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Utility Considerations for Sulfur Recovery Units

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1.0 Abstract

In comparison to the process side of the Sulfur Recovery Unit (SRU), the utility side of the SRU is frequently neglected in both the fine details in the conceptual design and in the normal day-to-day operation. However, the utility side frequently provides harsh reminders of the importance of keen attention in order to insure reliable, safe and high on-line operation of the SRU.

This paper intends to identify the key design and operating considerations for the utility side of an SRU with the primary intention of raising the awareness of the importance of the utility side of the SRU.

2.0 Background

The sulfur recovery unit utilities and problems associated with the operation and design that will be discussed in this paper include:

- Steam (imported and exported);
- Boiler Feed Water, Utility Water and Make-up Water;
- Fuel and Natural Gas;
- Nitrogen;
- Instrument Air;
- Electricity.

Most likely the problems associated with utility systems have always existed but it appears that in more recent years the frequency and severity of SRU problems associated with the utility systems have increased. It is suggested that the increase and severity of these problems are most likely related, but not limited, to the following items:

- Use of utilities may be intermittent.
- Utilities are not instrumented to the same degree as the primary process.
- DCS system has reduced field checkout.
- High turnover/inexperienced Operating staff.
- Overworked/understaffed Operating and Technical Support staff.
- Limited SRU design experience.

By their nature some of the utility streams are intermittently used during start-ups and shutdowns and the industry as a whole has moved to lengthening the run-time between scheduled shutdowns. At one-time annual turnarounds were common, today scheduled turnarounds are frequently three to four years apart. This change in turnaround philosophy has resulted in the start-up, shutdown and utility systems being less familiar to operating staff, increased the likely hood that the operating staff has changed and thus the operating experience has been lost since the last turnaround. Furthermore, the extended period of time increases the possibility that the utility systems may have been compromised since the last usage.

Another major change in the industry is the trend of replacing satellite control rooms necessitated by pneumatic control systems to central remote located control rooms utilizing electrically based DCS control systems. In itself the DCS systems have provided terrific advancements in control strategies, process variable data tracking, overall system component (i.e. control valves, rotating equipment, motors, etc.) tracking, allowing for statistical data analysis on both the process and utility side. However, there are certain critical items and in particular on the utility side which are not instrumented. In particular to an SRU, the steam traps require diligent manual inspection to verify correct operation. Too frequently, the failure of a steam trap is determined by a low temperature alarm on the process side or a high pressure alarm on the process side as a result of inadequate heat input due to a steam trap failure.

The safety and control features of the single remote control room based on a DCS/PLC system have been desirable. For many locations, an unfortunate casualty of this "advancement" is that field checkout is not as common. It is not unusual to spend an entire day in a refinery SRU and not see an Operator. There was an era in which a routine based walk through the "metal forest" would provide a sense on the operation of the unit based on the sound, look (i.e. sulfur rundowns, steam leaks, etc), smell and touch feel. This notion may seem nostalgic but the modern DCS/PLC systems have not been able to replace and are not as reliable as the human senses. At onetime the limited amount of data provided by the control system was supplemented and complemented by the database accumulated by human element. It is suggested that there may be too much reliance on the exclusive data provided by the DCS system.

The most recent strong economic factors of the oil and gas industry and the subsequent rapid expansion of the industry in combination with a prior period of right sizing (i.e. early retirements and hiring freeze) have put a significant dent on Operating and technical support experience. In some regions where exponential growth is occurring, the problem has been exaggerated by corporate raiding of operating and technical support staff. The result has been limited mentoring and significant loss of operating experience. This problem has been magnified in the refinery cost centers such as the sulfur units and utility units.

The lack of experience has been aggravated by the industry shortage of both operating and technical support personnel. Thus, typical operating staffs are inexperienced but also overworked. It is common to hear that the operating and technical staffs are only putting out fires and have no time for learning and ultimately optimizing the units. This becomes a significant problem for items related to the utility side that are intermittent by nature, less frequently monitored and/or are designed with limited instrumentation.

Design engineering firms are also facing the same shortage and lack of experience that is being experienced by the Operating companies. In many cases the level of responsibility exceeds the capabilities and the shortage of staff has reduced the quality control component of process package development. The design-engineering firms have also been affected by operating company's trend away from developing in-house expertise and more towards the development of process engineers that are exposed to multiple facets of the oil and gas industry and in particular specializing project engineering. The pool of sulfur recovery experts appears to be aging and also diminishing.

3.0 Utilities

The design and operation of the process side of an SRU is often more obvious and is given the respect that is required. However, for the utility side both the design and operation are as important but more likely to be neglected. The utility supply is very dependent on off-site supply and hence is more frequently taken for granted. There are certainly issues within the SRU battery limit that require attention, especially from an operating perspective. The typical utility systems that are required in an SRU and those will be discussed are as follows:

- Steam – low pressure and high pressure;
- Boiler Feedwater and Utility water;
- Natural gas or fuel gas;
- Instrument air;
- Nitrogen;
- Electric power.

3.1 Steam

Sulfur recovery units generate two products, sulfur and steam. In many cases in today's economic environment, the steam is more valuable than the sulfur. The steam is generated as a convenient way of transferring the significant amount of energy generated by the Claus process in both the thermal and catalytic stages. The steam generated in an SRU can be utilized within the SRU and the excess can be exported for heating (i.e. amine reboiler, sour water stripper reboiler, steam tracing, etc.) or to spin a turbine. In many cases, SRUs import high pressure steam, where it is not generated within the SRU, for indirect heating for feed preheaters and/or catalytic reheaters. It is the desirable and special properties of steam and water that make them so widely selected for the energy transfer role.

3.1.1 Imported Steam

As mentioned, in many cases high pressure steam is imported to the SRU as the heating medium for heat exchangers for amine acid gas preheating, sour water stripper acid gas preheating, combustion air preheating and/or catalytic reheaters and in some cases for driving steam turbines on a combustion air blower.

The steam pressure, related heat content and operating temperature of the steam are an important feature in the design of an SRU.

The use of indirect steam reheaters for the catalytic stages is highly favorable from both a design and operating perspective. However, the design must recognize the limitations of steam reheaters for the operation of the SRU and in particular for non-standard operation such as reactor bed heat soaks. Table 1 below summarizes steam properties for some typical steam pressures used in SRU designs.

Table 1
Typical SRU Steam Properties

Steam Pressure (psig)	Saturated Steam Temperature (°F)	Comments
35	280	Optimum for sulfur pump jacket.
50	298	Typical pressure generated from condensers (CD). Utilized for general heat tracing.
300	422	Common WHB pressure; too low for reheaters (RH).
400	448	Common WHB pressure; too low for RHs.
450	459	Common WHB pressure; acceptable for RH 2 and 3; too low for RH 1.
600	489	Common WHB pressure; acceptable for RH 2 and 3; too low for RH 1.

For a given heat exchanger approach temperature of 15 °F, the maximum process gas temperature that can be achieved is 444 °F and 474 °F for 450 psig and 600 psig steam, respectively. These temperatures are acceptable for normal and heat soak operation for second and third converters but in most cases is unacceptable for first converter bed heat soaks. To overcome this limitation for the No.1 Converter there are several options. One option would be to design the heat exchanger for superheated steam. The problems associated with this option include the supply of superheated steam and the mechanical design is challenging. A second option would be to use a direct-fired reheater, either acid gas or fuel gas fired rather than an indirect steam reheater. A final option that is only viable for small SRUs would be to supplement the indirect steam reheater with an electric trim reheater.

Another consideration in the design and repair of SRU heat exchangers is the tube-to-tubesheet weld procedure. For the low pressure heat exchangers, such as the condensers, a seal weld procedure is acceptable. A field proven example of a seal weld procedure is provided in Figure 1. For the high pressure heat exchangers, such as the Waste Heat Boiler, a strength weld procedure must be utilized. A field proven example of a strength weld procedure is provided in Figure 2 but other viable alternatives do exist. The proper strength weld procedure is mandatory but is too often neglected especially in field repairs.

Figure 1. Option for Seal Weld Procedure.

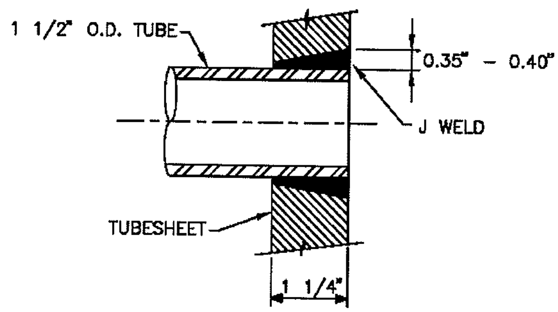
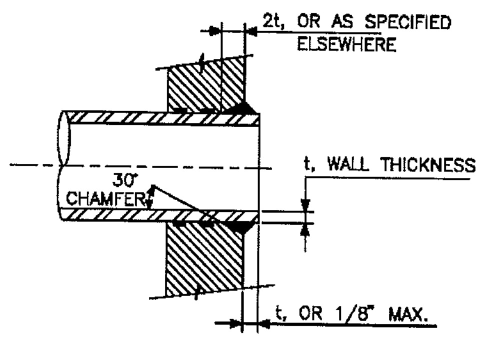


Figure 2. Option for Strength Weld Procedure.



Sulfur pumps are commonly damaged because too high of a steam pressure is supplied to the pump jacketing. Most vendors will recommend adjusting and controlling steam supply to a sulfur pump jacketing at 35 psig (2.5 barg) in order to avoid viscosity problems with the sulfur pump. The simplified P&ID (Figure 3) depicts a simple but effective steam pressure control scheme. As shown in Table 1, the saturated steam temperature of 35 psig steam is 280 °F. It is common to burn out sulfur pump motors because "the sulfur would not flow so it was decided to use higher pressure steam to help make the sulfur flow". The sulfur viscosity curve (Figure 4) supports the need for utilizing 35 psig (2.5 barg) steam and not higher than 35 psig pressure steam.

Figure 3. Sulfur Pump Supply Pressure Control.

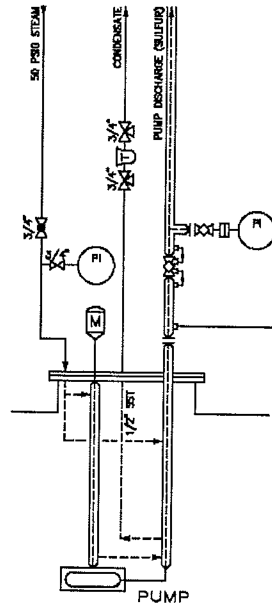
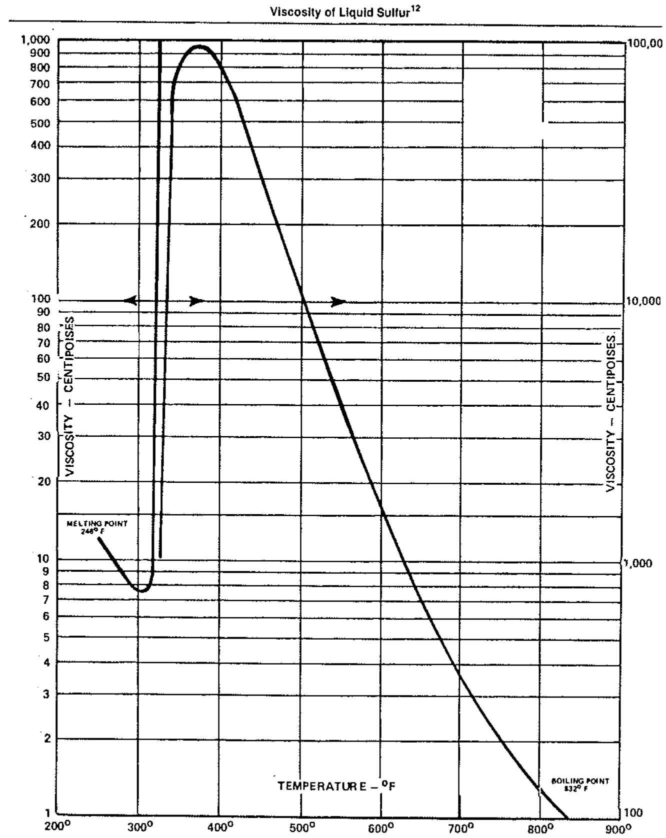


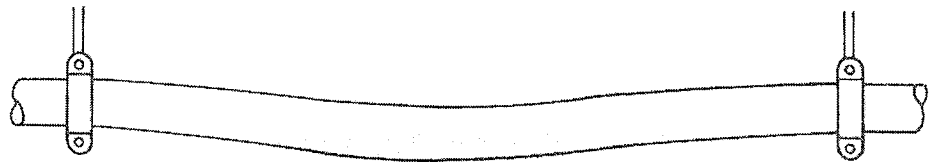
Figure 4. Pure Sulfur Viscosity Curve



There are some additional considerations associated with steam systems that have special significance for the steam trap design, SRU designer and SRU Operator. The problems include water hammer, air, non-condensible gases, corrosion and dirt.

Condensate will collect in the low points of a steam system unless special effort is made to drain low points and/or dead legs and design the delivery system free of low points. Steam flowing in a main header, often at very high speeds (i.e. 90 miles per hour) will pick up slugs of condensate and slam them into valves, elbows, steam traps or other equipment with damaging affect. A properly designed and closely monitored steam delivery system, especially for intermittent service, will provide a low point drain at the point of introduction to the unit. It is best to correct water hammer at its source by following good piping practice and to correct any problems that develop over extended operating time (Figure 5).

Figure 5. Accumulation of Condensate in a sagging Steam Main

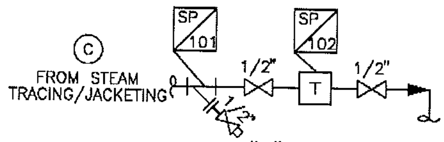


Boilers and steam systems are full of air prior to start-up. A very important requirement of getting any steam system operating efficiently is the removal of air. Air is a poor conductor of heat and thus mixtures of steam and air, for a given steam pressure, have less heat content than steam alone. This fact also means that the mixture will have an adverse affect on heat transfer rates. Thermostatic traps respond to changes in temperature and therefore can differentiate between steam and cooler non-condensible gases and thus can purge air from a system. Thermodynamic traps are phase detectors that differentiate between liquid and gases but cannot differentiate between steam and non-condensibles and therefore are limited in the ability to bleed off non-condensibles. Mechanical traps are density detectors and therefore also have difficulty venting non-condensible gases.

Non-condensible gases and specifically carbon dioxide and oxygen are both present in steam systems. Free oxygen is a normal component of a water system but it is the agitation of boiling that causes the carbonates in water to produce carbon dioxide. Both gases will cause corrosion in the entire steam/condensate system. A very important feature of a properly designed steam system is the ability to purge these non-condensibles from the steam system.

Corrosion is a given factor in a steam system. Corrosion attacks boiler tubes, steam mains, heat exchangers, valve components and fittings such as steam traps. The primary defense is to carefully monitor and maintain the boiler feedwater treatment system and control of the non-condensible gases (oxygen and carbon dioxide) that promote corrosion. There is a significant amount of trash and accumulated debris in both a newly commissioned and existing isolated system. It is mandatory to disconnect steam traps connected directly to the steam system, admit steam and flush the entire system until the system is blown clear. In older systems, especially those that are used intermittently, dirt, corrosion products and foreign debris will cause problems with traps, small valves, instruments and steam traps. Dirt prevents the free movement of internal parts or can get caught between valves and seat sealing surfaces leading to erosion damage. A properly designed pipe system will protect the steam traps by upstream pipe strainers (Figure 6).

Figure 6. Steam Trap Installation Detail



Another important component that is frequently missed in the design phase and/or damaged in operation is the steam system insulation on piping, valves, fittings and vessels. The insulation serves the dual purpose of heat conservation and personnel protection. Insulation keeps steam energy within the system to be used effectively by the process and helps reduce temperature fluctuations in the system due to disturbances such as changes in ambient conditions. There are two main approaches to improve steam system insulation. The first approach is in the design phase, which requires determining the economical insulation thickness required for the operations. This can be done using software tools available from the North American Insulation Manufacturers Association (NAIMA). The second approach involves a survey of existing systems to identify exposed surfaces that should be insulated, as well as any disturbed or damaged insulation. Listed below are examples of insulation tables that have been field proven to work well (Table 2 and 3).

Table 2.
Insulation Thickness for Personnel Protection

Nominal Pipe Size (NPS) System	Temperature (°F)									
	70 to 300	301 to 400	401 to 600	601 to 800	801 to 1000	1001 to 1100	1101 to 1200	1201 to 1300	1301 to 1400	1401 to 1500
	Insulation Thickness in inches									
1 ½ & Smaller	1	1	1 ½	2 ½	3	3 ½	3 ½	4	4 ½	4 ½
2"	1	1	2	2 ½	3	3 ½	4	4	4 ½	5
3"	1	1	2	2 ½	3 ½	3 ½	4	4 ½	5	5 ½
4"	1	1	2	2 ½	3 ½	4	4 ½	5	5	5 ½
6"	1	1 ½	2	3	3 ½	4	4 ½	5	5 ½	6
8"	1	1 ½	2	3	4	4 ½	5	5 ½	6	6 ½
10"	1	1 ½	2	3	4	4 ½	5	5 ½	6	7
12"	1	1 ½	2	3	4	4 ½	5	6	6 ½	7
14"	1	1 ½	2	3	4	4 ½	5 ½	6	6 ½	7
16"	1	1 ½	2	3	4	5	5 ½	6	6 ½	7
18"	1	1 ½	2 ½	3 ½	4 ½	5	5 ½	6	6 ½	7 ½
20"	1	1 ½	2 ½	3 ½	4 ½	5	5 ½	6	7	7 ½
24"	1	1 ½	2 ½	3 ½	4 ½	5	5 ½	6	7	7 ½
30"	1	1 ½	2 ½	3 ½	4 ½	5	6	6 ½	7	7 ½
36"	1	1 ½	2 ½	3 ½	4 ½	5 ½	6	6 ½	7 ½	8
Over 36" To Flat	1	1 ½	2 ½	3 ½	4 ½	5 ½	6	6 ½	7 ½	8
Single Layer of Insulation					Multiple Layers of Insulation					

Note: Thickness are for calcium silicate with ambient temperature 80 °F and no wind.

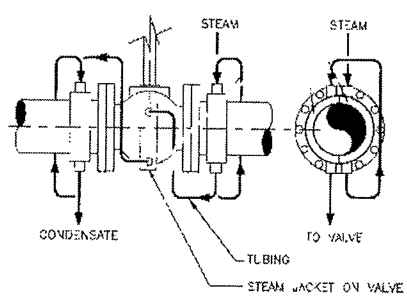
Table 3.
Insulation Thickness for Equipment and Piping Heat Conservation

Nominal Pipe Size (NPS) System	Temperature (°F)									
	70 to 300	301 to 400	401 to 600	601 to 800	801 to 1000	1001 to 1100	1101 to 1200	1201 to 1300	1301 to 1400	1401 to 1500
	Insulation Thickness in inches									
1 ½ & Smaller	1 ½	1 ½	2	3	3 ½	3 ½	4	4	4 ½	4 ½
2"	1 ½	1 ½	2	3	3 ½	3 ½	4	4	4 ½	5
3"	1 ½	2	2 ½	3 ½	3 ½	4	4	4 ½	5	5 ½
4"	1 ½	2	2 ½	3 ½	4	4	4 ½	5	5 ½	6
6"	2	2	3	3 ½	4	4 ½	4 ½	5	5 ½	6
8"	2	2 ½	3	4	4 ½	4 ½	5	5 ½	6	6 ½
10"	2	2 ½	3	4	4 ½	5	5	5 ½	6	7
12"	2	2 ½	3 ½	4	5	5 ½	5 ½	6	6 ½	7
14"	2	2 ½	3 ½	4 ½	5	5 ½	6	6	6 ½	7
16"	2	2 ½	3 ½	4 ½	5	5 ½	6	6	6 ½	7 ½
18"	2 ½	3	3 ½	4 ½	5 ½	5 ½	6	6	7	7 ½
20"	2 ½	3	3 ½	4 ½	5 ½	5 ½	6	6	7	7 ½
24"	2 ½	3	3 ½	4 ½	5 ½	6	6	6 ½	7	8
30"	2 ½	3	3 ½	4 ½	5 ½	6	6	6 ½	7	8
36"	2 ½	3	3 ½	4 ½	5 ½	6	6	6 ½	7 ½	8
Over 36" To Flat	2 ½	3	4	5	6	6 ½	7	7	8	8
Single Layer of Insulation					Multiple Layers of Insulation					

Note: Thickness are for calcium silicate with ambient temperature 80 °F and no wind.

For steam jacketed pipe, steam must be introduced to the top of the jacket and the condensate must be removed from the bottom, low-point of the jacket. Failure to design a system in this manner will result in the build-up of condensate in the jacket system that has a both an undesirable cooling effect and also this results in wet steam. Wet steam has a lower heat content than dry saturated steam. Figure 7 shows the recommended tie-in for steam and condensate connections for jacketed pipe and jump overs.

Figure 7. Steam/Condensate Connections on Jacketed Pipe with Jump-overs.



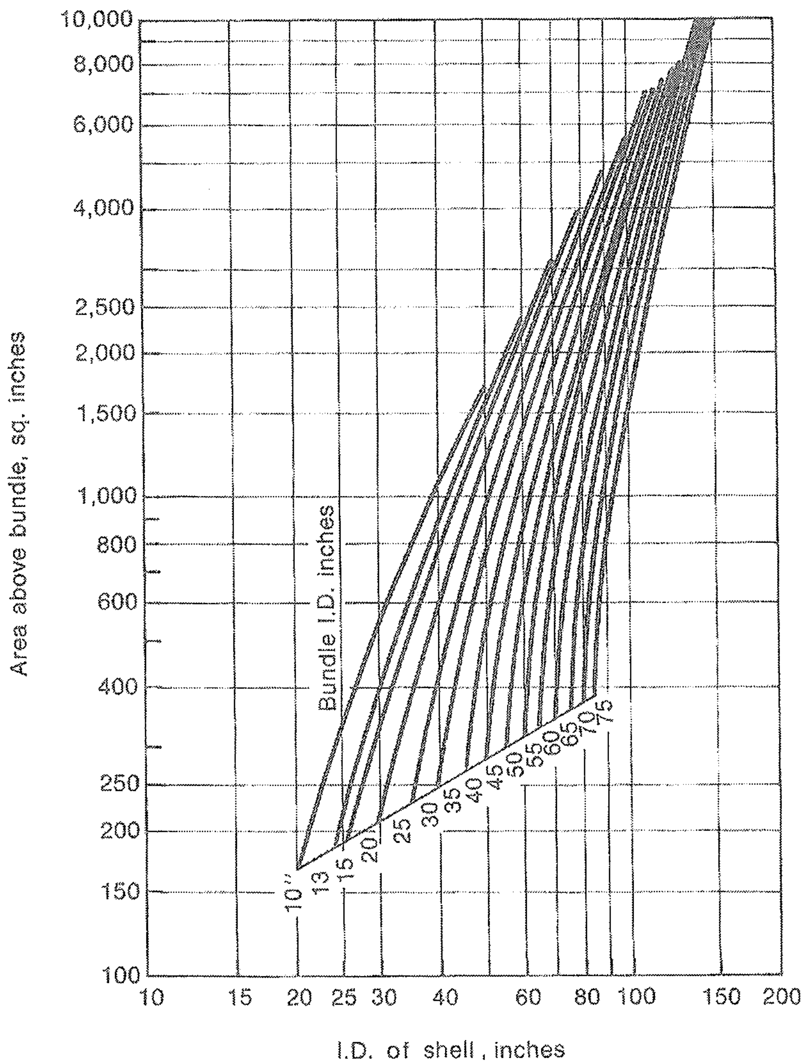
3.1.2 Exported Steam

As previously indicated sulfur recovery units generate two products, sulfur and steam. In many cases in today's economic environment, the steam is more valuable than the sulfur. The steam generated in an SRU can be utilized within the SRU but the amount generated generally exceeds the amount that is utilized and thus the excess is exported to a steam header system.

Depending on the steam pressure, SRU steam production is about 6,000 to 10,000 lbs of steam (2750 to 4500 kg) per long ton of sulfur recovered.

Even with high pressure steam used as a heating medium for both preheaters and reheaters, the SRU is a net exporter of high pressure steam. For the low pressure steam, an SRU only utilizes about 5% of the steam generated for internal steam jacketing and steam tracing and thus the SRU is a net exporter of low pressure steam. Thus, depending on the end user, the steam quality can be a significant issue. Wet steam can damage steam turbines and wet steam has a lower heat content than dry saturated steam. For both thermosyphon and kettle style systems, it is important in the design phase to consider the steam purification. In thermosyphon systems, the external steam drum must be designed with the correct circulation rate, water holding time, surge capacity, make-up water temperature and correct separation internals to generate high quality steam. From an operating perspective, it is important to check the steam drum internals for mechanical integrity and to insure that the operating conditions match the design basis. Frequently, the operating conditions do not match the original design and there is a resulting drop in steam quality. The steam drum design is vendor specific and it is recommended to have the vendor check the design versus the operation of the steam drum. The same holds true for kettle type boilers. The kettle must be large enough (low vapor velocities) to prevent/minimize any liquid entrainment with the vapor outlet. The required area above the tube sheet is a function of the steam specific volume and steam flow rate. Shown in Figure 8 (reference 1) is a kettle sizing chart that has been successfully utilized for sulfur recovery units.

Figure 8. Kettle Sizing Chart



3.2 Boiler Feed Water/Utility Water/Make-up Water

The treatment of water for steam generation is one of the most difficult branches of water chemistry. The pressure and design of the boiler determine the quality of water it requires for steam generation. The recommended boiler water limits for drum type boilers is given in Table 4 (reference 2).

Table 4
Recommended Boiler Water Limits

Drum Pressure (psig)	Range Total Dissolved Solids Boiler Water – maximum	Range Total Alkalinity Boiler Water (ppmw)	Suspended Solids Boiler Water – maximum (ppmw)	Range Total Dissolved Solids Steam (ppm)

	(ppmw)			
0 – 300	700 – 3500	140 – 700	15	0.2 – 1.0
301 - 450	600 – 3000	120 – 600	10	0.2 – 1.0
451 – 600	500 – 2500	100 – 500	8	0.2 – 1.0
601 – 750	400 – 2000	80 – 400	6	0.2 – 1.0
751 – 900	300 – 1500	60 – 300	4	0.2 – 1.0
901 – 1000	250 – 1250	50 - 250	2	0.2 – 1.0

Deposits, particularly scale, can form on boiler tubes. Each contaminant has an established solubility in water and will precipitate when it is exceeded. At the high temperatures found in a boiler, deposits are a serious problem causing poor heat transfer and a potential for boiler tube failure. From a design perspective, it is important to design the heat exchanger with the correct fouling factor in order to insure that the exchanger is not undersized. Recommended values for fouling factors are given in Table 5.

Table 5
Recommended Fouling Factors

Service	**Fouling Factor (ft²•hr•°F)/Btu**
Waste heat boilers, condensers, preheaters, reheaters	0.001
BFW preheater condensers	0.003

The other significant water-related boiler problem is corrosion. This problem has been described in the steam section of 3.1. Oxygen attack is accelerated by high temperature and by low pH. Corrosive attack can occur at steam-blanketed boiler surfaces where restricted boiler water flow causes overheating. The level of contamination build-up is adjusted by utilizing the correct level of blowdown and obviously, correct treatment in the makeup treatment system. During turnarounds, the process (inside) of tubes is normally scheduled for inspection and cleaning but frequently the utility (water/steam side) is neglected. The utility side must not be neglected if extended operating times are to be achieved.

From a design perspective, boiler feed water (BFW) preheater condensers are effective means of cooling the process gas temperatures to the desired temperatures just above the sulfur freeze point (250 °F (121 °C)) in order to maximize sulfur recovery. If the BFW temperature is too low, the first indication may be increased SRU pressure drop. Eventually, the tubes in the condenser will corrode and the exchanger will fail. Traditionally, chronic failure of BFW preheater condensers has occurred on designs that do not include proper control and monitoring of the BFW supply temperature. To avoid corrosion problems and subsequent exchanger failure, it is recommended that the BFW be preheated and maintained to a minimum of 240°F (116 °C). From an operating perspective, it is very common to find a BFW system without temperature measurement and/or a system with no insulation.

3.3 Fuel and Natural Gas

Most sulfur recovery units use natural gas on a continuous basis for the incinerator but on an intermittent basis for SRU start-up, shutdown and hot standby. For the case on start-ups where new catalyst has been installed, the main burner may be fired with excess air. For all other cases and for the majority of natural gas firing, the burner must be fired at slightly sub-stoichiometric (air deficient) air conditions. This is necessary because any excess air will cause catalyst deactivation and may result in sulfur fires that can be very damaging to catalyst and equipment.

When firing at near stoichiometric conditions the composition of the fuel gas or natural gas must be known and remain constant. That is where a clear distinction between fuel gas and natural gas exists. Natural gas is normally of fixed and known composition while fuel gas can be made up of almost any mix of constituent, hydrocarbon and non-hydrocarbon that can be found in a refinery. Furthermore, the only constant with fuel gas composition is that it most likely will change. The effect of composition is illustrated in the following two oxidation reactions involving methane and propane, respectively.

Methane stoichiometric combustion:

$$CH_4 \quad + \quad 2\ O_2 \quad \Psi \quad CO_2 \quad + \quad 2\ H_2O$$

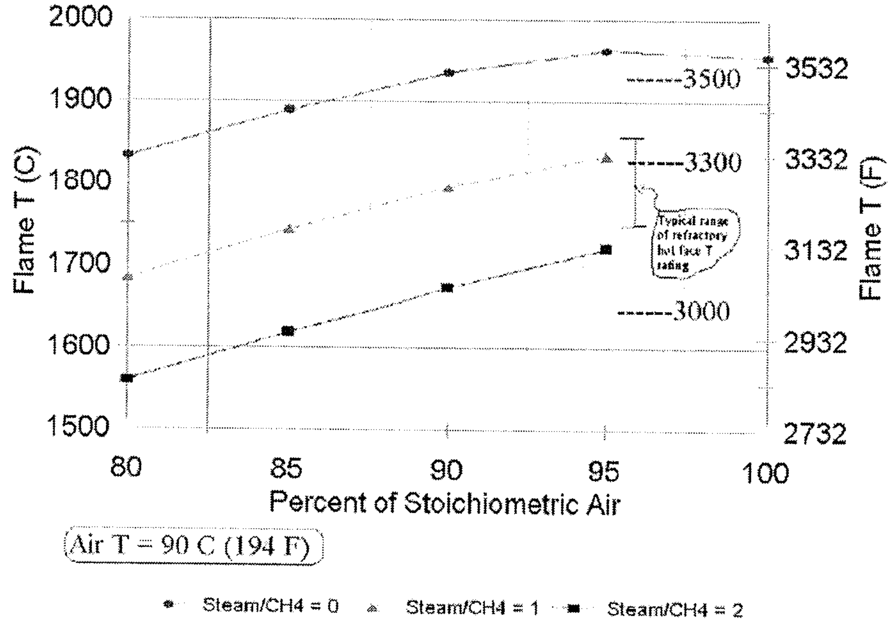
Propane stoichiometric combustion:

$$C_3H_8 \quad + \quad 5\ O_2 \quad \Psi \quad 3\ CO_2 \quad + \quad 4\ H_2O$$

Thus, as illustrated, the stoichiometric combustion of propane requires two and one-half times more air than methane. Obviously, heavier hydrocarbons will require even more air. Not knowing the exact composition of the fuel gas runs the risk of either firing with excess oxygen, resulting in potential sulfur fires, or firing with significantly deficient resulting in soot formation. The effects of a sulfur fire are quite clear. The formation of a significant amount of soot will result in catalyst damage and the soot will reduce SRU throughput capacity. If the additional pressure drop created by the soot can not be tolerated and if the soot cannot be removed on-line, a shutdown will be required to mechanically remove the soot and to clean the tubes on heat exchangers. The SRU must be designed and operated with known composition natural gas for start-up, shutdown and hot standby operation. During fuel gas operation it is recommended to field check the flame temperature color. An orange flame color is indicative of air-deficient operation, a blue flame is oxygen rich and a salmon pink flame color is indicative of stoichiometric burn.

The thermal stage is designed to operate with fuel gas for start-up, shutdown and hot standby. Fuel gas firing requires stoichiometric operation and the resulting flame temperature of 3000+ °F (1650+ °C) can be damaging and thus fuel gas firing requires flame moderation (figure 9) (reference 3). The refractory in the reaction furnace and, if applicable, fired reheaters must be designed for the elevated temperature of the fuel gas operation.

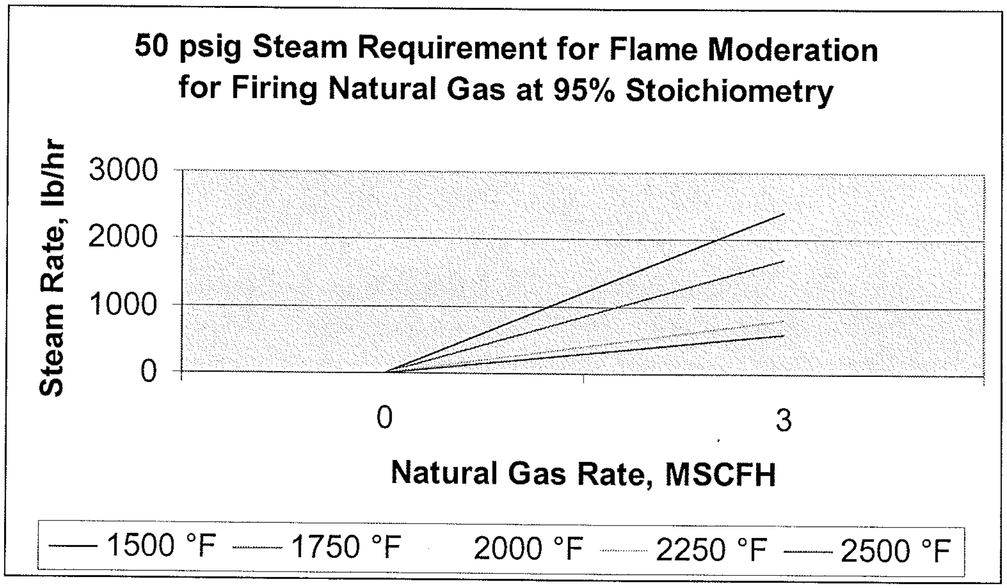
Figure 9. Flame Temperature as a function of Stoichiometric Air and Steam Injection.



Depending on the situation, flame moderation can be provided in the following ways:

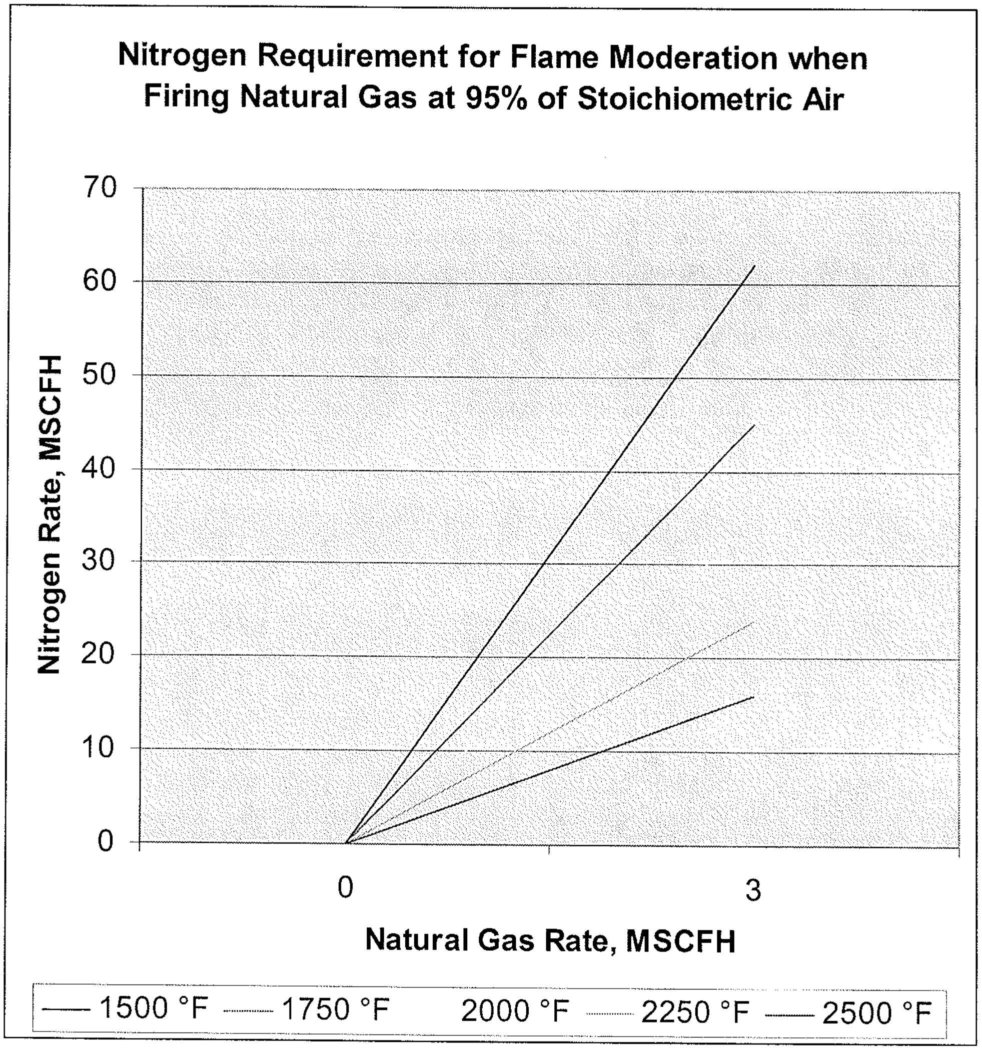
1. Excess air. This option is only viable when there is new catalyst throughout the entire SRU and thus no risk of sulphur fires due to the presence of oxygen.
2. Steam moderation. This option can be utilized when all SRU temperature measurements in the SRU are above 140°F (60 °C) in order to prevent water condensation. Condensed water vapor from the fuel gas fired flue gas will lead to SRU corrosion. It is recommended to add the steam to the center gun to avoid coating the air swirl vanes and/or to avoid condensing steam in the low and cold spots of the burner housing. Figure 10 provides the steam rate versus fuel gas rate to achieve the indicated flame temperatures of 1500, 1750, 2000, 2250 and 2500°F, respectively.

Figure 10



3. Nitrogen moderation. This is the most expensive option but can be safely utilized at any time regardless of the SRU temperatures or catalyst condition. The nitrogen can be added to either the air stream or fuel gas stream. Figure 11 provides the nitrogen rate versus fuel gas rate to achieve the indicated flame temperatures of 1500, 1750, 2000, 2250 and 2500°F, respectively.

Figure 11



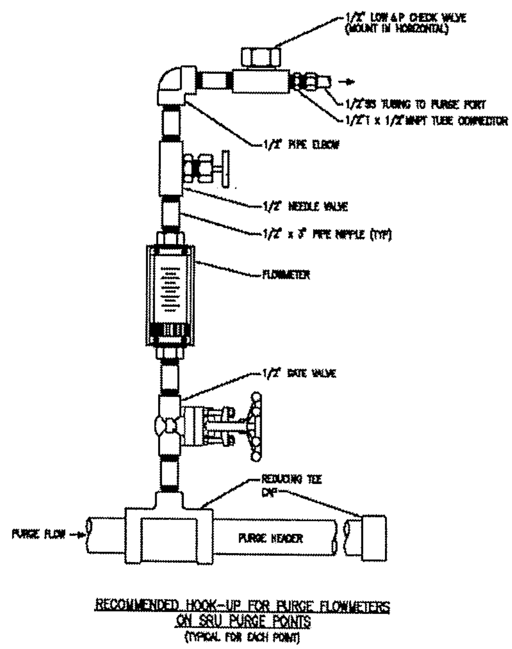
3.4 Nitrogen

It is paramount for the continuous successful operation of the reaction furnace burner that during normal operation the continuous purge is provided to the following burner nozzles:

- Flame scanners;
- Sight glasses on the burner and reaction furnace;
- Ignitor port;
- Reaction furnace temperature measurement;
- Idle ports, such as fuel gas, on burner (purge rate to be set by Vendor).

The suggested nozzle purge rate is 2 scfm per inch nozzle diameter. The purge medium can be instrument air during normal operation and nitrogen after an SRU shutdown. If it is available and there is no negative impact upon the furnace flame temperature and flame stability, nitrogen can be utilized at all times. Each purge connection requires an individual rotameter with proper tagging to allow for continuous system monitoring and troubleshooting (Figure 12).

Figure 12. SRU Nozzle Purge Detail.



The nitrogen purge system can be triggered by an SRU trip and thus automatically opening of a nitrogen isolation valve. The nitrogen purge is required to protect the burner assembly from radiant heat damage back from the reaction furnace refractory (heat source of approximately 2500 to 2800 °F) and to prevent the migration of corrosive thermal stage process gases back into the burner assembly. The SRU trip nitrogen purge must be provided to both the combustion air and acid gas lines in order to protect the entire burner assembly. The nitrogen purge rates that will protect the burner should set by the Vendor.

Nitrogen has become a popular medium for accelerating and eliminating the concerns for fires for SRU shutdowns. One significant risk of utilizing nitrogen in an attempt to accelerate the shutdown is the violation of the refractory vendors recommended cool down rate. In order to avoid catastrophic damage to reaction furnace refractory and tube sheet ferrules, the recommended cool down and start-up must be adhered to. Furthermore, use of large quantities of nitrogen for shutdowns is an intermittent operation and thus it is imperative to insure that nitrogen is being utilized. There have been several bad experiences in purging with what was believed to be nitrogen and in fact a different unknown medium was utilized. In one particular example, kerosene was inadvertently utilized in place of the intended nitrogen for the SRU purge! In another recent example of intermittent use, the nitrogen source was taken from upstream of the liquid nitrogen vaporizer and thus liquid nitrogen was fed to the SRU resulting in plugging of SRU equipment and damage to some of the front-end components. Intermittent use of nitrogen has benefits but it is mandatory to insure that nitrogen is being utilized.

Nitrogen is also commonly utilized as blanket gas for SRUs for extended unit shutdown and as well as blanket gas on sulfur storage tanks. This can be done but there must be an awareness of the formation of pyrophoric iron sulfide deposits on carbon steel surfaces. Subsequent entry and exposure to air may result in localized fires. For that reason it is recommended to utilize air as the preferred sweep medium for sulfur storage tanks. In the case of extended SRU shutdowns, nitrogen has been used successfully but caution must be exercised once the nitrogen is removed.

3.4 Instrument Air

The SRU is no different than other operating units in that the instrument air must be reliable, properly designed and maintained in order to insure safe and reliable of operation of the SRU. There are certain design and maintenance requirements that are somewhat unique to the sulfur recovery units.

The air system must have adequate capacity that, for an SRU, includes air-consuming instruments as well, if applicable, all furnace purge connections. As described in the nitrogen section, it is common to utilize air for the continuous purge of burner nozzles during normal operation. This is acceptable as long as the SRU is in operation but if the SRU trips the air must automatically be replaced by an inert medium such as nitrogen (preferred) or steam. The quantity of air required for the purges must be included in the design of the instrument air system and instrument air pipe delivery system.

The instrument air should be free of all contaminants such as dirt, oil, water and corrosive gases. It is recommended to utilize instrument air rather than a slipstream of air from the SRU combustion air blower for purging. The combustion air stream is dirty, wet and at a lower operating pressure. This will cause problems with rotameters and, where applicable, burner pilots and ignitors. The air system should be designed and operated with drying system that must reduce the water dewpoint to a minimum of 10 °F (6 °C) below the ambient temperature at operating pressure. The wet air has been known to short out some ignitor systems.

3.5 Electricity

Traditionally it has been the responsibility of the gas plant operator or refiner, not the utility company, to provide protection for connected electrical equipment against upsets such as voltage spikes caused by lightning, high or low voltage surges, etc. Traditionally, it has been the responsibility of the utility company to provide a reliable and continuous source of electricity but unfortunately problems with reliable electric supply are becoming more common. This makes the design of the battery back-up Uninterruptible Power Supply (UPS) system very important. The UPS must provide power to minimize erratic plant behavior.

Normally, the UPS is designed to provide enough battery back-up power to allow an orderly shutdown in the case that instrument air system is depleted of air. For the SRU it is imperative to backup the tail gas analyzer, flame scanners and, where applicable, the tail gas treating unit hydrogen and pH analyzer. An SRU designed with steam turbine air blowers will continue to operate without external power but without the analyzers the operator will be running the plant blind. While operating on battery back-up, it is recommended to field check the unit including the following items:

- Main burner sight glasses to verify the flame color and pattern;
- Draeger tube the tail gas sample to determine "ball park" H_2S/SO_2 ratio;
- Check quench water pH.

There is no replacement for field checkout! Extended off-ratio operation can lead to severe damage of the quench water system and the amine in the tail gas treating unit. Operator training becomes very important in this type of situation. There was a recent example in which an SRU was operating on back-up battery supply. The operator was provided with an indication in the control room that the unit was operating on back-up battery power. The operator had never seen this alarm, dismissed the alarm as a nuisance and then was surprised when the SRU tripped unexpectedly two hours after receiving the alarm. The good news was that the UPS system performed for an extra hour beyond the design one hour capacity.

4.0 Summary

In comparison to the process side of the Sulfur Recovery Unit (SRU), the utility side of the SRU is frequently neglected in both the fine details in the conceptual design and in the normal day-to-day operation. There have many examples of where the utility side frequently provides harsh reminders of the importance of keen attention in order to insure reliable, safe and high on-line operation of the SRU.

By their nature some of the utility streams are intermittently used during start-ups and shutdowns. The industry from design companies through to operation is plagued with a shortage of personnel and the result has been limited mentoring and significant loss of design and operating experience. This problem has been magnified in the refinery cost centers such as the sulfur units and utility units.

A key to successful SRU operation is paying special attention to the design and operation of the utility components.

References

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