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A Fresh Look at Float Valves, the First Line of Defense

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Abstract

Float valves have been an essential component of drill strings for many decades. In addition to minimizing the amount of drilling mud spilled on the rig floor when tripping into the well and reducing the amount of weight required to be lifted by the rig structure in everyday operations, it is the first line of defense to prevent wellbore fluid influx rising to the surface through the drill string and causing a life-threatening loss of control of a well.

Data gathered on the life expectancy of the more than 6000 float valve subs in service over the last 30 years that the life of the subs has rapidly decreased (Fig. 1). This observation led to an investigation as to the possible reasons for the shortened life and what can be done to address this trend. The material and manufacturing of the subs had not changed so this led to questions about whether it is only the harsher environment or is there a problem with the float valve/sub system overall.

Float valve design has remained largely unchanged over the years, while drilling practices have dramatically changed with the rise of performance and horizontal drilling techniques. Additionally, the move from offshore GOM to land drilling dramatically changed drilling parameters. Flow rates have steadily increased providing greater performance and improved hole cleaning necessary for these ever longer laterals.

In recent years, there has been an increase in float valve and carrier sub failures and the industry has responded with running multiple floats in the drill string to reduce the risk of well control problems.

This study looks at available float valve equipment, including DrillSafe™ float valves, used in today's drilling conditions and investigates their use in popular drill pipe and BHA threaded connections. Some recent drilling trends utilizing non-API connections and even most API connections, especially when cut at the edge of manufacturing tolerances, introduce sealing issues with industry standard float valves.

High flow rates can cause erosion and wash outs that reduce float valve and float sub life and, in some cases introduce well control issues. High-torque double-shouldered drill string connections complicate use of floats requiring specialized float subs. LCM (lost circulation material) use can cause floats to leak in operation and cause well control issues.

Three-dimensional, CAD & CFD modeling was used to examine seal locations and to compare the flow patterns of both plunger and flapper type float valves and the results are presented here.

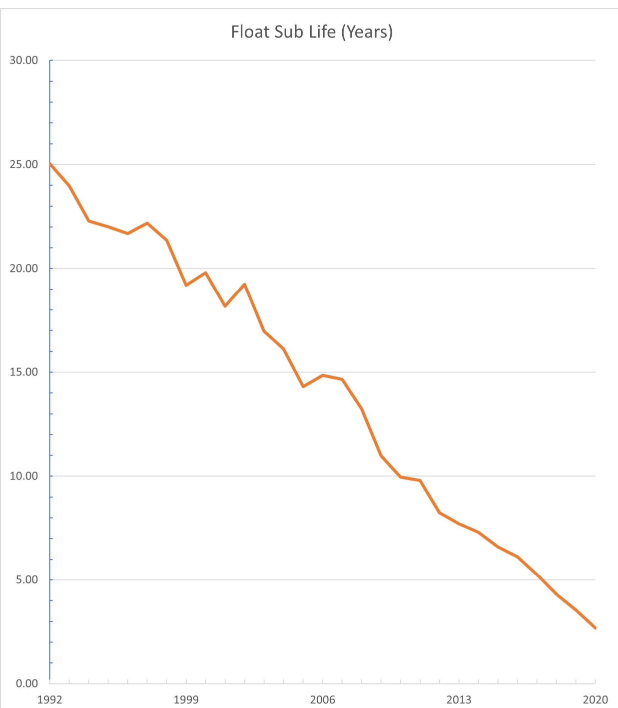

Figure 1 – Life span of float bore subs over the last three decades. (more than 6000 assets in the data)

History

The cartridge style float valve (Fig. 2) was patented by Reuben C. Baker and Charles M. King in 1956 (Baker and King, 1956). This valve is still the primary style used today. There have been some other models introduced, such as the G series, but the general design remains unchanged. What has changed is how these valves are used. Originally the valve was inserted into a box down connection directly above the bit. This allowed for the optimum configuration for the seals to operate.

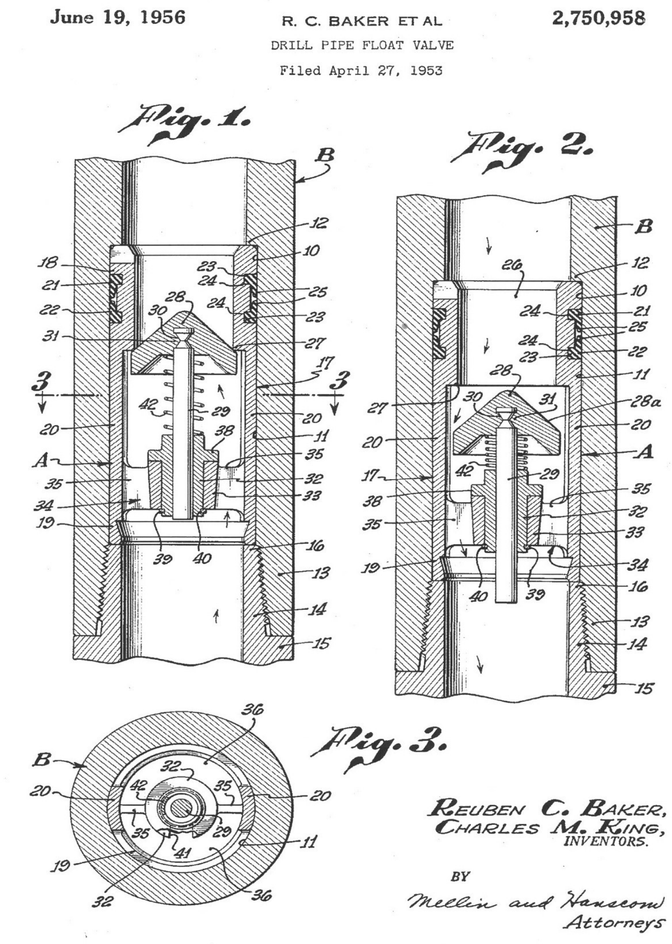

Figure 2 – Cover page of Baker Oil Tools patent for the cartridge-style float valve

With the advent of the steerable drilling assembly in the late 1980s and early 1990s the float valve could no longer be installed directly above the bit. Instead, it is installed in a box up connection on the top of the motor or in a float sub above the motor. Depending on the connection and how close it is cut to the tolerance limits, the top seal isn't always engaged within the float bore. The location of the seals on the valve vs the bore is compromised as the difference between the nose of the connection pin and the valve body outside diameter increases.

When the rig count started to recover from the downturn of 2015, the hi-spec rigs that started coming online had significantly more performance in both pressure and volume. The industry has been slow to move to larger floats and continues to run undersized 2F3R and 4R floats. This exacerbates the sealing issues and causes more erosion in both the float valve and the float sub, leading to more valve failures and potential well control events. The increase in downhole energy provided by the new, high performance, rigs started to exceed the useable capacity of many of the traditional API connections increasing the need for special fatigue features and double-shouldered premium connections that further complicated effective float valve use.

All the changes in the drilling environment and their impact on reliability and safety prompted a look at the venerable and often overlooked float valve. This crucial piece of drilling safety equipment is the first defense against well control situations.

Unintended Consequences of Float Valve Placement

When changes in drilling practices led to changing the placement of the float valve from a box down to a box up float bore, the ability of the seals to reliably operate was compromised. This is particularly true when the connections are manufactured to the outer limits of the tolerances provided by API. Below is a graphic that shows the most widely used tool connection and float valve combination (4½ IF w/ 4R float).

Note that even when the pumps are on (Fig. 3), the upper seal on the OD of the float valve does not fully contact the float bore. When the pumps are off (Fig. 4) the seal engagement is even less. Less than full seal engagement may cause the seal to leak and erosion of the bore of the float sub could occur. Degradation of the seal and sealing surface could cause leaks when pumps are off which could lead to a dangerous well control issue.

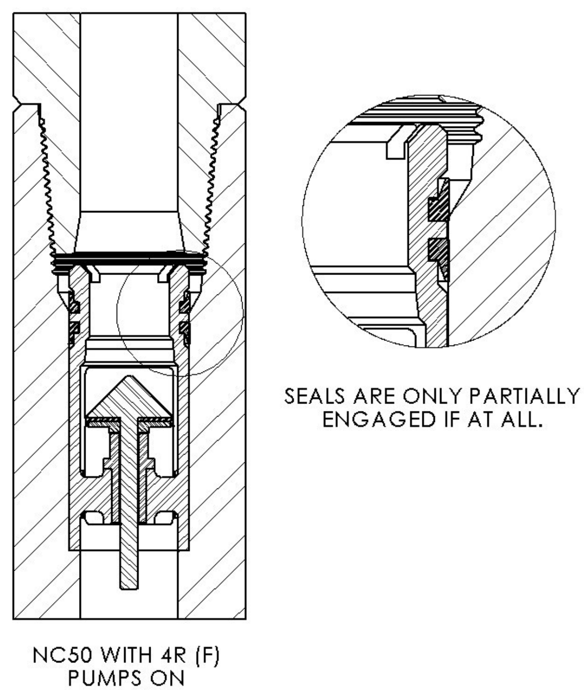

Figure 3- API NC50 connection with 4R Model F float valve in pumps on position.

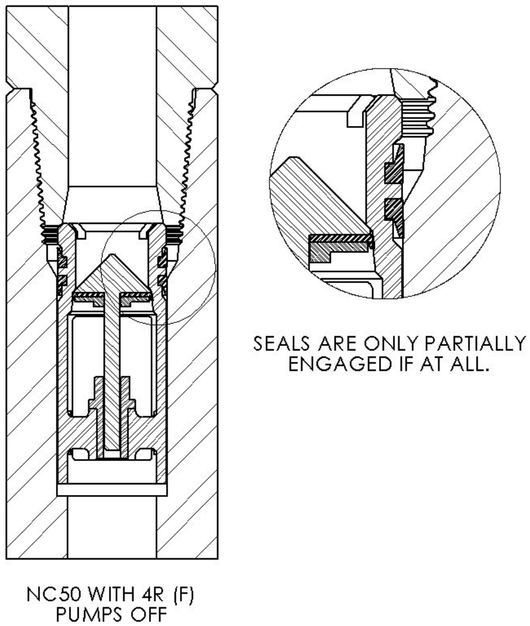

Figure 4 – API NC50 connection with 4R Model F float valve in pumps off position.

In the mid 2000's TH Hill revised the DS 1 standard to deepen the float bore of the box up configuration (Fig. 5) which allows both seals to be fully engaged when pumps are on, but with the pumps off the seals return to the same place they were without the deepened bore and are still not engaged. This change was an improvement, but the movement of the seals up and down in the float bore every time the pumps are cycled will wear the seals and the float bore and cause seal failures.

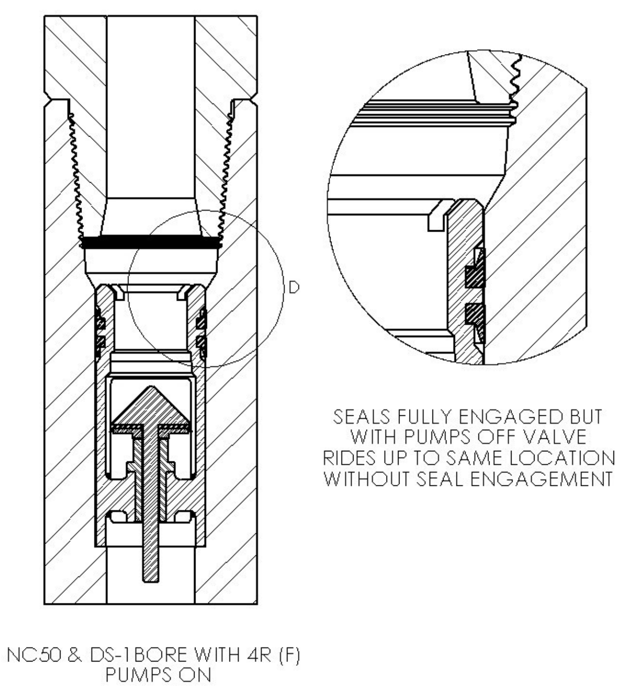

Figure 5 – API NC50 connection with 4R model F float valve in DS 1 float bore with pumps on.

The 3½ IF valve is specifically designed for the API 3½ IF connection but the seals are easily damaged without use of a special valve installation tool because the seals must ride across the threads in the bore during installation (Fig. 6). Also, as the valve moves up and down in the bore with each cycling of the pump the upper seal is at risk of tearing as it crosses the threads.

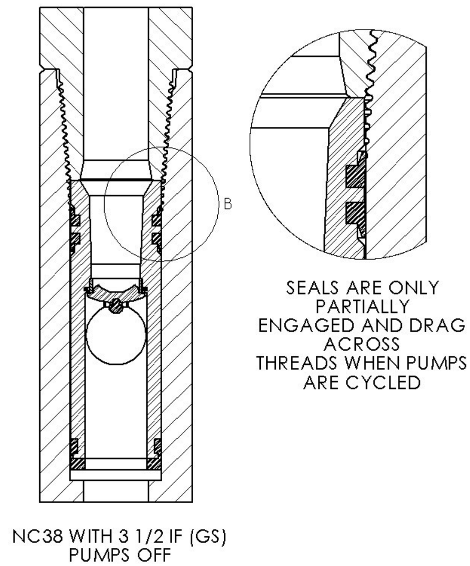

Figure 6 – API NC38 connection with 3½ IF Model G float valve with pumps off.

The seal location issue is also a problem with some non-API connections. The diagram shown (Fig. 7) is a popular proprietary connection in use today. The engagement of the seals is as bad as any case discovered in this study.

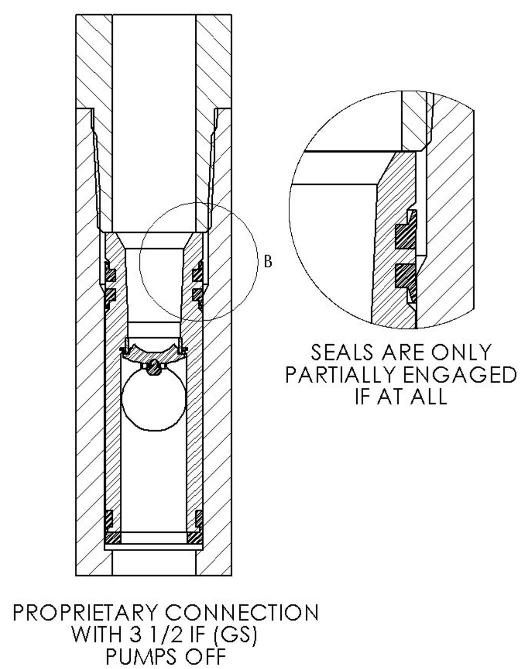

Figure 7 – Proprietary connection with 3½ IF Model G float valve with pumps off.

One valve manufacturer has the seals located in such a way the seals are always engaged with the float bore regardless of the pumps being on or off (Fig. 8).

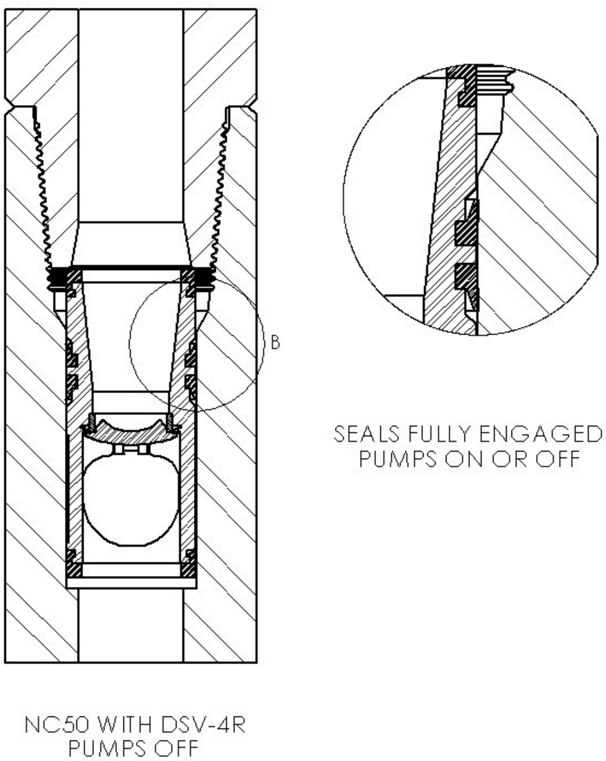

Figure 8 – API NC50 connection with DSV-4R float valve with pumps off.

Super-Spec Rigs Push the BHA & Float Valve to the Limit

With the advent of high-pressure super-spec rigs, the amount of energy available downhole has made a step change. This increase in energy has led to 50% increases in flow rates and available downhole pressure.

The 4R float, used for decades in intermediate (7⅞" to 8¾") hole sizes, historically operated at 500 gal/min and now is routinely pushed to 750 gal/min. This increase in velocity through the valve causes significant erosion to both valve and the bore of the float sub. This erosion has had a negative effect on both product life and safety.

A velocity plot from our CFD study of Model F valves vs Model GS valves, shows that the open cage plunger style floats Model F divert all the flow to the bore of the float sub (Fig. 9). The multiple rapid changes of direction cause turbulence and eddies that lead to erosion and washing. If a poorly retained valve moves past one of these eroded areas the seals could leak or be damaged. If a bore is pushed back when a connection is recut the erosion might not be noticed, and the seals could end up in the eroded area causing leaks and more erosion.

Use of the GS style floats allows a very axial flow path with no rapid changes of direction. This minimizes turbulence and thus erosion. The inner wall of the sub is isolated from the fluid running through the valve so there is no opportunity for erosion on the sub. Erosion is limited to the inner diameter of the valve and primarily on parts that are replaced at each valve service. This greatly reduces operational costs.

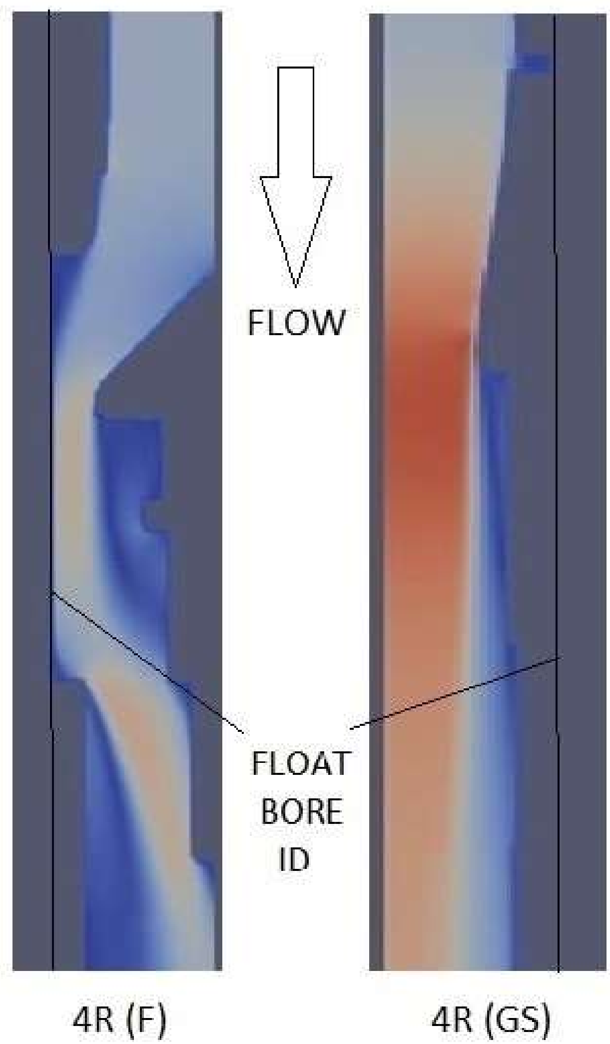

Figure 9 – API NC50 connection with 4R Model F float valve in pumps off position.

Increased energy downhole, higher rotational speeds, and longer laterals, especially with the use of rotary steerable systems, has led to an increase in fatigue failures in BHA connections. The box connection of the float sub used with common float valves does not allow for stress relief features in the box. The design of one float valve manufacturer will allow for traditional API style stress relief features and proprietary connections with similar features in the box up connections of the float subs (Fig. 10).

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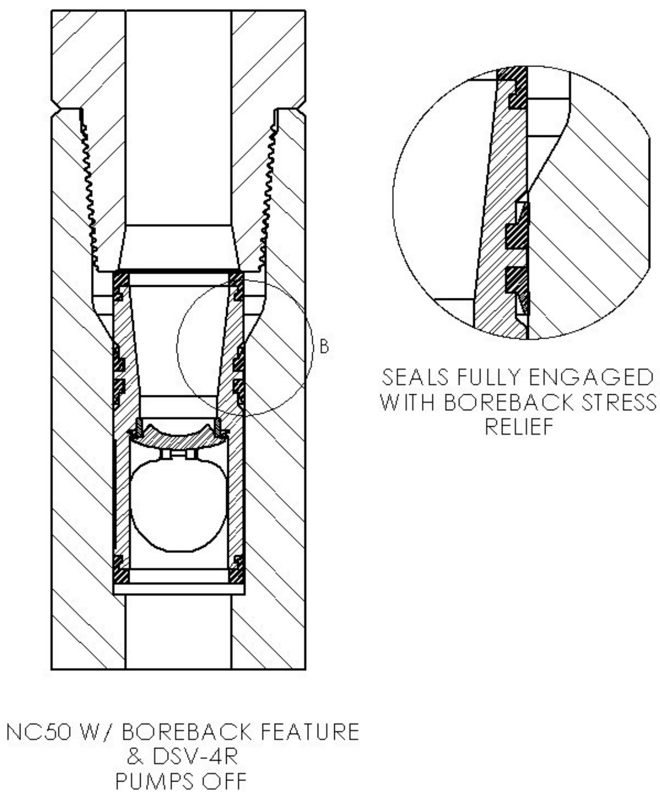

Figure 10 – API NC50 connection with a boreback feature and DSV-4R float valve with pumps off.

Increased downhole energy has led to the requirement of high-torque double-shouldered connections. Especially common in slimhole (5⅞” to 6¾”), these connections complicate float valve use. Since float valves require competent shoulders at both ends of the valve for containment, many equipment providers either use a smaller than recommended 2F3R float valve or a 3½ IF float valve with compromised shoulders.

If a 2F3R is used, the bore of the BHA equipment is commonly larger than the valve allowing it to float up the string to the first joint where the ID is smaller than the valve. The use of a retaining ring is sometimes employed but is not likely to withstand the 10ksi working pressure.

If a 3½ IF float valve is used, some equipment providers will remove some of the shoulder ID to get it to fit in the connection. This practice compromises the integrity of the double-shouldered connections. Grant Prideco strongly recommends using a two-part float sub to address this issue. (Grant Prideco – 2020).

Long Horizontals Push New Float Technology

A major oil company operating on the North Slope of Alaska drilling record wells of over 30,000 feet was having technological issues with float valve failures that were hampering their success. These failures were causing the wells to be tripped wet which was costing $250,0000 per trip and risking hazardous spills in the delicate arctic ecosystem.

Plunger-style floats were routinely failing even when four floats were run for redundancy. Lost circulation media was causing the plunger floats to leak. A switch to flapper style floats was tried with no success due to hinge wear on the float along with trapped LCM allowing the flapper to be off center and leak.

A new flapper valve technology with a self-aligning flapper, stronger hinge pin, and heavier springs, was adopted and has been very successful for many runs without a failure. The patented flapper (Fig. 11) has a unique profile which provides positive and highly repeatable sealing of the valve in very adverse conditions.

A relatively simple but very effective change to the float valves that have been run for decades made the difference between costly failure and great success.

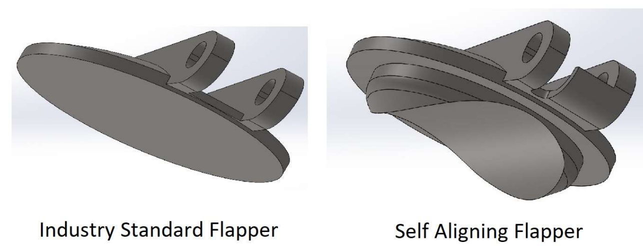

Figure 11 – Visual comparison of common flapper vs self-aligning flapper used in Model G/GS Floats.

Conclusions

- The float valve is and always has been the first line of defense to prevent dangerous well control situations.
- The float valve has been around for nearly 70 years and there have been very few improvements or changes to this technology during that time.
- In the last 30 years the drilling industry has changed profoundly with better rigs, better bits, better mud motors, and rotary steerable systems to mention just a few. The drilling environment has increasingly become more demanding, and the drilling equipment and technology has had to keep up.
- The current float valve designs are run in environments they were never designed to withstand. The design has not kept up with the current environment and is now in need of some improvements to maintain the safety of the drilling environment.
- Due to the valve being installed in box up connections the seals are not correctly engaged to prevent communication of the well bore fluids to the surface.

- The industry quite often runs floats that are undersized for the flow rates available in modern drilling, which has compromised reliability and safety.
- The current float technology can't safely be run with connection fatigue reducing features that would increase safety, reliability, and equipment life.
- When new rotary shouldered connections have been developed the effect on the efficacy of the float valve has often been overlooked increasing the likelihood of well control problems.
- The DrillSafe™ family of safety float valve systems provide technology solutions to address the shortcomings of the long overlooked float valve.

References

1. Baker, Reuben C. and Charles M. King, 1956. Patent #2,750,958, Drill Pipe Float Valve
2. Grant Prideco | NOV Wellbore Technologies, 2020, Product Bulletin PR-26.3-2001AUG02-EXT Rev.3