API 682 Arrangement 2 Configurations - Considerations for Outer Seal and Support System Design

Brian Kalfrin
Regional Engineer
John Crane
Pasadena, TX, USA

Luis Gonzalez
Rotating Equipment Specialist
S & B Engineers and Constructors, LTD.
Houston, TX, USA

Brian Kalfrin is a Regional Engineer with John Crane in Pasadena Texas with over 14 years of experience with mechanical seals and related systems. He is responsible for engineering expertise within the South Sales District of the United States for John Crane, which encompasses the majority of the state of Texas along with parts of Louisiana. His duties include on-site troubleshooting and diagnostic failure analysis, formulating recommendations and seal selections to address problem applications, along with design evaluation of existing and proposed mechanical seals utilizing Finite Element Analysis (FEA) software. He is also responsible for training of both customers and John Crane personnel in both mechanical seal application and troubleshooting. Mr. Kalfrin is a member of the Texas A&M International Pump Users Symposium Advisory Committee and a degreed Mechanical Engineer with a BSME from Drexel University in Philadelphia, PA.

Luis Gonzalez is a Rotating Equipment Specialist with S & B Engineers and Constructors, LTD., located in Houston, Texas. He has extensive experience with refining, petrochemical, chemical, equipment engineering, plant support and project management type roles. His assignments have ranged from maintenance plant execution support to Corporate Rotating Equipment Engineer with expertise in specification, evaluation, purchasing, commissioning, and maintenance of mechanical equipment, particularly rotating machinery for new and existing equipment facilities. Mr. Gonzalez is a graduate of Simon Boliver University in Venezuela with a degree in Mechanical Engineering.

ABSTRACT

API 682, now in its 4th Edition, has made a concerted effort to accurately define and distinguish between different types of seal configurations available under the designation of 'Arrangement 2', including 2CW-CW, 2CW-CS, and 2NC-CS. While the differences between the available types of seals associated with this designation are reasonably well understood by those in the industry, there are still questions end users have when considering an Arrangement 2 seal for an application; in particular, there are specific concerns regarding reliability and integrity of dry containment seals when compared to wet buffer outer seals. The process of selecting the configuration, and the associated support system (piping plan) requires an evaluation of all aspects associated with the functionality and interaction between these elements. The tutorial will address and discuss the following aspects to consider when evaluating the outer seal design in API 682 arrangement 2 configurations.

INTRODUCTION

As a precursor to further in depth discussions on specific nuances of Arrangement 2 configurations, it is important to have an understanding of the historical background behind the designation of Arrangement 2. API 682 "Arrangement 2" evolved from the "tandem seal" concept. Rather than attempt to revise the tandem concept, API 682 created a new term. Like a tandem bicycle, a tandem seal is two seals arranged with one seal in front of the other. Tandem seals were probably developed in the early 1950's for redundancy, safety, and to distribute total pressure drop between two sets of seal faces. The general thinking and design of a tandem seal typically called for the outer seal to be identical to the inner seal; however, often this was impossible because of restricted dimensional envelopes. Virtually all early tandem seals were oriented face-to-back and pressurized from the OD. Due to these limitations, early tandem configurations were not widely used. Piping Plan 52 was originally developed for tandem seals; however, it usually was simply vented to atmosphere and not connected to a flare or vapor recovery system.

After the implementation of the Clean Air Act of 1990, tandem seals with the accompanying Plan 52 connected to the flare system provided a means of reducing emissions as well as reducing emission monitoring requirements. At this point, API 682 defined Arrangement 2 in order to have a more adaptable terminology. Now in the 4th Edition, the terminology associated with Arrangement 2 configurations has expanded further and is even more specifically defined by the standard. Common terms used in the 4th Edition are:

Containment device - seal or bushing that is intended to manage leakage from the inner or outer seal and divert it to a location determined by the user.

Containment seal - special version of an outer seal used in

Arrangement 2 and that normally operates in a vapor (gas buffer or no buffer) but will seal the process fluid for a limited time in the event of an inner seal failure.

Containment seal chamber - component or aggregate of components that form the cavity into which the containment seal is installed.

Containment seal chamber leakage collector - reservoir connected by pipework to the containment seal chamber for the purpose of collecting condensed leakage from the inner seal of an Arrangement 2.

A representation of a typical Arrangement 2 seal is shown below:

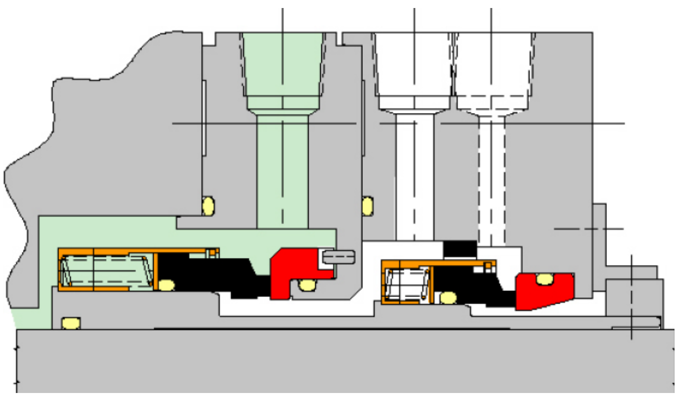

Figure 1 – Arrangement 2 seal design with containment seal

Prior to API 682 4th Edition, the term ‘containment seal’ was commonly associated as being the outer seal of any Arrangement 2 seal, whether wet or dry. What was found through discussions with most users of the standard was that most were thinking of a dry running outer seal when they referred to a ‘containment seal’. The 4th Edition of API 682 has re-defined this term to help alleviate potential confusion when referencing other clauses within the standard.

In an Arrangement 2 configuration, the outer seal can be a wet seal or a dry-running seal. The inner seal utilizes a piping plan typical of Arrangement 1 seals. The principal difference between Arrangement 2 and Arrangement 3 configurations is the concept of containment of leakage versus the elimination of process fluid leakage. The relevant abbreviations commonly used today provide reasonable insight into the seal design and what the user should expect to be associated with that design in terms of support system and interface lubrication. The more common abbreviations below as outlined in API 682 can be combined in various ways:

Contacting Wet (CW) seals—Seal design where the seal faces are not designed to intentionally create aerodynamic or hydrodynamic forces to sustain a specific separation gap.
Non-Contacting (NC) seals (whether wet or dry)—Seal design where the seal faces are designed to intentionally create aerodynamic or hydrodynamic separating forces to sustain a specific separation gap.

Containment Seals (CS), whether contacting or non-contacting—Seal design with one flexible element, seal ring and mating ring mounted in the containment seal chamber.

The purpose of this tutorial is to provide the user with an understanding of the primary considerations associated with selecting and applying the different types of Arrangement 2 outer seals along with some advantages and disadvantages associated with the required piping plan for that configuration. The attributes described for each configuration and piping plan are based on practical application experiences over the past 14 years since these concepts and piping plans were first introduced in the early editions of API 682.

LIQUID OR GAS BUFFER DIFFERENTIATION

Liquid Buffer (API Plan 52)

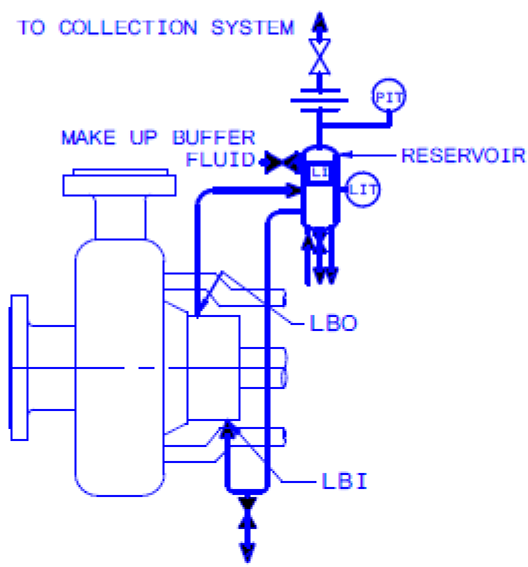

Figure 2 – API Plan 52 Schematic

Most are familiar with the terminology associated with contacting liquid buffer fluid systems, more specifically the description of an API Plan 52 support system. Plan 52 uses an external reservoir to provide buffer fluid for the outer seal of an unpressurized dual seal arrangement. During normal operation, circulation is maintained by an internal circulation device commonly referred to as a pumping ring. The reservoir in the system is usually continuously vented to a vapor recovery system and is maintained at a pressure less than the pressure in the seal chamber. Typically, the pressure in a Plan 52 is basically the static head of the liquid level. Some users tend to increase the level to get more positive pressure on the outer seal cavity in an effort to provide better lubrication to the outer seal, which in reality is only a small amount. An increase in static head in the system requires careful evaluation of the associated impacts on the piping and tubing in terms of increased friction and losses that will subsequently need to be overcome by the internal circulation device in the mechanical seal in order to generate the required flow for cooling and lubrication.

Liquid buffer fluid systems utilizing a Plan 52 have been used for many years, and are advantageous in terms of both the ability to provide a reduction in overall leakage when compared to a single seal and redundancy in the event of an inner seal failure. In some cases, the liquid buffer fluid can be viewed as a contained quench for the inner seal, providing the ability to keep any potential solids in suspension on the low pressure side of the inner seal.

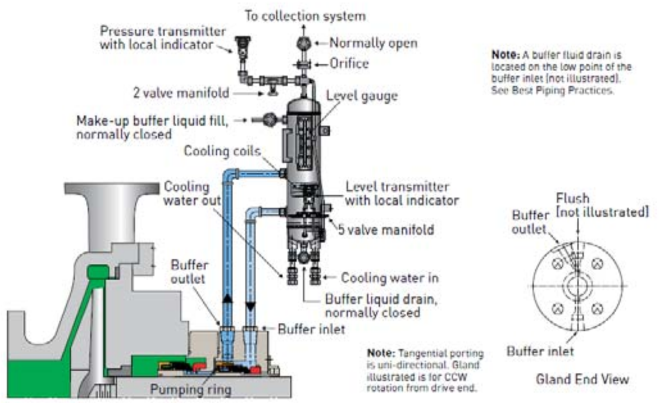

Figure 3 – API Plan 52 layout

Liquid buffer fluid systems utilizing Plan 52 should be carefully evaluated in terms of the application conditions and the volatility of the process fluid being contained by the inner seal. There will always be some process fluid leakage from the inner seal into the buffer system; therefore, the buffer system is contaminated by the process fluid. In an instance where the process fluid is considered a heavy, low vapor pressure fluid, it is possible for this heavier process fluid leakage to displace the buffer fluid resulting in the area between the two seals to be completely filled with process fluid, thereby losing a buffer between the product and atmosphere. The use of Plan 52 in a crude oil application would be a prime example of this scenario.

Speaking to this point, one needs to consider regular preventative maintenance schedules with Plan 52 systems especially in applications where the inner seal leakage would then condense inside the fluid reservoir, which has then at this point become a liquid containing vessel full of an emulsion of inner seal leakage and buffer fluid. Safe disposal of this contaminated fluid is a significant concern and should be evaluated well in advance of installation so that regular preventative and corrective maintenance practices can be set in place.

Conversely, if the process fluid has a low vapor pressure margin the heat from the outer seal can further reduce the margin and cause the inner seal to run with partial to full vapor between the sealing faces. Considerations given to managing the vapor pressure and controlling the environment for the inner seal are important in any application, but can be even more critical when evaluating the use of a liquid buffer system with Plan 52 for the above mentioned reason. Measures to manage the inner seal chamber conditions in this instance can add to the overall cost and complexity of the total support system; these potential impacts need to be reviewed with the mechanical seal manufacturer up front to evaluate the effectiveness and overall reliability of the selected system.

Stability of the buffer fluid needs to be considered when evaluating a Plan 52 system. Unpressurized buffer fluids may lose volatile materials, causing an adverse effect on their original performance characteristics. Highly volatile fluids should not be used. Fluids with low vapor pressure are essential to keep the volume of the lubricant constant. Intuitively, buffer/barrier fluids operated at high temperatures should be changed more regularly than those operated at lower temperatures. API 682 guidelines for allowable temperature rise in buffer/barrier fluid systems are 15°F (8.3°C) for water based solutions and diesel/kerosene but 30°F (16.6°C) for mineral or synthetic oils. As an example, a system using oil might have the reservoir at an average temperature of 130°F (54.4°C) with an outlet temperature of 115°F (46°C) and inlet of 145°F (62.8°C). API 682 does not provide guidelines for the average temperature.

A simple rule of thumb for chemical reactions typically applied is the Arrhenius principle (see appendix), which suggests that the lifecycle of a lubricant is cut in half for every 18 °F (10 °C) increase in temperature. The basis of the equation relates reaction rate to temperature, where at higher temperatures the probability increases two molecules will collide with sufficient kinetic energy to activate a chemical reaction (Khonsari and Booser 2003). A lubricant's life in hours can be calculated if oil operating temperature and product type are known; standardized laboratory tests for evaluating oxidation life of new oils including ASTM D943, D2272, D2893, and D4742 among others have verified and developed representative 'life' estimates for mineral oil lubricants based on the representative Arrhenius equation (Khonsari and Booser 2001). Advances in lubricant technology in the form of synthetic oils have mitigated the impacts of temperature on useful service life and many common buffer fluids in use in mechanical seal applications today are of this type; however the impacts of temperature on the service life of the fluid should still be considered.

One item of note with regard to oil life and temperature is that while assumptions for calculating or predicting useful life can be made, the calculations themselves assume no water or other contamination in the oil. In reality, oil life in a system may be significantly shorter than oil life equations might predict as found as a result of ASTM stability tests for certain oils (Khonsari and Booser 2001). As an example, if the original rule of thumb is applied to the decomposition of buffer fluids in Plan 52 systems and it is assumed that a certain buffer fluid performs well for six months at an average temperature of 130°F (54°C) and if the average oil temperature were to increase to 148°F (64°C), then the fluid change interval could potentially become three months. While this example does not highlight an extreme case the fundamental theory that oil life, even synthetic oil life, will be reduced in the presence of not only heat, but other contaminants as well, holds true. Fundamentally, in a Plan 52 system, the outer seal will be subjected to some form of heat and contaminants continually, therefore evaluation of not only the buffer fluid but management of heat transfer in the systems will be of significant importance.

Gas Buffer (API Plan 72)

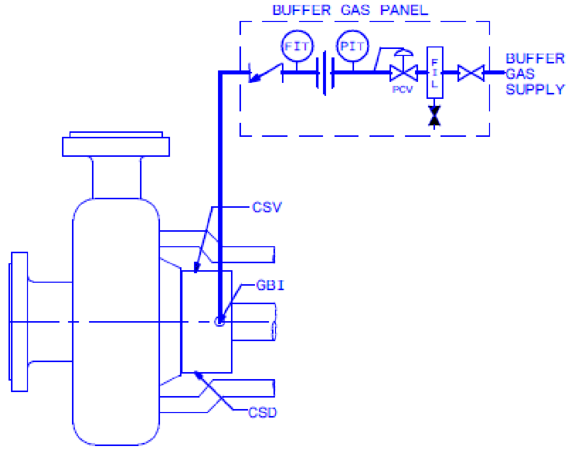

Figure 4 – Plan 72 Schematic

An alternative to a liquid buffer system would be to utilize a gas buffer instead, most typically referred to as an API Plan 72; Plan 72 can be implemented to support both contacting and non-contacting containment seals. Plan 72 uses an external low pressure buffer or purge gas which is regulated by a control panel and then injected into the outer seal cavity. Note that while Plan 72 systems typically use nitrogen, the indication of Plan 72 as the support system does not necessarily specify the buffer medium in use. There are some special high temperature applications that may utilize a steam buffer injected to the cavity between an inner seal and outer dry running containment seal – this is still a Plan 72 although the media being used is steam and not nitrogen; Plan 72 only specifies the arrangement of the seal and not the buffer gas used.

Focusing on the support system for Plan 72, a control panel is normally used, and may contain a pressure control valve to limit buffer gas pressure to prevent reverse pressure on the inner seal and/or limit pressure applied to the secondary containment seal, followed by either an orifice or needle valve to control the gas flow rate. An important feature of Plan 72 is that gas purge flow is introduced close to the seal faces whereas the vent and drain are away from the seal faces. In API 682, a bushing is required in the containment chamber to physically separate the buffer gas inlet from the vent and drain connections.

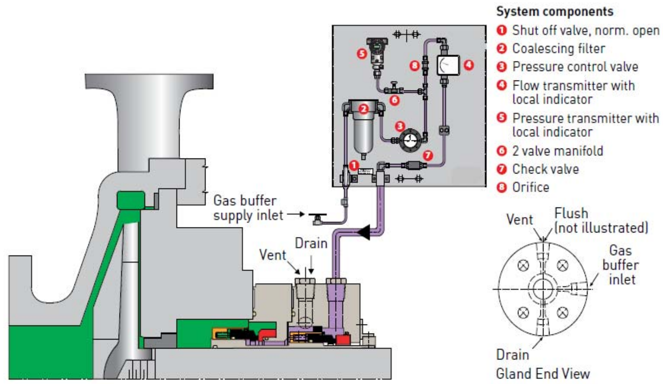

Figure 5 – API Plan 72 Panel Layout

Plan 72 can be advantageous for many reasons; primarily it tends to provide more benefit in applications where the process fluid lubricating the inner seal is operating with a low vapor pressure margin. Introduction of the low pressure gas to the outer seal cavity reduces the temperature, which minimizes the amount of heat transferred to the inner seal that could promote more flashing of a volatile process fluid being used as an inner seal face lubricant. A Plan 72 system would ordinarily be used in conjunction with Plan 75 for primary seal leakage that is condensing or Plan 76 for non-condensing leakage to help minimize process fluid affecting the containment seal faces and to also dilute inner seal leakage to the atmosphere.

A typical topic for debate would be the required purge rate associated with a Plan 72 system. When deciding on the purge rate, consideration should be given to the type of containment seal, the flow rate past the downstream orifice, and the purge rate. Excessive purge rates can have a detrimental impact to contacting containment seals by drying out the seal cavity due to the use of dry nitrogen. A generally accepted rule would be specify a purge rate on the order of 0.5 SCFM (0.014 SCMM) to the containment seal cavity, which relates to the rough flow rate for a 5 PSI (0.34 bar) differential pressure across a 0.062" (1.6 mm) orifice.

When discussing purge rates, one needs to take the evaluation further than the standard rule and also consider the type of inner seal being used along with the product sealed. API 682 4th Edition allows the use of non-contacting inner seals (2NC-CS), which utilize a hydrodynamic face enhancement to provide lift in certain applications. These seals are used in difficult to seal, high vapor pressure or mixed vapor pressure fluids where it is difficult to provide adequate vapor suppression for reliable contacting wetted face seal designs. Non-contacting inner seals harness the energy of the process fluid and allow it to vaporize across the seal faces, allowing the seal to function like a gas seal rather than a wetted seal. While these designs provide excellent reliability in these services, one needs to consider the subsequent flow rates required when evaluating the support system.

Typically, Plan 72 and 76 will be used in these configurations, but because of the non-contacting seals tendency to have a higher leak rate than a contacting seal, the Plan 72 flow for inner seal leakage dilution and total flow to the Plan 76 system will be higher when compared to a contacting inner seal. Plan 72 purge rates on the order of 1 – 2 SCFM (0.03 – 0.06 SCMM) are not uncommon with non-contacting inner seals. This is not an indication of poor performance, but the control system needs to be designed to accommodate these flows, including sizing the downstream orifice accordingly to provide realistic alarm points.

API Plan 75 – condensable leakage management

Plan 75 is intended for use when the process sealed by the inner seal condenses at lower temperatures or is mostly in a liquid form. In this arrangement the drain is located at the bottom of the outer seal gland and is routed to a reservoir. Liquid leakage is collected and the gaseous portion is further routed through an orifice to a flare or vapor recovery system. The reservoir does contain a pressure gauge and a transmitter to trend pressure and provide an indication of increase in pressure in the reservoir from excessive inner seal gaseous leakage or an inner seal failure of some magnitude. Some users prefer to isolate the secondary containment device with valves to the reservoir in the event of an inner seal failure.

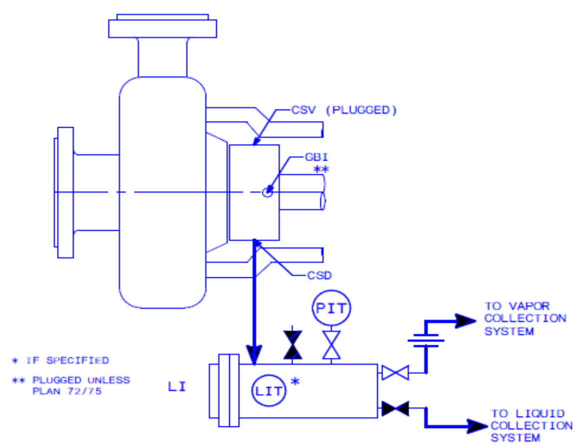

Figure 6 – Plan 75 Schematic

Plan 75 is advantageous in that typically there is a much lower initial cost alternative to liquid buffer seals using a Plan 52. As an example, there will typically be costs associated with additional utilities for Plan 52 systems such as cooling water and in some harsher climates, insulation and heat tracing costs associated with maintenance of the reservoir. If nitrogen is available in the unit, then 0.500” (12.7 mm) tubing runs for a Plan 72 & 75 costs significantly less than the 0.750” (19.1 mm) tubing and piping for Plan 52.

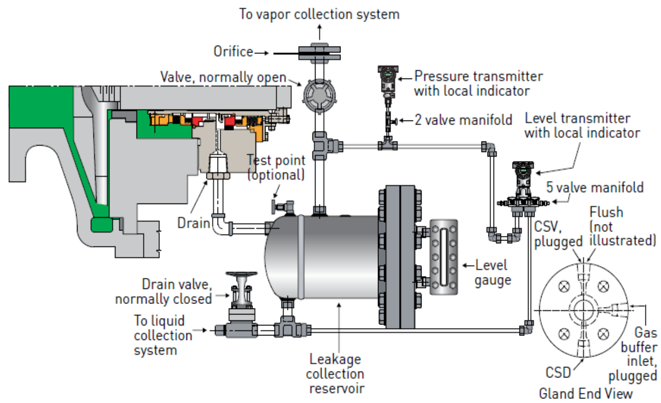

Figure 7 – Plan 75 Collection System Layout

When evaluating a Plan 75 system, it is important to realize that the secondary containment seal can become clogged with debris if the inner seal leakage is a heavy fluid that can coke or crystallize upon exposure to air. For this reason, the use of Plan 72 in conjunction with Plan 75 can mitigate these effects, along with the previously mentioned bushing or baffle between the seal and gland should be used to isolate the containment seal faces from the leakage of the inner seal. Based on the principle that the inner seal leakage will potentially be in liquid form, contacting containment seals are most typically used with Plan 75 to address the potential of any inner seal leakage bypassing the collection system and restricting flow to the atmosphere.

API Plan 76 – non-condensable leakage management

Where Plan 75 is intended for condensable inner seal leakage management, Plan 76 is intended for use when the process sealed by the inner seal will not condense at lower temperatures or pressures. In this arrangement the vent is located at the top of the outer seal gland and is routed to a flare or vapor recovery system through an orifice, with upstream pressure monitoring and alarm. API 682 requires a minimum orifice diameter of 0.125” (3 mm) but smaller sizes may be necessary to provide a realistic leakage alarm point. The estimated leakage rate of the inner seal depending on the design (contacting or non-contacting), can directly influence the orifice diameter on the Plan 76 system. It is important that all parties involved understand these variables at the design stage to avoid confusion and the creation of nuisance alarms.

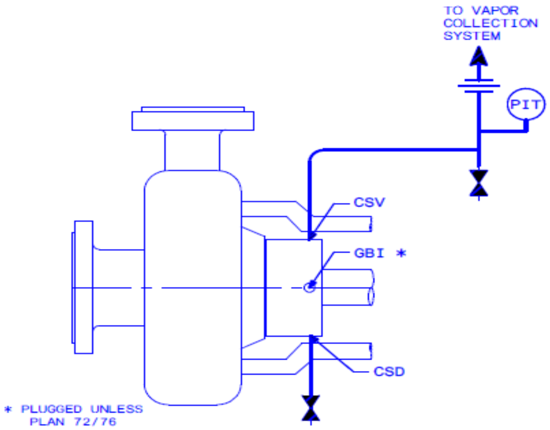

Figure 8 – Plan 76 Schematic

Plan 76 has many of the same benefits discussed prior with Plan 75 especially related to costs associated with maintenance and installation when compared to other support systems. Where Plan 76 is advantageous is in the case discussed previously where the vapor pressure margin within the seal chamber pressure (at the inner seal faces) is narrow, and additional heat added to the system from a liquid buffer seal would be a disadvantage, potentially promoting flashing of the process fluid. In utilizing a Plan 76, it is acknowledged that the leakage past the inner seal will be a vapor and therefore only containment of vapor leakage at the outer seal is necessary. In this case, a dry running containment seal, either contacting or non-contacting, can be used and a liquid buffer is eliminated further simplifying the system.

Installation requirements for a Plan 76 support system are not very complex either. It is recommended that the piping continually rise from the vent connection on the seal gland to the piping or instrument harness and should be properly supported so as not to impart strain to the gland. A drain connection in the piping is advisable in order to safely dispose of process fractions that may have condensed. A block valve is standard on this arrangement to isolate the containment seal in the event of a primary seal failure and pressure gages along with a pressure transmitter are standard for monitoring on this arrangement.

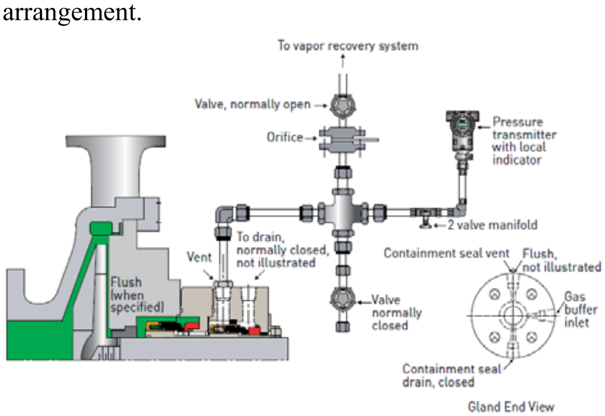

Figure 9 – Plan 76 System Layout

While the secondary containment seal is less subject to clogging in this arrangement the leakage from the inner seal may be a combination of a condensing and non-condensing fluid; when this is the case the addition of a Plan 72 & 75 is highly recommended. It is worthwhile to note that a portion of the typical Plan 75 arrangement includes a connection to a flare or vapor recovery system, along with provisions for pressure monitoring; in essence a Plan 76 is included with a Plan 75 system normally.

FLARE HEADER PIPING & SYSTEM EVALUATION

Integral to each of the support systems and seal arrangements to this point is that to ensure optimum reliability of this system, connection to a flare or vapor recovery system is required. By connecting the containment seal cavity to the flare system, the cavity itself essentially becomes part of that system and would ultimately be subjected to all of the same variances that the flare experiences. To this point, there are considerations that need to be addressed in terms of how potential variances in the flare system can therefore affect the various types of outer seal configurations. The most common concern and obvious source of issues with connecting the seal to the flare system is the potential for intrusion of liquids and other contaminants into the seal components from the flare side of the support system.

One of the most straight forward approaches to preventing flare side liquid intrusion is to utilize Plan 72 whenever feasible. An inert gas purge combined with a properly selected check valve is usually the best way to prevent liquids or undesirable gases to flow back from the flare into the dual seal cavity. In addition, detailed engineering of the flare piping configuration is recommended to identify any potential issues with the installation that could promote reverse flow to the containment seal cavity. Good practices would include insurance that all flare connections are taken to the top of the header, not the bottom, along with sloping of any lines and the inclusion of drain and drip legs where contaminants can be isolated from the mechanical seal. In some instances, end users have combined the above good practices with tracing of the flare lines as an additional measure to prevent liquid from back flowing into the seal cavity.

Liquid or gas backing into the seal from the flare could be a nuisance in a Plan 52 system as well, even though this contamination may not immediately cause an outer seal failure. In a dry running seal the liquid or dirty gas backing in from the flare will dramatically reduce its life causing premature wear of the dry running faces, which is one of the primary reasons Plan 72 provides substantial relief in terms of maintaining continuous positive flow out of the containment seal cavity.

Regardless of whether discussing a Plan 52 or dry running containment seal system, the vent connections to flare have been typically specified with a “bubble tight” low cracking pressure (0.5 psi / 0.03 bar) check valve. A “bubble tight” low cracking pressure check valve for a sealing system requires careful installation, maintenance and monitoring. If this type of check valve is installed in a carbon steel pipe, even pipe scale particles are enough to prevent the "bubble tight" seal. The additional concern is that the low cracking pressure can be a hindrance in terms of isolation of the seal cavity as these valves have a tendency to stick open and may not close in reverse flow scenarios, still allowing contaminants to the seal cavity.

One suggested recommendation which has been implemented successfully in the field is to utilize a 5 or 10 psi (0.3 or 0.7 bar) cracking pressure check valve as an alternative. The higher cracking pressure valve maintains back-pressure on the containment seal cavity, and better ensures positive retention in a reverse flow scenario as the valve is not continuously fully open. A controlled inert gas, typically nitrogen, purge flow set at 0.5 to1.0 SCFH (0.014 to 0.028 SCMM) can be supplemented to the outer seal cavity, providing a small amount of flow to slightly open the check valve and keep the flare piping dry. This is relatively straight forward in an instance where a Plan 72 is implemented, but a low pressure purge could be supplied to the vapor space of a Plan 52 as well. In any instance where the outer seal cavity is subjected to any pressure, reverse pressure capabilities of the inner seal must be verified for the maximum flare pressure plus the purge gas flow added to the cavity.

Ultimately, despite many considerations around the flare system and reliability of an Arrangement 2 configuration, availability to a flare can be the dominant determining factor in whether or not the discussed seal configurations are even an option. Permits and limitations on flare exceedances are more common to limit emissions, and many applications are driven towards an Arrangement 3 seal configuration to avoid requirements for flare access. Each application must be carefully evaluated to determine what potential sealing options are available based on potential restrictions regarding the flare system.

FAILURE MODES & IMPACTS TO THE OUTER SEAL

API 682 recommends that Arrangement 2 outer seals should operate for at least 25,000 hours without need for replacement (wet or dry seals) at any containment seal chamber or buffer fluid chamber pressure equal to or less than the seal leakage pressure alarm setting [not to exceed a gauge pressure of 0.07 MPa (0.7 bar) (10 psi)] and for at least 8 hours at the seal chamber conditions. It is a reasonable expectation that the outer seal in a wetted Arrangement 2 configuration with Plan 52 support system would be better suited to accommodate a liquid environment in the event that the inner seal fails with a substantial leak to the outer seal cavity. There can be somewhat of a false sense of security in this way of thinking depending on the nature of the process fluid. If there is continual liquid leakage into the buffer fluid then ultimately the outer seal is operating in an ever changing fluid emulsion that can impact its performance through gradual changes in viscosity and fluid break-down. Additionally, leakage into the reservoir of the process fluid when the process may be considered a VOC requires special attention in terms of replacement and disposal of the buffer fluid to limit personnel exposure and additional environmental concerns. One of the most significant drivers towards a dry system is the reduction in maintenance required to the support system.

Many equipment operators would indicate that a Plan 52 support system allows an added sense of determining outer seal integrity by being able to visually identify a 'drip' from the outer seal faces. This, in practice, is an on-line test of the outer seal faces in a Plan 52 system and should prompt a replacement of the seal cartridge at that point. Early installations of Plan 52 systems were treated as a run to failure arrangement, in that once the inner seal failed, the outer seal contained leakage and was continued to operate, essentially as a single seal at this point. API has made an effort to stress the importance of monitoring the outer seal cavity to determine integrity of the inner seal; it is an expectation that when an Arrangement 2 is used then the pump will be shut down and depressurized within 8 hours of detection of an inner seal leak beyond acceptable levels.

There have also been failure occurrences of high pressure light hydrocarbon applications where significant levels of seal leakage past the inner seal have forced the liquid buffer fluid out of the reservoir to the flare system, resulting in the outer seal operating in a vapor pocket and subsequently running dry and degrading rapidly. This sudden in rush of hydrocarbon to the outer seal cavity will also severely lower the temperature of the reservoir, so considerations regarding the reservoir materials of construction need to be made, particularly to comply with section 6.1.6.11.2 in API 682 4th, which addresses minimum design metal temperature. These scenarios outline the importance of instrumentation and monitoring of the outer seal cavity for fluctuations in pressure and level.

Additional concerns associated with dry running containment seals should also be discussed, particularly how both contacting and non-contacting designs can be influenced by the associated support system. As previously stated, once the outer seal cavity is connected to the flare system, it becomes subjected to variances in the flare system operating pressure. Contacting containment seals can provide the lowest leakage levels when sealing vapor or liquid leakage from the inner seal, but the disadvantage of a contacting seal is that it can be pressure limited. This can be a concern when considering flare pressure excursions beyond normal levels. However, typical containment seal designs are suitable in a gas environment of product vapors for continuous operation with excursions in gauge pressure to 0.275 MPa (2.75 bar) (40 psi) to allow for variation in the flare or vapor recovery system pressure. The influence of pressure on a contacting containment seal can accelerate wear on the softer carbon face, and in essence the contacting nature of the seal ensures a finite life to the seal faces due to frictional heat generated, which means that care must be taken when considering long term operation of a contacting containment seal.

The influence of pressure on a contacting containment seal can not only be from the flare or vapor recovery system, but also from higher than required set point values on a Plan 72 purge gas. The set pressure against normal flare operating pressure needs to evaluated and considered in the life cycle of the outer seal assuming it is of the dry contacting type. One way to verify contacting containment seal performance in the field is to implement a regular testing protocol, which can be used to ascertain some measure of the condition of the faces.

To properly test the containment seal, the outer seal cavity along with the piping to the inert gas supply system and any external vessel or reservoir within the closed system should have a volume in the 0.5 to 1.0 cubic foot (0.014 to 0.028 cubic meter) range. The gas volume in the containment seal cavity alone can be small such that any leakage can result in significant pressure drops. Many containment seals do not have an inert gas purge, but are vented to a flare or vapor recovery system. If the seal to be tested is connected to a purge gas system, either disconnect the system or otherwise isolate the purge gas from the outer seal cavity. Also any connections to a flare or vapor recovery system must be blocked off or disconnected and plugged.

In an API 682 design, the outer seal test pressure can be 25 psig (1.72 bar); observe the pressure gage for 5 minutes. The pressure loss should not exceed 3 psi (0.21 bar) if the gas volume is in the 0.5 to 1.0 cubic foot range (0.014 to 0.028 cubic meter). If the setup volume is greater than 1 cubic foot (0.028 cubic meter), the maximum pressure drop shall not exceed 3 psi per cubic foot (0.21 bar per cubic meter). In an application where the contained gas volume is less than 0.5 cubic feet (0.014 cubic meter) the pressure drop can be as large as 5 psi (0.34 bar). Should the pressure loss exceed the above stated values it is advisable to recondition the seal. If immediate reconditioning is not practical, it is advisable to monitor the containment seal via this test procedure on a weekly basis to determine the condition of the seal. The pressure drop should not exceed 5 psi in 2 minutes for a 1 cubic foot volume. A slight rise in pressure is possible as an increased cavity pressure can result in higher face and outer seal cavity temperatures.

This testing method can also be used for seals incorporating an API Plan 75 or 72 / 75. The previous outlined suggested test would be performed statically; the protocol can be adapted for a dynamic or online test of a contacting containment seal, but isolation of the containment seal in a dynamic state can result in accelerated wear of the faces.

When considering a dry containment seal option and some potential drawbacks of contacting seal designs, it is not surprising that non-contacting containment seals are the default option in API 682 for a dry outer seal system (liquid buffer not provided). Non-contacting containment seals utilize a face pattern to provide lift-off of the seal faces. Relative to contacting, dry-running containment seals, non-contacting face designs will have a lower wear rate in operation, be more tolerant to a buffer gas environment with dew points below −40 °C (−40 °F), and are designed for higher surface speeds and pressure differential. The nature of the lift-off of the seal faces and subsequent seal face gap height increase, a non-contacting seal may experience leakage rates an order of magnitude greater than that of contacting containment seals.

Non-contacting, dry running containment seals are advantageous when brought into comparison with their contacting counterparts in that the deliberate face separation of the design insulates the seal from potential accelerated wear due to pressure excursions from the flare or vapor recovery system. Subsequently, there is minimal compromise in the effectiveness of the seal faces to positively isolate the containment seal cavity from the atmosphere in the event of excessive leakage from the inner seal. It is still the expectation of API 682 that a non-contacting, dry running containment seal shall be shut down within 8 hours of detection of an inner seal leak as prolonged operation of the seal under a failure scenario could result in process emissions being pumped through the outer seal faces to the atmosphere. This would further illustrate the necessity to compliment a non-contacting containment seal with a Plan 72 purge for continued dilution of inner seal leakage. For this reason, condensable product leakage may be better accommodated with a contacting containment seal and Plan 72 / 75.

A benefit of non-contacting, dry running containment designs, along with theoretically no face wear in operation, is that they can be configured with additional instrumentation for monitoring outside of the standard pressure transmitter in the containment seal cavity to trend and alarm on increasing pressure. Under normal operation, these seal designs typically operate with minimal temperature in the containment seal cavity due to the non-contacting nature of the seal. Under increased pressure conditions, an inner seal failure for example, there will be contact of the seal faces in incremental amounts and the designs will operate more like a conventional wetted seal design. This wear mode can be used in monitoring the containment seal by adding a temperature measuring element to the outer seal gland in close proximity to the stationary seal face. Inclusion of this feature allows for not only cavity pressure, but also face temperature to be measured, which can provide an additional indication of elevated inner seal leakage levels and subsequent outer seal cavity pressure increases.

An example of an engineered wet / dry dual unpressurized arrangement supplied for hydrofluoric acid (HF) applications is shown in Figure 10, which illustrates the placement of a thermocouple port over the outer seal stationary face to monitor face temperature and outer seal cavity pressure. This logic could be implemented for more standard configurations should additional monitoring be desired for a non-contacting containment seal. A detailed description of the above mentioned design can be found in the proceedings from the 20th International Pump Users Symposium (Wasser, et al 2003).

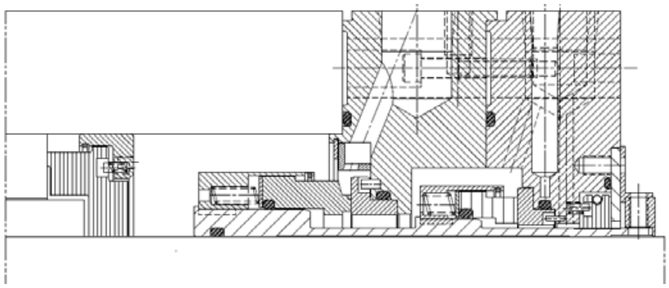

Figure 10 – Depiction of a containment seal with temperature monitoring capability

Of primary concern to any Arrangement 2 configuration is the potential for increased pressure in the outer seal cavity higher than that of the process or pressure at the inner seal, or a reverse pressure situation. In such a scenario, the thrust loads imparted to the inner seal non-process side diameters can cause dislodging of faces and secondary sealing elements, resulting in improper function of the mechanical seal. To this point, API 682 does recommend that the inner seal shall have an internal (reverse) balance feature designed and constructed to withstand reverse pressure differentials up to 0.275 MPa (2.75 bar) (40 psi) without opening or dislodging components. While in reality, it would be unusual for the containment seal cavity to achieve pressures in excess from this amount from the flare or vapor recovery system; there would be an additional concern in relation to dry containment seal utilizing Plan 72.

Normal to the control scheme in a Plan 72 system is a means to regulate buffer gas pressure to a positive set point above the normal flare operating pressure, but below the pressure limitations of the seal. The failure mechanism of the pressure regulation device needs to be evaluated in terms of failing open or closed – a fail open device would expose the outer seal cavity to the full pressure of the buffer gas upstream supply, which could potentially create a reverse pressure scenario for the inner seal components or exceed the stated limits of the outer seal. To minimize the potential impacts of such a scenario, some considerations should be given in terms of the outer seal and support system, not limited to but some potential options being:

- Installation of a relief valve or rupture disc to prevent over pressurization of the seal cavity.
- Stepping down supply pressure upstream of the Plan 72 control panel, independent of the pressure regulating device on the panel; step down pressure below the reverse pressure threshold of the inner seal. The 40 PSI (2.75 bar) threshold would be an ideal target.

It is possible to design the inner seal as a full reverse pressure capable, dual hydraulically balanced (outer and inner diameter) seal, but concessions may need to be made in the overall performance in terms of overall capability as an outer diameter pressurized design. All applications should be carefully reviewed between the seal manufacturer and end user to insure the best method of protection in this proposed scenario.

SUMMARY OF RECOMMENDATIONS

A summary of the recommendations and suggested parameters for evaluating an Arrangement 2 seal and support system has been provided:

- Is the fluid to be sealed at the inner seal a low vapor pressure margin or flashing product? Is the fluid to be sealed at the inner seal a condensable product? In either scenario, a wetted contacting seal with Plan 52 may not provide the desired reliability. In the flashing product scenario, heat added from the outer seal may worsen the vapor pressure margin. In the case of a condensable product, disposal of the contaminated buffer fluid and eventual degradation in the outer seal performance should be considered. Consultation with the seal manufacturer is recommended to evaluate all potential scenarios.

- Plan 52 piping/tubing should be a minimum size of 12 mm (½ in) for shaft diameters 60mm (2.5 in) and smaller and a minimum of 20 mm (¾ in) for shaft diameters larger than 60 mm (2.5 in), if the flow rate exceeds 8 liters/minute (2 gpm), or if the total piping run exceeds 5 m (16.4 ft). Due to the size constraint within even large bore seal chambers pumping rings have limited developed head capacity. The use of large diameter pipe/tubing reduces pressure drops in the system and should be used whenever practical. The schedule (thickness) should be correct for the design conditions.

- Do not use any valves in the piping loop of a Plan 52 system that could possibly restrict the flow of the buffer fluid. If ball or gate valves are used for isolation of the seal chamber and/or reservoir make sure these valves are fully open while filling and during operation. A recommended practice is to lock these valves in an open position to prevent accidental closure during equipment operation.

- Is a buffer gas, preferably nitrogen, available to be used in Plan 72? Nitrogen set pressure typically 5 psi (0.34 bar) above nominal flare or vapor recovery system pressure. Do flare regulations or environmental air permits allow a constant amount of nitrogen flow into the flare system? Plan 72 can enhance the performance of a dry running containment seal; however, if the answer to the second question is 'no', then alternative arrangements, even an Arrangement 3 design, should be considered.

- Consider the specified flow monitoring range for the Plan 72 system and subsequent buffer gas flow to the flare when utilizing a non-contacting inner seal. Non-contacting inner seals will yield higher leakage levels than a contacting design and subsequently there will be more Plan 72 flow required to dilute the inner seal leakage, increasing total flow to the flare or vapor recovery system.

- Does the pumped fluid contain solids over 0.5 % mass fraction of product that crystallizes due to de-watering (N2 drying effect)? Are fluids polymerizing at pumped conditions? Answering yes to these questions may prohibit the use of a dry system.

- Is it critical to minimize process leakage from reaching the atmosphere in case of an inner seal failure? In case of inner seal failure non-contacting containment seals may drip product due to the inherent design features of the faces. Properly instrumented support systems are recommended with all configurations.

- Does the pumped fluid (inner seal leakage) completely evaporate leaving no residue at the lowest ambient temperature and lowest vapor collection pressure? If not, the potential is that residue or build-up may open the containment seal faces. Application of a Plan 72 buffer gas and implementation of design features such as an isolation device to keep containment seal faces separated from inner seal leakage is required.

- Flare or vapor recovery system: is the flare line or vapor recovery system piping configuration prone to liquid accumulation and backflow of liquid to the seal cavity? Flare system back flow would be minimized and sometimes eliminated with the use of Plan 72. Drip leg draining on a regular basis is necessary prevent liquid from reaching the outer seal cavity, especially with dry running designs.

- If the flare is prone to liquid reversals or inner seal leakage condenses in the seal cavity or vent system, then evaluate the costs and benefits for Plan 72 and 75 or 76 vs. Plan 52 The initial cost of installation, operation, and maintenance of the Plan 72 and 75/76 will be less when compared to a Plan 52.

- Consider higher cracking pressure check valves on Arrangement 2 support systems for improved isolation of the outer seal cavity from contaminant intrusion (flare / vapor recovery side).

- Plan 75 notes: consider a method and safe procedure for disposal of seal leakage, which can include routing leakage to a sewer, vacuum truck, or forcing liquids to a safe location by pressurizing the collection reservoir with the buffer gas media. Consider pressure limitations of the outer seal and reverse pressure limitations of the inner seal when considering this disposal method.

- Plan 75 and 76 testing protocols: testing of containment seal integrity is recommended to detect a potential hidden failure of the outer seal. It is recommended to establish and adjust testing frequencies. Safety Instrumented Systems (SIS) guidelines could be used as an outline to implement a testing schedule and protocol.

- Consider temperature monitoring as a supplement for dry running, non-contacting containment seals in addition to the requisite cavity pressure instrumentation. Monitoring of the face temperature provides redundancy in evaluation of the outer seal cavity pressure and subsequently the inner seal face condition.

- There are no reduced emissions credits with these configurations unless the Arrangement 2 outer seal cavity is connected to a flare or other environmental disposal system.

CONCLUSIONS

There have been many field installations of the above mentioned configurations since they were first introduced in the early editions of API 682. As a result, lessons learned and additional manufacturer testing conducted during this time has yielded a better understanding of the capability and limitations of some Arrangement 2 configurations and support systems. Through continued communication between the end user, engineering contractor, and mechanical seal manufacturer, the most reliable, safe, and cost effective system can be selected for an application by keeping in mind some of the principles and concepts reviewed in this tutorial.

APPENDIX

The Arrhenius Equation is described as the formula for the temperature dependence of reaction rates, named after the Swedish chemist Svante August Arrhenius. The equation relates the dependence of the rate constant k of a chemical reaction on the absolute temperature T (in Kelvin); where A is the pre-factor, E_a is the activation energy, and R is the universal gas constant:

$$k = Ae^{-Ea/(RT)}$$

The rate constant k is the number of collisions that result in a reaction per second, A is the total number of collisions (leading to a reaction or not) per second and $e^{-Ea/(RT)}$ is the probability that any given collision will result in a reaction. It can be observed that either increasing the temperature or decreasing the activation energy will result in an increase in the rate of reaction. (Source: IUPAC Compendium of Chemical Terminology, 2nd Edition, McNaught and Wilkinson, Blackwell Scientific Publications, Oxford 1997)

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