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Contain 'normal' leakage from primary seals

Dry containment seals have gained popularity over the last few decades and provided reliable service. The refinery sector has used this sealing technology to limit fugitive emissions in a cost-effective manner by not incurring the cost of liquid dual-seal systems.

Little has been written about monitoring the condition of dry containment seals during operation, or how they behave in the event of high levels of leakage from a primary seal. These issues, and comparisons with other sealing options, are discussed here.

Secondary dry containment seals. The purpose and underlying principles of secondary dry containment seals are easy to grasp. A secondary seal is used on process pumps to prevent normal primary seal leakage from escaping to the ambient atmosphere. Instead, this leakage is diverted to a liquid collection or vapor recovery system. The *American Petroleum Institute (API) 682* standard requires secondary containment seals to contain pump process fluid for eight hours in the event of a primary seal failure.

The containment seals fitted in the 1990s are often used in conjunction with simple piping arrangements, which give little to no indication of seal condition. *API 682* provided for improved piping plans in 2002. The 4th edition of the standard, published in May 2014, further improves seal effectiveness by stipulating the mandatory use of transmitters, providing users with a better indication of the condition of the inner seal.

However, this transmitter deployment does not provide an indication of the integrity of the containment seal. In the event of high leakage from a primary seal, the operator will not know if the containment seal is effective. In such a fault condition, the levels of leakage from containment seals are not commonly understood by many operators. Static manual testing is the only way to test the integrity of containment seals, but this process has not been universally adopted by the industry.

At present, the API requires the containment seal to withstand full chamber conditions for a period of eight hours. By comparison, it is possible to simultaneously monitor the condition[1] of both inner and outer seal face pairs in dual-wet seals. If the seals are well designed, loss of containment will not occur, even with high levels of leakage from either the primary or secondary seal.

Dry containment seals were originally selected by owner/operators because of their perceived lower installation and operating costs. However, as containment plans have developed to become safer, the seals' competitive cost advantage has been eroded, and the safer technology of dual-wet seals now represents the lowest overall cost solution.

Seal history. In the late 1980s and early 1990s, users of pump mechanical seals in the oil and gas industries became increasingly concerned with the levels of emissions from single mechanical seals. There was also concern regarding containment of pump fluid in the event of the single seal (**FIG. 1**) failing in service. Leakage from a failed single seal could be controlled to some extent with a bushing, but leakage rates would be significant. Dual seals were developed to overcome these two issues.

Early dual seals were typically organized in a tandem arrangement with a buffer or barrier liquid between the interspace. The barrier/buffer would be circulated around a reservoir; the reservoir level required monitoring and occasional replenishing.

Dry containment seals were conceived in an attempt to simplify dual seals (**FIG. 2**). With no barrier/buffer fluid to

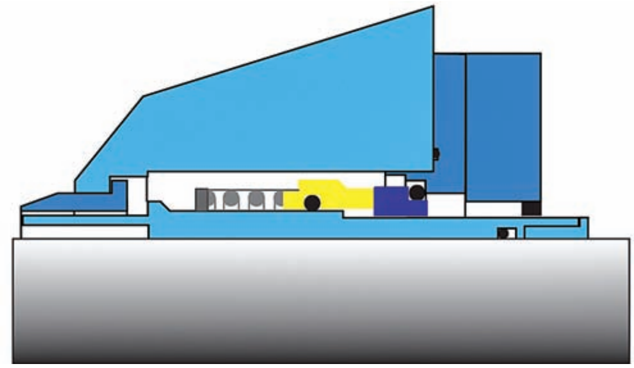


FIG. 1. Typical traditional single seal.

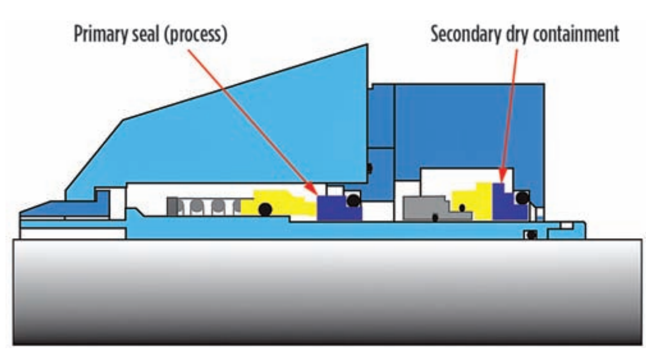
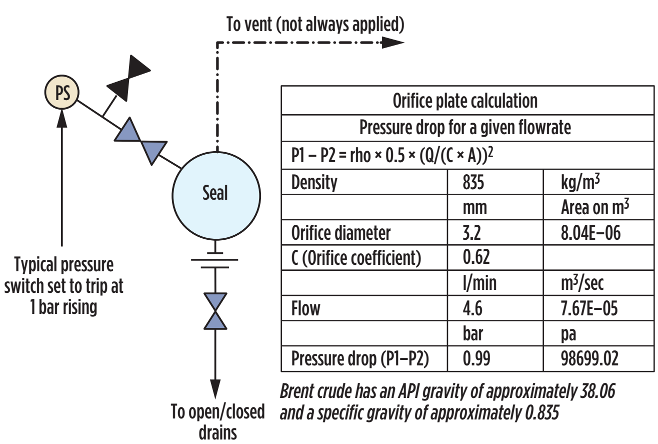


FIG. 2. Typical legacy containment seal.

replenish, operational savings were realized. The associated pipe work was also perceived to be simpler to install at a lower cost. There were no formal piping plans for use with containment seals, and, as a result, it was left for design engineers to configure. The normal practice was to connect the leakage port to a contained drain system or, sometimes, to a vapor recovery system. A piping system similar to that in API's Plan 65 was implemented (**FIG. 3**), where an orifice is used on the drain connection.

In the event of high leakage from the primary seal, alarms would typically trigger at 1 bar (14.5 psi). A relatively high flowrate from the primary seal is required to activate the alarm. Assuming a 3.2-mm orifice plate API minimum size was used, a leakage flowrate of approximately 4.5 l/min. would be required to activate the alarm. Some operators might use a pressure alarm, while others might use a small vessel with a level switch, which is almost identical to a Plan 65 solution.

The key difference is that a Plan 65 solution is intended for use with a single seal with a bushing, not a secondary containment seal. One of the operational problems with Plan 65 and its variant is that the orifice is potentially blocked, particularly on waxy or contaminated surfaces, causing false alarms.



Orifice plate calculation		
Pressure drop for a given flowrate		
P1 – P2 = rho × 0.5 × (Q/(C × A))^2		
Density	835	kg/m^3
	mm	Area on m^3
Orifice diameter	3.2	8.04E–06
C (Orifice coefficient)	0.62	
	l/min	m^3/sec
Flow	4.6	7.67E–05
	bar	pa
Pressure drop (P1–P2)	0.99	98699.02

FIG. 3. Historic and current practice: Typical early piping arrangement (Plan 65) with pressure switch.

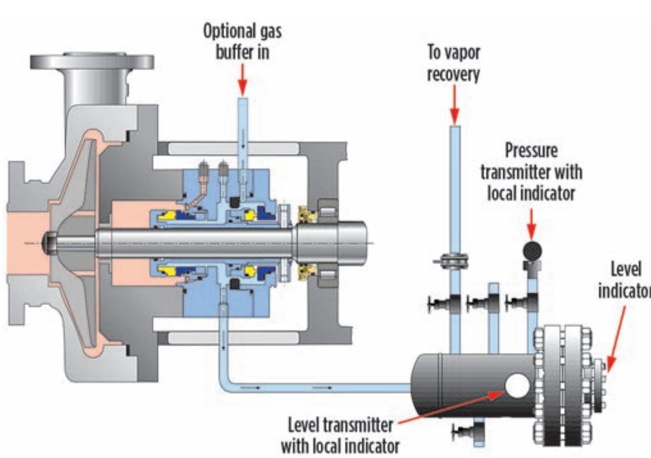


FIG. 4. Distributed control system (DCS) with Plan 75.

Incorporation into API standards. In 2002, dry containment seals were recognized in the 2nd edition of *API 682*. A series of piping plans offered to take leakage to a safe collection point. Plan 75 is used for pumped fluids where normal leakage would be condensing or mixed-phase fluid at ambient conditions. Plan 76 is used where the normal pump fluid leakage would vaporize in ambient conditions. Additionally, Plan 72 N_2 quench can be used to assist by sweeping the normal leakage to the collection location.

In Plan 75 (**FIG. 4**), leakage escape from the inner seal is restricted by the containment seal and routed to the drain line. The collector accumulates any liquid, while vapor passes into the vapor collection system.[1] Assuming that the leakage is predominantly condensing (**FIG. 5**), a visual level indicator on the collector is used to determine when the collector must be drained. If the user specifies the option for a level transmitter, the inner seal liquid leakage rate can be monitored remotely. As the leakage collects, the collection system will require draindown.[2]

Trending time intervals between draindown interventions provides the user with another clear indication of the condition of the inner seal. If the leakage is predominantly vaporizing, an orifice in the outlet line[1] of the collector restricts flow so that high leakage of the inner seal will cause a pressure increase, triggering the pressure switch or transmitter to alarm at a gauge pressure of 0.7 bar (10 psi).

The block valve in the outlet upstream of the orifice isolates the collector for maintenance. It may also be used to test the inner seal by closing while the pump is in operation, with respect to the time/pressure buildup relationship in the collector.

Plan 76 description and limitations. The Plan 76 system (**FIG. 6**) is intended for services where no condensation of the inner seal leakage or from the collection system will occur. Should liquid accumulate in the containment seal chamber, excessive heat could be generated, leading to hydrocarbon coking, blistering of the seal face and possible seal failure.

In Plan 76, leakage from the inner seal is restricted from escape by the containment seal and goes out via the containment seal vent. An orifice in the outlet line of the

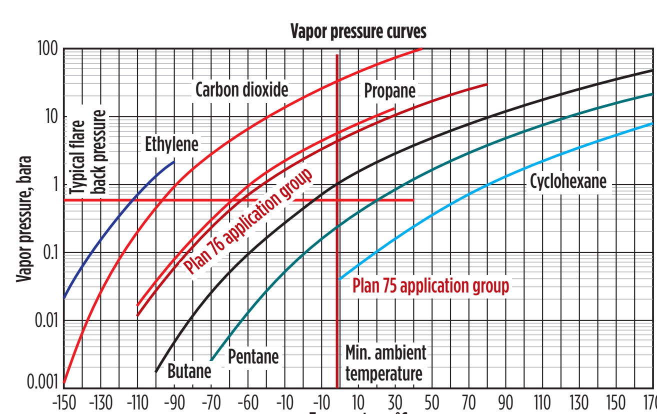


FIG. 5. Vapor pressure curves.

collector restricts flow so that high leakage of the inner seal will cause a pressure increase and trigger the pressure transmitter to alarm at a gauge pressure of 0.7 bar.

The application of Plan 76 is dependent on temperatures and actual atmospheric pressure. A review of vapor pressure curves would indicate that, in higher altitudes, Plan 74 is limited to light hydrocarbons. In tropical climates, Plan 76 has a broader application group. **FIG. 5** provides the application areas for Plans 76 and 75, based on the minimum flare backpressure and minimum ambient temperatures.

Containment seal integrity monitoring. In the event of a primary seal failure, the integrity of a containment seal is crucial to prevent process fluid escape. At present, no dynamic method for the condition monitoring of containment seals exists. A periodic static pressure test method was proposed by Bowden and Fone.[3] Both Plan 76 and Plan 75 have test connections available for statically pressurizing the containment chamber and for measuring pressure decay over time. With the containment chamber isolated, the proposed method suggests an acceptable pressure decay of 0.14 bar over 5 min.

Containment seal integrity is on the frequency of this test. Bowden/Fone[3] suggest that a weekly check will ensure confidence in the containment system. Periodic testing within the industry appears to be done on an ad hoc basis, or not at all. Weekly testing is impractical and may create other risks in the form of exposure to personnel carrying out the test in production areas.

Two types of containment seals. Contacting and non-contacting (sometimes referred to as gas lift) technologies are accepted within the *API 682*. The standard does not differentiate between the two technologies, giving them the same coding.

Dry contacting technologies use seal face geometries and materials that allow a rubbing contact mechanical seal face pair. Dry non-contacting technologies are designs where the mating faces have microface features to intentionally create fluid dynamic (usually gas) separating forces to sustain a specific separation gap.

Significant performance differences are evident between the two technologies. The *API 682* 4th edition does provide some details on the expected leakage rates from containment seals in Annex F. **FIG. 7** illustrates that the containment performance of a non-contacting design during a primary seal failure will be little better than a single seal with a segmented floating bushing arrangement. The choice between the two technologies is a trade-off between their features, as summarized in **TABLE 1.**

TABLE 1. Containment seal technology comparison

Advantages	Limitations
Contacting containment type	
High levels of containment in the event of primary seal failure	Will wear (> 25,000 hr min. API requirement)
Low levels of emission (normal operation)	Speed and/or size restricted
	Not tolerant of flare upset (over-pressurizing)* rubbing friction causing temperature rise and high wear
Non-contacting (gas lift) containment type	
Virtually no wear	Limited containment in the event of primary seal failure
Can be used at higher speeds and larger shaft diameters	Higher levels of emissions in normal operation; emissions meet *API 682* requirements of < 1000 ppm**
Tolerant of flare upset (over-pressurizing)	Face features vulnerable to clogging in some environments, congealing or abrasive leakage**

* If seriously abused (containment chamber blocked in), Bowden-Fone claim potential ignition source

** Can be minimized by use of Plan 72 N_2 quench

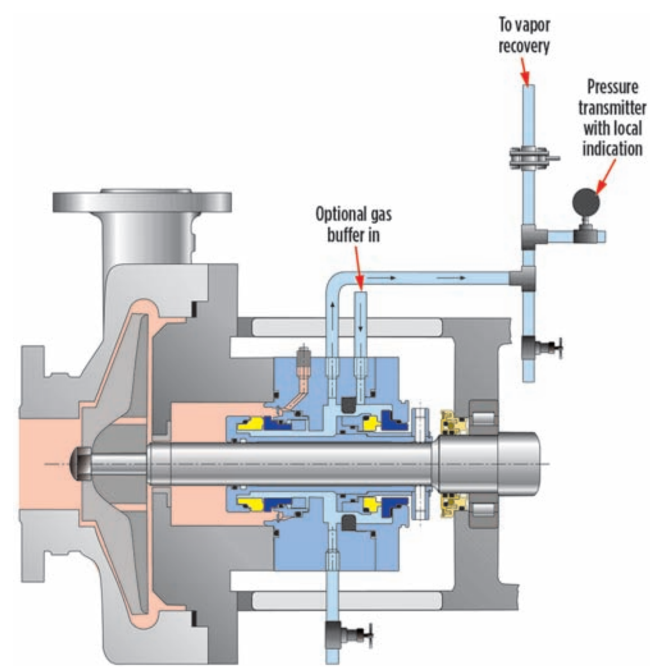


FIG. 6. DCS with Plan 76.

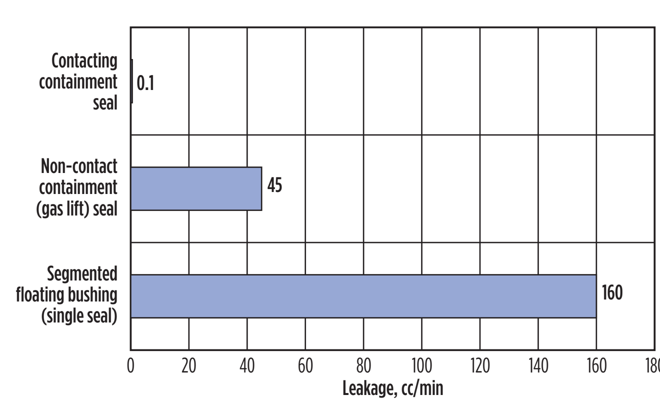


FIG. 7. Generalized comparison of leakage rates for 50-mm size, 3,000 rpm and with water at 2.75 barg.

Plan 72 description. This plan is used with dry containment seals (**FIG. 8**). An inert buffer gas (N_2) is injected through a port adjacent to the outer dry containment seal. The main purpose of Plan 72 is to "sweep" any leakage that comes across the primary seal away from the secondary (outboard) seal. Any "sweep gas," together with process fluid leakage, would go to a designated location, either a designated vent (Plan 76) or a liquid collection system (Plan 75).

Some operators have experienced problems where the N_2 flow from a number of Plan 72 systems affects the flare system.

Comparison with other dual-seal designs. Plan 52 (**FIG. 9**) is a wet containment seal where a buffer fluid (liquid) fills the interspace between the primary containment seal and the secondary containment seal. This plan is intended to be connected to a flare system. The 4th edition of *API 682* specifies transmitters for both pressure and level.

Plan 52 offers a simultaneous means of condition monitoring of the primary and secondary containment seals. A rise in liquid level in the tank, or an increase in pressure above the flare, would indicate high leakage from the primary seal. A reduction in liquid level would indicate high leakage from the secondary containment seal.

The limits of Plan 52 are described in the 3rd edition of *API 682,* in a tutorial in Annex A: Plan 52 works best with clean, non-polymerizing, pure products that have a vapor pressure higher than the buffer system pressure. Leakage of higher-vapor-pressure process liquids into the buffer system will flash in the seal pot, and the vapor can escape to the vent system. Inner seal process liquid leakage will normally mix with the buffer fluid and contaminate the buffer liquid over time. Maintenance associated with seal repairs, filling, draining and flushing a contaminated buffer system can be considerable.[2]

Fundamentally, if operated and designed correctly, Plan 52 is limited to the same application group as Plan 76 and is unsuited for process fluids, which condense at ambient conditions.

Pressurized dual seals are becoming increasingly common within the industry. The cost of the supporting systems has become more comparable with unpressurized containment seals, especially when considering the cost of utility connections. The principal difference is that, with a pressurized dual-sealing system, both primary and secondary seals will be sealing a clean, nonhazardous barrier fluid, as opposed to an unpressurized containment seal where the system is managing the hazardous (and/or contaminated) leakage from the primary seal. The barrier fluid of a pressurized dual seal can be non-compressible liquid (typically Plan 53A, B or C) or compressible gas (Plan 74).

Another safety feature of pressurized dual seals is that, in the event of a pump being accidently dry run (not an uncommon occurrence in tank farm product transfer or offloading), both seals are lubricated by an external barrier fluid and will survive. Liquid pressurized dual seals may run warmer, but survive the event.

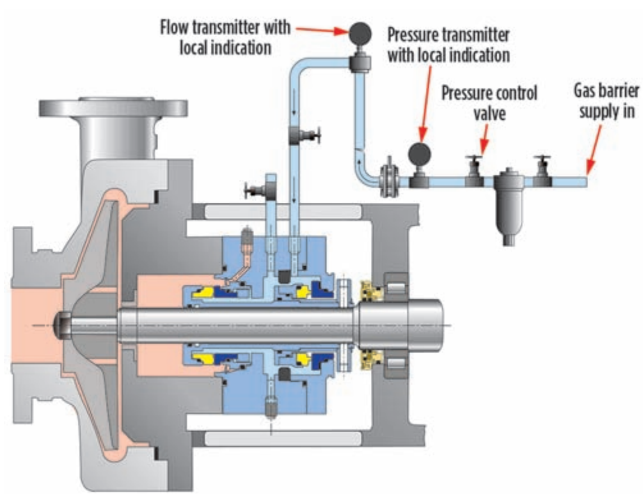


FIG. 8. DCS with Plan 72.

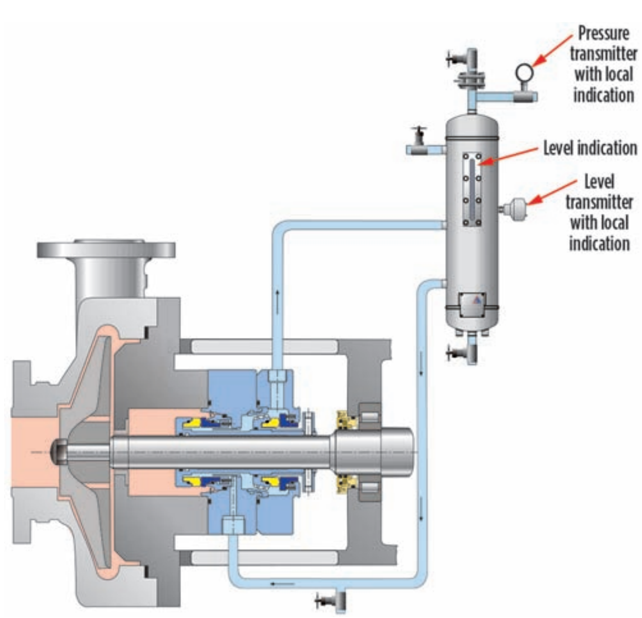


FIG. 9. Wet containment seal with buffer fluid, per Plan 52.

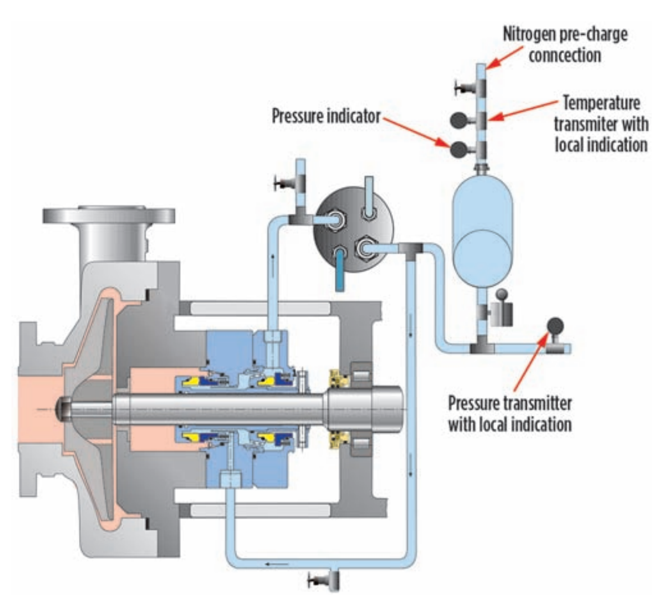


FIG. 10. Dual seal with popular and cost-effective Plan 53B.

Plan 53B description. Quickly becoming the most popular solution (**FIG. 10**), Plan 53B is favored by many users and operators because it does not require connections to any external utilities if an air-cooled system is adopted. The barrier fluid is pressurized in a bladder accumulator with an N_2 precharge. The bladder accumulator directs the barrier fluid to the seal cooling circuit, where the barrier fluid is pumped around the cooling circuit via an integral pumping ring within the seal assembly. During normal operation, controlled leakage of barrier fluid will enter the process fluid across the primary seal and to the atmosphere across the secondary seal.

Pressure is monitored, and, as the pressure decays over time, barrier fluid will be recharged either manually or by an automated top-up system. The required top-up frequency provides owners/operators with a clear indication of seal condition. Increasing refill frequency would provide an early warning of seal condition deterioration.

With a properly designed dual seal, in the event of major leakage from either the inner or outer seal, the process will be contained. With excessive leakage from the primary seal, the barrier fluid circuit pressure would become equal to the seal chamber pressure. The pressure would signal an alarm, but if the alarm was ignored for an extended period of time, then the outer seal would remain intact and act as a backup seal for a while.

If the alarm was further ignored, the barrier fluid cooling circuit would become contaminated with process fluid over time. In the event of excessive leakage from the secondary containment seal, provided the inner seal is hydraulically double balanced, the inner seal will contain the process fluid. Plan 53B is perhaps the safest of all the dual-seal plans, with the highest degree of fault tolerance.

Plan 74 description. Plan 74 requires a constant flow of N_2, and the overall condition of both inner and outer seals can be continuously monitored by observing the N_2 flowrate. In the event of either a primary or secondary seal having excessive levels of leakage and the available N_2 flow being unable to maintain pressure, some loss of containment will occur, as the seal faces are not designed to run on liquid.

System cost comparisons. Typical containment seals are compared against other popular dual-seal arrangements in **TABLE 2.** Various scenarios are presented with relevant alarm strategies and the effect of the condition. A traffic light color coding red-amber-green (RAG) illustrates areas of concern. In particular, **TABLE 2** focuses on a major event where the

TABLE 2. Fault tolerances dual-seal comparison RAG chart

			Scenario				
			Condition monitoring leakage detection		Catastrophic failure consequence		
API plan	Technology	VOC emissions	Primary seal	Secondary seal	Primary seal	Secondary seal	No liquid in seal chamber
Current historic practice	Contacting containment	Good	Leakage would need to exceed 4.5 gal/min to alarm	Manual air test (pump offline[e])	Pressure alarm.[a] Process leakage to atmos > 0.1 cc/min[f]	No way of detecting failure	Inner seal fails potentially catastrophically
Current historic practice	Non-contacting gas lift	Acceptable[b]	Leakage would need to exceed 4.5 gal/min to alarm	Manual air test (pump offline[e])	Pressure alarm.[a] Process leakage to atmos > 45 cc/min[f]	No way of detecting failure	Inner seal fails potentially catastrophically
75	Contacting	Good	Leakage detection[c] visual unless optional Level Transmitter *API 682* 4th ed. is specified	Manual air test (pump offline[e])	Level alarm.[a] Process leakage to atmos > 0.1 cc/min[f]	No way of detecting failure	Inner seal fails potentially catastrophically
75	Non-contacting gas lift	Acceptable[b]	Leakage detection[c] visual unless optional Level Transmitter *API 682* 4th ed. is specified	Manual air test (pump offline[e])	Level alarm.[a] Process leakage to atmos > 45 cc/min[f]	No way of detecting failure	Inner seal fails potentially catastrophically
53B	Pressurized dual wet 53B	Zero	Pressure transmitter[d]	Pressure transmitter[d]	Pressure alarm. Process fluid will contaminate barrier fluid over time	Pressure alarm. Inner seal will contain the process[g]	Seal faces lubricated by barrier liquid fluid—Barrier fluid temperature will increase
74	Pressurized dual gas 74	Zero	N_2 flow transmitter[d]	N_2 flow transmitter[d]	High flow alarm. If insufficient N_2 flow available, process fluid will not be contained by the outer seal	High flow alarm. Inner seal will not contain process	Seal faces lubricated by gas barrier fluid

a Assumes containment seal will contain; many operators do not perform regular period static tests of the containment system
b Can be improved by use of plan 72
c Assumes *API 682* 4th ed. philosophy and use of transmitter; 3rd ed. would rely on trending frequency of the level switch
d Assumes fluid is primary condensing (> C_5) level transmitter optional (*API 682* 4th ed.)—a switch is optional in earlier editions of *API 682*
e Most operators do not do this—no reference to this in *API 682* or in recommended procedure
f Assumes 50-mm seal/seal chamber pressure of 2.75 bar
g Assumes inner seal has reverse pressure capability

seal leakage is high. The nature of this event is not relevant, but could be caused by normal wear, abnormal wear due to abrasives, component failure, seal hangup, etc.

FIG. 11 compares the installation costs of different dual-seal systems and is offered as a guideline, as costs vary considerably with the level of specification. If only seal system hardware costs are considered, pressurized dual-seal systems would be considered more expensive; however, this is an industry-wide misconception, as the true cost of installation includes the cost of utilities hookup. When utilities connection costs are considered, containment seals do not fare as favorably, and Plan 75 may be one of the most expensive. Pressurized dual-seal Plan 53B costs can vary considerably, but they compare very favorably because utilities connections are not required.

One view is that containment seals do not incur high operating costs. This may be true if no testing of containment seals is undertaken; however, this is a potentially unsafe working practice. If best practices are adopted and containment seals are tested on a regular basis, then the cost of regular testing will be potentially higher than that of maintaining a Plan 53 or Plan 52 configuration. Periodic containment seal testing requires the pump to be static. Plan 53 and Plan 52 systems are normally configured for fluid replenishment while the pump is in operation. Plan 74 potentially offers the most cost-effective option with respect to maintenance costs, as no manual interventions are required.

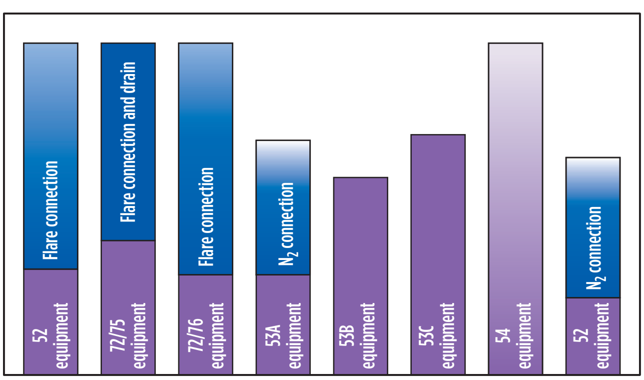


FIG. 11. Auxiliary system comparative costs/utilities connections.

Takeaway. If containment seal costs, including periodic static pressure testing, are considered, then they do not offer a cost advantage over dual-pressurized sealing systems. They also do not offer the ability to dynamically monitor the condition of the primary and secondary seals.

Users and operators should always consider the entire cost and not just the capital cost of the containment seal when making purchasing decisions. Failure to consider a dual-pressurized seal option can result in greater overall operation costs and reduced reliability. Safety issues are paramount, and dual-seal systems offer the highest levels of safe operation. HP

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[4] American Petroleum Institute, *API 682, 4th Ed.,* 2014.

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