

Handling Vent Gases in SRU's

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One objective of the Clean Air Act (CAA) in the United States is to improve air quality.

With the sulphur content of crude oil and natural gas on the increase and with the ever-tightening sulphur content in fuels, the refiners and gas processors will require additional sulphur recovery capacity. At the same time, environmental regulatory agencies of many countries continue to promulgate more stringent standards for sulphur emissions from oil, gas, and chemical processing facilities. It is necessary to develop and implement reliable and cost-effective technologies to cope with the changing requirements.

With the overall sulphur recovery efficiency of sulphur recovery units with tail gas treating commonly exceeding 99.9%, attention has turned to other sources of sulphur emissions in refineries and gas plants.

Recently there has been increasing interest in treating vent streams from sulphur pits, sulphur storage tanks, sulphur loading facilities as well as FCC regenerators.

Typically, the sulphur pit vent gas, sulphur storage tank vents, and truck loading rack vents have been routed to the incinerator or directly to the atmosphere without treatment. As a result of more stringent standards for sulphur emissions, all of these vents need to be treated. Currently, all western countries and many third world countries limit the amount of sulphur can be emitted to the atmosphere.

This paper presents methods to reduce emissions from any vent gas system such as sulphur pit, sulphur storage tanks, or any SO₂ stream from FCC unit should be processed in a most effective way to meet regulation effects of sulphur removal on worldwide facilities, ways to increase sulphur recovery the capacity, the global petroleum market and the key parameters to improve the existing plants, as well as the design criteria for the new plants to achieve the emission requirements established by environmental regulatory agencies.

When crude oil is processed in refineries, sulphur contained in the oil is mainly recovered as H₂S, which is converted to sulphur in the refinery Claus plant. Part of the sulphur in the crude oil accumulates in the refinery residues. The external use of heavy fuels is very restricted, and further upgrading the heavy residues to lighter hydrocarbons, or converting these residues to synthesis gas, requires additional processes and investment costs.

Combustion of refinery residues, as well as incineration of Claus tail gases, results in offgases containing SO₂. The environmental regulations in many countries require that most of the SO₂ is removed from these flue gas flows.

In response to this trend, several new technologies are now emerging to comply with the most stringent regulations. However, government regulations are only effective if compliance is monitored and if the regulations are strictly enforced. If gasoline that is exported for sale outside the United States, that gasoline is not subject to the requirements of the gasoline sulphur rule, including gasoline produced by a refiner located within the Gas Processing Associations (GPA).

Whether the initiative arose from government inducement, public pressure, or internally from corporate philosophy, there has been a considerable increase in demand from industries for what are regarded as the key elements for achieving higher sulphur recovery efficiencies. These are:

- 1) Process knowledge
 - Poor Reaction stoichiometry
 - Catalyst deactivation
 - Operating 1st converter too cold
 - Operating 2nd & 3rd conv. too hot
 - Bypassing gases around conversion stages
 - High final condenser temperature
 - Liquid sulphur entrainment
- 2) Existing process evaluation
- 3) Process modifications/optimization/converting to a suitable process in order to meet the new emission requirements for any unit involved with the emission requirements
 - Providing acid gas/air preheater
 - Changing Claus catalyst to higher performance catalysts
 - Converting unit to high efficient process
 - Adding new reactor
 - Optimizing SRU/BSR converter temperatures, H₂ consumption
 - Converting the amine solvent in the gas treating from generic solvent to proprietary solvent
 - Optimizing the amine flow rate and temperature for amine absorbers
 - Minimizing steam consumption in amine units & SWS
- 4) Selection of a new technology for the new plant
- 5) Evaluation of the existing process control/possibilities of additional new controls

6) Process monitoring

- Good process design
- Well-maintained equipment
- Well-trained operators
- Maintain correct P&T
- Maintain correct feed ratio to Air
- Analyzers Selection
- Use more active catalyst
- Efficiency Final phase of optimization process
- Meet required efficiency
- Good performance
- Good operating practice
- Optimal

7) Capital and operating costs

To achieve the higher recovery expected of a modern sulphur recovery unit, advances in the modified Claus sulphur recovery process itself are being implemented. These process technology advances are as a result of the evaluation of the key parameters. Each key element will be evaluated individually in the following sections.

Table 1-1 represents the worldwide sulphur recovery requirements for selected countries.

Table 1-1—Worldwide Sulphur Recovery Requirements

Country	Overall Sulphur Recovery, %
Asia	
Australia	99.9
China	99.9
India	99.0
Indonesia	99.0
Japan	99.9
Kazakhstan	99.9
Korea	99.9
Pakistan	< 99.0
Philippine	95.0 to 99.9
Singapore	< 99.0
Taiwan	99.9

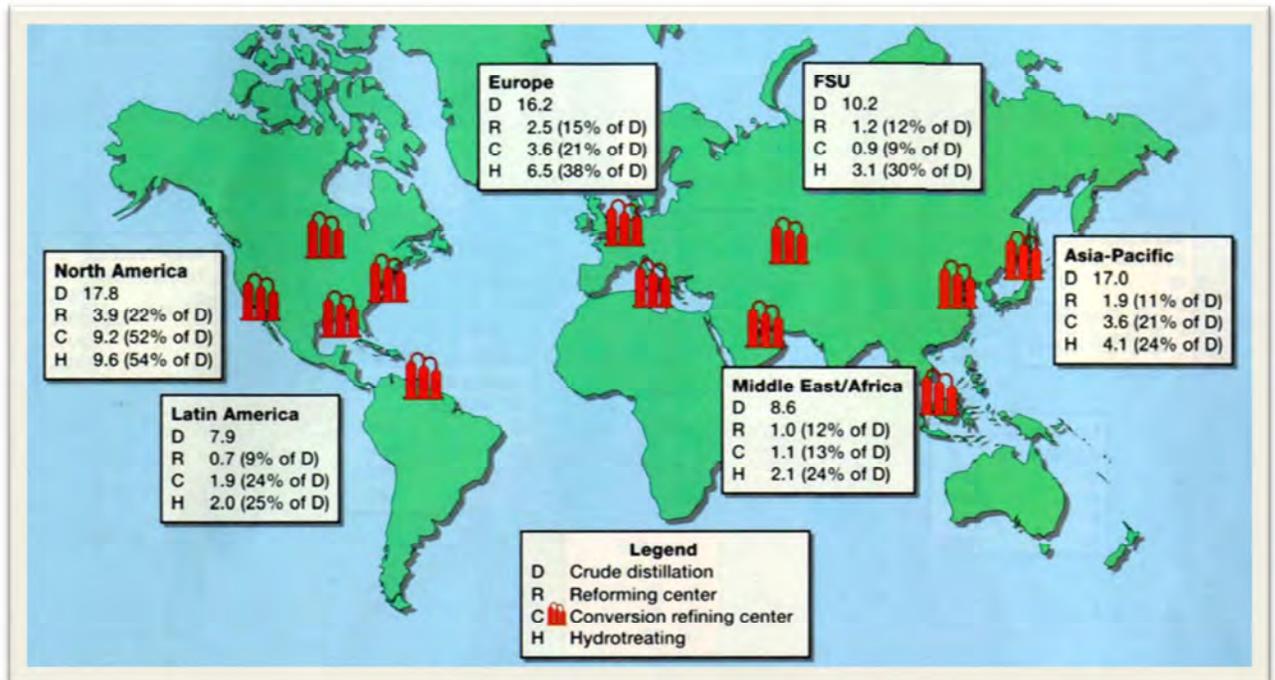
Country	Overall Sulphur Recovery, %
Thailand	99.9
Europe	
Italy	97.5 to 99.9
Most European Countries	98.5
Austria	99.8
Germany	99.5 to 99.8
Russia	99.9
United Kingdom (UK)	98 to 99.5
Middle East	
Abu Dhabi (UAE)	98.0
Egypt	99.0 to 99.9
Iraq	99.0
Kuwait	99.9
Qatar	99.0
Saudi Arabia	95.0
North America	
Canada	98.5 to 99
United States	99.9
South America	
Argentina	99.0 to 99.9
Jose Industrial, Venezuela	99.0
Mexico	98.5 to 99.9
Venezuela	98.5 to 99.5

Sulphur has been identified as the critical component in gasoline that needs to be restricted by the federal Reformulated Gasoline specifications. Sulphur in gasoline does not affect engine emissions of HC, CO, and NO_x, but it increases exhaust emissions of these pollutants by inhibiting catalyst performance. Sulphur inhibition is very sensitive to air/fuel ratio. The sensitivity of sulphur content on exhaust emissions is higher in newer advanced catalyst technology. The sulphur content in gasoline specifications under European law is 150 and 50 ppmw for the year 2000 and 2005 limits, respectively. The sulphur content in diesel specifications under European law is 350 and 50 ppmw for the year 2000 and 2005 limits, respectively. To comply with the CAA, the U.S. refiners invested in reformulating gasoline and diesel for low-sulphur content, in the oxygenates [methyl tert-butyl ether (MTBE) and, to a lesser extent, tertiary amyl ether (TAME)], isomerization, naphtha/reformate/cracked gasoline

fractionation, aromatics extraction/separation, and gasoline blending automation. Production costs have averaged around \$0.03/gal to make the new reformulated gasoline and \$0.01/gal for low-sulphur diesel.

The overall net impact will be an environment of modestly better, although still not stellar, refining margins for the Western European industry. Unlike the experience of the U.S. refiners during the 1990s, these margins should be adequate to cover the significant investments that must be made. Because domestic production will not be capable of satisfying the local demand growth, Western Europe will be increasingly reliant on imported products, resulting in greater price volatility in the future. Price volatility will occur with increasing frequency because any surge in demand or disruption in domestic supply will need to be replenished by offshore sources, which may have significant time lags in their delivery ability.

Figure 2-1 represents the crude capacity conversion units in Western Europe as 21% and in the United States as 52% when compared to the other countries in 1998.





Maintaining diesel fuel supplies in the face of increasing product demand and tight refinery capacity will present refiners with a serious challenge by itself. The reduced production capability, which results from a 15-ppm highway diesel fuel sulphur limit, poses a considerable risk that diesel supplies will be inadequate to meet demand. The U.S. environmental regulations have the following impacts:

- 1) Create inadequate diesel supplies
- 2) Increase fuel prices
- 3) Increase revamp activities for most refineries
- 4) Reduce net imported supplies
- 5) Produce a near-perfect operation
- 6) Lose product due to high severity desulphurization
- 7) Lose effective product due to reduction in product energy content
- 8) Maintain ability for 15-ppm cap diesel throughout the refinery's distribution system
- 9) Increase capital and operating costs

The new EPA Tier 2 emission regulations will require the following modifications:

- 1) Additional Fluid Catalyst Cracker (FCC) feed pre-treat
- 2) FC gasoline post-treat
- 3) Additional H₂ production
- 4) Additional Sulphur Recovery
- 5) Possible additional alkylation capacity
- 6) Debottlenecking and utility upgrades

The refining industry is committed to providing cleaner, more environmentally acceptable products to consumers. However, our national environmental goals must be consistent with our national energy needs. Close attention must be paid to the impact of future regulatory requirements on product supplies and energy security because the U.S. product refining and distribution system is already stretched to its limit. It is preferable that the EPA establish a cost-effective standard for engines and fuels that substantially reduces emissions and, yet, is close to the European regulations.



The vent gases from the sulphur pits, truck loading rack and the sulphur storage tanks have been routed to the thermal or catalytic incinerator and vented to the atmosphere for a long time and have met the target emission. The new emission regulation forces industries and operation companies to reduce their emissions. Therefore, the sulphur pit vents, truck loading rack and the sulphur storage tanks need to be treated that does not effect on the unit capacity and do not have significant impact throughout the unit and the same time provide a safe, reliable low cost operation. Therefore, there is no solid answer that fits all the sulphur plants. Each sulphur plant needs to be evaluated individually in terms of capacity, equipment and cost and find the best location to satisfy the needs. In some cases the site has more than one sulphur plant and it is desirable to collect all the vents and send it only to one sulphur plant to reduce the costs. There are many options and solutions are available to process the vent gas from the sulphur pit and from the sulphur storage tanks could be evaluated for reducing the sulphur emissions from the sulphur recovery units. There are required steps needs to taken for this evaluation as follows:

Evaluate unit capacity, with process simulator

If the unit capacity is not adequate, consider other processes to process the vent gas, out side of sulphur plant or use oxygen enrichment to improve the unit capacity

- Provide the performance test if feed compositions has changed from its original design and to get the actual unit performance
- Evaluate the performance and size of the existing equipment
- Adding vent gas such as SO₂ may lower the temperature in the reaction furnace, the stability of the flame temperature and increasing water content in the reaction furnace to be evaluated
- Evaluate the plot area and the piping distance
- Evaluate any possible options
- Evaluate safety, reliability, ease of operation
- Evaluate cost
- Select the option that meets all requirements

There are other concerns and evaluations are required as the result of lessons learned from those are already processing the vent gas to the sulphur plants as follows:

- If vent gas will be routed to the tail gas unit, use Nitrogen instead of air, since oxygen breakthrough will damage the catalyst. The disadvantage of this configuration is to cause fire in the sulphur pit during the shut down
- Evaluate eductor versus blower

- Evaluate steam eductor versus air eductor
- Recommended steam eductor versus blower
- Evaluate using Nitrogen versus air or tail gas to sweep the vent gas
- Locate the nozzle location where it will not cause plugging or back flow, such as air register
- Evaluate burner nozzle versus reaction furnace nozzle
- Injection nozzle to thermal reactor with refractory/ceramic lined to avoid contact the furnace refractory/shell interface with air
- Consider refractory limitation and cold spots

The configurations are summarized in the following pages but the most common options are listed below: The advantages and disadvantages will be discussed in details.

1. Collection and routing to the thermal oxidizer or directly to the stack, if it meets the required regulation emissions
2. Collection and routing the vent gases to one or both of the Reaction Furnaces in the Sulphur Recovery Unit.
3. Collection of the vent gases and catalytically oxidizing the sulphur compounds in the vent gases followed by sodium bicarbonate scrubbing.
4. Collection and routing the vent gases to one or both of the Reducing Gas Generator Burner in the Tail Gas Unit.
5. Sweep the tank vapor space with the small portion of the tail gas stream or nitrogen to one or both of the Reducing gas generator or Hydrogenation Reactor. Pit vent should be processed separately.
6. Build the sulphur tank inside of the sulphur pit to sweep the gas with the tail gas stream from the final condenser and pipe back to the reducing gas generator, which two new pipes should be routed.
7. Other Options could be evaluated for those cases limitation occurs.

Process Overview for Pit Vent or Sulphur Storage Tank Vents

As it was mentioned there are several alternatives to incineration include vapor recovery to: 1) new caustic scrubber; 2) front end of the existing SRU; 3) existing SRU tail gas unit; 4) new solid regenerable or non-regenerable adsorbent bed; 5) new chelated iron-redox LO-CAT[®] unit; or 6) new Oxidation[™] unit followed by caustic scrub. The full range of brainstormed alternatives is summarized below.

<u>No.</u>	<u>Alternative</u>	<u>Cost</u>	<u>Advantages</u>	<u>Disadvantages</u>
1.	Dilute vapor stream to thermal oxidizer	Low	<ul style="list-style-type: none"> ■ Reduces sulphur concentration 	<ul style="list-style-type: none"> ■ May not be permitted ■ Does not generate SO₂ credits
2.	Vent vapor directly to the atmosphere	Low	<ul style="list-style-type: none"> ■ None 	<ul style="list-style-type: none"> ■ Is not permitted ■ Environmental impact risk ■ Sulphur condensation can cause acid formation and corrosion ■ Personnel safety risks ■ Does not generate SO₂ credits
3.	Route vapor to a hot flue gas	Moderate	<ul style="list-style-type: none"> ■ Commercially proven ■ No sulphur condensation 	<ul style="list-style-type: none"> ■ May not be permitted ■ Does not generate SO₂ credits ■ Potential stack(s) are far away
4.	Route vapor to front end of the SRU	Moderate	<ul style="list-style-type: none"> ■ Open art – no license fee ■ Commercially proven ■ Generates SO₂ credits ■ Short lead time ■ No plot impact ■ Minimizes new facilities ■ Minimum permit impact 	<ul style="list-style-type: none"> ■ Need alternate disposition, e.g., thermal oxidizer, in the event of the loss of the SRU ■ Vent air could be large percentage of total combustion air required, especially if O₂ enrichment is being used in the SRU; air and oxygen control and metering needs to be looked at closely
5.	Route vapor to SRU Tail Gas	Moderate	<ul style="list-style-type: none"> ■ Generates SO₂ credits ■ Open art – no license fee 	<ul style="list-style-type: none"> ■ Can't do if vent streams don't go to Reducing Gas Regenerator (RGG) burner; O₂ will consume H₂ and/or deactivate catalyst ■ May reduce SRU/TGU capacity ■ Limited capacity to handle the incremental air ■ Need to remove oxygen to avoid catalyst poisoning

Alternatives (continued)

<u>No.</u>	<u>Alternative</u>	<u>Cost</u>	<u>Advantages</u>	<u>Disadvantages</u>
6.	Absorption in non-regenerable fixed bed absorbent, e.g., Sulfa Treat or GTP's Sulphur Rite	Moderate	<ul style="list-style-type: none"> ■ Generates SO_x credits ■ Open art – no license fee ■ Commercially proven 	<ul style="list-style-type: none"> ■ Generates solid waste elemental sulphur in the stream may plug the bed ■ Limited commercial experience in this application ■ Measurable SO₂ is present in vent streams ■ Plot space
7.	Adsorption by activated carbon or alumina	Moderate	<ul style="list-style-type: none"> ■ No license fee ■ Generates SO₂ credits 	<ul style="list-style-type: none"> ■ Lower sulphur adsorption than Sulfa Treat ■ Higher bed change-out frequency than Sulfa Treat ■ Higher operating cost than Sulfa Treat ■ Generates more solid waste than Sulfa Treat ■ Elemental sulphur in the stream may plug the bed ■ Not commercially proven ■ Measurable SO₂ is present in vent streams ■ Plot space
8.	Absorption by caustic solution	High	<ul style="list-style-type: none"> ■ Open art – no license fee ■ Commercially used on H₂S containing streams ■ Generates SO₂ credits 	<ul style="list-style-type: none"> ■ Generates sodium sulfite solution waste ■ Elemental sulphur in the stream may plug ■ Potential elemental sulphur plugging that needs careful consideration during design
9.	Absorption by LO-CAT II®	High	<ul style="list-style-type: none"> ■ Converts H₂S to sulphur ■ Does not impact SRU capacity ■ New generation Streford ■ Generates SO₂ credits 	<ul style="list-style-type: none"> ■ New emission point if vent cannot be routed to the SRU tail gas unit ■ Licensed process ■ Measurable SO₂ present in vent streams may effect absorbent performance ■ High capital cost ~\$1+ MM/train ■ Long lead time of ~12 months ■ May require two (2) 50% trains ■ High operator attention of ~3 hours per day/unit ■ Plot space 20' x 30' or 20' x 20'

Alternatives (continued)

<u>No.</u>	<u>Alternative</u>	<u>Cost</u>	<u>Advantages</u>	<u>Disadvantages</u>
10.	Absorption by regenerative caustic, e.g., Merichem or UOP Merox™	High	<ul style="list-style-type: none"> ■ 100% removal ■ Generates SO₂ credits 	<ul style="list-style-type: none"> ■ High capital cost ■ High utility cost ■ Licensed process ■ Not designed to handle sulphur vapor ■ Measurable SO₂ is present in vent streams ■ Plot space
11.	Absorption by regenerative solvent	High	<ul style="list-style-type: none"> ■ Operation is similar to amine scrubbers ■ Generates SO₂ credits 	<ul style="list-style-type: none"> ■ High capital cost ■ High utility cost ■ Licensed process ■ Not designed to handle sulphur vapor ■ Measurable SO₂ is present in vent streams may impact absorbent ■ Plot space
12.	Adsorption in a regenerative fixed bed	High	<ul style="list-style-type: none"> ■ Generates SO₂ credits 	<ul style="list-style-type: none"> ■ Solid waste disposal (non hazardous) ■ Sulphur vapor in the stream will plug the bed ■ Not commercially proven ■ Measurable SO₂ is present in vent streams ■ Plot space
13.	Catalytic incineration, e.g., Oxidation™	High	<ul style="list-style-type: none"> ■ Lower operating temperature 	<ul style="list-style-type: none"> ■ Regulations may not allow routing vapor incinerator ■ Does not reduce SO₂ emissions any more than thermal incineration ■ Does not generate SO₂ credits
14.	Oxidation™ followed caustic scrub	High	<ul style="list-style-type: none"> ■ Generates SO₂ credits 	<ul style="list-style-type: none"> ■ Generates caustic waste



Alternatives (continued)

<u>No.</u>	<u>Alternative</u>	<u>Cost</u>	<u>Advantages</u>	<u>Disadvantages</u>
15.	Degas sulphur from pit	Very High	<ul style="list-style-type: none">■ Commercially proven■ Licensed process from Goar Allison and Amoco■ Generates SO₂ credits■ Concentrates sulphur in vapor stream at high enough pressure to feed SRU front-end■ Low air rate, less effect on front-end air control■ Reduces pit sweep requirement (based on LEL of H₂S in air)■ Essentially eliminates H₂S from pit/tank/truck vapor; greatly reduces odor, fire hazard, safety concerns■ May become legislated due to accidents involving tanks and loading	<ul style="list-style-type: none">■ Does not eliminate sulphur in vapor from tank or truck loading rack operations, albeit concentrations could be acceptable (< 160 ppmv) for routing to thermal oxidizer■ Some technology requires license fee■ Larger pit, or external space for new equipment
16.	Sweep sulphur tank in the pit with SRU tail gas under pressure	High	<ul style="list-style-type: none">■ Generates SO₂ credits■ Commercially demonstrated■ At BP Carson and 2 units in Europe by Comprimo	<ul style="list-style-type: none">■ Requires alternate disposition for sulphur tank and truck loading rack



Treating of Vent Gas Streams - Option 1

The incinerator is the best home for the vent gases, if regulations permit. If the vapor stream is diluted it will reduce the sulphur concentration but does not generate any SO₂ credits. If a generic solvent is used in the tail gas unit which the H₂S concentration of the absorber overhead in the range of 150 to 200 ppmv, the amine solvent could be changed to proprietary solvent such as Flexsorb or HS-103 to reduce the H₂S concentration to 10 ppmv.

The ideal solution is to route vent gas to the incinerator and, if necessary, minimize SCOT SO_x by using acid-aided MDEA and increasing reactor inlet to 600-650°F to maximize COS/RSH conversion.

Treating of Vent Gas Streams - Option 2

The most common proposed scheme is to design the vapors from the existing sulphur pit, the truck loading rack and the sulphur storage tanks would be collected with the existing vapor recovery piping as currently installed. There are several key should be considered for routing the vent to the reaction furnace. Two problems with routing vent gas to the thermal reactor: solid sulphur accumulates in the air plenum (which can be melted out by temporarily minimizing main air), and increased backpressure on the vent gas blowers increases blower operating temperature from compression heat (about 15°F/psi), thus increasing blower maintenance. It is wise to have incinerator as an alternate disposition in the event of the loss of the sulphur plant. Vent air could be large percentage of total combustion air which is required in sulphur plant, especially if oxygen enrichment is being used in the SRU, air and oxygen control and oxygen demand and metering needs to be looked at very closely. Using this option will minimize the changes in the facility, no impact on plot plan, and it is a short lead time and it is commercially proven. Finally generates SO₂ credit for emission regulations.

Lesson Learned from Refineries Experience – Case 1

In one refinery the vent gas was injected into the air plenum as close to the burner as possible, and offset consistent with the direction of main air swirl. One rotary lobe blower pulls ambient air through the tanks, and a second through the two sulphur pits, sour water sump and sulphur load rack (intermittent). Each blower has an installed spare. Nominal capacity of one blower is ~ 200 ICFM. The vent gas was injected into the air plenum as close to the burner as possible, and offset consistent with the direction of air swirl.

The vent gas accounts for ~ 10% of the total airflow. Solid sulphur tends to accumulate in the air plenum, but not to the extent of impeding air flow. It can typically be melted out at low unit loads by temporarily minimizing the (cold) main air rate.

Resultant increased compression heat from the higher backpressure (6-8 psig) increased blower maintenance demands. Circa 1997 we switched to Tuthill M-D rotary lobe blowers, model 4009-81L2W-3758, purchased through GL Sales in Huntington Beach (Gary Lane, 714-841-1898). The bearing housings are water-cooled, and

shaft seals purged with instrument air. These were an improvement over the Sutorbilts, but still must typically be replaced (\$5.5M) at 4-6 month intervals, due primarily to buildup of corrosion products on the rotors.

The refinery switched from conventional HC-base to synthetic bearing lube oil and we see a major improvement in the condition of the oil after a couple weeks. Bearing life is expected to improve considerably as a result.

Occasionally the operators will attempt to melt out a frozen spare blower with 20-40# steam, and the refinery convinced this accelerates bearing corrosion from condensation. It s recommend providing a small steam heater to permit purging the blower with hot air if necessary to melt any sulphur which may have caused the blower to seize. The refinery is currently proceeding with this modification.

One particular design consideration is to ensure possible isolation of the spare blower without creating dead legs, which can accumulate liquid sulphur. Another option, which the refinery has considered but not done, is to equip the blowers with 2-speed motors and normally run both at half speed.

It is suspected blower/piping corrosion/fouling is aggravated by upstream steam jacket leaks, which tend to go undetected. I have considered installing a sample condenser on the blower discharge to enable the operators to routinely check for excessive water.

If the storage tanks can be pressurized, forced airflow obviously eliminates these blower maintenance problems.

It is favored preheating pit/tank inlet air to at least 260°F to avoid deposition of solid sulphur at localized cold spots, but have been unable to adequately justify the cost to management.

Several years ago four venturi flow meters were installed on the individual sulphur vent gas blower suction lines from the pits and storage tanks. The primary purpose was to provide early warning of undue flow reduction, typically due to a blower problem or sulphur plug. A potential secondary benefit is the balancing of branch flows by imposition of a modest pressure drop. Historically, the meters were generally unreliable and ignored. With the EPA consent decree, their reliable operation is now mandated as verification of proper vent gas system operation.

The venturi pressure taps are 1/8" ports to a relatively large chamber, to which is mounted a SS diaphragm sensor, which transmits pressure to the DP cell via filled capillary tubing. The venturi is encased in a custom Controls Southeast clamp-on cast aluminum steam jacket, which terminates flush with the outer face of the diaphragm chamber.

It is originally expected the steam jacket to keep any sulphur in the diaphragm chamber molten, but this has proven to not be the case. Solid sulphur and/or iron corrosion products (possibly suggesting condensation) have been found in the diaphragm chambers. Some of these deposits (suspected the iron corrosion products, in particular) were obviously due to inadequate insulation. It is believes that improved insulation has reduced, but not eliminated, fouling of the diaphragm chambers with solid sulphur. The engineer thinks the meters must still be serviced at least once/month. Preheating the pit/tank inlet air as previously mentioned would probably minimize/eliminate this problem.

Since cold ambient air is drawn through the pits/tanks, the bulk stream temperature is still well below the sulphur melting point en route through the venturi. Consequently, heat transfer efficiency through the venturi wall is more important than for, say, transmission of molten sulphur, where the process stream is already relatively hot. Proper practice would be to fill the gap between the steam jacket and venturi with heat transfer cement. This has not been done in our case; the operator is sure it is worthwhile, but don't really know to what extent it would reduce accumulation of solid sulphur in the diaphragm chamber.

It is suspected blower corrosion/fouling is aggravated by upstream steam jacket leaks, which tend to go undetected. It has considered installing a sample condenser on the blower discharge to enable the operators to routinely check for excessive water. Venturi flow meters have been installed on the branch lines (blower suction) to monitor flow. Diaphragm sensors transmit the pressures via filled capillaries to the transmitter. Venturi/diaphragms are encased by a custom steam-jacket from Control Southeast. The venturis also impose a modest pressure drop to help balance branch flows. The flow meters are not totally reliable, but also do not receive much maintenance attention.

One particular design consideration is to ensure possible isolation of the spare blower without creating dead legs which can accumulate liquid sulphur. Another option, which we've considered but not done, is to equip the blowers with 2-speed motors and normally run both at half speed.

One thought is to combine the vent gas with heated combustion air to the SCOT feed heater, which would minimize the backpressure on the vent gas blowers. If it is decided or have planning to divert the discharge from their pit steam jet eductors (which draw air into the pit) into the thermal reactor zone 1 downstream of the burner. In this case, the injection nozzle should be somehow refractory/ceramic lined so as to avoid contact at the furnace refractory/shell interface with air, which will ignite accumulated sulphur/ H₂S and result in localized sulfidation. Another refinery has two units which educt pit vapors to the front of the Claus unit. One unit has been doing this for almost three years now, with minimal problems. Hot plant air is the motive fluid. The biggest problem is plugging of the eductors; when the outlet becomes restricted, motive air reverse-flows into the pit, causing it to vent to atmosphere. They routinely shut the eductors down and clean them. The incinerator is the best home for the vent gases, if regulations permit.

Lessons Learned from Refineries Experience – Case 2

This site the vent system should be collected from two train sulphur plant, from truck loading arm and from sulphur storage tanks all routed to a common header originally routed to the thermal oxidizer. The new configuration would take the header to only one sulphur plant and keep the header to the thermal oxidizer in place for emergency disposition. A new common steam jacketed line would be connected to the existing vapor collection header and routed to a new vent gas steam eductor. This eductor will be a with steam jacketing, to assure that sulphur vapor does not solidify in the eductor. Also, piping to and from the eductor and the eductor casing itself, shall be steam jacketed and designed to free drain.

For this options the capacity of the sulphur plant is evaluated to make sure there is no reduction in the sulphur production of the unit. The sulphur plant is already running on oxygen enrichment. Total combined H₂S and elemental sulphur emissions from these sources is approximately 250,000 pounds per year as SO₂ based on continuous emission monitoring of the thermal oxidizer stack. The flow rate from all three sources are 78 lbmol/hr.

One of the studies was done in the oxygen enrichment to the sulphur plant to find a place for the pit vent system, truck loading rack and sulphur storage tank vent. The evaluation was performed to find out if the existing sulphur plant is capable of handling an additional gas without losing the sulphur production.

Table 1 shows the calculation for estimated O₂ demand for a sulphur plant operating at 150 LTPD of sulphur feed. Typical compositions for Sour Water Stripper (SWS) acid gas and Amine acid gas are assumed. Hydrocarbon concentrations in the acid gases are assumed to be low so hydrocarbons are not included in the oxygen demand calculations (see below).

The SWS acid gas flow rate is set at 95 MSCFH based on the maximum hourly SWS acid gas feed to Train 1 (the Train 2 maximum SWS feed rate was 85 MSCFH). The amine acid gas flow rate is set at 146 MSCFH to give a total sulphur feed to the unit of 150 LTPD. The 146 MSCFH of amine acid gas exceeds the maximum amine acid gas feed to either Train 1 (137 MSCFH) or Train 2 (124 MSCFH) for 2002 indicating that nether train actually operated at 150 LTPD during year.

Oxygen demand is calculated assuming complete conversion of H₂S to sulphur and water and complete conversion of NH₃ to nitrogen and water. The calculation probably overstates the true oxygen demand since some hydrogen will inevitably be produced by thermal cracking of the H₂S. The presence of hydrocarbons (which were neglected) would tend to increase the oxygen demand, so overall the calculation is probably accurate to within 5%. The calculated oxygen demand is 282 lbmole/hr for 1 train at 150 LTPD of sulphur feed (564 lbmole/hr for 2 trains at 150 LTPD of sulphur feed each).

Table 2 shows the flow of oxygen and air required for operation of 2 trains at 150 LTPD of sulphur feed each, based oxygen enrichment to 75% O₂ and the oxygen demand calculated in Table 1. The equivalent sulphur capacity (388 LTPD) is calculated based on the amount of H₂S that theoretically could be processed with the total O₂ feed shown in the table, i.e. 2 moles of H₂S per mole of O₂.

Table 3 shows the maximum oxygen enrichment level with vent gas and no air. The calculation is based on maintaining the same total flow of oxygen plus air plus vent gas (752 lbmole/hr) as was calculated in Table 2. The vent gas flow is based on the flow of 78.2 lbmole/hr provided by client plus 85.37 lbmole/hr (1538 lb/hr) of eductor motive steam calculated by an eductor vendor (Schutte and Koerting). Because the vent gas flow, including eductor motive steam, is less than the airflow shown in Table 2, it is possible to process the vent gas in the reaction furnaces without a loss in processing capacity. The equivalent sulphur capacity shown is based on the total O₂ in the table. In practice, that equivalent capacity could not be achieved because additional acid gas feed would impose an additional hydraulic load on the sulphur units. The actual achievable capacity would depend on the composition of the marginal acid gas feed (SWS acid or amine acid gas or a mixture of both).

Table 4 shows the air and oxygen flows required to maintain the same total O₂ flow (564 lbmole/hr) as shown in Table 1 if vent gas is fed to the units. The difference in oxygen flow between that shown here (538 lbmole/hr) and that shown in Table 2 (516 lbmole/hr) is the amount of oxygen required to compensate for the additional water in the vent gas stream (as compared to air). This 22-lbmole/hr increase in oxygen flow would be required any time that the units are operating above their maximum air-only capacity.

Table 3-1 - Oxygen Demand Estimate

	SWS ACID GAS				AMINE ACID GAS			
	Flow and Comp.		O2 Demand		Flow and Comp.		O2 Demand	
	mol%	Lbmol/hr	mol/mol	lbmol/hr	mol%	lbmol/hr	mol/mol	lbmol/hr
H2S	33.00	82.61	0.50	41.31	92.00	353.99	0.50	176.99
CO2	0.00	0.00	0.00	0.00	3.00	11.54	0.00	0.00
NH3	34.00	85.11	0.75	63.84	0.00	0.00	0.75	0.00
H2O	33.00	82.61	0.00	0.00	5.00	19.24	0.00	0.00
TOTAL	100.00	250.34		105.14	100.00	384.77		176.99
Flow, MSCFH		95000		39900		146016		67167
SULPHUR, LTPD		28.38				121.62		
Total Sulphur (1 Train), LTPD								150.00
Total O2 Demand (1 Train), lbmol/hr								282.13
Total O2 Demand (2 Trains), lbmol/hr								564.27

Table 3-2 - Max. Current Operation - 2 Trains - 150 LTPD Each

	Oxygen		Air		Vent Gas		Total	
	mol%	Lbmol/hr	mol%	lbmol/hr	mol%	lbmol/hr	mol%	lbmol/hr
O2	100.00	516.15	20.37	48.11	20.37	0.00	75.00	564.27
N2	0.00	0.00	76.63	181.00	76.63	0.00	24.06	181.00
H2O	0.00	0.00	3.00	7.09	3.00	0.00	0.94	7.09
TOTAL	100.00	516.15	100.00	236.20	100.00	0.00	100.00	752.36
O2 from Vent Gas		0.00%						
O2 from Air		8.53%						
O2 from oxygen		91.47%						
Equivalent Sulphur Capacity based on total O2, LTPD				388				

Table 3-3 - 2 Trains - with Vent Gas and No Air

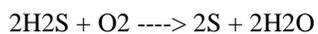
	Oxygen	Air	Vent Gas	Total
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	mol%	lbmol/hr	mol%	lbmol/hr	mol%	lbmol/hr	mol%	lbmol/hr
O2	100.00	588.79	20.37	0.00	9.74	15.93	80.38	604.72
N2	0.00	0.00	76.63	0.00	36.64	59.93	7.97	59.93
H2O	0.00	0.00	3.00	0.00	53.62	87.71	11.66	87.71
TOTAL	100.00	588.79	100.00	0.00	100.00	163.57	100.00	752.36
O2 from Vent Gas		2.63%						
O2 from Air		0.00%						
O2 from oxygen		97.37%						
Equivalent Sulphur Capacity based on total O2, LTPD				416				

Table 3-4 - 2 Trains - with Vent Gas and Air

	Oxygen		Air		Vent Gas		Total	
	mol%	lbmol/hr	mol%	lbmol/hr	mol%	lbmol/hr	mol%	lbmol/hr
O2	100.00	537.99	20.37	10.35	9.74	15.93	75.00	564.27
N2	0.00	0.00	76.63	38.93	36.64	59.93	13.14	98.86
H2O	0.00	0.00	3.00	1.52	53.62	87.71	11.86	89.23
TOTAL	100.00	537.99	100.00	50.80	100.00	163.57	100.00	752.36
O2 from Vent Gas		2.82%						
O2 from Air		1.83%						
O2 from oxygen		95.34%						
Equivalent Sulphur Capacity based on total O2, LTPD				388				

O2 Demand based on the following reactions:



Treating Vent Gas Streams - Option 3

We proposed process for the treatment of sulphur recovery unit vent gases uses oxidation catalyst Technology. In this process vent gases are collected, compressed and catalytically oxidized to sulphur dioxide in a reactor containing Oxidation catalyst. The effluent from the Oxidation reactor would then be scrubbed with a caustic / sodium sulfite solution to remove the sulphur dioxide formed in the Oxidation reactor. The produced sodium sulfite solution can then be disposed of in the refineries waste water system.

Detailed Description

It is proposed to design the vapors from the two existing sulphur pits, the truck loading rack and the sulphur storage tank would be collected with the existing vapor recovery piping as currently installed. A new common steam jacketed line would be connected to the existing vapor collection header and routed to a new vent gas eductor. This eductor will be a with steam jacketing, to assure that sulphur vapor does not solidify in the eductor. Also, piping to and from the eductor and the eductor casing itself, shall be steam jacketed and designed to free drain.

The discharge of the eductor will be routed to an electric Vent Gas Heater, which will heat the vent gases to 540°F. The power supplied to the heater is controlled by outlet temperature of the heater.

The hot vent gas is then piped to the refractory lined vent gas reactor. The vent gas reactor contains a bed of Oxidation catalyst in which all of the hydrogen sulfide and sulphur vapor in the vent gas stream are catalytically oxidized to sulphur dioxide. The Oxidation catalyst is a selective oxidation catalyst for sulphur compounds.

The hot vent gases from the vent gas reactor are then routed to the vent gas scrubbing system for removal of the sulphur dioxide formed in the reactor. The vent gas scrubbing system is a vendor standard package unit, which consists of a vent gas venturi scrubber a packed vent gas scrubber column, a scrubber solution tank, and a scrubber solution pump. The scrubber package is designed to remove at least 99% of the sulphur dioxide (SO₂) with a circulating 10% caustic / sodium sulfite solution.

In the scrubbing system, the hot process gases from the vent gas reactor will first be contacted with the circulating scrubbing solution in the vent gas venturi scrubber, where the majority the SO₂ is scrubbed out and the vent gas cooled to saturation temperature. The venturi discharges to the scrubber solution tank, where the solution and vent gas separate. The vent gas is contacted with the scrubbing solution a second time in the packed vent gas scrubber column to remove the balance of the SO₂, before venting to the atmosphere. The scrubber solution is re-circulated to both the venturi and packed scrubbers with the scrubber circulation pumps. As there is a net water loss due to evaporation in the scrubbing system it will be necessary to provide a condensate quality make-up water stream to the scrubber solution tank on level control. Makeup of the caustic to the scrubber system will be manually set with a hand control valve with adjustment based on the pH of the scrubbing solution (a pH Meter is provided). The purge of scrubbing solution will also be manually set to control the sodium sulfite / sulfate concentration in the scrubbing solution. As the scrubbing solution will only contain dilute caustic and sodium sulfite / sulfate (the majority of the sulfite is converted to sulfate in a warm basic solution in contact with air) it can be safely discharged to the refinery waste water system.

Table 3-5 – Equipment List

Title	Description, Size
VENT GAS BLOWER	Centrifugal blower, steam jacketed, 28,100 scfh @ 3.0 psi diff. press., motor driven
VENT GAS SCRUBBER	Packed column, 12" I.D. x 8'-0" tall, with packing, DP=15 psig, DT= 650°F
VENT GAS HEATER	Electric heat exchanger, Rated Duty= 60 kW; DP=15 psig, DT= 600°F (Note 4)
VENT GAS VENTURI SCRUBBER	Venturi scrubber, 28000 scfh, 43 gpm, DP=Atmos, DT= 650°F
SCRUBBER SOLUTION PUMP	Centrifugal pump, horizontal, 50 gpm, 50 psi diff. press., motor driven
VENT GAS REACTOR	Vertical vessel, 3'-0" ID x 6'-0" T/T, with 14 ft ³ Oxidation Catalyst, 2" refractory lining, DP= Atmos, DT= 650°F
SCRUBBER CIRCULATION TANK	Circular tank, 3'-6" I.D. x 3'-6" tall, DP=Atmos, DT=650°F

Total capital cost is 1,000,000 US dollars. Estimate Basis:

1. Type of Estimate = Equipment-Factored (+/- 30% Accuracy)
2. Construction Labor Rate = Union, Average All-in (Direct & Indirect) Rate of \$80.00/Hr
3. Productivity = USGC Unit Man-hour Rate X 1.11 (Wilmington Location)
4. Freight = 5% of Equipment and Material Costs
5. Sales Tax = 8.25% of Equipment and Materials
6. Home Office Engineering and Support = 30% of TIC (Ex. CM & UOC) or About 4,000 Man-hours at \$75 per Man-hour
7. Construction Management = Excluded
8. Client Staff = Excluded
9. Engineering Development Allowance = 20% of Total Project Cost

10. Exclusions = Construction Management, Client Staff (UOC), Royalties, Vendor Representatives, Spare Parts, & Demolition.

Treating of Vent Gas Streams - Option 4

The vent gases could be collected and routed to the air plenum or in a separate nozzle one or both of the Reducing Gas Generator Burner in the Tail Gas Unit via a steam eductor. The process is the same as option 2, except the location will be the reducing gas generator instead of the reaction furnace. The eductor would need a lower discharge pressure, and may save on capital cost. The stream could not be routed to the hydrogenation reactor due to presence of oxygen, which will deactivate the hydrogenation catalyst. In addition, the burner should be steam jacketed and may cause inflexible turndown issues.

The proposed design is to route the vapors from the existing sulphur pits, the truck loading rack and the sulphur storage tank would be collected with the existing vapor recovery piping as currently installed. A new common steam jacketed line would be connected to the existing vapor collection header and routed to a new eductor. This eductor will be with steam jacketing, to assure that sulphur vapor does not solidify in the eductor.

Also, piping to and from the eductor and the eductor casing itself, shall be steam jacketed and designed to free drain. The vent gas should be swept with nitrogen instead of air to prevent any catalyst deactivation. The disadvantage is to cause fire in the pit during SRU shut down. This option may reduce the SRU/TGU capacity and it will have limited capacity to handle incremental air.

Treating of Vent Gas Streams - Option 5

Some people recommend to sweep the tank vapor space in the tank with the small portion of the tail gas stream or nitrogen and rout them to one or both of the Reducing gas generator or Hydrogenation Reactor. Pit vent should be processed separately with a different method. This option is not recommended by We, because the mixture is very flammable and could capture the fire easily, if the tank is carbon steel, H₂S will form iron sulfide, and two different method is required to handle all the vent gases. Sometimes the vent gas is swept with Nitrogen and it is routed to the tail gas unit. Air is not used to prevent catalyst deactivation from excess oxygen. The disadvantage of this configuration is sulphur pit fire during the shutdown.

Treating of Vent Gas Streams - Option 6

This option is also used to process the vent gas for three refineries. The sulphur storage tank was built inside of the sulphur pit to sweep the gas with the tail gas stream from the final condenser in the sulphur pit. The gas from the final condenser is piped to the new sulphur tank to sweep the gas and piped back to the Reducing Gas Generator in the tail gas unit. The pipe is not steam jacketed but it is contra-traced. All of the sulphur seals were changed to " Sultrap" in order to re-route the sulphur to the new tank.

The project cost about 20 MM US dollars for total three sulphur plants on the site.

Treating of Vent Gas Streams - Option 7



There are other options are considered or recommended by the operation facilities and are not feasible or high capital cost, not easy to operate, high operation cost, license fee, create waste stream or do not provide enough SO₂ credit to emission requirements, which will be discussed briefly below.

- Route vapor to a hot flue gas, does not generate any SO₂ credit.
- Absorption in non-regenerable fixed bed absorbent, such as Sulfa Treat, will generate a waste elemental sulphur in the stream may plug the bed but provide SO₂ credit, and required more plot space.
- Adsorption by activated carbon or alumina, which provide SO₂ credit, but higher operation cost due to change bed, generate solid waste, requires plot space, and not commercially proven.
- Absorption by LO-CAT, requires license fee, high capital cost, plot space, long lead-time and the stream cannot be routed to the SRU/TGU.
- Absorption by regenerable caustic such as Merichem or UOP Merox, requires high capital cost, high license fee, plot space, but provides SO₂ credit.
- Absorption by solvent such as Sulfinol requires high capital cost, license fee, plot space and high utility cost.
- Absorption in a regenerable fixed bed, creates solid waste, and not proven commercially and needs plot space and may cause plug in the bed.
- Catalytic incineration, such as Oxidation, does not provide SO₂ Credit.
- Provide degassing for sulphur pit, it will not help with other vent from tanks and truck loading rack, but reduce the emission, high cost, and some technology needs license fee, capital and operating cost.

D-653 NH₃ ACID GAS KO.DRUM D-652 ACID GAS KO.DRUM B-651A/B PROCESS AIR BLOWER F-6x1 REACTION FURNACE BURNER F-6x2 REACTION FURNACE E-651 REACTION FURNACE BOILER E-651 NO. 1 SULFUR CONDENSER D-654 NO. 1 COALESCER E-652 NO. 1 AUX. BURNER

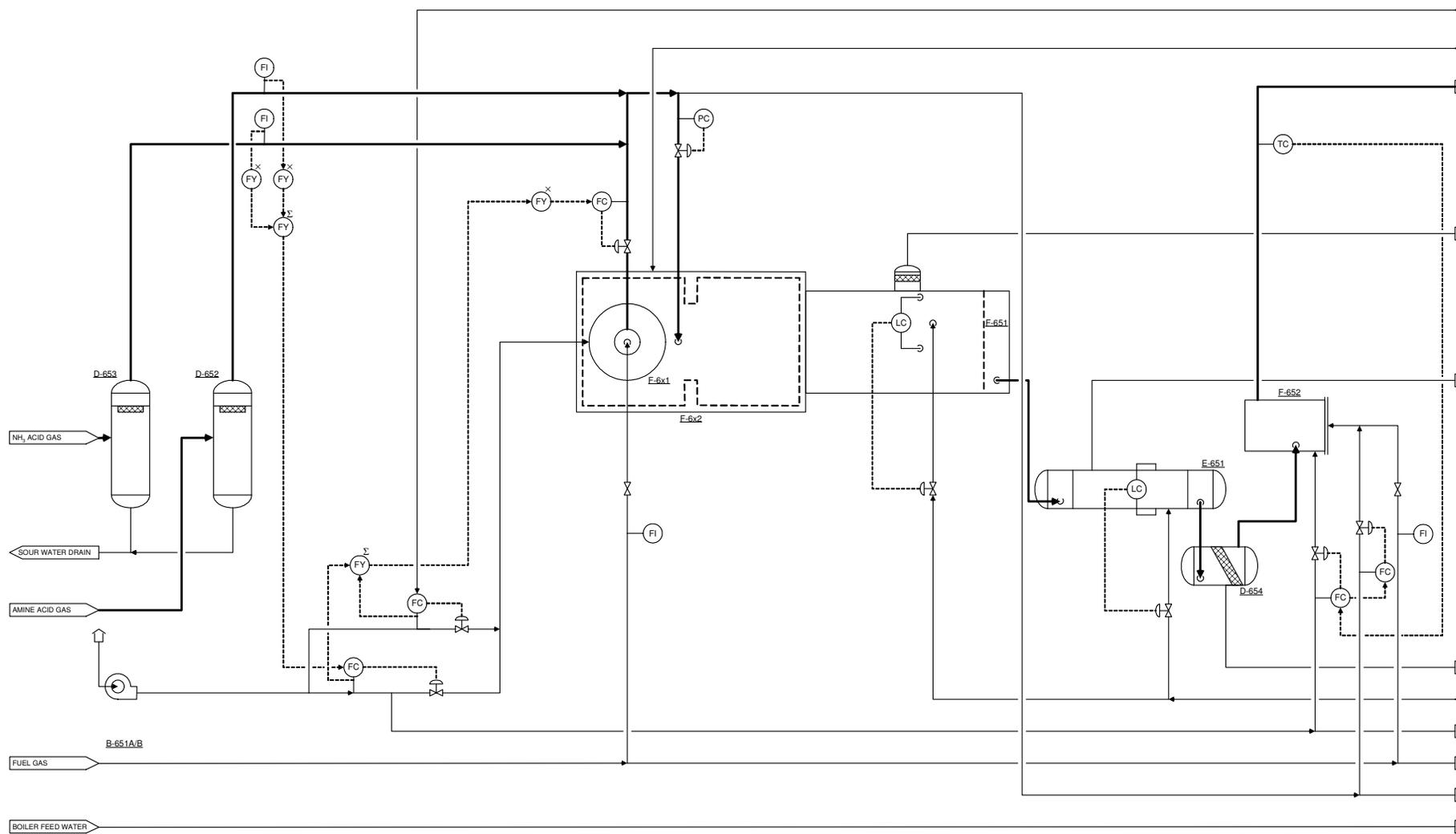


Figure 3-1, Sulphur Pit Vent Gas to Reaction Furnace

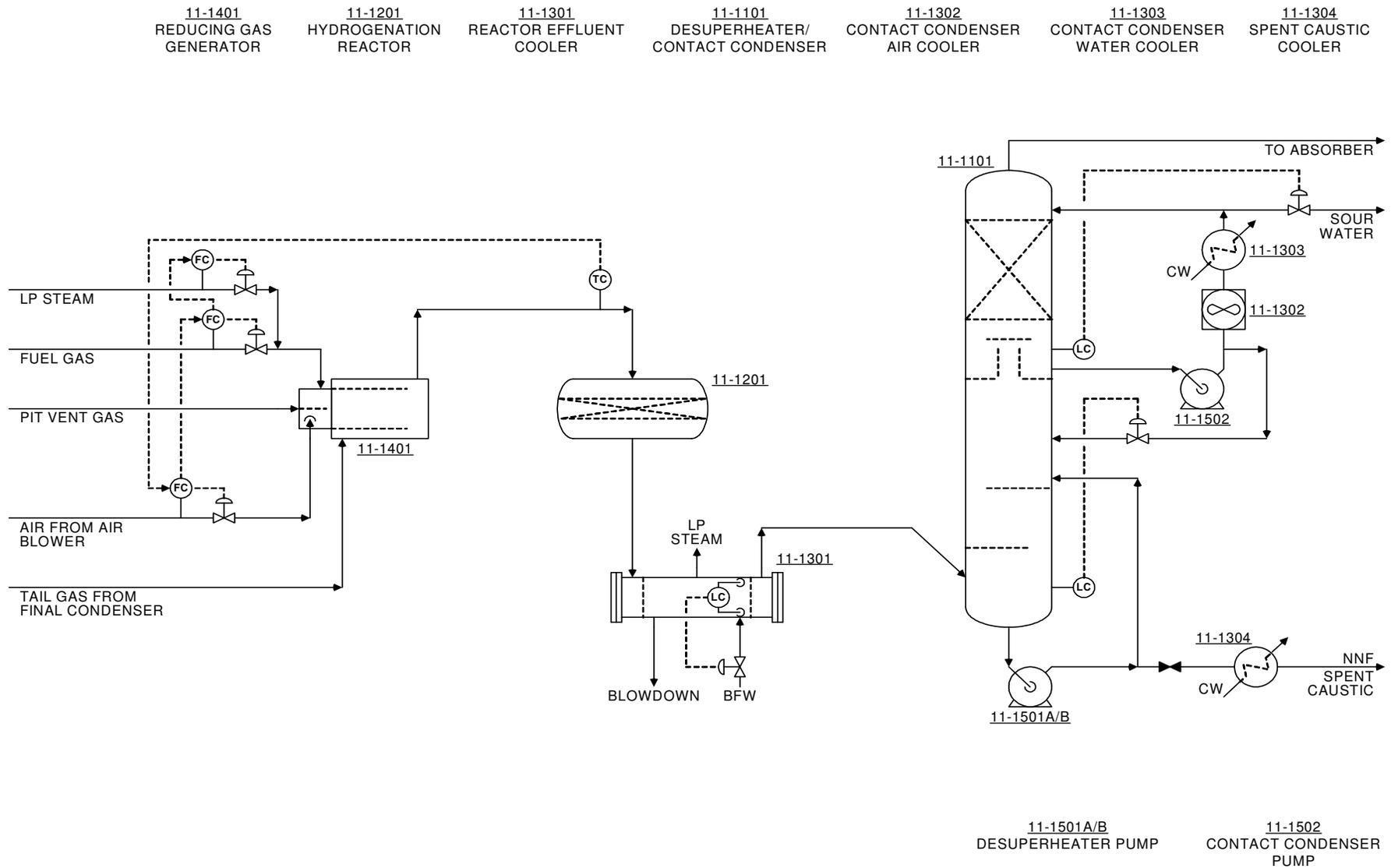


Figure- 3-2, Sulphur Pit Vent Gas to RGG

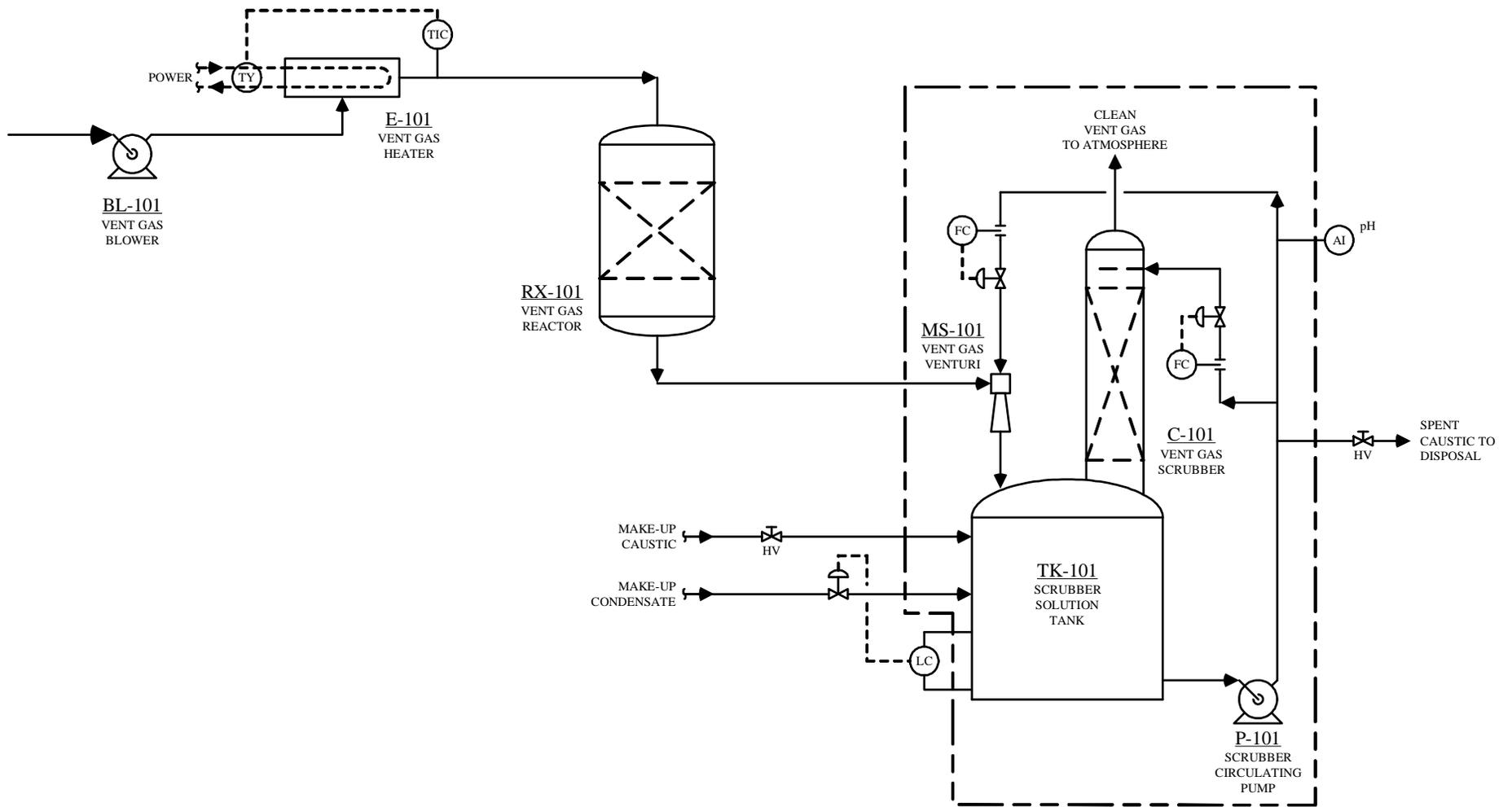


Figure 3-3, Sulphur Pit Vent Gas to Caustic Scrubber

The SO₂ stream needs to be processed and there are several configurations that could be evaluated: The source of SO₂ could be from Expansion of the FCC resulting in added sulphur from the Amine Recovery Unit (ARU) to the Sulphur Recovery Unit (SRU). Addition of a new Belco LABSORB FCC Flue Gas Scrubber with the product SO₂ routed to the SRU. Addition of a new CDTech Gasoline Desulphurizer also resulting in added sulphur to the SRU from the ARU. In order to meet the new emission regulations throughout the refinery sometimes major revamp is required. Therefore in order to meet future motor gasoline sulphur specifications it is required with the installation of a selective hydrotreating process. The Low Sulphur Gasoline project required an air permit amendment Part of the changes required in this air permit amendment is a SO_x Emission Reduction Technology Study. The studies include only the SO_x emissions from the FCC regenerator flue gas and the Sulphur Recovery Unit point sources.

There are different processes available to handle the stream from FCC prior entering the sulphur plant as follows:

Belco Technology, Labsorb

LABSORB™ process utilizes an in-organic regenerable scrubbing reagent to react with SO₂. Reagent rich in SO₂ from the scrubber is processed in a regeneration unit to strip off the captured SO₂, producing fresh reagent for scrubbing. The SO₂ removed from the reagent is discharged as concentrated/pure SO₂ (90+%) and can be sent to the front end of a CLAUS plant (or sulphuric acid plant) for recovery. Solids are removed from the flue gas in a pre-scrubbing section and de-watered in a system similar to what is used in the purge treatment unit of our caustic soda based FCCU scrubbing system. LABSORB™ provides the same continued uninterrupted operation in excess of 5 years as our caustic soda based FCCU scrubbing systems. Caustic soda (NaOH) and phosphoric acid (H₃PO₄) are used for the buffer and small additions are required to make up for small buffer losses. Low-pressure steam is used for buffer regeneration in single or double effects evaporation loop. General process discussions and more information on EDV and LABSORB are contained in the enclosed paper.

The LABSORB™ process produces a minimum amount of waste for disposal, while recovered SO₂ can be converted to saleable products such as elemental sulphur, sulphuric acid or liquid SO₂. This system can be adapted to many processes, including fossil fuel fired boilers, CLAUS Tail Gas Treatment, FCCU, Non Ferrous Smelters, Sulphuric Acid Plants, and other SO₂ emitting facilities.

Cansolv

Cansolv Technologies Inc. has performed a budget level cost estimate for a CANSOLV® SO₂ Scrubbing System in order to recover high purity SO₂ gas from a FCCU

The main part of the Cansolv process consists of a structured packing absorption tower and a regeneration tower, also containing structured packing, equipped with a reboiler and an overhead condenser. Associated peripheral equipment consists of process pumps, heat exchangers, and a process particulate filter. The unit also includes an electro dialysis solvent purification unit.

The gas is contacted counter currently in the absorption tower, where the Cansolv® solvent absorbs the sulphur dioxide, reducing the effluent gas down to the design SO₂ concentration. The rich amine accumulates in the absorption sump. A constant stream of the Cansolv® solvent is withdrawn from the rich amine sump to be regenerated in the stripping tower. Once regenerated, the solvent is re-circulated to the absorption tower to pick up additional sulphur dioxide. A counter current absorption system would result in SO₂ emissions of less than 25 ppmv(dry gas basis) has been assumed for this estimate. Emissions as low as 10 ppmv can be achieved.

The CANSOLV® SO₂ Scrubbing System is very similar to the well-known amine treater process for removal of H₂S and CO₂ from refinery streams and natural gas. The CANSOLV® process employs similar engineering methods, equipment selection and process control. Materials of construction are adjusted to handle the lower pH values resulting from the higher acidity of SO₂ compared to H₂S and CO₂.

Stronger acids such as sulphuric and hydrochloric are not released in the regeneration column, ensuring that the product SO₂ is of high purity.

Thiosolv or Similar Processes for Making Ammonium Sulfate

The SO₂ stream from Belco or Cansolv could be processed in the sulphur plant. Thiosolv is a different technology which requires ammonia stream to make ammonium sulfate if there is market to sell that directly, then sulphur plant is not required to burn the ammonia.

SO₂ Stream to the Sulphur Plant

The following steps should be taken for the SO₂ stream

- a. Identification of the optimal tie-in point for the new SO₂-rich stream
- b. The control strategy for the new SO₂ stream.
- c. Revised Heat & Material Balances for the SRU and Tail Gas Treating (TGT) units
- d. Identification of any equipment that may need replacement or upgrading as a result of the changes.
- e. A cost estimate for any required changes in equipment, piping, controls etc.
- f. Hydraulic evaluation at the new conditions

SO₂ Feed Optimization

The location of SO₂ stream to the sulphur plant needs to be optimized for the following reasons.

- Avoid reduction of the reaction furnace temperature
- Prevent water condensation and corrosion
- Provide a proper insulation
- Air demand consideration
- Provide a proper angle tee for mixing
- Provide purge connection
- Prevent localized cold spot in the condenser
- Choose the optimized location

The SO₂ recycle lines tee into the process gas between the waste boiler and the first condenser. The tie-in is a tee connection without any injection nozzle/quill. The SO₂ recycle itself consists of any SO₂ and water and is recycled at a temperature between 75°F and 90°F. Moreover, there is not any insulation or heat tracing on the line. All of these circumstances, taken together, lead to the strong possibility of both water condensation in the line plus a relatively low-temperature stream in the feed to the first condenser, without any assurance of good mixing with the hot gas leaving the waste heat boiler. This could easily result in localized cold spots in the condenser and condensation of sulphuric acid or one of its salts, which may be a cause of some of the corrosion experienced in the first condenser. The single most important recommendation for handling this SO₂ stream is that the recycle line be heat traced and insulated to prevent any additional cooling of the stream and condensation of water. In addition, the tie-in should have some type of injection nozzle to ensure good mixing with the process gas. One refinery had similar problems with corrosion in the first condenser until they installed a simple injection nozzle, which appears to have reduced or eliminated corrosion in the first condenser. It is also possible to change the location of the SO₂ recycle injection point. It may be preferable to inject the SO₂ recycle stream into the second chamber of the reaction furnace. This change in recycle location does not affect the overall sulphur recovery but it does shift the major sulphur condensation load from the second condenser to the first condenser. It does have the benefit operationally of catching more sulphur upstream of the catalyst beds, which might be fouled. Regardless of where the SO₂ stream is injected, the recycle line should be heat traced and insulated. If it is injected into the second chamber of the reaction furnace, it will have to be tied into the amine acid gas line to the second chamber. It is very important to locate this tie-in as close to the reaction furnace as possible. In addition, both lines amine acid gas and SO₂ recycle must be purged when there is no flow through these lines.



The Wellman Lord tail gas process generated the SO₂ stream, which recycled to the sulphur plant. In some refinery this stream is injected to the reaction furnace tie-in with the reaction furnace bypass.

In addition to above, the SO₂ recycle has the impact on the reaction furnace temperature, which lowers the combustion temperature, and reduce the air demand. The proper instrumentation could be provided to measure the SO₂ stream with conjunction to air demand, so the proper air demand to the sulphur plant to be calculated. In some refinery no control system related to air demand is provided, and it allows the tail gas analyzer to adjust that. A typical sketch of control system configuration is provided at the end of this section.

The SO₂ laden gas is added at the inlet of the first condenser. Simulations show that this gas should not be introduced at the front end of the External Combustion Chamber to avoid lowering the temperature, thus maximizing the destruction of ammonia. One must remember that the Claus Reaction is endothermic at the high furnace temperatures. Ammonia destruction requires high temperatures to be able to dissociate the molecule into N₂ and H₂ or



The reason not to add it at the rear end of the chamber is similar, to avoid lowering the chamber temperature because of the endothermic nature of the Claus reaction at high temperatures. The destruction of any hydrocarbons in the feed gas will depend on temperature, in addition to residence time.

This stream will provide additional reactant for the Claus reaction to take place in the catalytic converters. Thus, the air requirement for the plant is affected by the quantity of this stream, and although the plant of sulphur, compressor air has not being affected by much.

The modifications will still allow the refinery to operate such that the lead SRU will process all of the SWS acid gas, Belco acid gas, and some of the ARU acid gas.

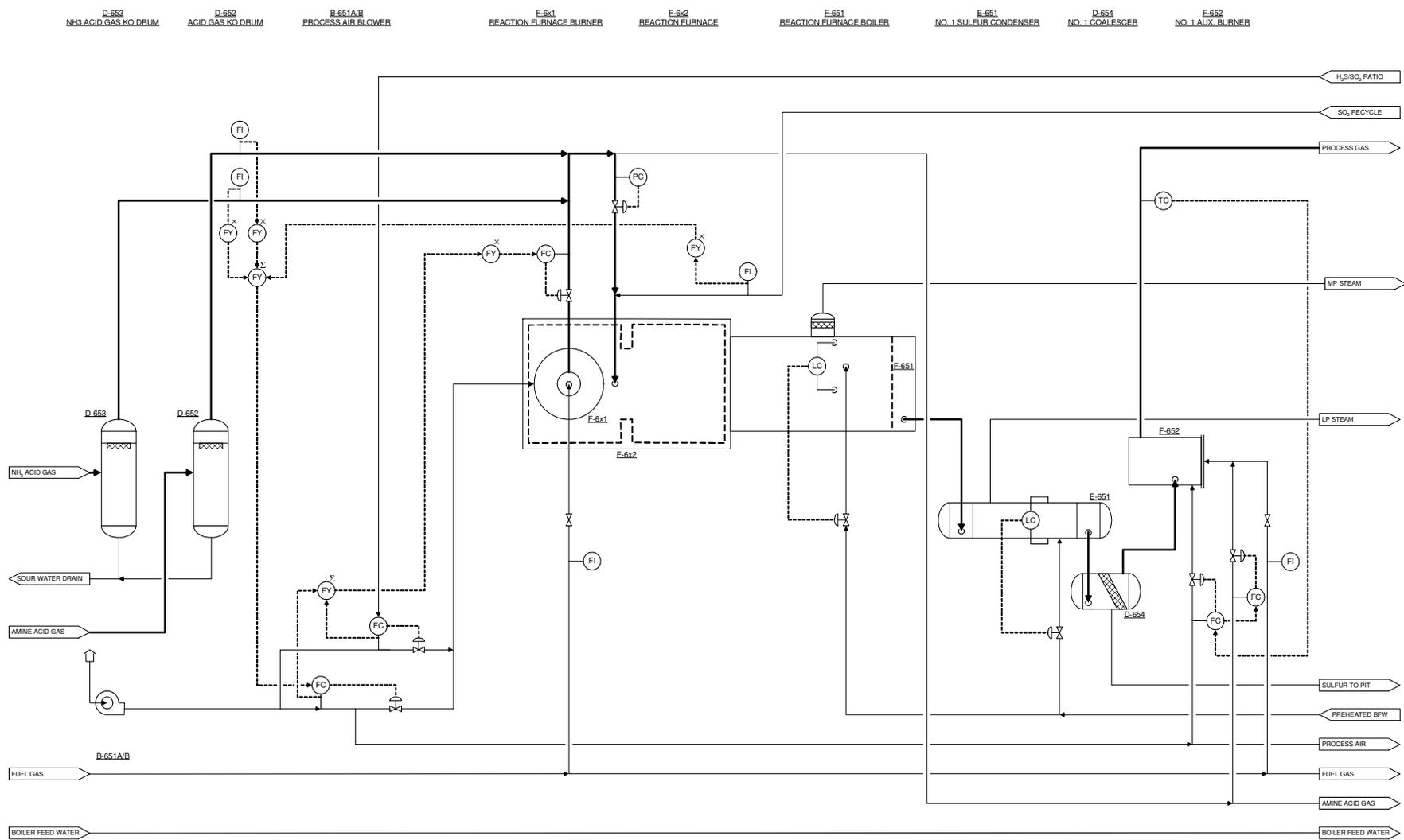


Figure 4-1, SO₂ Recycle to Reaction Furnace

