SRU CAPACITY RESTORATION THROUGH SAFETY/OPERABILITY/RELIABILITY PROGRAM

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ABSTRACT

Worley Comprimo and Nasato Consulting Ltd (NCL) were contracted by the refinery to investigate the current bottlenecks in the four SRUs as well as complete an operability/reliability study to identify gaps versus modern plants and prioritize investments. The scope from the study and existing projects was combined into one unified view of investment required to improve safety and reliability of the overall complex, including the three amine regenerators, two sour water strippers, one foul water stripper, four sulfur recovery units and two TGTUs which consist of a quench, absorption and regeneration sections.

The focus of this study was to make improvements in safety, operability and reliability by conducting an assessment of current conditions and practices including:

1. Single point of failure risk assessments and options to reduce risk (severity and/or frequency) of failures in those locations (including mechanical integrity, instrumentation, rotating equipment, etc).
2. Control strategies to improve reliability/robustness of the system.
    - Operability review of current controllers and those running in abnormal modes.
3. Instrumentation selection and location.
4. Operator experience level and training needs.
5. Incorporate specific feedback from previous sulfur plants health check.

The main objective for the study outcome was to build a wholistic multi-year plan to improve the plant's safety/reliability/operability.

1.0 INTRODUCTION

The customer considers the current nominal capacity of its refinery to be 275 LTPD of sulfur in the feed and anticipates a potential increase of sulfur capacity to 328 LTPD due to future crude slate change to include Canadian Trans Mountain Pipeline (TMX) crude. The refinery has a permitted capacity of 342 LTPD.

The intent of the Safety/Operability/Reliability program was to complete an operability/reliability study to identify gaps versus modern plants and prioritize investments. The scope from the study and existing projects were to be combined into one unified view of refinery's investment required to improve safety and reliability of the overall complex, including the three amine regenerators, two sour water strippers, one foul water stripper, four sulfur recovery units including common third Claus stage and two two TGTUs which consist of a quench, absorption and regeneration sections.

The focus of this study was to make improvements in the refinery sulfur block's safety, operability and reliability by conducting an assessment of current conditions and practices including:

1. Single point of failure risk assessments and options to reduce risk (severity and/or frequency) of failures in those locations (including mechanical integrity, instrumentation, rotating equipment, etc).
2. Control strategies to improve reliability/robustness of the system.
   a. Including an operability review of current controllers and those running in abnormal modes.
3. Instrumentation selection, location, PM schedule.
   a. Includes a review of I/E training needs such as air demand analyzer troubleshooting/repair.
   b. A look at bad actors/modern solutions (such as sticking butterfly valves, missing temperature indicators vs. modern plants).
4. Operator experience level and training needs.
5. Incorporate customer-specific feedback from previous sulfur plants health check of the refinery sulfur complex.

The objective for the study outcome:

- Build a wholistic multi-year plan to improve the refinery's sulfur block's safety/reliability/operability. The intent is to make practical modifications for improvement rather than replacement-in-kind with a completely modern plant.

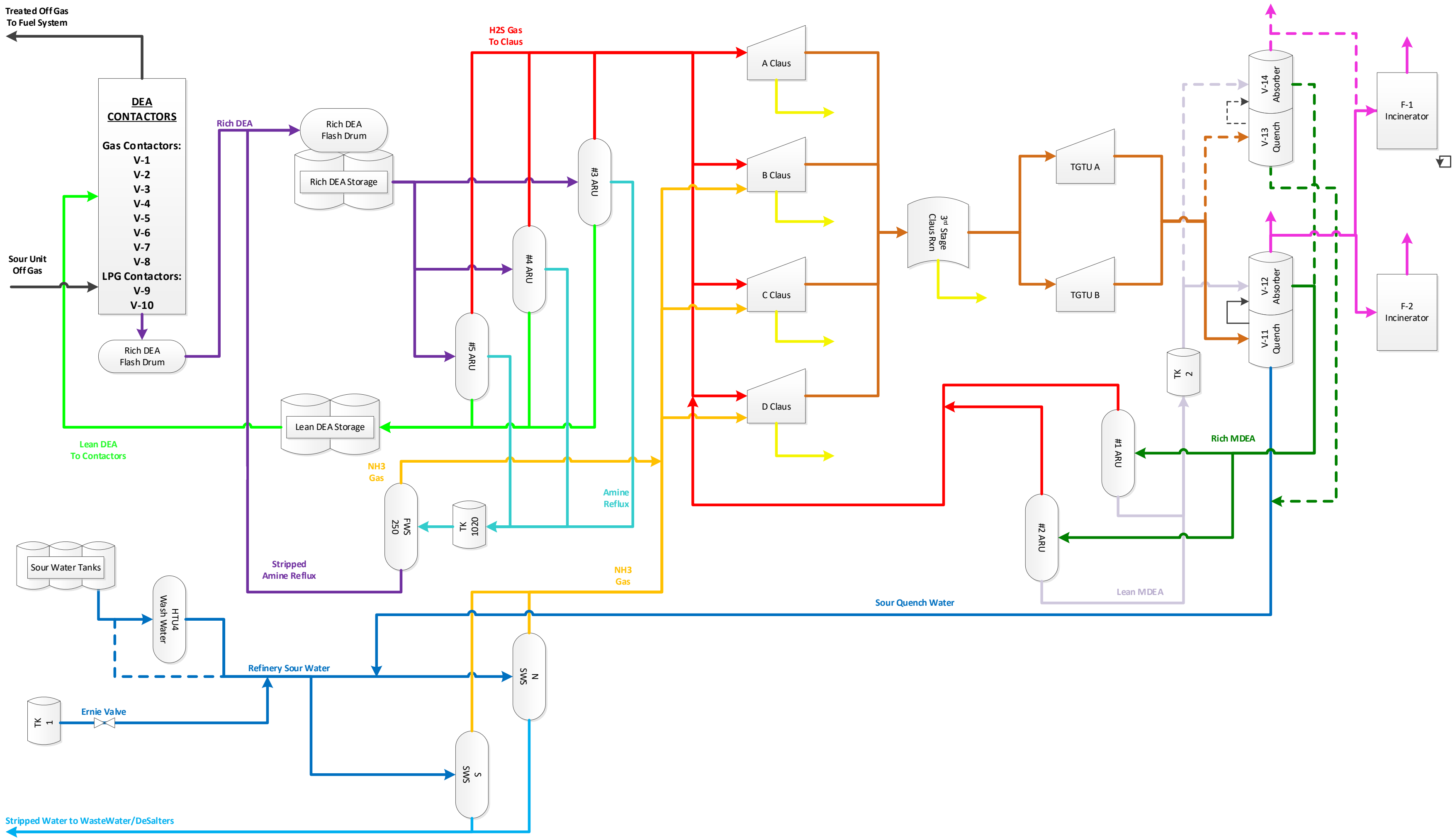

Figure 1 - General Overview Sulfur Block

2.0 PREVIOUS STUDIES

2.1 HISTORICAL INFORMATION

In 2023, an initial study was done by Worley Comprimo to determine what was limiting the processing capacity of the facility. Circa 2000, the nominal processing capacity of the facility was considered to be somewhere between 310 and 328 LTPD with a TGTU tail gas rate of around 1,250 MSCFH. At that time the plant would run out of combustion air for the SRUs at a tail gas rate of about 1,300 MSCFH, corresponding with about 320-340 LTPD. In addition, as the CO_2 concentration in the acid gas is lower today than experienced in the early 2000s, there was an expectation that higher processing capacities should be possible currently,

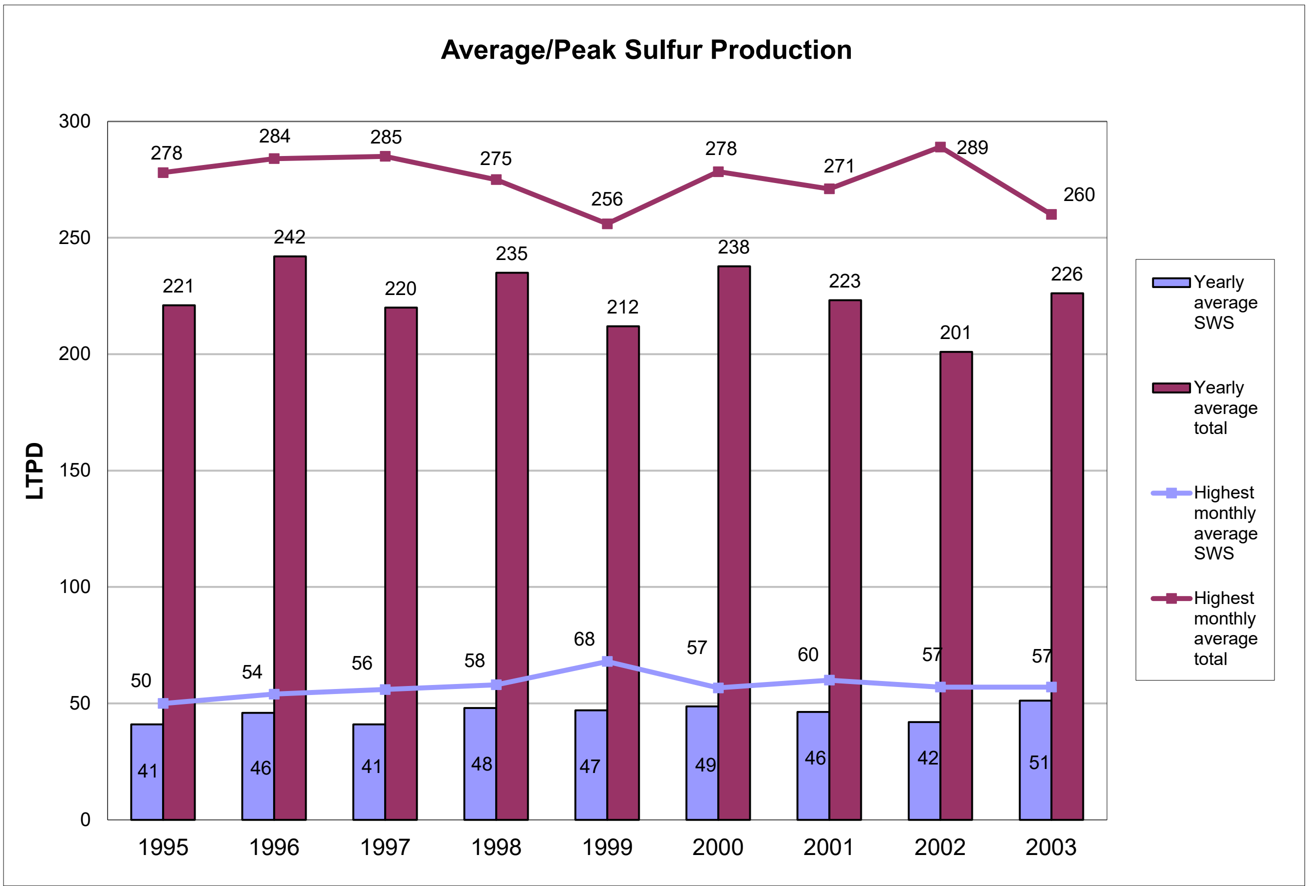

Figure 2 - Past Sulfur Production

During that period the empirical Figure 3 was developed to predict effect of fresh feed Nitrogen/Sulfur (N/F) on the refinery sulfur plant capacity. A higher nitrogen content of the crudes processed in the refinery will lead to higher sour water acid gas rates (and ammonia), leading to a reduced capability to produce sulfur. A general rule of thumb is that for every tonne of ammonia, the sulfur processing capacity may be reduced by three tonnes.

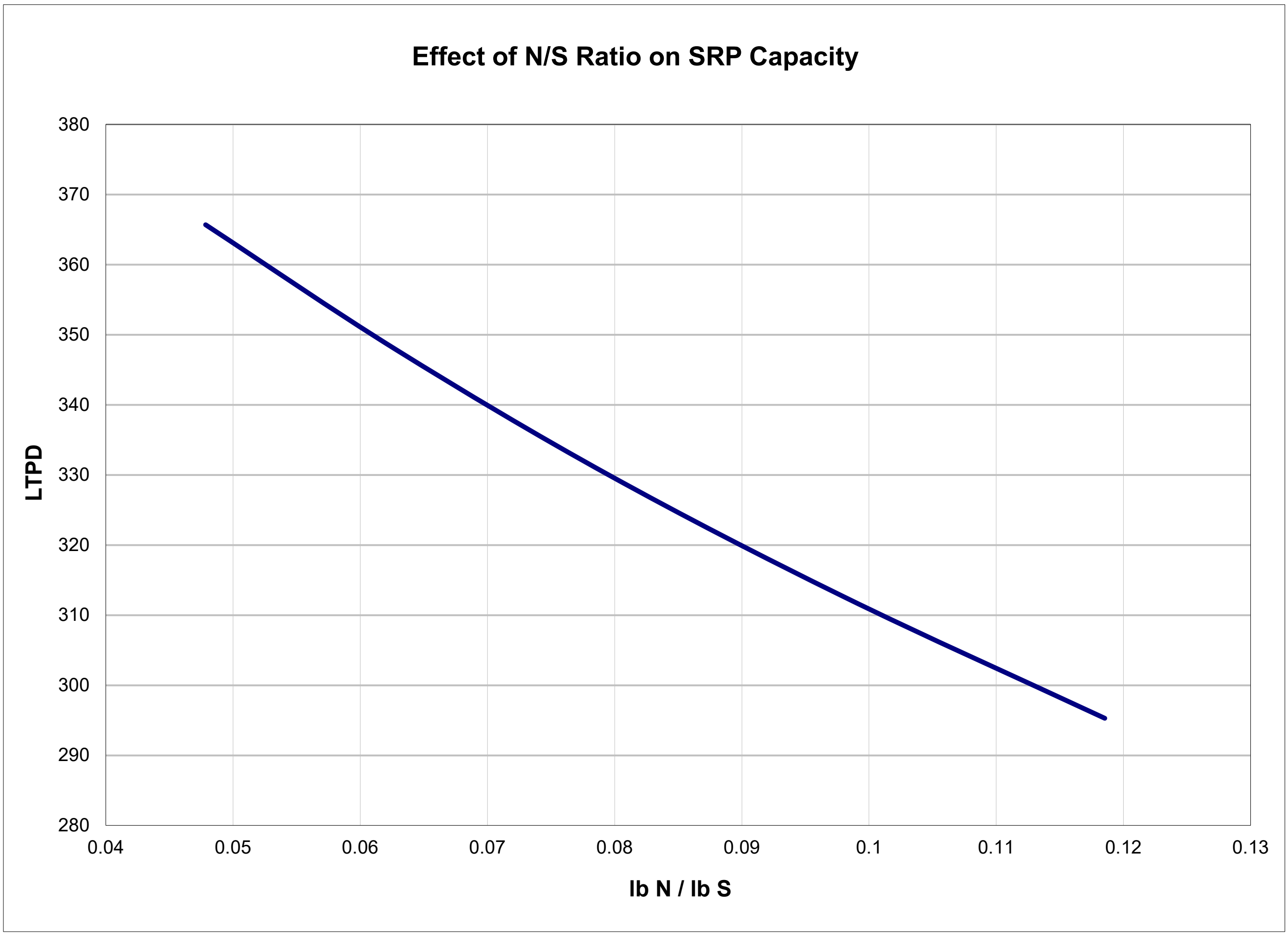

Figure 3: Effect of Fresh Feed N/S on the refinery sulfur recovery Capacity

Figure 4 shows average annual N/S for the period where, for example, 0.1 N/S corresponds to 310 LTPD per Figure 3.

Current/future N/S is only 0.0525, corresponding to 360 LTPD in Figure 3. While 360 LTPD seemed overly optimistic, suffice it to say that current expected N/S ratios plus lower % CO_2 directionally tend to increase the refinery sulfur recovery plant capacity compared with two decades ago.

Hence there was a need to further evaluate why the historic capacity could no longer be achieved.

In Figure 4, the historical nitrogen to sulfur ratio in the crudes processed in the refinery are provided. This can be directly correlated to the ammonia and sulfur in the acid gas feeding the SRUs.

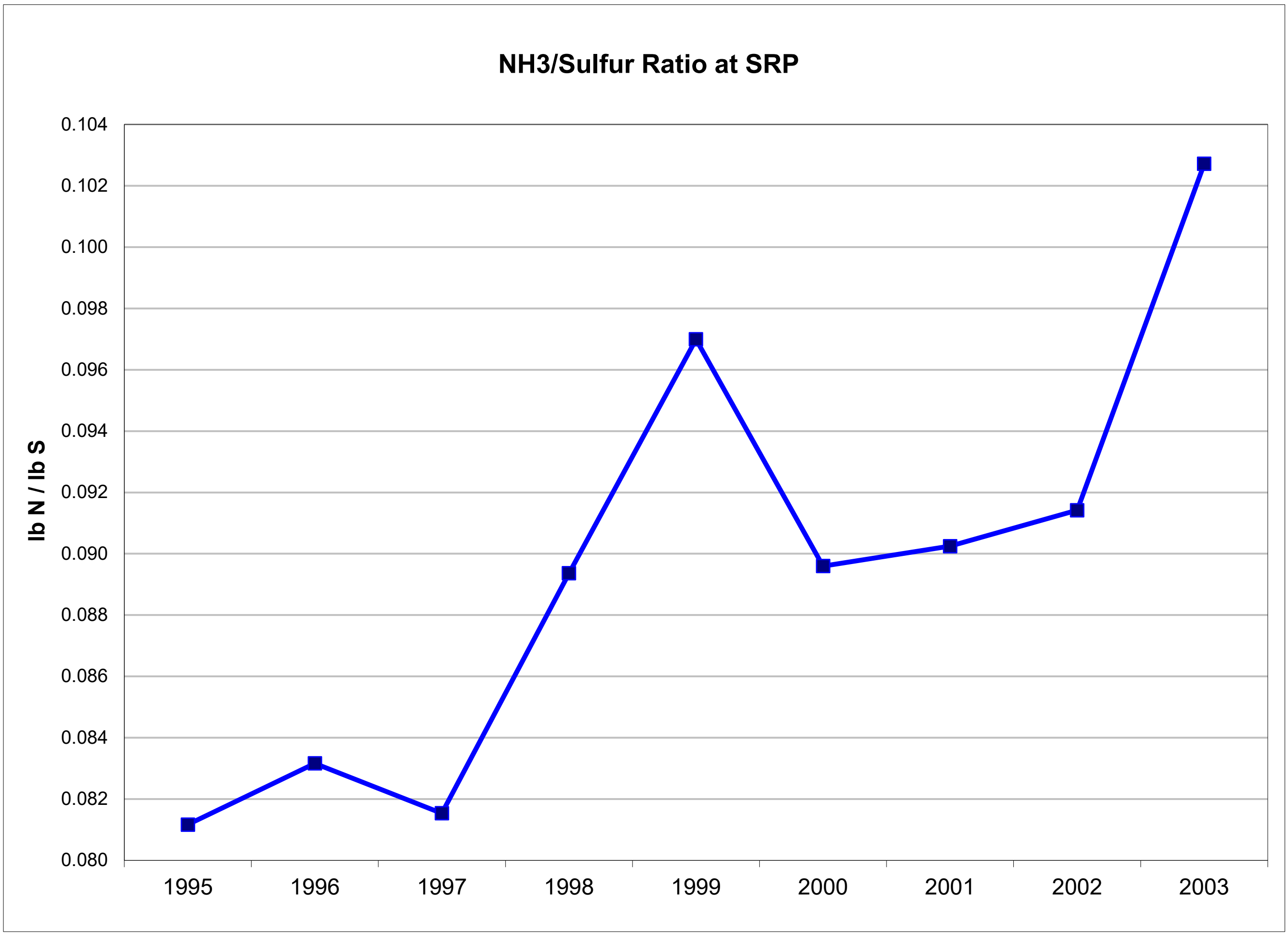

Figure 4: Historical Crude Nitrogen/Sulfur ratio

2.2 COMBUSTION AIR LIMITATIONS

The customer reports that, in some cases at least, combustion air control valves cannot be fully opened without risk of tripping on low low differential pressure (PDALL). This appears to be a non-issue as discussed below.

The most common flow element is an orifice plate based on the Bernoulli equation which states that local static head decreases as velocity increases. The downstream pressure is ideally measured at the point of maximum velocity known as the *vena contracta.* In practice, pressures are typically measured at flange taps for convenience, thus relying on empirical as well as theoretical design correlations. As velocity subsides downstream of the vena contracta, roughly half of the pressure drop is typically recovered.

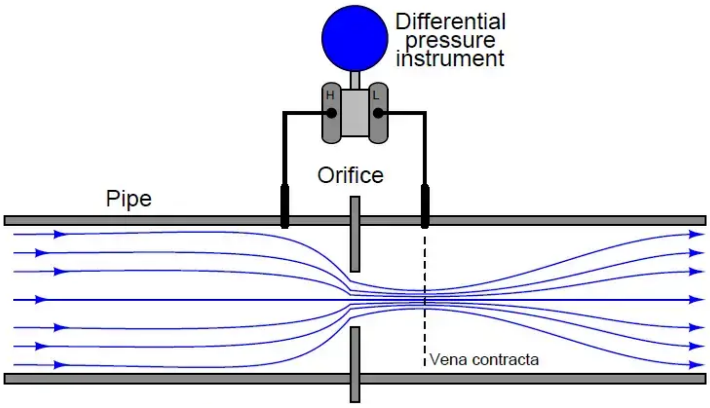

Figure 5: Conventional Orifice Plate FE

A common alternative is a venturi flow tube which is streamlined to avoid the exit turbulence inherent with orifices. Comparable accuracy is thus achieved at much lower pressure drops.

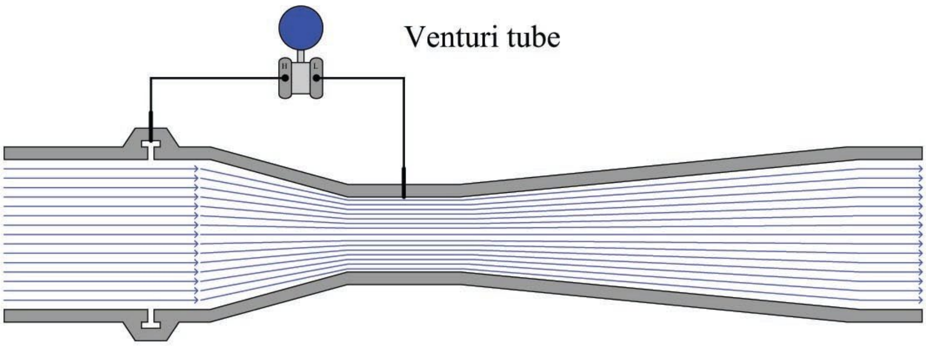

Figure 6: Venturi Flow Tube

A key safety concern is reverse flow of process gas out the air blower intake if the blower trips, since the industry generally regards check valves as insufficient protection due to the severity of consequences, should backflow occur. The problem is that, unlike orifice plates, venturi flow signals are not a reliable basis for safety trip because reverse flow is registered as positive. This is generally counterintuitive, and Shell allegedly discovered it by chance during a startup when the blower tripped and the unit did not.

With reverse flow in an orifice plate, the vena contracta automatically shifts downstream and indicated flow will at least be zero, if not negative. With a venturi, however, the vena contracta is fixed such that pressure recovery always results in $H_1 > H_2 > L$ (Figure 7*).* While flow must pass through zero before reversal results, the transition may be too quick to register.

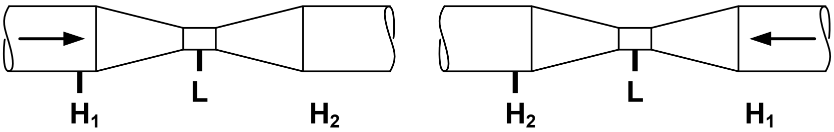

Figure 7: Effect of Venturi Reverse Flow

Shell's solution was independent PD measurement across a major segment of the air header, with PDT range of -10 to 10 inches of water (normally over-ranged) and PDALL trip point = 0.

The customer currently achieves this with the following 2oo3 PDTs across the main air control valve, with a PDT range of -1 to 25 inches of water and trip point of 0.1 inch. In at least some cases, the trip point is reached before the main air valve is 100% open.

With exception of A SRU main air, all FEs are shown as orifice plates in P&IDs. However, photos suggest A SRU, C SRU and D SRU are actually Type C flow nozzles as show in Figure 8*.*

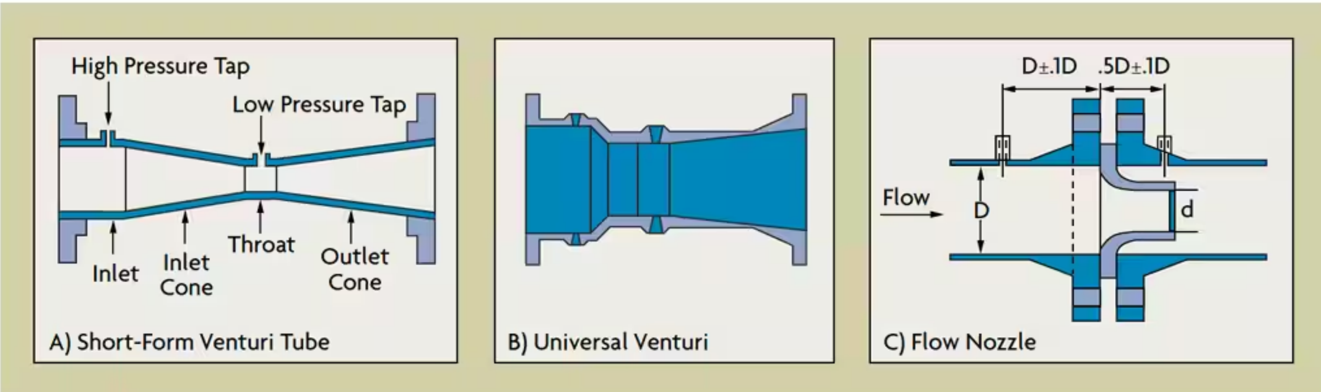

Figure 8: Comparison of Venturi Tubes and Flow Nozzles

We would expect these to be analogous to orifice plates in that reverse flow would be reported as zero/negative, however this has not yet been blessed internally in the client as a solution for the potential back flow issues.

With the flow meters as they are, there is little to no risk of false low flow indication and hence there was no need to operate with a large margin for the low low differential pressure across the flow meters. Maintaining a high differential pressure across the flow meter, limits the maximum back pressure allowed on the thermal reactor burner and thereby the capacity that can be processed in the unit. It was observed from past operation that the SRUs were operated with back pressures below 6 psig, which is lower than the typical values of 8-10 psig.

2.3 HYDRAULIC ANALYSIS

In Figure 9 below, a hydraulic analysis of the SRUs is provided to evaluate the expected back pressure on the SRUs during maximum future operation and the available margin between the expected operating pressures and sulfur seal rated pressures (i.e. the maximum pressure the seal can withstand before vapor breaks through to the sulfur pit).

Location	Current Operating Pressure (psig)	Future Operating Pressure (psig)	Margin for Sulfur Seals (psid)
A SRU			
Reaction Furnace	2.31	2.4	7.2
1st Condenser	1.87	1.96	4.2
2nd Condenser	1.20	1.29	4.2
3rd Condenser	0.62	0.71	2.3
B SRU			
Thermal Reactor	3.4	6.3	4.4
1st Condenser	2.83	4.82	4.5
2nd Condenser	1.71	2.43	4.4
3rd Condenser	0.66	0.84	4.1
C SRU			
Waste Heat Boiler	4.14	5.13	6.6
1st Condenser	3.43	4.18	4.4
2nd Condenser	2.13	2.44	4.5
3rd Condenser	0.73	0.87	4.1
D SRU			
WHB 3rd Pass	2.42	2.62	8.1
2nd Condenser	1.68	1.79	8.4
3rd Condenser	0.67	0.77	8.1

Figure 9: Hydraulic analysis of SRUs and margin for Sulfur Seals

From the analysis it is clear that the perceived limitation in the SRUs is not caused by having to operate the units with high back pressure or limitations with the sulfur seal depths.

3.0 THE TECHNICAL AUDIT

In 2024 a technical audit was organized to evaluate the current design, installation, operation, controls and personnel aspects of the facility that limit capacity and efficiency of the units. The following items are recommended by the team to be added to the future projects for the refinery to enhance the Operability and Reliability, as well as the ability to return the facility to its originally intended processing capacity.

3.1 ANALYZER OPERABILITY AND AVAILABILITY

The availability of the tail gas analyzers in the SRUs is essential for proper operation of the units as well as prevention of SO_2 breakthrough to the TGTU. SO_2 breakthrough can lead to high corrosion rates in the Quench Column as well as excessive Heat Stable Salts (HSS) formation in the Tail Gas Unit TG-10 amine solvent that is used to meet the H_2S specification of less than 10 ppmv in the overhead of the TGTU Absorber.

The following projects are recommended to enhance the performance of the analyzers:

- Increase the pressure of the steam supply to the analyzer probe and sample line inside the cabinet from 40 psig to 75 psig.
    - This can be done by letting down the 140 psig steam to 75 psig steam via a pressure regulator and local pressure indicator. No desuperheat is required for this letdown of steam.
- Improve the insulation of the analyzer probe to minimize heat losses.
    - Heat conservation insulation, 2" calcium silicate or mineral wool (preferred) should be adequate to maintain the temperature in the sampling system.
- In case there are more issues in the summertime with the electronics of the analyzer.
    - Install a vortex cooler in the analyzer cabinet to cool the electronics.
- Investigate whether there is any evidence of excessive sulfur carry over from the condenser upstream of the analyzer. Excessive sulfur carry over (for instance through a blocked or partially blocked rundown) can lead to substantial issues with the performance of the analyzer. This liquid sulfur carryover problem is exacerbated due to the SRU unit with vertical downflow condensers.

3.2 STEAM AND CONDENSATE SURVEY

In a Sulfur Recovery Plant, the design and reliability of the steam and condensate system is essential for proper operation of the unit. At the facility, there has been a lack of design review and maintenance of the existing steam supply and condensate return systems. This has especially been an issue in the sulfur rundown trenches that are commonly filled with run-off ground water.

The following projects are recommended to improve the design and reliability of the steam and condensate systems:

- Contract a steam and condensate specialty company that is familiar with liquid sulfur to perform a survey of the total system at the facility.
- Install a dedicated condensate return line in the drain trench for the sulfur rundown piping.
- Implement a Trap Management Champion in the organization.
    - Verify trap selection and performance.

- Install Gleason Trap Temperature Management devices to facilitate easy steam trap surveys.

3.3 AMINE ACID GAS KO DRUM HIGH LEVEL TRIP ADDITION

The common Amine Acid Gas KO drum is currently a single point of failure for all four trains of the Sulfur Recovery Plant and a project is ongoing to add a high high level trip on the KO drum to meet industry and the customer's internal standards. As this vessel is a single point of failure, level measurement needs to be very reliable and have sufficient redundancy to prevent spurious trips.

The following projects are recommended to minimize spurious trips for this vessel:

- Install the level instruments for the trip on separate nozzles and bridle assemblies on the vessel.
- Install a vortex breaker in the bottom of the vessel to prevent inaccurate level measurement in the vessel.

3.4 UPGRADE OF THE COMBUSTION AIR CONTROL IN A/B/C/D SRUS

Combustion air control is currently causing substantial limitations to the processing capacity of the four SRUs. This is due to the installation of butterfly control valves that are not operating in the optimal operating range for these types of control valves. Additionally, the presence of Venturi and Flow Nozzle type flow meters, which require the installation of a differential pressure trip to prevent back flow through the valve during a blower trip, can lead to H_2S release from the Combustion Air Blower intakes.

The following projects are recommended to improve the combustion air control system:

- Replace all combustion air flow meters with Balanced Orifice Flow meters.
    - Install two transmitters, one for control and one for low low flow trip.
    - Eliminate the Differential Pressure Trips across the air control valves.

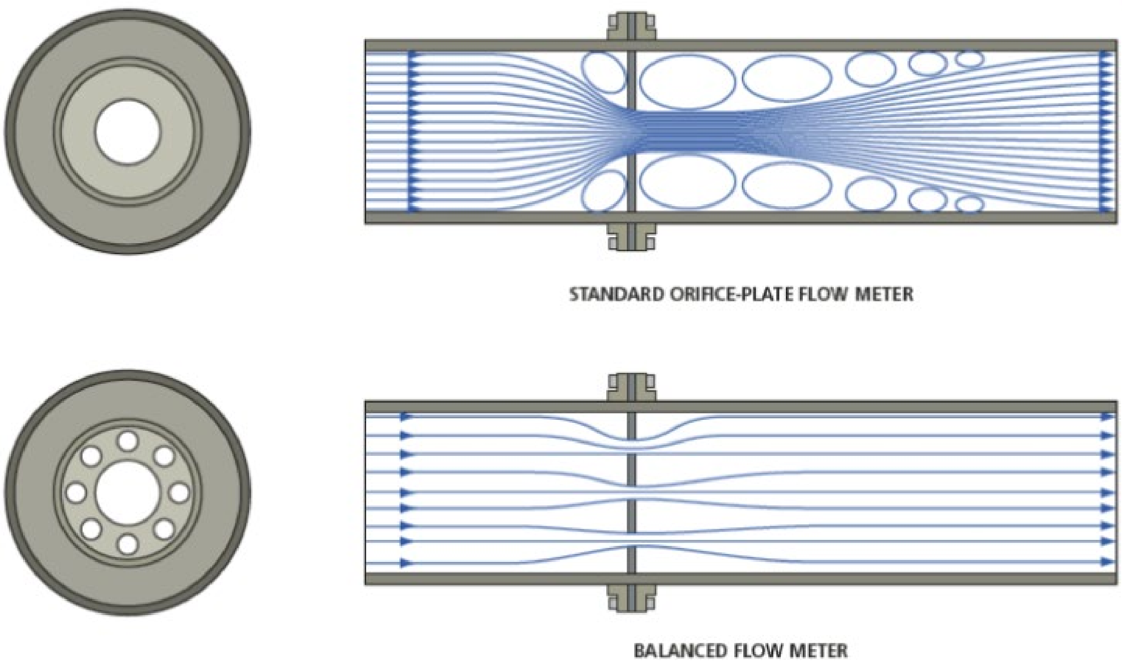

Figure 10*: Balanced Orifice Flow meter versus standard orifice flow meter*

- Replace all combustion butterfly air flow control valves with V-ball type control valves.
    - These valves need to be sized correctly on the basis of the design air flowrate for normal operation as well as startup conditions, combustion air blower discharge pressures, and expected back pressure on the SRUs.

3.5 INSTALLATION OF NATURAL GAS CONTROL VALVES AND CORRESPONDING BMS LOGIC

The plant currently uses manual valves for the introduction of natural gas to the main and auxiliary burners for light off and heat up of the Thermal Reactor and Inline Reheaters, respectively. There are flow meters installed on the natural gas piping, however they are currently not tied into the combustion air control system for automatic air to natural gas ratio control.

The following project is recommended to improve operation on natural gas in the SRUs:

- Install control valves for the implementation of AUTO control of the natural gas addition to the main and auxiliary burners.
- Implement air to natural gas ratios into the burner management system (BMS) to allow the combustion air to automatically follow the natural gas flow rate.

- This will also allow automatic air control during startup, shutdown, hot standby as well as co-firing operating modes.

3.6 INSTALLATION OF LOW PRESSURE STEAM CONTROL VALVES TO THE BURNERS AND CORRESPONDING BMS LOGIC

The plant currently uses manual valves for the introduction of steam to the main and auxiliary burners for temperature moderation and soot suppression of the flame during substoichiometric combustion of natural gas. There are no flow meters installed on the steam supply piping, and there is no automatic link between natural gas firing and steam addition, which can lead to potential problems with very high temperatures in the Thermal Reactor and the potential for soot formation during stoichiometric firing.

The following project is recommended to improve operation on natural gas firing in the SRUs:

- Install control valves for the addition of LP steam to the main and auxiliary burners.
- Implement steam to natural gas ratios into the burner management system to allow the steam to be added automatically to the burner during modes of operation with natural gas and no acid gas.

3.7 IMPLEMENT ADVANCED COMBUSTION AIR CONTROL

The current combustion air control system uses the main air valve to feedforward ratio control the air flow required for the acid gas flows entering the burner and feedback trim air valve is used to control the air demand from the tail gas analyzer. With the tail gas analyzers not operating reliably this can lead to combustion air control using the main air control valve only, which is the larger of the two control valves, thereby leading to inaccurate control.

The following project is recommended to improve the operation of the combustion air control system:

Installation of the Worley Comprimo Advanced Burner Control (ABC) system or equivalent:

- In the Worley Comprimo ABC system, the main and trim air control valves are always operated together, with modifications to the total air demand (which is a combination of the feed forward air demand corrected with the output of the tail gas analyzer output) being enacted on the smaller trim air valve first. The opening of the main air valve is then changed with a delay to bring the trim air valve back to its optimal position for further deviations.

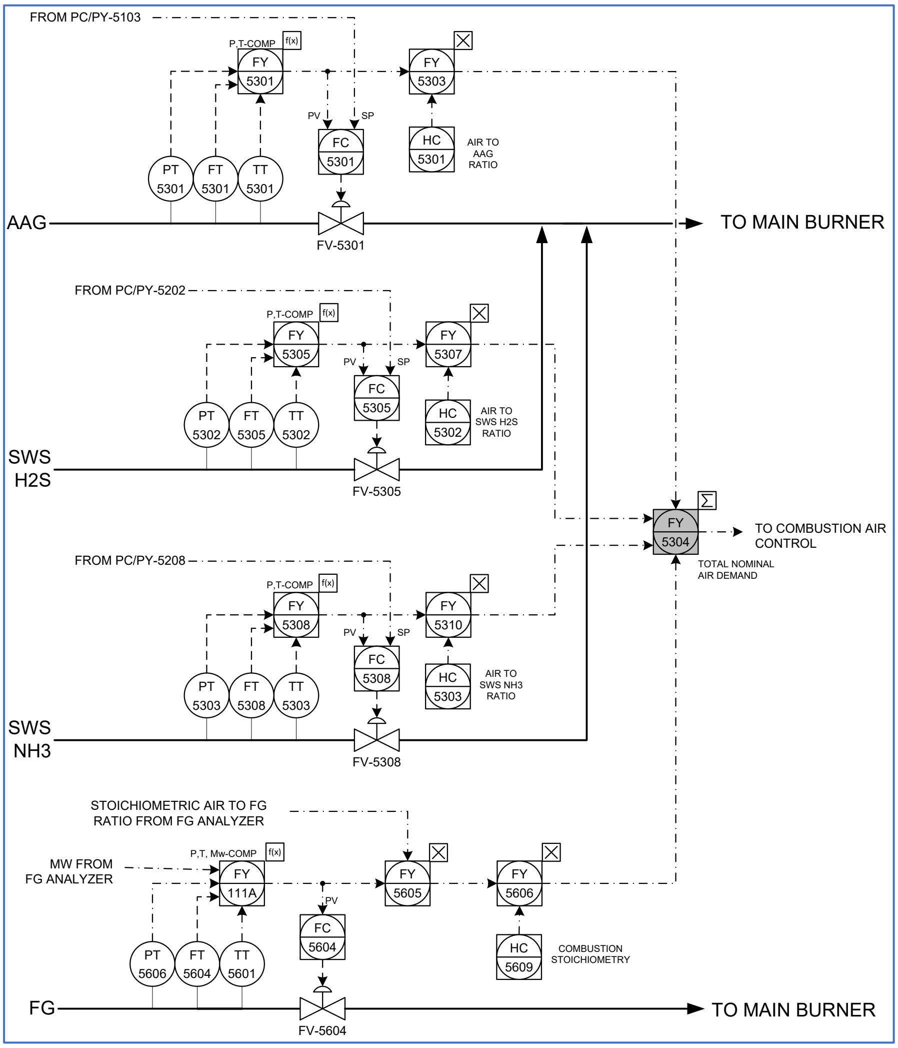

Figure 11*: Worley Comprimo ABC System Feed Forward Air Demand*

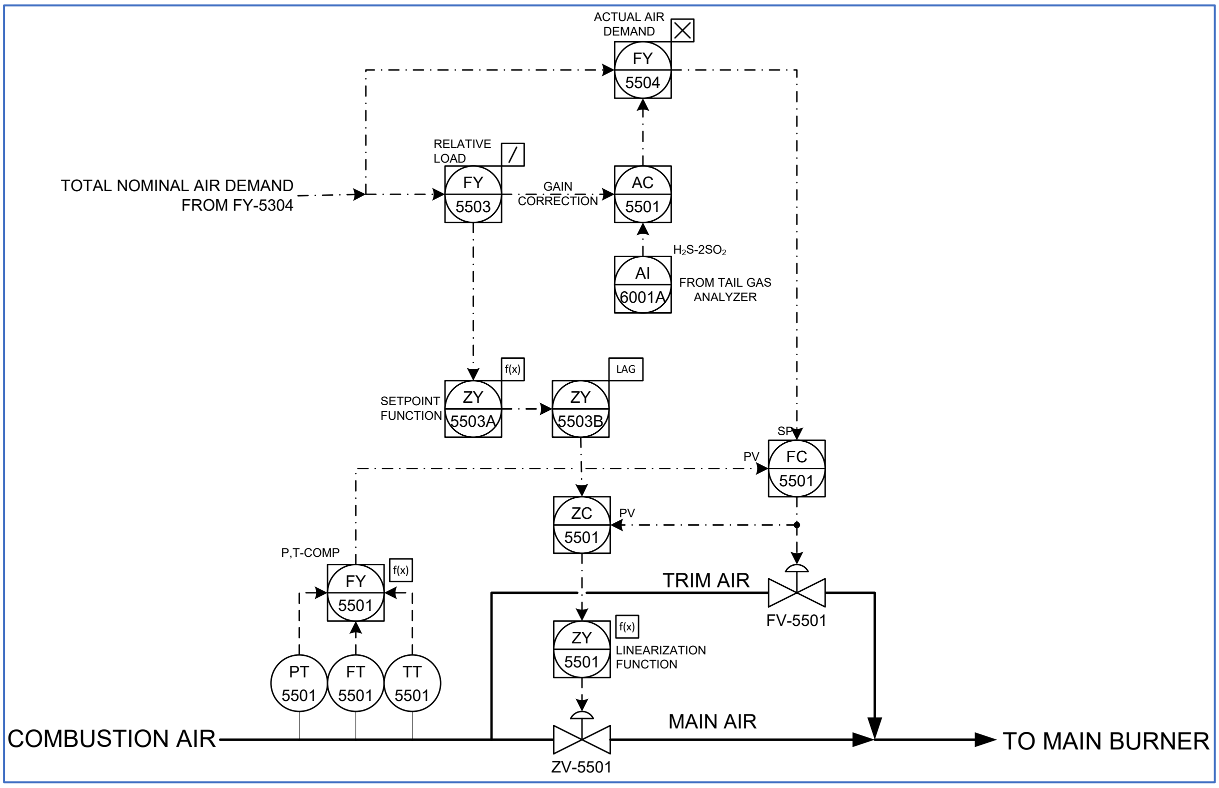

Figure 12*: Worley Comprimo Advanced Burner Control System Air Control*

- Implement pressure and temperature compensation for all acid gas and air control systems to allow for maximum accuracy of the control of the plant.
    - Natural gas in general is stable enough in composition and conditions that typically this does not need pressure and temperature compensation.
- In addition, by having ABC with natural gas, acid gas and air control fully integrated, the plant can consider implementation of automatic light off of the main and auxiliary burners as well.

3.8 ELIMINATION OF COMMON THIRD CLAUS STAGE

Typical industry standard is to have a two stage Claus unit upstream of an amine based TGTU. With proper design and selection of catalyst, two beds should be adequate to meet the required sulfur recovery efficiency in the SRU to allow full conversion of all sulfur species in the tail gas to H_2S in the TGTU hydrogenation reactor.

One item for the customer to consider is whether there is sufficient capacity in the RGGs to allow operation without the third stage.

- The third stage typically adds 1-1.5 psig pressure drop to the hydraulics of each SRU.

- The TGTU catalyst typically has sufficient ability to convert the remaining SO_2 after two stage of Claus conversion.
- The amine unit typically has adequate amine absorption/regeneration capacity to operate with a 2-stage Claus Unit upstream.
- The additional acid gas from the TGTU regenerators, which is recycled to the front of the SRUs, may result in more pressure drop than the reduction in pressure drop that can be achieved with the removal of the third stage.

3.9 D SRU ISOLATION VALVE TO INCINERATOR

Per discussion, the location of the D SRU isolation valve (i.e. tail gas diverter valve) to the incinerator is causing substantial issues during shutdown of D SRU. Due to the valve not being located at a high point, which is industry best practice, an accumulation of liquid sulfur can develop upstream of the valve. The accumulation of sulfur occurs when the plant goes into shutdown, and the resulting introduction of liquid sulfur into the incinerator on re-start (when the TGTU is bypassed) causes higher than permit SO_2 emissions from the incinerator and delays in shutdown for this unit.

The following project is recommended to remove the potential for sulfur build up at the inlet of the butterfly isolation valve to the incinerator:

- Study whether it is possible to move the tail gas diverter valves for D SRU to a high point.
- Study whether it is possible to install a low point drain with a liquid sulfur sealing device to allow for removal of the liquid sulfur upstream of the valve.
- Install Bolt-on Jacketing to maintain a wall temperature of 257°F on the entire tail gas line from the third condenser to the diverter valves for D SRU.

3.10 OPERATIONAL CHANGE FROM 2:1 TO 6:1 H_2S TO SO_2

The standard practice in a two stage or three stage Claus unit is to operate the tail gas analyzer to maintain a ratio of 2:1 for the H_2S and SO_2 to maximize recovery. With the installation of an amine based TGTU downstream of a Claus unit, the industry best practice is to operate the tail gas analyzer between a ratio of 4:1 and 6:1. The key advantage of this is that the plant operates further away from a potential SO_2 breakthrough to the Quench and Amine absorption sections. In addition, it has been proven that operating at higher than 2 to 1 ratio, reduces the amount of sulfation that happens on alumina catalyst, thereby increasing the performance and life of the Claus catalyst.

The following project is recommended to improve the operation and life of the Claus catalysts:

- Change operating guidelines to use between 4:1 and 6:1 for the H_2S to SO_2 ratio for the tail gas analyzer control.

- Change the output of the analyzer from the traditional air demand control to a true H_2S to SO_2 ratio control by using the outputs of H_2S and SO_2 concentration to calculate the ratio. The main benefit of this is that the operators will have the actual H_2S to SO_2 ratio available for control instead of an air demand value that does not directly relate to the ratio.

3.11 SRU THERMAL REACTORS THERMAL SHROUDS

In order to maintain the shell temperature of a thermal reactor between 325°F and 625°F, it is a common practice to install a thermal shroud around the thermal reactor. When the temperature of the shell falls below a temperature of 325°F, there is an increased risk of acid dewpoint corrosion through the condensation of SO_2 and water on the shell. When the temperature exceeds a temperature of 625°F, there is an increased risk of high temperature sulfidation of the carbon steel shell. For that reason, it is specified in API-565 that a thermal shroud needs to be designed as part of the overall thermal protection system of a thermal reactor. This is not a requirement for existing facilities however still a good practice to review for existing facilities as well.

Upon review of the thermal shroud (also call rain shield by the site) of D SRU, it was determined that it did not have a vent on the top, which will lead to potential hot spots on the top of the shell of the Thermal Reactor. The thermal shroud was installed to protect against SO_2 corrosion due to cold shell temperatures during rainstorms, however through incorrect design and installation, the corrosion might now have shifted to high temperature sulfidation, as the heat cannot dissipate from the shroud.

The following project is recommended to reduce the corrosion on the thermal reactor shells in all four units:

- Add a vent across the entire length of the thermal shroud in D SRU, to allow continuous flow of warm air around the thermal reactor shell to control the shell temperature between 325°F and 625°F.

- Install thermal shrouds for the thermal reactors in A SRU, B SRU and C SRU to limit the temperature between 325 and 625 °F.

    - There was a preliminary design proposed to install thermal shrouds on the thermal reactors, however upon review of the preliminary drawings it was found that the design included two individual stacks on the inlet and outlet side of the thermal reactor. This is not adequate to prevent high temperature sulfidation of the shell as this design will result in insufficient air movement in the shroud.

    - The minimum recommended coverage of the shell is 240 degrees as shown in Figure 13 and Figure 14.

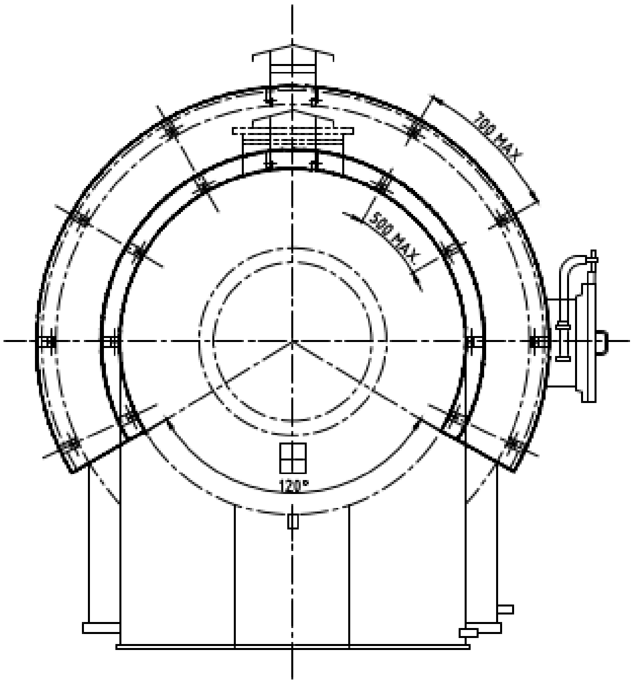

Figure 13*: Partial Thermal Shroud with Vent Stack*

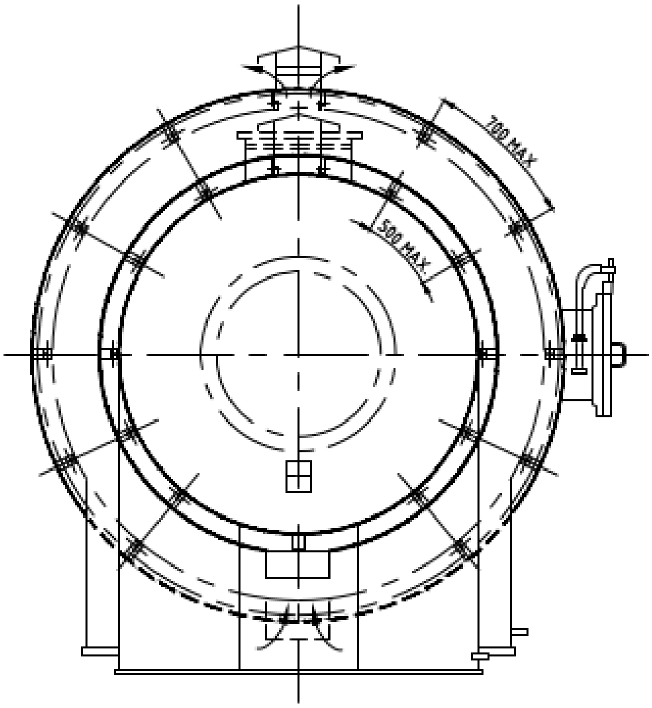

Figure 14*: Totally Closed Thermal Shroud with Inlet Louvers and Vent Stack*

3.12 OPERATOR TRAINING

Through the discussions, it became evident that a substantial incident occurred in the past year which led to a major failure of a piece of piping associated with the Quench Column. This resulted in a substantial outage of the TGTU. The event was described as an incident where one of the SRUs was operated at a large excess of air, resulting in an SO_2 breakthrough event to the TGTU for over 12 hours. Incoming SO_2 caused a very low pH in the quench water circuit with extremely high corrosion rates, leading to the eventual failure.

Due to turnover and retirement, the average years of experience of the operators has declined and it appears that customized training could be useful to the operators. It is not recommended to arrange basic amine and sulfur unit training for the operators as it is not believed to add much value with respect to the specific facility. Demonstrated successful training requires site-specific customization.

The following project is recommended to improve the know-how of the operators:

- Develop a customized training that focusses on all the specific details of the refinery sulfur block units. This should include training based on observed operating scenarios to get a better understanding of what to look for on the DCS for potential indications of problems as well as strategies on how to respond to failure scenarios.
    - Worley Comprimo has developed a dynamic training tool that allows the operators to mimic the operation of their SRUs in a safe and virtual environment. The tool is called IMMERSE and it can be customized to the specific conditions and parameters of the refinery's sulfur block.
    - Nasato Consulting has successfully conducted site-specific training for Operating and Tech. Services personnel in facilities worldwide.
- Generic training is not considered very beneficial for the operators.

4.0 CONCLUSIONS

The refinery in question had been experiencing a number of issues over the years that seemed not to be in line with general industry experience. In addition, the plant had not been able to process the nameplate capacity in the unit, with a potential increase in sulfur processing capacity looming due to a crude slate change.

Through a rigorous process of reviewing the following items, the team of Worley Comprimo, Nasato Consulting and the customer were able to develop a wholistic multi-year plan to improve the plant's safety, reliability and operability.

1. Single point of failure risk assessments and options to reduce risk (severity and/or frequency) of failures in those locations (including mechanical integrity, instrumentation, rotating equipment, etc).
2. Control strategies to improve reliability/robustness of the system.
    - Operability review of current controllers and those running in abnormal modes.
3. Instrumentation selection and location.

4. Operator experience level and training needs.
5. Incorporate specific feedback from previous sulfur plants health check.

In the near future, there is a plan to performance test some of the equipment that has been deemed to be limiting the current capacity to understand what modifications to either equipment or operating philosophy need to be made to bring the plant back to its nameplate capacity. In addition, a study to improve the sulfur pit vent gas hydraulics is underway to eliminate the potential for fugitive H_2S emissions during certain scenarios.