Importance of Heat Maintenance in SRUs

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Introduction

From time-to-time, operational issues in an SRU are related to the accumulation of liquid sulphur. In the Claus process, sulphur is produced both in the thermal stage and in the catalytic stages. Since the Claus reaction is a chemical equilibrium, the production of sulphur is inhibited if sulphur vapor is already present in the process gas. Therefore, a sulphur condenser is generally used to condense and remove the produced sulphur and ensure continued conversion to sulphur in the subsequent stage(s).

The condensers do not remove all the sulphur. It is sufficient to condense and remove as much sulphur to stay above the sulphur dewpoint in the following catalytic stage. In sub-dewpoint processes such as CBA, Sulfreen and MCRC, there is some deliberate condensation of sulphur in the converters to force the Claus equilibrium closer to completion.

If the liquid sulphur is not removed properly from the SRU, it can accumulate in the equipment and piping. Accumulation of the liquid sulphur can impede the flow of process gas in the unit. It can also cause sulphur fires and equipment damage in the presence of oxygen (>10 vol%) and a source of ignition. In addition, the accumulated liquid sulphur can freeze if the plant is let to cool down or can turn into "sulphur concrete" due to poor housekeeping practices. Solid sulphur not only poses the risk of fire, but it can also be difficult and time consuming to remove.

For continuous flow and removal of liquid sulphur in an SRU, it is essential that all piping and equipment are designed and sloped properly. The impact of increased viscosity at temperatures above 158 °C or at lower concentrations of dissolved H_2S must be considered. It has to be ensured that catalyst dusts and debris do not remain in the plant after loading. Furthermore, the SRU must be equipped with an adequately designed heating system to keep the liquid sulphur within a specific range of temperature during all operating conditions. In addition, the heating system is expected to be able to melt the sulphur in case of a freeze up. The most common heating systems utilized in the SRU's include electrical or glycol tracing or some type of steam heating system.

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Many Sulphur Recovery Units around the world rely on steam heating systems for the purposes mentioned above. The flowing sulphur must be maintained within an approximate temperature range from 120°C at which sulphur freezes to 160°C at which sulphur viscosity starts to increase rapidly due to polymerization. When troubleshooting the performance and reliability of a steam heating system, the focus is typically on the method of heating (jacketed piping, bolt-on jacketing or tube tracing).

However, experience shows that most often the problems with the steam heating systems are not related to the type of the system. Most malfunctioning steam heating systems have issues with the steam supply and condensate removal from the system. These inadequacies are the result of certain rules of thumb and legacy standards which are applied in the design of steam heating systems instead of concrete engineering rules. Finally, some of the wrong beliefs which have crept into the design of the steam heating systems and lead to under-performance and increased capital and operational costs are discussed.

Risks of Accumulated Liquid Sulphur

Sulphur Fire

The best-known risk of accumulated liquid sulphur is a sulphur fire which can cause severe damage to the SRU equipment. The condenser tubes and the mist pads are especially vulnerable. Sometimes the fire is limited either by the available sulphur or oxygen. In this case, the sulphur fire will have a noticeably higher temperature but perhaps with no damage.

Note, however, that in every sulphur fire not only SO_2 but also SO_3 and sulphuric acid will be produced. Sulphuric acid can eventually lead to extensive corrosion damage in lines and equipment.

For a sulphur fire to happen oxygen has to be present in sufficiently high concentrations (>10 vol%). At lower concentrations of free oxygen in the process gas, the sulphur will be oxidized to SO_2, thereby generating extra heat of oxidation.

Besides sulphur vapor (from liquid sulphur) and oxygen in sufficiently high concentrations (>10 vol%) there has to be an ignition source. The following sources of ignition have been identified:

- When the temperature in the process is above the auto-ignition temperature of sulphur. The auto-ignition temperature is most often mentioned as 230°C but values ranging from 190°C to 261°C have been reported, possibly linked to the sulphur particle size.
- Pyrophoric iron sulphide (FeS), when exposed to air (oxygen) will ignite a sulphur/air mixture.
- Static electricity generated by liquid sulphur agitation. Sulphur, being one of the best electric insulating liquids known, and having a high dielectric constant can easily generate enough static electricity to cause a spark ignition.

The following sources of oxygen are identified in the SRU's:

Oxygen Concentration during Normal SRU Operation

During normal operation of a Claus unit with a good quality main burner, hardly any oxygen will slip from the main combustion chamber to the catalytic stages, therefore the process gas does not contain free oxygen and there is no risk of a sulphur fire. During normal operation, the risk of oxygen ingress is increased if air is used instead of nitrogen for the main burner purges or if fuel gas fired direct reheaters (inline burners) are used. In the SUPERCLAUS® process, oxygen enters the plant through the oxidation air which is introduced for the selective oxidation of H_2S to elemental sulphur. The oxygen concentrations in all of these cases are limited and will not lead to sulphur fires.

In the SUPERCLAUS® or EUROCLAUS® installations, oxygen concentration is precisely controlled such that the H_2S is converted to elemental sulphur, and the catalyst is maintained in an oxidized state. The oxygen concentration in the reactor outlet is controlled at 0.5 vol% during normal operation.

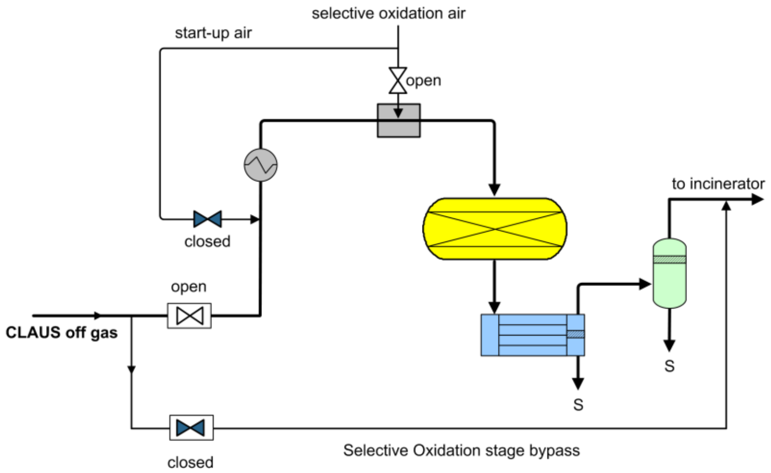

Figure 1. Air Supply to the Selective Oxidation Stage

Oxygen Concentration during Abnormal SRU Operation

The risk of a sulphur fire increases as soon as higher concentrations of oxygen enter the system. This happens most often when the main burner is in the start-up phase and/or operated with fuel gas, for example, during heating up, hot standby or during taking the unit out of operation, when the burner is operated with excess air.

During the plant heating up or when the unit is in the hot standby mode, the oxygen concentration can rise due to the wrong setting of the air to fuel gas ratio. This can occur easily when the main burner is not operated with a fuel gas of constant composition (preferably natural gas), but with a fuel gas of varying composition and molecular weight, which leads to wrong measurement of the fuel gas flow rate. A fuel gas analyzer such as Wobbe Index Meter can be installed to compensate for the fluctuations in the fuel gas composition and air demand.

When the unit is being taken out of operation for maintenance, the oxygen (air) supply is intentionally increased gradually to convert the pyrophoric FeS to Fe_2O_3 in a controlled way. If the air supply gets out of control, the oxygen concentration can reach dangerous levels.

Oxygen Concentration during Abnormal SUPERCLAUS® Operation

In the Selective Oxidation stage of a SUPERCLAUS® plant, higher concentrations of oxygen can be present during heating up or shutting down or during a bypass of the selective oxidation stage. A bypass of the selective oxidation stage occurs in case of either a high temperature in the catalyst bed or a high concentration of inlet H_2S. The bypass operation protects the Selective Oxidation stage against excessive reactor temperatures which can occur during upset condition. During the bypass operation, the reactor temperature is maintained by purging the reactor with air. The air supply also keeps the catalyst under oxidizing conditions and prevents potential ingress of sulphur containing tail gas via the back-end of the Selective Oxidation stage.

Therefore, during a bypass, the atmosphere in the Selective Oxidation stage contains 20 vol% oxygen. When this atmosphere comes in contact with any accumulated sulphur in the piping or equipment (reheater, condenser, coalescer), there is an increased risk of fire. It is important to note that unlike the Claus catalyst, the selective oxidation catalyst does not retain liquid sulphur in its pores and hence the sulphur in the Selective Oxidation catalyst does not contribute to the risk of a sulphur fire.

Obstruction of Process Gas Flow

Besides a sulphur fire, the accumulation of sulphur has other unwanted effects in an SRU. When the level of stagnant sulphur rises high enough, it will impede the flow of process gas and will cause pressure drops leading to lower acid gas feed rates. A sudden limitation in the capacity or an increased main burner inlet pressure may be a sign of sulphur accumulation. Although, a normal inlet pressure is no guarantee that there is no sulphur accumulation.

If there is a pool of liquid sulphur, the flow of process gas can carry it downstream in the form of mist or even slugs of liquid sulphur. In the downstream equipment, the sulphur can be knocked out and will accumulate at low points in the unit. This results in a pool of liquid sulphur when the sulphur cannot be drained properly. In this respect, it is relevant to mention that agitation of liquid sulphur by the process gas flow can generate static electricity and act as an ignition source, as described before.

The entrained sulphur can also block lines or demister pads. Entrained sulphur has been found to plug instrument lines and even tail gas analyzers. The efficiency of the demister pads can be significantly compromised by the accumulated sulphur in the pad. Furthermore, if the entrained sulphur makes its way to the incinerator, it can lead to increased stack SO_2 emissions.

Solid Sulphur

Finally, when an installation containing liquid sulphur is allowed to cool, the sulphur will solidify, and mechanically removing the solid sulphur from the lines and equipment can be very difficult and time consuming. In addition, liquid sulphur can turn into a form of "sulphur concrete" if it is combined with the catalyst dust or debris remaining in the reactors after the loading procedure. It is essential to load the catalyst in such a way that little dust is generated and to ensure that the reactor is blown clean of dust after the loading is completed. Damaged catalyst grids can also result in the catalyst particles being carried away through the condensers to the sulphur locks and rundowns, and cause blockage.

Case Histories

The following case histories provide examples of how the accumulation of liquid sulphur can compromise the performance of an SRU.

Case 1: Refinery Application, 3-Stage Claus Unit

Description

The unit was operating fine, but because of a small instrument problem, the acid gas was shut down and the unit was operated in hot standby mode. After approximately 30 minutes, a sulphur fire was seen in the first reheater.

Cause

Sulphur had accumulated in the first reheater and could not drain because of a wrong slope of the reheater. Also, the sliding strips in the reheater shell prevented proper draining of sulphur. In the hot standby mode, the air-to-fuel-gas ratio was too high, and consequently air contacted the accumulated sulphur. The ignition source is not known, it could be either pyrophoric iron sulphide or the hot reheater tubes. Initial oxidation of sulphur by air may have increased the temperature in the reheater to above the auto-ignition temperature.

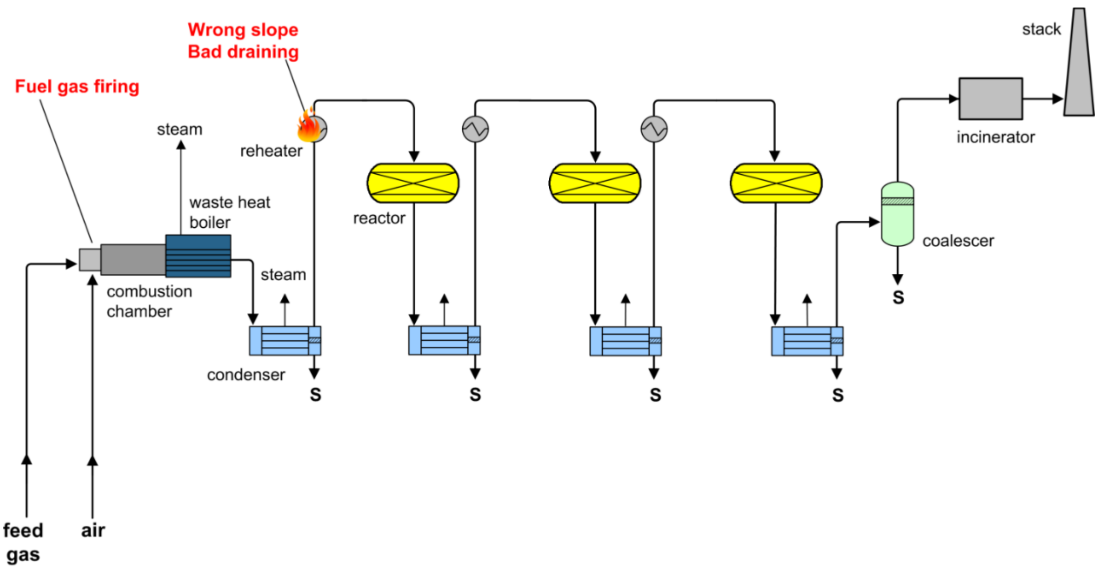

Figure 2. Sulphur Fire in the First Reheater

Case 2: Natural Gas Application, 2-Stage Claus Unit with SUPERCLAUS® Tail Gas Treating

Description

During normal operation, the tail gas analyzer signal was seen to fall away periodically. Also, the sulphur flowing out of the last Claus condenser was coming in surges and vibrations were noticed. The plant appeared to operate at nominal acid gas flow.

Cause

It was found that although the acid gas input flow rate was according to the design, the H_2S content of the acid gas was higher by 40%. This caused overloading of the Claus condensers resulting in the entrainment of sulphur and plugging of the downstream tail gas analyzer. Because of this, the analyzer read-out became unreliable.

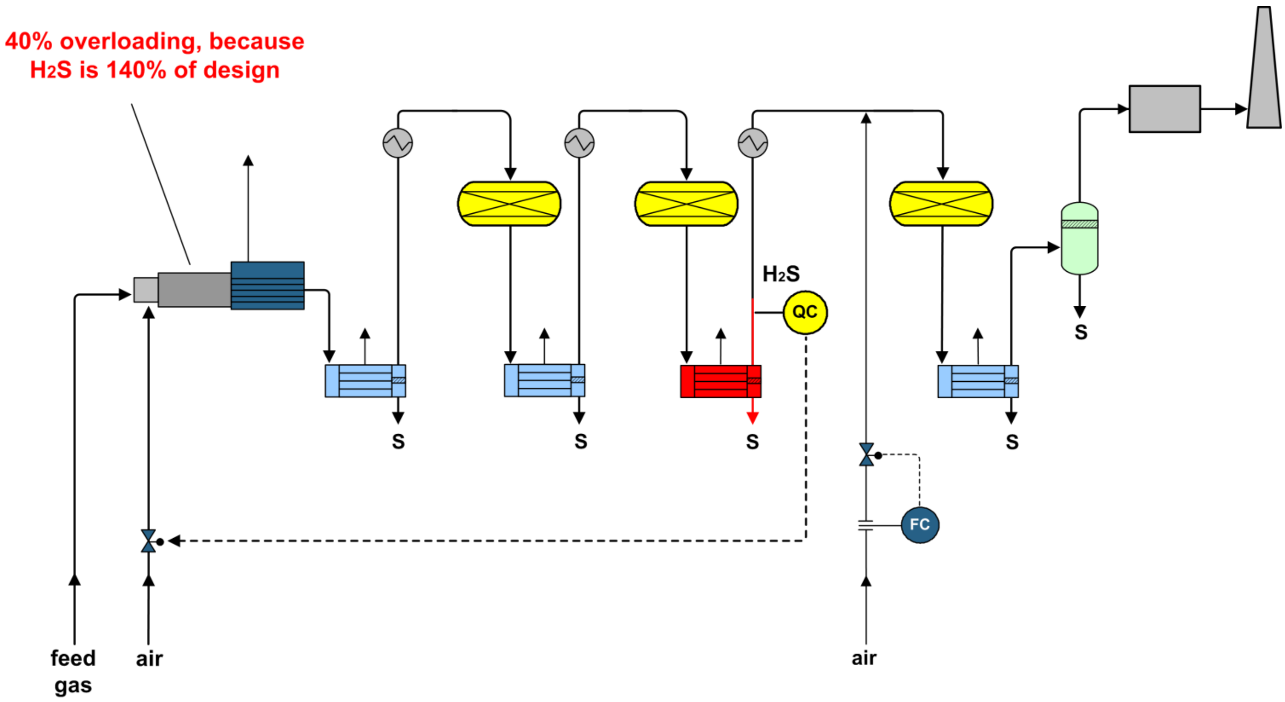

Figure 3. Blockage of Tail Gas Analyzer

Case 3: Natural Gas Application, 3-Stage Claus Unit with SUPERCLAUS® Tail Gas Treating

Description

Within a period of two weeks, two sulphur fires were experienced in the SUPERCLAUS® condenser. The SRU had been in operation for eight years without incidents. The fires occurred when the Selective Oxidation stage was bypassed, and oxidation air was supplied to the SUPERCLAUS® bed. The fire resulted in some severe damage and corrosion to the internals of the condenser.

Cause

It was found that the sulphur lock was blocked by debris and the sulphur had accumulated in the last condenser (SUPERCLAUS® condenser), even flowing through the condenser tubes to the inlet channel. Upon bypassing of the SUPERCLAUS® reactor, hot undiluted air at a temperature of 252°C contacted the liquid sulphur in the inlet channel. Since the auto-ignition temperature of liquid sulphur in pure air (20% O_2) is 230°C, a sulphur fire started. As is commonly seen, the fire spread from the inlet channel through the condenser into the outlet channel and caused severe damage to the condenser.

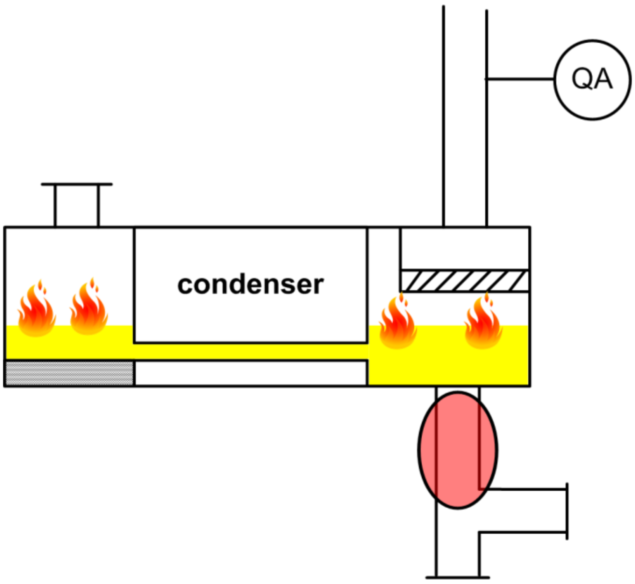

Figure 4. Sulphur Fire in the SUPERCLAUS® Condenser

Classification of Causes and Mitigations

The major causes of liquid sulphur accumulation in the SRUs are, as follows:

- A common cause of accumulation of liquid sulphur is the blockage of sulphur locks and rundown lines by catalyst dust or debris. To prevent this, catalyst loading should be done in such a way that little dust is produced, and dust must always be removed during loading. After the loading, dust should be blown out and the space below the catalyst grid should be inspected and cleaned. A damaged grid can also lead to the catalyst particles being carried away to the downstream equipment. In one example, it was found that the catalyst particles had been discharged through the lock and the sulphur rundown line all the way down into the sulphur collection vessel. Dust or debris can also combine with liquid sulphur and turn into a form of "sulphur concrete". In this state the sulphur not only causes sever blockage but can also catch fire if enough oxygen and a source of ignition exist.
- Liquid sulphur accumulation can also be the result of blockage in lines which are not designed properly. For example, not taking into account the high viscosity that can be expected at temperatures over 158°C or at lower H_2S concentrations in the liquid sulphur downstream the SRU.
- An obvious cause which is still sometimes observed is the wrong sloping or routing of the lines. If the SRU lines are not sloped or routed properly, sulphur may accumulate in the bottom of equipment or in the pockets. As an example, condensed sulphur is sometimes observed in the WHB outlet where it is not supposed to be in a properly designed SRU.
- A malfunction in the plant heating system can lead to the unintended condensation and accumulation of the liquid sulphur. If the SRU is equipped with a steam heating system, the problem can be a malfunction of the tracing or jacketing due to insufficient steam supply or improper condensate removal. Contrary to the common perception, the underperformance of the steam heating systems is most often irrespective of the type of the system (jacketed piping, bolt-on jacket, or tracing).

Experience with real life-situations has shown that steam supply calculations and steam trap selections are commonly performed based on the rules of thumb, past "similar" projects and legacy standards instead of engineering design.

The outcome can be a heating system with poor performance and capital and operational costs which are higher than necessary. In the following sections, some of the basic engineering facts pertaining to the design of the steam heating systems are explained.

These facts challenge the most common industry myths and make it possible to take the most informed approach when designing the steam heating systems for the sulphur facilities.

Heat Maintenance in the Sulphur Plants

Heat Maintenance Options

The most common heat maintenance techniques applied in the sulphur plants are:

Conventional Tube Tracing

Tube tracing involves small bore piping system which is laid along the process piping or equipment. The heating medium (steam) is circulated inside the small bore piping around the process system. The process pipe or equipment and the tracing must be insulated together with appropriate insulating material.

Jacketed Piping

Jacketed piping consists of a core pipe surrounded completely by a jacket pipe. The process medium (sulphur) flows through the core pipe and the heating medium (steam) flows in the annular space between the core pipe and the jacket. In this system, the heating medium is in direct contact with the process piping and provides maximum heat transfer with the process fluid.

Bolt-on Jacketing

Bolt-on jacketing consists of 2”x1” rectangular heating elements which are secured to the pipe or vessel. The heating medium can be steam or hot oil. Bolt-on jacketing is not capable of the maximum heat transfer rates achieved in the jacketed pipes. However, the amount of heat transfer can be adjusted to the process needs by the number of elements used. Bolt-on jacketing is particularly suitable for applications where cross contamination is a concern.

Skin-Effect Electrical Tracing

Skin-effect electrical tracing features a small magnetic metal tube which is welded to the outside wall of the process pipe. The welding must be performed across the entire length of each tracer. Inside the tube, a non-magnetic conductor is inserted and welded at the far end. When an AC voltage is applied to the inner tube, an electromagnetic current is created on the inside wall of the outer tube. The current heats up the entire heating tube due to electrical resistance. Electrical tracing eliminates the possibility of cross contamination. However, it is considered a fire hazard.

Steam Heating Systems – Basic Facts

The heating system for the sulphur piping must be designed for the no-flow conditions

Sulphur piping is typically designed for continuous flow. A common perception is that as long as the sulphur is flowing it means that the heating system is working properly. While a no-flow condition is definitely a sign that the heating system is not working, the opposite is not true. In reality, as long as the sulphur is continuously flowing in well insulated lines, very little or no heat is required to keep the sulphur flowing.

The real purpose of the heating system for the sulphur piping is not to keep the sulphur in the liquid state. Instead, the heating system should be designed with the following purposes:

- Keep the sulphur in the liquid state during a no-flow condition.
- Quickly melt the solid sulphur in case of a freeze up due to loss of steam.

While the sulphur can flow through an unheated transfer line without approaching its freezing point, that same line can quickly freeze if the flow of sulphur is stopped. Therefore, when the heating system is designed for flowing conditions, it is perceived as "working" satisfactorily during normal operation but will lead to quick freeze up during a turn-around. When the sulphur freezes, there is an even higher demand on the heating system. In this case, the heating system is expected to introduce enough heat to melt the solid sulphur and heat it up to the required temperature (and viscosity) for proper flow.

The steam load for jacketed pipes is based on heating the sulphur to the steam temperature

In order for the heating system to operate properly, it must be supplied with adequate amount of steam. This means that the boiler and the steam supply piping must be sized such that they can supply the required amount of the steam to the heating system. A common belief is that the purpose of the heating system is to prevent the heat loss to the ambient and the steam demand is calculated accordingly. In reality, the steam does more than just compensating for the ambient heat loss. The steam actually increases the liquid sulphur temperature until the sulphur and steam reach a thermal equilibrium. This additional heat transfer considerably exceeds the ambient heat loss and yet, is often not considered.

The heat transfer from the steam to the sulphur can be determined through engineering calculations to ensure that the utilities system is able to supply the required amount of steam to the piping. As indicated, the steam-sulphur heat transfer is considerably larger that the ambient heat transfer which means that the jacketed piping consumes a lot more steam than is necessary for thermal maintenance only. If the steam system capacity is limited or operational cost is a concern, bolt-on jacketing can be considered instead of jacketed piping.

The number of installed steam traps depends on the steam pressure loss in the system

During the process of heat transfer, the steam condenses and hence provisions must be made for periodic removal of condensate from the heating system. Condensate removal is performed by means of steam traps and the required number of steam traps is commonly specified as one trap for every jacketed pipe spool. The basis for this assumption is the concern that if several pipe spools are connected in series to allow the steam and condensate to flow from one spool to the next, the condensate will prevent the flow of steam to the next spool. In reality, several spools can be interconnected before a steam trap is installed.

As the steam flows through the system, it loses pressure due to the frictional losses as well as the static head of the water column accumulated in the jumpers. Since for saturated steam the pressure dictates the temperature, the steam pressure loss must be carefully managed. However, calculation of the pressure loss can be challenging and as a result many designs rely on overly conservative rules to determine the required number of steam traps. Such designs lead to significant capital, operational and maintenance costs. Every steam trap requires an associated set of valves, fittings, tubings and field labor. In addition, the steam traps are a weak feature in the steam systems with an average life of three years which increases the ongoing maintenance costs of the system.

Not all trap types meet the basic requirements of the pipe heating system

Steam traps come in four main types: float, inverted bucket, thermodynamic (disc) and thermostatic. Each of these trap types are unique in construction and the way they detect and remove condensate. Many believe that any standard type of steam trap will work with any system and the steam trap selection does not have an impact on the performance of the steam heating system.

In reality, the steam traps in a pipe heating system need to meet the following requirements:

- Remove the condensate.
- Continuously purge any entrained air.
- Operate properly against the condensate return back pressure.

Not all trap types can achieve all the above requirements.

Float Traps

Float traps work based on the buoyancy principle. Inside the trap, there is a hollow spherical float which rises as the level of condensate rises in the trap. When the condensate level is low, the float covers the trap orifice. When the float rises, the condensate is removed through the orifice. While the float trap is very effective at removing the condensate, removal of entrained air in this system can be difficult. Since the trap orifice is submerged, air removal requires provisions for additional venting above the condensate level. For this reason, most float traps are also provided with thermostatic air vents.

Inverted Bucket Traps

Inverted bucket traps also use the buoyancy principle. Instead of a spherical float, the trap contains an upside-down bucket which rises as the steam enters the trap. When the bucket is elevated, the trap orifice is closed. When the steam sitting under the bucket condenses, the bucket moves down and opens the trap orifice, allowing the condensate to be removed. In the top of the bucket there is a weep hole through which the entrained air is vented to the top of the trap. When the trap orifice is opened, the vented air is removed with the condensate. In this way, the inverted bucket trap is effective at removing both the condensate and the entrained air.

Thermodynamic Traps

In the thermodynamic traps, the orifice opens and closes based on the differential pressure on either side of a disc. The control chamber is above the disc. When the chamber is filled with steam the steam pressure holds the disc in the closed position. As the steam starts to condense in the control chamber, the steam/condensate pressure below the disc will be enough to lift the disc and open the trap. Once the condensate is completely removed, the control chamber is filled with a new batch of steam and the cycle is repeated. The inlet/outlet ports that contact the disc are carefully designed to generate the required forces on the disc. The drawback of this system is that if the condensate return pressure is too high the disc will not function properly which will lead to poor trap performance. This sensitivity to the back pressure is particularly important in low pressure steam application. Thermodynamic traps can typically remove small quantities of entrained air. However, they can lock in case of large quantities of air.

Thermostatic Traps

Thermostatic traps work based on a temperature change within the trap. The trap is supplied with a bimetallic strip or gas filled diaphragm that is designed to open the trap orifice at a certain temperature (which can also be a function of the operating pressure). Above this temperature, the trap orifice remains closed. The problem with the thermostatic traps in the jacketed pipe applications is that they require a significant cooling of the condensate in order to open the trap. To achieve this required cooling, a column of condensate must form in the trap tubing. This column of condensate could back up into the jacketing and impair the thermal performance of the jacketing system. The advantage of the thermostatic traps is that they effectively purge any entrained air since the trap orifice opens on contact with any cold material.

The above discussions point to the fact that there is no such thing as "the best" steam trap. Each of the trap types may function well in a specific system but perform poorly in another application. Therefore, the selection of the steam traps requires a thorough evaluation of the steam heating method and the steam/condensate systems. Having said that, the inverted bucket traps have proved to be the most robust traps as they can adapt well with almost any heating system with no special considerations.

Summary

Unintentional condensation and accumulation of liquid sulphur in the SRU's can lead to major problems such as obstruction of process gas flow, blockage of lines and instrument, formation of solid sulphur, fire and equipment damage. These incidents are not typical of Sulphur Recovery Units but have root causes which stem from inadequate engineering design or inexperienced field activities.

Some examples include improper piping slope and routing, poor housekeeping leading to the entrainment of dust and debris in the locks and rundown lines, uncontrolled admission of air during special operations such as start-up, hoy standby, shutdown and SUPERCLAUS® bypass and finally, malfunction of the steam heating system. Experience has shown that the design of the steam heating systems for the most part relies on the common perceptions and legacy standards which lead to poor performance of the heating systems. Through many troubleshooting projects some basic engineering facts are established which are contrary to the common practices in the design of the steam heating systems. The following is a list of the main lessons learned:

- The steam heating system for the sulphur lines must be designed such that it keeps the sulphur in the liquid state during a no-flow condition and that it is able to melt the sulphur in case of a freeze up.
- The calculation of steam demand must take into account the heat transfer between the steam and the sulphur in addition to the ambient losses.
- Jacketed piping uses more steam that is normally expected. The reason is that in the jacketed pipes the steam heats up the sulphur until a thermal equilibrium is reached. If the steam system capacity or operational savings are a concern, bolt-on jacketing can be considered.
- The steam trap selection depends on the type of the steam heating system and the characteristics of the steam/condensate system. The inverted bucket traps are the most robust traps which work with almost any steam heating system.

Interested or have any questions? We're ready to help.

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