Eliminating H$_2$S & SO$_2$ Emissions at SRU, Coker and Other Sulfur Handling Units of Refineries
Eliminating H₂S & SO₂ Emissions at SRU, Coker and Other Sulfur Handling Units of Refineries

Agenda

• What are H₂S & SO₂?
• What is driving change?
• How are H₂S & SO₂ removed?
• Case Studies
• Challenges to Sulfur Removal
• Benefits of Sulfur Removal

1. DCU Compressor De-Inventory
2. Full DCU De-Inventory
3. SRU Incinerator Maintenance
4. Hydrotreater De-Inventory
What are $\text{H}_2\text{S} \ & \ \text{SO}_2$?

Both occur naturally and emerge from refining processes of sour crude.

**Hydrogen Sulfide (H$_2$S) - OSHA**

- Colorless, flammable, and extremely hazardous gas
- Heavier than air – collects in low laying areas
- Smell detection at 0.5 ppb ("rotten egg")
- Possibly deadly at concentrations $\geq 500$ ppm

**Sulfur Dioxide (SO$_2$)**

- $\text{H}_2\text{S}$ and Oxygen burn to form $\text{SO}_2$ and water
- Per the EPA, $\text{SO}_2$ and other oxides contribute to acid rain
- Affects both, health and the environment
What is driving the change?

The Federal Environmental Protection Agency (EPA) and state enforcement agencies have placed more stringent regulations that directly impact flare operations. Translates into significant operational downtime and unplanned interruptions leading to additional costs and loss of production at refineries (i.e. thermal destruction devices).
How are $\text{H}_2\text{S}$ & $\text{SO}_2$ removed?

Commonly through one or several of the following methods:

**Thermal Treatment**
- Creates Sulfur Oxides ($\text{SO}_x$)

**Specialized Activated Carbon**
- Requires offsite waste disposal

**Liquid Scrubbing**
- Requires proper handling and disposal

**Amine Treating**
- Capital extensive and typically only used as a process
Liquid Scrubbing Technology

**Liquid Scrubbing:**

- Liquid caustic (NaOH)
  - \( \text{H}_2\text{S} + \text{NaOH} = \text{Na}_2\text{S} + \text{H}_2\text{O} \)
- Specialty chemistries (scavengers)
Case Studies from Refineries
Gulf Coast Refinery challenged with the complete de-inventory of their DCU
- Restrictions on flare SO$_2$ emissions caused very slow purge of operating components

Project Goals
- Reduce the H$_2$S concentration from vapors being routed to the flare header
  - Max expected H$_2$S levels at 18% or 180,000 ppm
- Implement a liquid scrubbing system to meet the specified targets
  - Max H$_2$S: 160 ppm. Operate at flow rates as high as 2,000 cfm
  - ASME coded vessels required (MAWP > 50 psig)
- Reduce the historical downtime associated with the de-inventory process
- Reduce exposure and increase safety for all personnel
Solution

- Dual – 90” liquid scrubbers arranged in “series”
  - ASME coded (rated to 75 psig)
- Reverse manifold to bypass flare line into scrubber system. Treated gas back to flare line
  - Single scrubber operation or lead/lag conf.
- 1,000 gallons specialty chemistry in each
  - H$_2$S loading capacity = 1,700 lbs
  - Max expected = 1,150 lbs (50% safety factor)
- Perimeter H$_2$S monitoring system
# 1 – Delayed Coker Unit (DCU) De-Inventory

**System Layout**

- Inlet at top of flare drum and tied back into flare line
- VOCs pass through to flare
Eliminating $\text{H}_2\text{S}$ & $\text{SO}_2$ Emissions at SRU, Coker and Other Sulfur Handling Units of Refineries

### Results and Achievements

Significant time reduction, 30 days, as the dual scrubbers were in operation for approx. 62.5 hrs

- **VaporLock™ system provided 99.76% removal of $\text{H}_2\text{S}$ (5 gas meter & drager tube samples)**
- Due to safety hazards of $\text{H}_2\text{S}$ exposure, inlet concentrations were “calculated”
- Analysis of the spent scavenger demonstrated effective removal of $\text{H}_2\text{S}$ and mercaptans
  - Calculated (lbs) emitted to flare line was only **0.56 lbs**

### Diagram: DCU Sulfur Removal Performance

- **Mercaptans Removed:** 1938 lbs
- **$\text{H}_2\text{S}$ Removed:** 893 lbs
- **Sulfur to Flare:** 0.56 lbs

POUNDS OF CONTAMINANT
South Louisiana Refinery challenged by controlling H$_2$S and SO$_2$ emissions while keeping their Sulfur Recovery Unit (SRU) in operation

**Project Goals**

- Implement a liquid scrubbing system to meet the specified objectives
  - Pull vacuum on the sulfur pit
  - Remove H$_2$S and SO$_2$ vapors
    - H$_2$S concentration ranging between 500 and 100,000 ppm
  - Temp $>$ 300 deg F due to use of steam eductor
    - Exhaust flow rate = 180 CFM
- Allow workers in the area to work without fresh air system
- Reduce exposure and increase safety for all personnel
- Estimated project duration: 45 days
# 2 – SRU Incinerator Maintenance

## Solution

- Two (2) Water Quench Tanks arranged in parallel with vacuum venturi on each
  - Removes sulfur dust and reduce temperature
- Three (3) x 48” ASME coded Liquid Scrubber Vessels (2 used in series, 1 backup)
  - Each unit can be operated and isolated independently

![Diagram of SRU Incinerator Maintenance System]

*Ability to isolate each of the VaporLocks for chemical changeout*
Results and Achievements

• System operated for 39 days
• No safety incidents or accidents
  ▪ Elevated temperatures
  ▪ Elevated $\text{H}_2\text{S}$ concentrations
• No detectable $\text{H}_2\text{S}$ or $\text{SO}_2$ was recorded
  ▪ Continuous monitoring provided by a 3rd party
• No facility downtime caused by the treatment process
# 3 – HydroTreater De-Inventory

- A South Louisiana Refinery to perform turnaround on their HydroTreater Unit and expected to generate over 630 lbs of H₂S during a 5 day period
- Wide range of H₂S concentrations and flow rates during different phases of unit cleaning

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<thead>
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<th>Stage 1</th>
<th>Stage 2</th>
<th>Stage 3</th>
<th>Stage 4</th>
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<tr>
<td>Avg. H₂S Conc.</td>
<td>989</td>
<td>431</td>
<td>388</td>
<td>410</td>
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<td>(ppm)</td>
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<td>Max H₂S Conc.</td>
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<td>5226</td>
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<td>Max Air Flow</td>
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<td>173</td>
<td>164</td>
<td>153</td>
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<tr>
<td>(MSCFH)</td>
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</table>
Solution

- Implement a temporary proprietary caustic treatment system
- Two (2) x 200 bbls, 125 psi VaporLock™ scrubbers
  - Vapor / Chemical interaction
  - One for backup
- Two (2) Electric Driven Vacuum Pumps rated for 4000 CFM each
  - Heat exchangers
  - Liquid knockout drums
- Diaphragm pumps and storage tanks
- Resulting sweet gas is then routed to the client’s flare system
# 3 – HydroTreater De-Inventory

**Achievements**

- System resulted in the reduction of outage time by up to 20 Days
- Managed H$_2$S outlet conditions to ensure plant complied with Ja limitations
Challenges to Sulfur Removal

- Operating conditions of the refining units
  - Liquid carryover, high temperatures, high pressures
- Personnel Safety
  - High exposure risks to toxic / harmful effluents
  - Breathing air requirements
- Chemical Hazards
  - Special PPE when loading scavenger chemistries
- \( \text{H}_2\text{S} \) Monitoring
  - Handled electronic meters typically range from 0 to 200 ppm
  - Drager / Sendidyne tubes have ranges of effectiveness
Benefits of Sulfur Removal

- Safer working conditions
  - Decrease in breathing air requirements

- Reduced downtime during turnarounds

- Minimized SO\(_x\) Production

- Reduced corrosion potential in flare lines and other system components

- Commercial and marketing opportunities for cleaner fuels

- Compliance with newer and more stringent regulations
Thank you for your time & interest.

Questions?