

# Recommended Practice for Care and Use of Subsurface Pumps

API RECOMMENDED PRACTICE 11AR  
FOURTH EDITION, JUNE 2000

ERRATA, DECEMBER 2013

REAFFIRMED, FEBRUARY 2020



AMERICAN PETROLEUM INSTITUTE



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## Upstream Segment

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## FOREWORD

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Suggested revisions are invited and should be submitted to the general manager of the Upstream Segment, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.



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# Recommended Practice for Care and Use of Subsurface Pumps

## 1 Scope

**1.1** The intent of this recommended practice is to give information on the proper selection, operation and maintenance of subsurface pumps so the best economical life can be obtained.

**1.2** The basic walking-beam sucker rod combination for producing fluids from the ground had its beginning in very early history. In more recent times, many advances in design and metallurgy have evolved. The method is so popular that today approximately 90 percent of all artificially lifted wells are produced by a sucker rod pump.

**1.3** The downhole sucker rod pump is only one portion of the pumping system (see Figure 1). The other major components are the sucker rod string, the surface pumping unit and the prime mover. For proper pumping operation and long maintenance-free runs, all components of the system must be designed and sized properly, taking into account well depth, the amount and viscosity of fluids (oil, water or gas) to be produced, and abrasiveness and corrosiveness of fluids. A failure of any one of the pumping components will result in a shut down of the system, resulting in a costly repair, downtime and possible loss of production.

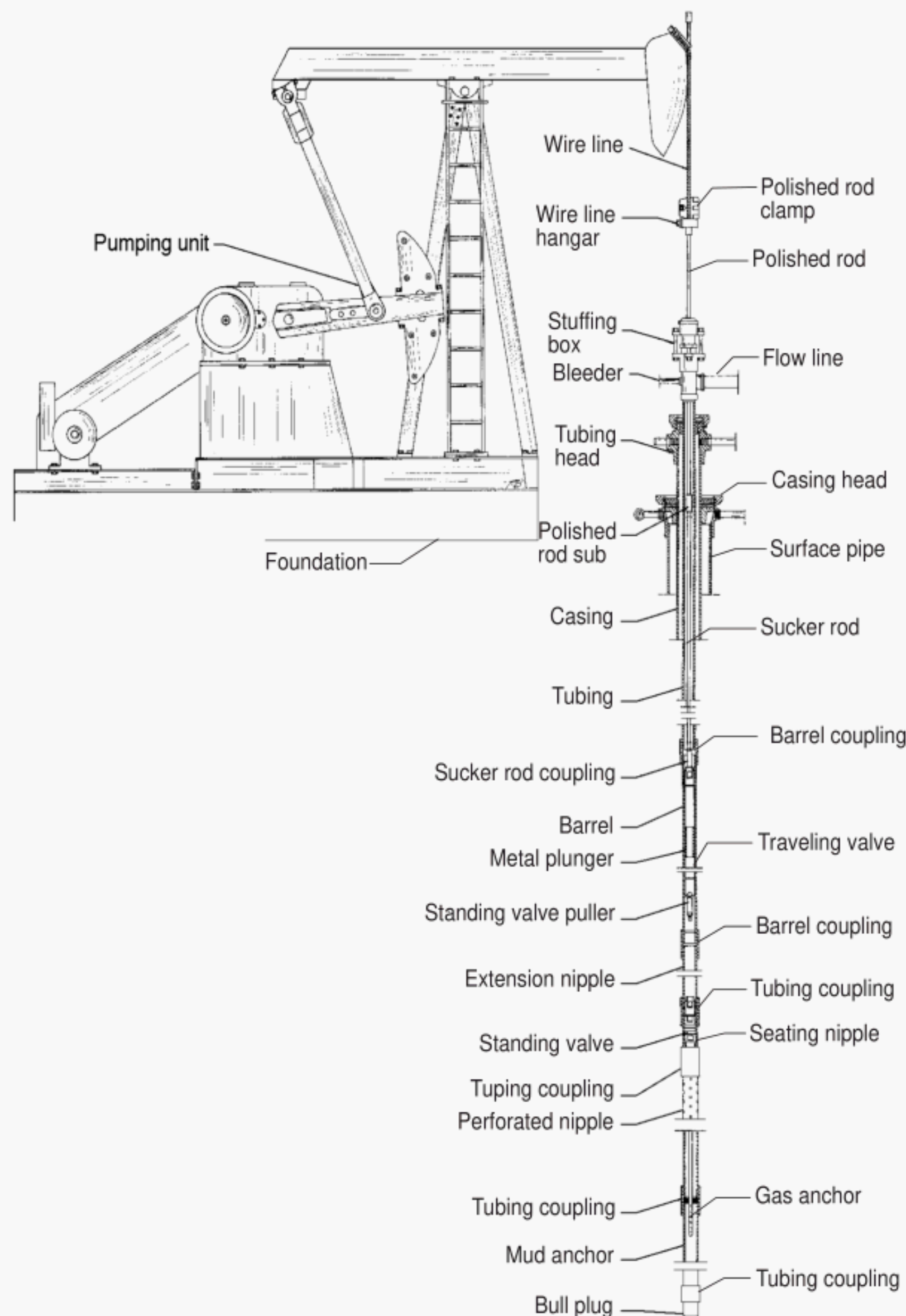


Figure 1—Pumping System



## 2 References

### 2.1 REFERENCED STANDARDS

This recommended practice includes by reference, either in total or in part, the most recent editions of the following standards, unless a specific edition is listed:

#### API

- |           |  |
|-----------|--|
| Bull 5C3  | <i>Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties</i> |
| Spec 11AX | <i>Specification for Subsurface Sucker Rod Pumps and Fittings</i>                                    |

#### NACE

- |            |   |
|------------|---|
| Std MRO176 | <i>Metallic Materials for Sucker Rod Pumps for Corrosive Oilfield Environments; National Association of Corrosion Engineers</i> |
|------------|---|

**2.2 Other References.** In addition to the referenced standards listed above, the following technical publications were considered in preparing Section 5.4 of this recommended practice:

#### API

*Fatigue of Materials*; J. Y. Mann; Melbourne University Press, 1967, Table I, p. 50.

*Stress, Strain, and Strength*; R. Juvinall; McGraw-Hill, 1967, Table I13.1, p. 251.

## 3 History

**3.1** The first formal work toward development of API Std 11A was in 1924. In that year, a Committee on Standardization of Pumping Equipment and Engines was organized. The first issue of API Std 11A, *Specification for Cold Drawn and Machined Working Barrels for Sucker Rod Pumps* was dated May 1926.

**3.2** In 1956, a subcommittee on subsurface pumps approved in principle a proposal that a task group be appointed to carry out the assignment of developing complete API standard pumps with interchangeability of parts and simplified part numbering system for pump assemblies and component parts. This charge was the beginning of API Spec 11AX and the demise of API Std 11A.

**3.3** The first printing of API Spec 11AX was in January of 1961. At the 1966 Standardization Conference, the Committee on Production Equipment agreed that a task group be appointed to revise the diagrams of typical pumps and incorporate them into a separate RP, *Recommended Practice of Care and Use of Subsurface Pumps*. The work of this task group culminated in the First Edition of API RP 11AR being published in 1968.

## 4 Types of Subsurface Pumps

**4.1** API Spec 11AX designates two general types of pumps: The tubing pump (T), and the rod or insert pump (R). Both

tubing and rod type pumps consist of metal barrel units with plungers having either metallic or non-metallic sealing surfaces.

**4.2** API full barrels are one-piece tubes, threaded at both ends.

**4.3** Metal plungers may be one of one-piece or assembled construction. One-piece plungers generally have a hard plating or coating, while assembled plungers have a hard sleeve supported by a plunger tube and end fittings.

### 4.4 TUBING PUMPS (FIGURE 2)

a. The tubing pump is rugged in construction and simple in design. The barrel of a tubing pump is attached directly to the tubing string, usually at the bottom. Below the pump barrel is a seating nipple that receives and locks in place the standing valve of the pump assembly. After this assembly has been run into the well and landed, the plunger assembly is run in on the sucker rod string. When the correct number of sucker rods and pony rods are run to allow the plunger assembly to fit into the pump barrel and seat the standing valve in the seating nipple, the plunger is ready for final spacing.

b. The standing valve is run into the well spacing to the bottom of the pump plunger by means of a standing valve puller. When the standing valve engages the seating nipple, it locks in place with either a mechanical lock or friction cups. The plunger may then be released from the standing valve by rotating the rod string counterclockwise. The plunger assembly is then raised to clear the standing valve on the bottom of the pump stroke, plus about a foot to compensate for rod overtravel. Final spacing is adjusted by the placement of the clamp on the polished rod.

c. As the motion of the pumping unit causes the rods and the plunger to reciprocate, the pumping action begins. As the plunger starts the upstroke, the weight of fluid in the tubing causes the traveling valve to close. The upward motion of the plunger causes reduction of pressure in the pump barrel below the plunger and the pressure of fluid in the casing annulus then opens the standing valve, filling the void created by the upward movement of the plunger.

d. As the plunger starts down, the standing valve closes. The pressure below the plunger builds up and opens the traveling valve. Thus the fluid that passed the standing valve on the upstroke, passes the traveling valve and through the hollow center of the plunger on the downstroke. This fluid is now above the plunger in the annulus between the sucker rods and tubing. On the subsequent upstroke, this fluid, along with the rest of the fluid filling the rods and tubing annulus, is lifted. It is important to note that the actual lifting of fluid is accomplished on the upstroke. On the downstroke, the plunger drops through the fluid that entered the pump through the standing valve on the upstroke.

e. The decision as to whether to pump a well with a tubing pump or a rod pump depends on several factors.

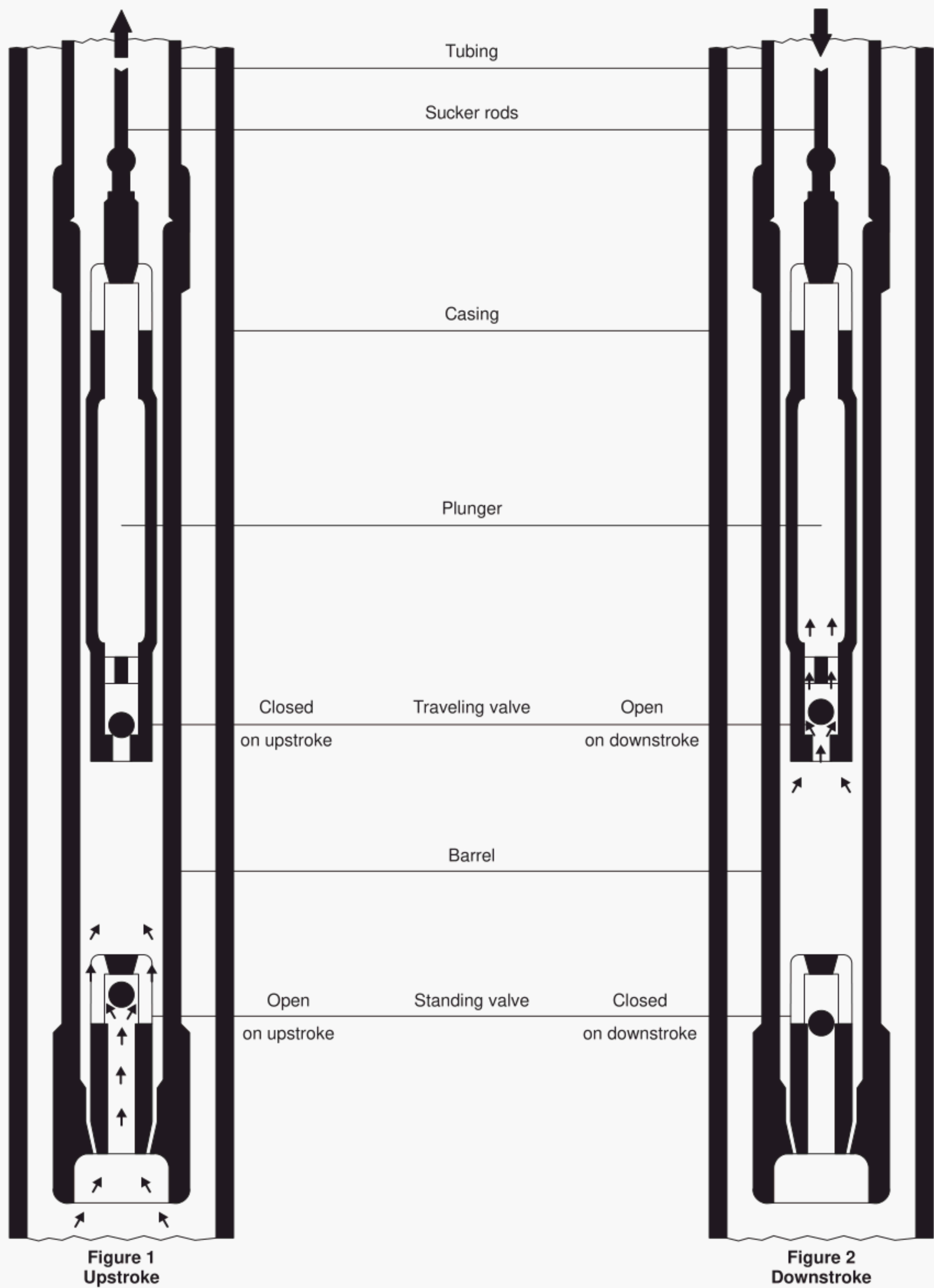


Figure 2—Operation of Tubing Type Pump



## 4.5 ROD PUMPS

a. The rod pump is preferred over the tubing pump in the great majority of rod-pumped wells. The fact that the complete pump can be pulled with the sucker rod string without disturbing the tubing is the main reason for this preference. This reduces pulling unit time at the well by more than 50 percent over a tubing pump when both the barrel and plunger must be pulled. There are three types of rod pumps; the traveling-barrel, bottom-anchor (API RWT, or RHT), the stationary-barrel, bottom-anchor (API RWB, or RHB), and the stationary-barrel, top-anchor (API RWA, or RHA).

b. When a rod pump has been selected, an API seating nipple is run on or near the bottom joint of tubing. Depending on well conditions or user preference, either the cup type or the mechanical bottom lock may be run if the pumps are bottom-anchor, or the cup type or mechanical top lock if the pumps are top-anchor. The complete rod pump with a seating assembly to match the seating nipple on the tubing string is run in on the sucker rod string. When the pump seats in the seating nipple, it is spaced as closely as possible to the bottom with pony rods. The final adjustment is made with the placement of the clamp on the polished rod. In gassy wells, it is desirable to keep the spacing very close, with the traveling assembly of the pump nearly touching at the bottom to minimize valve clearance at the bottom of the stroke. The principle of operation of the rod pump is identical to that described for the tubing pump. The void created in the barrel by the upward motion of the plunger in stationary-barrel pumps permits the pump to be filled from the well bore. This fluid is then displaced into the rod tubing annulus on the subsequent downstroke.

## 5 Application of Subsurface Pumps

### 5.1 TUBING PUMPS (FIGURE 3)

#### 5.1.1 Advantages

- A tubing pump provides the largest displacement possible in any size of tubing, just one quarter inch smaller than the nominal tubing I.D. Where the maximum displacement is needed, the tubing pump is the logical choice.
- A tubing pump is the strongest pump made. The heavy wall barrel is connected directly to the bottom of the tubing string with a collar, eliminating the need for a seating assembly on the pump to hold the pump in position. Also, the sucker rod string connects directly to the plunger top cage, eliminating the need for the valve rod required in stationary-barrel rod pumps.

#### 5.1.2 Limitations

- The greatest disadvantage of the tubing pump is that the tubing string must be pulled in order to replace the pump barrel. This increases the pulling unit time at the well.

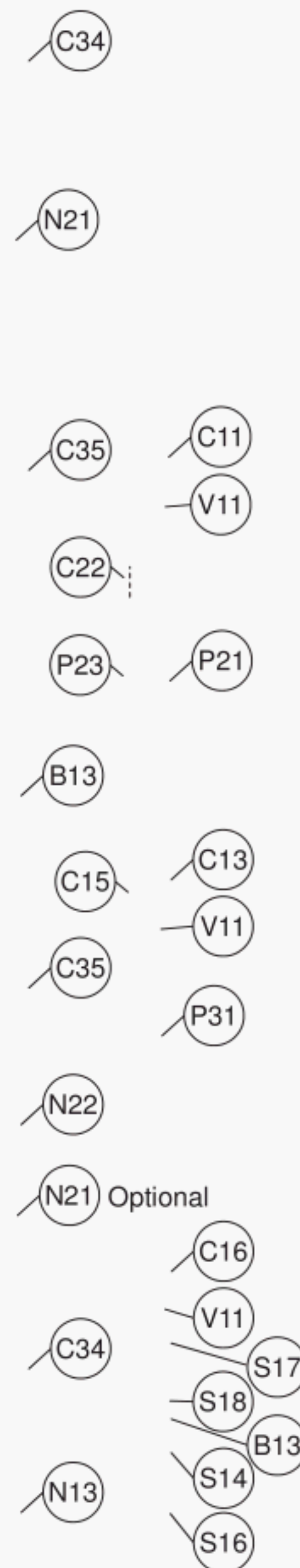


Figure 3—A Typical Tubing Pump  
(See API Spec 11AX for Part Descriptions)

- The tubing pump is a poor installation in gassy fluid. Because of the length of the standing valve assembly and the puller on the plunger (and frequently the increased bore of an extension nipple) there is a large unswept area at the bottom of the stroke, causing a poor compression ratio. This reduces the effectiveness of the pump valving. It also causes low pump efficiency in wells where gas enters the pump suction along with the produced fluid.
- The increased bore of a tubing pump causes increased load on the rod string and pumping unit. It also increases stroke loss due to rod and tubing stretch. As the pump is set deeper, this





## 5.2.2 Stationary Barrel Bottom Anchor Pump (Figure 5)

### 5.2.2.1 Advantages

- The stationary barrel, bottom anchor pump is the first pump to consider in deep wells. Like the traveling-barrel pump, it has the advantage of having the hydrostatic tubing pressure applied to the outside of the barrel without the disadvantage of the column loading on the plunger bowing the pull tube on the downstroke.
- The stationary barrel, bottom anchor pump is normally recommended for wells with low static fluid level, since the production tubing may be run in with only a short perforated nipple or mud anchor below the seating nipple. Thus, if required, the standing valve of the pump may be less than two feet from the bottom of the well.
- The stationary barrel, bottom anchor pump is superior to the traveling barrel, bottom anchor pump for low fluid level wells, because the fluid has only to pass the larger standing valve located immediately above the seating nipple in order to be pumped. The top anchor pump shares this advantage.
- The stationary barrel, bottom anchor pump is excellent for gassy wells when run in conjunction with a good liquid gas separator or gas anchor. The short rise required for the fluid to pass the standing valve and enter the pump minimizes the tendency to foam and thus reduce efficiency.

### 5.2.2.2 Limitations

- It is not a good practice to run a stationary-barrel, bottom-anchor pump in a sandy well because sand can settle in the annulus between the pump and the tubing and stick it tightly in the joint.
- It also has the disadvantage on intermittent operation that sand or other foreign material can settle past the barrel rod guide and on top of the pump plunger when the well is shut down, with the possibility of sticking the pump when it is put back on production.

## 5.2.3 Stationary Barrel Top Anchor Pump (Figure 6)

### 5.2.3.1 Advantages

- The top anchor pump is recommended in sandy wells where a bottom anchor pump may become sanded in and cause a stripping job. The amount of sand that can settle over the seating ring or top cup is limited to a maximum of about three inches, since the fluid discharge from the guide cage keeps it washed free above this point. In this respect, it is even superior to the traveling barrel, bottom anchor pump, since if a travel barrel pump is spaced too high, sand can settle around the pull tube up to the lowest point reached by the pull plug on the downstroke.
- The top anchor pump is specifically recommended in low-fluid-level gassy or foamy wells where it is particularly

advantageous to have the standing valve submerged in the fluid being pumped. A gas anchor should be run below the shoe on the tubing.

### 5.2.3.2 Limitations

- The outside of the pump barrel of a top anchor pump is at suction pressure. Consequently, it is more subject to bursting or parting the barrel tube than a bottom anchor pump. Well depth and the possibility of fluid pound should be carefully considered before running a top-anchored pump with a thin wall barrel. If the depth of the well is within the depth recommendations, a top-anchor pump is a good general purpose installation.

## 5.3 TO OBTAIN OPTIMUM PERFORMANCE

### 5.3.1 Pump Submergence

The energy to fill a pump during the upstroke must be supplied by the well formation. Therefore, it is essential the pump be installed as low in the well bore as possible to maintain minimum back pressure on the formation. The pump intake should be placed below the perforations, or as close above them as possible.

### 5.3.2 Gas Separation

Gas production through the pump severely reduces pump efficiency. Where gas interference is a problem, a properly designed gas separator should be installed as a part of the sub-surface pumping assembly. Various styles are available with each having merits for particular well conditions. It is important to keep the back pressure on the annulus at the wellhead at a minimum.

### 5.3.3 Installations Where Formation Sand Can Be a Problem

A pump will inherently have problems if sand is allowed to enter. Therefore, it is best to utilize some method of sand control to prevent entrance of sand into the well bore. Gravel packs, screens, and chemical bonding agents are frequently used for this purpose.

## 5.4 ALLOWABLE PUMP SETTING DEPTHS

The formulas for the determination of the maximum allowable pump setting depth (ASD) are presented in this section.

### 5.4.1 Limitations

The limitation for the ASD is determined by the maximum allowable stress generated in the working barrel of the pump. Depending on the pump type, this maximum stress can be generated by 1) Burst pressures, 2) Collapse pressures, or 3) Axial loads, with the critical modes listed in Table 1.



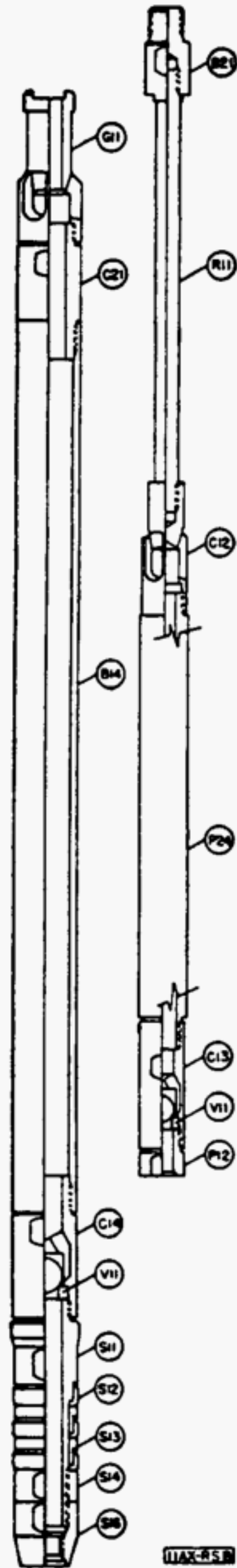


Figure 5—A Typical Stationary Barrel,  
Bottom Hold Down, Pump  
(See API Spec 11AX for Part Description)

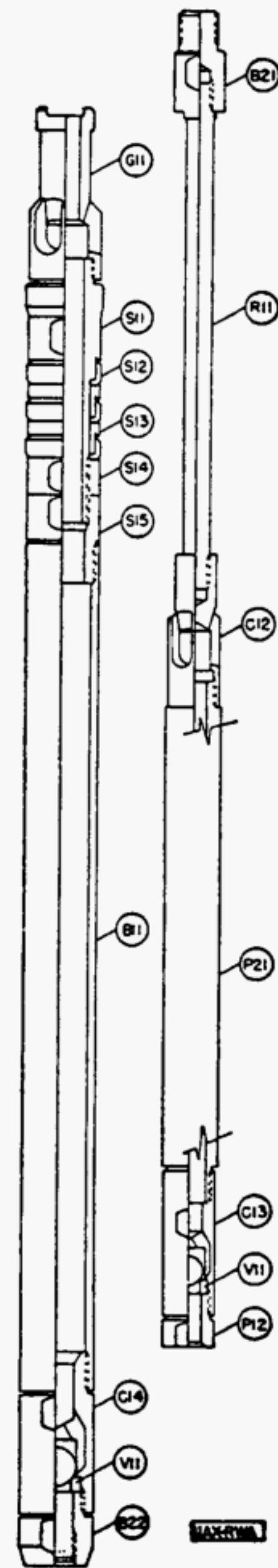


Figure 6—A Typical Stationary Barrel,  
Top Hold Down, Pump  
(See API Spec 11AX for Part Description)

Table 1—Pump Type Modes of Failure and Reference Figures

Type Pump	Failure Mode	Figure
<b>A. Rod Insert Pumps</b>		
1. Stationary Barrel, Top Anchor (RHA, RWA, RSA)	Burst or Axial	7A 7B
2. Stationary Barrel, Bottom Anchor (RHB, RWB, RSB)	Collapse	7C
3. Traveling Barrel, Bottom Anchor (RHT, RWB, RST)	Collapse	7D
<b>B. Tubing Pumps (TH, TP)</b>		
	Burst or Axial	7E

## Notes:

- For the pumps where the critical mode is listed as “Burst” or “Axial,” calculations are to be done for both modes to determine which gives the lower ASD value. Typically, the Axial(tensile) mode gives the lower value.
- This same methodology as given in Table 1 should be used for Extension Couplings, depending on if they are used with a top (RHA) or bottom (RHB) holddown pump.

## 5.4.2 Burst Mode

In the Burst mode, there exists a differential pressure from the barrel I.D. to O.D., typically during the downstroke, as shown in figure 7A.

The ASD formula in the Burst mode is a derivative of the Barlow formula for tangential stress as given in API Bulletin 5C3: Formula 31.

$$ASD1 = \frac{2(S)(t)(SF)}{FS(.433)(D_o)(SG)} \quad (1)$$

$S$  = Endurance Limit (PSI).

$t$  = Min. Barrel Thickness (Inches) at Thread Root or at the Extension Coupling Bore.

$D_o$  = Min. Barrel O.D. (Inches).

$SF$  = Service Factor ( $SF < 1.0$ ).

$FS$  = Design Factor of Safety.

$SG$  = Fluid Specific Gravity.

## 5.4.2.1 Alternate Formula, if Barrel Thickness at Thread Root Is Unknown

$$ASD1 = \frac{2(S)(t_w/2.00)(SF)}{FS(.433)(D_o)(SG)} \quad (2)$$

$t_w$  = Barrel Thickness at Bore =  $(D_o - D_i)/2$ .

$D_i$  = Bore Diameter.

## 5.4.2.2 Assumptions

- The maximum differential pressure exists across the barrel, i.e., with zero pressure on the outside of the barrel.
- The radial stresses are negligible.
- Pressure increases due to fluid compression on the downstroke are neglected.

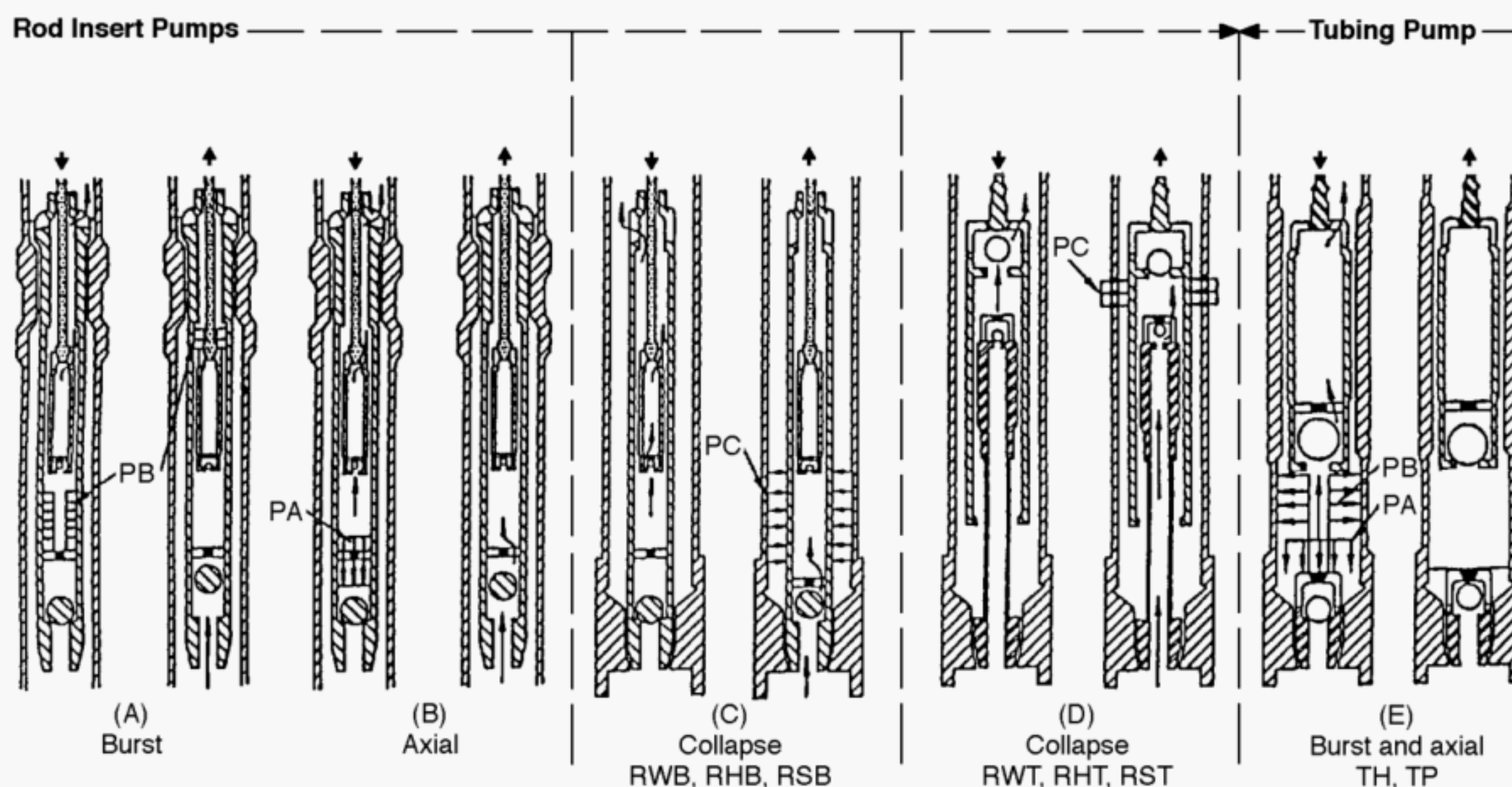


Figure 7—Subsurface Sucker Rod Pump Loading Configurations

### 5.4.3 Axial Mode

In the Axial mode, there exists a tensile load on the barrel created by the hydrostatic load of the fluid in the tubing acting on the Standing Valve, as shown in Figures 7B and 7E. Tubing weight hanging below a tubing pump should also be considered in combination with the Burst pressure. These loads are negligible if the tubing is anchored or if the load is supported by the seating nipple (bottom holddown).

The ASD formula is a derivative of the standard Tensile Stress ( $S_a$ ) formula ( $S_a = F/A_i$ ;  $F = P \cdot A_i + TBG$ , WGT)

$$ASD2 = \frac{S(A_i)(SF)}{FS(A_i)(.433)(SG)(K)} \quad (3)$$

$A_i$  = Internal Area of Barrel or Extension Coupling at Bore (in<sup>2</sup>) =  $.785(D_i)^2$

$A_t$  = Cross Sectional Area of Barrel or Extension Coupling at Thread Root (in<sup>2</sup>)

$$\text{f/RWA \& RSA} \quad A_t = \frac{3.14(OD^2 - TMD^2)}{4}$$

$$\text{f/RHA} \quad A_t = \frac{3.14(TMD^2 - ID^2)}{4}$$

$S$  = Endurance Limit (psi).

$K$  = Stress Concentration Factor.

$P$  = Internal Hydrostatic Pressure at Standing Valve (psi) =  $H \cdot g$ .

$H$  = Height of Fluid Above Pump (ft).

$TMD$  = Thread Minimum Diameter.

$g$  = Fluid Gradient (psi/ft) =  $.433$  psi/ft ( $SG = 1.0$ ).

$SG$  = Fluid Specific Gravity.

#### 5.4.3.1 Alternate Formula, if Cross Sectional Area of Barrel at Thread Root Unknown

$$ASD2 = \frac{2(A_w/2.00)(SF)}{FS(.433)(A_i)(SG)(K)} \quad (4)$$

$A_w$  = Cross Sectional Area of Barrel at Bore (in<sup>2</sup>)

### 5.4.4 Collapse Mode

In the Collapse mode, there exists a differential pressure from the barrel O.D. to I.D., during the upstroke, as shown in Figures 7C and 7D.

The ASD formulas in the Collapse mode are derivatives of the formulas given in API Bulletin 5C3, depending on the maximum  $D/t$  of the barrel housing:

$$D/t_w < (D/t)_{yp}$$

$$ASD3 = \frac{2(Sy)[(D/t_w - 1)/(D/t_w)^2]SF}{FS(.433)(SG)} \quad (5)$$

$$D/t_{yp} < (D/t_w) < (D/t)_{pt}$$

$$ASD4 = \frac{[(Sy)[A/Dt_w - B] - C](SF)}{(FS)(.433)(SG)} \quad (6)$$

$$(D/t)_{yp} = \frac{((A - 2)^2 + 8(B + C/Sy))^{0.5} + (A - 2)}{2(B + C/Sy)} \quad (7)$$

$$(D/t)_{pt} = \frac{Sy(A - F)}{(C + Sy(B - G))} \quad (8)$$

$Sy$  = Barrel Yield Strength (psi).

Refer to Table 2 for applicable  $D/t$  ranges for yield strength collapse  $[(D/t)_{yp}]$ , and Tables 3 and 4 for factors and applicable  $D/t$  ranges for plastic collapse  $[(D/t)_{pt}]$ .

For  $D/t_w$  values greater than  $(D/t)_{pt}$ , refer to formula 5, 6 and 7 in 5C3 for the applicable Collapse pressure formula.

Table 2—Yield Collapse Pressure Formula Range

Grade	$D/t$ Range
H-40	16.40 and less
J-K-55	14.81 and less
J-K-60	14.44 and less
J-K-70	13.85 and less
C-75 & E	13.60 and less
L-N-80	13.38 and less
C-90	13.01 and less
C-T-95	12.85 and less

Table 3—Formula Factors and  $D/t$  Ranges for Plastic Collapse

Grade	A	B	C	$D/t_w$ Range
H-40	2.950	.0465	754	16.40 to 27.01
J-K-55	2.991	.0541	1206	14.81 to 25.01
J-K-60	3.005	.0566	1356	14.44 to 24.42
J-K-70	3.037	.0617	1656	13.85 to 23.38
C-75 & E	3.054	.0642	1806	13.60 to 22.91
L-N-80	3.071	.0667	1955	13.38 to 22.47
C-90	3.106	.0718	2254	13.01 to 21.69
C-T-95 & X	3.124	.0743	2404	12.85 to 21.33

Table 4—Formula Factors and D/t Ranges for Transition Collapse

Grade	F	G	D/t Range	
H-40	2.063	.0325	27.01	to 42.64
J-K-55	1.989	.0360	25.01	to 37.21
J-K-70	1.984	.0403	23.38	to 33.17
C-75 & E	1.990	.0418	22.91	to 32.05
L-N-80	1.998	.0434	22.47	to 31.02
C-90	2.017	.0466	21.69	to 29.18
C-T-95 & X	2.029	.0482	21.33	to 28.36

A complete set of values for factors A, B, C, F, G can be found in API Bulletin 5C3, Tables 2 and 3.

#### 5.4.4.1 Assumptions

- The differential pressure across the barrel is at a maximum, with zero pressure inside the barrel.
- Radial stresses are negligible.
- The length-to-diameter ratio ( $L/D$ ) is greater than 8.
- For traveling-barrel pumps, the barrel is weaker than the plunger, pull tube, or other elements exposed to collapse pressure.

#### 5.4.5 Factors of Safety

It is generally recommended that a minimum design Factor of Safety ( $FS$ ) of 1.25 be used to account for material and dimension variations.

An additional Service Factor ( $SF$ ) should also be used for each application and each manufacturer, depending on the particular well conditions and usage. Consideration should be made for at least the following pump service problems that are known to affect pump service life.

- Corrosion.
- Fluid Pound.
- Gas Pound.
- Gas Lock.
- Sand Problems.
- Scale Problems.
- Usage (Cycles/Day; Total Cycles, and so forth.)

This Service Factor ( $SF$ ) should be less than or equal to one.

#### 5.4.6 Stress Concentration Factor ( $K$ )

Due to the cyclical loads, a stress concentration value should also be applied to the barrel threads. This value is typically a function of the thread root radius and diameter. For standard 'V' type machined threads, a value of 2.8 is recommended. Typical values can be found in Stress, Strain, and Strength; R. Juvinall; McGraw-Hill, 1967, Table I13.1, p. 251.

#### 5.4.7 Endurance Limit ( $S$ )

Due the cyclic nature of the loads, it is recommended that the fatigue Endurance Limit ( $S$ ) at the maximum number of cycles be used for the maximum stress in the Burst and Axial modes.

For many materials, the Endurance Limit ( $S$ ) is unavailable from suppliers, and therefore the Ultimate Tensile Strength ( $S_u$ ) should be substituted using suggested correction factors of 2.5 for steel & 3.0 for brass.

$$\text{Steel } S = S_u/2.5 \quad (9)$$

$$\text{Brass } S = S_u/3.0 \quad (10)$$

Typical Ultimate Tensile Strength values are given in Table 5. These values should be used unless the actual Tensile Strength or Endurance Limit of the material is known.

#### 5.4.8 Dimensional Data (Table 6)

#### 5.4.9 Examples

**5.4.9.1 Burst or Axial Mode Example.** Determine the maximum setting depth of a 2-3/8 x 1-1/2 RWA pump, made of low carbon steel (oil = 10 degrees API):

Step 1: By Table 1 failure mode is Burst or Axial, use the minimum value determined from formulas 1 and 3.

Step 2: Calculate ASD1:

$$ASD1 = \frac{2(32,000)(.0885)(1.00)}{1.25(.433)(1.750)(1.00)} = 5,980 \text{ ft}$$

$$S = 32,000 \text{ psi.}$$

$$t = .0885 \text{ in.}$$

$$SF = 1.00$$

$$FS = 1.25$$

$$D_o = 1.75 \text{ in.}$$

$$SG = 1.00 \text{ (10 degree API).}$$

Step 3: Calculate ASD2: Assume weight below pump negligible.

$$ASD2 = \frac{32,000(.461)(1.00)}{1.25(1.76625)(.433)(1.00)(2.8)} = 5,520 \text{ ft}$$

Step 4: Compare ASD1 to ASD2, and select lower value:

$$ASD2 < ASD1, \text{ therefore } ASD = ASD2 = 5,520 \text{ ft.}$$



Table 5—Common Pump Barrel Material Mechanical Properties

Material	Typical Ult Tensile Strength (psi) (Su)	Typical Yield Strength (psi) (Sy)	Endurance Limit Strength (psi) (S)
Low Carbon Steel (UNS G10200)	80,000	60,000	32,000
Low Alloy Steel (UNS G41300)	80,000	50,000	32,000
Admiralty Brass (UNS C44300)	75,000	60,000	25,000
Red Brass (UNS C23000)	75,000	35,000	25,000
4-6% CR Steel (UNS S50100)			
Chrome Plated	98,000	70,000	39,200
Carbonitrided	109,000	70,000	43,600
NI-CU Alloy (UNS N04400)	82,000	55,000	32,800

Table 6—Pump OD/ID/Thread Data

Barrel ID	Threads	Barrel OD	Thread Maj. Dia. (TMD)	Wall Thickness at Bore (t1)	Wall Thickness Under Thread (t2)
Pump Type: RWA, RWB, RSA, RSB, RWT					
	Box (B11)*				
1.25	1.3330-16	1.500	1.3330	.125	.0835
1.50	1.5730-16	1.750	1.5730	.125	.0885
2.00	2.0870-16	2.250	2.0870	.125	.0815
2.50	2.5730-16	2.750	2.5730	.125	.0885
$t1 = (OD - ID)/2$ ; $t2 = (OD - TMD)/2$					
Pump Type: RHA, RHB, RHT					
	Pin (B12)*		Thread Min. Dia. (TMD)		
1.25	1.5730-16	1.750	1.4963	.250	.1232
1.50	1.8750-16	2.000	1.7983	.250	.1492
1.75	2.0870-16	2.250	2.0100	.250	.1302
2.25	2.5730-16	2.750	2.4963	.250	.1232
$t2 = (TMD - ID)/2$					
Pump Type: TH, TP					
	Pin (B13)*				
1.75	2.2380-11.5	2.250	2.1313	.250	.1907
2.25	2.7380-11.5	2.750	2.6313	.250	.1907
2.75	3.2380-11.5	3.250	3.1313	.250	.1907
Pump Type: TH, TP					
	Pin Thread Tapered (B15)*		Taper		
1.781	178-11.5	2.250	$\frac{3}{8}$	.250	.1650
2.250	225-11.5	2.750	$\frac{3}{4}$	.250	.1805
2.750	275-11.5	3.250	$\frac{3}{4}$	.250	.1805

Table 6—Pump OD/ID/Thread Data (Continued)

Barrel ID	Threads	Barrel OD	Thread Maj. Dia. (TMD)	Wall Thickness at Bore (t1)	Wall Thickness Under Thread (t2)
Extension Couplings					
	(C31)*				
1.312	1.5730-16	1.750	1.5730	.2190	.0885
1.593	2.0870-16	2.260	2.0870	.3335	.0865
1.812	2.0870-16	2.250	2.0870	.2190	.0815
2.312	2.5730-16	2.750	2.5730	.2190	.0885

\*See API Specification 11AX

#### 5.4.9.2 Collapse Mode Example

Determine the maximum setting depth of a  $3\frac{1}{2} \times 2\frac{1}{4}$  RHB pump, made of Admiralty Brass material (oil = 10 degrees API):

Step 1: By Table 1, the failure mode is Collapse.

Step 2: Calculate  $D/t_w$ :  $D/t_w = 2.75/.25 = 11.00$

From Table 2 for an H-60 equivalent barrel,  $(D/t)_{yp} = 16.4$  and less. Therefore  $D/t_w < (D/t)_{yp}$  and ASD3 applies.

Step 3: Calculate ASD3:  $S_y = 60000$ . Table 7.

$$ASD3 = \frac{2(60,000)[(11.00 - 1)/(11.00)^2](1.00)}{(1.25)(.433)(1.00)} = 18,323 \text{ ft}$$

Table 7—Pump Setting Depths (ft) for Common Barrel Materials  
( $FS = 1.25$ ;  $SF = 1.00$ ;  $SG = 1.00$ )

Bore Size	1.25	1.50	1.75	2.00	2.25	2.50	2.75
(Matl: Low Carbon Steel: $S_u = 80$ ksi; $S = 32$ ksi; $S_y = 60$ ksi)							
RWA, RSA	6,394	5,520	—	3,732	—	3,183	—
RWB, RSB, & RWT	16,936	14,705	—	9,727	—	6,362	—
RHA	8,321	8,818	6,749	—	4,876	—	—
RHB, RHT	27,148	24,249	21,897	—	18,323	—	—
TH, TP	—	—	10,019	—	7,763	—	6,262
TH, TP (Tapered Thread)	—	—	8,187	—	7,047	—	5,726
EXT CPLGS*							
w/RHA	7,568	6,118	4,706	—	3,824	—	—
w/RHB	25,728	28,714	20,708	—	17,294	—	—
(Matl: Admiralty Brass: $S_u = 75$ ksi; $S = 25.0$ ksi; $S_y = 60$ ksi)							
RWA, RSA	4,989	4,306	—	2911	—	2,482	—
RWB, RSB & RWT	16,936	14,704	—	9727	—	6,362	—
RHA	6,490	6,878	5,264	—	3,802	—	—
RHB, RHT	27,148	28,714	21,897	—	18,323	—	—
TH, TP	—	—	7,815	—	6,062	—	4,890
TH, TP (Tapered Thread)	—	—	6,386	—	5,496	—	4,466
EXT CPLGS*							
w/RHA	5,913	4,780	3,675	—	2,986	—	—
w/RHB	25,728	24,249	20,708	—	17,294	—	—

Table 7—Pump Setting Depths (ft) for Common Barrel Materials  
( $FS = 1.25$ ;  $SF = 1.00$ ;  $SG = 1.00$ ) (Continued)

Bore Size	1.25	1.50	1.75	2.00	2.25	2.50	2.75
(Matl: 4-6% CR Steel, Carbonitrided: $S_u = 109$ ksi; $S = 43.6$ ksi; $S_y = 70$ ksi)							
RWA, RSA	8,711	7,520	—	5,084	—	4,337	—
RWB, RSB, & RWT	19,759	17,016	—	10,782	—	6,814	—
RHA	11,337	12,015	9,195	—	6,643	—	—
RHB, RWT	31,672	28,291	25,546	—	21,376	—	—
TH, TP	—	—	13,655	—	10,577	—	8,531
TH, TP (Tapered Threads)	—	—	11,155	—	9,602	—	7,801
EXT CPLGS*							
w/RHA	10,312	8,336	6,412	—	5,210	—	—
w/RHB	30,016	33,500	24,159	—	20,176	—	—
(Matl: NI-CXU Alloy; $S_u = 82$ ksi; $S = 32.0$ ksi; $S_y = 55$ ksi)							
RWA, RSA	6,553	5,658	—	3,825	—	3,263	—
RWB, RWT	15,525	13,480	—	11,209	—	8,199	—
RHA	8,529	9,038	6,917	—	4,998	—	—
RHB, RHT	24,886	22,229	20,072	—	16,796	—	—
TH, TP	—	—	10,459	—	5,984	—	4,752
TH, TP (Tapered Threads)	—	—	8,392	—	7,223	—	5,869
EXT CPLGS*							
w/RHA	7,757	6,271	4,823	—	3,919	—	—
w/RHB	23,584	26,322	18,982	—	15,853	—	—

\*The limiting setting depth should be that of the specific RHA or RHB with which the extension coupling is used.

## 6 Common Pump Problems and Solutions

### 6.1 CORROSION

Corrosion occurs in many wells with resulting damage to subsurface equipment. Many National Association of Corrosion Engineers (NACE) papers and documents have been issued describing inhibitors and methods of treatment to reduce damage to downhole equipment. However, inhibitors do not protect the subsurface pump efficiently. It is recommended that pump metallurgy be seriously considered as the primary method of corrosion control. See Section 7 for pump metallurgy selection.

### 6.2 FLUID POUND

When a pump does not fill completely with liquid during the upstroke, a low-pressure gas cap forms in the top of the pump chamber between the traveling and standing valves. During the subsequent downstroke, the traveling valve stays closed until it impacts the fluid. This condition is called

“Fluid Pound,” and causes a severe shock load to the entire pumping system.

**6.2.1** The two conditions that can cause “Fluid Pound” are:

- “Pump Off” occurs when the fluid head in the casing above the pump is less than the minimum head required to fill the pump and the reservoir cannot furnish more fluid for pump fillage. A “Pump Off” condition can be determined by shutting the well down for a few minutes and then restarting the system. If pump fillage is good after start up and then a short time later a “Fluid Pound” condition reoccurs, the “Pump Off” is confirmed.
- Restricted Intake (“Starved Pump”) occurs where additional well bore pressure is required to fill the pump at the pumping rate desired, indicating a restricted intake. This condition will have a higher than normally required fluid head above the pump in the casing. Testing for this condition is accomplished by shutting the well down for a few minutes and restarting the system. If “Fluid Pound” occurs immediately after start-up, it is indicative of a “Starved Pump” condition.

**6.2.2** Damage caused by “Fluid Pound.” When a “Fluid Pound” is allowed to exist, extreme damage can occur to the entire system and can be the primary cause of the following equipment failures:

- a. Surface Equipment.
  1. Fatigue failure of the pumping unit structure.
  2. Fatigue failure of gear teeth and bearings.
  3. Fatigue failure of the pumping unit base.
- b. Subsurface Equipment.
  1. Fatigue failure within the rod string. (“Fluid Pounding” is especially damaging to the lower portion of the rod string because of the compressive force applied upward by the “Fluid Pound” condition).
  2. Within the pump, a “Fluid Pound” causes accelerated damage to the traveling valve and its cage. Valve rod breakage, barrel rupture, and standing valve failure can also occur.
  3. “Fluid Pound” action accelerates wear of the tubing threads, causing leakage. It is frequently the cause of fatigue parting of the tubing.

**6.2.3** Minimizing Damaging Effects of “Fluid Pound.”

- a. A good approach to this problem is to design a pumping system that, when working at 80 percent efficiency, will achieve the desired production from the reservoir. “Fluid Pound” that occurs in the first 20 percent of the downstroke is less severe than in the mid-portion of the downstroke where velocity is the highest. When pump capacity greatly exceeds the well productivity the stroke length, pumping speed, plunger diameter should be changed to more closely approach the above mentioned good design guidelines.
- b. When pumping systems are engine driven, the engine speed and/or sheaves can frequently be adjusted to match the pump displacement to well productivity.
- c. When pumping systems are electric motor driven, the strokes per minute can be adjusted by a sheave change to match the pump displacement (80 percent efficiency) to well productivity. Electric motor controls are also available for intermittent production.
  1. A percentage timer within the motor control that enables the operator to match pumping time to well productivity will reduce the “Fluid Pound” condition. Normally, the idle periods should be of short duration to prevent a high fluid level build-up that would reduce rate of flow into the well bore.
  2. Various devices are available that “sense” a “Fluid Pound” condition and automatically shut the well down for a predetermined time period.
  3. When “Fluid Pound” is caused by a “Starved Pump” condition, percentage timers and pump-off devices will not eliminate the problem. If such a condition exists, the pump should be properly serviced with special attention given to the pump intake passages.

**6.3 GAS POUND**

A gas pound is very similar to a “Fluid Pound,” but is different in the following respects:

- a. A “Pump Off” condition does not exist.
- b. A “Restricted Intake” condition might or might not exist.

**6.3.1** Gas pound is caused by:

- a. Free gas going through the subsurface gas separator and entering the pump intake. This condition usually causes erratic gas pounding in various downstroke positions.
- b. Gas breaking out of solution during upstroke pump fillage after passing through the gas separator. This condition usually causes consistent gas pounding in the same portion of the downstroke.
- c. If gas entering the pump is at sufficiently high pressure due to a high fluid level in the annulus, the resulting gas pound will be cushioned and less severe than a “Fluid Pound.” As the closed traveling valve moves downward toward the liquid in the pump chamber, the compressed gas supplies a pneumatic cushion that reduces the severity of the impact. As the pressure of the gas entering the pump decreases, the severity of the gas pound increases.
- d. If gas pound is caused by free gas going through the separator, a better subsurface gas separator is needed. If it is caused by gas breaking out of solution during pump fillage, all restrictions affecting pump fillage should be opened up.

**6.4 GAS LOCK**

A gas lock occurs when the pump chamber is gas-filled and the downstroke does not compress the gas sufficiently to open the traveling valve. Both valves remain closed throughout one or more complete pump cycles.

**6.4.1** Spacing the pump’s traveling valve closer to the standing valve at the bottom of the stroke will improve the pump’s compression ratio, thereby reducing the likelihood of a gas lock.

**6.5 SAND PROBLEMS**

If sand enters the well bore with produced fluid, numerous problems can occur. The entire subsurface equipment design must be considered to reduce the frequency of sand problems. Special consideration should be given to metallurgy and basic design of the pump. Practical experience in the particular locale is most important to achievement of a successful operation.

**6.6 SCALE PROBLEM**

Many wells contain produced fluids that cause scale deposits in areas where agitation or pressure drops occur. Usually this problem is best resolved by use of chemical treatment that prevents, reduces, or dissolves the deposit.



**6.6.1** Casing perforations can become plugged by scale that reduces well productivity and causes premature pump off. Gas separator openings can become plugged, causing “Starved Pump” conditions.

**6.6.2** All valves, openings and parts within a pump can become plugged, making the pump inoperative.

**6.6.3** Scale can cause a stuck plunger condition. The use of an RH- or TH-type pump with barrel length and extension length designed to ensure that a portion of the plunger will

stroke out of each end of the heavy wall barrel on every stroke will reduce stuck-plunger problems caused by scale.

## 6.7 SYSTEMATIC PROBLEM SOLVING

The determination of what has caused an oil well to lose production can sometimes be a frustrating experience. Tubing, rods, casing, formation as well as a subsurface pump can be the causes. The use of dynamometer to weigh the well and obtain basic load/time relation can expedite the trouble shooting process. Tables 8 to 14 present a systematic approach to solving the problems with tests.

Information to be collected prior to weighing operations:

1. Production: daily oil, water, gas, allowable.
2. Pump: size and type.
3. Rods: size and type, length of each rod taper.
4. Tubing: size, type and seating nipple location.
5. Mud anchor: size and type.
6. Gas anchor: size and type.
7. Producing interval and TD or PBTD.
8. Motor or engine: size.
9. Fluid: specific gravity.
10. Auxiliary equipment.
11. Stroke length (SL) and strokes per minute (SPM).
12. Pertinent well treating data.
13. Daily pumping time and schedule.
14. Power consumption.
15. Calculations: Rod weight in air.  
Rod weight in fluid.  
Fluid weight on pump (pounds)  
Volumetric pump capacity (bbls/day).

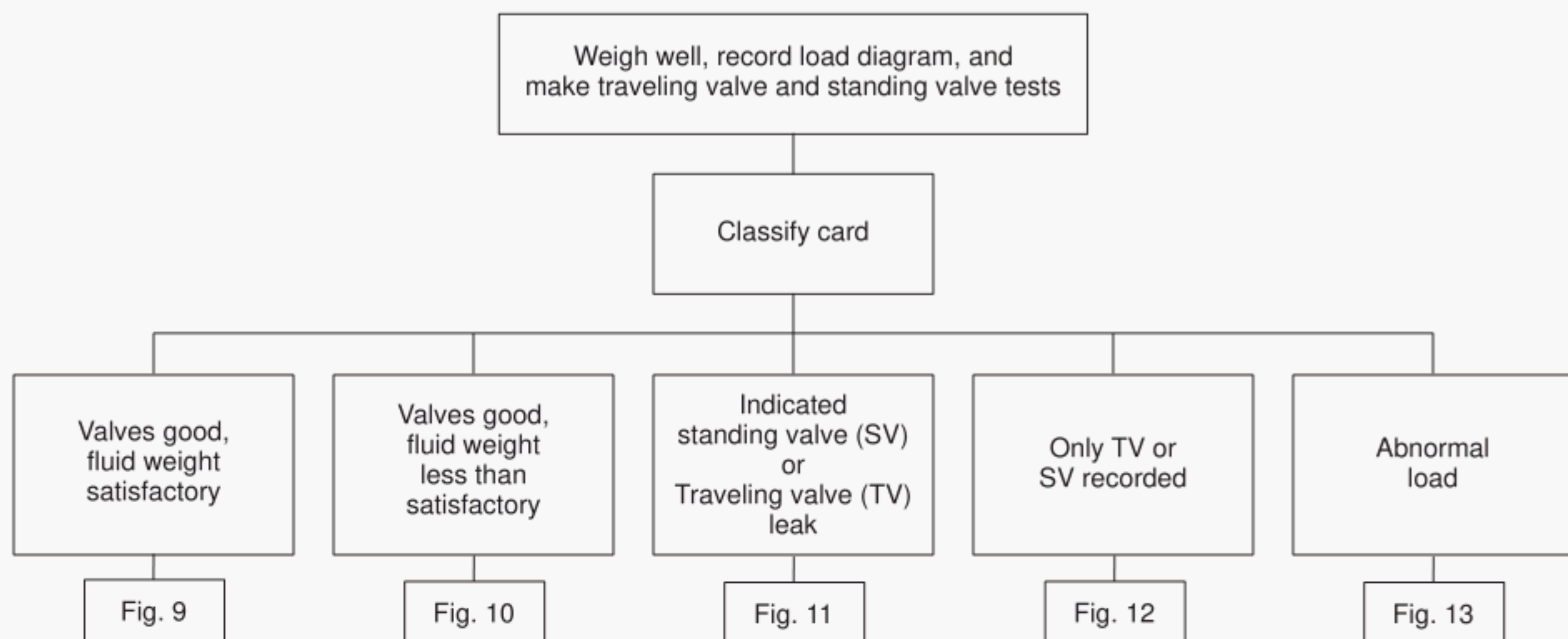


Figure 8—A Systematic Approach to Problem Well Tests

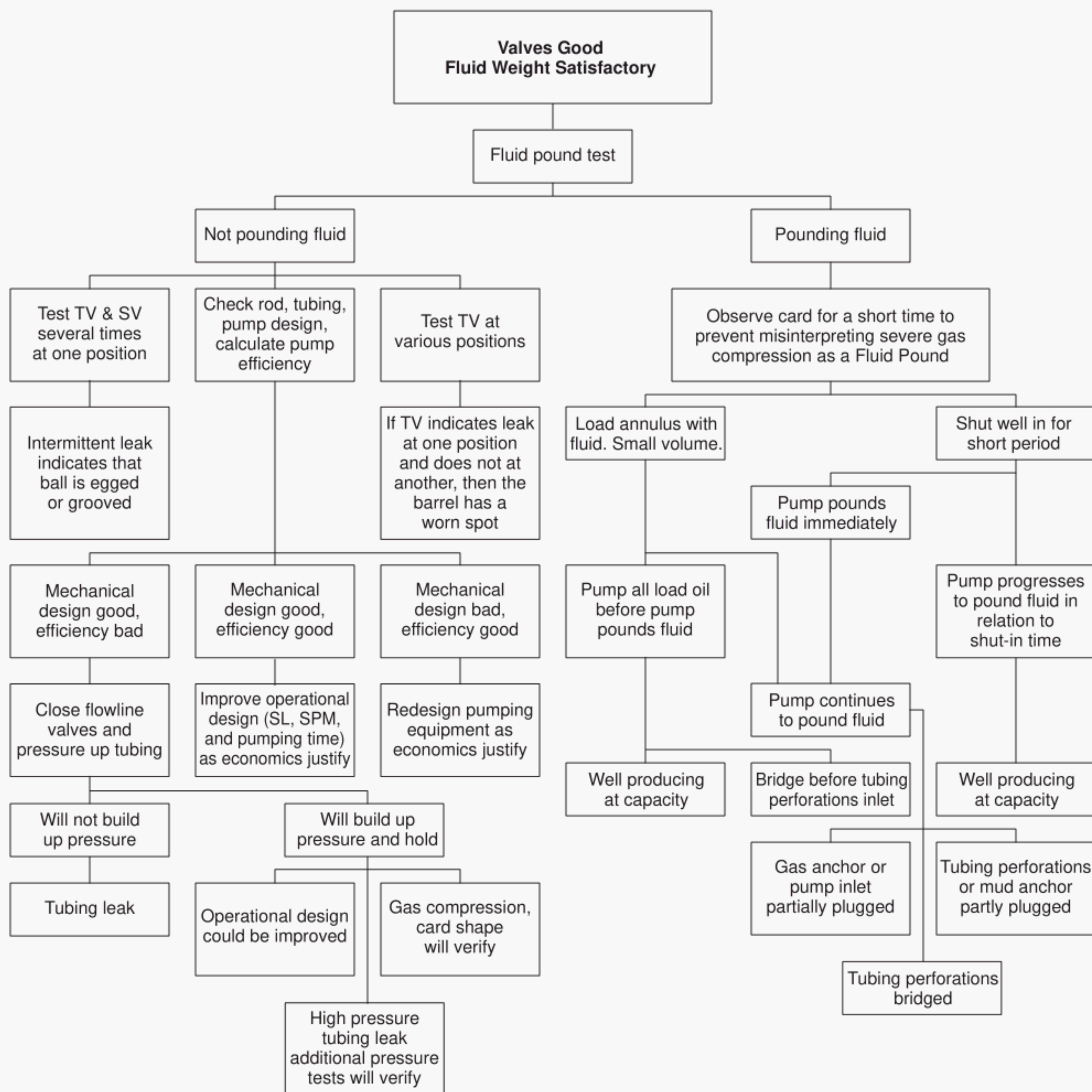


Figure 9—Valves Good Fluid Weight Satisfactory

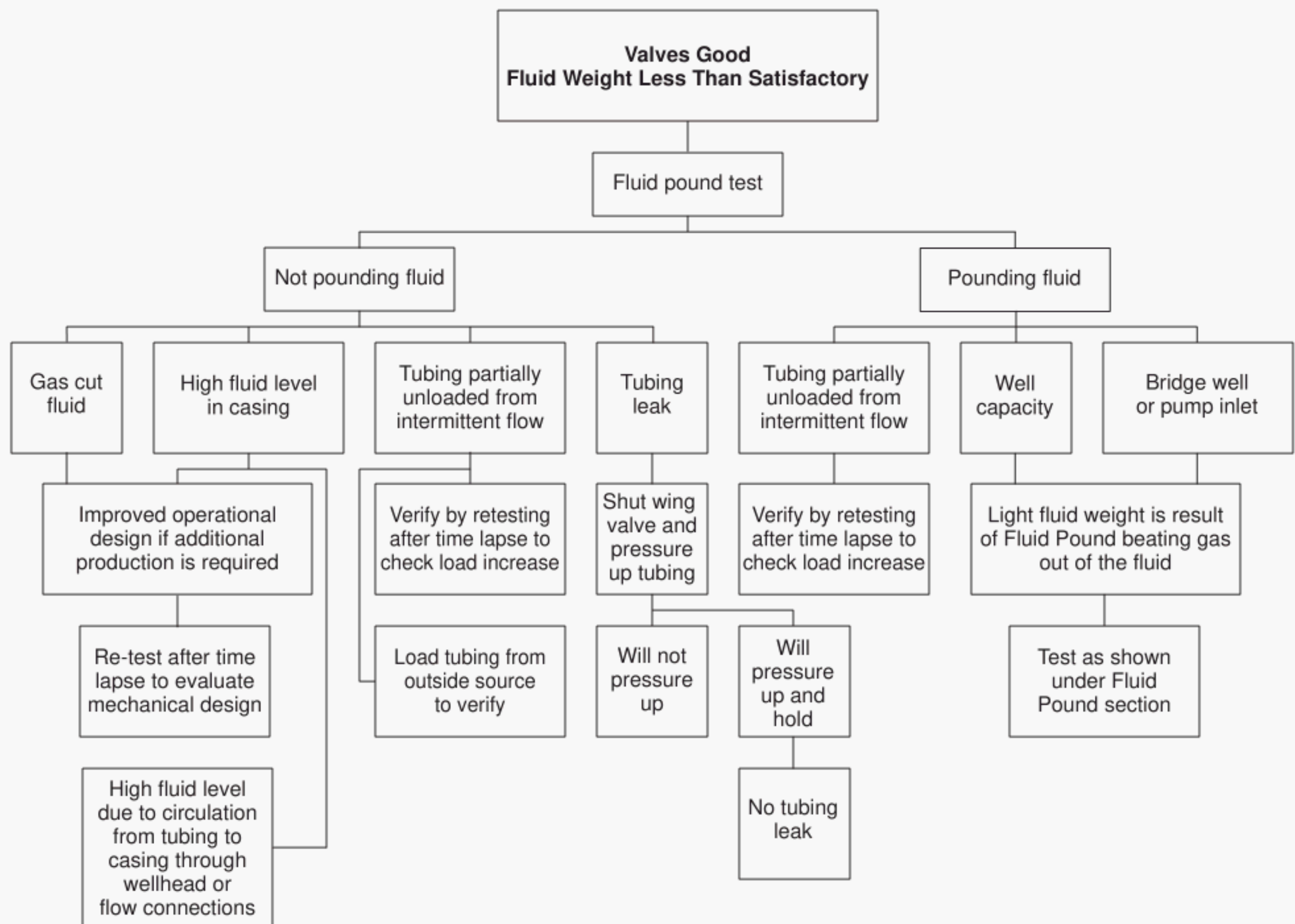


Figure 10—Valves Good Fluid Weight Less Than Satisfactory



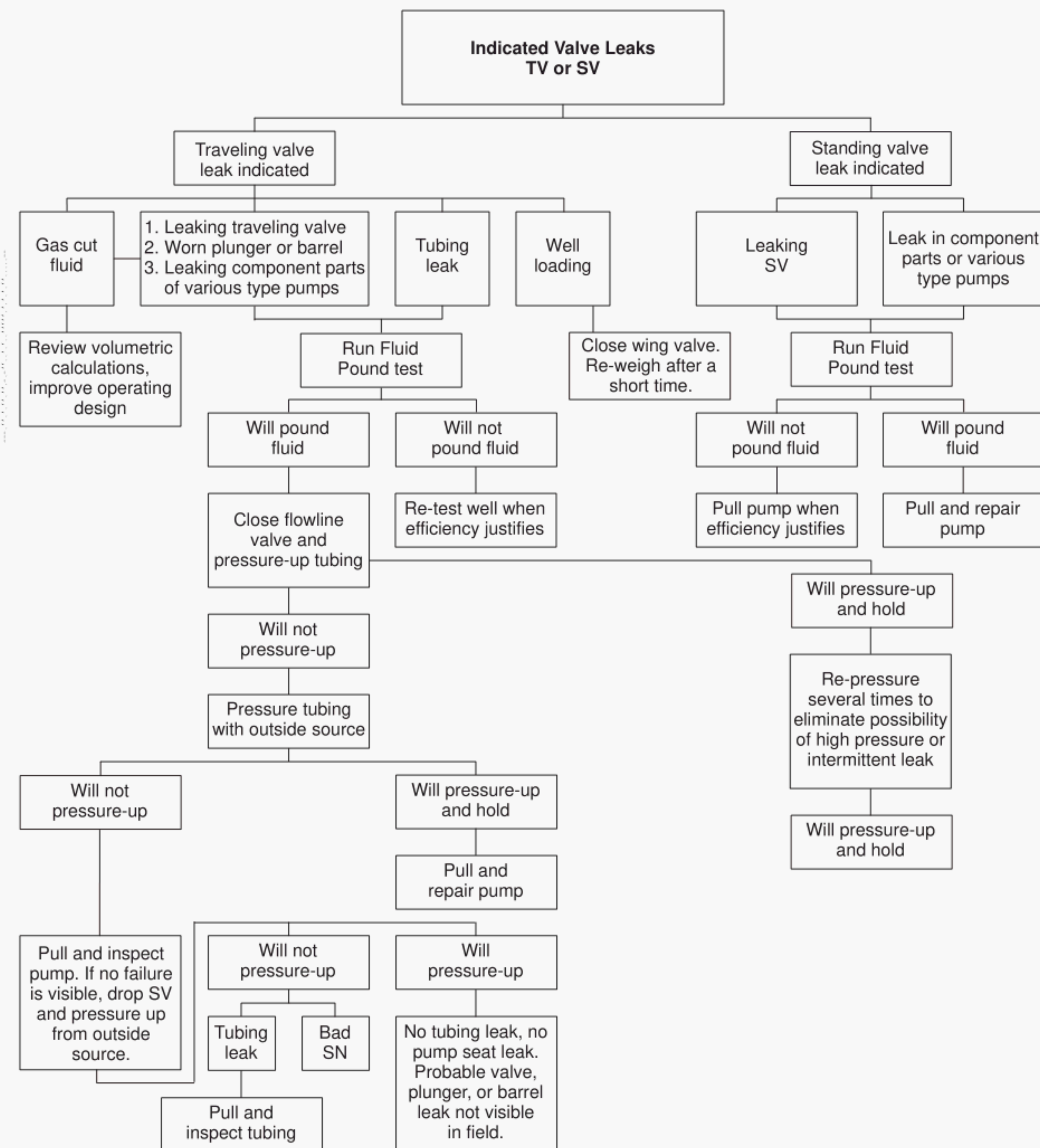
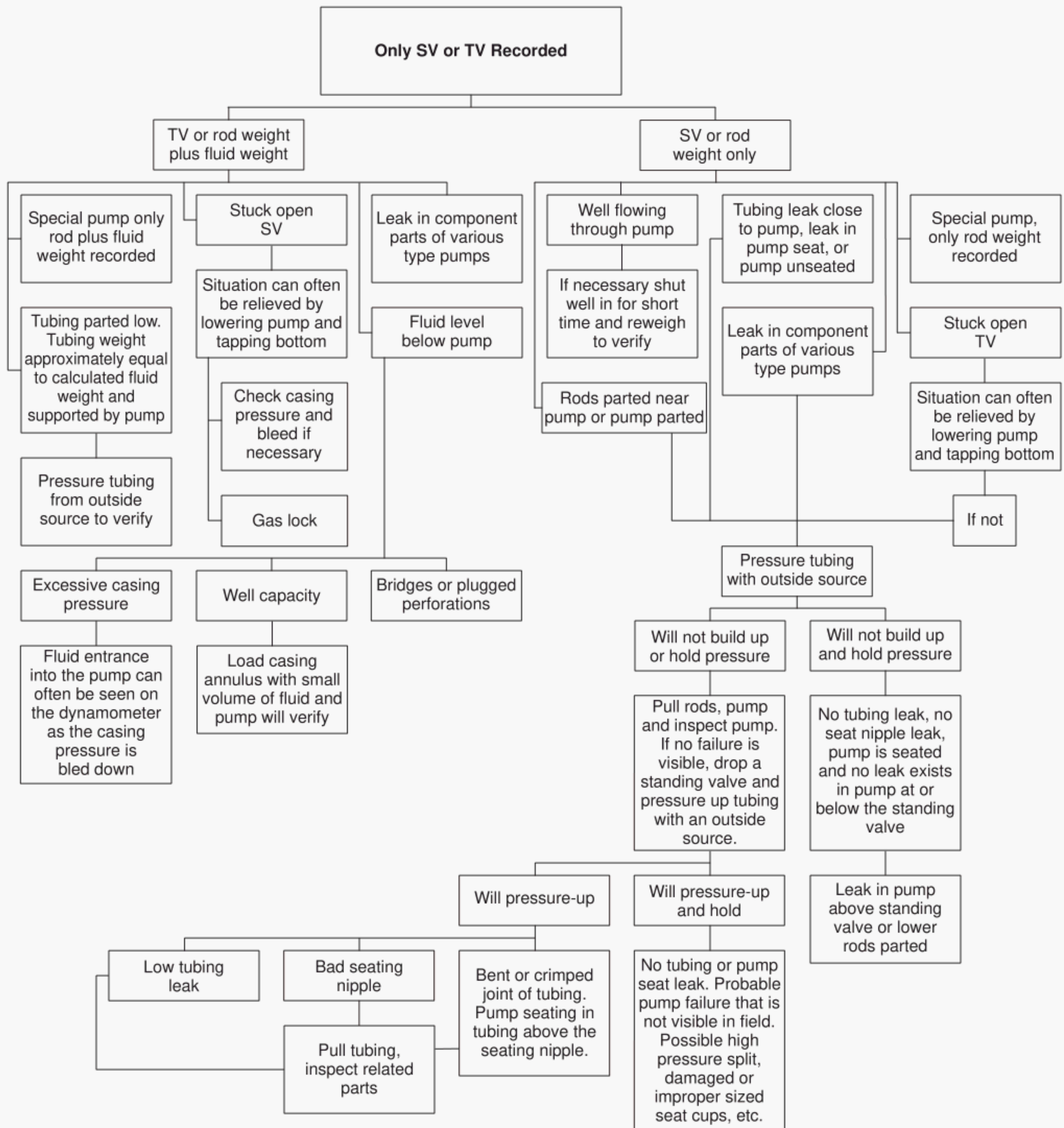


Figure 11—Indicated Valve Leaks TV or SV



Note: Bent joint of tubing above the seating nipple may not pass a pump, but it may pass a short standing valve and permit the tubing to hold fluid and pressure.

Figure 12—Only SV or TV Recorded

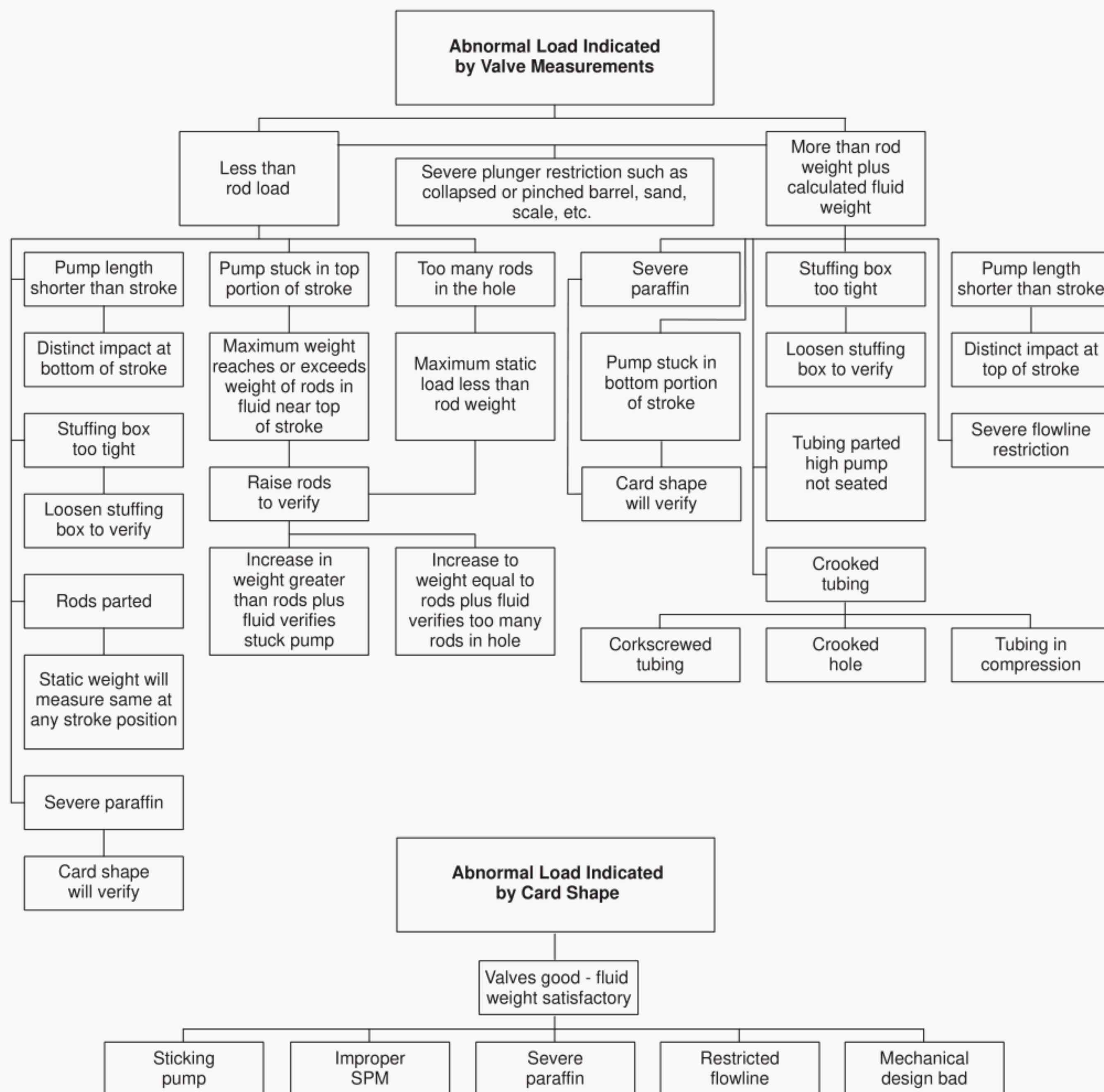
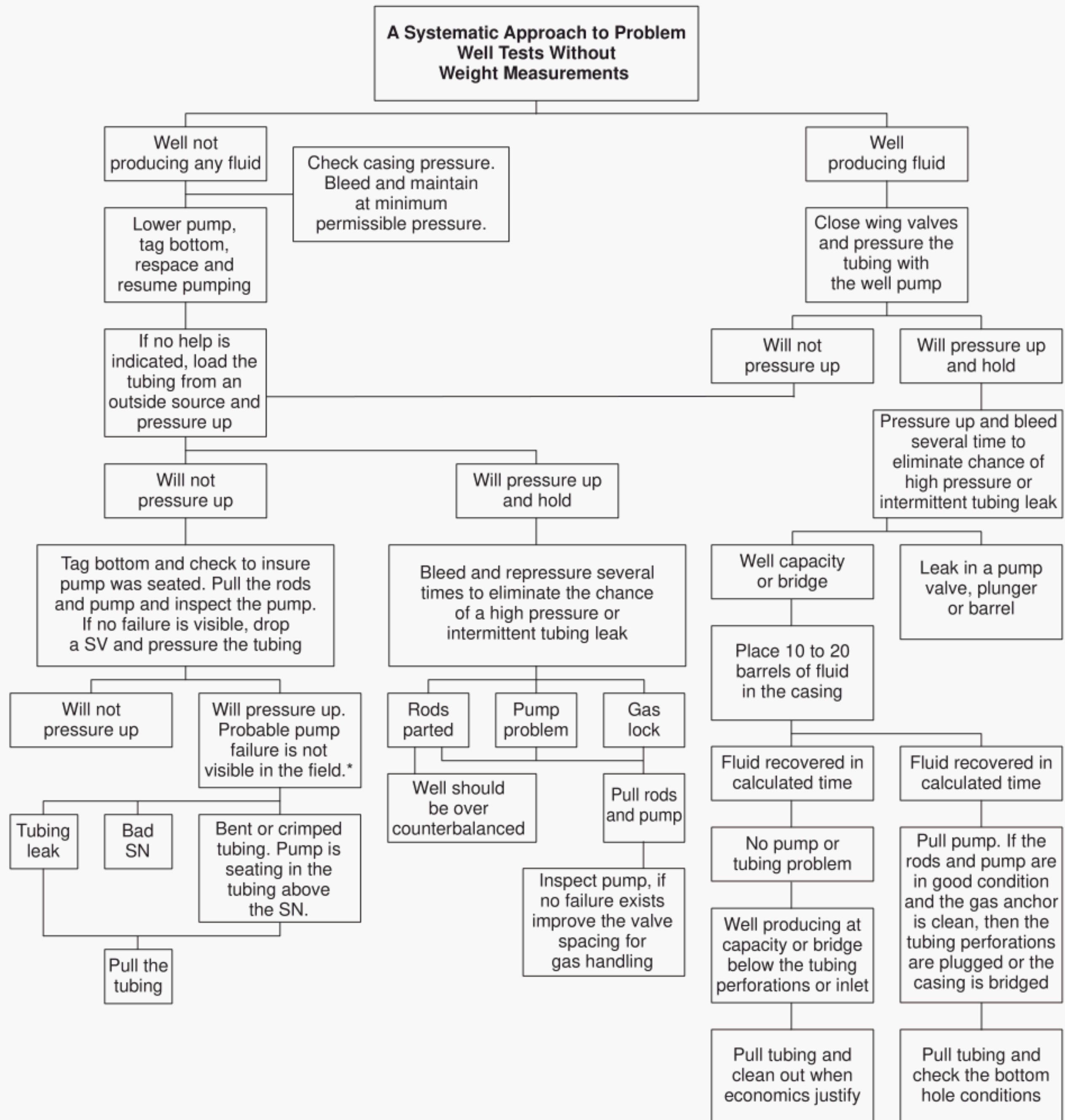


Figure 13—Abnormal Load Indicated by Valve Measurements and by Card Shape





\*Note: A bent or crimped joint may pass a free SV and permit pressuring up of the tubing, but may not pass a pump.

Figure 14—A Systematic Approach to Problem Well Tests Without Weight Measurements

## 7 Material Selection

**7.1** Over the history of the oil industry in the world, material manufacturers as well as process developers have developed new material and processes that have contributed significantly to better and longer pump life. Such developments are continuously being tested by the oil industry in a joint effort to help producing wells stay pumping longer.

**7.2** Many developments over the past years have proven or disproven their worth by trial in the oilfields. Although some are extremely successful in one area or application, they may fail in others. Some materials or processes may perform well in West Texas or California, but for reasons of economics or well conditions, they may be unprofitable to use in many parts of the world.

**7.3** The many materials or processes used in past years, if categorized, would fill a volume greater than this text and would be meaningless, as much of it is no longer available. In general, material information can be obtained by contacting individual manufacturers or suppliers.

**7.4** Since the introduction of chemical inhibition, the life of casing, tubing and sucker rods have been greatly improved. However, because of fluid turbulence, metal-to-metal, wear and sand abrasion, subsurface pumps have not experienced the same degree of protection and success as other oilwell components. Thus, subsurface pumps are designed using materials most likely to resist the corrosion and abrasive action of an oilwell environment.

**7.5** The major corrodants encountered in the well fluids are carbon dioxide, hydrogen sulfide, oxygen and brine, either singly or in combination. The corrosiveness and abrasiveness of fluids pumped must be taken into consideration when selecting pump assembly materials. Differences in metals can cause strong galvanic cells; i.e., chrome-plated steel barrels can pit rapidly if the plating is scratched or flakes off.

Chrome-plated brass barrels, however, have a smaller potential difference and the problem is minimized. Similarly, in a corrosive environment, a brass barrel connected directly to a small carbon steel part can result in a rapid corrosion attack of the carbon steel. Failure mechanisms most commonly encountered in subsurface pumps are: sulfide stress cracking (embrittlement), corrosion fatigue, erosion-corrosion, stress corrosion cracking, galvanic corrosion, pitting corrosion and mechanical wear or wear by abrasion.

**7.6** For those oilfield pumping applications where hydrogen sulfide is present, the National Association of Corrosion Engineers (NACE) has prepared Specification MR 01 76 *Materials Requirements, Metallic Materials for Sucker Rod Pumps for Corrosive Oilfield Environments*. API Specification 11AX designates approved materials for rod-drawn subsurface pumps.

**7.7** Per API Spec 11AX, Subsurface Sucker Rod Pumps and Fittings, pumps are currently designated as shown in Table 8 and Figure 15. (Note material reference in 7.7.1).

Example: A 1<sup>1</sup>/<sub>4</sub> in. (31.8 mm) bore rod type pump with a 10 ft (3.048 m) heavy wall barrel, 2 ft (0.610 m) upper extension, 1 ft. lower extension, a 4 ft (1.219 m) plunger, and a bottom cup type seating assembly for operation in 2<sup>3</sup>/<sub>8</sub> in. (60.3 mm) tubing, would be designated as follows:

20-125 RHBC 10-4-2-1

**7.7.1** In addition to the pump designation described in Par. 6.7.2., it is necessary for the purchaser to provide the following information:

- Barrel material.
- Plunger material.
- Plunger clearance (fit).
- Valve material.

Note: *Metallic Materials for Subsurface Sucker Rod Pumps for Corrosive Oilfield Environments* are listed in NACE Std MR0176.

Table 8—Pump Designations

(1)	(2)	(3)	(4)	(5)
Type of Pump	Letter Designation			
	Metal Plunger Pumps		Soft-Packed Plunger Pumps	
	Heavy-Wall Barrel	Thin-Wall Barrel	Heavy-Wall Barrel	Thin-Wall Barrel
Rod Pumps				
Stationary Barrel, Top Anchor	RHA	RWA	—	RSA
Stationary Barrel, Bottom Anchor	RHB	RWB	—	RSB
Stationary Barrel, Bottom Anchor	RXB	—	—	—
Traveling Barrel, Bottom Anchor	RHT	RWT	—	RST
Tubing Pumps	TH	—	TP	—

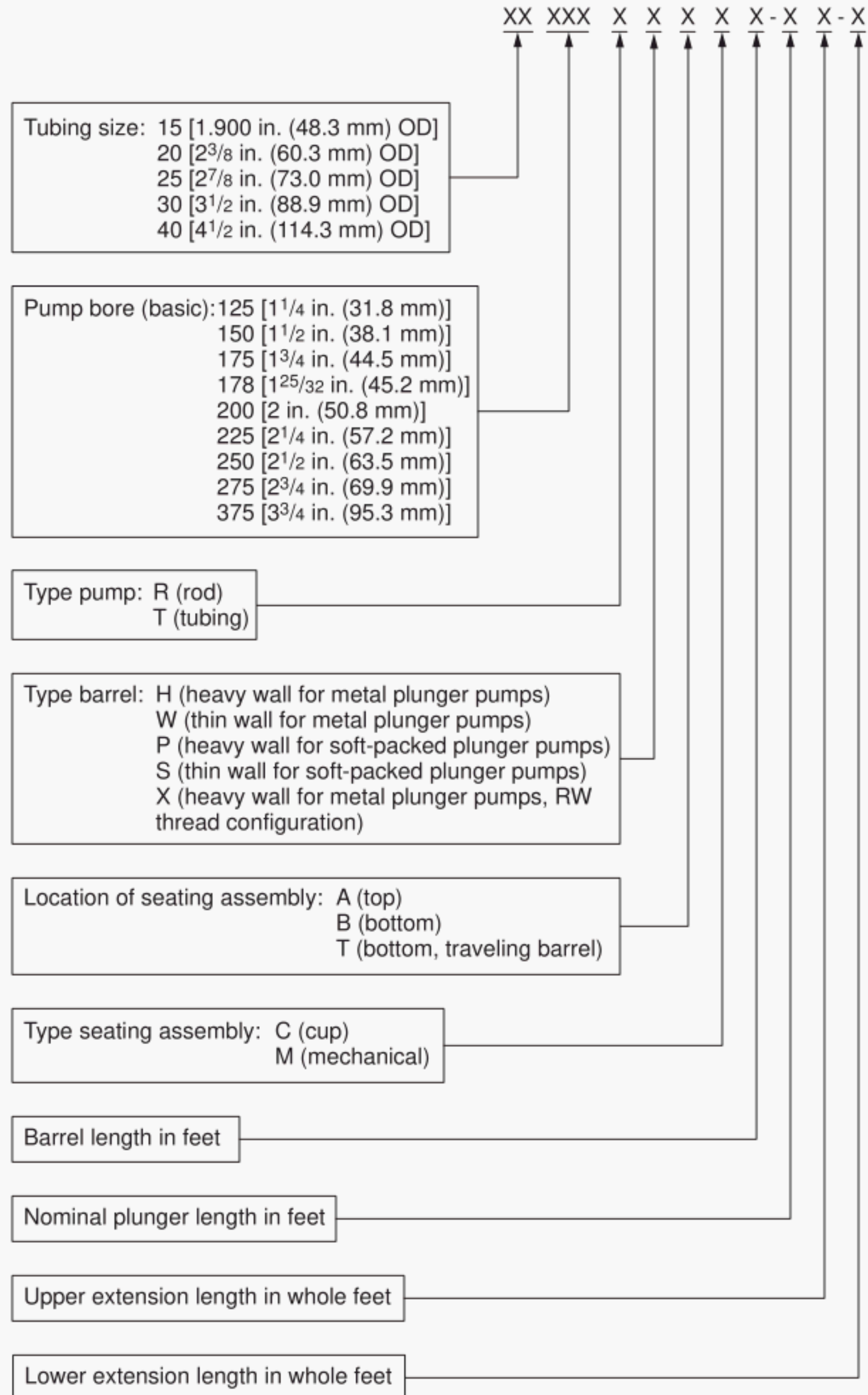


Figure 15—Pump Designations



## 8 Pump Repair

### 8.1 GENERAL

This section is outlined as guidance in detailed disassembly inspection and reassembly of sucker rod pumps. These procedures are the general practice of many repair and service operations and should be considered a suggested recommended practice rather than a specification.

### 8.2 CONDITIONS

Varying well conditions such as depth, specific gravity, viscosity and temperature will create different requirements from the suggested tolerances in this section. These are only suggested dimensions and a good general starting point for average pumping wells of moderate depth and conditions. The cumulative total of plunger and barrel wear should be considered when evaluating individual replacement. The key to the production success of any pumping system lies in the proper functioning of all the mechanical equipment that produce it. The failure or poor operation of any of the major components can destroy profitable productivity.

### 8.3 INSERT PUMP

#### 8.3.1 Disassembly of RWA or RWB Insert Pump

**8.3.1.1** Thoroughly clean outside of pump assembly (Figure 16, page 24).

**8.3.1.2** Select proper pump vise blocks and secure pump in blocks (Figure 17, page 25).

**8.3.1.3** Back up standing valve cage (lower end of barrel) and break out seat retainer, hold down, or double cage (Figure 18, page 25).

**8.3.1.4** Remove standing valve ball and seat from lower cage (Figure 19, page 26).

**8.3.1.5** Secure barrel tightly in vise blocks, loosen and unscrew standing valve cage (Figure 20, page 26).

**8.3.1.6** While barrel is in secured position, loosen and unscrew top hold down or top guide and connector assemblies.

**8.3.1.7** Pull out valve rod and plunger assembly.

**8.3.1.8** Secure plunger assembly in plunger blocks (Figure 21, page 27).

**8.3.1.9** Back up plunger cage. Loosen and remove seat retainer (Figure 22, page 27).

**8.3.1.10** Remove traveling ball and seat from cage (Figure 19, page 26).

**8.3.1.11** Secure plunger in blocks tightly, loosen and remove plunger cage (Figure 23, page 28).

**8.3.1.12** While plunger is in secured position, loosen and remove top plunger connector and valve rod assembly.

**8.3.1.13** Clean all parts thoroughly (Figure 24, page 28).



Figure 16





Figure 17



Figure 18



Figure 19

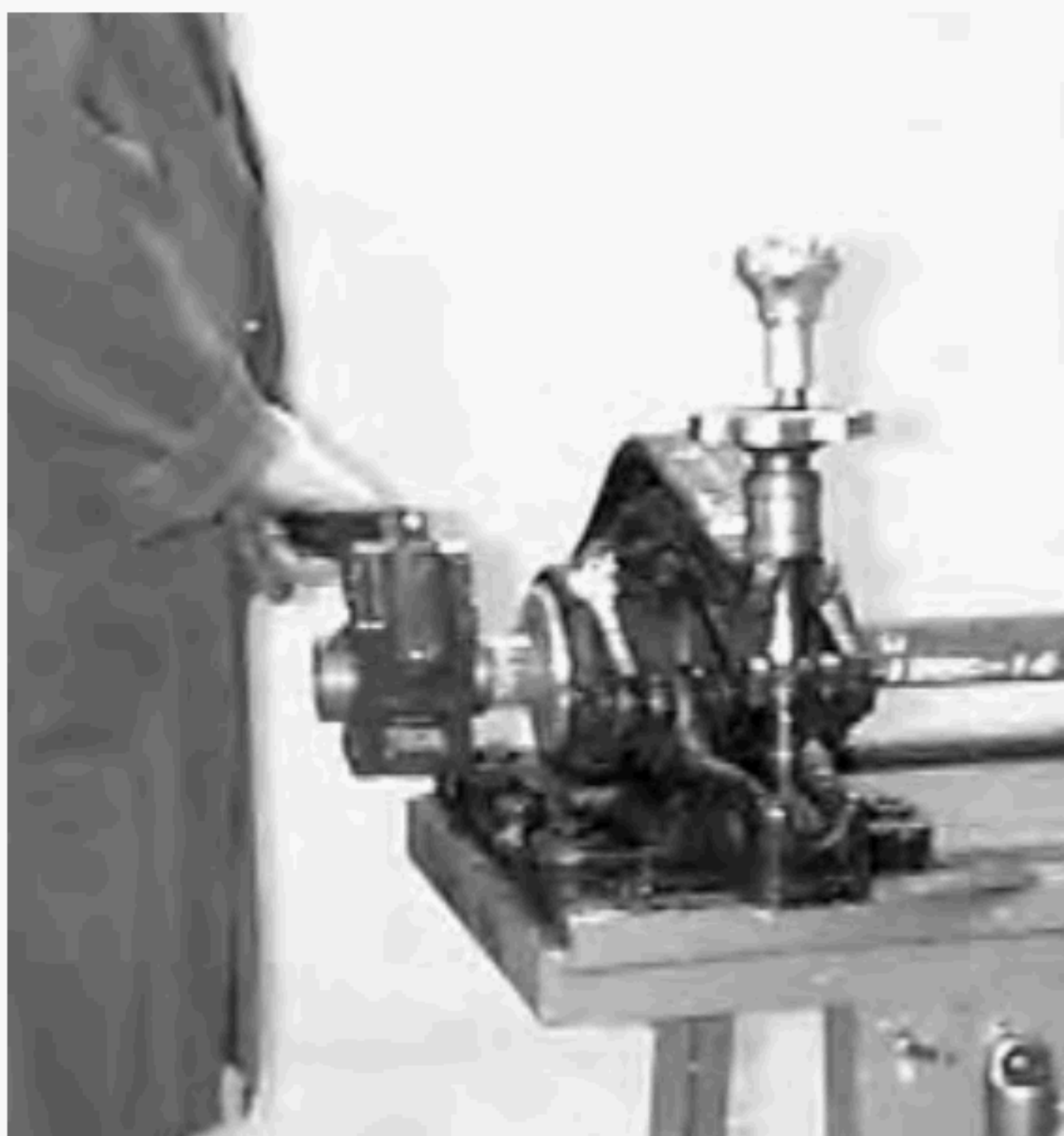


Figure 20

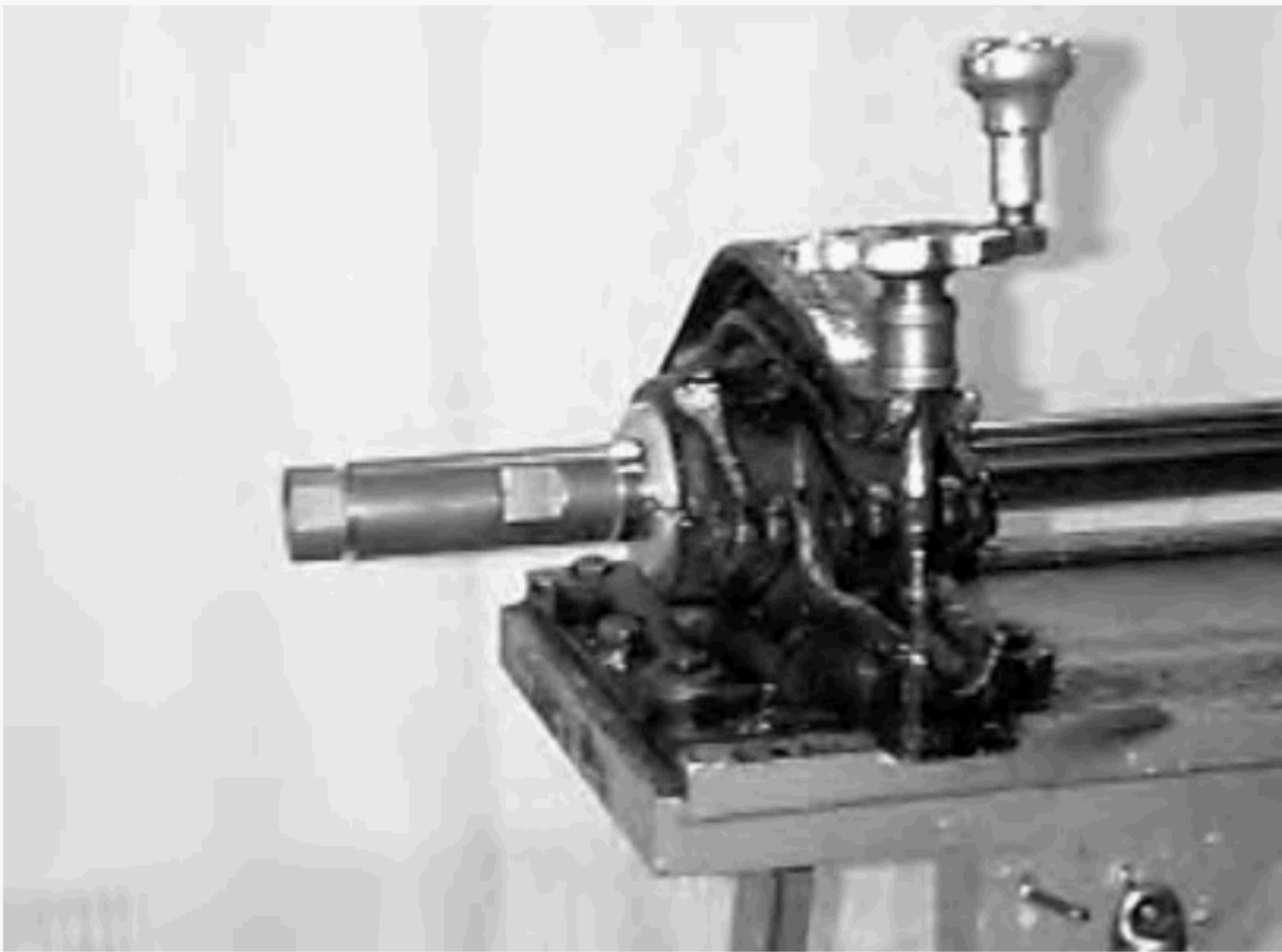


Figure 21



Figure 22





Figure 23



Figure 24

### 8.3.2 Inspection of All Component Parts

#### 8.3.2.1 Bottom “heavy duty” hold down.

- Inspect body face, seating surface of brass or stainless steel ring and locking angle (prongs) (Figure 25, page 29).
- If seating surface is pitted, worn or fluid cut—replace.
- If locking mandrel shows wear—replace.

#### 8.3.2.2 Alternate cup hold down.

- Completely disassemble and discard old seating cups.
- Inspect all threads for corrosion.
- Replace any worn parts.
- Always replace all seating cups.

#### 8.3.2.3 Top hold down—use same procedures.

#### 8.3.2.4 Standing valve ball and seat and cages.

- Clean and vacuum test balls and seats. Replace if assembly fails test (Figure 26, page 30). If ball guides inside of cages are worn or deformed to where less than  $\frac{2}{3}$  of the original thickness remains, the cage should be considered for replacement (Figures 27, page 30, and 28, page 31).
- All shouldering faces (outside at thread base) and (inside at seat flange) must be clean and free of any cuts. Rough faces indicate replacement (Figures 29, 30, and 31, all on page 31).

#### 8.3.2.5 Pump barrel inspection. The cumulative total of plunger and barrel wear should be considered when evaluating individual replacement.

- Clean barrel thoroughly—removing all oil, wax, sand and scale if present (Figure 34, page 32).
- Dial gauge inside diameter of barrel to measure wear (Figures 35, page 32, and 36, page 33).
- If gauged wear area reflects .005 in. more than nominal ID—barrel should be considered for replacement.
- Sand cuts, grooves, galling or corrosive deterioration of the barrel ID indicate replacement is required.

#### 8.3.2.6 Plunger traveling valve retainer.

- Inspect threads and face—replace if cut (Figure 30, page 31).

#### 8.3.2.7 Traveling valve ball and seat and cages.

- Use same procedure as standing valve for ball and seat.

#### 8.3.2.8 Plunger. The cumulative plunger and barrel wear should be considered when evaluating individual replacement.

- Thoroughly clean inside and out.
- Inspect surface and measure with micrometers to determine OD of plunger (Figure 37, page 33).
- If OD wear is .002 in. to .003 in. under original plunger fit, over most of its length, the plunger should be considered for replacement.
- Sand scores, grooves, pits, galling and the wearing of surface coatings indicate plunger replacement (Figure 38, page 34).
- Check threads both on pin-end and box-end plungers. All plunger threads and pins should not be rerun if corrosion damage is indicated.
- Check the straightness of the plunger in accordance with the manufacturer's recommendations and tolerances for straightness (Figure 39, page 34). If the plunger is out of tolerance discard the plunger or straighten it in accordance with the manufacturer's recommended method.

#### 8.3.2.9 Valve rod assembly.

- Inspect valve rod. If it is worn and remaining area is less than 80% of its original O.D., it should be considered for replacement (Figure 40, page 35).
- Inspect valve rod guide. If guide hole is enlarged by  $\frac{1}{3}$  its original size—it should be considered for replacement (Figure 41, page 35).
- Inspect clutch coupling. If pounded or worn—replace (Figure 42, page 34).



Figure 25



Figure 26



Figure 27





Figure 28



Figure 29



Figure 30



Figure 31



Figure 32

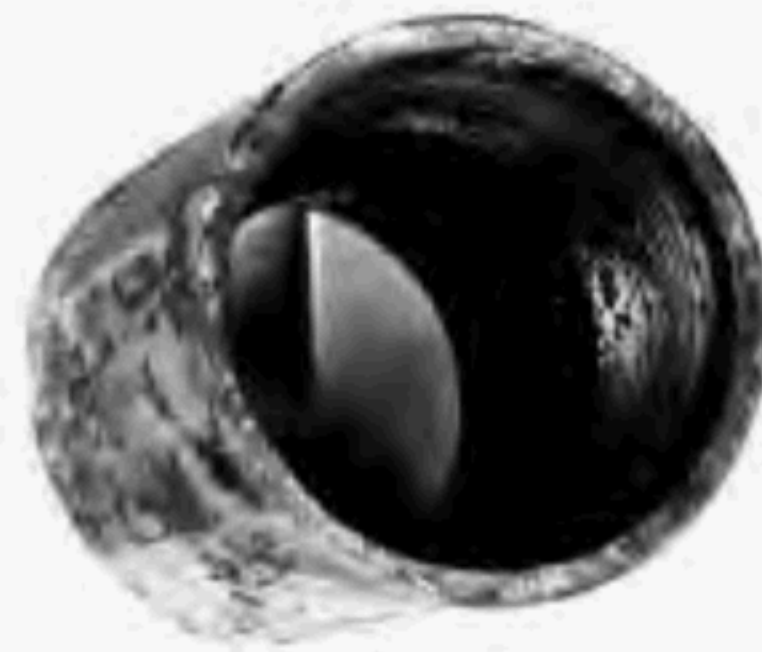


Figure 33

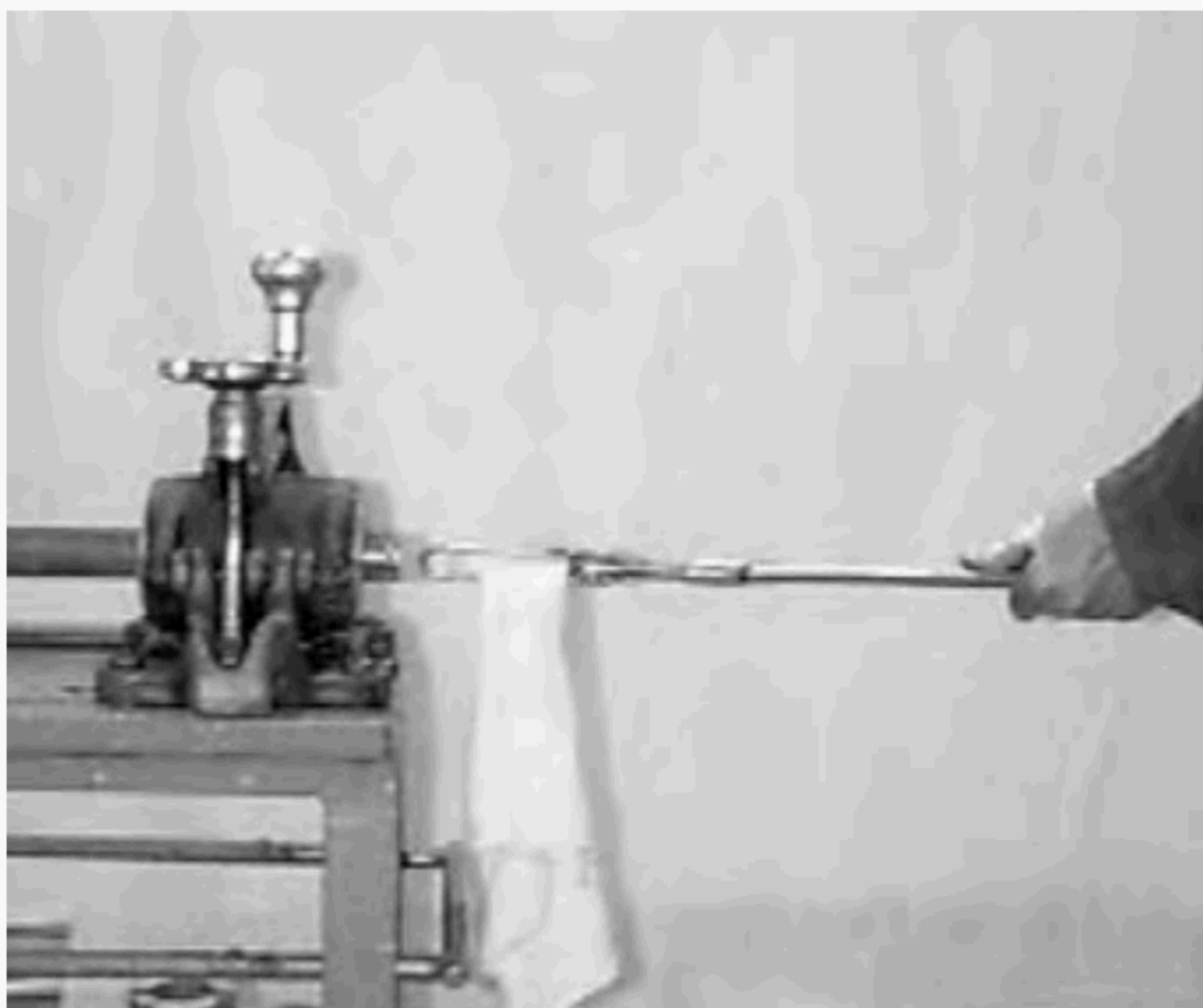


Figure 34



Figure 35

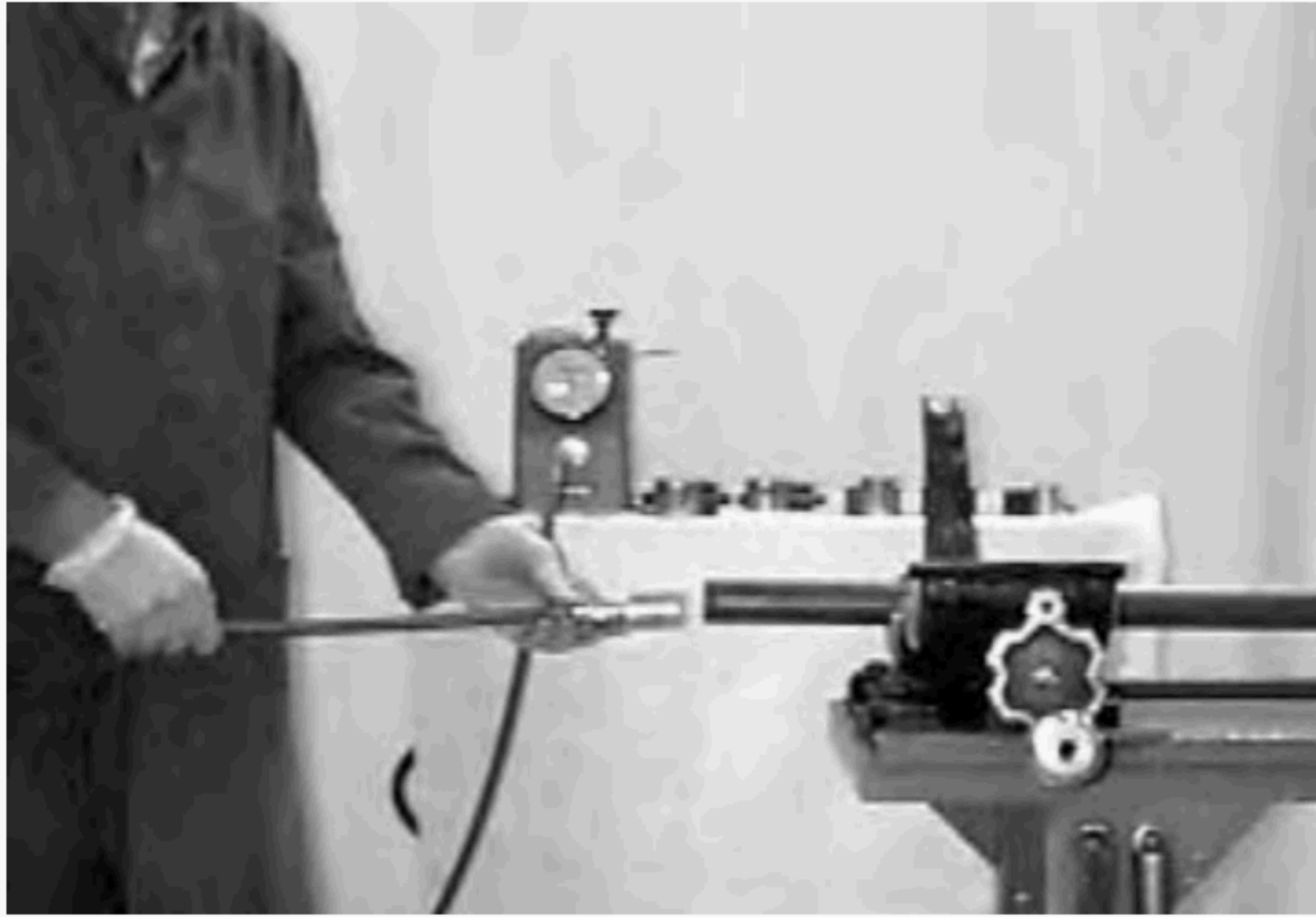


Figure 36



Figure 37





Figure 38

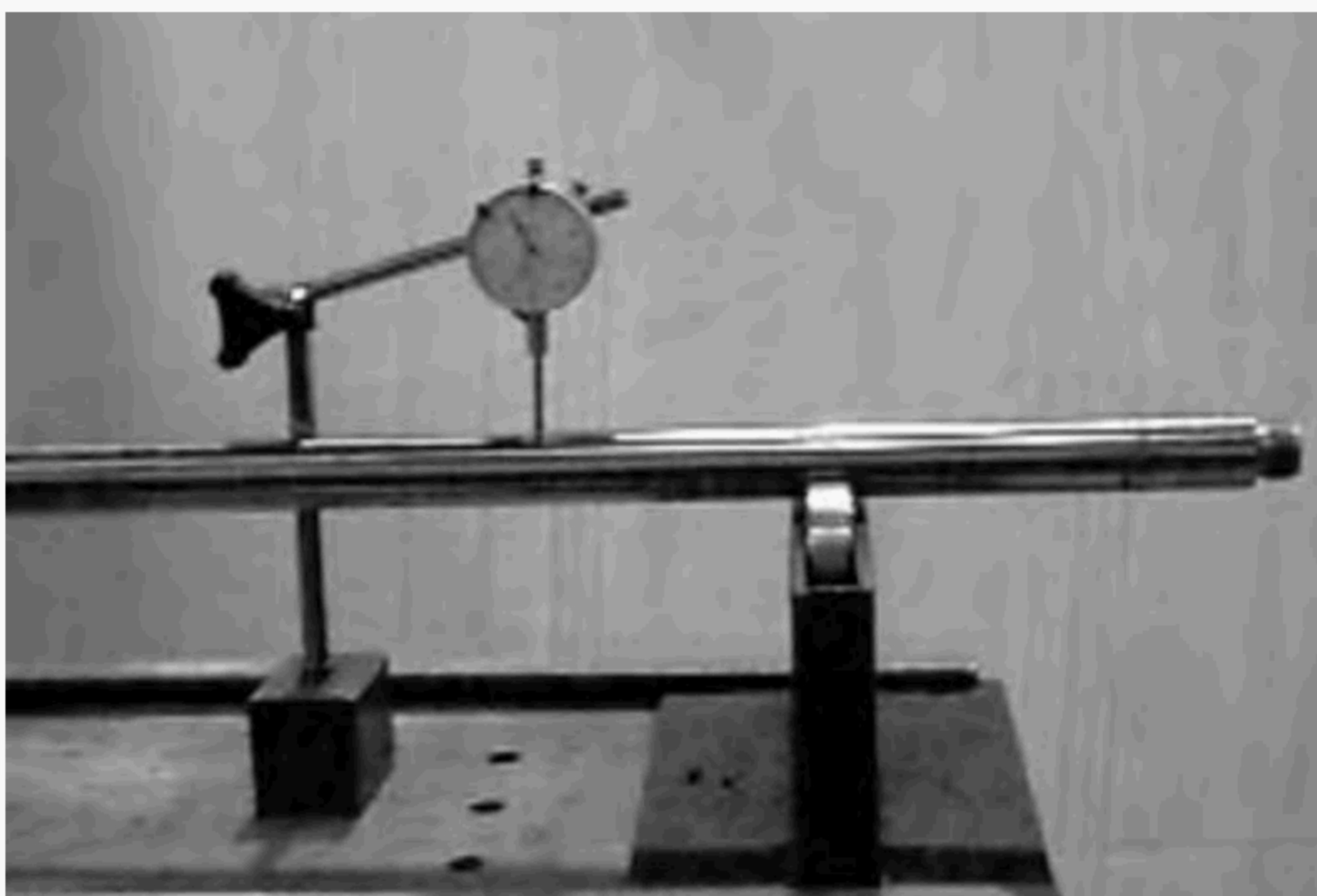


Figure 39



Figure 40



Figure 41



Figure 42

### 8.3.3 Assembly of RWA or RWB Insert Pumps

**8.3.3.1** Use good thread compound on all threads before assembly (Figure 43, page 36).

**8.3.3.2** Assemble valve rod assembly.

**8.3.3.3** Secure plunger in plunger vise (Figure 44, page 37). Tighten valve rod assembly and traveling cage to plunger.

**8.3.3.4** Insert ball and seat in cage and assemble seat retainer.

**8.3.3.5** Back up traveling valve cage and tighten seat retainer or double cage (Figures 45, page 37, 46 and 47, page 38).

**8.3.3.6** Clean and lubricate pump barrel.

**8.3.3.7** Lubricate barrel ID and plunger assembly with good light grade of motor or turbine oil.

**8.3.3.8** Insert plunger assembly into barrel and stroke full length. Travel should be smooth throughout.

**8.3.3.9** With plunger and valve rod assembly inserted into barrel—secure pump barrel in friction vise and tighten top hold down or guide and connector assembly.

**8.3.3.10** Push valve rod completely in until clutch coupling engages rod guide.

**8.3.3.11** Check lower end of pump barrel to ensure plunger seat retainer is no more than 2 in. from bottom of barrel. If plunger assembly is more than 2 in. off bottom, it is recommended the rod be replaced with a longer one. If plunger assembly is less than  $\frac{1}{4}$  in. off bottom, valve rod should be shortened.

**8.3.3.12** Install standing valve cage to pump barrel and tighten (Figure 48, page 39).



Figure 43



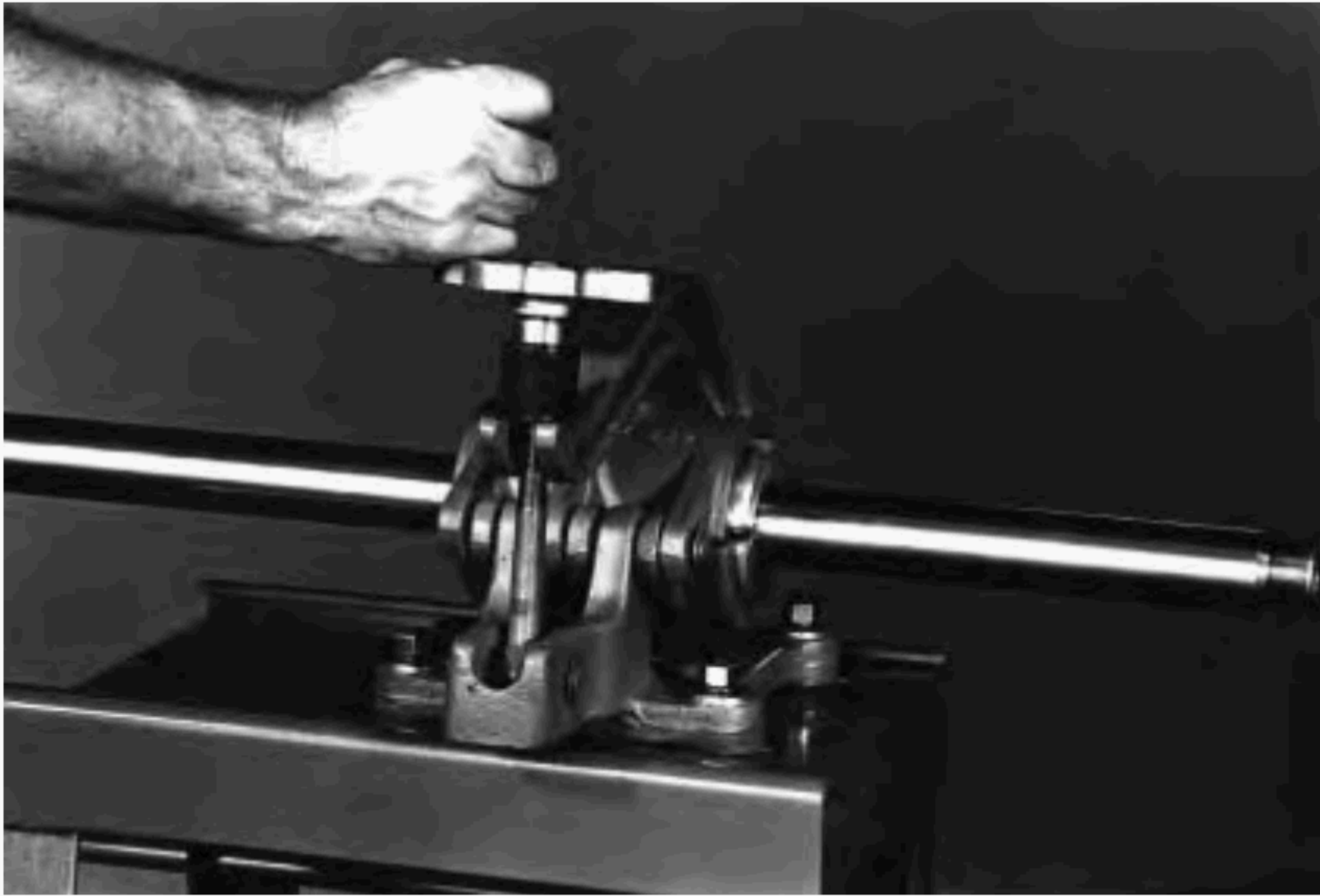


Figure 44

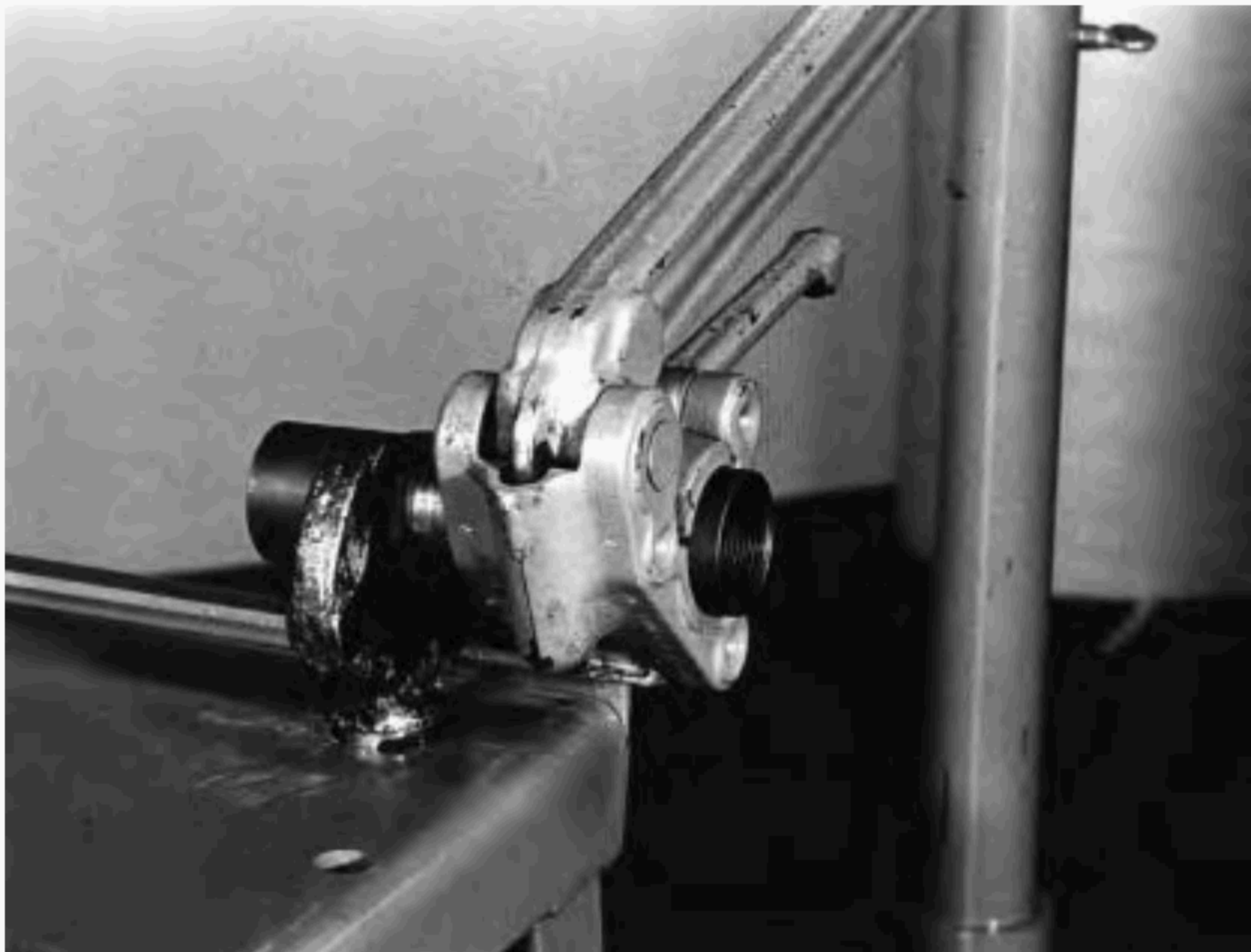


Figure 45

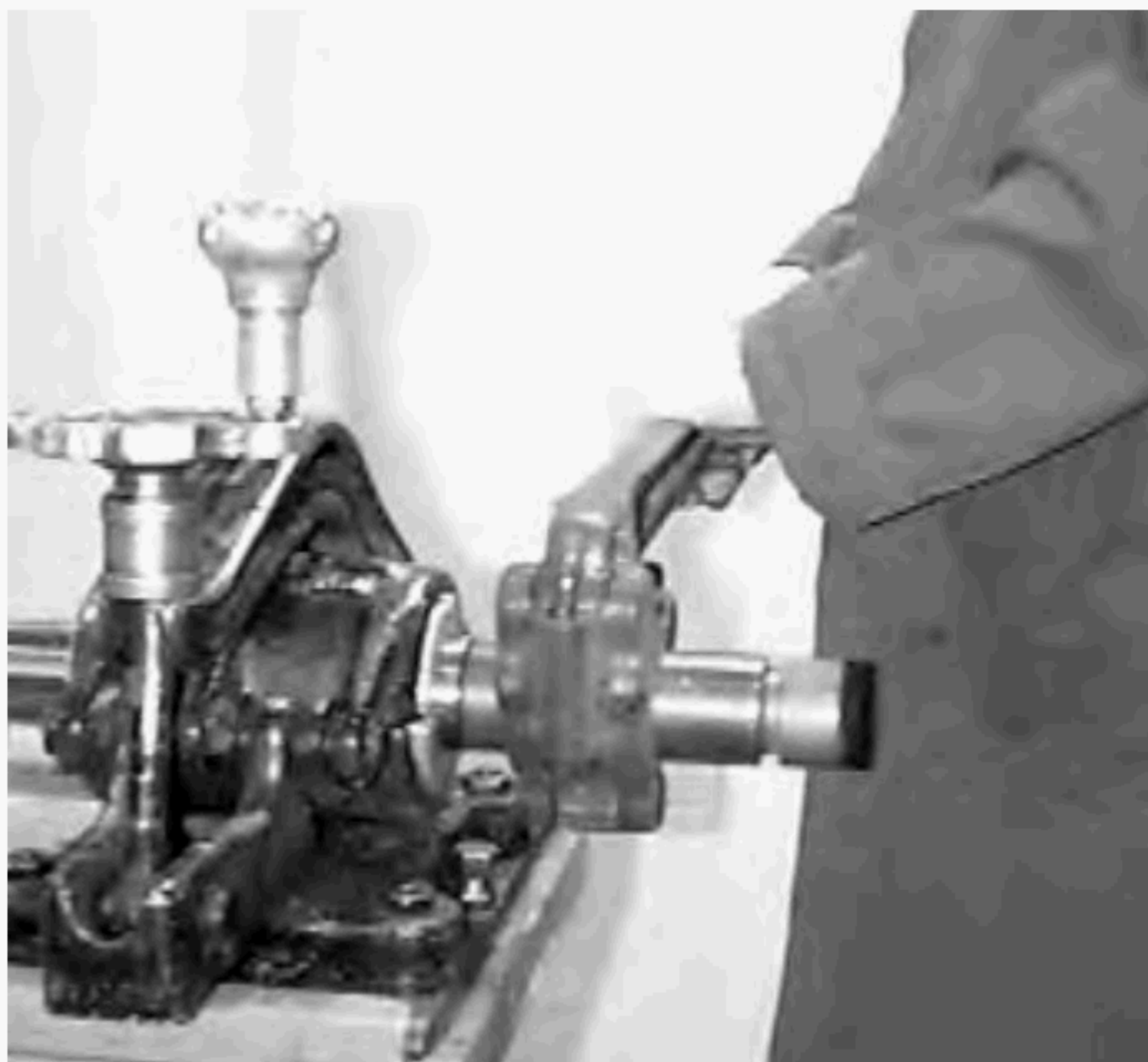


Figure 46



Figure 47

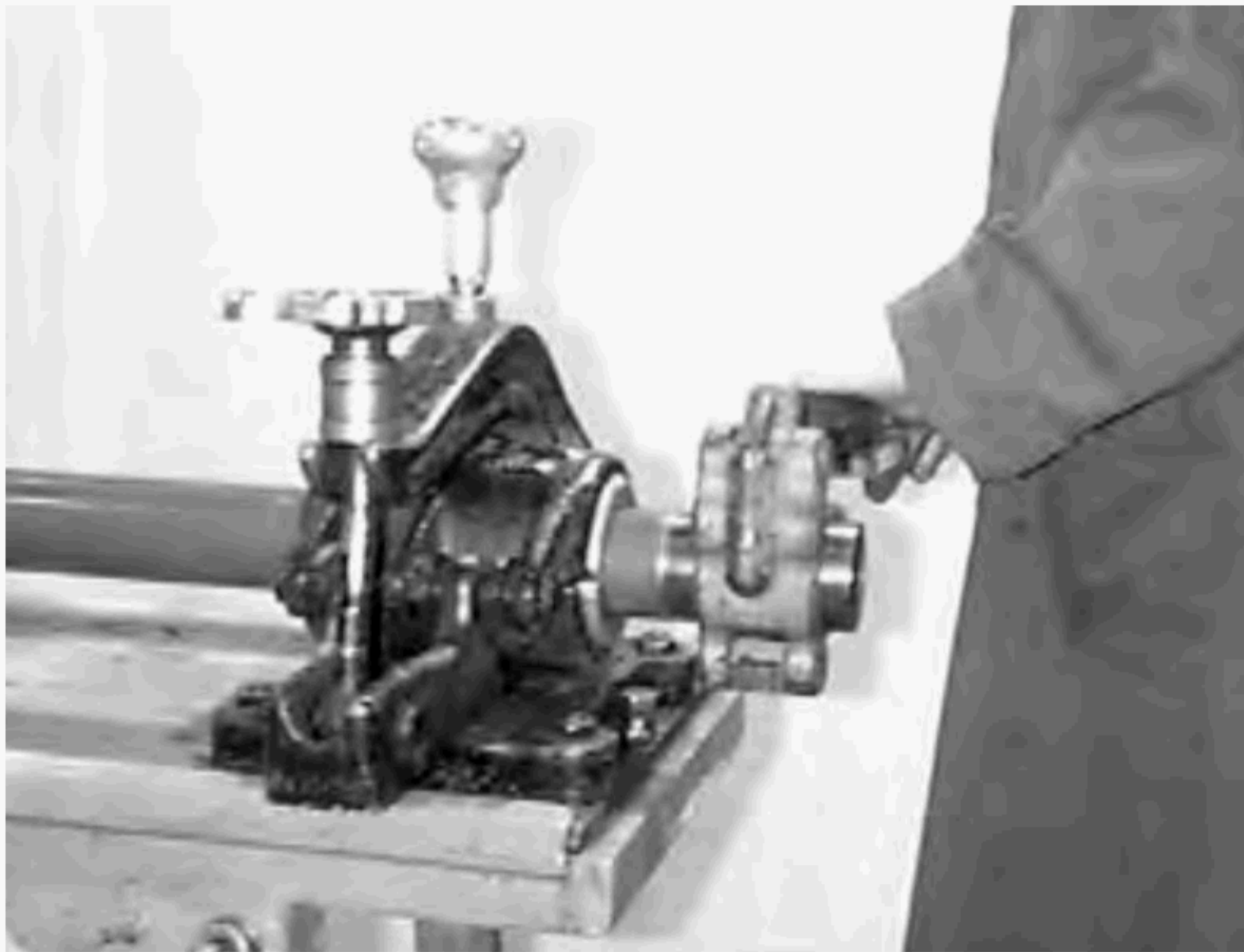


Figure 48



Figure 49



**8.3.3.13** Install standing valve ball and seat.

**8.3.3.14** Assemble sanding valve seat retainer or bottom hold down assembly.

**8.3.3.15** Back up standing valve cage and tighten seat retainer or hold down (Figure 49, page 39).

**8.3.3.16** Check for proper functioning of the valves by attaching a vacuum gauge to the standing valve and pulling on the valve rod (Figure 50, page 42). The manufacturer's recommendations and test parameters should be used as controls for this test.

**8.3.3.17** Pull valve rod out again to insure smooth travel. Measure and record full length of free stroke (Figure 51, page 42).

**8.3.3.18** Tie valve rod assembly to top guide, wrap each end of pump assembly and tag as complete.

Table 9 will indicate the approximate tightness pump fittings should be made up to.

### 8.3.4 Disassembly of RHA or RHB Insert Pump

**8.3.4.1** Thoroughly clean outside of pump assembly (Figure 16, page 24).

**8.3.4.2** Select proper pump vise blocks to fit barrel extension and secure pump in blocks (Figure 17, page 25).

**8.3.4.3** Back up standing valve cage (lower end of barrel) and break out seat retainer, hold down or double valve cage (Figure 18, page 25).

Table 9—Pump Fittings

Pump Bore	Length of Handle in.	Applied Weight
1 <sup>1</sup> / <sub>4</sub>	18	75#
1 <sup>1</sup> / <sub>2</sub>	18	130#
1 <sup>3</sup> / <sub>4</sub>	18	150#
2	18	180#
2 <sup>1</sup> / <sub>4</sub>	24	180#
2 <sup>3</sup> / <sub>4</sub>	36	180#
3 <sup>1</sup> / <sub>4</sub>	36	250#
3 <sup>3</sup> / <sub>4</sub>	36	300#
Tubular Fittings		
2 <sup>3</sup> / <sub>8</sub> EUE 8 RND	36	180#
2 <sup>7</sup> / <sub>8</sub> EUE 8 RND	60	200#
3 <sup>1</sup> / <sub>2</sub> EUE 8 RND	84	200#
4 <sup>1</sup> / <sub>2</sub> EUE 8 RND	84	300#

Note: The weight and wrench handle lengths listed above are suggested torque or tightness ratings. Different materials, well conditions and the type of thread lubricant used have a direct relationship to how tight a fitting or joint must be. The use of antifrictional thread compound (those containing Teflon) will tend to make up tighter using the above weight and handle length than others using lead- or petroleum-base compounds.

**8.3.4.4** Remove standing valve ball and seat from lower cage (Figure 19, page 26).

**8.3.4.5** Secure barrel extensions tightly in vise blocks, loosen and unscrew top hold down or top guide and connector assemblies.

**8.3.4.6** Select proper pump barrel vise blocks and secure pump barrel in vise blocks.

**8.3.4.7** Break out extension from pump barrel.

**8.3.4.8** Pull out valve rod and plunger assembly.

**8.3.4.9** Secure plunger assembly in plunger blocks (Figure 21, page 27).

**8.3.4.10** Back up plunger cage, loosen and remove seat retainer or double valve cage (Figure 22, page 27).

**8.3.4.11** Remove traveling ball and seat from cage (Figure 19, page 26).

**8.3.4.12** Secure plunger in blocks tightly, loosen and remove plunger cage (Figure 23, page 28).

**8.3.4.13** While plunger is in secured position, loosen and remove top plunger connector and valve rod assembly.

**8.3.4.14** Clean all parts thoroughly (Figure 24, page 28).

### 8.3.5 Inspection of Component Parts

**8.3.5.1** Bottom "heavy duty" hold down.

- Inspect body face, seating surface of brass or stainless steel ring and locking angle (prongs) (Figure 25, page 29).
- If seating surface is pitted, worn or fluid cut—replace.

**8.3.5.2** Alternate cup hold down.

- Completely disassemble and discard old seating cups.
- Inspect all threads for corrosion.
- Replace any worn parts.
- Always replace all seating cups.

**8.3.5.3** Top Hold Down—use same procedure as 8.7.1 and 8.7.2

**8.3.5.4** Standing valve ball and seat and cages.

- Clean and vacuum test balls and seats (Figure 26, page 30). Replace if test is bad.
- If ball guides inside of cages are worn or deformed to where less than <sup>2</sup>/<sub>3</sub> of the original thickness remain, the cage should be considered for replacement (Figures 27, page 30, and 28, page 31).
- All shouldering faces (outside at thread base) and (inside at seat flange) (Figures 29, 30 and 31, all on page 31) must be clean and free of any cuts. Rough faces indicate a need for replacement.

**8.3.5.5 Pump Barrel Inspection.** The cumulative total of plunger and barrel wear should be considered when evaluating individual replacement.

- a. Clean barrel thoroughly—removing all oil, wax, sand and scale if present (Figure 34, page 32).
- b. Dial gauge diameter of barrel to measure wear (Figures 35, page 32, and 36, page 33).
- c. If the gauged wear area reflects .005 in. over nominal ID, the barrel should be considered for replacement.
- d. Sand cuts, grooves, galling or corrosive deterioration of the barrel ID indicates replacement is required.
- e. Check the face of each end of the barrel extension for bad faces or threads (Figure 29, page 31).
- f. Check barrel faces.
- g. If the faces of extension or barrel are fluid-cut or galled—replace.
- h. Check ID of extension for corrosive or erosive action. If it is more than  $\frac{1}{3}$  of original thickness is gone, it should be considered for replacement.

**8.3.5.6 Plunger traveling valve retainer.**

- a. Inspect threads and face—replace if cut (Figure 30, page 31).

**8.3.5.7 Traveling Valve Ball and Seat Cages.**

- a. Use same procedures as for the standing valve ball and seat.

**8.3.5.8 Plunger.** The cumulative total of plunger and barrel wear should be considered when evaluating individual replacement.

- a. Thoroughly clean inside and out.
- b. Inspect surface and use micrometers to determine OD of plunger.
- c. If OD wear is .002 in. to .003 in. under original plunger fit, over half of its length, the plunger should be considered for replacement.
- d. Sand scores, grooves, pits, galling, or the wearing off of surface coatings indicate plunger replacement (Figure 38, page 34).
- e. Check threads and pins; they should not be rerun if any corrosive action is indicated.
- f. Check the straightness of the plunger in accordance with the manufacturer's recommendations and tolerances for straightness (Figure 38, page 34). If the plunger is out of tolerance, discard the plunger or straighten it in accordance with the manufacturer's recommended method.

### **8.3.6 Assembly of RHA or RHB Insert Pump**

**8.3.6.1** Use good thread compound on all threads (Figure 42, page 35).

**8.3.6.2** Assemble the valve rod assembly.

**8.3.6.3** Secure plunger in plunger vise. Tighten valve rod assembly and traveling cage to plunger.

**8.3.6.4** Insert ball and seat in cage and assemble seat retainer.

**8.3.6.5** Back up traveling valve cage and tighten seat retainer.

**8.3.6.6** Clean and lubricate pump barrel.

**8.3.6.7** Lubricate plunger assembly with a good light grade of motor or turbine oil.

**8.3.6.8** Secure pump barrel in proper vise blocks and tighten extensions at both ends.

**8.3.6.9** Change vise blocks to fit pump barrel extensions and proceed with assembly.

**8.3.6.10** Insert plunger assembly into barrel and stroke full length. Travel should be smooth throughout.

**8.3.6.11** With plunger and valve rod assembly inserted into barrel, secure pump barrel in friction vise and tighten top hold down or guide and connector assembly.

**8.3.6.12** Push valve rod completely in until clutch coupling engages rod guide.

**8.3.6.13** Check lower end of pump barrel and be sure plunger seat retainer is no more than 2 in. from bottom of barrel. If plunger assembly is more than 2 in. off bottom, it is recommended the rod be replaced with one longer. If plunger assembly is less than  $\frac{1}{4}$  in. off bottom, valve rod should be shortened.

**8.3.6.14** Install standing valve cage to pump barrel and tighten.

**8.3.6.15** Install standing valve ball and seat.

**8.3.6.16** Assemble standing valve seat retainer or bottom hold down assembly.

**8.3.6.17** Back up standing valve cage and tighten seat retainer of hold down.

**8.3.6.18** Check for proper functioning of the valves by attaching a vacuum gauge to the standing valve and pulling on the valve rod (Figure 50, page 42). The manufacturer's recommendations and test parameters should be used as controls for this test.

**8.3.6.19** Pull valve rod out again to insure smooth travel. Measure and record full length of free stroke (Figure 51, page 42).

**8.3.6.20** Tie valve rod assembly to top guide, wrap each of pump assembly and tag as complete with required customer information (Figures 52 and 53, both on page 43).

Table 9 will indicate the approximate tightness pump fittings should be made up to.



Figure 50

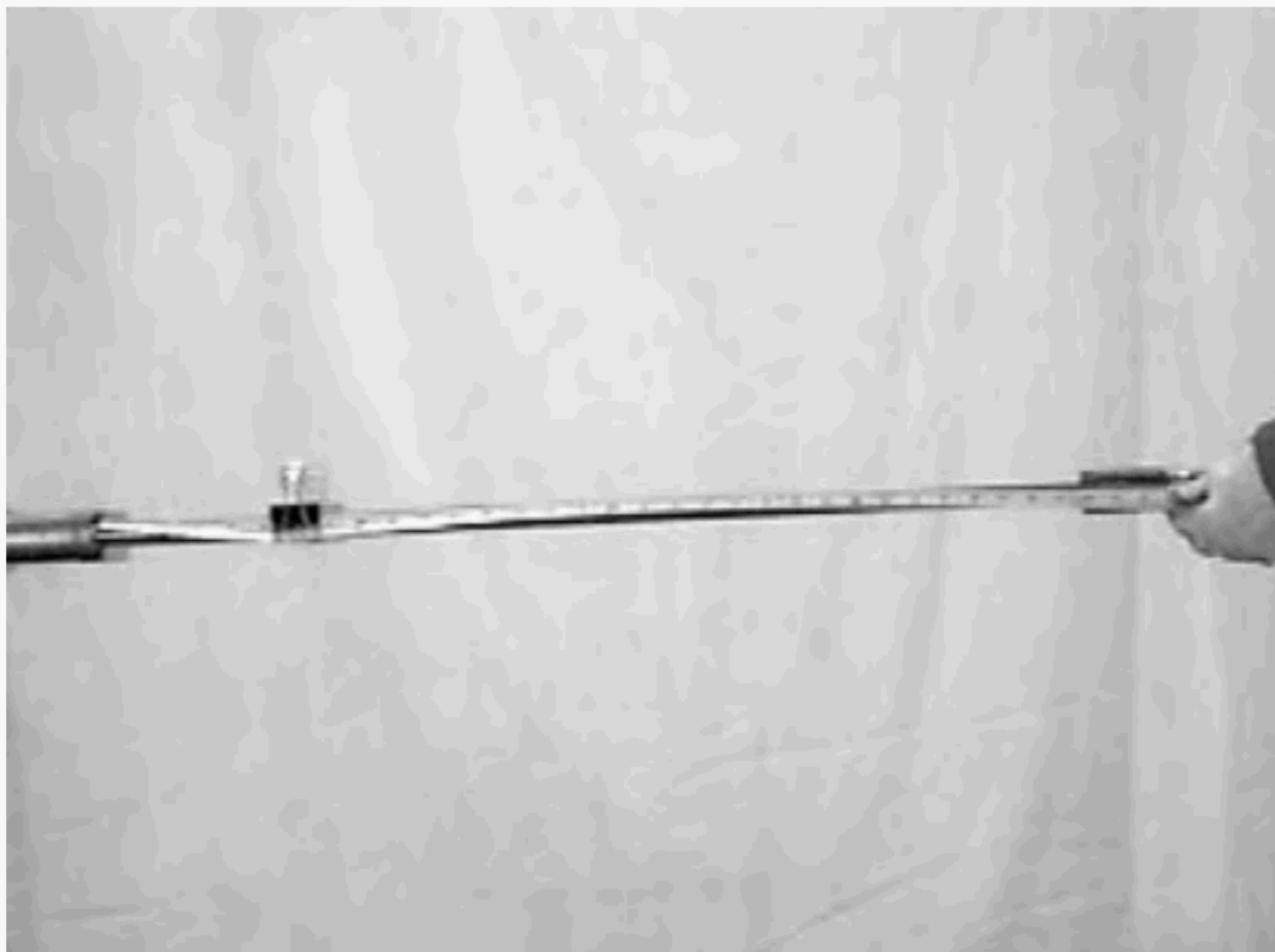


Figure 51



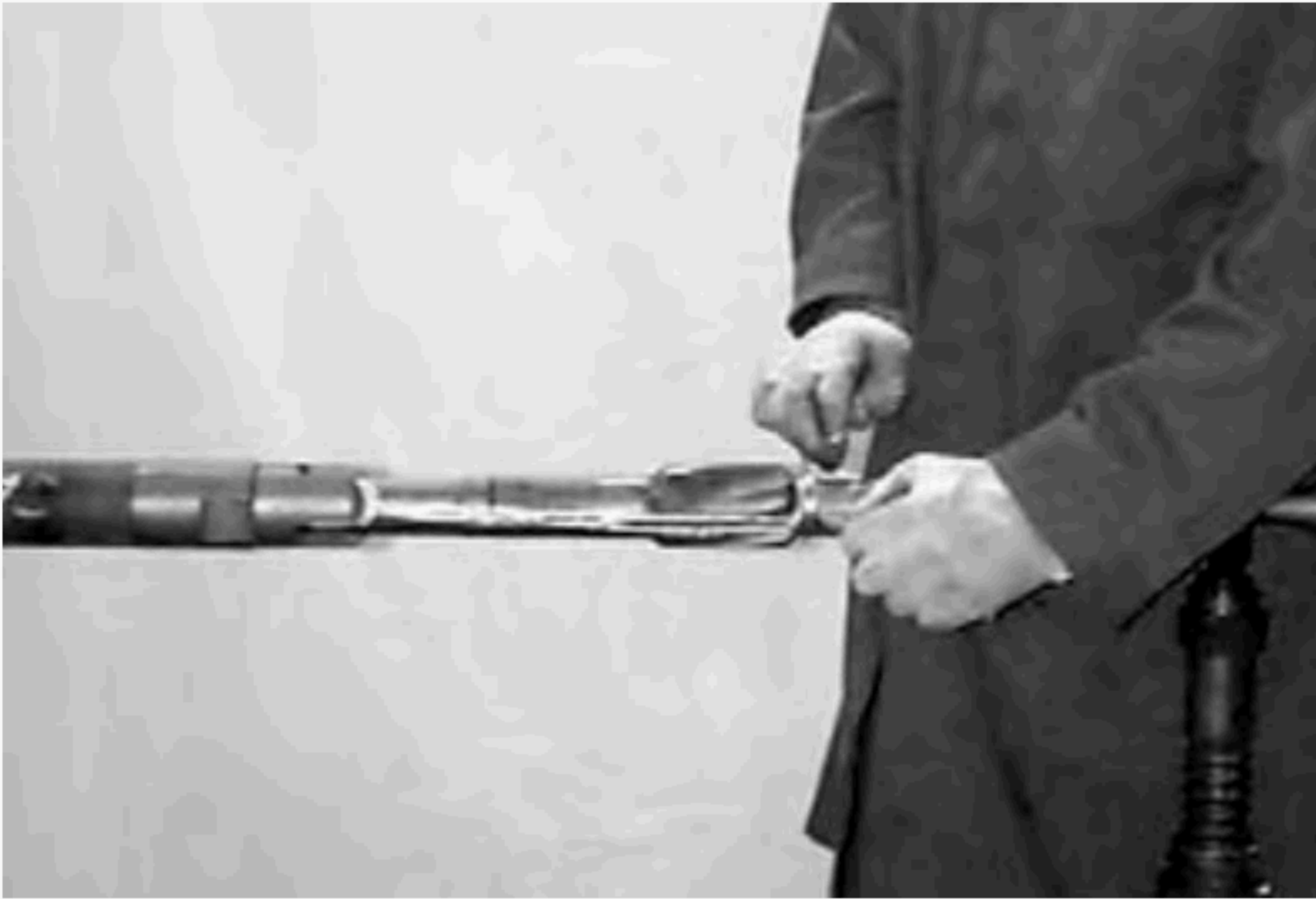


Figure 52



Figure 53



Figure 54

### 8.3.7 Disassembly of RHT or RWT Insert Pump

**8.3.7.1** Thoroughly clean the outside of the pump assembly (Figure 16, page 24).

**8.3.7.2** Select proper vise blocks to fit OD of pump barrel or barrel extension and secure pump in vise (Figure 17, page 25).

**8.3.7.3** Back up top connector to cage, loosen and unscrew the top-traveling valve cage.

**8.3.7.4** Remove traveling valve ball and seat.

**8.3.7.5** Tighten vise block sufficiently to hold RW barrel or extension, or back up same with proper size friction-grip wrench and loosen top connector.

**8.3.7.6** Carry out same procedure and loosen lower barrel or extension plug.

**8.3.7.7** Back up nut on mechanical hold down and loosen mandrel and seating ring.

If cup hold down is used, back up seating mandrel, loosen and remove all cups, rings, nuts and couplings. Discard all used seating cups.

**8.3.7.8** Back up lower pull tube coupling and break out mechanical hold down bushing or cup hold down seating mandrel.

**8.3.7.9** Select proper size friction-grip wrench. Back up pump pull tube and unscrew lower pull tube coupling.

**8.3.7.10** Remove plunger and pull tube assembly from pump barrel. Clean completely.

**8.3.7.11** Select proper vise blocks to fit plunger and secure plunger in vise.

**8.3.7.12** Loosen and remove standing valve cage.

**8.3.7.13** Remove standing valve ball and seat.

**8.3.7.14** Back up lower plunger to pull tube coupling and loosen.

**8.3.7.15** While holding plunger securely, loosen and remove pull tube assemblies.

**8.3.7.16** Clean all parts thoroughly (Figure 24, page 28).

### 8.3.8 Inspection of Components

**8.3.8.1** Bottom “heavy duty” hold down.

- Inspect body face and seating surface of brass or stainless steel ring and locking angle (prongs).
- If seating surface is pitted, worn or fluid cut—replace (Figure 25, page 29).
- If locking mandrel shows wear—replace.

**8.3.8.2** Alternate cup hold down.

- Completely disassemble hold down and all seating cups.
- Inspect all threads and cup faces for corrosion or erosion.
- Replace worn parts.
- Replace all seating cups.

**8.3.8.3 Valves Inspection.**

a. Vacuum test in accordance with API Spec 11AX for removed balls and seats. If leakage occurs and unit cannot be lapped—replace (Figure 26, page 30).

**8.3.8.4 Cages, connectors and extension inspection.**

- a. Inspect ball guides of all cages. If ball guides inside of cages are worn or deformed to where less than  $\frac{2}{3}$  of the original thickness remains, the cage should be considered for replacement (Figures 27, page 30, and 28, page 31).
- b. Inspect all extension faces, both external and internal.
- c. Inspect all faces, threads and general condition of all bushings, couplings, and pull tubes, if worn or damaged—replace (Figures 29 and 30, both on page 31).

**8.3.8.5 Barrel Inspection.** The cumulative total of plunger and barrel wear should be considered when evaluating individual replacement.

- a. Clean barrel thoroughly removing all oil, wax, sand, gip, or scale (Figure 34, page 32).
- b. Dial bore gauge ID of pump barrel to detect if worn or if questionable looking areas indicate extra wear (Figures 35, page 32, and 36, page 33).
- c. If gauged wear area reflects .005 in. more than nominal ID—barrel should be considered for replacement.
- d. Check all threads and faces for corrosion, galling, and fluid cut. Replace as necessary.

**8.3.8.6 Plunger Inspection.** The cumulative total of plunger and barrel wear should be considered when evaluating individual replacement.

- a. Thoroughly clean inside and out.
- b. Inspect OD surface and caliper with OD micrometer (Figure 37, page 33).
- c. If OD wear is .002 in. to .003 in. under original plunger fit over most of its length, the plunger should be considered for replacement. The cumulative total of plunger and barrel wear should be considered when evaluating individual replacement.
- d. Sand scores, grooves, pits, galling or wearing off of surface coatings indicate plunger replacement (Figure 38, page 34).
- e. Check threads on both ends for galling or corrosive action and replace plunger, if necessary.
- f. Check carefully ID of plunger for corrosion or erosion and replace, if necessary.
- g. Check the straightness of the plunger in accordance with the manufacturer's recommendations and tolerances for straightness (Figure 39, page 34). If the plunger is out of tolerance, discard the plunger or straighten it in accordance with the manufacturer's recommended method.

**8.3.9 Assembly of RHT or RWT Insert Pump**

Use good thread compound on all threads (Figure 43, page 36).

**8.3.9.1** Secure plunger in pump vise. Assemble standing valve cage with ball and seat and tighten.

**8.3.9.2** Assemble pull tube coupling to plunger and tighten.

**8.3.9.3** Back up pull tube coupling. Assemble and tighten pull tube to coupling with proper size friction grip wrench.

**8.3.9.4** Secure pump barrel in pump vise.

- a. If RH barrel is used, assemble and tighten extensions to barrel tube.
- b. Change vise blocks to fit barrel extensions and secure pump in vise.

**8.3.9.5** Clean and lubricate pump barrel.

**8.3.9.6** Lubricate plunger assembly with a good light grade motor or turbine oil.

**8.3.9.7** Insert plunger assembly into barrel and stroke full length. Travel should be smooth throughout.

**8.3.9.8** With barrel extension secured in pump vise or backed up with friction grip wrench, assemble lower pull plug and tighten.

**8.3.9.9** Select proper friction grip wrench and back up lower end of pull tube coupling and tighten.

**8.3.9.10** Back up pull tube coupling, assemble hold down mandrel or HD hold down bushing and tighten.

**8.3.9.11** Back up HD hold down bushing or cup hold down mandrel, assemble seating ring (metal) and mandrel—or seating cups, rings and lock nut and tighten.

**8.3.9.12** For cup hold down, back up seating cup nut after proper torque has been applied, seating the cups. Assemble bottom coupling and tighten.

**8.3.9.13** Again stroke plunger assembly to ensure smooth travel. Measure and record full free stroke (Figure 51, page 42).

**8.3.9.14** Secure top barrel extension in pump vise or friction grip wrench. Assemble top barrel connector and tighten.

**8.3.9.15** Back up top barrel connector. Assemble traveling valve cage with ball and seat and tighten.

**8.3.9.16** Check for proper functioning of the valves by attaching a vacuum gauge to the standing valve and pulling on the valve rod.(Figure 50, page 24).The manufacturer's recommendations and test parameters should be used as controls for this test.

**8.3.9.17** Tie pull tube assembly to pump barrel assembly, wrap each end of pump assembly and tag as complete (Figures 52 and 53, both on page 43).

Table 9 will indicate the approximate tightness pump fitting should be made up to.



## 8.4 TUBING PUMP

### 8.4.1 Disassembly of TH or TP Pump

#### 8.4.1.1 Barrel assembly.

- a. Thoroughly clean outside of pump assembly (Figure 16, page 24).
- b. Select proper pump vise block and support pump in blocks.
- c. Back up lower extension, coupling, loosen and remove seating nipple. In case of TP pump, back up lower barrel coupling and remove seating nipple.
- d. Back up lower extension nipple, loosen and remove lower extension coupling.
- e. Back up lower barrel coupling, loosen and remove lower extension nipple.
- f. Back up upper extension nipple, loosen and remove upper extension coupling.
- g. Back up upper barrel coupling, loosen and remove upper extension nipple.
- h. Secure pump barrel in pump vise blocks, loosen and remove both upper and lower barrel couplings.
- i. Clean all parts thoroughly (Figure 24, page 28).

#### 8.4.1.2 Plunger and standing valve assembly.

- a. Select proper plunger vise blocks.
- b. Using machinist vise or proper wrenches, loosen hold down assembly from standing valve cage.
- c. Remove ball and seat.
- d. Back up hold down bushing and loosen hold down mandrel and seating ring.
  1. In case of cup hold down, back up cup mandrel, loosen and remove all nuts, cups and rings. Discard all used seating cups.
- e. Secure plunger in vise blocks or back up top plunger bushing, loosen and remove top plunger cage. Remove ball and seat, if applicable.
- f. Back up lower plunger cage or bushing and remove puller plug.
- g. Secure plunger in vise blocks or back up lower plunger bushing, loosen and remove lower plunger cage, if applicable. Remove ball and seat, if applicable.
- h. For cup plunger assemblies, back up top plunger bushing, loosen and unscrew lower plunger bushing and plunger nut.
- i. Remove all rings, cups or packing. Discard all used cups and composition rings and packing units.
- j. Thoroughly clean all parts.

### 8.4.2 Inspection of All Component Parts

**8.4.2.1** Barrel Assembly. The cumulative total of plunger and barrel wear should be considered when evaluating individual replacement.

- a. Inspect ID and threads of seating nipple.
- b. If seating surface is fluid cut, pitted or threads are bad, replace.

1. In case of cup type seating nipple, ID should be smooth and free from scores or corrosion.

c. Inspect all threads of upper and lower extension couplings for damaged or galled threads. If questionable, replace (Figures 32 and 33, both on page 31).

d. Inspect barrel couplings. TH barrel coupling should have smooth inside shoulder faces and good threads. Replace if either is bad.

1. TP barrel coupling being tapered threads should have good threads on both ends. Replace if fluid-cut, galled, or corroded.

e. Clean barrel, removing all oil, wax, sand, scale or gip (Figure 34, page 32).

f. Check ID for scores or wear in excess of .005 in. over nominal replacement should be considered.

g. Check barrel faces. Both ends should be smooth and free of cuts or corrosion. Replace, if questionable.

1. In case of TP barrel, ID should be smooth. If the wall is in excess of .010 in. more than nominal barrel should be replaced.

h. In case of chrome-plated ID barrels, make sure there are no deep scores or pits in chrome surface.

i. Once parts are cleaned and inspected, or replaced and cleaned, lightly lubricate with light motor or turbine oil.

j. Inspect all balls and seats. Vacuum test and replace, if necessary (Figure 26, page 30).

k. Inspect all cages for wear, bad threads, faces and ball guides. If ball guides inside of cages are worn or deformed to where less than  $\frac{2}{3}$  of the original thickness remains, the cage should be considered for replacement (Figure 27, page 30, and 28, page 31).

l. Inspect seating ring of hold down. If scored, pitted, or fluid-cut, replace (Figure 25, page 29).

1. For cup hold down, inspect all faces and threads of hold down components. Replace, as necessary.

m. Inspect all threads of connecting tubing couplings, if threads are fluid cut or worn, replace.

n. Inspect all ID of extension nipples for erosion or corrosion. Replace as necessary.

### 8.4.3 Assembly of TH or TP Pump. Use Good Grade of Thread Compound (Figure 43).

#### 8.4.3.1 Secure pump barrel in proper pump vises.

**8.4.3.2** Attach and tighten both upper and lower barrel couplings.

**8.4.3.3** Back up lower barrel coupling, attach and tighten lower extension nipple.

**8.4.3.4** Back up tightened nipple, attach and tighten lower tubing coupling.

**8.4.3.5** Back up lower tubing. Attach and tighten seating nipple.

**8.4.3.6** Back up upper barrel couplings, attach and tighten upper extension nipple.

**8.4.3.7** Back up upper extension nipple, attach and tighten top tubing coupling.

**8.4.3.8** Lubricate ID of barrel thoroughly.

**8.4.3.9** Select proper wrench or vise and secure hold down mandrel or bushing.

**8.4.3.10** Insert ball and seat into standing valve cage, assemble, and tighten to bushing or mandrel.

a. If cup hold down, assemble new seating cup, reassemble seating rings. Tighten cup nut with sufficient torque to seat cups. Lock cup nut in place with lower bushing.

b. If mechanical hold down is used, assemble new metal ring to mandrel, assemble and tighten to bushing.

**8.4.3.11** Secure plunger in pump vise, insert ball and seat in top cage if applicable, or assemble both upper and lower cages to plunger and tighten securely.

a. If cup plunger is used, back up top plunger bushing and attach top cage as above.

b. Assemble all new cups or rings, tighten with sufficient torque to properly seat cup.

**8.4.3.12** If traveling ball and seat is housed in lower (blind) plunger cage—insert ball and seat, puller plug or seat retainer.

**8.4.3.13** Back up lower plunger cage and tighten puller plug or seat retainer.

**8.4.3.14** Lightly oil assembled standing valve and insert into pump barrel assembly.

**8.4.3.15** Lightly oil plunger assembly and insert into pump barrel assembly.

**8.4.3.16** Using a pony rod, of sufficient length, stroke plunger assembly through lubricated pump barrel several times. Travel must be smooth.

**8.4.3.17** Securely tie plunger assembly to barrel assembly—wrap both ends, tag as complete (Figures 52 and 53, both on page 43).

Table 9 will indicate the approximate tightness pump fittings should be made up to.

## 9 Care and Handling of Subsurface Pumps

**9.1** When storing subsurface pumps certain precautions must be taken to prevent damage to the pump. The ends of the pump must be sealed to exclude any outside influence that may affect the precision components inside the pump. Some examples of outside influences are foreign particles, such as blowing sand or dirt, rain, high humidity, and/or insects building nests. The pump should be supported at no more than eight foot (8') intervals to prevent bowing of the pump barrel.

While this applies to all pumps, it is especially important for metal-to-metal pumps, otherwise the precision fit between the plunger and the barrel may be destroyed. Pumps should be stored horizontally and placed in single layers.

**9.2** When transporting subsurface pumps, it is essential to prevent mechanical damage caused by bending, denting, dropping or contacting other hard objects. Subsurface pumps give the impression of being strong like tubing, but slight flexure can result in permanent damage and/or misalignment due to their relatively thin wall sections. When transporting pumps longer than sixteen feet (16') on truck or car side racks, it is important to provide alignment supports in no more than eight foot (8') increments. Pumps longer than twenty four feet (24') should be transported on a flat bed trailer or disassembled into shorter sections. Excessive overhang of the pump ends should be avoided when transporting pumps on truck or car racks. The maximum unsupported length should be no longer than three feet (3') at each end. Pumps should be secured to the transportation vehicle with non-metallic straps to prevent compression damage or excessive bouncing and/or movement fore and aft. Parts of the pump that can move or "scope out" should be tied with twine or some other sufficiently strong material to prevent their moving during transportation. When transporting pumps with other equipment, it is desirable to use special containers or crating to separate the items and prevent damage.

**9.3** In handling long pumps 16 ft and longer, it is particularly important that they be properly supported to prevent damage. Extra care should be exercised in handling or transporting thin wall barrel pumps to prevent bending or denting.

**9.4** All pump openings should be wrapped or protected against entry of foreign material that may damage the highly finished sealing surfaces of the pump.

**9.5** When transporting or handling subsurface pump parts, precaution must be taken to prevent damage to highly finished surfaces, seal faces, threads, and so forth.

**9.6** Extreme care must be exercised in picking up a pump for running into the well. The use of a lifting sub (pony rod) will greatly facilitate this operation. Special handling is required for assembled pumps more than 30 ft in length. It is preferable that these be broken down and assembled vertically at the wellhead. If vertical assembly is not possible, it is imperative a sling device be used to support the middle pump section while raising assembly to the vertical position.

**9.7** A final inspection should be made before running the pump into the well to assure that all caps, plugs, or protective wrappings have been removed.

**9.8** The use of a sucker rod guide located as close as practical to the pump will help maintain alignment of pump in relation to the tubing and reduce pump wear.



## 10 Recordkeeping

**10.1** A pump performance or maintenance record system should be kept to optimize pump design in the various fields or environments. This is an ideal application for computerizing the records for fast comprehensive evaluations.

**10.2** Other methods that can be used include:

- a. Keeping performance or maintenance records on several pumps with different metallurgies used in a similar environment by comparing their initial and repair costs and service life.
- b. Dividing pump maintenance or servicing in a field between several companies and comparing costs between these firms.

**10.3** These last two methods are not as comprehensive and effective as complete maintenance records, but used properly, can result in substantial cost savings and longer pump operation.

**10.4** The API Sucker-Rod Pump Repair/New Pump Log Form (Figures 55 and 56) is designed to provide the neces-

sary information to enable the end user and the manufacturer to:

- a. Track the life of the pump with the use of the pump control number.
- b. Determine which part is actually causing the failure by using the pump-fail code.
- c. Determine the reason for pulling the pump by using the pull code.
- d. Record the new parts and the old parts used in the pump.
- e. Keep a record of wear on the plunger and barrel tube.
- f. Determine the life of the parts by recording the proper dates.
- g. Make well calculations with the pertinent well and installation data recorded in the shaded area of the form.

The form consists of three categories. On the front side (Figure 55), the white area contains the data pertinent to each pump repair. The shaded or grey area is the background information on the well and needs to be recorded only once or whenever a change is made. The reverse side of the form (Figure 56) is dedicated to a tabulation of the various codes.

The pump form is very comprehensive. It should be recognized, however, if the form is properly filled out, information will become available to both the user and manufacturer that will enable the industry to identify and to correct pump problems through the building and subsequent interpretation of a data base.



Log No.: \_\_\_\_\_ Cast. Acct. No.: \_\_\_\_\_ Repair Date: \_\_\_\_/\_\_\_\_/\_\_\_\_ Job No.: \_\_\_\_\_

Operator: \_\_\_\_\_ Store Doing Repair Work: \_\_\_\_\_

Lease &amp; Well: \_\_\_\_\_ Field/District/Other: \_\_\_\_\_

Pump Designation (API & non-Std):  -     -  -  -  Pump Control No.:

Install Date:    /    /         In Shop Stroke        in.      Solid Pull Rod?             Cast. Serial No.:                        

Fail Date: \_\_\_\_ / \_\_\_\_ / \_\_\_\_      Into Shop: \_\_\_\_ / \_\_\_\_ / \_\_\_\_      Reason for Failure: \_\_\_\_\_      Pump Fail Code: \_\_\_\_

Pull Date:   /  /   Out of Shop:   /  /   Reason for Pulling: \_\_\_\_\_ Pull Code:   

Pump Disposition: Repaired ☐ Junked ☐ Cleaned ☐ New ☐ | Pump Repair Authorized By: \_\_\_\_\_

[illegible]

Foreign Material Found in Pump	1	2	3	4	5	6	7	8
	Sand	Mud	Iron Oxide/ Sulfide	Rubber	Metal	Paraffin	Scale	Other _____

## New Parts Log

☐ Scrapped      ☐ New Parts Log[illegible]

Recommendations/Comments: \_\_\_\_\_

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Total Cost of Bonds: \$

\_\_\_\_\_ Total Cost of Repair \$ \_\_\_\_\_

Operator's Rep.: \_\_\_\_\_ Company's Rep. \_\_\_\_\_ Store No.: \_\_\_\_\_

County/Parish: \_\_\_\_\_ State/Prov. \_\_\_\_\_ Country: \_\_\_\_\_

Pumping Unit Type:	Pump Depth:	ft	Inhibitor:	None	Moder	Severe
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Conv. Improved Air Bal. Pump Depth: \_\_\_\_\_ ft. Inhibitor: \_\_\_\_\_ None Moder. Severe  
Fluid Level from Surf: \_\_\_\_\_ ft. H<sub>2</sub>S ☐ ☐ ☐

Pumping Speed: \_\_\_\_\_ SPM. Pump Vol. Effy. \_\_\_\_\_ % Time Clock: \_\_\_\_\_ %

Surface Stroke: \_\_\_\_\_ in. Water: \_\_\_\_\_ BPD Gas: \_\_\_\_\_ MCFPD Paraffin ☐ ☐ ☐

Plunger Travel: \_\_\_\_\_ in. | Oil: \_\_\_\_\_ BPD Oil Gravity: \_\_\_\_\_ °API Chlorides ☐ ☐ ☐

Rod String Design: _____	Spec. Grav. of Water: _____	Sand	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
	Temperature at Pump: _____	Coals	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

Tubing Size: \_\_\_\_\_ in Temperature at Pump: \_\_\_\_\_ °F Scale ☐ ☐ ☐

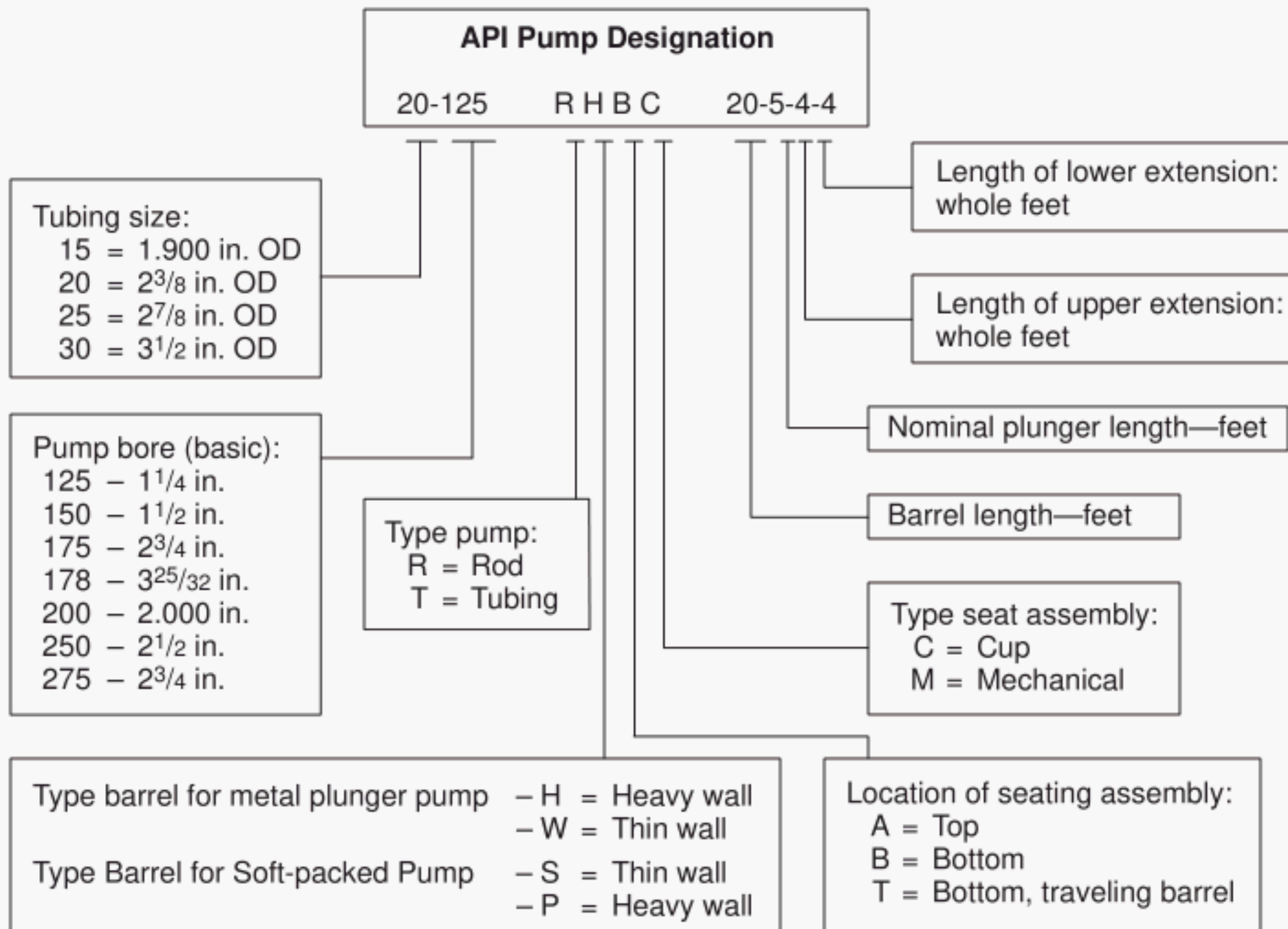
Casing Press.: \_\_\_\_\_ psi    Tubing Size: \_\_\_\_\_ in.    Anchored:    Yes ☐    No ☐

Figure 55—API Sucker Rod Pump Repair/New Pump Log

Unshaded area: Fill in for each pump repair.

Shaded area: Fill in only at start of program, for new well, or when change occurs.

### CODE FOR API PUMP DESIGNATION (EXAMPLE)



### Pump Control No.:

Use a number (7 characters max.) in this space. For example MID0087. Use this number until the entire pump is junked. This will provide a method to trace the pump and part life data from well to well.

Reason for Pulling Pump (Pull Code)	Cause of Failure (Pump Fail Code)	Pump Part Failure Codes (Parts Log Fail Code)
01 Production decline	00 None	00 None
02 Rod failure	10 Barrel—wear/abrasion	01 Break
03 Tubing failure	11 Barrel—split/crack	02 Corrosion—external
04 Resize pump	12 Barrel—hole	03 Corrosion—internal
05 Acidize well	20 Ball & seat—wear/abrasion	04 Hole
06 Frac well	21 Ball & seat—split/crack	05 Split or crack
07 Well work	22 Ball & seat—hole	06 Worn, deformed or collapsed
08 Abandon well	30 Cage—wear/abrasion	07 Fluid cut/leak/abrasion scored
09 Other (explain in comments)	31 Cage—split/crack	08 Gyp/scale
	32 Cage—hole	09 Galled
	33 Cage—thread failure	10 Unscrewed
	40 Plunger—wear/abrasion	11 Improper handling
	41 Plunger—split/crack	12 Exceeds dimensional tolerance
	42 Plunger—hole	13 Acid flaking
	43 Plunger—pin break	14 Pounding
	50 Pull tube—wear/abrasion	15 Thread damage
	51 Pull tube—split/crack	16 Assembly change
	52 Pull tube—hole	17 Other (explain in comments)
	53 Pull tube—thread failure	
	60 Flow restriction—scale	
	61 Flow restriction—mud	
	62 Flow restriction—paraffin	
	70 Sanded pump	
	71 Stuck plunger	
	72 Foreign material in pump	
	73 Improper handling	
	99 Other (explain in comments)	

Figure 56—API Sucker Rod Pump Repair Report

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