PRESSURIZED DUAL MECHANICAL SEALS SUPPORTING PIPING PLAN DEVELOPMENTS

by

Richard J. Smith

Director

AESSEAL plc

Rotherham, United Kingdom

Richard J. Smith became a Director of AESSEAL plc, in Rotherham, United Kingdom, in 1998. He began his career training as Design Engineer with the Ford Motor Company, working in both production and product development areas. He has been active in the sealing technology field for the past 24 years. Joining AESSEAL in 1989, Mr. Smith has worked for many years with the application engineering of sealing technology. He has extensive knowledge of field applications in many industry sectors. For the past seven years, he has been at the forefront of the Company's involvement in the oil and gas industry sectors for both upstream and downstream applications. He is currently AESSEAL's representative on the API 682 Task Force. Mr. Smith has had a number of technical papers published at conferences with articles published in international journals. These have been predominantly on the practical application of sealing technology and energy conservation.

ABSTRACT

The American Petroleum Institute recognizes four auxiliary piping plans for supporting pressurized dual wet mechanical seals. There is limited published information guidance as to which plan will offer the most suitable solution for any particular application. Recent work within the mechanical seal industry has led to an enhanced understanding of operational issues.

This paper is intended to fill in some of the gaps in knowledge and provide an overview of options available. A detailed description of the four plans is provided alongside a summary of the advantages and disadvantages of each. Issues associated with gas absorption and ambient temperature changes are explored alongside practical solutions. There is scope for innovation within supporting piping plans. New technologies are explained alongside test data and a case study.

Improved understanding will lead to improved specification that will reduce total cost of ownership. Greater knowledge will assist the operator in obtaining improved seal reliability.

INTRODUCTION

Over the past few decades the use of dual seals on pumping equipment has increased in popularity. Within the hydrocarbon and chemical process industries, plant safety requirements and the need for reduced fugitive emissions are the predominant drivers. Dual seals where a pressurized clean *liquid barrier fluid* is placed between the seals are most commonly applied. To maintain barrier fluid pressure and provide outer seal cooling a variety of associated supporting auxiliary piping plans have been developed. In the international mechanical seal standard (API 682 ISO 21049, Third Edition, 2004), the American Petroleum Institute (API) recognizes three piping plans, plan numbers 53A, 53B and 53C, that utilize internal circulating devices and one piping plan with external circulation, plan number 54. The three variations of the plan 53 type were first published in July 2002 (API 682 ISO 21049, Second Edition, 2002), while API plan 54 has been recognized for many decades. There is little discussion within the international standard of different plans and little guidance as to which plan will offer the most suitable solution for any particular application.This paper provides a detailed description of each of the plan 53 types and its operation. A general overview of some of the many variations of plan 54 is provided. The advantages and disadvantages of each of the different types are summarized. Nitrogen absorption and its effects upon the operation of plan 53A's are discussed and illustrated with accompanying test data. The influence of ambient temperature changes on plan 53A and B is discussed alongside proposed solutions. Plan 53C is also discussed in detail, including its primary advantages and also its Achilles heel where it is susceptible to contaminated fluid applications.

New technology can overcome the weaknesses of all the plan 53 types and is explained alongside test data and potential application groups that are presented together with a case study.

PRESSURIZED DUAL SEALS

Seal Arrangements

Arrangement 3 dual seals utilize high pressure fluid between the seals (Figure 1) and were traditionally called "double seals." The fluid between the seals is of a higher pressure than the process fluid in the seal chamber and this fluid is termed barrier fluid. The barrier fluid is normally pressurized approximately between 20 and 60 psi (1.4 to 4.2 bar) greater than the pump seal chamber. Arrangement 3 seals offers the highest level of safety and the elimination of process leakage to the atmosphere. The 53A, 53B, 53C and 54 plans discussed in this paper are used in conjunction with arrangement 3 seals.

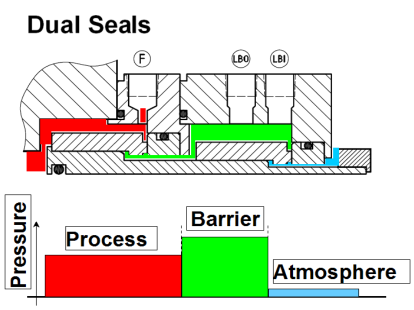


Figure 1. Arrangement Three Dual Seal.

ARRANGEMENT 3 PLAN DESCRIPTION

Primary Differences

All Plan 53 systems consist of a pressurized barrier fluid reservoir. An internal pump ring or circulating device (Figure 2) within the seal cartridge provides circulation of the barrier fluid. In plan 54 systems the barrier fluid is circulated by an external pump. Plan 54 systems may or may not incorporate a reservoir.

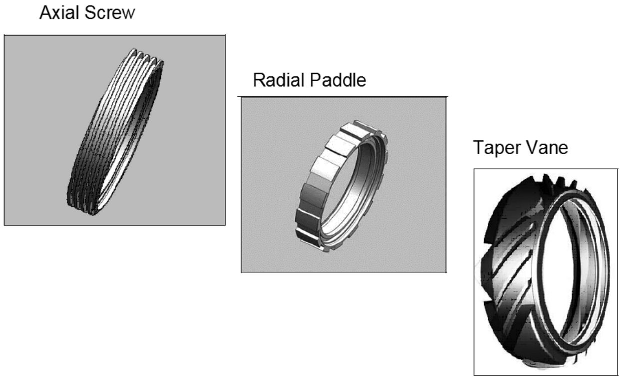


Figure 2. Internal Pumping Ring Types.

Plan 53A—Constant Pressure

A pressurized external barrier fluid reservoir stores a volume of clean barrier fluid that is circulated through the seal. Flow is maintained by an internal pumping ring; the barrier fluid passes from the seals through the reservoir and then returned back to the seals. The reservoir normally has an internal cooling coil; pressurization of the barrier fluid is normally via nitrogen from an external source. A regulator is normally used to maintain a constant pressure (Figure 3). Instrumentation is incorporated to Alarm in case of low liquid level and pressure.

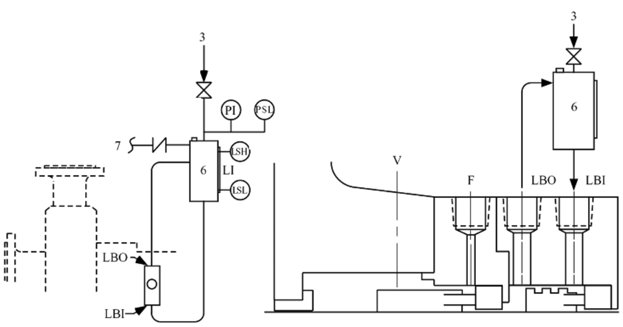


Figure 3. API Piping Plan 53A.

Plan 53B—Variable Pressure

Plan 53B differs from Plan 53A in that barrier fluid is stored and the pressure is maintained through the use of a prepressurized bladder-type accumulator. The barrier fluid is not circulated through the bladder accumulator but around a cooling "loop," which will include a separate heat exchanger. The accumulator is effectively on a "dead leg" (Figure 4), and its sole purpose is to store fluid and pressure; it does not play any part in cooling the barrier fluid. Flow is maintained by an internal pumping ring within the seal. The pressure will vary depending on the level of the liquid in the reservoir, and a pressure switch is used to alarm for a low liquid level based upon pressure in the system. Volume of fluid in a bladder accumulator cannot be directly measured.

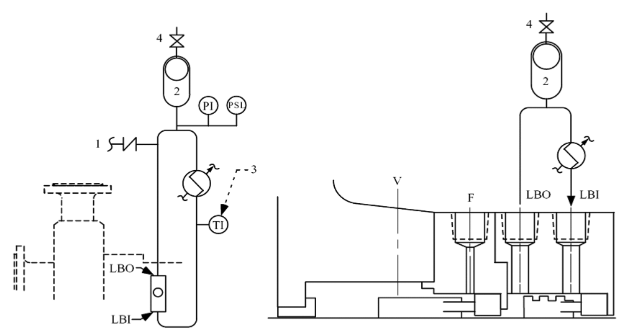


Figure 4. API Piping Plan 53B.

Plan 53C—Constant Differential Pressure Ratio

Plan 53C utilizes a piston-type accumulator to maintain pressure above seal chamber pressure. Similar to the 53B barrier the accumulator is on a dead leg with fluid circulated around a cooling loop with a heat exchanger (Figure 5). A reference line is taken from the pump seal chamber to the piston accumulator. The accumulator will therefore have process fluid on one side of the piston and barrier fluid on the other. The cross sectional areas on either side of the piston differ as a result of the accumulator having a piston rod on one side and not on the other. As the system is in equilibrium, the resulting forces on either side of the piston being equal, then the pressures will vary according to the mathematical formula pressure = force/area. It is therefore possible to provide a constant higher pressure in the barrier fluid above the process fluid pressure by exploiting the difference in cross sectional areas of the piston. Some piston accumulators use a spring to create higher pressure rather than using the area differential. The differential pressures across the inner seal faces remain virtually constant regardless of changes in pressure in the process fluid. Liquid level is monitored by a level switch or via a piston proximity switch.

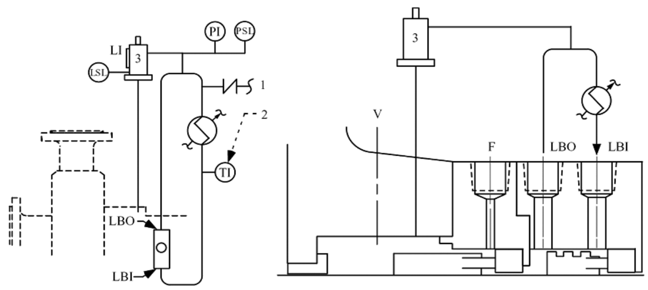


Figure 5. API Piping Plan 53C.

Plan 54

The API 682 standard provides very little in the way of guidelines to the configuration on plan 54. The plan is described as a pressurized external barrier fluid reservoir or system supplying clean fluid to the seal chamber. The diagram (Figure 6) in the international standard provides no details of instrumentation or fluid flow or pressure control. Users and seal vendors have effectively a blank canvas to design a suitable system for any given application or set of circumstances. The standard also states that the reservoir pressure is greater than the process pressure being sealed. However this is misleading, as there is not a reservoir mandated for plan 54. Future editions of API 682 are likely not to reference reservoir.

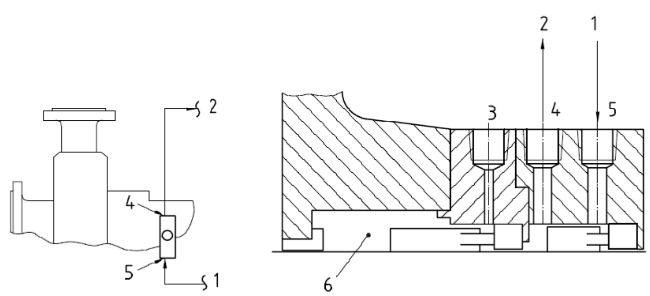


Figure 6. API Piping Plan 54.

There are many interpretations of plan 54 in operation of varying complexity. The scope of supply between the seal vendor and user will need to be clearly defined. The alarm philosophy will need to be properly thought out but such systems may incorporate pressure, flow, reservoir level and temperature alarms.

Some users may opt to specify API Standard 614 (1999), "Lubrication Shaft-Sealing and Control-Oil Systems for Special-Purpose Applications"; however this approach may provide users with an unnecessarily complex and expensive system for any service. A properly engineered system is often expensive. Where these systems are properly engineered, they provide among the most reliable systems.

Plan 54 systems can be divided into two basic groups: a once-through system and a dedicated recirculation system.

Once-Through Systems

These can be further broken down into two types

- A system that is based on a slip stream from a suitable process source, which is then, after passing through the seals, returned to the process. Pressure is normally maintained by use of restriction orifices and pressure control valves.
- A system that is based on a fluid stream from a suitable source, which is passed through the seals to a liquid effluent plant or recovery system. Such systems are more generally found in aqueous processes. Pressure is normally maintained by use of restriction orifices and pressure control valves.

Once-through systems can be attractive due to their relative simplicity; care should be taken to ensure that the source of the barrier fluid is always available when the seal is rotating. If orifices are used exclusively consideration needs to be taken for viscosity changes in the barrier fluid due to temperature changes.

Dedicated Pumped Systems

Again this group can be further broken down into two distinct types:

- A separate circulation system with an unpressurized tank (reservoir) with top up replenishment to maintain the barrier fluid volume. The external circulating pump will also serve to provide barrier fluid pressure in conjunction with a pressure control valve normally situated downstream of the seal.
- A separate circulation system with a pressurized reservoir with top up replenishment to maintain the barrier fluid volume. The pump provides circulation but not pressure. These systems are typically very similar to a plan 53A, B or C with the addition of the external circulation pump.

Dedicated external pump systems—These pump barrier systems should be designed so that each seal cartridge has facilities to indicate seal failure and loss of barrier pressure. Multiple seals connected to a common reservoir are prone to cross contamination, in an upset condition. If process fluid enters the barrier fluid system all seals will become contaminated. A robust pressure alarm system/procedure is required or using a separate reservoir for each seal (or pump in the case of a between-bearings pump) will resolve this issue.

Many users will view the barrier supply pumps to be a critical service and therefore insist on a system incorporating installed spare barrier fluid pumps and in some circumstances, a separate power supply.

Barrier reservoirs also need a level transmitter to initiate a low and a high level alarm. Unpressurized tanks are sometimes specified with a nitrogen blanket and a vent to atmosphere or to the flare system.

SYSTEM SELECTION INFORMED CHOICE OR USER PREFERENCE

Geographical Anomaly

Since the incorporation of the three piping plans into the international standard API 682 ISO 21049, Third Edition (2004), the most popular specified plan 53 in Europe and Asia is the API Plan 53B. Interestingly, the North American market has not had such a widespread adoption of this plan with the traditional Plan 53A being the most widely specified and used. The reasons for this regional variation in piping plan preferences are unknown. In the preparation of this paper, the author researched and could not find any authoritative text that could lead users to such choices. One commonly held belief is that 53B offers the advantage in that there is a membrane (the rubber bladder) between the pressurizing gas, nitrogen, which prevents nitrogen absorption into the barrier fluid. There is a commonly held notion that this absorbed gas will impact on the reliability of the outboard seal in any dual mechanical seal arrangement. The author again is unaware of any text that explains this phenomenon or proves this hypothesis in practice. One would also expect the North American market to enjoy lower levels of reliability on dual mechanical seals because of predominate use of Plan 53A systems than the European market, which has predominately adopted 53B. Again, no specific studies have been undertaken on such a small seal group. However, it has been reported (API Standard 682, Annex A, 2004) that North American refinery seal mean time between repair (MTBR) is virtually identical to European seal MTBR. It is suspected that the choice between Plans 53A and 53B comes down purely to customer preference, or company tradition or cost.

Cost Implications of Different Plans

Figure 7 provides an illustration of the comparative costs of auxiliary piping plan hardware. Plan 52 is added to provide a relative benchmark. The cost indicated does not include the cost of the services that the auxiliary piping plan will need to be hooked up to. Table 1 provides guidelines as to the hidden costs.

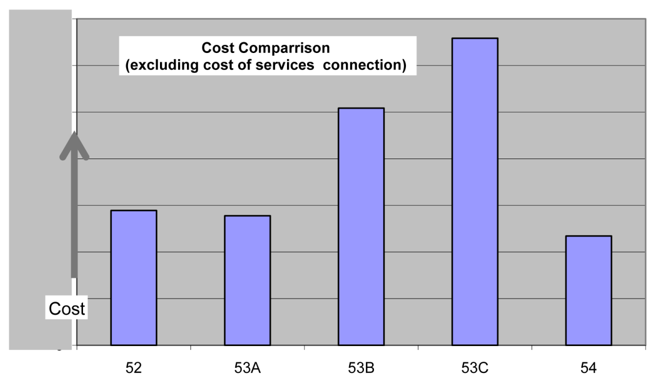


Figure 7. Relative Hardware Cost Comparison.

Table 1. Services and Instrumentation Requirements.

Plan	Services	Instruments
52	Flare	1
53a	N2	2
53b	None	1 current practice
53c	None	1
54 once thro	BF piping	1 or more
54 Recirc	power	2 or more

Potentially plan 54 can offer the lowest cost system; however this is dependent on the level of specification. A simple once-through system has the cost of piping to consider. A simple recirc system with an atmospheric tank and unspared pressurizing pump will be low cost. However, consideration needs to be made for the cost of running a power cable to the pump head.

API 682 illustrates Plan 53A seal reservoirs with screwed connections. Many users opt to upgrade to flanged connections. There are also many users who prefer stand off flanged level gauges. Optional flange bottom reservoirs (for cleaning) are also available. The additional cost of such items rapidly increases the cost of the 53A unit and the price then becomes comparable, or in some instances, more expensive than the equivalent 53B plans.

Plan 53A will also have a greater installation cost in that it requires connection of at least two instruments and connection to a nitrogen service.

There is a common perception that Plan 53B is relatively low cost; bladder accumulators are mass produced and effectively "off the shelf." However, all the ancillary instrumentation and cooling has to be incorporated into the system package. These ancillaries are normally mounted onto a panel on a stand. With a 53A these components are mounted directly onto the vessel; 53B systems tend to be more expensive than a standard 53A as a result. However, with no connection required for a plant nitrogen system and only currently one instrument specified the installed cost is probably about the same as a standard 53A. 53C is the potentially highest level of pricing; effectively this system has the same cost as a plan 53B but with the complexity of the piston accumulator replacing the bladder accumulator. However, with few instruments and no external services, the 53C can be surprisingly competitive.

COMPARATIVE ADVANTAGES AND DISADVANTAGES OF 53 PLANS

Plan 53A

One of the principle advantages of 53A is its simplicity; operators can easily understand its operation. Limitations of Plan 53A are that its maximum pressure is limited to that of the nitrogen system available in the plant. This can be overcome by use of nitrogen bottles, which adds to the complexity and cost. Some users also have reservations about the use of a 53A system due to concerns over the robustness of the nitrogen supply and any potential contamination into the nitrogen header. Absorption of nitrogen into the barrier fluid remains a concern. This is discussed further in the section, "NITROGEN ABSORPTION AND 53A."

Cooling Circuit and Reservoir Placement

53A reservoirs form part of the cooling circuit. As circulation of any plan 53 system is via a pumping ring within the seal consideration needs to be given to reduce the pressure drop within the circuit. The reservoir has little restriction to the barrier fluid flow; however the length of the lines between the reservoir and seal gland plate should be minimized. To promote thermosyphon cooling when the pump is idle, the height of the normal liquid level in the reservoir above the gland plate of the seal should be not be less than 3 ft (1 m). All lines need to slope up from the pump gland to the reservoir at a minimum of ½ inch per ft (10 mm per 240 mm). Reservoir placement is therefore effectively restricted to be adjacent to the pump.

The internal cooling coil on standard API reservoirs may not provide sufficient heat removal on some high temperature services. Additional coolers are occasionally employed to supplement cooling and are installed in series within the cooling circuit.

Ambient Temperature Effects/Solar Radiation

There is a potential for the nitrogen pressure within the reservoir to be affected by ambient temperature changes. With the process fluid passing through the reservoir the temperature will be stabilized to some degree. If the cooling coil is used, this further mitigates the effect. However, if the unit is an installed spare then ambient temperature variation and resultant pressure changes can be a factor to consider. Use of a self-relieving regulator overcomes these issues but environmental consideration of any product contamination of the barrier fluid and subsequent release to atmosphere are concerns cited against this approach. However, the potential for release of process fluid to the atmosphere would be an extremely unlikely event with three or more fault conditions to occur simultaneously and alarms to be ignored.

Section Summary

The advantages and disadvantages are summarized in Table 2.

Table 2. Plan 53A Advantages and Disadvantages.

53A Advantages	53A Disadvantages
Simple Operation Visible liquid level	Limited to plant gas pressure can be over come by use of pressure intensifiers or bottles
Any contamination debris wear particles will settle in bottom of pot	Barrier is in contact with pressurising gas perceived issue with nitrogen absorption
Lowest system resistance provides high Barrier Fluid flow rates	Heat dissipation values limited to size of internal coils and surface area of vessel. Other plans have separate and potentially larger coolers
Potentially lowest cost	Reservoirs need to be located in close proximity to seal to ensure adequate BF circulation
large installed base - good understanding	Pressure is not variable and therefore on variable duties pressure differentials may be high
Constant barrier pressure	May be subject to pressure changes due to diurnal and seasonal changes
Easy operation and maintenance	Change in system temperature may change BF pressure

Plan 53B

One of the advantages of the 53B system is that there is no connection to an external nitrogen source. The bladder accumulator is precharged with nitrogen during commissioning. The nitrogen is separated from the barrier fluid by a rubber bladder so the nitrogen absorption issue is avoided. A disadvantage with a 53B is there is no direct method of measuring liquid level within the accumulator. Pressure will be higher when the accumulator is topped up with liquid and the gas volume reduced. As the liquid depletes through normal seal leakage and the gas volume increases the pressure in the accumulator decays. The alarm is by low pressure rather than low liquid level. The system pressure is therefore variable and this can cause some reliability issues with the seal faces. Tutorial Annex A of API 682 ISO 21049, Third Edition (2004), describes how:

"after a contacting seal has worn in to match a certain set of operating conditions, changing those conditions can result in increased leakage until the faces have worn to match the new conditions."

With a 53B there is a slow pressure decay; the faces will be continually bedding themselves in to match the reducing pressure. Upon refilling of the accumulator the pressure is increased, in some cases significantly. The worn-in faces will have to rapidly wear to bed themselves into this new condition with increased leakage during this period.

Cooling Circuit Considerations and Accumulator Placement

Unlike Piping 53A, Piping Plans 53B and 53C may utilize an external cooler; the circulating flow does not pass through the accumulator. The accumulator and instrumentation are effectively up a dead leg and not part of the barrier fluid circuit. The accumulator set has more freedom of position; this is a potential advantage in installations where space is restricted. Placement is also possible for convenience of maintenance.

The external cooler is placed in the cooling circuit and has similar restrictions of placement as a 53A reservoir. Coolers can be conventional shell and tube, forced draft air coolers, or natural draft air coolers (finned piping). For lower duties it may be that the surface area of the piping in the cooling circuit is sufficient to dissipate the heat load from the seal.

Care needs to be taken where heat loads are high; the flow restrictions in traditional coolers may cause a pressure drop and negatively affect the pump ring's ability to provide for adequate flow. A number of coolers are now available on the market that minimize these effects.

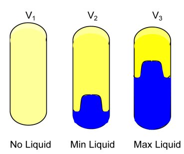
Ambient Temperature Affects/Solar Radiation

53B systems with their trapped gas volume are very susceptible to changes in ambient temperature. Where there is a large diurnal and seasonal changes in ambient temperature, barrier fluid pressure will correspondingly be affected. If ambient temperature conditions are not taken into consideration when designing the alarm strategy, in extremely hot ambient conditions, it may be possible that the accumulator becomes completely depleted of liquid without triggering the pressure alarm.

On extremely cold nights, the pressure alarm may be activated when there is still sufficient liquid remaining in the accumulator. The operator will then refill the barrier fluid, causing excessive fluid volumes in the accumulator, which may over-pressurize the system if the temperature rises the following day. Solar radiation can amplify this problem (Figure 8). Figure 9 provides a user with a proposed alarm strategy. However adopting this may force users to specify unnecessarily high barrier fluid pressure. This will cause unnecessary wear and stresses on the seal faces and may limit operators in the use of back-to-back dual seals, which have compromised reliability (Smith, 2008) on contaminated and abrasive services. Another proposed strategy, which is included in the Draft International Standard for the fourth revision of API 682 ISO 21049, will propose that the simple pressure switch is replaced by a pressure and a temperature transmitter. Taking both readings and using simple logic of a distributed control system (DCS) the actual liquid level is thus calculated. The effects of ambient temperature change can be further mitigated by the following:

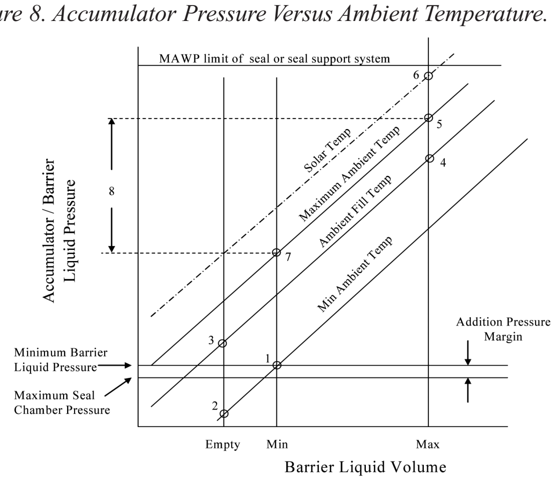
- Pressure relief valve in the barrier liquid piping
- Shade the accumulator to eliminate solar radiation effects.
- By insulating and/or temperature control (heat tracing for example) of the accumulator

Input Data					
Max Site Temperature		104	°F	40	°C
Min Site Temperature		14	°F	-10	°C
Solar Radiation Temperature		176	°F	80	°C
Ambient Temperature @ time of filling		68	°F	20	°C
Reservoir Size	V_1	5.28	gal	20	l
Minimum Liquid Volume	$V_1 - V_2$	0.53	gal	2	l
Liquid Volume @ V_3	$V_1 - V_3$	1.24	gal	4.7	l
Seal Box Pressure	P_{SB}	508	psig	35	barg
Require Pressure above Seal Box @ Min Liquid Level		0	psig	1.4	bar
Estimated Seal Leakage Rate		0.04	fl oz/hrs	1.23	gr/hrs
Minimum Ambient Conditions					
Pre-Charge pressure @ V_1	P_c	475	psig	32.76	barg
Pressure at Minimum Liquid Volume	P_{min}	528	psig	36.40	barg
Gas Pressure @ Volume V_3	P_{max}	621	psig	42.82	barg
Delta P Max Liquid Level to Min Liquid Level	P	93	psig	6.42	bar
Estimated Time Max to Min Liquid Volume				91	Days
@ Ambient Conditions					
Pre-Charge pressure @ V_1	P_c	529	psig	36.50	barg
Pressure at Minimum Liquid Volume	P_{min}	588	psig	40.55	barg
Gas Pressure @ Volume V_3	P_{max}	692	psig	47.71	barg
Delta P Max Liquid Level to Min Liquid Level	P	104	psi	7.16	bar
@ Maximum Ambient Conditions					
Pre-Charge pressure @ V_1	P_c	565	psig	38.99	barg
Pressure at Minimum Liquid Volume	P_{min}	628	psig	43.32	barg
Gas Pressure @ Volume V_3	P_{max}	739	psig	50.96	barg
Delta P Max Liquid Level to Min Liquid Level	P	111	psi	7.64	bar
Check Max Pressure @ Solar Radiation Temperature					
Pressure		833	psig	57.48	barg



Calculations are based on Boyles law. It is assumed that no work takes place

Figure 8. Accumulator Pressure Versus Ambient Temperature.



1 Minimum pressure at minimum barrier liquid volume and minimum ambient temperature.
2 Gas pre-charge pressure zero liquid volume min ambient temperature.
3 Gas pre-charge pressure normal ambient temperature at the time of charging.
4 Maximum pressure with the maximum barrier liquid volume at the normal ambient
5 Maximum pressure at maximum barrier liquid volume maximum ambient temperature.
6 Pressure at maximum barrier liquid volume, but at the solar radiation temperature.
7 Alarm pressure set point. Pressure at minimum liquid volume &maximum ambient temperature.

Figure 9. Proposed Alarm Strategy.

Section Summary

The advantages and disadvantages are summarized in Table 3.

Table 3. Plan 53B Advantages and Disadvantages.

53B Advantages	53B Disadvantages
Remote location of accumulator possible	Complex Operation liquid level not visible
Not dependent on nitrogen or gas source	Complex to set up requiring calculation of precharge pressures
BF isolated from nitrogen preventing Gas absorption	Subject to pressure changes due to diurnal and seasonal ambient temp change
Change in system temperature does not significantly change system pressure (No BF flow through accumulator)	Pressure is not variable and therefore on variable duties pressure differentials may be high
Bladder accumulators wide range readily available	Any contamination debris wear particles will remain in the seal loop
Can accommodate different liquids by varying the bladder material	Smaller volume of liquid gets thermally cycled more frequently limiting the life of the BF
High pressure accumulators are available	Finite volume of the accumulator - pressure dependent on Liquid level. Pressure differentials need to be considered when selecting seal configarations
Compact modular design - small footprint	Separate heat exchanger may increase system resistance and reduce BF flow (pump ring efficiency
Full welded design meets ASME/PED requirements	Varying pressure may cause higher wear & leakage rates to inner & outer seal. inner and outer seals are continually operating and attempting to wear in at different pressures.

Plan 53C

The 53C system potentially offers a very elegant solution. There is no nitrogen in contact with the barrier fluid, therefore gas absorption issues are eliminated. The barrier fluid pressure tracks the changes of the seal chamber pressure. This provides an idealized working environment for the inner seal. Differential pressure across these faces will always be at a constant ratio reducing inner seal stresses, wear and improving reliability. Changes in ambient temperature will have no effect as there is no stored gas volume and any expansion of the liquid will be relieved back to the seal chamber via the reference line. However, 53C has its Achilles heal: the reference line and the piston accumulator have to be compatible with the process fluid. Contaminated fluid may block the reference line or potentially damage the piston seals. This limits the 53C application group to clean noncorrosive fluids. If the process fluid is dirty, contaminated, corrosive or very high viscosity at ambient temperature, then the choice of a 53C may well be inappropriate.

Cooling Circuit Considerations and Accumulator Placement

As the 53C cooling circuit is identical to that of a 53B, cooling considerations detailed in the previous section, *"Cooling Circuit Considerations and Accumulator Placement."*

Section Summary

The advantages and disadvantages are summarized in Table 4.

Table 4. Plan 53C Advantages and Disadvantages.

53C Advantages	53C Disadvantages
Remote location of accumulator possible	Can only be used on clean non solidifying fluids. Reference line blockages or contamination damaging piston accumulator will cause failure in barrier fluid pressure
Not dependent on nitrogen or gas source	Any contamination debris wear particles will remain in the seal loop
Constant pressure differential across inner seal faces reducing stresses Leakage and wear	Smaller volume of liquid gets thermally cycled more frequently limiting the life of the Barrier Fluid
Volume of Barrier Fluid can be monitored	Tends to be more expensive option
Can be used in applications where seal chamber pressure vary considerably	Piston seal has to be compatible with process fluid
Change in system temperature does not change system pressure (No BF flow through accumulator)	Less compact than 53B due to pipe work connections

Plan 54

The principle advantage of plan 54 is the increased potential for heat removal from a seal system. Flow rate on a plan 53 system is dependent on the efficiency of the pumping ring within the seal and the resistance within the auxiliary piping plan pipework. Plan 54 does not have these restrictions as the external pump is not restricted in size. With higher flow/head available plan 54 can be used with larger heat exchangers; an example would be a finned tube heat exchanger. Hypothetically with plan 54 the tube can be of infinite length.

The most common application group of plan 54 is for hot temperature services to improve heat removal or maintain a lower barrier fluid temperature. Plan 54 is also suited to applications with small shaft sizes, low rotational speed or variable speed drive, where plan 53 system seal circulation devices performance is compromised. In services where there is a limited operating temperature window for the process fluid plan 54 can potentially offer more thermal stability. Barrier fluid may be heated or cooled as appropriate and circulation can be guaranteed in periods of operational idleness.

Section Summary

The advantages and disadvantages are summarized in Table 5.

Table 5. Plan 54 Advantages and Disadvantages.

54 Advantages	54 Disadvantages
Location unrestricted	No Standard design each application will need to be properly thought through at the design stage.
Not dependent on nitrogen or gas source	Designs can become extremely complex
BF Isolated from Nitrogen preventing Gas absorption	Non standardization & complexity provides opportunity for human error in operation
Heat removal capacity unrestricted	Moving parts will require maintenance
Can be adapted to track seal chamber pressure	
Can maintain flow during period of operational idleness (stand by)	

Plan 53A, B, and C Reservoir Size

API 682 dictates the size of a 53A reservoir to 5 gallons (25 liters) for seals intended to fit shafts above 2.5 inches (60mm). For smaller shafts a 3 gallon (12 liters) reservoir is specified. However, this is a little misleading as the actual working volume of the reservoir is significantly less (Figure 10). The maximum and minimum liquid levels are dictated by the length of the sight glass. This provides for typically 1.3 gals (5 liters) and 0.7 gals (2.7 liters) volume for the two size reservoirs. The *hold up time* or time between top up intervals is based on the seal leakage rate and this smaller working volume.

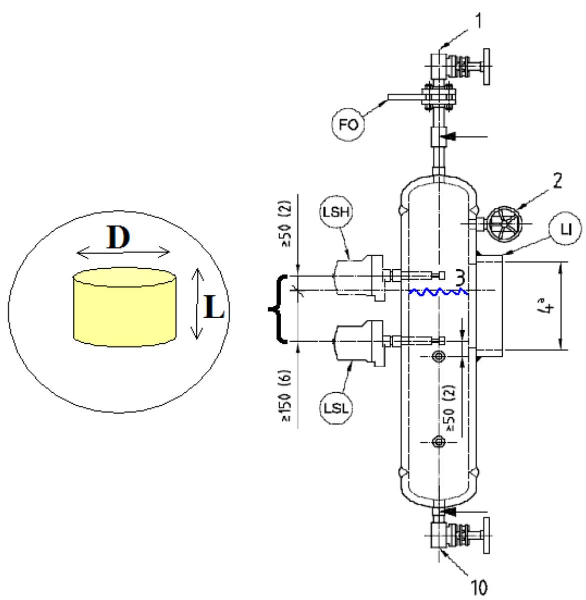


Figure 10. Reservoir Working Volume.

There are currently no specified sizes for Plan 53B or C reservoirs. For Plan 53C the calculation is relatively straightforward in that the volume should be at least that of a 53A reservoir. This will provide a broadly equivalent hold up time between refills. For 53B, the calculation can be more complex. However for shaft sizes greater than 2.5 inches (60 mm), an accumulator of 9 gals (35 liters) and for smaller shaft sizes of 5 gals (20 liters) should provide an adequate volume for most applications. The choice of these sizes has been based on achieving broadly comparative working liquid volumes to the 53A. When barrier fluid is at minimum pressure (at minimum ambient pressure) the retained liquid in the accumulator should be at least 1 percent by volume.

Selection Flowchart

Figure 11 is a flow chart that is offered as a general guideline for selection of appropriate dual seal piping plan. The flow chart takes into account some of the principle decision points. Step three is in line with current API guidelines on the use of barrier fluid systems where the nitrogen is in direct contact with the fluid and concerns with absorption. This philosophy is discussed in this paper in the following section, "NITROGEN ABSORPTION AND 53A." Step four makes the assumption that API 682 seals are used and that ambient temperature will vary by 70°F (40°C). Use of 53B systems above this limit could cause pressure variation at extreme temperatures to exceed the scope of API 682 seals. If higher pressure seals are used then this limit can be ignored. For more detailed selection the seal vendor should be consulted.

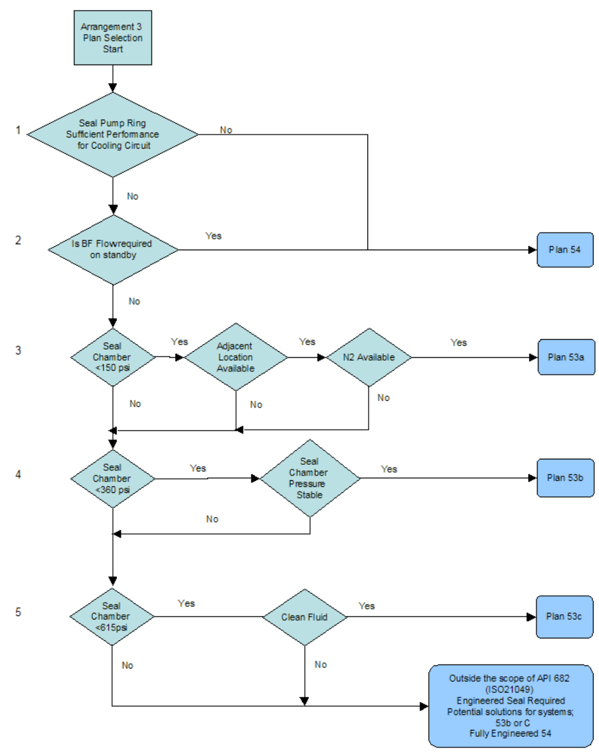


Figure 11. Dual Seal Piping Plan Selection General Guideline.

NITROGEN ABSORPTION AND 53A

With a 53A system the pressurized nitrogen is in direct contact with the barrier fluid. The hypothesis is that over time nitrogen may become absorbed in the barrier fluid. During seal operation a minute amount of this barrier fluid will be passing across the outer seal faces as fluid film and passing to atmosphere, therefore subject to a pressure drop across the faces. There is evidence that nitrogen may be liberated due to rapid decreases in pressure and the theory is that this can happen at the seal faces where pressure reductions occur and the result can be instability or contact with the outer seal faces. There is anecdotal evidence from the field that foaming barrier fluid has been observed on the atmospheric side of dual seal outer faces. This "theory" of the effects of nitrogen absorption is widely discussed within the industry; however there appears to be no publicized information on this subject and the effects upon seal reliability. The author has been unable to trace any field or scientific studies in the presentation of this paper.

In 2002 the international standard API 682 Second Edition (2002) was published. This standard offered a tutorial that advised a maximum pressure limitation for plan 53A systems of 145 psi (10 bar) in an attempt to eliminate or at least minimize the effects of gas absorption (Smith, 2008). In February 2007, the API 682 task force preparing revision four discussed this phenomenon again and there was considerable difference of opinion among the task force members as to what this threshold value should be, if indeed there should be one. Several individuals advocated that the 145 psi (10 bar) threshold was far too conservative. Indeed, one major manufacturer had performed the majority of its qualification tests using plan 53A and had observed no negative effects to seal performance due to gas absorption.

Testing

In 2007 a test rig was designed and built to provide direct comparison between 53A and 53B operation. Seals could be dynamically tested utilizing a plan 53B system and then switched over to a plan 53A system (Figure 12).

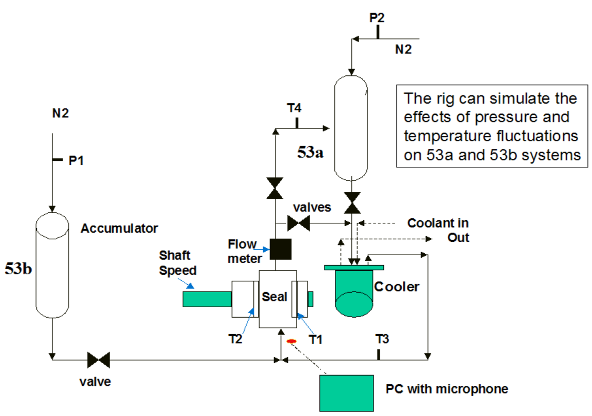


Figure 12. Gas Absorption Test Rig.

Barrier fluid pressure was set at an arbitrary 363 psi (25 bar), which is considerably higher than the threshold advocated in API 682 ISO 21049, Third Edition (2004). The seal was first operated in 53B mode and then switched over to 53A. Of particular interest is the outside seal faces as they are subject to the highest pressure differentials, 363 psi (25 bar) to atmosphere, and therefore the highest stresses and will consequently exhibit the highest temperatures. Accurate temperature measurement (Figure 13) would therefore indicate any contact or abnormal running. However surprisingly it was observed that temperatures were virtually identical between 53A and 53B mode operation. The 53A system was left pressurized for 15 hours to ensure nitrogen absorption; again no difference was observed in outside face temperatures.

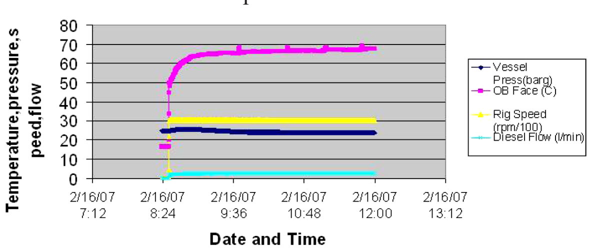


Figure 13. Start after 15 Hours Overnight at 360 psig (25 barg).

When the seal was subject to rapid decompression it was noted that in plan 53A mode outside face temperature rapidly increased. It was also observed that barrier fluid flow rate decreased and flow was lost. However the pressure had to decay to a very low level, approximately 7 psi (0.5 bar) before a significant effect was noted (Figure 14). One conclusion of this may be that the circulating device or pumping ring within the seal starts to cavitate as nitrogen is liberated during decompression.

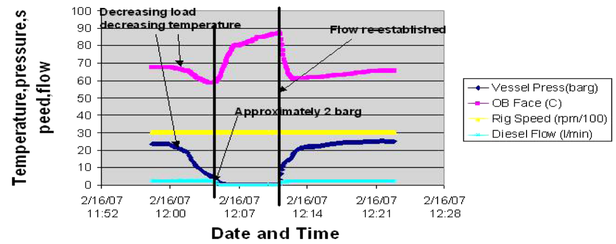


Figure 14. Slow Depressurization after 18 Hours at 360 psig (25 barg).

From these limited experiments the author cannot conclusively say that nitrogen absorption does not cause a problem in the field. The jury is still out!

A MODIFIED PLAN 53C

General Description

An alternative solution that opens up the application group for 53C applications has been developed (Figure 15). The system can be used on contaminated, corrosive, high temperature/viscosity process fluids. In this system the piston accumulator is pressurized by nitrogen via a pressure tracking valve (Figure 16). A pressure reference line from the seal chamber is used and use of an instrument isolator prevents process fluid entering the instrument while referencing the process pressure to the instrument. Typically the reference line will be filled with a benign fluid.

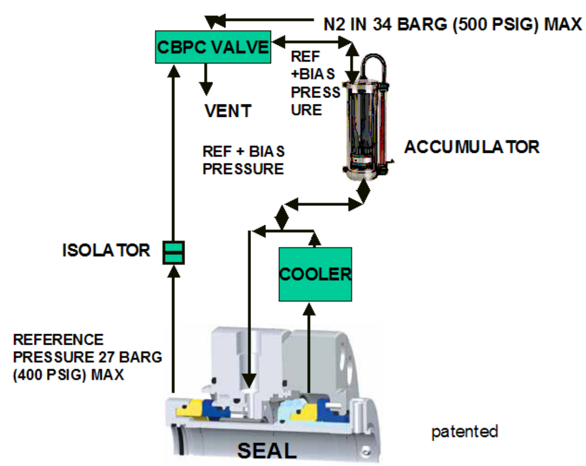


Figure 15. Plan 53C Modified.

Figure 16. Tracker Valve.

Function

The system will track the seal chamber pressure in a similar way to the standard 53C system thereby providing all the reliability advantages of constant pressure ratio across the inner seal faces. As the pressure in the seal chamber increases, the tracking valve increases the nitrogen pressure in the piston accumulator by a set amount that can be varied, thereby increasing the pressure in the barrier fluid by a corresponding amount. With a reduction in seal chamber pressure the tracking valve vents pressure away from the piston accumulator, thus reducing the barrier fluid pressure. The differential pressure can be set to optimize conditions.

Testing

Testing was carried out to understand the ability of the tracking valve to react to pressure variations in the seal chamber. Results of some of the testing are illustrated (Figure 17) and indicate rapid tracking valve response to changing pressures.

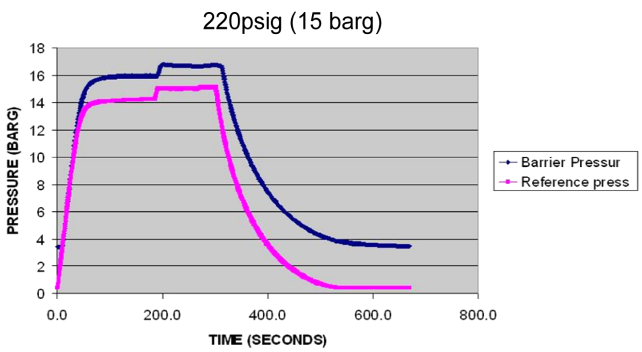


Figure 17. Reference Pressure Simulated Stuffing Box Pressure.

Applications of Tracking Valve Technology

Traditionally, on abrasive and contaminated services, users have opted for Plan 53A or B systems. One of the drawbacks of these systems is the potential for high barrier fluid differential, which infers the selection of back-to-back or face-to-face dual seals. Both these designs have inferior performances for contamination and abrasive services (Smith, 2008). Face-to-back designs have a more limited differential pressure capability; however they offer superior reliability in abrasive and contaminated services and will now enjoy a far wider application group when used in conjunction with tracker valve technologies.

Use with 53A

The tracking valve can also be applied to plan 53A systems in a similar way (Figure 18).

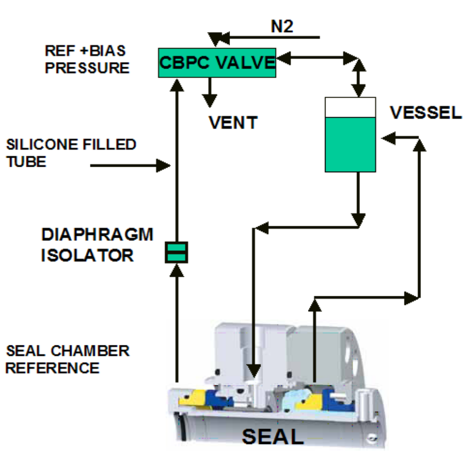


Figure 18. API Plan 53A Modified.

CASE STUDY

Pressure Tracker Installation

At a major pharmaceutical production facility in the United Kingdom, a pressure tracking valve with a diaphragm instrument isolator is installed in conjunction with a plan 53A barrier support system. The system supports a dual mechanical seal on a top entry reactor vessel. The duty is summarized in Table 6; pressure tracking pressure varies from 7 psi (0.5 bar) to 225 psi (15.5 bar). The pressure tracker is supplied with nitrogen at 290 psi (20 bar), which will enable maintenance of the pressure in the barrier support system at 29 psi (2 bar) above the pressure in the production vessel. The tracker is connected via the mechanical seal flush line, which will give the reference pressure for the tracker unit (Figure 19).

Table 6. Summary Pressure Tracking Valve Duty Details.

Details	Agitator top entry
Equipment	Initiator tank
Location	United Kingdom
Production	Heptane and propylene with other unknown chemicals
Vessel temperature	53°F (12°C)
r.p.m.	168 rpm
Vessel pressure (barg)	Variable between 7-230psig (0.5 – 15.5 barg)
Seal type	3CW-FB Model AESSEAL CAPI 1.575" (40mm
Barrier support system	Plan 53a Modified Aes15-1
Barrier fluid	Exxon Isopar
Barrier fluid pressure	Tracked between 37 - 260 psig (2.5 - 17.5barg)

Figure 19. Tracking Valve Installation.

The seal has seen the significant variations in service conditions (Figure 20); leakage rates are consistently low at a fraction of API 682 qualification test limits.

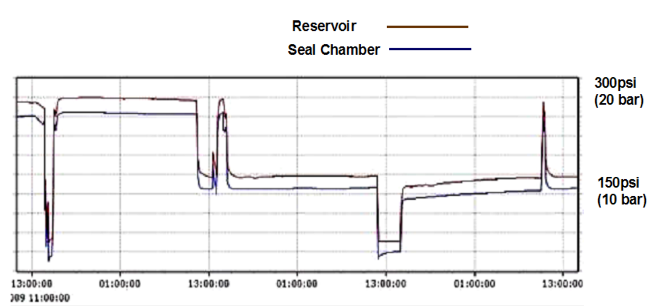


Figure 20. Tracking Valve Operation.

CONCLUSION

With many options of liquid barrier fluid piping plans available the choice can sometimes appear daunting. Informed application of liquid barrier fluid piping plans can improve mechanical seal reliability and reduce total cost of ownership. There are many variables to consider at the design stage. The understanding of these issues will also assist in operation and troubleshooting. Sound engineering principles are applicable across all industry sectors.

Pressure tracking barrier fluid piping plans reduce the stresses on mechanical seals and improve longevity.

Technology continues to develop and pressure tracking systems are now available for use on contaminated services. With these systems combined with face-to-back seal designs the user will enjoy improved seal life.

REFERENCES

API Standard 614, 1999, "Lubrication Shaft-Sealing and Control-Oil Systems for Special-Purpose Applications," Fourth Edition, American Petroleum Institute, Washington, D.C.

API Standard 682, 2002, "Shaft Sealing Systems for Centrifugal and Rotary Pumps," Second Edition, American Petroleum Institute, Washington, D.C.

API Standard 682, 2004, "Shaft Sealing Systems for Centrifugal and Rotary Pumps," Third Edition, American Petroleum Institute, Washington, D.C.

API Standard 682, 2004, Annex A, Sheet 10 of 10 "Shaft Sealing Systems for Centrifugal and Rotary Pumps," Third Edition, American Petroleum Institute, Washington, D.C.

Smith, R., 2008, "Contradicting Requirements in API 682 Dual Seal Design Configurations," AESSEAL plc, Proceedings of the 10th Fluid Machinery Congress, IMECHE.

ACKNOWLEDGEMENTS

The author would like to acknowledge the following for their valued work on some of the issues presented: Stephen Shaw and John T. Bright, AESSEAL plc; Chris Fone, European Sealing Association; Tom Arnold, Fluor. The author would also like to acknowledge the work of Tony Semple from Bechtel. Tony was originally going to coauthor this paper. He was probably the individual who first grasped some of the temperature pressure issues with plan 53A and B systems and also the first to offer the combined temperature pressure measurement to overcome 53B alarm strategy problems. Sadly, Tony died in October 2008 before he was able to see some his ideas incorporated into the revision of the API 682 Standard.