Intermittent Gas Lift

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In order to understand the functions of intermittent gas lift, both continuous flow and intermittent flow should be defined.

Continuous flow constitutes the continual flow of liquids, associated gases, and injected lift gases to the surface. The injection of lift gas into the well or flow string may or may not be continuous. It is generally injected at a restricted rate. This is accomplished by a choke at the surface injection line, a choke in the operating gas lift valve, or a combination of the two.

Intermittent flow (commonly referred to as "slug flow") constitutes the flow of liquids, associated gases, and injected gases to the surface in the form of "slugs". These slugs are removed at intervals. Normally, gas is injected into the casing/tubing annular space by means of a time cycle controller. However, if fluid operated valves are being used for intermittent flow, the gas may be injected continually into the tubing/casing annular space at a restricted rate.

In most instances there will be no question as to whether or not a well should be placed on continuous flow or intermittent flow. However, there are cases of the so called "borderline well". Reference should be made to "The Power of Gas" by Mr. C. V. Kirkpatrick for a complete analysis of the borderline well. This procedure involves an analysis of injection pressure, injection gas/oil ratio and horsepower requirements.[1]

The following types of intermittent flow installations utilized in the field today are: 1. tubing flow with a packer only (semi closed installation), Fig. 1, 2. tubing flow with a packer and a standing valve (closed installation), Fig. 2, 3. tubing flow from a chamber (closed installation), Fig. 3, and 4. any one of the three preceding installations in combination with a "piston" or "plunger". (Fig. 4)

TYPE OF INSTALLATION

A choice as to the type of installation, as well as the type of intermittent valve, must be decided upon. Whether or not the valve is to be of the standard intermitting type, controlled spread type, or whether it is to be casing pressure opened or fluid pressure opened is subject to choice. A valve opened by fluid pressure is commonly called a fluid operated valve.

If a well has a high bottom hole pressure and a low P.I. (productivity index), a semi closed installation (packer without a standing valve) will be suitable. However, a landing nipple for a standing valve should be installed in the original design to facilitate placement of additional equipment at a later date.

If a well has a medium P.I., a closed installation (tubing packer and standing valve) will be satisfactory. It is sometimes difficult to determine whether or not a well should have a standing valve. A rather common field practice is to attempt to fill a well with its producing fluid. If the fluid reaches the surface a standing valve is not necessary; if the formation takes the fluid, a standing valve should be installed.

Low Bottom Hole Pressure

For low bottom hole pressure high P.I. wells, a chamber should be the choice. A chamber permits a maximum of fluid entry with a minimum of sand face back pressure. For example, assume that fluid entry rises approximately 1000 feet in tubing. If this fluid has a density of 9.6 lb/gal, and exerts a gradient of .50 psi/ft, the hydrostatic head of 1000 feet is 500 psi. This head, in turn, is acting on the sand face. If the same amount of fluid in a chamber rises only 100 feet, its hydrostatic head is only 50 psi. The advantages of a chamber are then evident.

Chambers are of two types. One is an insert chamber and the other is a two packer chamber. (Figs. 5 and 6) For wells that have multiple completion intervals or have open hole completions, the insert chamber is preferable. This is because the chamber can be inserted directly into the open interval and thus utilize the bottom hole pressure of the well to the fullest extent. A two packer chamber installation offers the advantage of more storage space per unit of height.

A piston or plunger should be considered in all intermittent installations. Efficiencies can be increased greatly by the use of pistons since it places a solid interface between the fluid slug and the gas.

TYPES OF FLOW VALVES

Intermittent flow valves can be divided roughly into three categories, namely 1. standard intermitting valves, 2. a valve in which the spread can be controlled with very small changes in seat size, and 3. fluid operated valves. These valves all employ the same basic operating elements but, due to differences in construction, exhibit different performance.

In order to establish the basic difference between a continuous flow valve and an intermittent valve, both valves will be described. The operating principles of these valves will be described best by a simple pressure operated valve incorporating a piston. It should be pointed out that various manufacturers of valves may incorporate different controlling elements in their valves such as the bellows, springs, etc. However, the basic operating principles will be essentially the same in most valves.

The Standard Intermitting Valve

The standard intermitting valve is shown in Fig. 7. The forces involved in the operation of this valve are as follows:

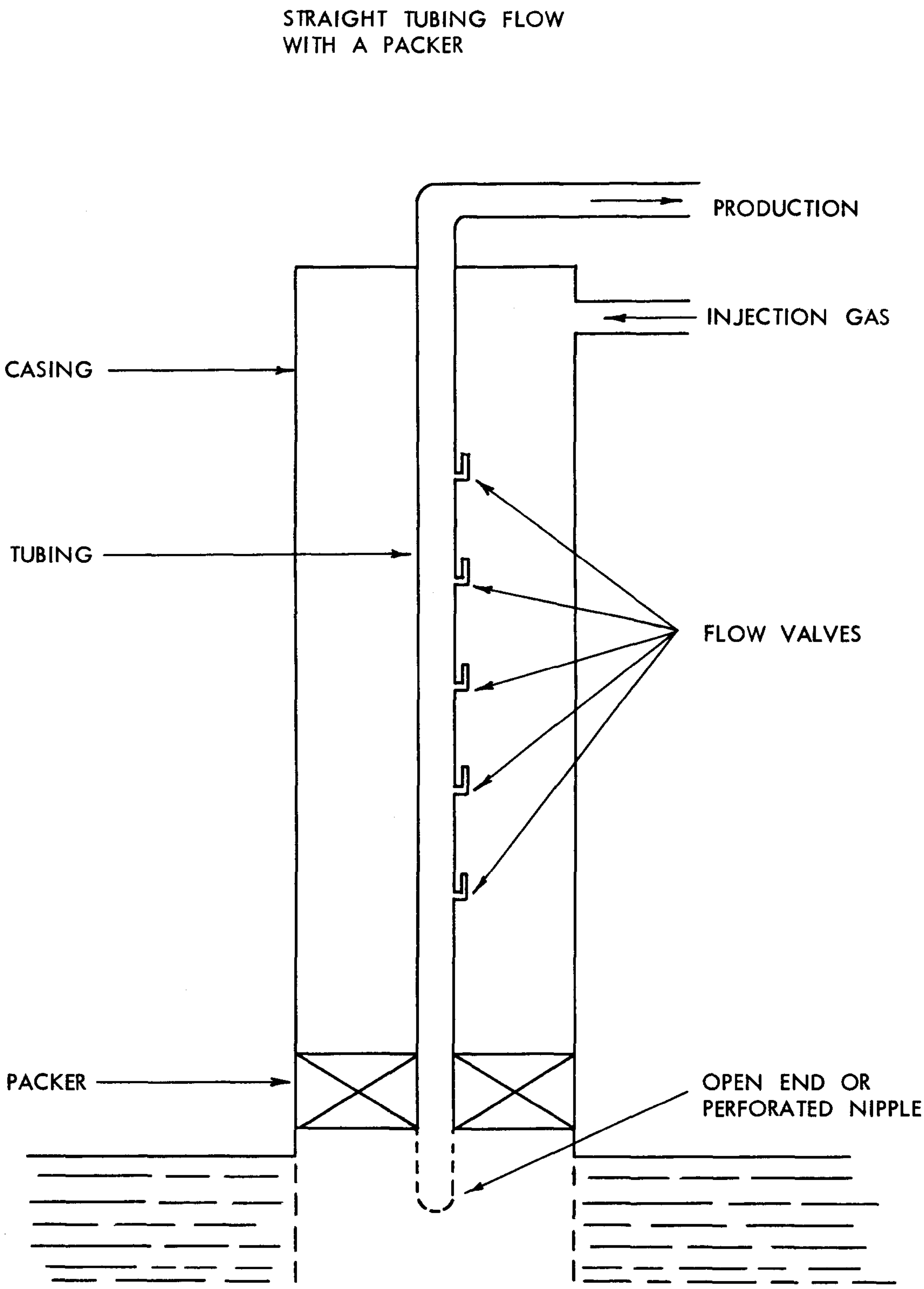

STRAIGHT TUBING FLOW
WITH A PACKER
PRODUCTION
INJECTION GAS
CASING
TUBING
FLOW VALVES
PACKER
OPEN END OR
PERFORATED NIPPLE

Fig. 1

STRAIGHT TUBING FLOW WITH A
PACKER AND STANDING VALVE

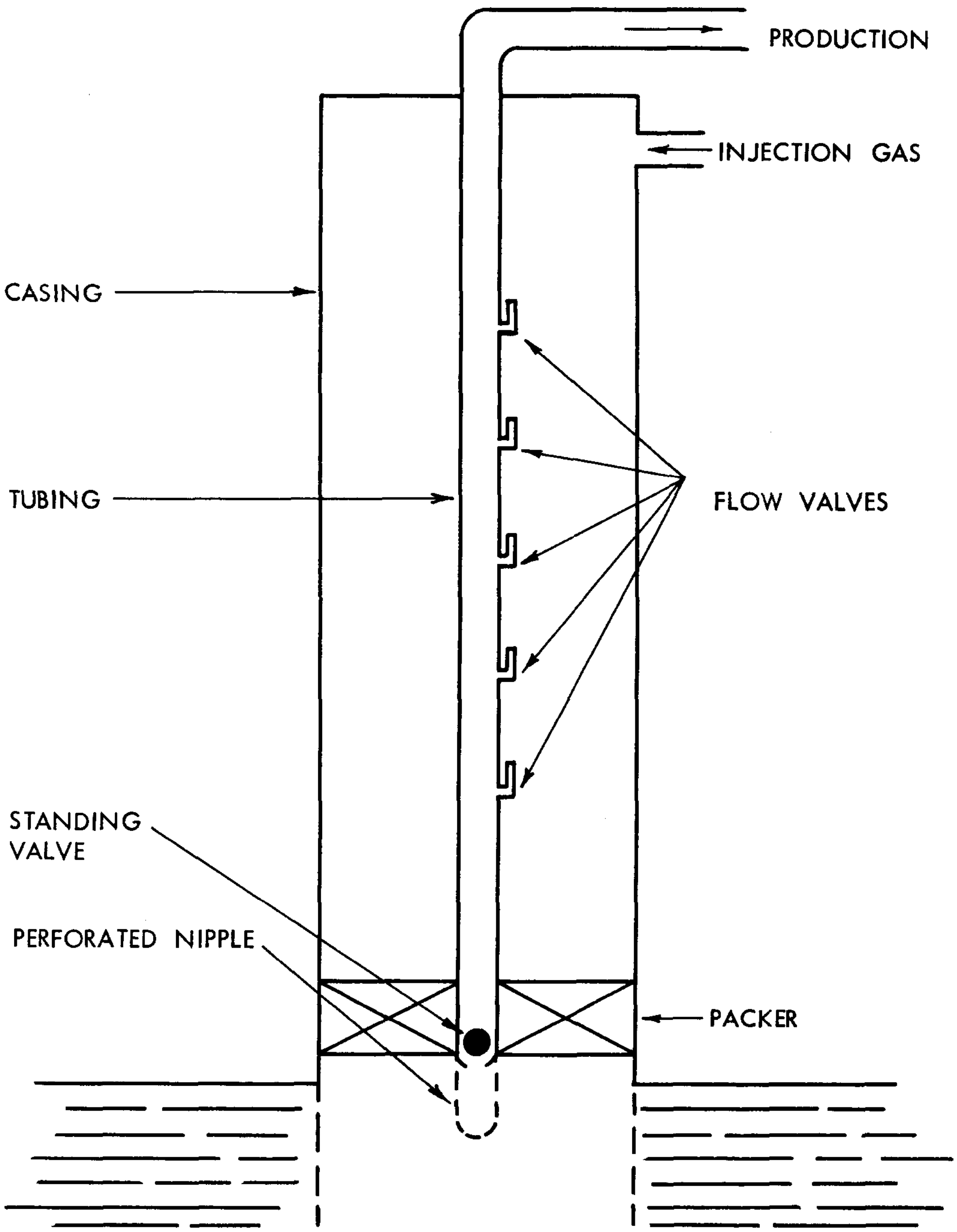


Fig. 2

TYPICAL CHAMBER INSTALLATION

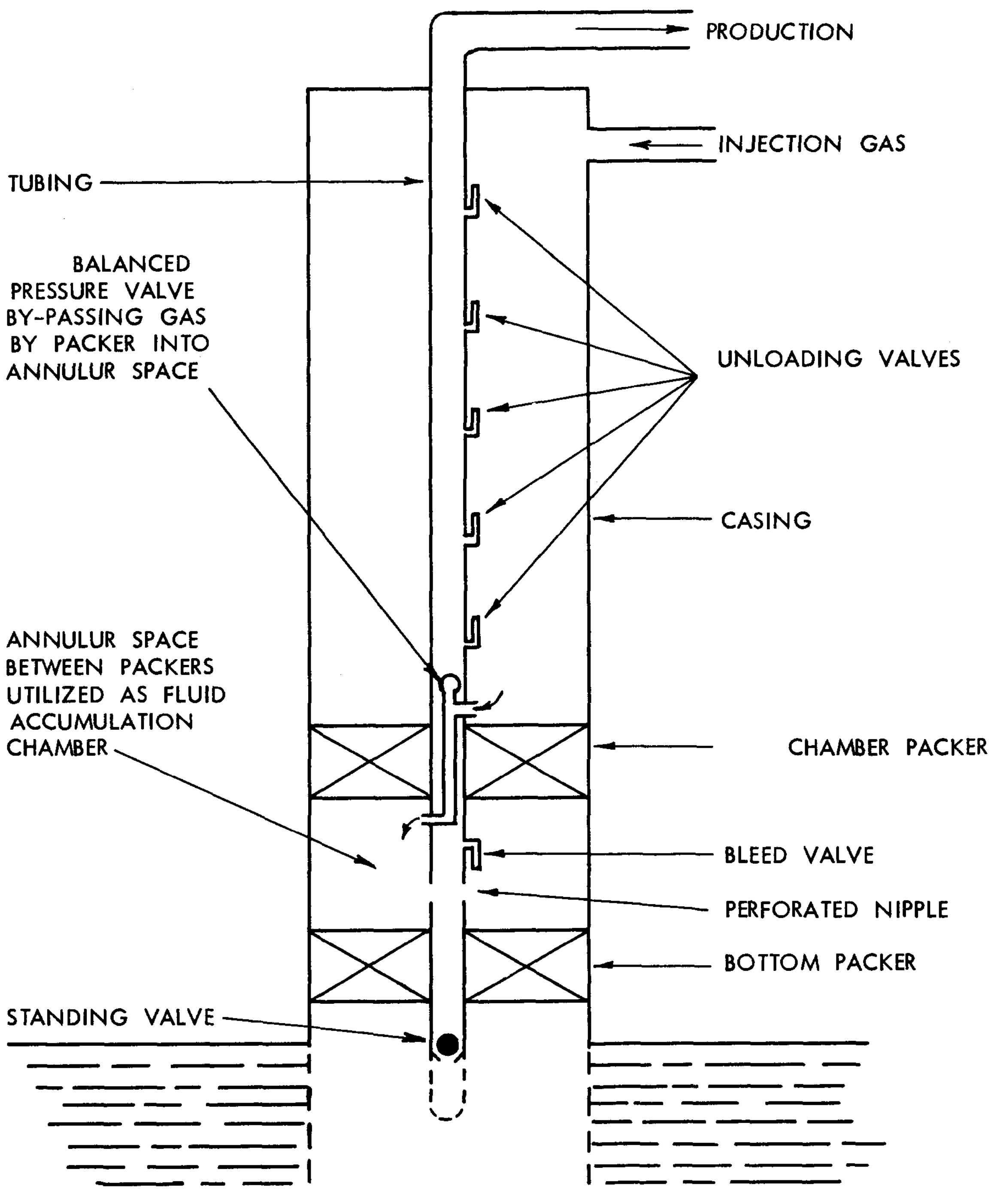


Fig. 3

STRAIGHT TUBING FLOW WITH A
PACKER, STANDING VALVE AND PISTON

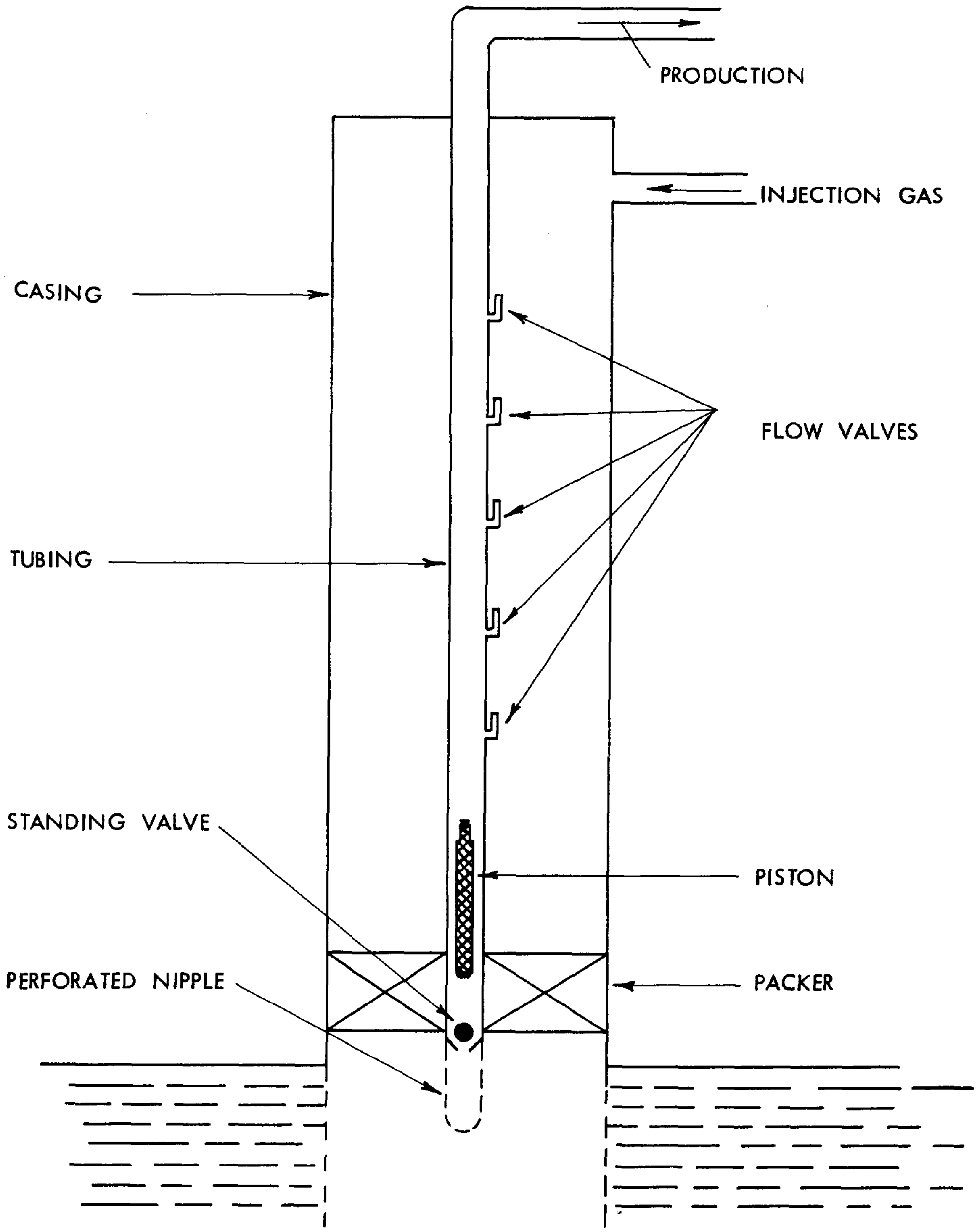


Fig. 4

TYPICAL INSERT CHAMBER INSTALLATION

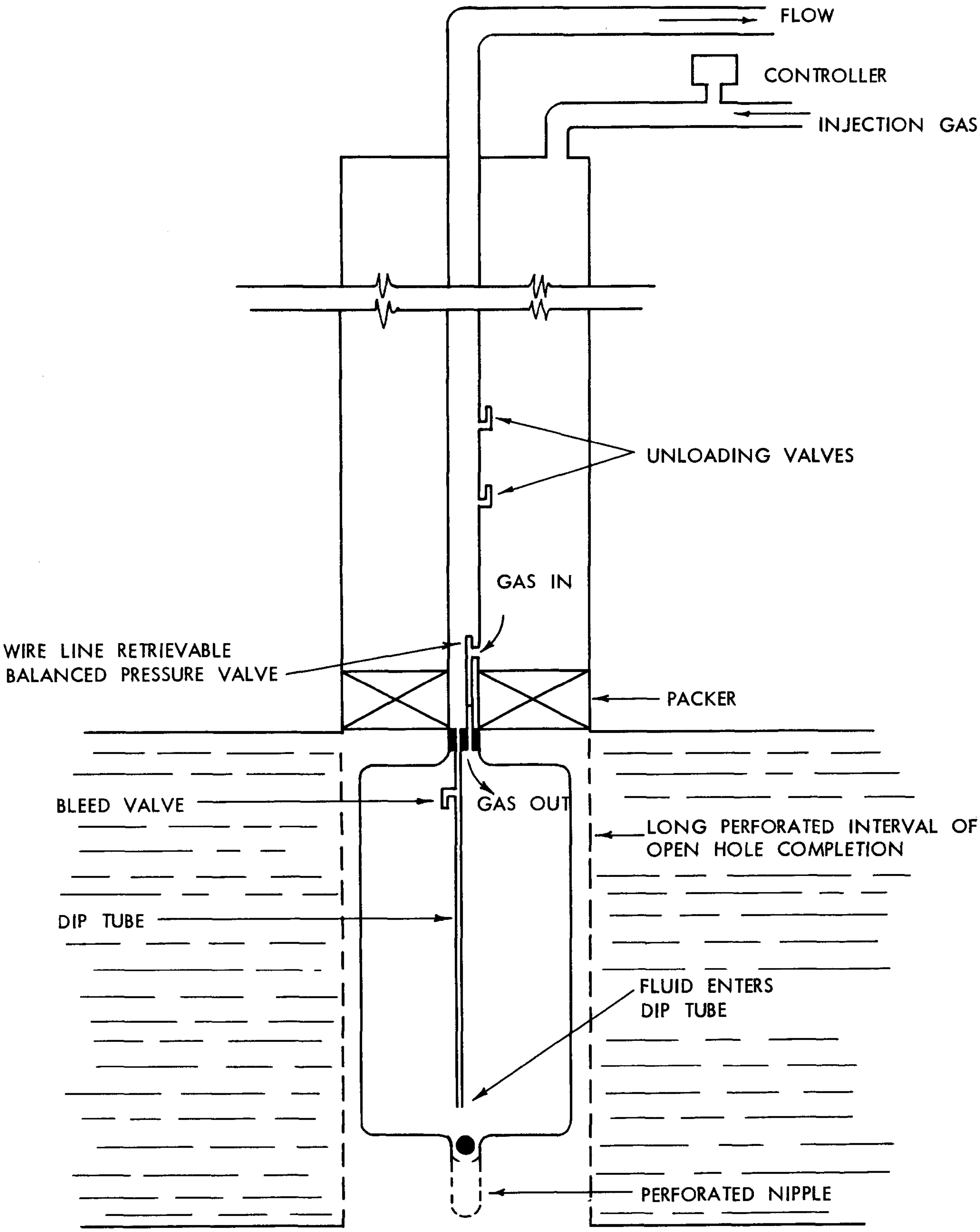
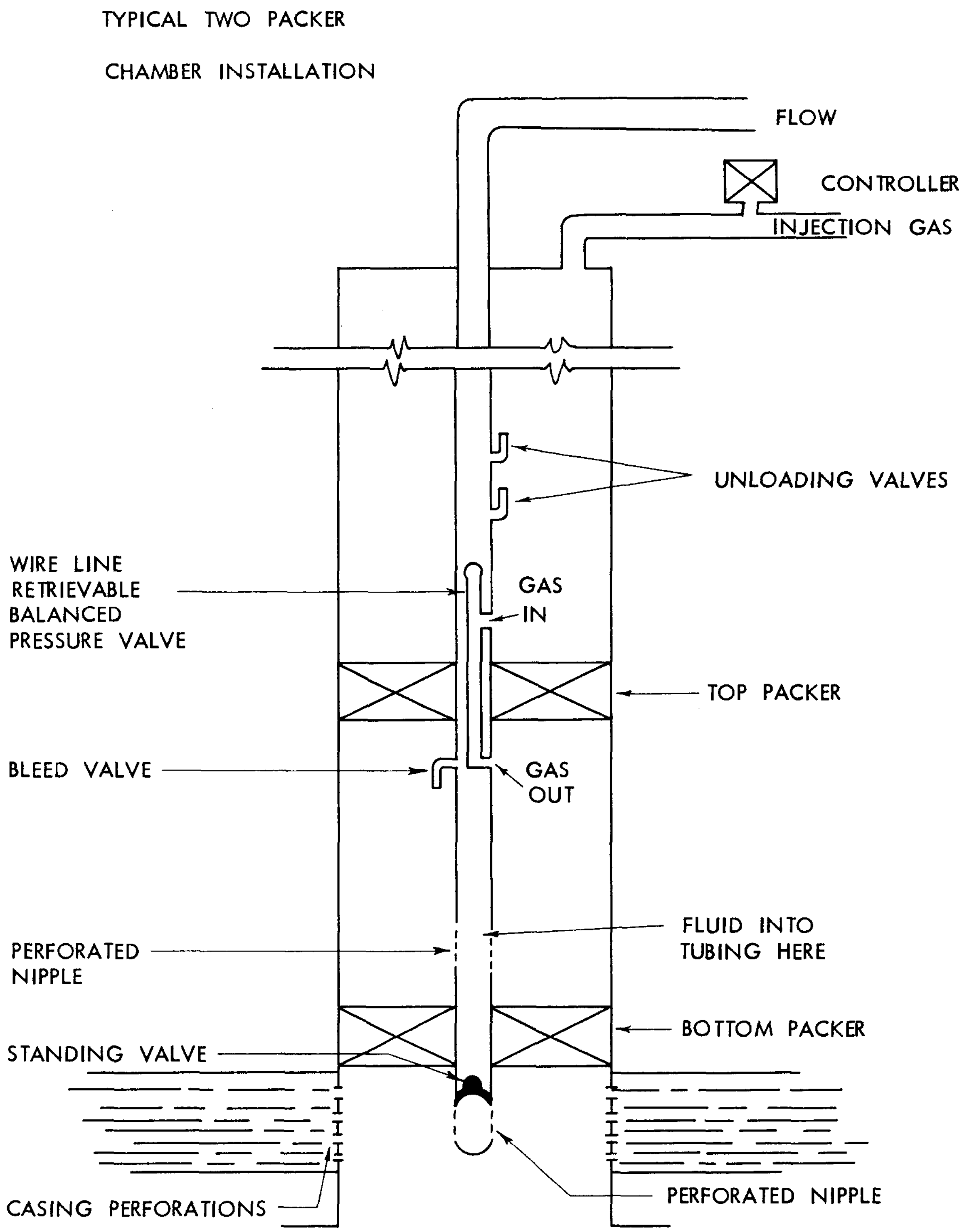


Fig. 5



TYPICAL TWO PACKER
CHAMBER INSTALLATION
FLOW
CONTROLLER
INJECTION GAS
UNLOADING VALVES
WIRE LINE
RETRIEVABLE
BALANCED
PRESSURE VALVE
GAS
IN
TOP PACKER
BLEED VALVE
GAS
OUT
FLUID INTO
TUBING HERE
PERFORATED
NIPPLE
BOTTOM PACKER
STANDING VALVE
CASING PERFORATIONS
PERFORATED NIPPLE

Fig. 6

DIAGRAM OF PISTON OPERATED VALVE
SHOWING BASIC PRINCIPLE OF OPERATION
AND THE FORCES INVOLVED

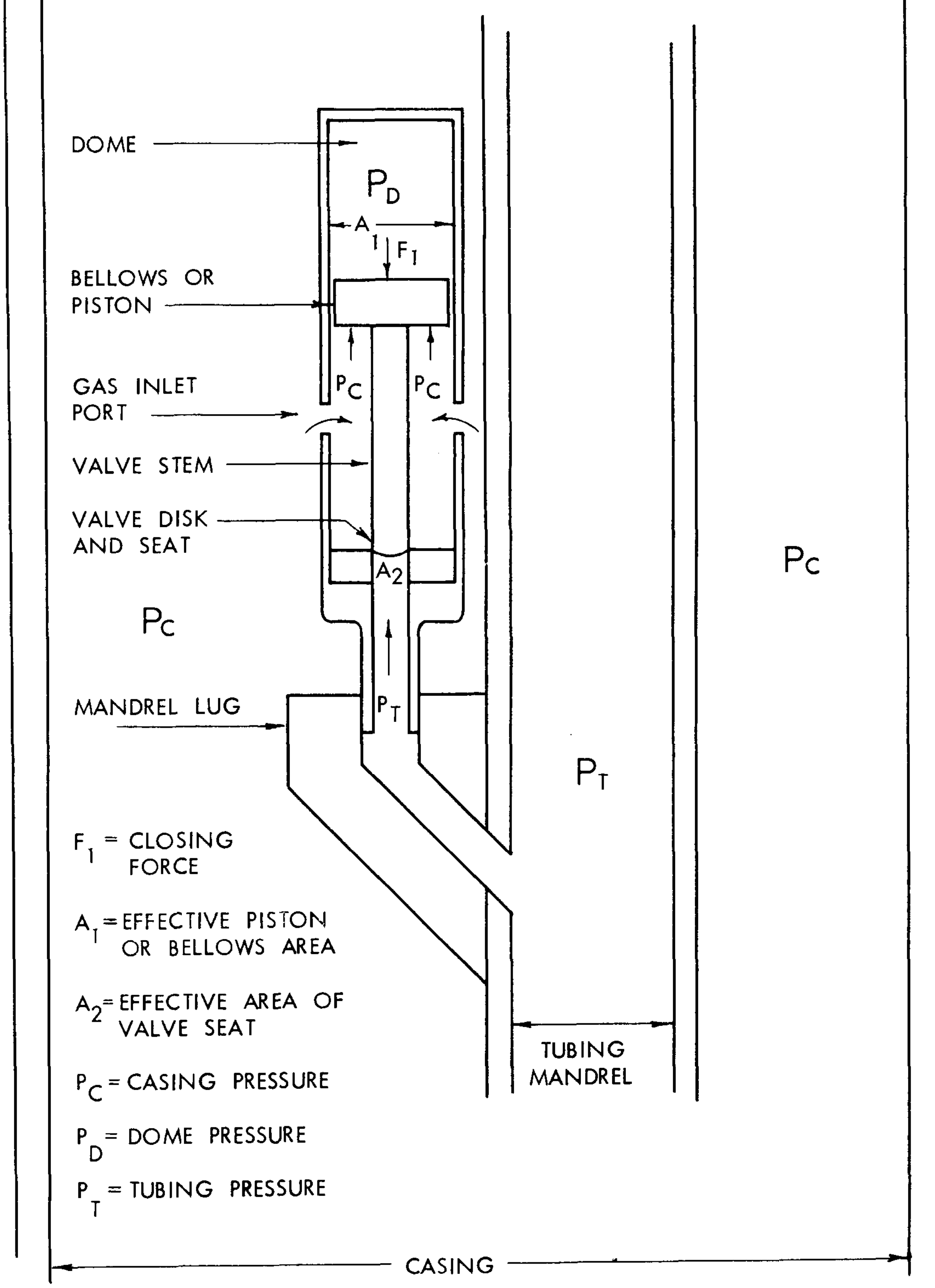


Fig. 7

1. Closing force = (dome pressure) X (area top of piston)

   $(PD) \times (A_1) = F_1$

2. Valve opening force = (casing pressure) (area bottom of piston) + (tubing pressure) (area valve seat)

   $(Pc)(A_1 - A_2) + (Pt)(A_2) = F_2$

Once the valve is open, the casing pressure Pc acts on the full effective area of the piston and the casing pressure required to hold the valve open is that of the dome pressure. For the valve to close, the casing pressure must drop below the dome pressure so that $Pd\,A_1 < PcA_1$.

One factor that has been neglected in this analysis is the compressing of the dome gas itself. If this is appreciable for any particular valve it should be accounted for. This means that the pressure in the dome will vary depending upon whether the valve is open or closed. A large dome will, of course, make this difference negligible.

The Continuous Flow Valve

The continuous flow valve operation is as follows: (Fig. 8).

1. Closing force = (dome pressure) (areas top of piston)

   $(Pd)(A_1) = F_1$

2. Valve opening force = (casing pressure) (area bottom of piston) + (tubing pressure) (area valve seat)

   $(Pc)(A_1 - A_2) + Pt\,(A_2) = F_2$

When the valve is open the casing pressure, because of the valves restricted entry port, is not acting on the full effective piston area, which the intermittent valve does. In the vicinity of A_2 (valve seat area) pressure has dropped to Pt (tubing pressure). The forces holding the continuous flow valve open differ from the forces holding the intermittent valve open. The forces holding the valve open are the same as the ones which opened it originally or $F_3 = Pc\,(A_1 - A_2) + Pt\,(A_2)$.

For the valve to close, the casing pressure (Pc) does not have to drop to the dome pressure (Pd). Since the valve is in a balanced position, a comparatively small drop in casing pressure (Pc) or tubing pressure (Pt) will cause it to move to the closed position.

No appreciable drop in casing pressure is expected, but gas entering the tubing and lightening the flowing gradient should decrease the tubing pressure and the valve will close. This type of valve is then sensitive to tubing pressure, while the casing pressure at which it closes is not necessarily constant. This feature makes this type valve more desirable for continuous flow installations.

Controlled Spread Valve

Another valve for intermittent flow that gives a controlled pread is illustrated in Fig. 9. It is commonly called a balanced pressure valve. This valve is particularly suitable for chamber installations, where the tubing pressure acting on the valve, due to hydrostatic fluid load, is negligible.

An analysis of the forces involved is as follows:

1. Closing force = (dome pressure) (area top of piston)

   $(Pd)(A_1) = F_1$

2. Opening force = (casing pressure) (area bottom of piston) + (casing pressure) (valve seat area)

   $(Pc)(A_1 - A_2) + Pc(A_2) = F_2$ or $F_2 = Pc\,A_1$

3. When the valve comes to the full open position, casing pressure is still acting on A_2 because the gas entry into the tubing is restricted downstream from A_2. The valve is then balanced and only a slight drop in casing pressure will cause the valve to close. The spread can be controlled to any degree by varying A_2 and leaving the area on the bottom of the piston constant.

Fluid Operated Valve

Another common type of valve used in intermittent flow operations is the fluid operated valve. (Fig. 10). This valve has the same features as the pressure operated intermittent valve but utilizes the tubing pressure for its opening force. Its basic principle of operation and the forces involved are:

1. Closing force = (dome pressure) (area top of piston)

   $F_1 = (Pd)(A_1)$

2. Opening force = (valve seat area) (tubing pressure) + (tubing pressure) (area bottom of piston)

   $(Pt\,(A_1 - A_2) + (Pt)(A_2) = F_2$

   $(Pt)(A_1) = F_2$

VALVE SPREAD

It should be noted that a characteristic of the standard intermitting valve is that it will always have a constant closing pressure and a variable opening pressure depending upon tubing pressure. This is an important design feature and is commonly referred to as valve spread. Therefore, this type of valve

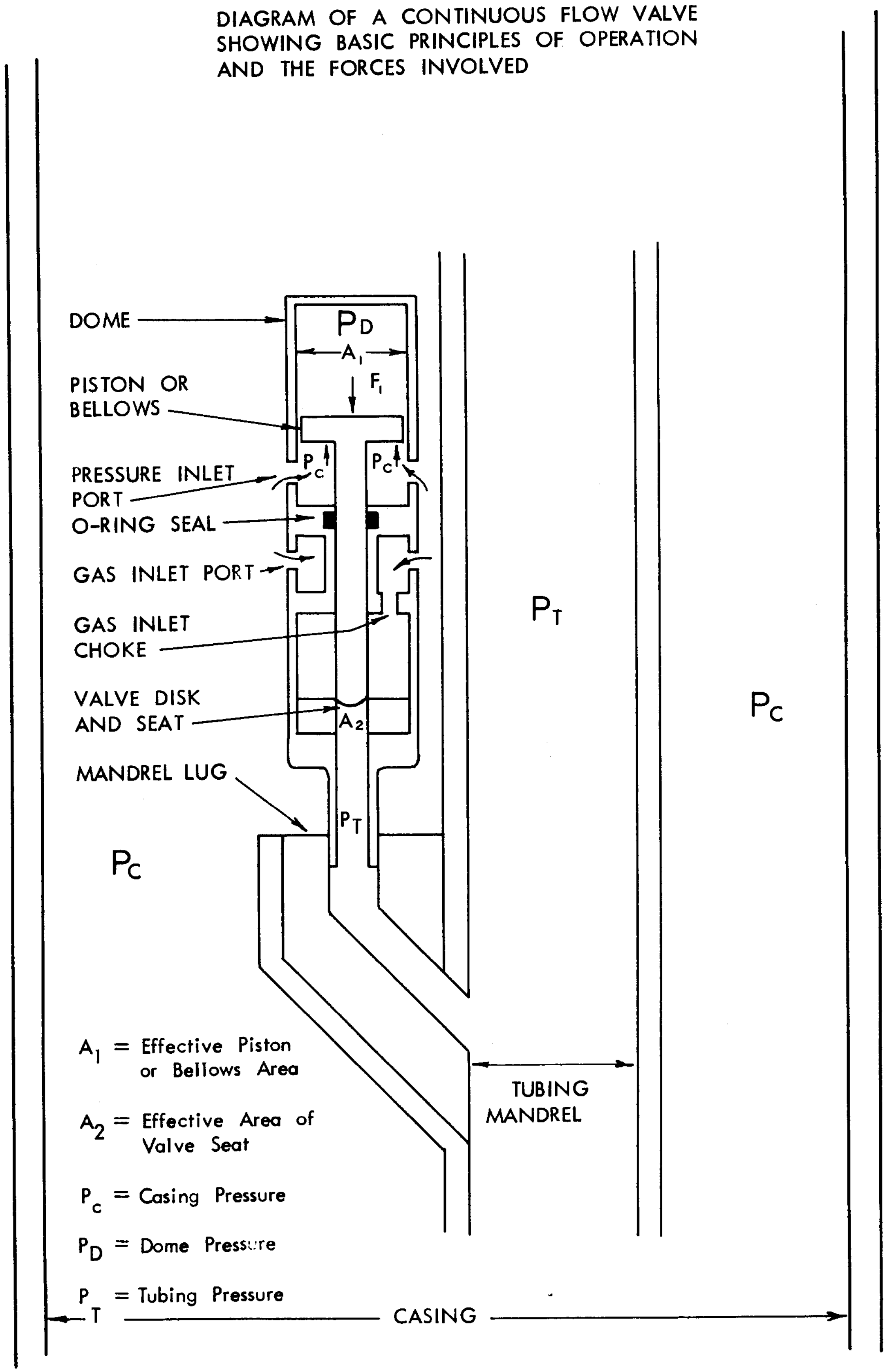


DIAGRAM OF A CONTINUOUS FLOW VALVE SHOWING BASIC PRINCIPLES OF OPERATION AND THE FORCES INVOLVED
DOME
PD
A1
F1
PISTON OR BELLOWS
PRESSURE INLET PORT
Pc
Pc
O-RING SEAL
GAS INLET PORT
GAS INLET CHOKE
PT
VALVE DISK AND SEAT
A2
Pc
MANDREL LUG
PT
Pc
TUBING MANDREL
A1 = Effective Piston or Bellows Area
A2 = Effective Area of Valve Seat
Pc = Casing Pressure
PD = Dome Pressure
PT = Tubing Pressure
CASING

Fig. 8

DIAGRAM OF A BALANCED PRESSURE VALVE
SHOWING THE BASIC PRINCIPLES OF OPERATION
AND THE FORCES INVOLVED

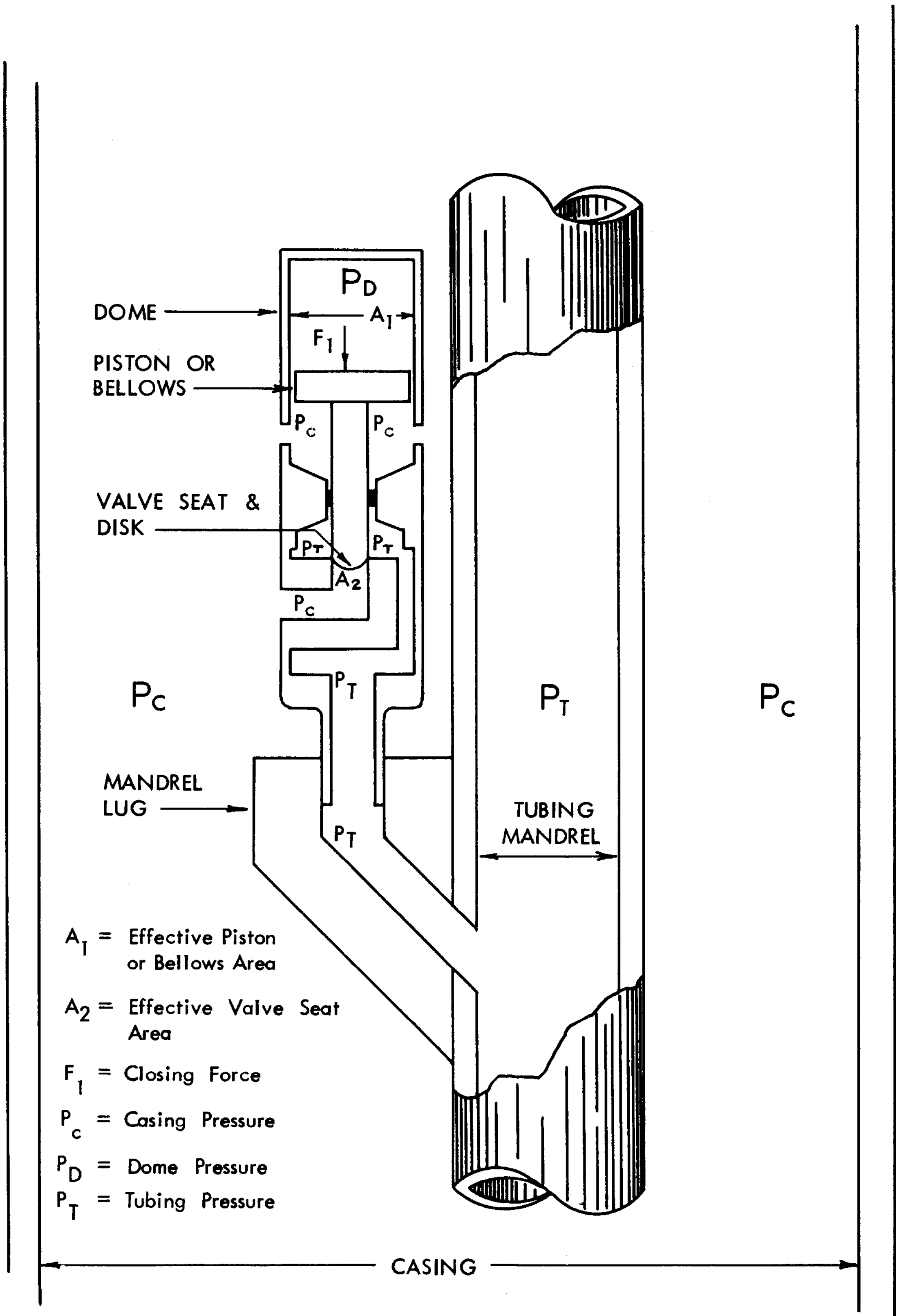


Fig. 9

DIAGRAM OF FLUID OPERATED BALANCED PRESSURE VALVE SHOWING BASIC PRINCIPLES OF OPERATION AND THE FORCES INVOLVED

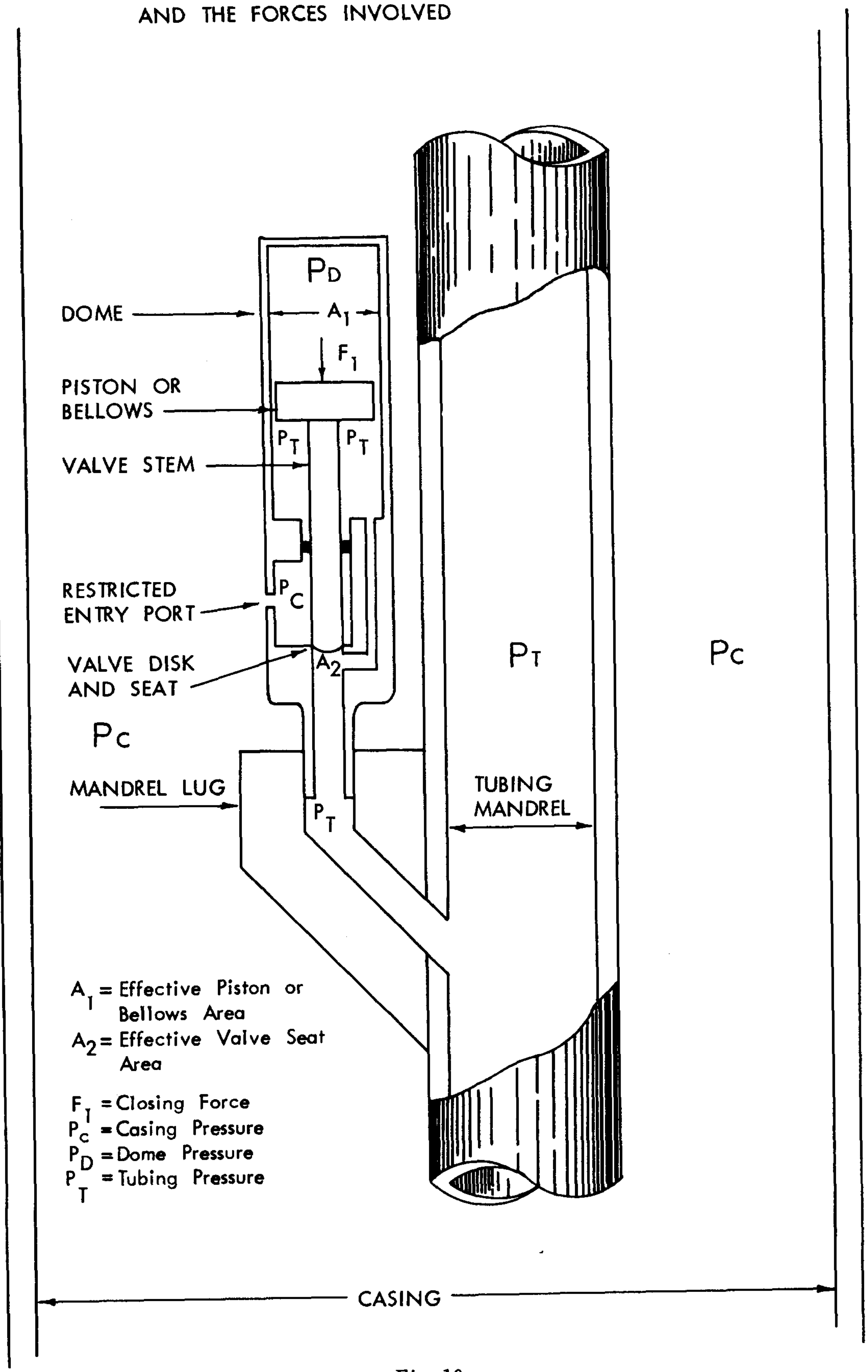


Fig. 10

should be used for intermitting flow only. The placing of chokes in this type of valve and the use of it for continuous flow is not considered a good design procedure. The "spread factor" is illustrated by the following example.

$A_1 = 1.25 \text{ in}^2$

$A_2 = .10 \text{ in}^2$

$Pd = 600$ psia @ 60°F

For zero tubing pressure (maximum spread), the casing pressure required to balance the dome pressure is:

$$(Pc)(A_1 - A_2) + A_2 \ (0) = (Pd)(A_1)$$

$$Pc = \frac{(Pd)(A_1)}{(A_1 - A_2)} = \frac{(600)(1.25)}{(1.25 - .10)}$$

$Pc = 650$ psi @ 60°F

Therefore, for a valve with a dome pressure of 600 psia at 60°F with respective piston and seat areas of 1.25 in^2 and .10 in^2, and for zero tubing pressure, an actual opening pressure of 650 psia is required. As previously pointed out, the valve closing pressure will be the dome pressure (Pd) or 600 psia in this example. This difference in opening and closing pressure (650 psia - 600 psia = 50 psia) is the spread factor.

The importance of the spread factor is immediately realized when installations are being designed for similar wells having different sized casing and tubing strings. This is best illustrated by the following example:

Well No. 1

Casing - 5 1/2 inch - 17# per foot
Tubing - 2 7/8 inch O.D.
Depth - 5000 feet
Annular capacity .0856 ft^3
Volume of space = 428 ft^3
Avg press = 600 psia
Avg temp = 100°F
Valve spread = drop in avg casing pressure = 50 psi (600 psi to 550 psi)
S.G. of gas = 0.65
Compressibility factors "Z" = .91 and .92 respectively
No. of standard ft^3 used for a 50 psi drop in casing pressure = 1700 @ 14.7 psia and 60°F

Well No. 2

Casing - 7 inch - 17#/foot
Tubing - 2 3/8 inch O.D.
Depth 5000 feet
Annular capacity = .2022 ft^3/ft.
Volume of space = 1011 ft^3
Avg press = 600 psia
Avg temp = 100°F
Valve spread = Drop in avg casing press = 50 psi (600 psi to 550 psi)
S.G. gas = 0.65
Compressibility factors "Z" = .91 and .92 respectively
No. of standard ft^3 used for a 50 psi drop in casing pressure = 4020 at 14.7 psia and 60°F

From the preceding example it is noted that 1700 scf (std cubic feet) were used from the 5 1/2 inch - 2 7/8 inch annular space and that 4020 scf were used from the 7 inch - 2 3/8 inch annular space. This example clearly illustrates why valves with different spread factors should be used for these two wells.

However, for the standard intermitting valve, the spread decreases with increased tubing pressure. In most cases, the actual difference in opening and closing pressure is small, and gas over and above the actual spread of the valve must be supplied from a surface controller. This merely points out that if ample injection gas (both pressure and volume) is available, the spread may be smaller than needed, and yet a good installation will result. However, for compressor systems, where it is desirable to supply gas to the annular space at a restricted rate, a correct spread is extremely important.

DESIGN OF THE INTERMITTENT INSTALLATION

For the complete design of an intermittent gas lift installation the following information should be obtained:

1. Size of casing
2. Size of tubing
3. Depth of well
4. Expected maximum and minimum production including the percent water, gas and oil
5. Trap pressure and separator capacity
6. Expected flowing surface tubing pressure
7. Injection gas pressure needed and injection gas pressure available
8. Volume of injection gas required and volume of gas available
9. Productivity index
10. Static bottom hole pressure
11. Bottom hole temperature and temperature gradient
12. Method of well completion (open hole, perforated casing, etc.)
13. Pressure build up curves.
14. Static fluid level and information as to whether the well is to be loaded with fluid prior to running valves
15. Solution gas/oil ratio
16. Formation volume factor
17. Specific gravity of injection gas and solution gas

The expected maximum production is very important in determining maximum gas requirements. The expected flowing surface tubing pressure and trap pressure are extremely important. Depending upon the bottom hole pressure and P.I. of the well, an abnormally high trap pressure may retard the fluid entry rate. The carrying of an abnormally high trap pressure seems to be a common mistake in the design of closed rotative systems.

In an attempt to lower compressor horse power requirements, a high suction pressure is carried on the system, thereby retarding production of low bottom hole pressure wells. For example, it has been noted that some wells will produce from 5 - 10 barrels more oil per day by decreasing the trap pressure from 15 psig to 5 psig. A very careful economic balance should be observed for wells of this type and lower compressor costs should be weighed against loss in production.

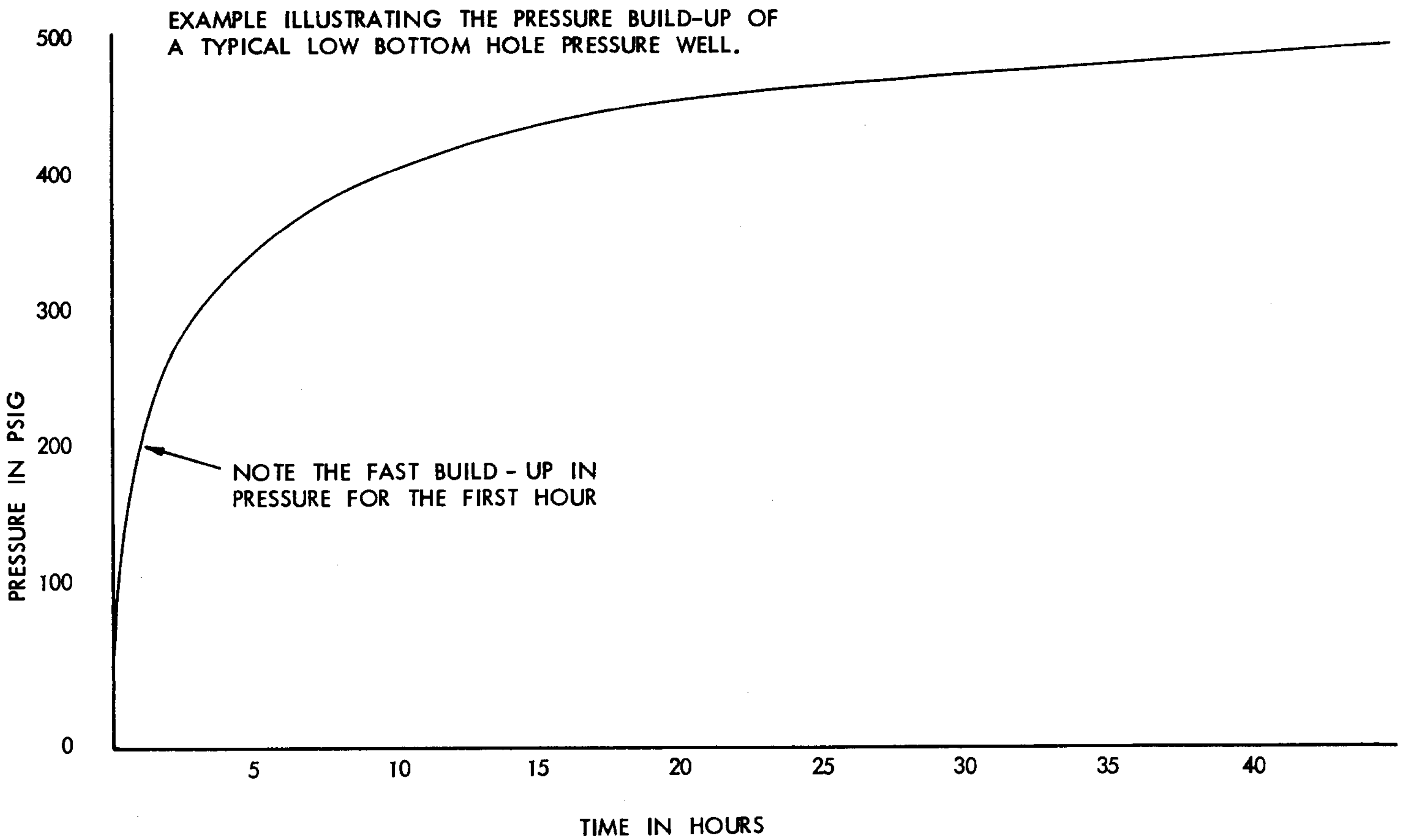


Fig. 11

The flow line and separator capacity should be checked and balanced against the produced slug size. Numerous separator safety valves and burst plates have been blown by a failure to balance the produced fluid and follow up gas slug with capacity. This can be eliminated by choking at the well head or separator, but additional well bore slippage then can be expected. However, recent progress in the use of pistons and plungers has greatly reduced slippage, even when producing fluid against relatively small surface chokes.

The injection gas pressure needed for intermittent wells has been lowered considerably by using pistons and plungers. A rule of thumb of 100 psig per 1000 ft of depth will be on the safe side. However, 8000 foot wells have been lifted with as low as 150 psig surface injection pressure. The use of such low injection pressure should not be attempted without the use of a piston or plunger to reduce slippage.

The volume of gas needed again depends upon the type of installation and the expected efficiency. The volume of gas needed to completely displace the slug to the surface should be calculated. This volume should then be divided by the efficiency expected, to give the desired volume of gas needed per slug. Efficiencies for deep intermittent wells are very low (10-15%), but can be increased above 50% and perhaps approach 90% with a piston or plunger.

The productivity index is the basis for determining fluid production: on most intermittent wells a maximum drawdown is desired. Furthermore, the PI, together with the bottom hole pressure, may indicate the type of installation needed. For example, for a high bottom hole pressure well with a low PI, a straight tubing installation with only a packer may suffice. For a low bottom hole pressure high PI well, a chamber installation is desirable. Of course, all the reservoir properties should be evaluated so that gas coning, etc. will not be aggravated.

The method of completion is important for wells requiring chamber installations. For example, a well having a low bottom hole pressure and several hundred feet of perforations is suitable for an insert chamber installation. This type of chamber allows maximum utilization of bottom hole pressure, as explained previously. If only a few feet are perforated, a two packer chamber installation can be employed. Such an installation provides more storage space than the insert chamber.

Pressure build up curves are important in determining the frequency of cycles. The resulting build up of fluid should be removed at the upper end of the first straight line portion of the curve. (Fig. 11)

As soon as all possible information has been accumulated, the actual design of the installation may be considered. Even though complete information is not available, enough flexibility in design can be made for most gas lift installations to assure satisfactory operation.

A typical plot on cartesian coordinate paper is shown in Fig. 12. Such items as the depth of the well, static bottom hole pressure, static fluid level, static fluid gradient, and the static surface tubing pressure can be plotted on the graph. From the PI of the well, which in turn indicates the psi drawdown needed, the position of the operating valve can be determined. In the majority of cases this will be the bottom of the well for

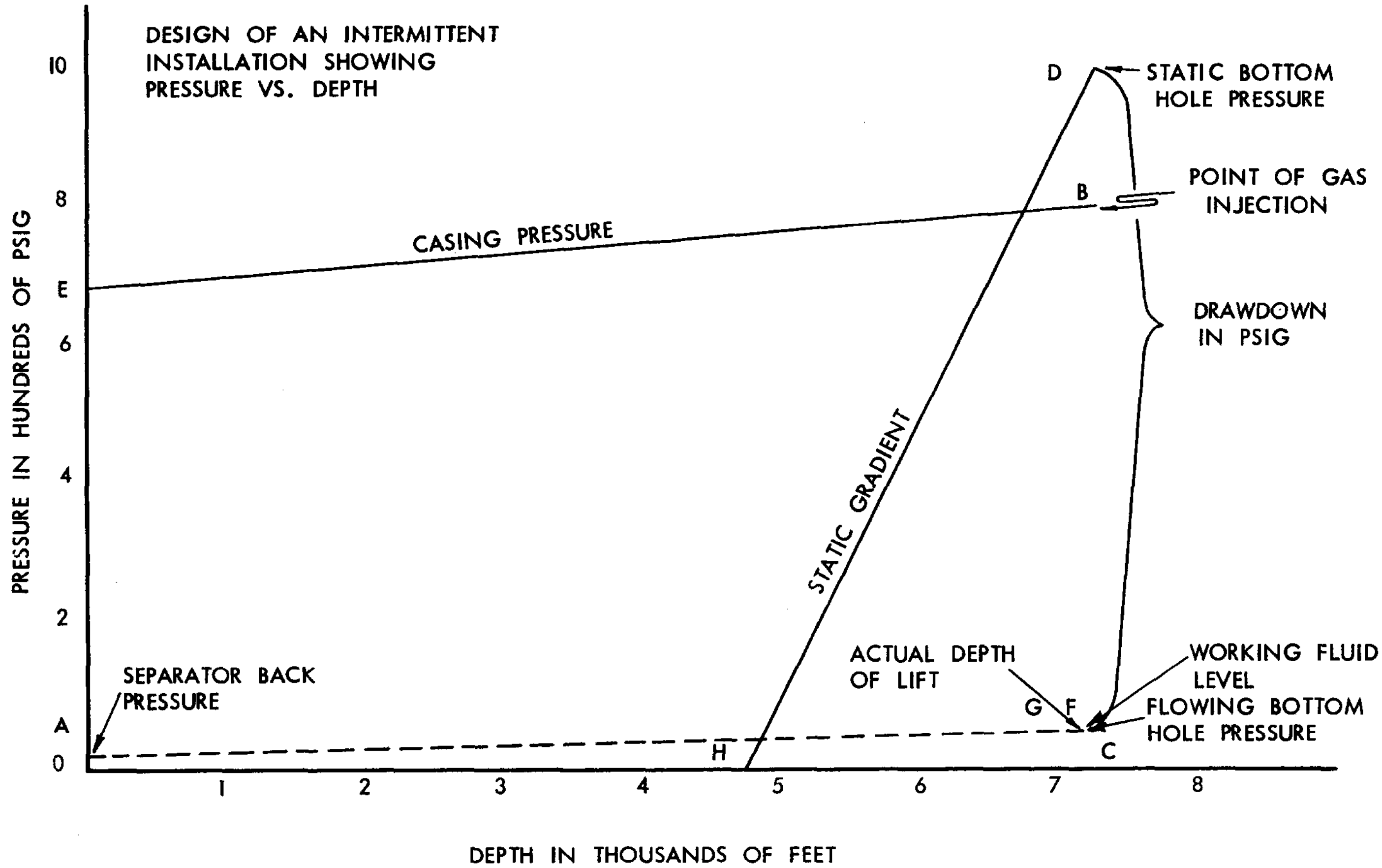


Fig. 12

an intermittent installation.

From the pressure buildup curve (Fig. 11), the slug size and consequent slug height should be determined. This information then determines the necessary injection gas operating pressure desired opposite the gas lift valve. A common field procedure is to use 100 psi additional injection pressure over and above the actual pressure in the tubing at that point. However, this is not always necessary, especially if a piston or plunger is used in conjunction with the installation. Reference should be made to Fig. 13 for a chart showing velocities vs. slug sizes. This chart is helpful in determining the pressure excess needed over the slug head.

Once the typical plot has been completed, a choice of the type of valve and type of installation must be made. This decision should not be too difficult. If gas is available at a slow flow rate and the annular space must be used for storage, fluid operated valves may be desirable. The basic advantages of a chamber also should be considered.

The actual spacing of the valves is the final step. If the well must be loaded with fluid prior to pulling the tubing, valves will have to be spaced to the surface unless swabbing is used to unload the well. If not, the first valve may be placed at the static fluid level or slightly below, as indicated by the following formula.

$$L_1 = S + \frac{P}{G_s (R \ 1)}$$

L_1 = depth to 1st valve (feet)
S = depth to static fluid level (feet)
P = kick off pressure, psia
G_s = static gradient psi per foot.
R = ratio of annular area to tubing area

If pressure operated valves are being used, all succeeding unloading valves should be spaced by the following formula.

$$L_2 = L_1 + \frac{P_{vl} - P_t - (G_{fa} \times L_1)}{G_s}$$

L_2 = depth to second valve (feet)
L_1 = depth to 1st valve (feet)
P_{v1} = opening pressure of valve #1 (psi)
P_t = tubing pressure, psi
G_s = static gradient, psi per foot
G_{fa} = gradient in tubing above valve #1, psi per foot.

Some controversy exists as to exactly what gradient (G_{fa}) should be used for unloading wells. It is believed that this should not be less than .04 psi per foot. For pressure operated valves, the pressure of each succeeding valve down the hole should be lowered at least 10 psi if all valves have the same spread factor.

If fluid operated valves are to be used, they should be spaced by the following formula.

Valve #1 may be spaced the same as the pressure operated valve, as shown previously. The next valve should be spaced as follows:

$$L_2' = L_1 + \frac{D}{G_s}$$

L_2 = depth to valve #2 in feet
L_1 = depth to valve #1 in feet
D = difference in pressure between the operating gas pressure opposite the gas lift valve and

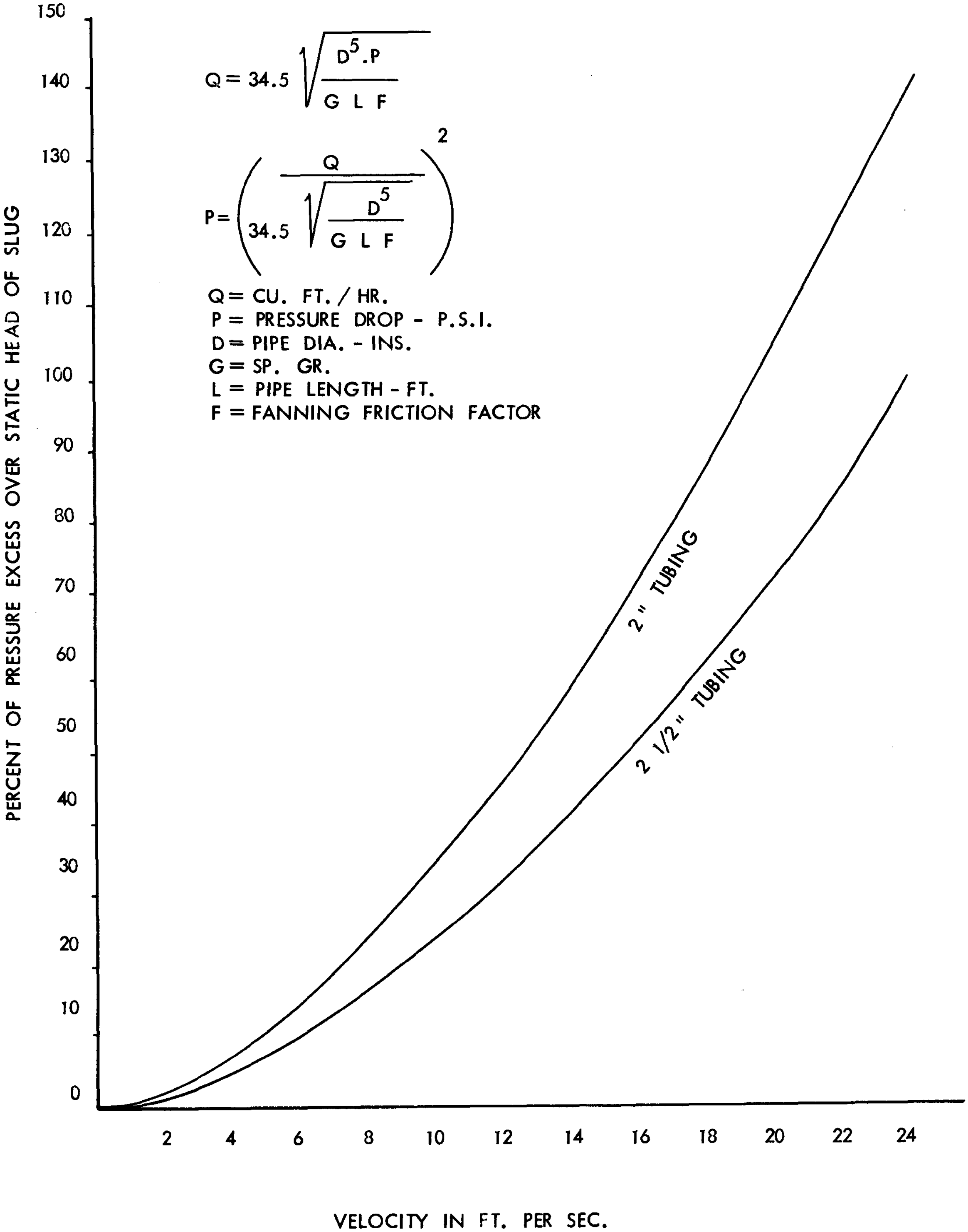

$Q = 34.5\sqrt{\dfrac{D^5 . P}{G\ L\ F}}$
$P = \left(\dfrac{Q}{34.5\sqrt{\dfrac{D^5}{G\ L\ F}}}\right)^2$
Q = CU. FT. / HR.
P = PRESSURE DROP - P.S.I.
D = PIPE DIA. - INS.
G = SP. GR.
L = PIPE LENGTH - FT.
F = FANNING FRICTION FACTOR
2" TUBING
2 1/2" TUBING
PERCENT OF PRESSURE EXCESS OVER STATIC HEAD OF SLUG
VELOCITY IN FT. PER SEC.
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
2
4
6
8
10
12
14
16
18
20
22
24

Fig. 13

the fluid opening pressure of the valve in psi.

G_s = static gradient in psi per ft.

A very convenient graphical solution can be arranged for the spacing of fluid operated valves, which automatically incorporates the weight of the injection gas column.

CONCLUSION

In conclusion, it should be noted that no mention has been made of valve port sizes. Formerly it was thought that a maximum port size should be used to insure greater tubing velocity and thereby minimize fluid slippage. However, with the advent of pistons and plungers, slippage is controlled at a very low velocity. Therefore, any of the standard port sizes now being incorporated in valve manufacture should be satisfactory. The choking of unloading valves may be desirable to eliminate unnecessary surges on the separator for the initial unloading process.

The design of good intermittent flow installations is actually more difficult than the design of continuous flow installations. A study must be made of such variables as 1. optimum port sizes, 2. optimum slug sizes and velocities, 3. reliable flowing gradients and 4. improved pistons and plungers to obtain better efficiencies. Fortunately, the gas lift installation is flexible enough to produce most intermittent wells, but a determined effort should always be made to design the most efficient installation.

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REFERENCES

(1) "Gas Lift Practice and Theory" by Kermit E. Brown with Robert F. McAfee (Presently being published by Garrett Oil Tools, Inc.)

(2) "The Power of Gas" by C. V. Kirkpatrick, Camco, Inc.