

AN INNOVATIVE DESIGN FOR DOWNHOLE GAS SEPARATION

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ABSTRACT

Gas problems can cost a company valuable time, money and resources. The presence of gas in the pumping zone causes various problems like gas lock, gas pound, and gas interference, resulting in reduced pump efficiency and pump failures. In order to overcome these problems, the in-house research team developed and patented an innovative design called the Don-Nan Gas Separator, which diverts the gas away from entering the pump intake and thus reducing pump failures and improving the pump efficiency. The major topics of discussion are:

1. Review of the problems that are encountered in gaseous wells.
2. Design and working principle of the “Don-Nan Gas Separator”.
3. Effectiveness of the system compared with respect to fluid fall velocities and gas bubble rising velocities.
4. Observed case histories and improvements in the pump efficiency.

GAS PROBLEMS IN THE WELL

Gas is found in two forms in oil wells: (1) in solution with the well fluids, and (2) as a free gas in the formation. Gas is held in solution by pressure and is released by turbulence, heat and reduced pressure. The presence of gas can reduce pump efficiency. Gas entering the well along with the oil is the factor which causes most pump problems. It may pocket around the pump or may accumulate inside the pump and “gas lock” the valves.

Gas lock occurs when gas accumulates in the pump chamber. A pump can discharge fluid, which is not compressible, into the tubing under high pressure, but it cannot do the same with gas, which is compressible. Wells with higher and lower than normal levels of fluid are both prone to gas lock.

In wells with a high fluid level, the high head of fluid exerts high pressure causing the gas to remain in solution form. When this fluid flows through the pump intake, the gas breaks out due to the pressure drop. This free gas enters the pump intake chamber and causes the gas interference, leading to gas lock and gas pound. As the plunger falls during the down stroke, the presence of gas in the solution causes the fluid to compress and does not create enough pressure for the traveling valve to open. This is called gas lock and appears to be a pump off condition.

As the gas in its solution passes through the pump intake, the reduction in pressure causes the gas to break out. This free gas occupies a part of the pump intake chamber which restricts the amount of fluid available to fill the chamber. As a result of this condition, the plunger will compress the gas during the down stroke and then contact the fluid. The presence of gas provides some amount of cushion, but still the pump can experience a sudden shock upon striking the fluid. This causes the gas pound to occur followed by the fluid pound. This phenomenon results in great damage to the pump assembly and to the rod string. A few examples of problems caused by this phenomenon are: rod buckling, rods rubbing against tubing causing tubing leaks, and in severe conditions, the splitting of the barrel and/or cages can occur.

In wells with a low fluid level, small amounts of gas enter the pump along with, or absorbed within the well fluid. This gas separates out of the oil and fills the upper part of the pump chamber. This situation does not create enough pressure for the travelling valve to open, resulting in a pump off condition. In the same manner, gas pound occurs when the falling plunger encounters fluid, and displaces an amount something short of the full capacity of the pump chamber, into the tubing. The symptoms of these conditions are recognizable at the surface; it delivers less than normal levels of fluid and can usually be verified by an accompanying fluid pound at an intermediate point on the stroke.

Gas interference may be recognized by:

1. Low pump efficiency.
2. During the early stage of pumping a gaseous well, pressurized gas from the pump bore agitates the well to a flowing condition, which might result in an improper lubrication along the moving parts.
3. The presence of high pressure gas causes intermittent heading, which results in the pump jack experiencing heavier than normal loads. The presence of gas in the tubing column does not provide as much buoyancy as a column of oil would, which might result in an out of balance condition causing inefficiency and higher operating costs.
4. The well appears to be pumping, but with no production of fluid whatsoever at the surface.

DESIGN AND PRINCIPLE OF THE "DON-NAN GAS SEPARATOR"

The gas separator is an assembly of five individual components: Ported Coupling (Figure 1), Seal Coupling (Figure 2), O-Ring Body (Figure 3), Inner Flow Tube (Figure 4), and Outer tube (Figure 5).

The inner tube is screwed into the center hole of the ported coupling. The o-ring body is screwed into the other end of the inner flow tube. The outer tube is screwed into the ported coupling. Finally, the seal coupling is screwed onto the other end of the outer tube. The o-ring body is positioned in the center of the seal coupling as shown in the assembly (Figure 6). All of these parts can be manufactured in a variety of metallurgies making the gas separator suitable for a diversity of bottom hole environments. The assembly is made up of individually machined components all connected through a series of pin and box threads, establishing the ability to interchange parts, and providing a longer life by limiting the effects of corrosion and breakage commonly associated with welded connections.

The packer type gas separator is positioned within the tubing string above the tubing anchor catcher, rotational packer and below the seating nipple. The rotational packer, when expanded, holds tightly against the casing wall to serve two purposes: to keep the entire assembly in position and to separate the column of fluid in the tubing/casing annulus into two chambers, one above the packer and one below. The presence of the packer insures that all of the formation fluid from the well bore passes through the gas separator before entering the pump intake.

The function of the gas separator is to create a turbulent and low pressure atmosphere which the fluid will pass through in route to the pump intake allowing the gas in its solution form to break out and escape through the tubing/casing annulus. The gas separator is designed and installed in such a way that, once the gas breaks out of the fluid, it travels upwards at a velocity faster than the downward velocity of the liquids being drawn into the pump (assuming that the viscosity of the liquids is within the considered range). Preventing the free gas from reaching the pump intake reduces the occurrence of gas interference and gas lock and improves the pump efficiency. It also creates a favorable situation for lowering the fluid level in the casing at a faster rate, and provides an environment that is conducive to continuous chemical treatment which will keep the well corrosion free.

Formation fluid consisting of a mixture of oil, water, and gas from the well bore travels through the tubing string and reaches the ported coupling. The fluid passes through the seven drilled holes in the ported coupling and enters the annulus space between the inner flow tube and the outer tube. This fluid path creates a low pressure region which breaks out a major portion of gas from the fluid. Once the annulus space between the outer tube and the inner flow tube is filled with fluid, it passes through the four slots that are machined on the upper portion of the outer tube and falls back in to the annulus space between the casing and the outer tube, settling on the packer. This accumulated fluid on top of the packer passes into the inner flow tube through the "L" shaped hole that is drilled in the ported coupling, travels through the inner flow tube, and finally passes into the pump intake. This diversion of fluid from the outer tube slots to the tubing/casing annulus creates a major turbulence in the flow and helps break out the gas from the fluid. This free gas travels upwards through the tubing/casing annulus space, diverting most of the gas away from entering the pump intake. With this kind of fluid flow, problems such as gas interference, gas lock, and gas pound can be greatly reduced, improving the efficiency and life of the pump.

EFFECTIVENESS OF THE SYSTEM COMPARED WITH RESPECT TO FLUID FALL VELOCITIES AND GAS BUBBLE RISING VELOCITIES

Calculation Procedure

The gas separator calculations are based on the general oil field assumption that gas bubbles rise in most produced, low-viscosity (< 10 cp.) liquids at a rate of 6 in/sec.¹ The gas separator is developed based on this bubble rise rate.

The separator allows the pump to fill with the bubbles rising at a velocity greater than the downward velocity of the liquid. The procedure adopted for calculating the maximum capacity of the gas separator is based on the maximum volume of fluid that can flow through the gas separator without allowing the liquid velocity in the tubing/casing annulus to exceed the gas bubble rising velocity. This maximum volume that can flow through the tubing/casing annulus depends on the cross sectional area between the inner diameter of the casing and the outer diameter of the gas separator's outer tube. The greater the cross sectional area, the lower the velocity is of the liquid in the tubing/casing annulus. By keeping the downward velocity of the liquids below the upward velocity of the gas bubbles, a significant amount of gas can be separated from the fluid. For maximum capacities see Table 1. Following is a sample calculation for finding the maximum capacity.

Note: The term "maximum capacity" used here is not restricted to the maximum pumping capacity. This indicates that, by pumping lesser than or equal to this volume of fluid, the gas is allowed to be separated efficiently from the well fluid.

Sample calculation :

The maximum capacity when a 2 3/8" gas separator is installed in 5 1/2" casing (15.5 lb/ft)

Outer diameter of outer body (d) = Ø 2.625 in

Inner diameter of casing (D) = Ø 4.950 in

$$\begin{aligned}\text{Annulus area} &= \pi/4 (D^2 - d^2) \\ &= 13.83 \text{ in}^2\end{aligned}$$

The volume of fluid that can flow at the rate of 6 in/sec = 82.9 in³/sec

Maximum capacity at 100% efficiency = 738.33 BPD

Maximum capacity at 80% efficiency = 590.66 BPD

Losses of 20% are considered to compensate for the variation in the well fluid viscosity from the considered range. The above calculation states that, by pumping volumes less than or equal to 738.33 BPD, most of the gas will be allowed to be directed away from entering into the pump intake. For inner tube capacities, with water as the flow medium see Table 2. ²

Results and Observations

From our observations and case studies, it has been found that selecting the largest gas separator possible for the casing, while keeping the downward flow rate below 6 in/sec in the tubing/casing annulus for the desired production rate, results in efficient gas separation from the well fluid. It is also suggested that consideration be given to the feasibility of fishing for the gas separator. Furthermore, it has been determined that the greater the area available within the outer tube/casing annulus, the more efficient the gas separation is, and the lower the casing fluid levels remain, which will facilitate continuous chemical treatment of the well to ensure a corrosion free environment. The separation of the fluid column in the casing using a packer provides a good environment for the entire formation fluid to flow through the gas separator.

FUTURE SCOPE AND DISCUSSIONS

In the present work the focus has been on the gas bubble rise velocity versus the fluid fall velocity in relatively low viscosity fluids. An extended study on the design and installation techniques must be done with high viscosity fluids to find an efficient means of gas separation keeping the production rates same. A detailed study must be conducted on how the length of the gas separator will affect the gas separation from the well fluid. Initial findings from our case studies and observations suggest that a 40 foot gas separator has produced much better gas separation than the 20 foot gas separator. The main factor for this could be that a 40 foot gas separator provides a longer path for the fluid to travel giving it significantly more time for the gas to break out before reaching the inner tube. Ideally, if a well is pumping at 10 strokes per minute, the pumping cycle time is 6 seconds: 3 seconds for the up stroke and 3 seconds for the down stroke. During the down stroke there is no movement of the fluid, and during the upstroke the

fluid is sucked into the inner tube. The gas bubbles travel upwards a distance of 18 inches during the 3 seconds of upstroke at a rate of 6 inches per second. Consequently, there should be at least 18 inches of travel path available for the gas separation to occur³.

CASE STUDIES

The following are two case studies, where the Don-Nan Gas Separator has potentially provided a solution for gas problems within an oil well:

Case Study #1

Lufkin Automation.

Before installing the packer type gas separator, dynamometer results retrieved from the Lufkin SAM well manager revealed severe gas interference. This prevented the pump from filling properly a large percentage of the time resulting from poor down hole gas separation. Pump intake pressure analysis also derived from the SAM well manager dynamometer data and fluid level data performed by Lufkin Automation personnel revealed a PIP of 750 psi. This suggested that current conditions would not allow the well to be pumped off. Well test results at this time showed oil at 12 BPD, water at 82 BPD, and gas production at 100 MCFGPD.

After installing the packer type gas separator, dynamometer data and run time data retrieved from the Lufkin SAM well manager revealed 100% fillage of the pump and 100% run time. Pump intake pressure analysis from dynamometer data revealed a PIP of 400-450 psi, concurring that the well was now able to be pumped down, suggesting that proper down hole gas separation was now occurring. Well test results after the installation of the packer type gas separator showed oil production at 42 BPD, water at 162 BPD, and gas at 213 MCFGPD.

Estimated production increase returns:

Oil: before - 12 BPD, average oil production for the 1st 30 days after installation – 42 BPD = 30 BPD increase
Considering oil at \$55 per barrel= \$1650 per day

Gas: before - 100 MCFGPD, average gas production for 1st 30 days after installation - 213 MCFGPD = 113 MCFGPD increase
Considering gas at \$5/MCF= \$565 per day

Total potential production increase= \$66,450 in increased revenue for the 1st 30 days

Now, having the ability to pump the well off will in turn yield maximum production and allow the well to cycle on the pump off controller. This will allow savings on power (well will not run when pumped off or severely over-displaced), and minimize wear and damage to the surface equipment, rod string, and down hole pump, resulting in additional monetary savings on electricity, repairs and maintenance.

Case Study #2

Independent Pump Co.

IPC has worked in collaboration with their customers and suppliers to assist in innovating pumping solutions to reduce downtime and increase profitability.

Before installing the packer type gas separator, the well was carrying a large gaseous fluid column. Manual foam depressions indicated that incremental production was available, but the bottom hole pump was unable to operate efficiently due to the intake of gas.

Before the separator was installed, the pump efficiency was observed to be 30% with oil at 100 BPD, water at 50 BPD, and gas at 190 MCFGPD. Immediately after installing the gas separator, the pump efficiency had increased to 60% with oil at 178 BPD, water at 96 BPD, and gas at 373 MCFGPD.

Estimated production increase returns:

Oil: before - 100 BPD, average Oil production for the 1st 30 days after installation – 138 BPD = 38 BPD increase
Considering an oil netback of \$55per barrel = \$2090 per day or \$62,700 increase in oil revenue

Gas: before – 190 MCFGPD, average Gas production for 30 days after installation – 279 MCFGPD = 89 MCFGPD increase

Considering gas at \$5/MCF = \$445 per day or a \$13,350 increase in gas revenue in the 1st 30 days.

Total potential production increase = \$76,050 in increased revenue for the 1st 30 days.

The well has continued to produce with increased pump efficiency resulting in increased production and incremental revenue.

REFERENCES

1. “IMPROVED DOWNHOLE GAS SEPARATION” by J.N. McCoy, Echometer Company, A.L. Podio, University of Texas at Austin. Presented at the Southwestern Petroleum Short Course on April 7 & 8, 1998, Department of Petroleum Engineering, Texas Tech University, Lubbock, Texas.
2. Table 2 of this paper is referenced from Table 3 of “IMPROVED DOWNHOLE GAS SEPARATION” by J.N. McCoy, Echometer Company, A.L. Podio, University of Texas at Austin. Presented at the Southwestern Petroleum Short Course on April 7 & 8, 1998, Department of Petroleum Engineering, Texas Tech University, Lubbock, Texas.
3. “IMPROVED DOWNHOLE GAS SEPARATION” by J.N. McCoy, Echometer Company, A.L. Podio, University of Texas at Austin. Presented at the Southwestern Petroleum Short Course on April 7 & 8, 1998, Department of Petroleum Engineering, Texas Tech University, Lubbock, Texas.

Table 1
Gas separator maximum capacity based on bubble rise velocity

S no.	Gas Separator (in inches)	Casing size (in inches)	Max capacity of GS (in BPD)	Max capacity at 80% Efficiency (in BPD)
1	2 3/8	4 1/2	382	305
2	2 3/8	5 1/2	738	590
3	2 7/8	4 1/2	261	208
4	2 7/8	5 1/2	618	494
5	2 7/8	7	1291	1032
6	3 1/2	5 1/2	438	350
7	3 1/2	7	1110	888
8	3 1/2	7 5/8	1448	1158
9	3 1/2	8 5/8	2107	1685
10	4	7 5/8	1366	1092
11	4	8 5/8	2025	1620
12	4	9 5/8	2668	2134

Table 2²
Inner tube liquid capacity

Inner tube size (in inches)	Inner tube description	Capacity (in BPD)*
1	1.315 X 1.049 SCH 40	630
1 1/4	1.660 X 1.380 SCH 40	1350
1 1/2	1.990 X 1.610 SCH 40	1930

*The above water capacities cause a pressure drop of 0.5 PSI in 7 feet of standard schedule 40 line pipe or 7 feet of thin-wall, schedule 10, seamless, 316 stainless steel.

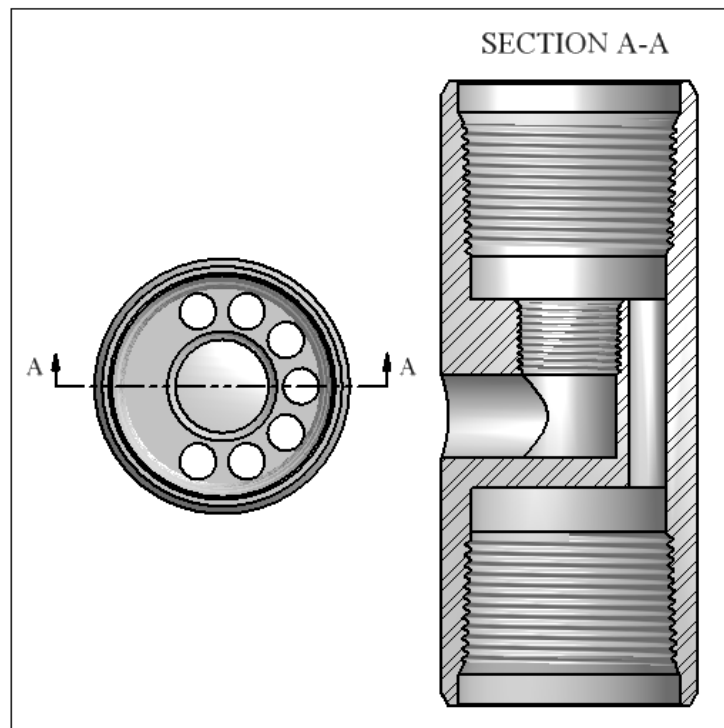


Figure 1 - Ported Coupling

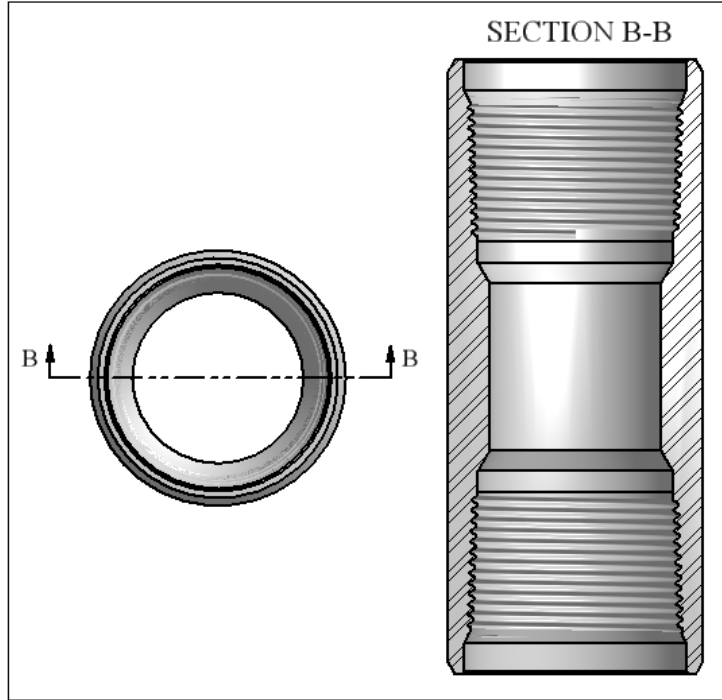


Figure 2 - Seal Coupling

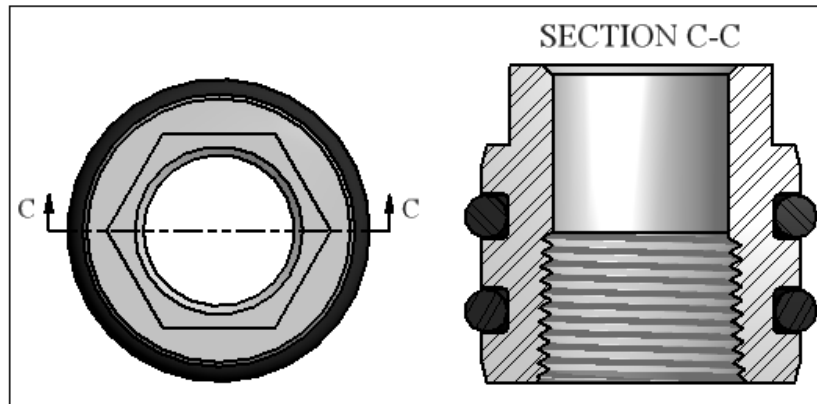


Figure 3 - O-Ring Body

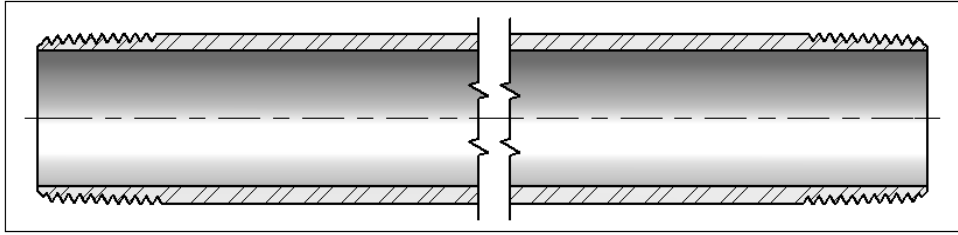


Figure 4 - Inner Tube

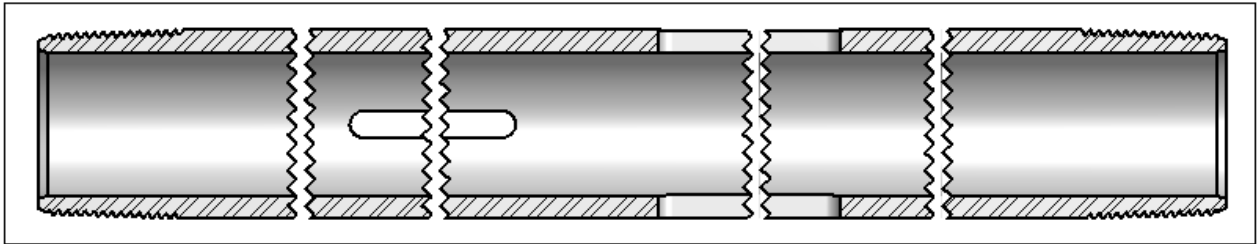


Figure 5 - Outer Tube

Don-Nan Gas Separator

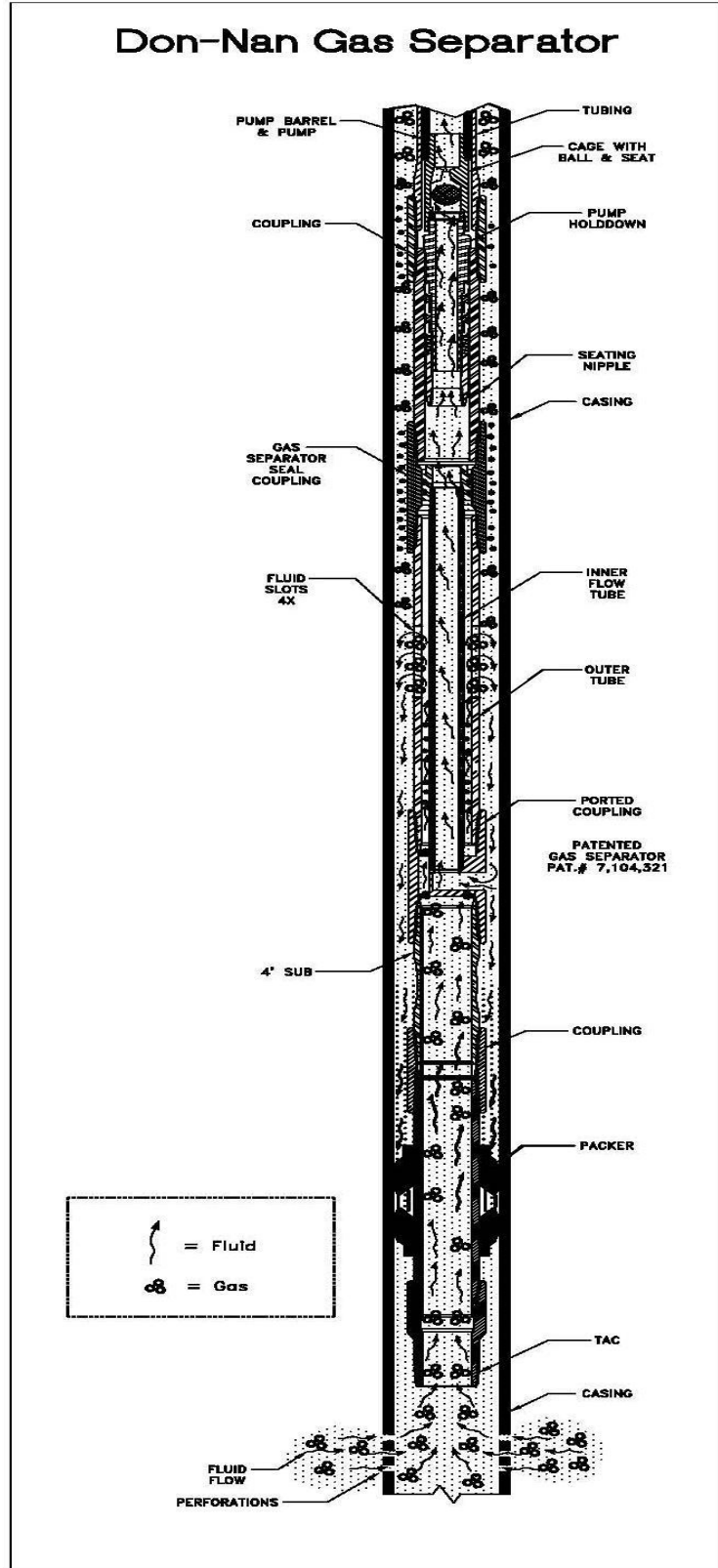


Figure 6 - Don-Nan Gas Separator Assembly