REDUCING SULFUR DIOXIDE EMISSIONS DOWNSTREAM OF AMINE UNITS WITH DRY SORBENT INJECTION

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International Petroleum Environmental Conference
San Antonio, Texas

Oct. 30 – Nov. 1, 2017
Presentation Overview

- Company Overview
- Why the Need for this Technology?
- Using DSI for SO$_2$ Removal - System Overview
- Summary
UCC is a 97 year old global firm specializing in engineered material handling solutions for power and industrial customers.

Dry Sorbent Injection (DSI) Experience for Air Pollution Control

- Over 100 full-scale DSI tests and temporary systems
- Almost 100 large, permanent systems total
- Approximately one-half of the DSI systems used for SO₂ reduction
Spartan Energy Overview

- Spartan Energy is a provider of natural gas treating and processing equipment and services globally
- Spartan provides turnkey installation, commissioning, operations and maintenance services

<table>
<thead>
<tr>
<th>Equipment</th>
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</thead>
<tbody>
<tr>
<td>Amine Plants and Facilities</td>
<td>Dehydration Units</td>
</tr>
<tr>
<td>Mechanical Refrigeration Units</td>
<td>Cooling Units</td>
</tr>
<tr>
<td>Condensate Stabilizers</td>
<td>JT Units</td>
</tr>
<tr>
<td>Natural Gas Compression</td>
<td>Natural Gas Gensets</td>
</tr>
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</table>
WHY THE NEED FOR THIS TECHNOLOGY?
Produced natural gas high in Hydrogen Sulfide (H\textsubscript{2}S) can create significant issues for operators.

H\textsubscript{2}S is typically removed from produced natural gas streams using two methods:
- Scavenger: a liquid or solid media that removes H\textsubscript{2}S
- Amine Treating: a regenerative solvent that removes H\textsubscript{2}S and CO\textsubscript{2}

Scavenger and Amine Treating each have their own benefits and disadvantages.

The biggest issue with amine treating of high H\textsubscript{2}S gas is the disposal of H\textsubscript{2}S rich acid gas.
Disposal of H₂S

H₂S emitted from Amine Unit Regeneration System

- Oxidation into SO₂ (Flare or Thermal Oxidizer)
- Acid Gas Injection
- Claus or Liquid Redox Process
H₂S Disposal Considerations

H₂S emitted from Amine Unit Regeneration System

- Oxidation into SO₂ (Flare or Thermal Oxidizer)
- Acid Gas Injection
- Claus or Liquid Redox Process

<table>
<thead>
<tr>
<th></th>
<th>Capital Cost</th>
<th>Operating Cost</th>
<th>Regulatory Burden</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oxidation into SO₂</td>
<td>Low</td>
<td>Low</td>
<td>Low to High</td>
</tr>
<tr>
<td>Acid Gas Injection</td>
<td>High</td>
<td>Moderate</td>
<td>Very High</td>
</tr>
<tr>
<td>Claus or Liquid Redox Process</td>
<td>Moderate to High</td>
<td>Moderate to Low</td>
<td>Moderate</td>
</tr>
</tbody>
</table>

DSI Used to Reduce Regulator Burden
Dry Sorbent Injection Overview

- Dry Sorbent Injection is a process of injecting a sorbent into a waste gas stream to remove pollutants.
- It was commercialized over the last 25 years as a way for power plants to minimize SO\textsubscript{2} and other pollutants.
- It is used extensively in power plants, waste incinerators, and other industrial processes.
- Spartan and UCC developed a modular DSI system that can be used in the oil and gas industry to reduce pollutant emissions downstream of an amine unit.
- Spartan / UCC process is Patent Pending.
UCC developed test units for power plants to demonstrate DSI at power plants

The units are modular, trailer-mounted systems that are used to feed sorbent into power plant flue gas

With additional components that Spartan and UCC developed for amine systems, the DSI system can be set up on a site in a few weeks

Using DSI, SO$_2$ pollution can be reduced by up to 90%
Production Limits at NSR Permit Threshold

Flow Rate (mmscfd) vs. H₂S PPM

- 5.0
- 10.0
- 15.0
- 20.0
- 25.0
- 30.0
- 35.0
- 40.0

- 1,000
- 2,000
- 3,000
- 4,000
- 5,000
- 6,000

250 Ton Per Year SO₂ Emissions "Limit"
Production Limits at NSR Permit Threshold

- Production limitations
- Lead time
- Cost

Flow Rate (mmscfd) vs. H₂S PPM

250 Ton Per Year SO₂ Emissions “Limit”
Production Limits at NSR
Permit Limit with DSI

Flow Rate (mmmscf/d) vs \( \text{H}_2\text{S} \) PPM

- 250 Ton Per Year (TPY) Control with DSI
- 85% Control

250 Ton Per Year SO\(_2\) Emissions "Limit"
Selection of a Sulfur Removal Process requires evaluation of several variables:

- Concentration of $\text{H}_2\text{S}$ in produced gas
- Concentration of $\text{CO}_2$ in produced gas
- Total gas flow and production curve
- Anticipated life of production facilities and future drilling plans
- Availability of existing infrastructure for treatment and disposal of $\text{H}_2\text{S}$
- Operational/Complexity considerations
## Traditional Sulfur Removal and Disposal

<table>
<thead>
<tr>
<th>Solution</th>
<th>Scavenger</th>
<th>Liquid Redox</th>
<th>Sulfur Recovery Unit</th>
<th>Acid Gas Injection</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Summary</strong></td>
<td>Liquid or Solid media used to remove H₂S from process gas</td>
<td>Removal of H₂S using a reduction/oxidation reaction using a catalyst</td>
<td>Recovers H₂S as elemental sulfur through the Claus Reaction</td>
<td>Injection of H₂S and other acid gases into a non-producing formation to prevent emission into atmosphere</td>
</tr>
</tbody>
</table>

**DSI**

Sorbent injection to remove SO₂ from an acid gas stream
<table>
<thead>
<tr>
<th>Solution</th>
<th>Scavenger</th>
<th>DSI</th>
<th>Liquid Redox</th>
<th>Sulfur Recovery Unit</th>
<th>Acid Gas Injection</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sulfur Removal “Sweet Spot”</strong></td>
<td>&lt;0.5 TPD</td>
<td>0.3-2 TPD</td>
<td>&lt;15 TPD</td>
<td>&gt;10 TPD</td>
<td>High Volumes</td>
</tr>
<tr>
<td><strong>High H2S in gas</strong></td>
<td>❌</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
</tr>
<tr>
<td><strong>Removal of CO2</strong></td>
<td>Amine Required</td>
<td>Amine Required</td>
<td>Amine Required</td>
<td>Amine Required</td>
<td>Amine Required</td>
</tr>
<tr>
<td><strong>Anticipated Life of Production</strong></td>
<td>Short-Long Term</td>
<td>Short-Medium Term</td>
<td>Long Term</td>
<td>Long Term</td>
<td>Long Term</td>
</tr>
<tr>
<td><strong>Availability of Existing Infrastructure</strong></td>
<td>Limited Infrastructure Needed</td>
<td>Temporary Equipment</td>
<td>New Facility</td>
<td>New Facility</td>
<td>Great if Available</td>
</tr>
<tr>
<td><strong>Operational Complexity</strong></td>
<td>Minimal Complexity</td>
<td>Minimal Complexity</td>
<td>Moderate Complexity</td>
<td>High Complexity</td>
<td>High Complexity</td>
</tr>
<tr>
<td><strong>Cost Considerations</strong></td>
<td>Low Capital /High Variable</td>
<td>Low Capital/Moderate Variable</td>
<td>Moderate Capital / Low Variable</td>
<td>High Capital / Low Variable</td>
<td>High Capital / Low Variable</td>
</tr>
</tbody>
</table>
USING DSI FOR SO$_2$ REMOVAL
SO₂ Removal – Sorbent Choice

**Trona**
- Use when:
  - Moderate SO₂ removal needed (approx. 80% or less)
  - Must be milled
  - Optimum temperature is 275F to 1000F

**Sodium Bicarbonate**
- Use when:
  - High removals needed (> 80%)
  - Want to minimize waste loading
  - Optimum temperature is 275°F to 650°F

**Hydrated Lime**
- Use when:
  - Lower removals needed (<60%)
  - Optimum temperature is 600 to 1100°F
  - Highest usage/waste generation
SO₂ Removal – Sorbent Comparison

Relative Sorbent Usage vs. % Removal

% SO₂ Removal

SBC  Trona  Hydrated Lime
SYSTEM OVERVIEW
Dry Sorbent Injection System (DSI)
Stage 2
Semi-Mobile System, Sorbent Storage Silo

- 50 ton capacity (2000 ft³)
Greatest opportunity for increased performance is to reduce particle size

- Increased surface area for reaction
- Increased number of particles/collisions
- Increased dispersion
VIPER® Mill

Unmilled Trona
25-40 µm

Milled Trona
12-15 µm

Unmilled SBC
150-180 µm

Milled SBC
15-19 µm
Splitters/Lances

- Splitter design critical for performance and reliability (auto purge system shown)
- Lances designed for optimum dispersion (COBRA™ Lances shown)
Filter Separator and Waste Handling

- Collects spent sorbent
- Byproduct directed into two “dumpsters” using screw feeders
- Byproduct disposal is non-hazardous
Installation - Silo Preparation
Installation - Silo Set Up
SUMMARY
Factors to consider when choosing sulfur removal technology:

- CO₂ and H₂S amount in gas
- Gas flow and anticipated life of production facilities
- Existing infrastructure and operational/complexity considerations

Reducing SO₂ emissions downstream of amine units with DSI

- Economical solution for applications ranging from 500-4000 lbs/day of sulfur, particularly when amine treating is also required.
- Mobile equipment allows for quick set-up and operation
- Enables higher gas production while maintaining permit limits
- Dry system – eliminates water and wastewater concerns
- Proven equipment
Questions?
For More Information

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