\frac{S_p}{S}$, Plunger Stroke Factor
Figure 3 $\frac{F_1}{Sk_r}$, Peak Polished Rod Load
Figure 4 $\frac{F_2}{Sk_r}$, Minimum Polished Rod Load
Figure 5 $\frac{2T}{S^2k_r}$, Peak Torque
Figure 6 $\frac{F_3}{Sk_r}$, Polished Rod Horsepower
Figure 7 T_a, Adjustment for Peak Torque for Values of $\frac{W_{rf}}{Sk_r}$ other than 0.3
Figure 7a Added Chart to API RP11L for T_a, Adjustment for Peak Torque

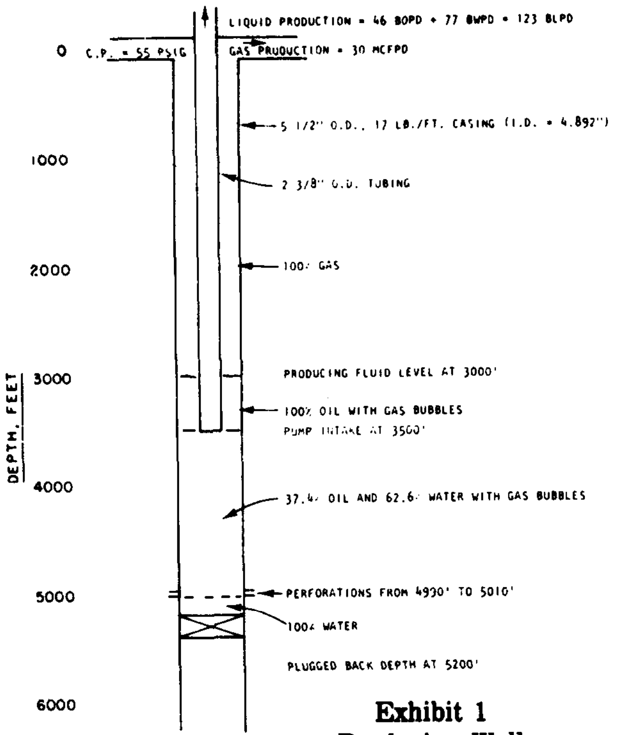


Exhibit 1
Producing Well

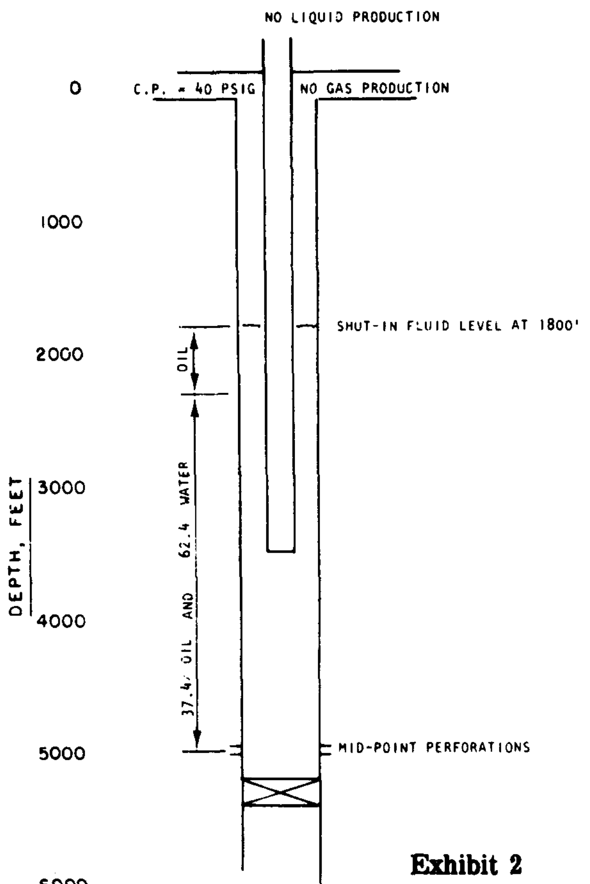


Exhibit 2
Shutin Well

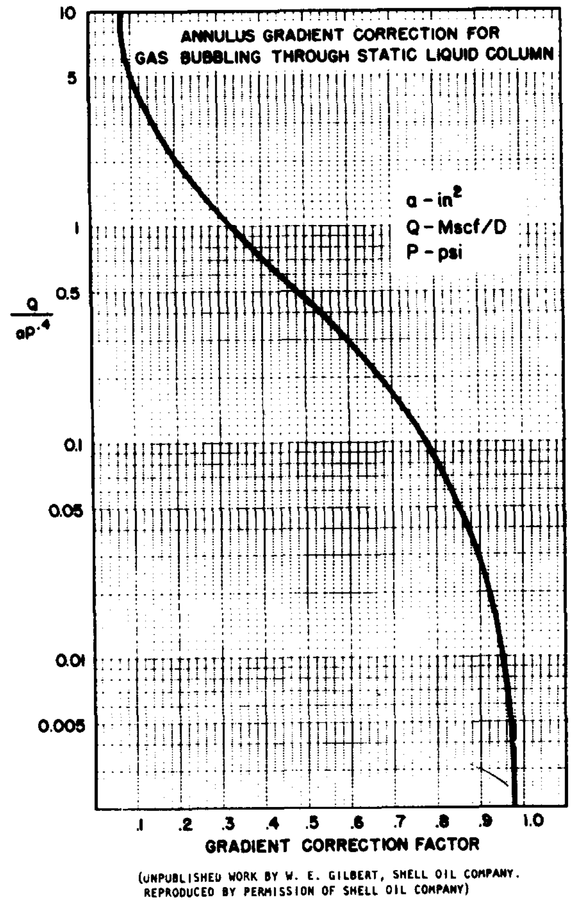
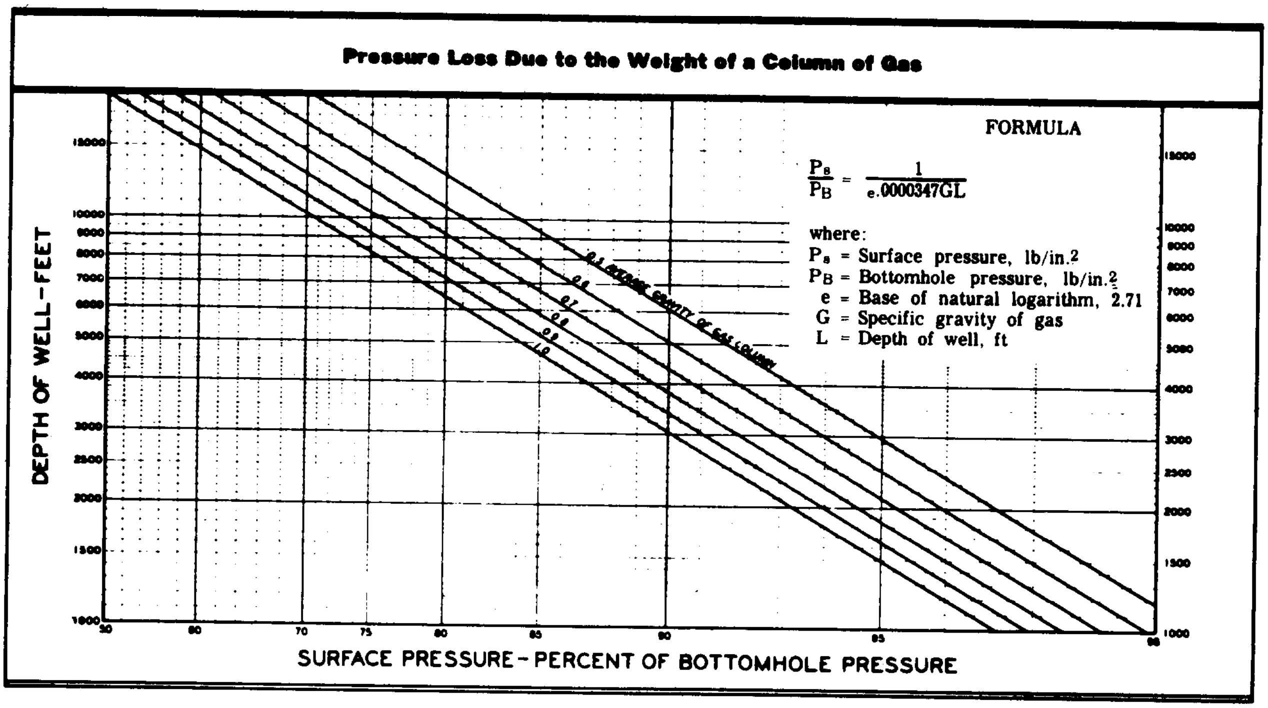
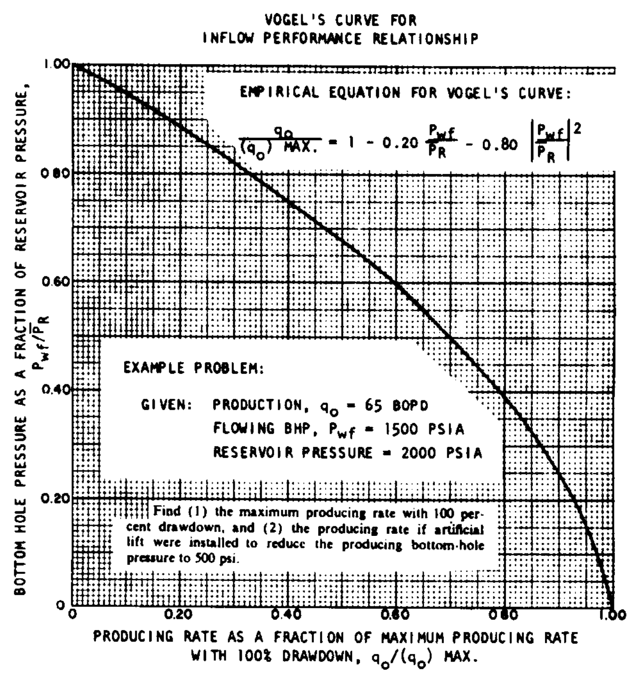


Figure 1
Annulus Gradient Correction for Gas Bubbling Through Static Liquid Column



Reproduced courtesy ARMCO Steel Corporation

Figure 2
Pressure Loss Due to the Weight of a Column of Gas



The solution is: (1) with p_{wf} = 1,500 psi, $p_{wf}/\bar{p}_R$ = 1,500/2,000 = 0.75. From Fig. 5, when $p_{wf}/\bar{p}_R$ = 0.75, $q_o/(q_o)_{max}$ = 0.40, $65/(q_o)_{max}$ = 0.40, $(q_o)_{max}$ = 162 BOPD; (2) with p_{wf} = 500 psi, $p_{wf}/\bar{p}_R$ = 500/2,000 = 0.25. From Fig. 5, $q_o/(q_o)_{max}$ = 0.90, $q_o/162$ = 0.90, q_o = 146 BOPD. (After Vogel, SPE TRANSACTIONS, 1968. Courtesy Society of Petroleum Engineers of AIME)

Figure 3
Vogel's Curve for Inflow Performance Relationship

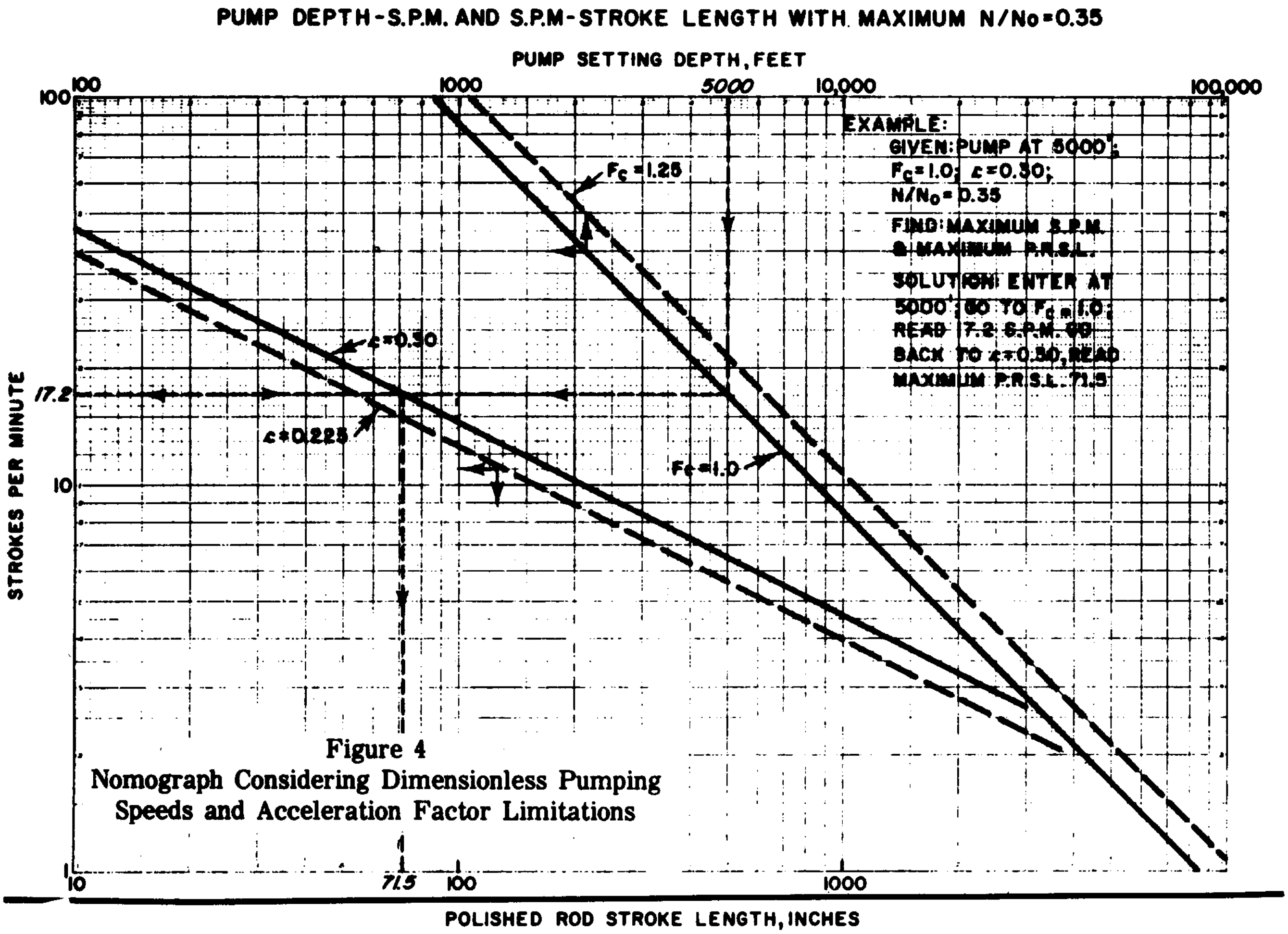
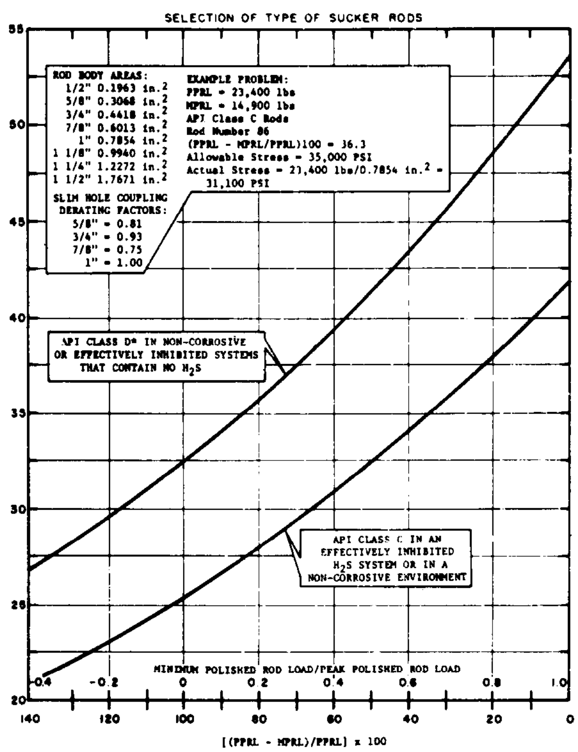


Figure 4
Nomograph Considering Dimensionless Pumping Speeds and Acceleration Factor Limitations



*To be used only where API Class C rod capabilities are exceeded.

Figure 5
Selection of Type of Sucker Rods

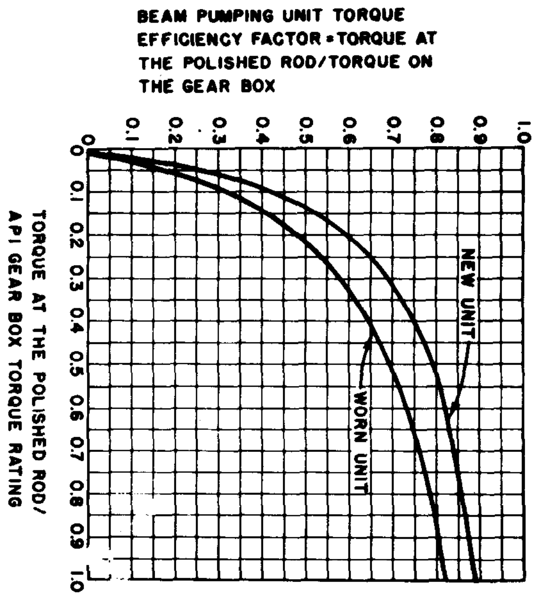


Figure 7
Beam Pumping Unit Torque Efficiency Factor

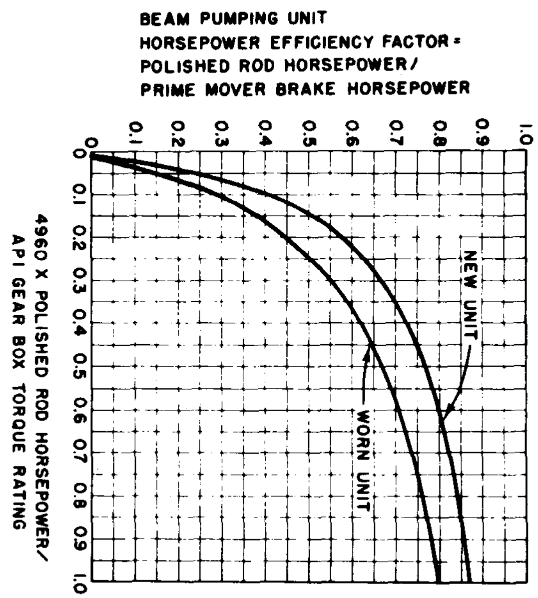


Figure 8
Beam Pumping Unit Horsepower Efficiency Factor

DESIGN CALCULATIONS SHEET
CONVENTIONAL SUCKER ROD PUMPING SYSTEM

Well Optimum 1 Calculated By FWG Date 4-20-72

Known or Assumed Data:

166 BPPD ÷ 0.70 Vol. Efficiency = 237 PD, Bbls. per day.
Fluid Level, H = 5050 Ft. Pump Depth, L = 5050 Ft.
Tubing Size 2 In. Is it anchored? Yes X No Pumping Speed, N = 17.55 SPM
Length of Stroke, S = 64 In. Plunger Diameter, D = 1.5 In.
Specific Gravity of Fluid, G = 1.00 Sucker Rods 65
API Class: C, D, S.S., K, H.T. (Circle one)

Record Factors from Tables 1 & 2:

1. W_r = 1.33 (Table 1, Column 3)
2. E_r = 1.119×10^{-6} (Table 1, Column 4)
3. F_c = 1.103 (Table 1, Column 5)
4. E_t = --- (Table 2, Column 5)

Calculate Non-Dimensional Variables:

5. $F_o = .340 \times G \times D^2 \times H$ = .340 × 1.0 × 2.25 × 5050 = 3860 lbs. (Gross Plunger Load)
6. $1/k_r = E_r \times L$ = 1.119×10^{-6} × 5050 = 5650×10^{-6} In./Lb. (line 2 × L)
7. $Sk_r = S \div 1/k_r$ = 64 ÷ 5650×10^{-6} = 11,330 Lbs. (S/line 6)
8. F_o/Sk_r = 3860 ÷ 11,330 = 0.34 (line 5/line 7)
9. $N/N_o = NL \div 245{,}000$ = 17.55 × 5050 ÷ 245,000 = 0.362
10. $N/N_o' = N/N_o \div F_c$ = 0.362 ÷ 1.103 = 0.328 (line 9/line 3)
11. $1/k_t = E_t \times L$ = --- × --- = --- In./Lb. (line 4 × L)

Solve for S_p and PD:

12. S_p/S = 0.805 (Figure 2) (line 10 to line 8 to answer)
13. $S_p = [(S_p/S) \times S] - [F_o \times 1/k_t]$ = [0.805 (line 12) × 64 (S)] - [-- (line 5) × -- (line 11)] = 51.5 In.
14. $PD = 0.1166 \times S_p \times N \times D^2$ = 0.1166 × 51.5 (line 13) × 17.55 (N) × 2.25 (D^2) = 237 Bbls. per day.

Determine Non-Dimensional Parameters:

15. $W = W_r \times L$ = 1.33 × 5050 = 6720 (Lbs.(line 1 × L)
16. $W_{rf} = W [1 - (.128G)]$ = 6720 [1-(.128 × 1.0)] = 5860 Lbs.
17. W_{rf}/Sk_r = 5860 ÷ 11,330 = 0.517 (line 16/line 7)

Record Non-Dimensional Factors from Figures 3 through 7:

18. F_1/Sk_r = 0.60 (Figure 3) (line 9 to line 8 to answer)
19. F_2/Sk_r = 0.247 (Figure 4) (line 9 to line 8 to answer)
20. $2T/S^2k_r$ = 0.425 (Figure 5) (line 9 to line 8 to answer)
21. F_3/Sk_r = 0.377 (Figure 6) (line 9 to line 8 to answer)
22. T_a = Torque Adjustment for Peak Torque for Values of W_{rf}/Sk_r other than 0.3

a. % = -1.2 (Figure 7)(Intersection of lines 10 and 8 is %)

b. T_a = 0.97 (Figure 10.8)(From % on Fig.7 to W_{rf}/Sk_r from line 17 to T_a)

Solve for Operating Characteristics:

23. PPRL = $W_{rf} + [(F_1/Sk_r) \times Sk_r]$ = 5860 (line 16) + [0.60 (line 18) × 11330 (line 7)] = 12,660 Lbs.
24. MPRL = $W_{rf} - [(F_2/Sk_r) \times Sk_r]$ = 5860 (line 16) - [0.247 (line 19) × 11330 (line 7)] = 3060 Lbs.
25. PT = $(2T/S^2k_r) \times Sk_r \times S/2 \times T_a$ = 0.425 (line 20) × 11330 (line 7) × 32 (S/2) × 0.97 (line 22) = 149,500 Lb.In.
26. PRHP = $(F_3/Sk_r) \times Sk_r \times S \times N \times 2.53 \times 10^{-6}$ = 0.377 (line 21) × 11330 (line 7) × 64 (S) × 17.55 (N) × 2.53×10^{-6} = 12.1
27. CBE = $1.06 (W_{rf} + 1/2\ F_o)$ = 1.06 × (5860 (line 16) + 1930 (line 5/2)) = 8250 Lbs.
28. (PPRL - MPRL) × 100/PPRL = 76 % [(Line 23 - Line 24) × 100/Line 23]
29. Actual Rod Stress = 12,660 (line 23) ÷ 0.442 (area of top rod) = 28,700 psi
30. Allowable Rod Stress = 28,700 (From Figure 5.1) psi
31. If line 29 is greater than line 30, Overload = (Line 29) - (Line 30) = 0 psi, and system should be redesigned.

(Revised: 2-10-71)

Figure 6
A Completed Design Calculations Sheet, Conventional Sucker Rod Pumping System (After API RP11L)

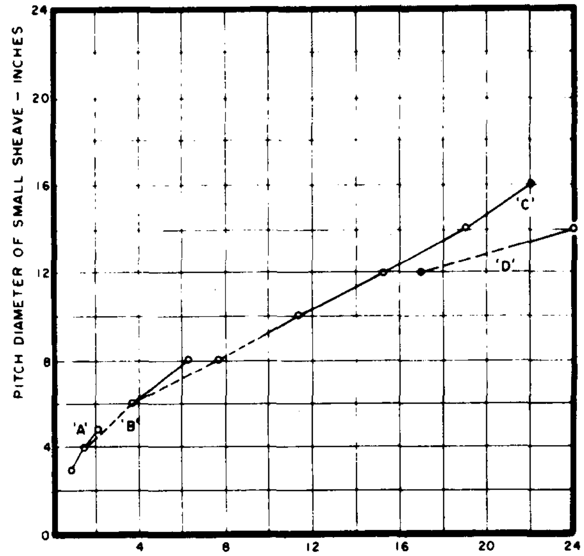


Figure 9
Horsepower Capacity of One V-Belt @ 1120 RPM

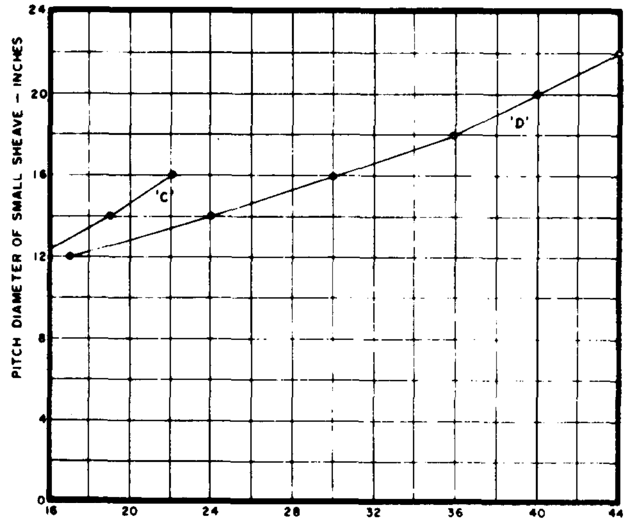


Figure 9A
Horsepower Capacity of One V-Belt @ 1120 RPM

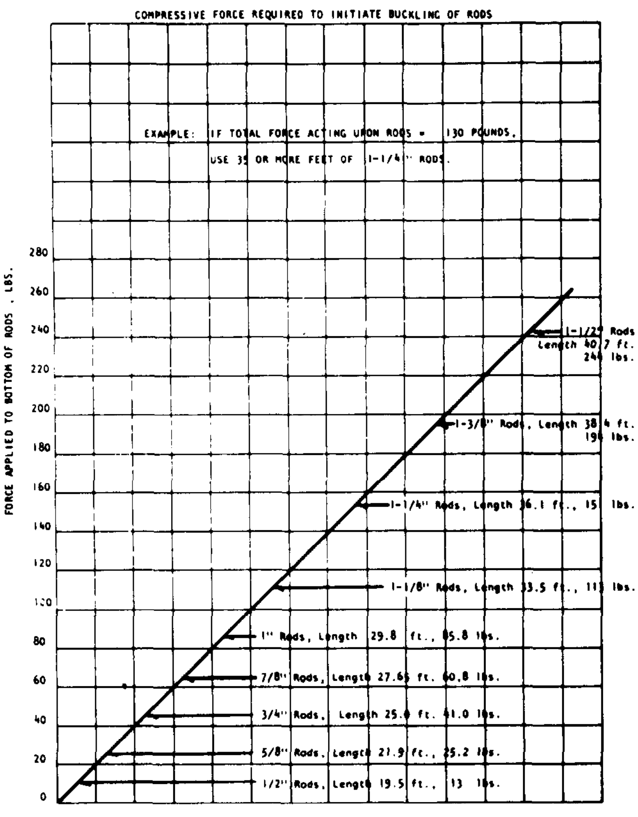


Figure 10
Compressive Force Required to Initiate Buckling of Rods

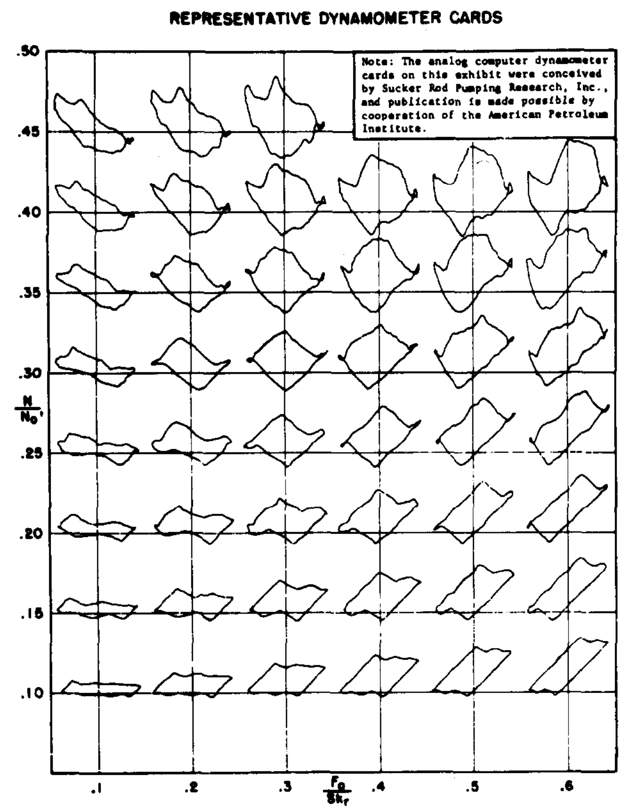


Figure 11
Representative Dynamometer Cards

Table 1
Pump Plunger Sizes Recommended for Optimum Design

PUMP DEPTH AND FLUID LEVEL FEET	FLUID PRODUCTION, BARRELS PER DAY - 100% VOLUMETRIC EFFICIENCY - 1.00 SPECIFIC GRAVITY												
	25	50	75	100	200	300	400	500	600	700	800	900	1000
1000	1.06	1.06	1.25	1.50	1.75 1.50	1.75 1.50	2.25 2.00	2.25 2.00	2.25 2.50	2.25 2.50	2.75 2.50	2.75 2.50	2.75
2000	1.06	1.06	1.25	1.50	1.75 1.50	1.75 1.50	2.25 2.00	2.25 2.00	2.25 2.50	2.25 2.50	2.75 2.50	2.75 2.50	2.75
3000	1.06	1.06	1.25	1.50	1.75 1.50	1.75 1.50	2.25 2.00	2.25 2.00	2.25 2.50	2.25 2.50	2.75 2.50	2.75 2.50	2.75
4000	1.06	1.06	1.25	1.50	1.75 1.50	1.75 1.50	2.25 2.00	2.25 2.00	2.25 2.50	2.25 2.50	2.75 2.50	2.75 2.50	2.75
5000	1.06	1.06	1.25	1.50	1.50	1.50	2.00	2.00	2.25 2.50	2.50	2.50	2.50	
6000	1.06	1.06	1.25	1.25	1.25	1.75 1.50	1.75 2.00	2.00	2.25	2.25			
7000	1.06	1.06	1.06	1.25	1.50 1.25	1.50	2.00	2.00	2.25	2.25			
8000	1.06	1.06	1.25	1.25	1.50 1.25	1.75	1.75	2.00					
9000	1.06	1.06	1.06	1.06	1.50	1.75							
10000	1.06	1.06	1.06	1.06	1.50	1.75							

LEGEND:

IN THIS TABULATION SURFACE PUMPING STROKES UP TO 120 INCHES ONLY ARE CONSIDERED. 2", 2-1/2" AND 3" NOMINAL TUBING ARE CONSIDERED. TOP LINE INDICATES PLUNGER DIAMETER, INCHES, TO USE WITH API CLASS C RODS. IF TOP LINE IS BLANK, CAPABILITIES OF CLASS C RODS WILL BE EXCEEDED.

BOTTOM LINE INDICATES PLUNGER DIAMETER, INCHES, TO USE WITH API CLASS D RODS. IF BOTTOM LINE IS BLANK, AND TOP LINE IS NOT, USE PLUNGER DIAMETER INDICATED ON TOP LINE.

IF BOTH LINES ARE BLANK, CAPABILITIES OF CLASS D RODS WILL BE EXCEEDED.

FWG:rss
JAN. 21, 1971

EXPLANATION OF TABLE OF PUMP PLUNGER SIZES RECOMMENDED FOR OPTIMUM DESIGN

The pump plunger sizes considered in constructing this table agree with those listed in API RP11L and differ from the API pump plunger sizes listed in API Std. 11AX, "API Specification for Subsurface Pumps and Fittings," in that a 1.06 (1-1/16-in.) pump is not listed in 11AX and a 1-25/32-in. pump is not covered in 11L.

API RP11L covers 3.75 and 4.75-in. plungers, but these were not considered because the tubing size was limited to 3-in. nominal in this study.

When an optimum design called for an excessively long polished rod stroke length because the tubing ID limited the sucker rod sizes which could be considered, the optimum design for the next larger tubing size was considered. For example, to lift 75 BFPD from 8000 ft with 2-in. nominal tubing in the well, a 1.06-in. plunger and a 100-in. polished rod stroke is required, while 2-1/2-in. nominal tubing allows the 75 BFPD to be lifted with a 1.25-in. plunger and with only a 48-in. polished rod stroke length. This reduces the calculated peak polished rod torque at the polished rod from 199,000 to 111,000 in.-lb. For these reasons, a 1.25-in. plunger was selected as optimum in this instance.

Table 2
Sinker Bar Factor Table

Column 1 Plunger Diameter	Column 2 Plunger Area	Column 3 a&b [(Seat Contact O.D. Area/I.D. Area) minus 1.0] Harbison-Fischer Data	Column 3 a&b [(Seat Contact O.D. Area/I.D. Area) minus 1.0] O'Bannon Data	Column 2 x Column 3a Sinker Bar Factors	Column 2 x Column 3b Sinker Bar Factors	Column 5 Recommended Sinker Bar Factors
1 1/16"	0.886 in.^{2}	0.235	0.33	0.209	0.293	0.30
1 1/4"	1.227	0.219	0.26	0.269	0.319	0.30
1 1/2"	1.767	0.216	0.24	0.382	0.424	0.40
1 3/4"	2.405	0.156	0.19	0.375	0.458	0.45
2"	3.142	0.139	0.17	0.436	0.535	0.50
2 1/4"	3.976	0.120	0.15	0.477	0.595	0.55
2 1/2"	4.909	0.099	0.13	0.490	0.640	0.60
2 3/4"	5.940	0.099	0.13	0.588	0.772	0.70
3 3/4"	11.045	-	0.13	-	1.433	1.40

Table 3.1
Groove Dimensions for V-Belt Sheaves

See Fig. 3.1

All dimensions in inches, except as shown.

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
					Standard-Groove Dimensions					Deep-Groove Dimensions				
V-Belt Cross-Section Symbol	Minimum Recommended Pitch Diameter	Pitch Diameter	No. of Grooves	Groove Angle, deg	Width of Groove W_g	Depth of Groove D	Addendum X	Groove Spacing S	Edge Distance E	Width of Groove W_g	Depth of Groove D	Addendum X	Groove Spacing S	Edge Distance E
A	3.0*	2.4 to 2.59		32	0.490	0.490	0.125	5/8	3/8	.....	Not Applicable			
		2.6 to 5.4		34	0.494	0.490	0.125	5/8	3/8	0.589	0.645	0.280	3/4	7/16
		Over 5.4		38	0.504	0.490	0.125	5/8	3/8	0.611	0.645	0.280	3/4	7/16
A-B	....	3.0 to 6.6†	1	34½	0.620	0.625	0.375	3/4	7/16	....	Not Applicable			...
	....	3.0 to 6.6†	2 to 6	34½	0.620	0.625	0.375	3/4	1/2	....	Not Applicable			...
	....	Over 6.6†	1 to 6	38	0.640	0.625	0.375	3/4	1/2	.	Not Applicable			...
B	5.4*	3.4 to 4.59		32	0.630	0.580	0.175	3/4	1/2		Not Applicable			
		4.6 to 7.0		34	0.637	0.580	0.175	3/4	1/2	0.747	0.760	0.355	7/8	9/16
		Over 7.0		38	0.650	0.580	0.175	3/4	1/2	0.774	0.760	0.355	7/8	9/16
C	9.0*	6.0 to 6.99		34	0.879	0.780	0.200	1	11/16		Not Applicable			.....
		7.0 to 7.99		34	0.879	0.780	0.200	1	11/16	1.066	1.085	0.505	1¼	13/16
		8.0 to 12.0		36	0.887	0.780	0.200	1	11/16	1.085	1.085	0.505	1¼	13/16
		Over 12.0		38	0.895	0.780	0.200	1	11/16	1.105	1.085	0.505	1¼	13/16
D	13.0*	10.0 to 11.99	....	34	1.259	1.050	0.300	1 7/16	7/8	....	Not Applicable			.....
		12.0 to 12.99		34	1.259	1.050	0.300	1 7/16	7/8	1.513	1.465	0.715	1¾	1 1/16
		13.0 to 17.0		36	1.271	1.050	0.300	1 7/16	7/8	1.541	1.541	0.715	1¾	1 1/16
		Over 17.0		38	1.283	1.050	0.300	1 7/16	7/8	1.569	1.541	0.715	1¾	1 1/16
E	21.0*	18.0 to 24.0		36	1.527	1.300	0.400	1¾	1⅛	1.816	1.745	0.845	2 1/16	1 5/16
		Over 24.0		38	1.542	1.300	0.400	1¾	1⅛	1.849	1.745	0.845	2 1/16	1 5/16

*Below these diameters, horsepower ratings decrease sharply and result in less economical drives.

†Pitch diameter of "A" section.

Table A.1
V-Belt Sheave Sizes Generally Listed in Manufacturers Catalog

1	2	3	4	5	6	7	8	9	10	11
A Section		Combination A - B Section			B Section		C Section		D Section	
PD	Grooves	PD Using A Belts	PD Using B Belts	Grooves	PD	Grooves	PD	Grooves	PD	Grooves
3.0	1 thru 4	4.6	5.0	1 thru 6	5.0	1 thru 6	8.0	2 thru 6, 8, 10	12.0	4, 5, 6, 8, 10, 12
3.2	1 thru 4	4.8	5.2	1 thru 6	5.2	1 thru 6	8.5	2 thru 6, 8, 10	13.0	4, 5, 6, 8, 10, 12
3.4	1 thru 4	5.0	5.4	1 thru 6, 8, 10	5.4	1 thru 6, 8, 10	9.0	2 thru 6, 8, 10, 12	13.5	4, 5, 6, 8, 10, 12
3.6	1 thru 4	5.2	5.6	1 thru 6, 8, 10	5.6	1 thru 6, 8, 10	9.5	2 thru 6, 8, 10, 12	14.0	4, 5, 6, 8, 10, 12
3.8	1 thru 4	5.6	6.0	1 thru 6, 8, 10	6.0	1 thru 6, 8, 10	10.0	2 thru 6, 8, 10, 12	14.5	4, 5, 6, 8, 10, 12
4.0	1 thru 4	6.0	6.4	1 thru 6, 8, 10	6.4	1 thru 6, 8, 10	10.5	2 thru 6, 8, 10, 12	15.0	4, 5, 6, 8, 10, 12
4.6	1 thru 4	6.4	6.8	1 thru 6, 8, 10	6.8	1 thru 6, 8, 10	11.0	2 thru 6, 8, 10, 12	15.5	4, 5, 6, 8, 10, 12
5.0	1 thru 4	7.0	7.4	1 thru 6, 8, 10	7.4	1 thru 6, 8, 10	13.0	2 thru 6, 8, 10, 12	16.0	4, 5, 6, 8, 10, 12
5.6	1 thru 4	8.2	8.6	1 thru 6, 8, 10	8.6	1 thru 6, 8, 10	16.0	2 thru 6, 8, 10, 12	18.0	4, 5, 6, 8, 10, 12
7.0	1 thru 4	9.0	9.4	1 thru 6, 8, 10	9.4	1 thru 6, 8, 10	20.0	2 thru 6, 8, 10, 12	22.0	4, 5, 6, 8, 10, 12
8.2	1 thru 4	10.6	11.0	1 thru 6, 8, 10	11.0	1 thru 6, 8, 10	24.0	2 thru 6, 8, 10, 12	27.0	4, 5, 6, 8, 10, 12
9.0	1 thru 4	12.0	12.4	1 thru 6, 8, 10	12.4	1 thru 6, 8, 10	30.0	3 thru 6, 8, 10, 12	33.0	4, 5, 6, 8, 10, 12
10.6	1 thru 4	15.0	15.4	1 thru 6, 8, 10	15.4	1 thru 6, 8, 10	36.0	3 thru 6, 8, 10, 12	40.0	4, 5, 6, 8, 10, 12
12.0	1 thru 4	18.0	18.4	1 thru 6, 8, 10	18.4	1 thru 6, 8, 10	44.0	3 thru 6, 8, 10, 12	48.0	4, 5, 6, 8, 10, 12
15.0	1 thru 4	24.6	25.0	3 thru 6, 8, 10	25.0	3 thru 6, 8, 10	50.0	3 thru 6, 8, 10, 12	58.0	4, 5, 6, 8, 10, 12
18.0	1 thru 4	29.6	30.0	3 thru 6, 8, 10	30.0	3 thru 6, 8, 10				

V-BELT SHEAVE SIZES AVAILABLE FROM SOME MANUFACTURERS

1	2	3	4	5	6	7	8	9	10	11
A Section		Combination A - B Section			B Section		C Section		D Section	
PD	Grooves	PD Using A Belts	PD Using B Belts	Grooves	PD	Grooves	PD	Grooves	PD	Grooves
4.2	1 thru 4	3.0	3.4	1 thru 6	3.4	1 thru 6	7.0	2 thru 6	13.0	14, 16, 18, 20
4.8	1 thru 4	3.2	3.6	1 thru 6	3.6	1 thru 6	7.5	2 thru 6	14.0	14, 16, 18, 20
5.2	1 thru 4	3.4	3.8	1 thru 6	3.8	1 thru 6	12.0	2 thru 6, 8, 10, 12	16.0	14, 16, 18, 20
6.0	1 thru 4	3.6	4.0	1 thru 6	4.0	1 thru 6	14.0	2 thru 6, 8, 10, 12	18.0	14, 16, 18, 20
6.4	1 thru 4	3.8	4.2	1 thru 6	4.2	1 thru 6	18.0	2 thru 6, 8, 10, 12	20.0	14, 16, 18, 20
		4.0	4.4	1 thru 6	4.4	1 thru 6			48.0	14, 16, 18, 20
		4.2	4.6	1 thru 6	4.6	1 thru 6			52.0	12, 14, 16, 18, 20
		19.6	20.0	1 thru 6, 8, 10	20.0	1 thru 6, 8, 10			56.0	12, 14, 16, 18, 20
		37.6	38.0	2 thru 6, 8, 10	38.0	2 thru 6, 8, 10			58.0	14, 16, 18, 20
									60.0	12, 14, 16, 18, 20
									64.0	12, 14, 16, 18, 20
									70.0	12, 14, 16, 18, 20

*NOTE: *This information is shown here as an aid to the drive designer. It does not constitute a rigid standard, and is not intended to preclude future additions or deletions of sheave sizes.*

SECTION II
Pump Designation

2.1. The basic types of pumps and letter designation covered by this specification are as follows:

Type of Pump	Letter Designation: Metal Plunger Pumps — Heavy-Wall Barrel	Liner Barrel	Thin-Wall Barrel	Soft-packed Plunger Pumps — Heavy-Wall Barrel	Thin-Wall Barrel
Rod Pumps					
Stationary Barrel, Top Anchor	RHA	RLA	RWA	....	RSA
Stationary Barrel, Bottom Anchor	RHB	RLB	RWB	....	RSB
Traveling Barrel, Bottom Anchor	RHT	RLT	RWT	....	RST
Tubing Pumps	TH	TL	....	TP	....

2.2 Complete pump designations include: (1) nominal tubing size, (2) basic bore diameter, (3) type of pump, including type of barrel and location and type of seating assembly, (4) barrel length, (5) plunger length, and (6) total length of extensions when used, as follows:

XX - XXX X X X X   X - X - X

- X (last) — Total length of extensions, whole feet.
- X — Nominal plunger length, feet.
- X — Barrel length, feet.
- Type seating assembly; C — Cup type; M — Mechanical type
- Location of seating assembly; A — Top; B — Bottom; T — Bottom, traveling barrel
- Type barrel; H — Heavy-wall, L — Liner barrel, W — Thin-wall: For metal plunger pumps; S — Thin-wall, P — Heavy-wall: For soft-packed plunger pumps
- Type pump; R — Rod; T — Tubing
- Pump bore (basic): 106 — 1 1/16 in.; 125 — 1¼ in.; 150 — 1½ in.; 175 — 1¾ in.; 178 — 1 25/32 in.; 200 — 2 in.; 225 — 2¼ in.; 250 — 2½ in.; 275 — 2¾ in.
- Tubing size; 15 — 1.900 in. OD.; 20 — 2⅜ in. OD.; 25 — 2⅞ in. OD.; 30 — 3½ in. OD.

Example: A 1¼ in. bore rod type pump with a 7 ft liner barrel and 4 ft of extensions, a 2 ft plunger, and a bottom cup type seating assembly for operation in 2⅜ in. tubing, would be designated as follows:

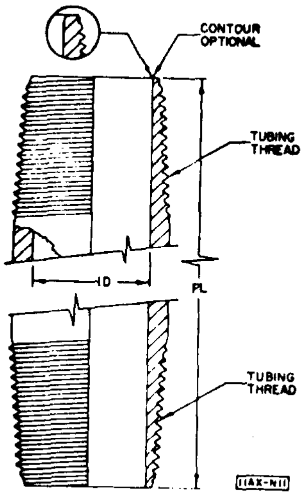
20-125 RLBC 7-2-4

2.3 In addition to the pump designation described in Par. 2.2, it is necessary for the purchaser to provide the following additional information:

a. Liner or barrel material
b. Plunger material
c. Plunger clearance (fit)
d. Valve material
e. Length of each extension

(These tables reproduced courtesy API Division of Production)

N11
Nipple, Seating, Cup Type (Rod Pump)

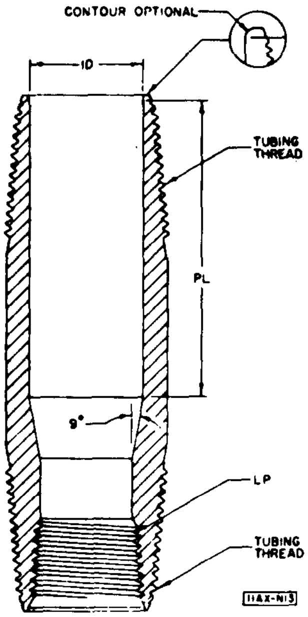


1	2	3	4	5
Dimensional Symbol	Part Number			
	N11-15	N11-20	N11-25	N11-30
[1]Tubing Thread	[2]1.900-10 LJ	2⅜-8 EU	2⅞-8 EU	3½-8 EU
ID	1.460 $^{+.010}_{-.000}$	1.780 $^{+.010}_{-.000}$	2.280 $^{+.010}_{-.000}$	2.780 $^{+.010}_{-.000}$
PL	6 min.	6 min.	6 min.	6 min.

[1]See API Std 5B for tubing thread details.

[2]Upper connection may be 1.900-10 LJ box thread, thus eliminating need for C34-15 coupling.

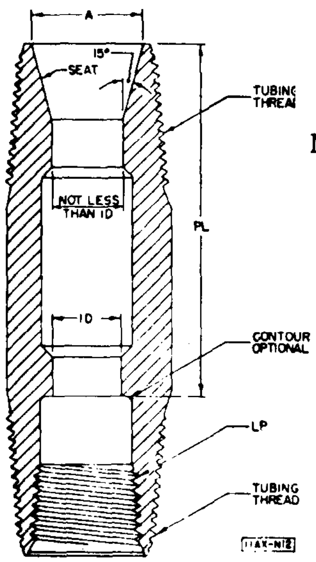
N13
Nipple, Seating, 2 Cup Type (Tubing Pump)



1	2	3	4
Dimensional Symbol	Part Number		
	N13-20	N13-25	N13-30
[1]Tubing Thread	2⅜-8EU	2⅞-8EU	3½-8EU
ID	1.710 $^{+.010}_{-.000}$	2.210 $^{+.010}_{-.000}$	2.710 $^{+.010}_{-.000}$
PL	5¼	5¾	5½
[2]LP	1½ nom.	2 nom.	2 nom.

[1]See API Std 5B for tubing thread details.
[2]Line pipe thread. See API Std 5B for details.

N12
Nipple, Seating, Mechanical Bottom Lock



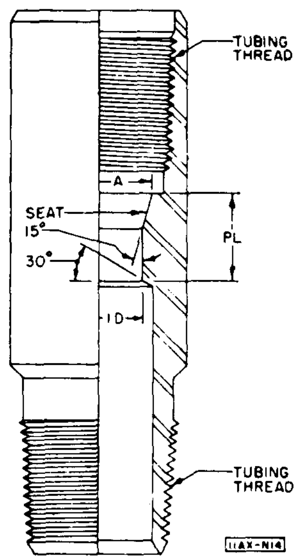
1	2	3	4	5
Dimensional Symbol	Part Number			
	N12-15	N12-20	N12-25	N12-30
[1]Tubing Thread	[3]1.900-10 LJ	2⅜-8 EU	2⅞-8 EU	3½-8 EU
A	1.475	1.688	2.188	2.688
ID	1.125	1.375	1.750	2.250
PL	3.856 $^{+.000}_{-.016}$	4.352 $^{+.000}_{-.016}$	5.102 $^{+.000}_{-.016}$	6.164 $^{+.000}_{-.016}$
[2]LP	1 nom.	1½ nom.	2 nom.	2½ nom.

[1]See API Std 5B for tubing thread details.

[2]Line pipe threads. See Std 5B for details.

[3]Upper connection may be 1.900-10 LJ box thread, thus eliminating need for C34-15 coupling.

N14
Nipple, Seating, Mechanical Top Lock



1	2	3	4
Dimensional Symbol	Part Number		
	N14-20	N14-25	N14-30
[1]Tubing Thread	2⅜-8EU	2⅞-8EU	3½-8EU
A	1.875	2.344	2.844
ID	1.780	2.280	2.780
PL	0.973 $^{+.000}_{-.005}$	0.918 $^{+.000}_{-.005}$	0.918 $^{+.000}_{-.005}$

[1]See API Std 5B for tubing thread details.

(These figures and data reproduced courtesy API Division of Production)

Table 3.1
General Dimensions and Tolerances for Sucker Rods and Pony Rods

All dimensions in inches except rod lengths which are in feet. See Fig. 3.1.

1	2	3	4	5	6	7	8	9	10
Size of Rod	Nominal Diameter of Pin	Outside Diameter of Pin Shoulder and Box D_f	Width of Wrench Square $\pm\frac{1}{32}$ W_s	Length of Wrench Square[1] W_l	Diameter of Bead D_u	Total Length of Rod Box, min. L_b	Length of Box-and-Pin Rod[2] ±2.0 in.	Length of Pin-and-Pin Rod[3] ±2.0 in.	Length of Box-and-Pin and Pin-and-Pin Pony Rods[2, 3] ±2.0 in.
1/2	3/4	$1.000^{+0.005}_{-0.010}$	5/8	3/4		—	—	25, 30	1 1/3, 2, 3, 4, 6, 8, 10, 12
5/8	15/16	[4]$1.250^{+0.005}_{-0.010}$	7/8	1 1/4	Not	2 1/8	25	25, 30	1 1/3, 2, 3, 4, 6, 8, 10, 12
3/4	1 1/16	$1.500^{+0.005}_{-0.010}$	1	1 1/4	to	2 3/8	25	25, 30	1 1/3, 2, 3, 4, 6, 8, 10, 12
7/8	1 3/16	$1.625^{+0.005}_{-0.010}$	1	1 1/4	Exceed	2 3/8	....	25, 30	1 1/3, 2, 3, 4, 6, 8, 10, 12
1	1 3/8	$2.000^{+0.005}_{-0.010}$	1 5/16	1 1/2	D_f	3	....	25, 30	1 1/3, 2, 3, 4, 6, 8, 10, 12
1 1/8	1 9/16	2.250 ± 0.015	1 1/2	1 5/8		3 1/4	....	25, 30	1 1/3, 2, 3, 4, 6, 8, 10, 12

[1]Minimum length exclusive of fillet.
[2]The length of box-and-pin rods shall be measured from contact face of pin shoulder to contact face of box.
[3]The length of pin-and-pin rods shall be measured from contact face of pin shoulder to contact face on the field end of the coupling.
[4]Dimension D_f of 5/8 in. box-and-pin rods shall be 1.375 ±0.015.

Table 2.1
Polished Rod Specifications

(See API Std 11B for polished-rod thread details)

1	2	3	4
Polished-Rod Size (OD), in.	[1]Length, ft.	Thread Size (Nominal Pin Dia., in.)	Size Sucker Rod with which used
1	8, 11, 16	3/4	1/2
[2]1 1/8	8, 11, 16, 22	15/16, 1 1/16	5/8, 3/4
[2]1 1/4	11, 16, 22	1 3/16	7/8
1 1/2	16, 22	1 3/8	1
[3]1 1/2 (upset)	16, 22	1 9/16	1 1/8

[1]Polished rods in lengths greater than 22 ft may be furnished by agreement between purchaser and manufacturer.

[2]1 1/8 and 1 1/4 in. polished rods may be furnished with an upset on one end if so specified on the purchase order.

[3]The upset on 1 1/2 in. polished rods to be made on one end only with a shoulder diameter equal to dimension D_f (2.250±.015 in.) in accordance with Std 11B, and the length of this shoulder parallel to the body of the rod shall be 1/2 in. minimum.

Table 4.2
Slimhole Coupling and Subcouplings

(All dimensions in inches, See Fig. 4.1)

1	2	3	4
Nominal Coupling Size*	Outside Diameter .005 - .010 W	Length Min. N_L	Used With Min. Tubing Size
1/2	1	2 3/4	1.660 OD
5/8	1 1/4	4	1.990 OD
3/4	1 1/2	4	2 1/16 OD
7/8	1 5/8	4	2 3/8 OD
1	2	4	2 7/8 OD

*Also size of rod with which coupling is to be used.

Table 2.2
Polished Rod Liners Specifications

1	2	3
Liner Size, (OD), in.	*Threaded End Connection (UN-Class 2A)	Size Polished Rod with which used (OD), in.
1 3/8	1 3/8 — 16	1 1/8
1 1/2	1 1/2 — 16	1 1/4
1 3/4	1 3/4 — 16	1 1/2

*See Handbook H28, Screw-Thread Standards for Federal Service; obtainable from Superintendent of Documents, U. S. Government Printing Office, Washington 25, D. C.

Table 2
Pumping Unit Size Ratings

1	2	3	4	5	6	7	8	9	10
	Series A			Series B			Series C		
Pumping Unit Size	Reducer Rating, in.-lb	Structure Capacity, lb	Max. Stroke Length, in.	Reducer Rating, in.-lb	Structure Capacity, lb	Max. Stroke Length, in.	Reducer Rating, in.-lb	Structure Capacity, lb	Max. Stroke Length, in.
6.4—32—16	6,400	3,200	16						
6.4—21—24				6,400	2,100	24			
6.4—32—24				6,400	3,200	24			
10—32—16	10,000	3,200	16						
10—21—24				10,000	2,100	24			
10—32—24				10,000	3,200	24			
10—40—20	10,000	4,000	20						
10—27—30				10,000	2,700	30			
10—40—30				10,000	4,000	30			
16—40—20	16,000	4,000	20						
16—27—30				16,000	2,700	30			
16—40—30				16,000	4,000	30			
16—53—24	16,000	5,300	24						
16—43—30				16,000	4,300	30			
16—53—30				16,000	5,300	30			
25—53—24	25,000	5,300	24						
25—43—30				25,000	4,300	30			
25—53—30				25,000	5,300	30			
25—67—30	25,000	6,700	30						
25—56—36				25,000	5,600	36			
25—67—36				25,000	6,700	36			
40—67—30	40,000	6,700	30						
40—56—36				40,000	5,600	36			
40—67—36				40,000	6,700	36			
40—89—36	40,000	8,900	36						
40—76—42				40,000	7,600	42			
40—89—42				40,000	8,900	42			
57—89—36	57,000	8,900	36						
57—76—42				57,000	7,600	42			
57—89—42				57,000	8,900	42			
57—109—42	57,000	10,900	42						
57—95—48				57,000	9,500	48			
57—109—48				57,000	10,900	48			
80—109—42	80,000	10,900	42						
80—95—48				80,000	9,500	48			
80—109—48				80,000	10,900	48			
80—133—48	80,000	13,300	48						
80—119—54				80,000	11,900	54			
80—133—54				80,000	13,300	54			
114—133—48	114,000	13,300	48						
114—119—54				114,000	11,900	54			
114—133—54				114,000	13,300	54			
114—169—54	114,000	16,900	54						
114—143—64				114,000	14,300	64			
114—169—64				114,000	16,900	64			
160—169—54	160,000	16,900	54						
160—143—64				160,000	14,300	64			
160—169—64				160,000	16,900	64			
160—200—64	160,000	20,000	64						
160—173—74				160,000	17,300	74			
160—200—74				160,000	20,000	74			
228—200—64	228,000	20,000	64						
228—173—74				228,000	17,300	74			
228—200—74				228,000	20,000	74			
228—246—74	228,000	24,600	74						
228—212—86				228,000	21,200	86			
228—246—86				228,000	24,600	86			
320—246—74	320,000	24,600	74						
320—212—86				320,000	21,200	86			
320—246—86				320,000	24,600	86			
320—298—86	320,000	29,800	86						
320—256—100				320,000	25,600	100			
320—298—100				320,000	29,800	100			
320—213—120							320,000	21,300	120
320—256—120							320,000	25,600	120
456—298—86	456,000	29,800	86						
456—256—100				456,000	25,600	100			
456—298—100				456,000	29,800	100			
456—213—120							456,000	21,300	120
456—256—120							456,000	25,600	120
456—365—100	456,000	36,500	100						
456—304—120				456,000	30,400	120			
456—365—120				456,000	36,500	120			
456—253—144							456,000	25,300	144
456—304—144							456,000	30,400	144
640—365—100	640,000	36,500	100						
440—304—120				640,000	30,400	120			
640—365—120				640,000	36,500	120			
640—253—144							640,000	25,300	144
640—304—144							640,000	30,400	144
640—427—120	640,000	42,700	120						
640—356—144				640,000	35,600	144			
640—427—144				640,000	42,700	144			
640—305—168							640,000	30,500	168
640—356—168							640,000	35,600	168
912—427—120	912,000	42,700	120						
912—356—144				912,000	35,600	144			
912—427—144	912,000	42,700	144	912,000	42,700	144			
912—305—168							912,000	30,500	168
912—356—168							912,000	35,600	168
912—427—168				912,000	42,700	168			
912—380—192							912,000	38,000	192
912—427—192							912,000	42,700	192

Notes to Table 1

Series A pumping units are established on the basis of most generally used combinations of reducer size and stroke length. Structure capacities for Series A units are derived from the following formula, assuming 75 per cent maximum counterbalance effect.

$$C = \frac{8 \times PT}{S}$$

wherein:

C = structure capacity, lb.
PT = reducer peak-torque capacity, in.-lb.
S = maximum stroke length, in.

Series B and C are intended to provide pumping units with stroke lengths longer than those provided for in Series A by increasing the front portion of the walking beam (dimension "a", Fig. 1), and/or increasing the crank radius.

A maximum structure capacity of 42,700 lb has been established because sucker rod limitations currently prevent utilization of higher capacities.

Table 1
Rod and Pump Data

1	2	3	4	5	6	7	8	9	10	11
Rod* No.	Plunger Diam., inches D	Rod Weight, lb per ft W_r	Elastic Constant, in. per lb ft E_r	Frequency Factor, F_c	Rod String, % of each size					
					1⅛	1	⅞	¾	⅝	½
44	All	0.726	1.990×10^{-6}	1.000						100.0
54	1.06	0.892	1.697×10^{-6}	1.128					40.5	59.5
54	1.25	0.914	1.659×10^{-6}	1.139					45.9	54.1
54	1.50	0.948	1.597×10^{-6}	1.142					54.5	45.5
54	1.75	0.990	1.525×10^{-6}	1.130					64.6	35.4
54	2.00	1.037	1.442×10^{-6}	1.096					76.2	23.8
55	All	1.135	1.270×10^{-6}	1.000					100.0	
64	1.06	1.116	1.441×10^{-6}	1.234				28.1	33.1	38.8
64	1.25	1.168	1.368×10^{-6}	1.222				31.8	37.5	30.7
64	1.50	1.250	1.252×10^{-6}	1.191				37.7	44.5	17.8
64	1.75	1.347	1.116×10^{-6}	1.137				44.7	52.7	2.6
65	1.06	1.291	1.150×10^{-6}	1.085				31.3	68.7	
65	1.25	1.306	1.138×10^{-6}	1.093				34.4	65.6	
65	1.50	1.330	1.119×10^{-6}	1.103				39.2	60.8	
65	1.75	1.359	1.097×10^{-6}	1.111				45.0	55.0	
65	2.00	1.392	1.071×10^{-6}	1.114				51.6	48.4	
65	2.25	1.429	1.042×10^{-6}	1.110				59.0	41.0	
65	2.50	1.471	1.010×10^{-6}	1.097				67.4	32.6	
65	2.75	1.517	0.974×10^{-6}	1.074				76.6	23.4	
66	All	1.634	0.883×10^{-6}	1.000				100.0		
75	1.06	1.511	1.030×10^{-6}	1.168			22.6	26.1	51.3	
75	1.25	1.548	1.006×10^{-6}	1.179			24.8	28.6	46.6	
75	1.50	1.606	0.969×10^{-6}	1.185			28.3	32.6	39.1	
75	1.75	1.674	0.924×10^{-6}	1.180			32.4	37.4	30.2	
75	2.00	1.754	0.874×10^{-6}	1.160			37.2	42.8	20.0	
75	2.25	1.843	0.816×10^{-6}	1.128			42.5	49.2	8.3	
76	1.06	1.787	0.822×10^{-6}	1.061			25.9	74.1		
76	1.25	1.798	0.818×10^{-6}	1.066			27.8	72.2		
76	1.50	1.816	0.811×10^{-6}	1.073			30.9	69.1		
76	1.75	1.836	0.803×10^{-6}	1.080			34.3	65.7		
76	2.00	1.861	0.793×10^{-6}	1.087			38.5	61.5		
76	2.25	1.888	0.782×10^{-6}	1.094			43.1	56.9		
76	2.50	1.919	0.770×10^{-6}	1.096			48.3	51.7		
76	2.75	1.953	0.756×10^{-6}	1.096			54.1	45.9		
76	3.75	2.121	0.690×10^{-6}	1.048			82.5	17.5		
77	All	2.224	0.649×10^{-6}	1.000			100.0			
85	1.06	1.709	0.957×10^{-6}	1.237		15.9	17.7	20.1	46.3	
85	1.25	1.780	0.919×10^{-6}	1.250		17.9	19.9	22.5	39.7	
85	1.50	1.893	0.858×10^{-6}	1.242		21.0	23.4	26.5	29.1	
85	1.75	2.027	0.786×10^{-6}	1.218		24.8	27.5	31.0	16.7	
85	2.00	2.181	0.703×10^{-6}	1.180		29.0	32.3	36.3	2.4	
86	1.06	2.008	0.757×10^{-6}	1.127		19.3	21.9	58.8		
86	1.25	2.035	0.748×10^{-6}	1.136		20.7	23.5	55.8		
86	1.50	2.079	0.733×10^{-6}	1.148		23.0	26.0	51.0		
86	1.75	2.130	0.716×10^{-6}	1.157		25.6	29.0	45.4		
86	2.00	2.190	0.696×10^{-6}	1.162		28.7	32.5	38.8		
86	2.25	2.257	0.674×10^{-6}	1.158		32.1	36.5	31.4		
86	2.50	2.334	0.650×10^{-6}	1.146		35.8	41.6	22.6		
86	2.75	2.415	0.621×10^{-6}	1.125		40.3	45.6	14.1		
87	1.06	2.376	0.615×10^{-6}	1.048		22.3	77.7			
87	1.25	2.384	0.613×10^{-6}	1.061		23.5	76.5			
87	1.50	2.397	0.610×10^{-6}	1.055		25.5	74.5			
87	1.75	2.414	0.606×10^{-6}	1.061		27.9	72.1			
87	2.00	2.432	0.602×10^{-6}	1.066		30.6	69.4			
87	2.25	2.453	0.598×10^{-6}	1.072		33.7	66.3			
87	2.50	2.477	0.592×10^{-6}	1.077		37.2	62.8			
87	2.75	2.503	0.586×10^{-6}	1.082		41.0	59.0			
87	3.75	2.632	0.558×10^{-6}	1.082		60.0	40.0			
87	4.75	2.800	0.520×10^{-6}	1.035		84.7	15.3			
88	All	2.904	0.497×10^{-6}	1.000		100.0				
96	1.06	2.264	0.698×10^{-6}	1.181	14.8	16.7	19.7	48.8		
96	1.25	2.311	0.685×10^{-6}	1.208	16.0	17.8	21.0	45.2		
96	1.50	2.385	0.664×10^{-6}	1.215	17.7	19.9	23.3	39.1		
96	1.75	2.472	0.639×10^{-6}	1.218	19.9	22.0	25.9	32.2		
96	2.00	2.572	0.610×10^{-6}	1.218	22.1	24.8	29.2	23.9		
96	2.25	2.686	0.577×10^{-6}	1.197	24.9	27.7	32.6	14.8		
96	2.50	2.813	0.540×10^{-6}	1.168	27.9	31.0	36.6	4.5		
97	1.06	2.601	0.576×10^{-6}	1.103	17.0	19.1	63.9			
97	1.25	2.622	0.572×10^{-6}	1.109	18.0	20.1	61.9			
97	1.50	2.653	0.568×10^{-6}	1.117	19.3	21.9	58.8			
97	1.75	2.696	0.558×10^{-6}	1.125	21.4	23.8	54.8			
97	2.00	2.742	0.549×10^{-6}	1.132	23.4	26.2	50.4			
97	2.25	2.796	0.539×10^{-6}	1.139	25.8	28.9	45.3			
97	2.50	2.853	0.528×10^{-6}	1.144	28.5	31.7	39.8			
97	2.75	2.918	0.516×10^{-6}	1.143	31.4	35.0	33.6			
97	3.75	3.239	0.453×10^{-6}	1.108	45.9	51.2	2.9			
98	1.75	3.086	0.472×10^{-6}	1.046	23.6	76.4				
98	2.00	3.101	0.470×10^{-6}	1.050	25.5	74.5				
98	2.25	3.118	0.468×10^{-6}	1.054	27.7	72.3				
98	2.50	3.136	0.465×10^{-6}	1.058	30.1	69.9				
98	2.75	3.157	0.463×10^{-6}	1.063	32.8	67.2				
98	3.75	3.259	0.449×10^{-6}	1.076	46.0	54.0				
98	4.75	3.393	0.431×10^{-6}	1.070	63.3	36.7				
99	All	3.676	0.393×10^{-6}	1.000	100.0					

*Rod No. shown in first column refers to the largest and smallest rod size in eighths of an inch. For example, Rod No. 76 is a two-way taper of 7/8 and 6/8 rods. Rod No. 85 is a four-way taper of 8/8, 7/8, 6/8, and 5/8 rods. Rod No. 77 is a straight string of 7/8 rods, etc.

(These tables reproduced courtesy API Division of Production)

Table 2
Tubing Data

1	2	3	4	5
Tubing Size	Outside Diameter, in.	Inside Diameter, in.	Metal Area, sq. in.	Elastic Constant, in. per lb ft E_t
1.900	1.900	1.610	0.800	0.500×10^{-6}
2⅜	2.375	1.995	1.304	0.307×10^{-6}
2⅞	2.875	2.441	1.812	0.221×10^{-6}
3½	3.500	2.992	2.590	0.154×10^{-6}
4	4.000	3.476	3.077	0.130×10^{-6}
4½	4.500	3.958	3.601	0.111×10^{-6}

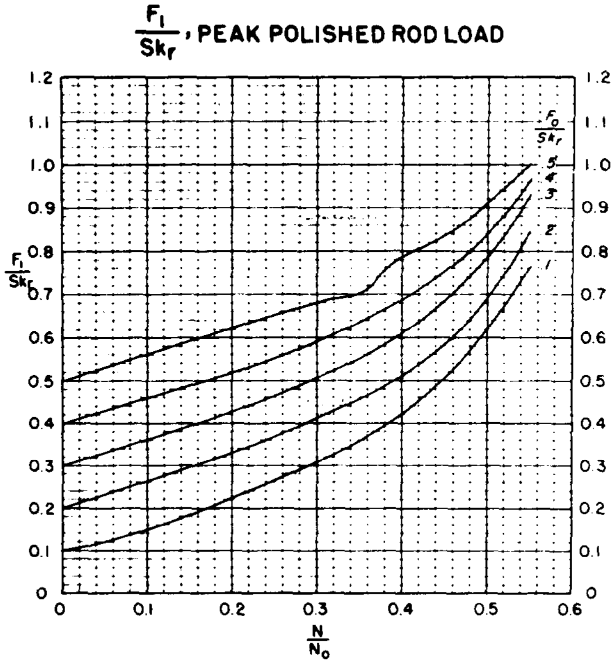


Figure 3

Table 3
Sucker Rod Data

1	2	3	4
Rod Size	Metal Area, Sq in.	Rod Weight in air, lb per ft W_r	Elastic Constant, in. per lb ft E_r
½	0.196	0.72	1.990×10^{-6}
⅝	0.307	1.13	1.270×10^{-6}
¾	0.442	1.63	0.883×10^{-6}
⅞	0.601	2.22	0.649×10^{-6}
1	0.785	2.90	0.497×10^{-6}
1⅛	0.994	3.67	0.393×10^{-6}

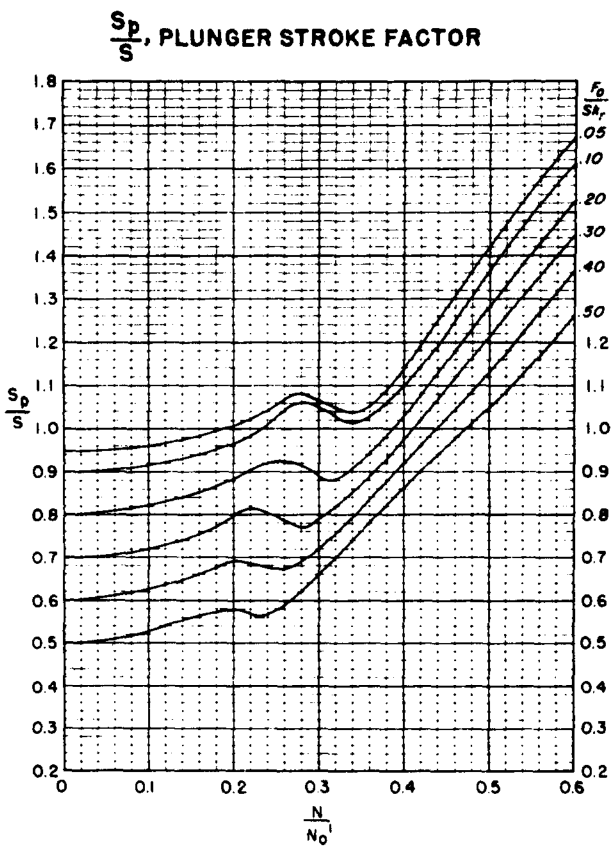


Figure 2

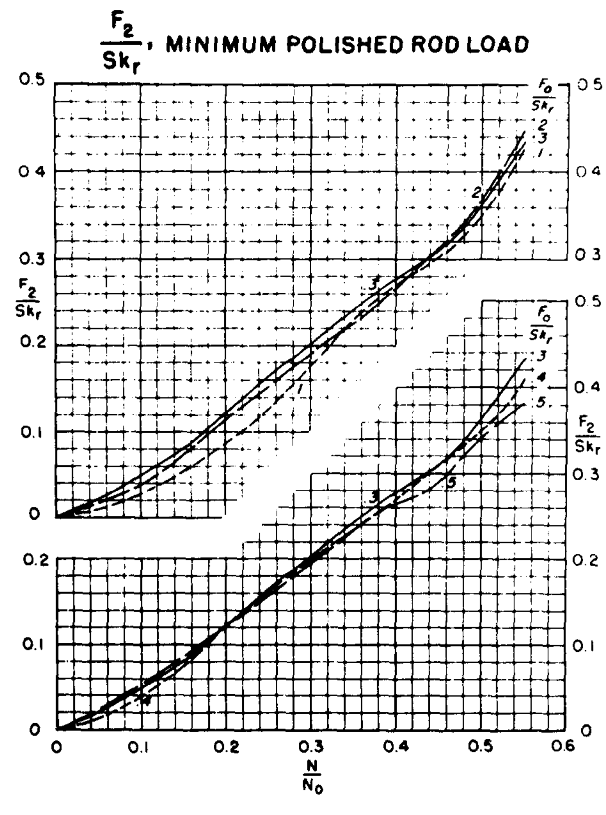


Figure 4

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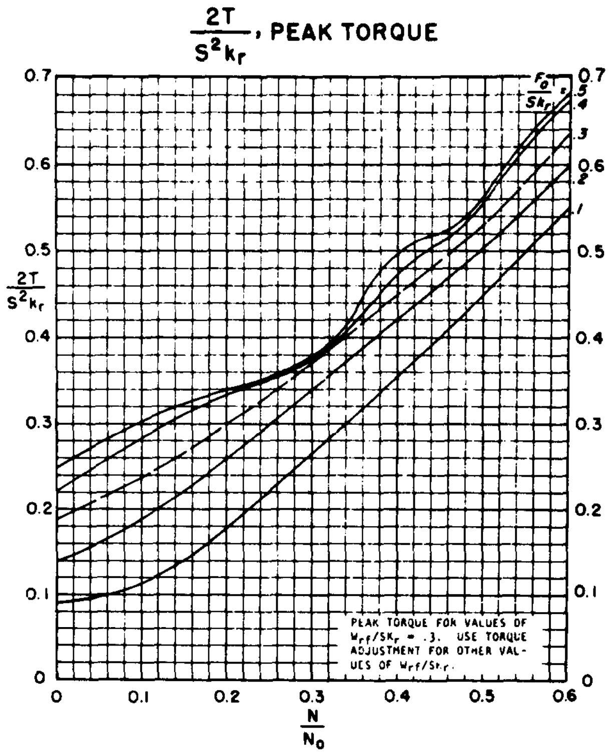

Figure 5

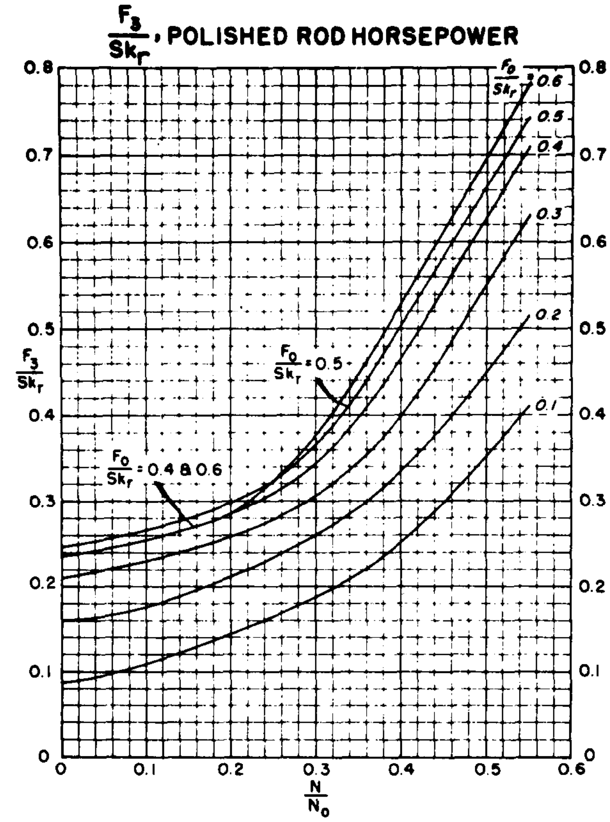

Figure 6

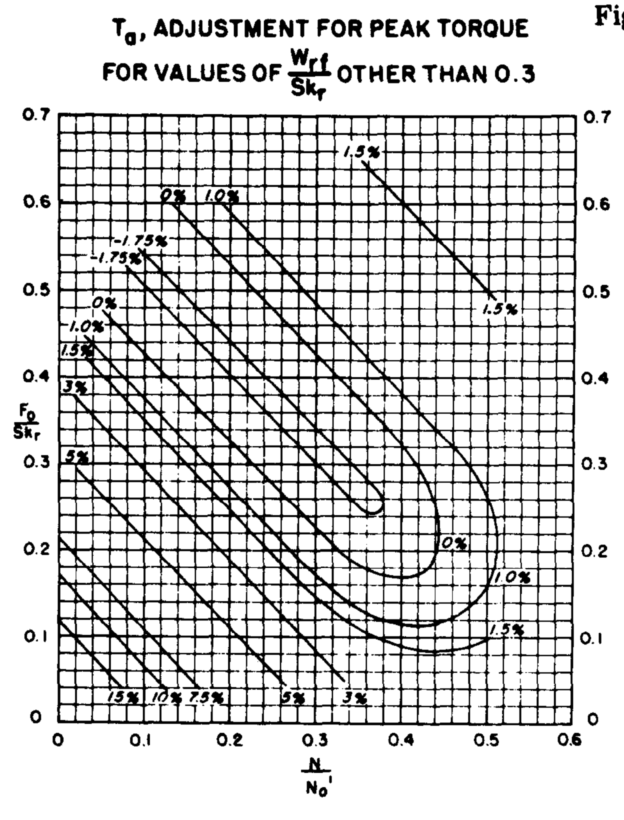

Figure 7

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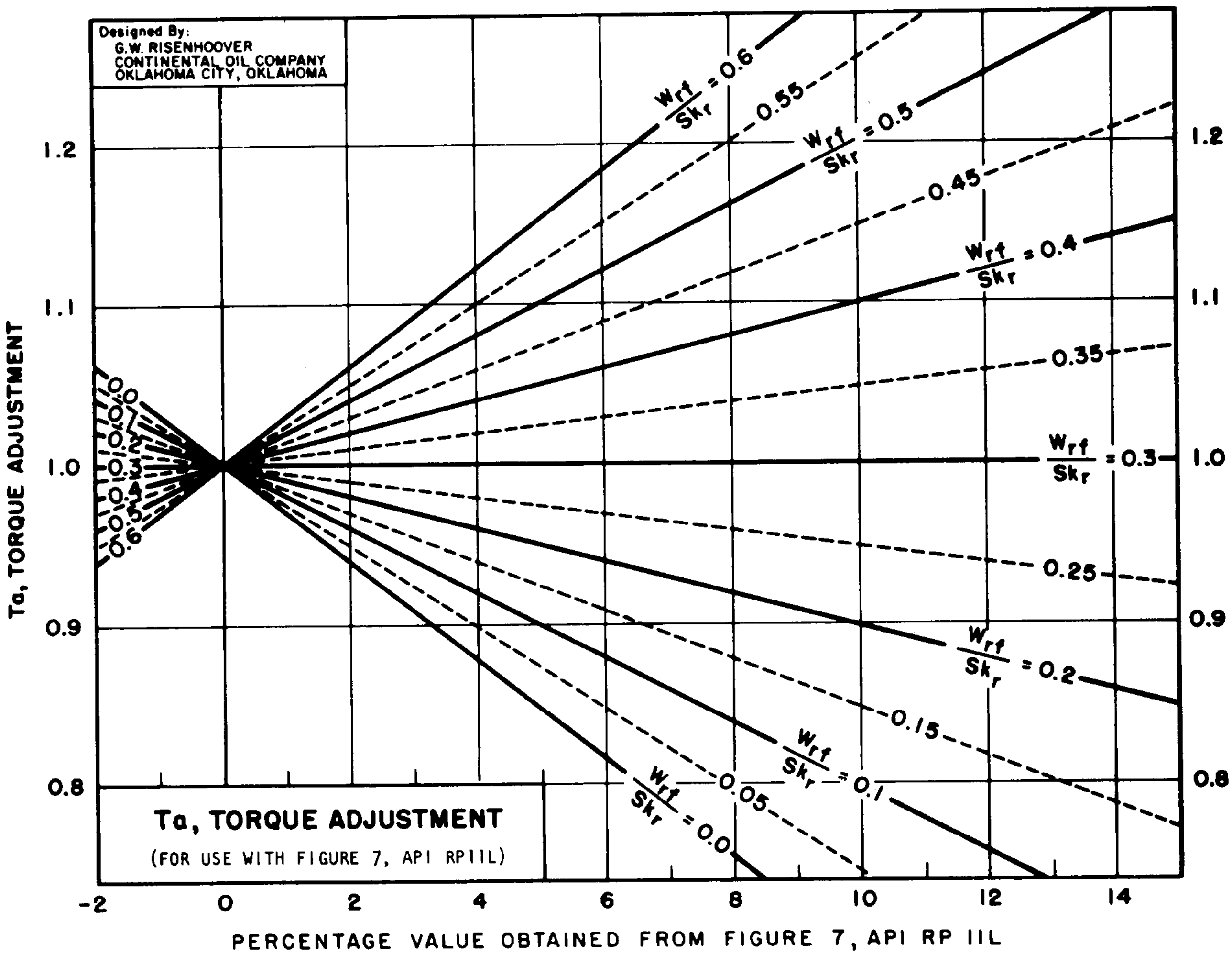

Figure 7a

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