

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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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.

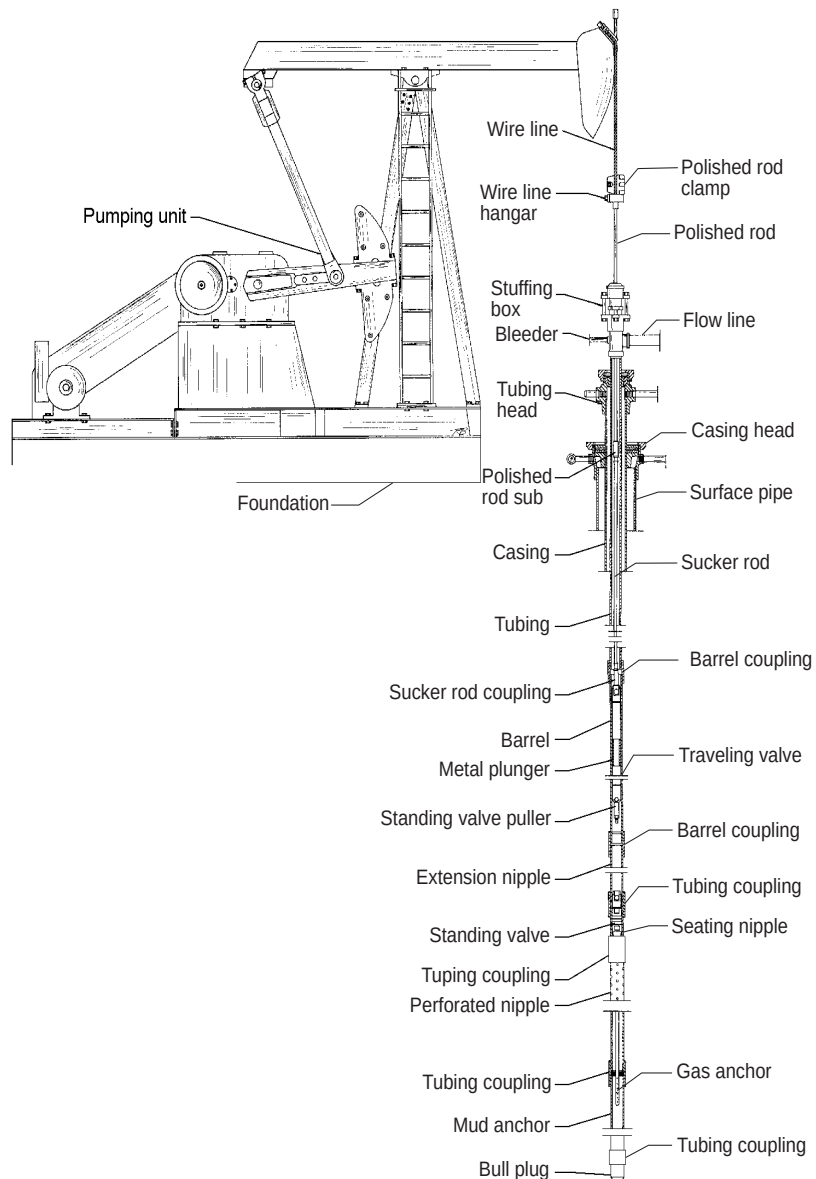


Figure 1—Pumping System

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 *Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties*
- Spec 11AX *Specification for Subsurface Sucker Rod Pumps and Fittings*

NACE

- Std MRO176 *Metallic Materials for Sucker Rod Pumps for Corrosive Oilfield Environments; National Association of Corrosion Engineers*

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 wall 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.

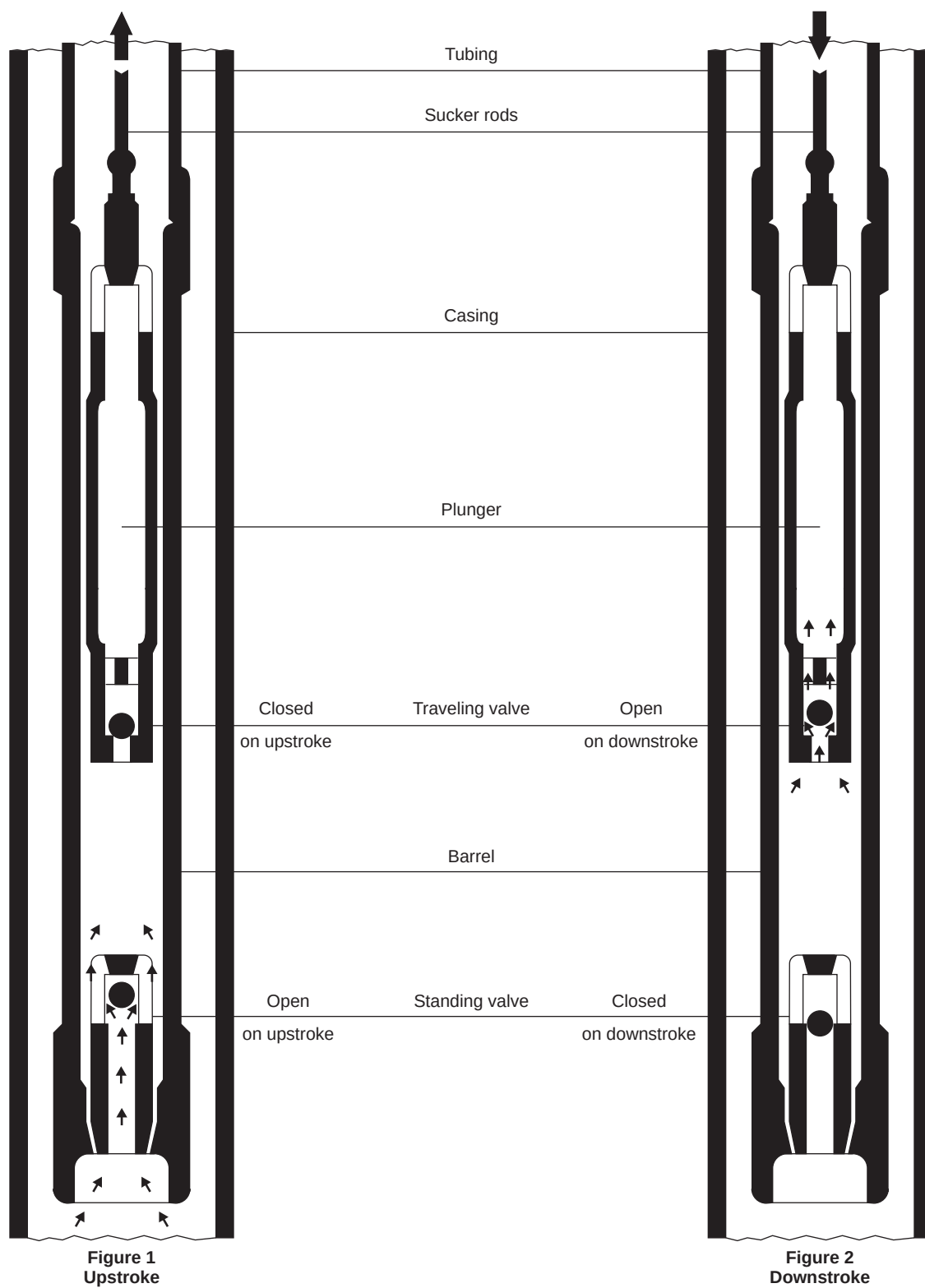


Figure 2—Operation of Tubing Type Pump

stroke loss may actually result in a lower net displacement than would be obtained with the smaller plunger of a rod pump. API RP11L calculations should be made on both the tubing pump and the rod pump to determine the optimum selection.

5.2 ROD PUMPS

5.2.1 Traveling Barrel Bottom Anchor Pump (Figure 4)

5.2.1.1 Advantages

- a. The movement of the traveling barrel keeps the fluid in motion and sand washed clear almost down to the seating nipple. This minimizes the possibility of sand settling around the pump and sticking it, causing a “wet” pulling job.
- b. The traveling barrel is particularly recommended for wells that are pumped intermittently. Because the ball in the top cage will seat when the well is shut down, sand cannot settle inside of the pump. This is important, since it is possible for even a small quantity of sand settling on top of the plunger of a stationary-barrel pump to cause the plunger to stick when the well again starts pumping.
- c. The sucker rod string connects directly to the top cage, which in turn connects to the pump barrel. This top cage is greater in diameter and stronger in construction than a plunger top cage, so the fluid on the upstroke is carried by stronger components than in a stationary-barrel pump.
- d. Both the standing and traveling valves on a traveling-barrel pump have open type cages. These are more rugged, have more fluid passage than blind cages, and are less prone to beat out from ball action.
- e. Due to equalized pressure on the outside of the barrel, a bottom-anchored pump (either traveling or stationary-barrel) has greater resistance to bursting than a top-anchored pump. In wells that pound fluid, or in wells where top-anchored pumps have experienced burst barrels, the traveling-barrel pump is a good application.

5.2.1.2 Limitations

- a. The traveling-barrel pump is at a disadvantage in wells that have a low static fluid level because of the greater pressure drop between the well bore and the pumping chamber. Since the standing valve is located in the plunger top cage on a traveling-barrel pump, it is smaller in diameter and uses a smaller ball and seat than would be used in the standing valve blind cage on a stationary-barrel pump.
- b. There is a relationship between pump length, well depth and pump bore that must be observed. When the standing valve (in the plunger top cage) is closed, a column load is transmitted by the plunger through the pull tube and seating assembly into the seating nipple. In a deep well, this load will be sufficient to put a bow in a long pull tube, thus setting up a drag between the pull plug and the pull tube.

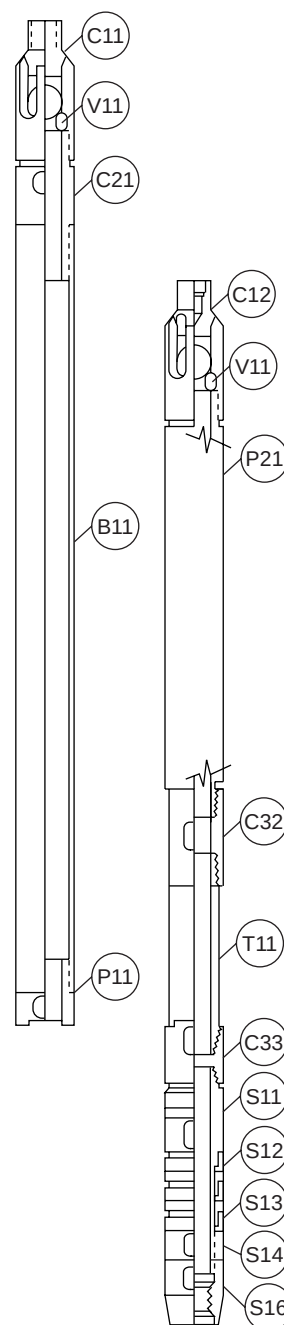


Figure 4—A Typical Traveling Barrel Pump
(See API Spec 11AX for Part Descriptions)

5.2.2 Stationary Barrel Bottom Anchor Pump (Figure 5)

5.2.2.1 Advantages

- a. 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.
- b. 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.
- c. 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.
- d. 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

- a. 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.
- b. 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

- a. 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.
- b. 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

- a. 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.

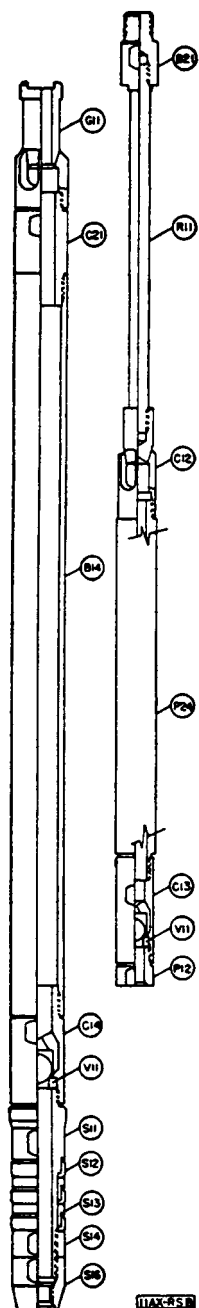


Figure 5—A Typical Stationary Barrel,
Bottom Hold Down, Pump
(See API Spec 11AX for Part Description)

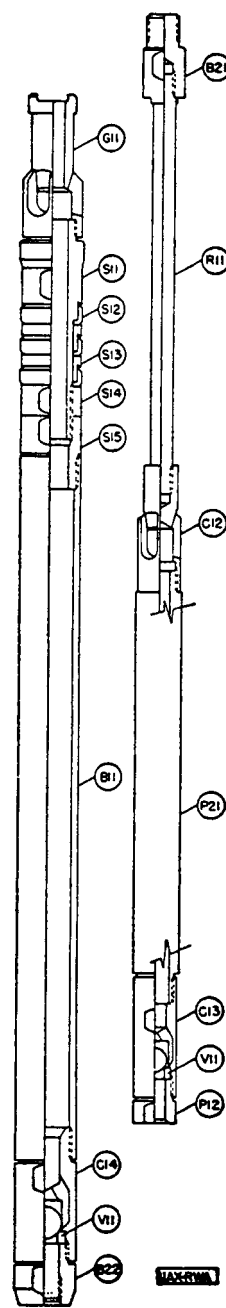


Figure 6—A Typical Stationary Barrel,
Top Hold Down, Pump
(See API Spec 11AX for Part Description)

Table 1—Pump Type Modes of Failure and Reference Figures

Type Pump	Failure Mode	Figure
A. Rod Insert Pumps		
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. Tubing Pumps (TH, TP)	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.

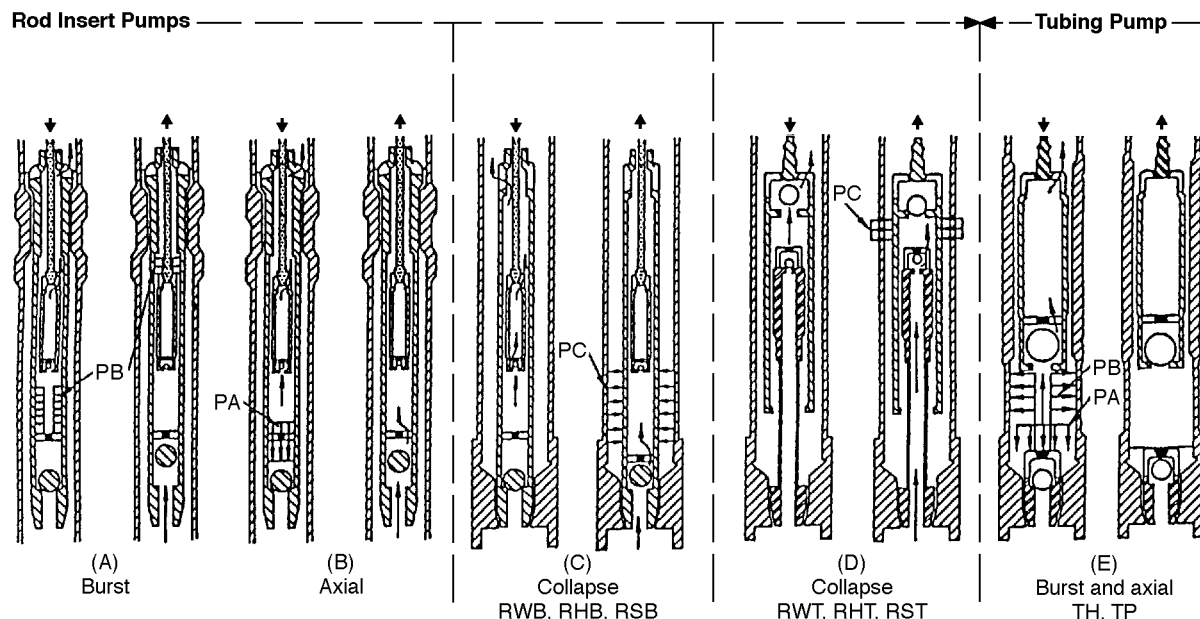


Figure 7—Subsurface Sucker Rod Pump Loading Configurations



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 (in²) = .785(D_i)²

A_t = Cross Sectional Area of Barrel or Extension Coupling at Thread Root (in²)

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

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

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 (in²)

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 to 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 (Su) should be substituted using suggested correction factors of 2.5 for steel & 3.0 for brass.

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

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

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:

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