In-Ground Versus Above-Ground Sulfur Sealing?

– An Industry Survey

Thomas C. Willingham, PE

Controls Southeast, Inc. (CSI)

Charlotte, North Carolina, USA

Abstract

Sulfur Recovery Units convert deadly hydrogen sulfide into elemental sulfur and water. This conversion occurs in vapor phase at elevated temperature and pressure via the modified Claus process. Since the Claus process is equilibrium-limited, successive process stages are required for high conversion rates. After each stage, a condenser is used to convert vaporous sulfur into liquid sulfur. Once in liquid phase, the sulfur gravity-drains from the condenser into temporary storage. To prevent the process vapor (with remaining hydrogen sulfide and sulfur dioxide) from escaping with the liquid sulfur, some sealing means is required between the condenser and temporary storage. Historically, SRU operators have made use of in-ground and above-ground sulfur-sealing devices. Both in-ground and above-ground approaches have characteristic strengths and weaknesses, and this paper will survey the spectrum of industry position and rationale that drives sulfur-sealing technology choices.

Background

Sulfur Recovery Units convert deadly hydrogen sulfide (H_2S) into elemental sulfur and water. This conversion occurs in vapor phase at elevated temperature and pressure (4-18 psig) via the modified Claus process. Since the Claus process is equilibrium-limited, successive process stages are required for high conversion rates. After each stage, a condenser is used to convert vaporous sulfur into liquid sulfur. Once in liquid phase, the sulfur gravity-drains from the condenser into temporary storage—typically a pit or collection vessel. To prevent process vapor (with remaining H_2S and SO_2) from escaping with the liquid sulfur, some sealing means is required between the condenser and temporary storage.

Historically, SRU operators have made use of in-ground and above-ground sulfur-sealing devices. Both in-ground and above-ground approaches have characteristic strengths and weaknesses, and varied industry support. The purpose of this paper is to survey the spectrum of industry position and rationale that drives sulfur-sealing technology choices. To that end, 25 sulfur industry experts were surveyed. These experts represented operating companies (8), licensing and/or engineering companies (11), and independent consultants (6). Figure 1 indicates the distribution of respondents as a percentage of the total. Given this distribution, the survey provides a meaningful cross-section of industry positions on sulfur-sealing technology options. The survey was conducted anonymously, in order to promote maximum information sharing. Accordingly, this paper presents a summary of survey results, preceded by a brief description of conventional sealing approaches.

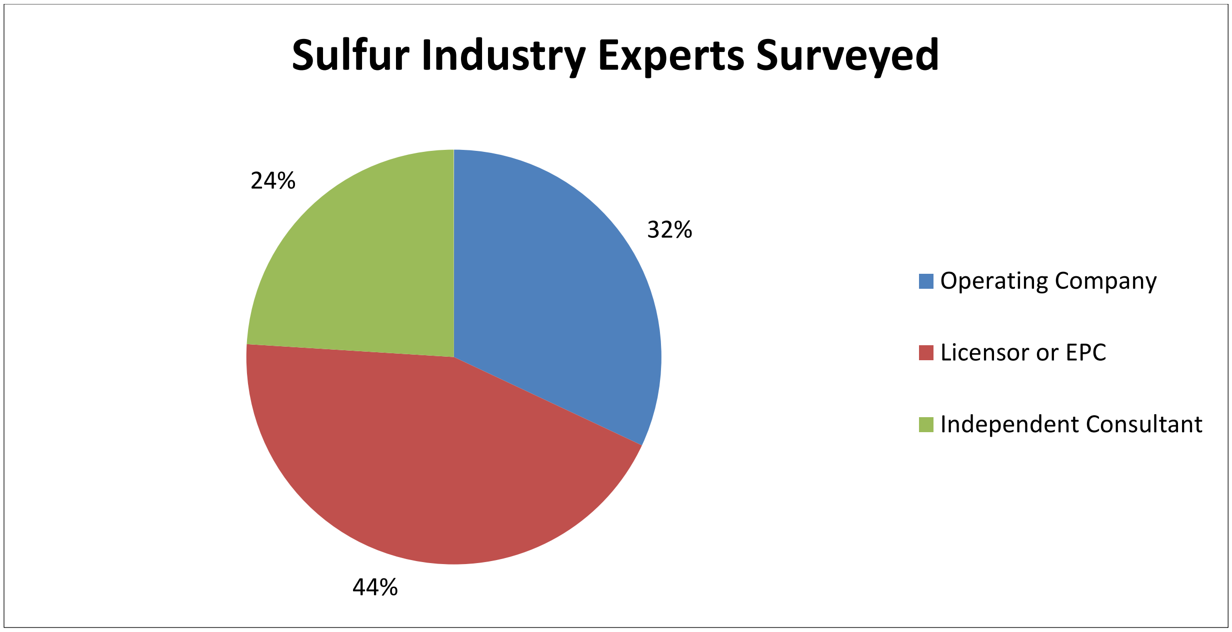

Figure 1: Sulfur industry experts surveyed

Conventional Approaches to Sulfur Sealing

Historically, the oil and gas industry has used two types of devices to achieve a vapor seal in sulfur rundown lines. One type is the in-ground device, which is commonly referred to as a seal leg. The other type is an above-ground sealing device, such as Sultrap® and S_xSeal™.

In-ground Sealing

The traditional in-ground device is the seal leg, shown in Figure 2, which has been employed in SRUs for over 50 years. During normal operation, liquid sulfur flows into the seal leg via a rundown line from the condenser. Once inside the seal leg, sulfur flows downward through the inlet piping to the bottom of the leg, and then upward through the annular outlet piping to the sulfur outlet. Similar to a wastewater P-trap, the presence of liquid sulfur in the bottom of the seal leg establishes a vapor seal. This prevents H_2S and SO_2 vapor from passing from a condenser through the seal leg into the sulfur pit or collection vessel. During normal operation, the sulfur level in the inlet piping is always lower than the sulfur level in the outlet piping. The difference in sulfur level is determined by the pressure differential between the condenser and downstream sulfur storage. Thus, the below-ground depth of a seal leg is determined by the maximum expected upstream pressure during normal operation. Typically, the maximum upstream pressure is 15 psig. Given the density of sulfur, this maximum operating pressure necessitates a below-ground depth of 20 feet or more. Sulfur recovery units operating at higher pressure require even deeper seal legs. If the SRU were to experience a pressure spike that exceeded the hydrostatic pressure created by the depth of the seal leg, the elevated pressure would push the liquid out of the seal leg, thereby creating a supplemental pressure-relief path (provided the pressure-event duration is long enough to overcome the momentum of the liquid sulfur in the seal leg).

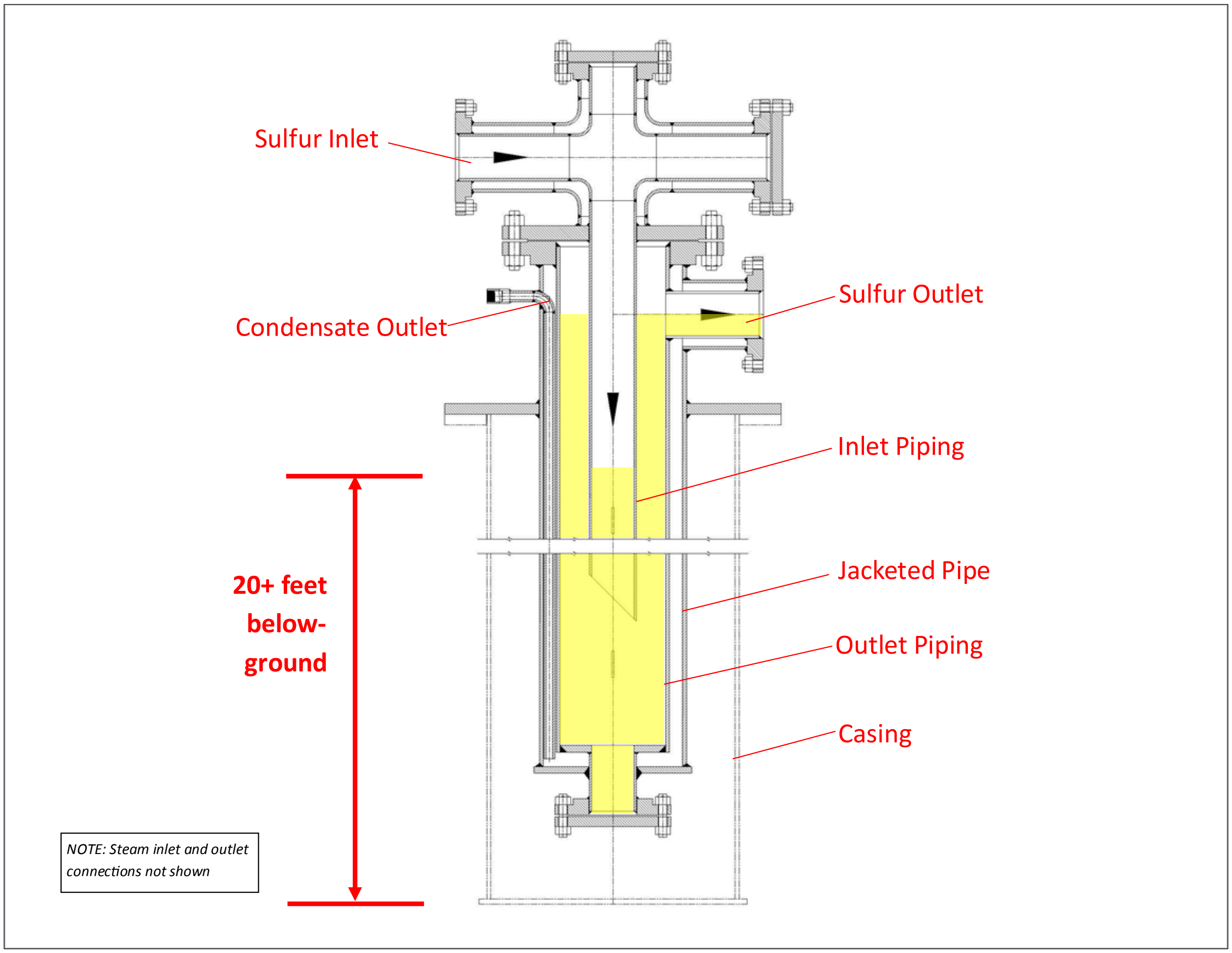

Figure 2: Seal leg – traditional in-ground sulfur-sealing approach

Over time, debris can accumulate at the bottom of a seal leg. Depending upon SRU operational conditions and feedstock, sulfur flowing into the seal leg typically contains entrained debris, which sinks to the bottom and collects below the inlet piping. Once debris accumulation reaches the inlet piping, sulfur flow through the device becomes impeded. When this occurs, the seal leg must be removed from the ground, cleaned out, and re-installed.

The base cost of a seal leg typically ranges from $15,000 - $75,000, depending on size, material, and non-destructive examination (NDE) specifications. The typical installation cost of a new seal leg ranges from $50,000 - $200,000. Thus, the total installed cost of a seal leg can range from $65,000 - $275,000.

Above-ground Sealing

The conventional above-ground design has an operational history dating back to the 1990s. Since its introduction, the above-ground design has begun to complement and even replace the in-ground seal leg. Above-ground sealing devices, such as the Sultrap® and S_xSeal™ 1000, function similar to a float-style steam trap. These conventional above-ground devices use a float to open and close an orifice. The float and the sulfur inlet are located in an upper chamber. The sulfur outlet is in a lower chamber. A dividing plate with an orifice separates the chambers. When the liquid in the upper chamber reaches a high liquid level, as shown in Figure 3, the float rises and opens the orifice. Once a sufficient amount of liquid drains through the orifice, the float lowers and closes the orifice.

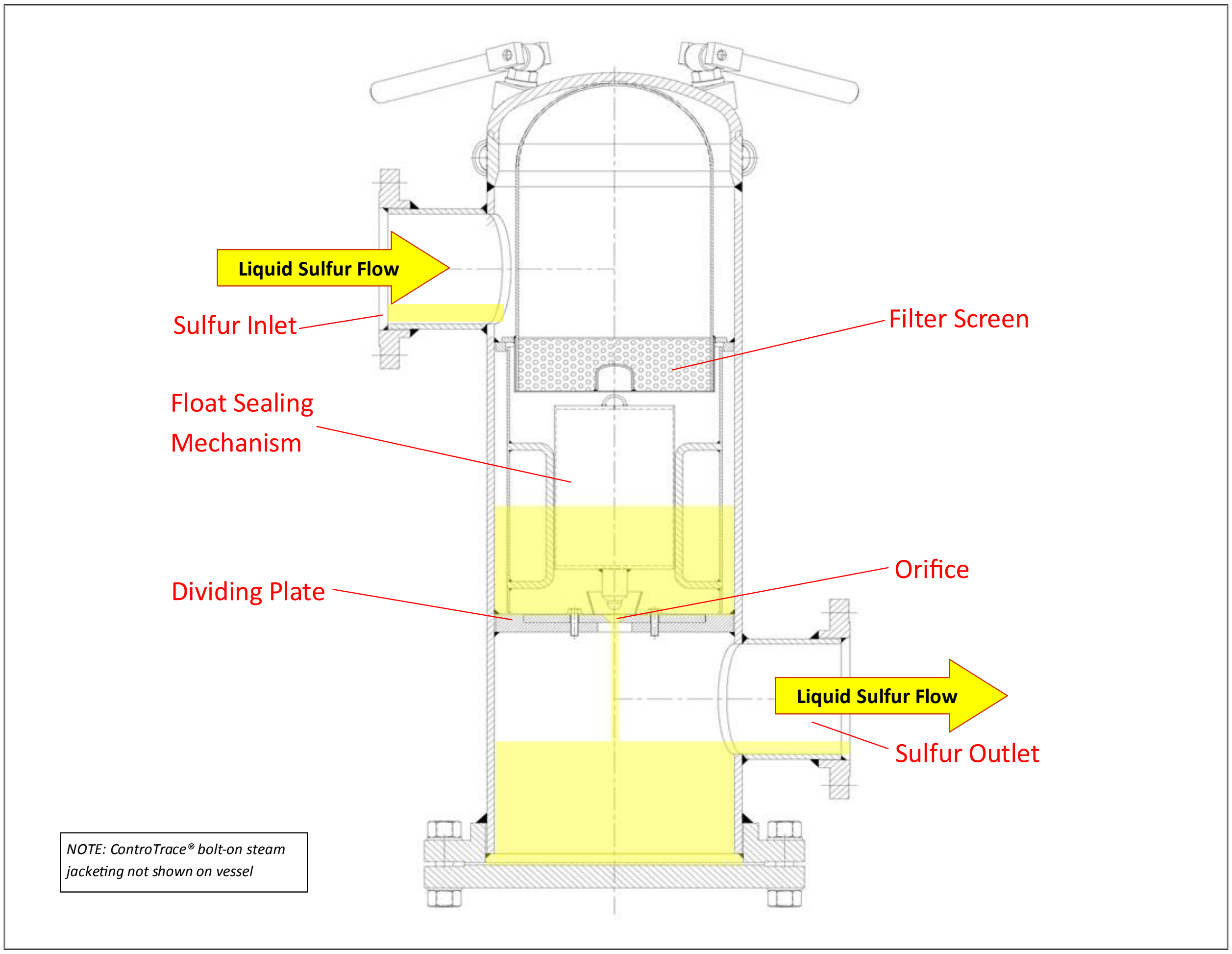

Figure 3: S_xSeal™ 1000 – conventional above-ground sulfur-sealing technology

The above-ground device is designed to maintain a minimum level of liquid sulfur above the orifice, in both a flowing and non-flowing condition. During no-flow, the float sealing mechanism completely seals the orifice, preventing the liquid from exiting and maintaining a minimum liquid level. In a flowing condition, the unit accommodates sulfur until the high liquid level is achieved. At this point, buoyancy lifts the float and opens the orifice. As sulfur flows out through the orifice, the float lowers and re-establishes the seal at the minimum liquid level. Therefore, whether in a non-flowing or flowing condition, the above ground device always maintains a minimum level of liquid sulfur, thereby creating a vapor barrier that prevents downstream flow of H_2S and SO_2. It is important to note that the unit only opens in response to the buoyancy of the float. Thus, the conventional above-ground device will not open in response to an upstream over-pressure event. In fact, elevated pressure will act against the float sealing mechanism and make it less likely to open.

The conventional above-ground design employs some type of filter screen to prevent debris from compromising the seal. Typically, a filter screen is positioned between the inlet and orifice to prevent entrained debris larger than 1/8-inch from affecting sealing integrity. As debris accumulates, this filter screen requires regular cleaning. A cleaning frequency of once a month seems most common, based on survey responses. However, actual cleaning frequency may be more or less frequent depending upon operational and feedstock characteristics of a given SRU, as well as any plant events that warrant additional cleaning.

The cost of a conventional above-ground sealing device typically ranges from $45,000 - $70,000 for the unit itself. The installation cost ranges from $5,000 - $10,000. Thus, the total installed cost of a conventional above-ground sealing device can range from $50,000 - $80,000.

Survey Results

The following survey results are divided into three primary aspects of industry position on sulfur sealing:

- Sealing configuration preferences;
- Pressure-relief preferences; and,
- Maintenance frequency.

For each of these aspects of sulfur-sealing philosophy, the corresponding survey questions are provided, and the response choices given to survey participants are listed.

Sealing Configuration Preferences

First, sulfur industry experts were asked, “My preferred sulfur-sealing configuration is...?”, and given four response choices:

- All in-ground sealing devices;
- All above-ground sealing devices;
- Combination of in-ground and above-ground sealing devices; or,
- No preference.

Figure 4 summarizes the survey responses. As indicated in the chart, the survey responses suggest the industry favors the above-ground approach, with 72 percent preferring either all above-ground sealing devices, or a combination of above- and in-ground devices.

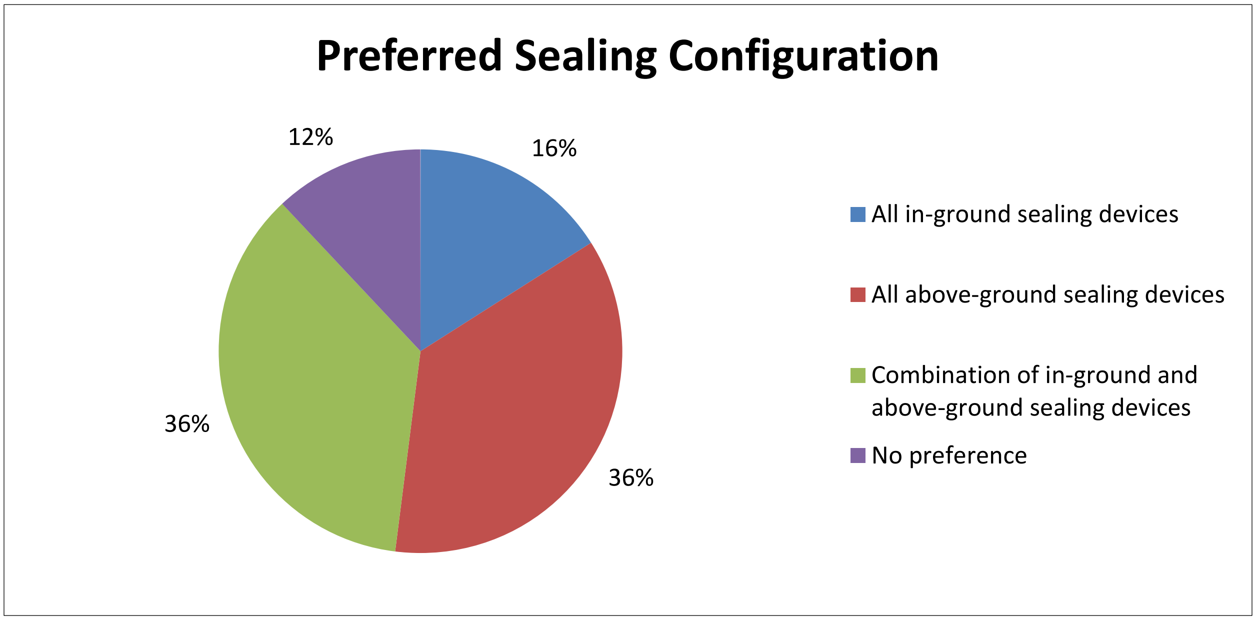

Figure 4: Preferred sealing configuration

Reasons Respondents Favored Above-ground Sealing Devices

Asked to discuss their rationale for favoring above-ground sealing devices, survey participants provided many responses, which can be grouped into three main categories:

- Ease of maintenance / accessibility;
- Safety issues; and
- Depth / ground-water issues.

Each of these rationale categories is explained below in more detail.

Ease of Maintenance / Accessibility

One of the primary reasons industry experts preferred above-ground devices was the above-ground unit’s accessibility and ease of maintenance when compared to a seal leg. The biggest maintenance concern with a seal leg is mechanical plugging at the bottom of the device due to the accumulation of debris. Survey participants noted the following primary sources of debris:

catalyst beads/fines; refractory chunks/dust; pipe scale; and soot/carsul from a combination of unreacted hydrocarbons and sulfur. The length of time before the debris plugs a seal leg varies widely with location. Some respondents reported plugging in a matter of days after startup. Others indicated that plugging occurred after more than 3-5 years of operation, and some units had never experienced plugging.

When seal leg plugging occurs during normal unit operation, the disruption can result in costly SRU downtime, or decreased sulfur conversion if a particular catalyst/condenser stage is bypassed. According to survey participants, the maintenance necessary to clean out a plugged seal leg is significant. Given its depth, a seal leg must be removed from the ground and laid down horizontally to remove accumulated debris. Doing so requires ample overhead access—typically measured by the height of the seal leg, along with any additional crane clearance needed. Interference with adjacent equipment can also be a concern. In many refineries, such as the one represented in Figure 5, the close proximity of rundown lines and adjacent sulfur-sealing devices makes seal leg removal particularly difficult.

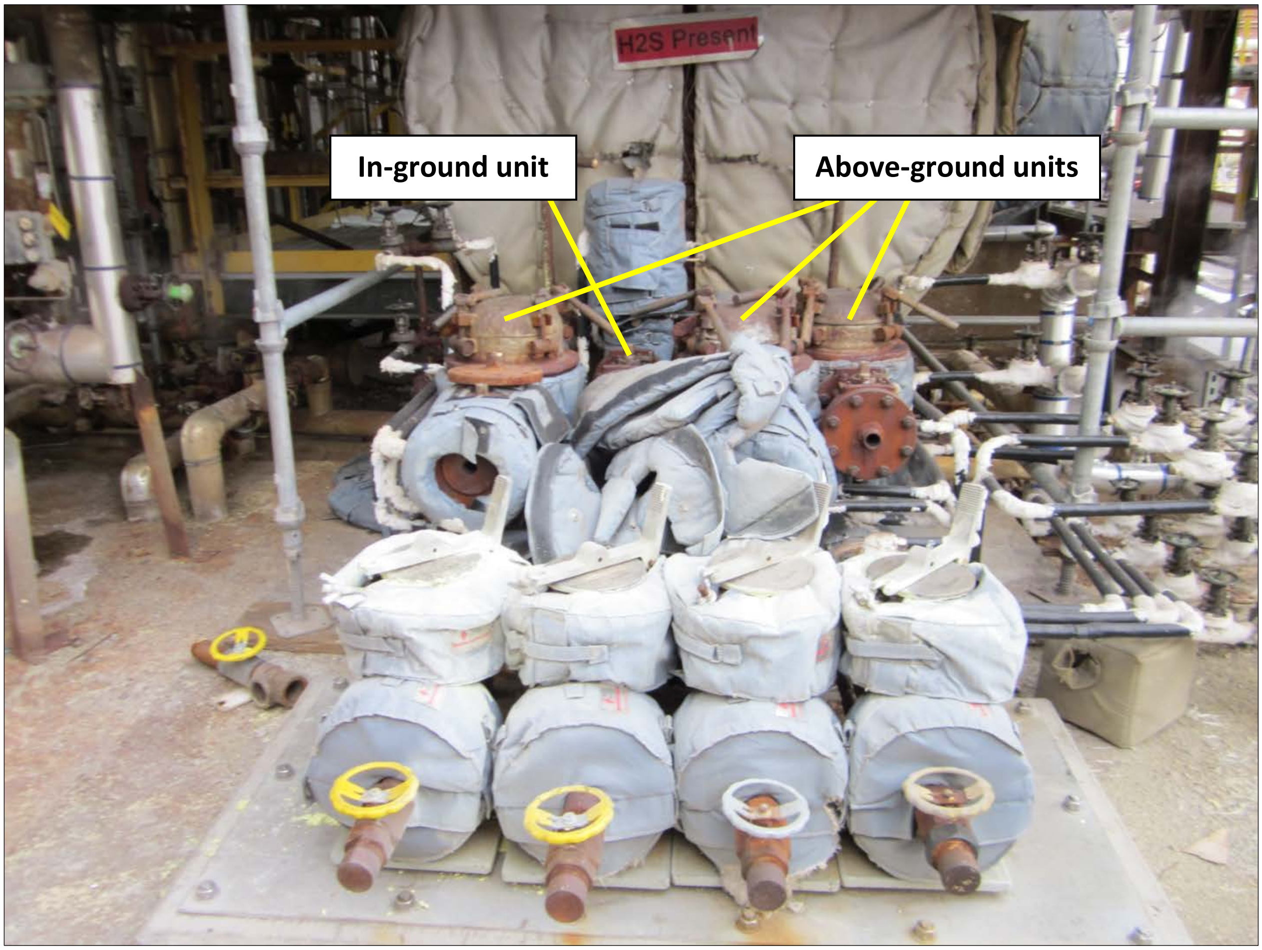

Figure 5: Four adjacent sealing devices (3 above-ground units & 1 in-ground unit)

According to survey responses, during seal leg removal, sulfur in the unit freezes, and the solid sulfur must be removed along with the debris. The most common procedure for sulfur and debris removal is hydro-blasting. Survey respondents agreed that it is best to remove and clean a seal leg proactively during a scheduled turn-around. This reduces the likelihood of experiencing an unexpected service disruption.

Some survey respondents noted alternative approaches to preclude or minimize seal-leg maintenance. For example, one expert responded that in some cases, installing a new seal leg is quicker and less expensive than cleaning a plugged device. Another respondent described a well-known licensor's preventive maintenance approach. This method involves a proactive flushing protocol, whereby sulfur from the pit/collection vessel is periodically pumped through the seal leg, at a flow rate equal to the load-out pump velocity, in order to remove accumulated debris. On the other hand, those favoring above-ground units noted that they appreciate having the entire seal above ground, thereby simplifying maintenance measures.

Minimal Safety Issues

Another reason survey participants gave for favoring above-ground sealing devices was safety. According to survey responses, a fully plugged seal leg must be pulled out of the ground for cleaning, while a partially plugged seal leg can often be cleaned in place. Both of these seal leg cleaning approaches present safety risks. Respondents reported that in-ground cleaning is the more hazardous of the two procedures. In-ground seal leg cleaning, one expert explained, is more dangerous because "procedures are often rushed, and they do not always follow well-defined protocols for personal protective equipment, system isolation, and step-by-step planning." One other safety concern associated with seal legs is the vapor blow-by through a seal leg during a pressure event. This can result in a release of molten sulfur, along with H_2S and SO_2 vapor into the pit area, potentially injuring operators. For these reasons, many survey participants viewed the above-ground sealing device as a safer unit to maintain and operate.

Depth / Ground-water Issues

Based on operating pressure, seal legs are usually designed for in-ground depths of 20 feet or more. This requirement, coupled with the high water tables in many refinery and gas plant locations, contributes to the risk of ground-water intrusion. If corrosion or weld failures result in water intrusion, the seal leg must be lifted out of the ground to be repaired. According to survey participants, the repair procedure would be similar to that used for removal of accumulated debris. In addition, all sulfur must be removed prior to welding the damaged seal leg, in order to prevent a fire hazard. Favoring a preventive approach instead, one expert noted, "By keeping the seals out of the ground, we avoid many of the problems associated with ground-water intrusion and corrosion."

Reasons Respondents Favored In-ground Sealing Devices

Asked to discuss their rationale for favoring in-ground sealing devices, survey participants provided many responses, which can be grouped into two primary categories:

- Supplemental pressure relief; and,

- No filter screen cleaning.

Each of these rationale categories is explained below in more detail.

Supplemental Pressure Relief

SRU design must account for the possibility of upset events and mechanical failures that have the potential to create high pressure in the unit. Most of the experts surveyed agreed that a sealing device should not be relied upon as the primary relief path. Instead, the industry trend is to employ more sophisticated pressure trips on all incoming streams, such as a high-integrity pressure protection system (HIPPS). A few others utilize pressure-relief valves (PRVs) or rupture discs on these lines, which are routed to the incinerator. Nevertheless, nearly half of the respondents relied on the sealing device as a secondary relief path. As one respondent noted, "With at least one seal leg, the SRU is always protected from over-pressure." A seal leg's design inherently provides this supplemental pressure-relief capability, whereas the conventional above-ground sealing device has no such relief path.

The three most common types of pressure events are: 1) light-off; 2) TGU/bypass valve closure; and 3) waste heat boiler tube rupture. First, a light-off event would occur upon ignition of the Claus burner if natural gas has not been fully combusted. A light-off pressure event can result in a significant pressure spike, which could exceed the unit's pressure rating if the unit is rated for less than 75 psig. Second, a TGU/bypass valve pressure event would occur if both the valve to the TGU and the bypass valve to the incinerator were inadvertently closed at the same time. This would result in a unit pressure equal to the maximum blower head pressure. According to survey responses, such an event is considered less likely in newer units, due to more sophisticated interlocks. The third type of pressure event, which was of greatest concern to survey respondents, is an event resulting from a tube rupture in the high-pressure waste heat boiler (WHB), located immediately downstream of the Claus furnace/reactor. A WHB tube rupture would allow 150 – 650 psig steam and boiler feed water to enter the process, sending a high-pressure steam and/or a two-phase flow into the SRU piping and equipment. In this scenario, the magnitude of the pressure event depends upon the size of the rupture. In the case of a light-off pressure event or a WHB tube-rupture event, most respondents would expect there to be a relief path through the SRU to the incinerator via the TGU or TG bypass. Notably, some SRU designs do consider a "double jeopardy" scenario, in which a catastrophic WHB tube failure occurs in conjunction with the closure of both TG valves. Citing the potential incidence of these three types of pressure events, half of all survey participants favored at least one seal leg as a means of supplemental pressure relief.

No Filter-screen Cleaning

Conventional above-ground sealing devices have a higher regular maintenance frequency compared with a seal leg. Conventional above-ground units employ filter screens to prevent debris from compromising the seal. These filter screens must be cleaned regularly in order for the unit to function properly. Because filter-screen maintenance carries the potential for minor fugitive H_2S emissions into the immediate area, standard operating procedures in most SRUs require operators to wear self-contained breathing apparatus (SCBA). Industry experts reported that a monthly maintenance frequency is most common for conventional above-ground sealing devices, but some operators clean weekly or even daily. In contrast, a seal leg does not contain filter screens; therefore, its maintenance intervals are longer during steady-state operation.

Summary of Reasons for Sealing Configuration Preferences

Table 1 summarizes the reasons cited for each sealing configuration preference:

	Sealing Configurations:		
Reason for Configuration Preference	***All Conventional Above-ground***	***Conventional Above-ground & ≥ 1 In-ground***	***All In-ground***
Ease of Maintenance / Accessibility	✓		
Minimal Safety Issues	✓		
Depth / Ground-water Issues	✓		
Supplemental Pressure Relief		✓	✓
No Filter-screen Cleaning			✓

Table 1: Summary of reasons cited for sealing configuration preferences

Pressure-relief Preferences

The subject of pressure relief has greatly influenced the debate between in-ground and above-ground approaches. To clarify the breadth of industry position on this point, survey recipients were asked, "I believe the sulfur-sealing configuration…?", and given four response choices:

- Must fully relieve an API-521 catastrophic waste heat boiler tube failure (rupture at both ends);
- Must provide some level of supplemental pressure relief;
- Must prevent any pressure spike from propagating to downstream sulfur storage; or,
- Must be designed for sealing integrity only, and its pressure-relief capability is not important.

As shown in Figure 6, the responses to this survey question indicate a wide spectrum of opinion.

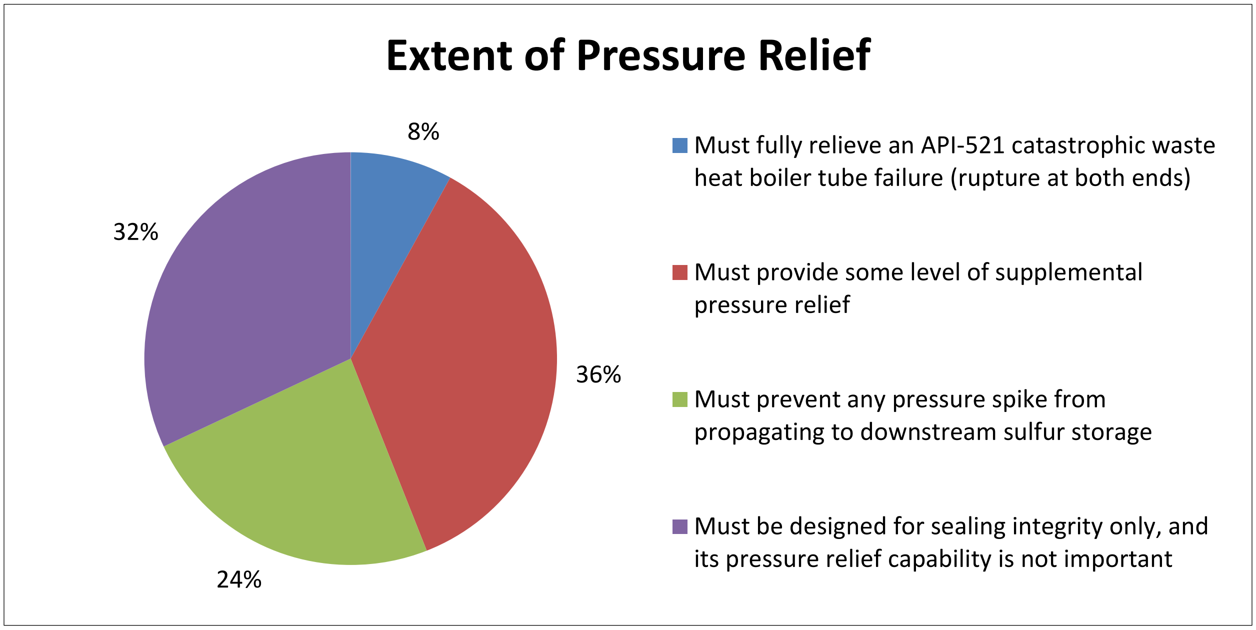

Figure 6: Extent of pressure relief that sulfur-sealing configuration should provide

Almost half of all respondents believe that the sealing configuration must provide some pressure relief. However, opinion varies as to the degree of pressure relief that the sealing configuration must provide. On one hand, 8 percent of survey participants responded that the sealing configuration should fully relieve a catastrophic WHB tube failure, as described by the API-521 standard. On the other hand, 36 percent of industry experts believe that the sulfur-sealing configuration does not have to meet the API-521 guideline, but must provide some level of supplemental pressure relief. Opinions among this segment of respondents likely reflect the work of Justin Lamar (of Black & Veatch) regarding a WHB tube rupture that occurred in 1999 at an undisclosed refinery (Lamar, 2005). Using actual measured boiler pressure from the event, Lamar calculated the size of the tube rupture. Lamar then performed a dynamic simulation of that event, which demonstrated that the actual pressure event the SRU would have seen was 46-70 psig. The fact that the seal legs did not blow during the event suggests that the unit was open to the incinerator. Consequently, several experts commented on the likely organization of an API subcommittee to revisit the double-ended tube rupture condition in the current API calculation. Prompting this reconsideration is the fact that, unlike power boilers, which have high-pressure steam on the inside of the tube, sulfur unit WHBs have high-pressure steam on the outside of the tube. Thus, they tend to collapse rather than rupture at both ends. Although 32 percent of survey participants indicated the sealing configuration should be designed for sealing only, almost half agreed that the sulfur-sealing configuration should provide at least supplemental pressure relief.

In a related question, survey recipients were asked, “Please discuss the best design approach for relieving an SRU pressure spike (>15 psig).” Figure 7 indicates the categories of responses to this question. The consensus approach among most respondents (42 percent) involved utilizing unit pressure trips and designing the SRU for higher pressure. One sulfur expert said, “A properly designed and maintained protective instrument system should eliminate most, if not all, of these types of over-pressure incidents.” Another expert recommended a “combination of equipment and instrument design.” Additionally, 29 percent of respondents favored maintaining an open path to the incinerator. Twenty-four percent recommended using at least one seal leg. Only 5 percent of respondents favored using a rupture disc to relieve a pressure spike greater than 15 psig.

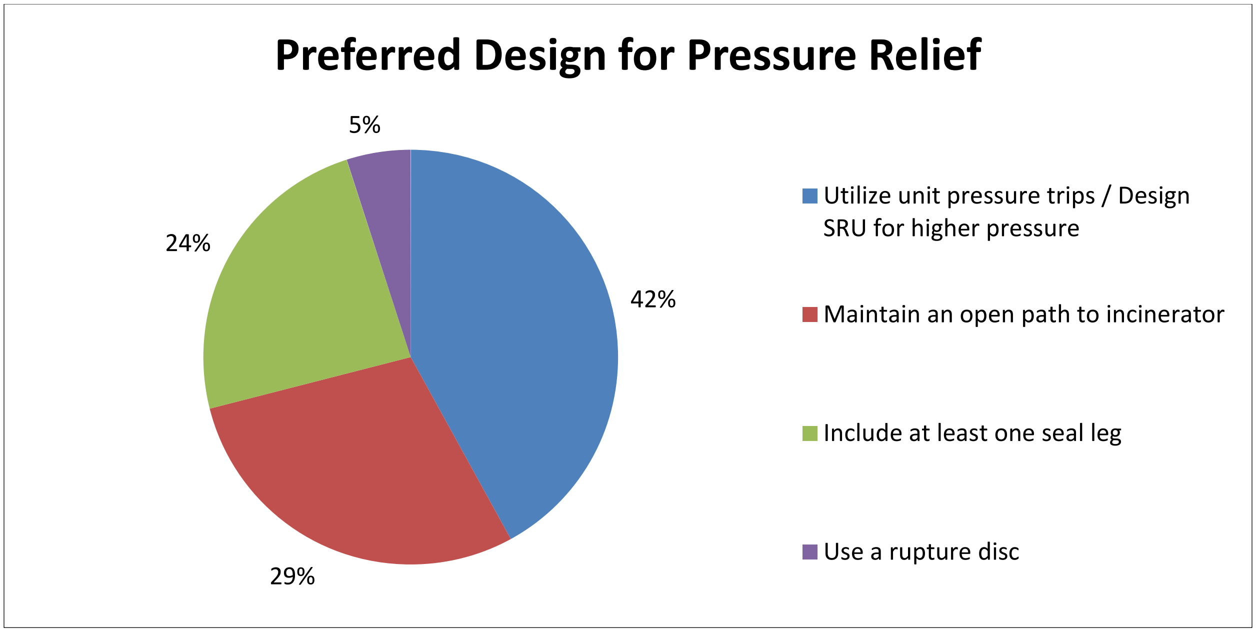

Figure 7: Preferred design approach for pressure relief (>15 psig)

Maintenance Frequency

Finally, survey recipients were asked, "The highest regular maintenance frequency I am willing to incur for my sealing configuration is…?", and were given six response choices:

- Daily;
- Weekly;
- Monthly;
- Quarterly;
- Annually; or,
- At turn-around.

Figure 8 indicates the distribution of responses to this question. As shown in the chart, one third of respondents were willing to incur maintenance at least weekly, one third preferred monthly or quarterly maintenance, and one third were only willing to perform sulfur seal maintenance yearly or during a scheduled turn-around.

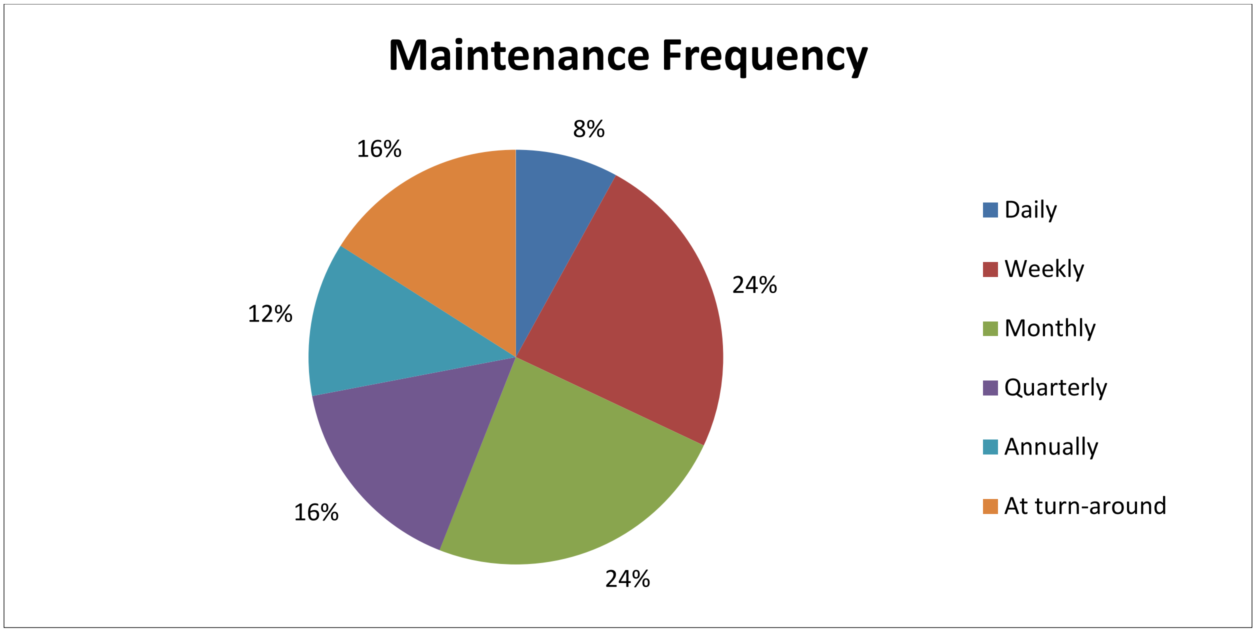

Figure 8: Tolerance for maintenance frequency

Recent Above-ground Design Advancement

As this industry survey has demonstrated, both the seal leg and conventional above-ground sulfur seal have inherent strengths and weaknesses, resulting in industry demand for a comprehensive solution. In late 2012, following an extensive research and development effort, CSI introduced an advanced above-ground design known as S_xSeal™ 2000. This new design addresses the perceived weaknesses of the conventional above-ground design, including the regular maintenance frequency and pressure-relief issues that were borne out by the survey results. Like the conventional above-ground sealing device, the S_xSeal™ 2000 also uses a float sealing mechanism to open and close an orifice. However, in the new design, the orifice and the flow are inverted, as shown in Figure 9. Sulfur flows into a lower chamber and moves upward through the orifice into an upper chamber. During normal operation, the float maintains an equilibrium position with the orifice partially open. This results in a steady flow of sulfur through the outlet.

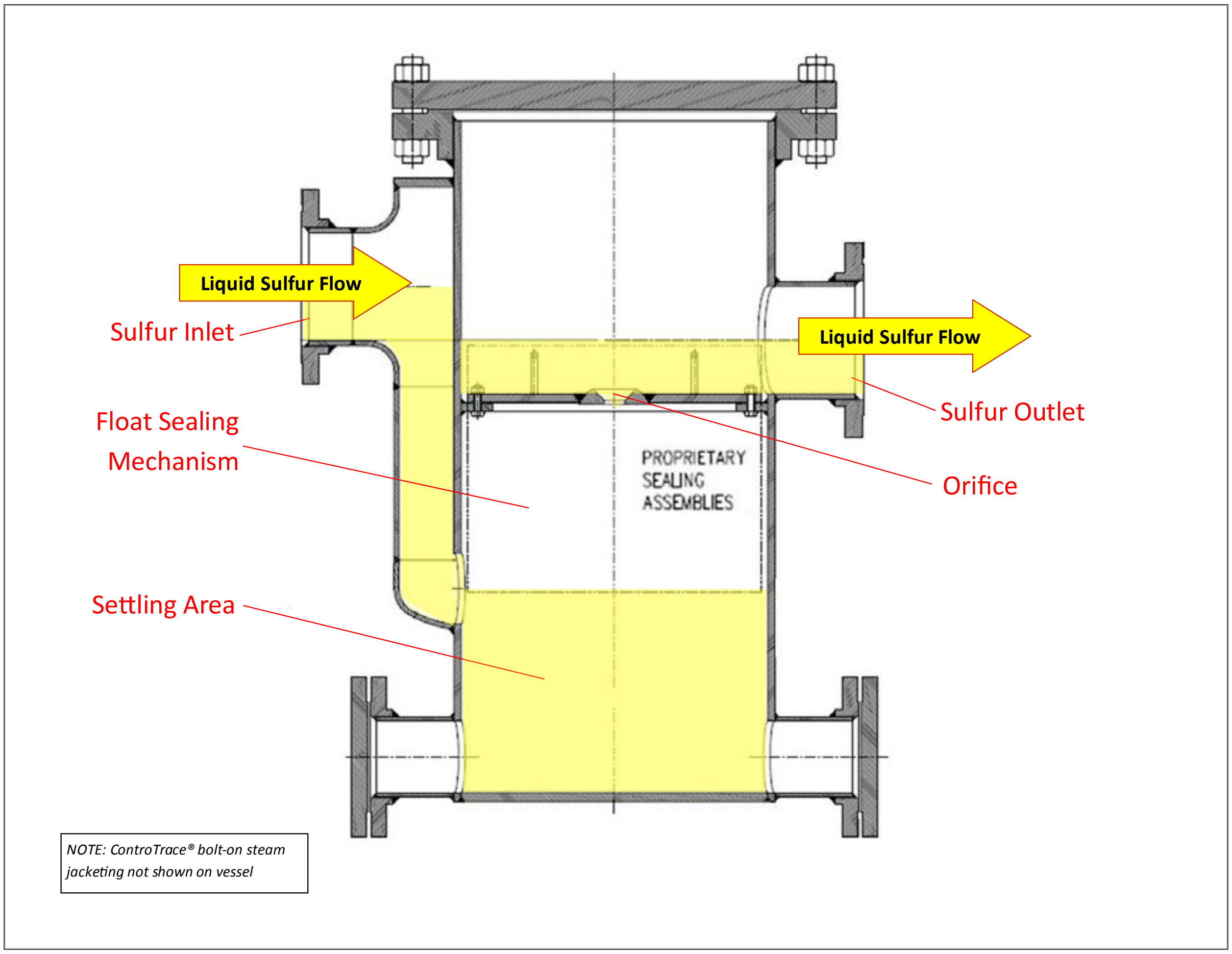

Figure 9: SxSeal™ 2000 – improved above-ground sulfur-sealing technology

The lower chamber also functions as a settling area. Thus, the S_xSeal™ 2000 does not require a filter screen to prevent debris from compromising the seal. As sulfur flows upward through the orifice and out of the unit, entrained debris sinks and accumulates at the bottom of the settling area. Consequently, debris does not compromise the sealing integrity.

In addition, the upward-flowing design provides a supplemental relief path, which is comparable to a seal leg. The float sealing mechanism is designed to open the orifice via buoyancy or pressure. The weight of the float sealing mechanism divided by the orifice area establishes the pressure-relief set point. The S_xSeal™ 2000 standard relief pressure is 15 psi. This supplemental relief capability was referenced in a recent study (Flood, Wong, & Chow, 2013). In discussing viable options for mitigating elevated pressure events in SRUs, the authors concluded that CSI's S_xSeal™ 2000 "will allow passage of process gas or pushed liquid into the sulfur pit or collection vessel. This gives designers an above-grade option which still provides a supplemental relief flow path."

The cost of a S_xSeal™ 2000 typically ranges from $55,000 - $100,000 for the unit itself. The installation cost ranges from $5,000 - $10,000. Thus, the total installed cost of a S_xSeal™ 2000 can range from $60,000 - $110,000.

Summary

Based on an anonymous survey of a representative cross-section of sulfur industry experts, there is a wide spectrum of industry position on sulfur-sealing approaches. The survey clearly indicates an industry trend (72 percent) towards above-ground sealing. The reasons for this trend include: safety; ease of maintenance and accessibility; and no potential for ground-water intrusion. The survey also suggests an industry hesitation to universal adoption of the conventional above-ground sulfur seal—reportedly due to concerns over supplemental pressure relief and maintenance frequency. To address these concerns, CSI has developed the S_xSeal™ 2000. This improved above-ground sulfur seal delivers the safety, ease of maintenance and accessibility, and no risk of ground-water intrusion found in conventional above-ground devices. The S_xSeal™ 2000 also provides the infrequent maintenance and supplemental pressure relief of a seal leg.

References

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