Sulfur Area Materials of Construction

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Objectives

1. To facilitate an open discussion of common corrosion issues encountered in the industry today.

2. To improve understanding of the causes of corrosion and means to mitigate corrosion.

3. To capture – to the greatest extent possible – typical industry practice currently used in the design and construction of sulfur processing facilities.

4. Your active participation is vital to achieving these objectives.

Our goal is to provide the facility engineer with enough knowledge to oversee the design process and to alert operating personnel to practices and procedures which will maximize the life of sulfur processing facilities.
Agenda

1. Review of corrosion mechanisms and corrosive environments which are common in sulfur processing facilities
2. Review of common materials of construction
3. Group discussion of corrosion “hotspots” identified by questionnaire responses

...all subject to the constraints of our allotted time!
An Unusual Example of Erosion

Schedule 160 hydrogen pipe.
An Unusual Example of Erosion

Stainless steel bolt and nut which attached an instrument to a support stand.

Vibration from a reciprocating compressor caused the pipe to repeatedly strike the bolt and nut.
Corrosion Mechanisms
Sulfide Corrosion

- Hydrogen sulfide attacks carbon steel to form iron sulfide.
- Corrosion of carbon steels by sulfides (including H$_2$S) in a hydrogen-free environment was studied by McConomy in 1963.
- Corrosion of carbon steels by H$_2$S in a hydrogen environment was studied by Sharp and Haycock in 1959.
  - At temperatures below 650 °F and H$_2$S partial pressures below 10 psi, the corrosion rate is less than 50 mils/year
  - However, the resulting sulfide scale is fairly impervious and resists further corrosion
Corrosion/Erosion

- Hydrogen sulfide will corrode carbon steel to form an iron sulfide layer on the surface of the steel.
- If undisturbed, this iron sulfide layer prevents further corrosion.
- However, if the layer is disrupted mechanically, the underlying carbon steel is again exposed to corrosion. This can lead to very rapid corrosion rates.
- The iron sulfide layer is not mechanically strong and can be disrupted:
  - Mechanically, for example, by high liquid velocities and/or turbulence in amine systems.
  - Thermally, for example, by temperature cycles in sub-dewpoint Claus units leading to spalling of the sulfide scale.
Stress Corrosion Cracking

Stress Corrosion Cracking is a cracking process resulting from *both*:

- Action of a corrodent, and
- Sustained tensile stress, either the result of applied stress (e.g. internal pressure) or residual stress from manufacturing.

Potential corrodes of interest include:

- Amines
- Chlorides
- Hydrogen sulfide

High stress areas are most susceptible to cracking.

Steels with higher yield strengths are more susceptible to cracking.
Alkaline Stress Corrosion Cracking

Alkaline SCC can be caused by amines, caustic, ammonia, etc.

- Carbon steels are susceptible to alkaline SCC.
- High temperatures increase the likelihood of cracking.
- Stronger bases increase the likelihood of cracking.
Another form of SCC is Chloride Stress Corrosion Cracking:

- Cracking of Austenitic stainless steels in the presence of chlorides
- Temperatures above 160°F increase likelihood of cracking
- Cracking can occur with very low chloride levels (~50 ppmw)
- Low pH increases risk

Chloride stress corrosion cracking (SCC) on the cooling water side of a 316L stainless steel exchanger tube. The cooling water contained approximately 400 ppm chlorides had been blocked in with the 350°F shellside process still flowing. The black stringers are sulfide inclusions. 100X
Sulfide Stress Cracking

By far, the most common form of SCC in sour environments.

- Occurs in the presence of a liquid water phase and hydrogen sulfide
- Reaction of H$_2$S with iron at the surface of the steel:
  \[ \text{Fe} + \text{H}_2\text{S} \rightarrow \text{FeS} + 2\cdot\text{H}^0 \]
- The hydrogen atoms are free to dissolve into the steel, leading to embrittlement and possible cracking.
Hydrogen Induced Cracking / Hydrogen Stress Cracking

Unlike SCC, Hydrogen Induced Cracking can occur in low stress areas.

- HIC affects only carbon steel plate; castings and forgings are not affected.
- Atomic hydrogen diffuses into the steel and accumulates at trap points by recombining into molecular hydrogen.
- Trap sites are commonly found in steels with (a) high impurity levels, or (b) a high density of planar inclusions, or (c) regions of anomalous microstructure.

Closely related is Hydrogen Stress Cracking:

- Caused by embrittlement of metal by diffused hydrogen in the presence of applied stress and galvanic coupling to another metal that is corroding as an anode.
Ammonium Bisulfide Corrosion

- When significant amounts of ammonia are present in the water phase (for example, in a refinery sour water stripper) the pH increases, increasing the solubility of H$_2$S and the concentration of the bisulfide ion.

- The combination of high pH and high ammonium bisulfide concentration leads to a high hydrogen flux rate $\Rightarrow$ high corrosion rates

- This is exacerbated by the presence of cyanides – cyanides poison the surface reaction that leads to formation of a stable iron sulfide protective coating
Materials of Construction
Carbon Steel

- Contains 0.10% – 0.31% maximum C and 0.85% – 1.2% Mn.

Carbon steel may be:

- *Annealed* by heating above the Austenite transition temperature followed by controlled cooling in the furnace to produce a softer, uniform steel;

- *Normalized* by heating above the transition temperature followed by air cooling to reduce internal stresses;

- *Killed* (or deoxidized) by addition of aluminum or other oxygen scavenger. SA-516 grades of carbon steel plate are killed; A-106 grade B carbon steel pipe is killed.

The fabricated equipment may be:

- *Post-weld heat treated* (or stress relieved) to eliminate residual stresses from fabrication.
Austenitic Stainless Steel

• Addition of chrome and nickel to carbon steel prevents the phase transformation from Austenite to ferrite / cementite on cooling.

• Generally requires about 18% chrome and 8% (and higher) nickel (the chrome content allows lower nickel content)

• Not susceptible to hydrogen cracking

• Welding stainless steel can lead to *sensitization* – where carbon is concentrated in the HAZ and can form Chromium carbide – leading to decrease corrosion resistance. The “L” grades of stainless steel have lower carbon content and are not easily sensitized.

• Very susceptible to chloride stress cracking
  - Significant increases in nickel content or addition of molybdenum reduces susceptibility to chloride cracking (e.g. 316 SS contains 11% - 14% nickel and 2% molybdenum
NACE MR0175 / ISO 15156-1

- First issued in 1975. Latest revision is dated 2009.
- Addresses all cracking mechanisms caused by H₂S including:
  - Sulfide stress cracking (SSC)
  - Stress corrosion cracking (SCC)
  - Hydrogen induced cracking (HIC)
  - Stress oriented hydrogen induced cracking (SOHIC)
  - Soft zone cracking (SZC)
  - Galvanically induced hydrogen stress cracking
- Applies to H₂S-containing environments in oil and gas production and natural gas sweetening plants.
- “Not necessarily applicable” to refining or downstream processes and equipment.
- Part 2 specifies requirements for both carbon or low-alloy steels; part 3 specifies requirements for corrosion resistant alloys (CRAs)
100 kPa ≈ 15 psia
Region 0 (pale green):

- No precautions are required; however, very high-strength steels (>140,000 psi) can crack in H₂S-free aqueous environments.

Region 3 (pale red):

- Carbon or low alloy steels must meet the requirements of A.2.

Region 2 (yellow):

- Carbon or low alloy steels must meet the requirements of A.3.

Region 1 (pale yellow):

- Carbon or low alloy steels must meet the requirements of A.4.

Note: Complying with the above does not necessarily provide protection against HIC, SOHIC, or SZC.
NACE MR0103

- Establishes material requirements for resistance to sulfide stress cracking in sour petroleum refining environments containing \( \text{H}_2\text{S} \) as a gas or dissolved in an aqueous phase, with or without the presence of hydrocarbon.

Differences between MR0103 and MR0175:

- Recognizes the impact caused by the presence of ammonia and cyanide in sour environments
- *Does not* address chloride stress cracking (a key difference from MR0175) because chloride concentrations tend to be lower in refineries.
- Recognizes that \( \text{CO}_2 \), which tends to be lower in concentration in refineries, results in lower pH and mitigates hydrogen production and therefore cracking potential.
Sour refinery environments consist of any of the following:

- More than 50 ppmw H$_2$S in the aqueous phase, OR
- An aqueous phase pH less than 4 and some H$_2$S present, OR
- An aqueous phase pH greater than 7.6 and more than 20 ppmw HCN concentration and some H$_2$S present, OR
- A gas phase H$_2$S partial pressure greater than 0.0003 MPa (0.05 psia) associated with an aqueous phase.
Questions and Comments from the Survey
Survey

1. Quench loop corrosion in piping such that we cannot make 5 year run. What metallurgy is typical on piping? PWHT? What design is used for caustic injection (or other chemistry)? What limits of operation (high/low pH) are used? What design is used for mix point of caustic/process?

Background:

We are experiencing accelerated corrosion here due to SO₂ breakthrough and lack of hydrogen. We don’t add hydrogen (typically) because of excess hydrocarbons in our hydrogen. Can’t achieve >2% H₂ at this point. Solution is to supply purchased (clean) H₂ to the unit.
Survey

2. TGU MDEA reboiler inlet. Regenerator is SS clad with SS internals; reboiler inlet piping is CS. After huge SO$_2$ breakthrough (not followed immediately by H$_2$S-containing gas) lost half the wall thickness in days.
Survey

3. Mixed metal exchanger bundles – Several locations purchased L/R exchanger bundles with SS tubes and CS tie rods, baffles, etc. We found several “cut” tubes or severely corroded tubes in proximity to where SS tubes contacted CS parts.
Survey

4. Pitting on last sulfur condenser tubes (process side). Not a lot of details. We suspect some type of ammonia corrosion but mechanism unknown.
Survey

5. Several locations have problems with acid gas reheater burner corrosion. Most of them were due to carburization.
Survey

6. Areas of most corrosion are in CS quench columns in amine-based tail gas units. This is from $\text{SO}_2$ breakthrough. Any new insights would be great.
Survey

7. We had nozzles on our sulfur converters fail in about 18 months. The nozzles were not insulated.
8. Thru-wall corrosion most prevalent in regions of low temperature such as piping to incinerator and sub-dewpoint units. Has also occurred in hotter zones like 1st condenser outlet piping. How best to repair without taking the unit down?
9. Very severe corrosion of condenser tubes in the 1st condenser following an unexpected shutdown where no heat soak was performed.
Survey

10. Corrosion in sulfur pits: (a) sulfur pit pumps, (b) sulfur pit steam coils, (c) sulfur pit concrete walls and support steel.
Survey

11. Note that while it is well and good to discuss proper design and selection of materials, many of us have to live with what we have. Please discuss how to prevent or fix leaks in existing systems.
12. Waste heat boiler tube to tubesheet joint issues with corrosion of tube ends and loss of joint integrity:

One company uses alonized tubes welded to the back side of the front tube sheet. Tubesheet has 1/8” stainless cladding and tube holes in tubesheet have a SS insert. 18 years of trouble-free operation at 500 psi.
Survey

13. As SRU throughput increased over time, spot IR surveys showed WHB outlet line temperature increased to above 700 F. Had high corrosion rates on piping from WHB to 1st Condenser, in the 1st Condenser inlet channel and tube inlets. At shutdown, refractory lined the pipe and inlet channel and installed ceramic ferrules in condenser tube inlets.
Specific Applications – Claus Sulfur Recovery
Amine Acid Gas Piping

Process Conditions and Corrosion Mechanisms
- 100 – 120 °F and 20 – 25 psia
- H₂S, CO₂, trace NH₃, H₂O (V+L)
- Sulfide stress cracking, HIC (welded piping)

Corrosion Mitigation Strategies
- Use carbon steel with hardness control to avoid cracking
- No pockets to prevent liquid accumulation; consider tracing

Typical Industry Practice
- Design 300 °F and 50 psig (or match upstream equipment)
- A-106 Gr. B, 0.125” – 0.25” CA, NACE applies
SWS Acid Gas Piping

Process Conditions and Corrosion Mechanisms

- 180 – 200 °F and 20 – 25 psia
- H₂S, NH₃, H₂O (V+L), trace cyanide and phenols
- Sulfide stress cracking, HIC (welded piping)

Corrosion Mitigation Strategies

- Use carbon steel with hardness control to avoid cracking
- No liquid pockets; heat trace to prevent solids formation

Typical Industry Practice

- Design 300 °F and 50 psig (or match upstream equipment)
- A-106 Gr. B, 0.125” – 0.25” CA, NACE applies
Acid Gas Knockout Drums

Process Conditions and Corrosion Mechanisms
- 100 – 120 °F and 20 – 25 psia
- H₂S, CO₂, trace NH₃, H₂O (V+L)
- Sulfide stress cracking, susceptible to HIC

Corrosion Mitigation Strategies
- Use carbon steel with hardness control to avoid cracking
- 304L SS cladding optional; consider heat tracing

Typical Industry Practice
- Design 300 °F and 50 psig (or match upstream equipment)
- SA-516-70, 0.125” – 0.25” CA, NACE applies
SWS Knockout Drums

Process Conditions and Corrosion Mechanisms

- 200 °F and 25 – 30 psia
- H₂S, CO₂, trace NH₃, H₂O (V+L)
- Sulfide stress cracking, susceptible to HIC

Corrosion Mitigation Strategies

- Use carbon steel with hardness control to avoid cracking
- 304L SS cladding optional, heat trace to prevent solids

Typical Industry Practice

- Design 350 °F and 150 psig (or match upstream equipment)
- SA-516-70, 0.125” CA, HIC, NACE applies
Process Conditions and Corrosion Mechanisms

- Up to 2750 °F and 15 – 25 psia
- H₂S, CO₂, SO₂, NH₃, COS, CS₂, H₂O(V), elemental sulfur, reducing
- Sulfide corrosion (>650 °F); low temperature acid attack

Corrosion Mitigation Strategies

- Use CS and keep the shell temperature between 400 °F and 650 °F
- Internal refractory lining + external thermal shroud

Typical Industry Practice

- Design steel to 650 °F & 50 – 100 psig; refractory lined
- SA-516-70, 0.25” CA
**Claus Waste Heat Boiler (Process Side)**

### Process Conditions and Corrosion Mechanisms
- Up to 2750 °F and 15 – 25 psia
- $\text{H}_2\text{S}$, $\text{CO}_2$, $\text{SO}_2$, $\text{NH}_3$, $\text{COS}$, $\text{CS}_2$, $\text{H}_2\text{O}(\text{V})$, elemental sulfur, reducing
- Sulfide corrosion (>650 °F); low temperature acid attack

### Corrosion Mitigation Strategies
- Use CS; keep the tube / tubesheet metal temperatures below 650 °F
- Refractory line tubesheet and provide ferrules

### Typical Industry Practice
- Design steel to 650 °F and 50 – 100 psig; refractory lined as above
- Shell: SA-516-70, 0.25” CA; Tubes: SA-106 Gr. B Sch. 80
Claus Condensers (Process Side)

Process Conditions and Corrosion Mechanisms

- 350 – 650 °F and 15 – 25 psia
- \( \text{H}_2\text{S}, \text{CO}_2, \text{SO}_2, \text{NH}_3, \text{COS}, \text{CS}_2, \text{H}_2\text{O(V)}, \) elemental sulfur, reducing
- Sulfide corrosion (>650 °F); low temperature acid attack

Corrosion Mitigation Strategies

- Carbon steel construction is adequate
- Refractory line specific areas

Typical Industry Practice

- Design steel to 650 °F and 15 – 50 psig; refractory lined
- Shell: SA-516-70, 0.125” – 0.25” CA; Tubes: SA-179 0.134” wall
Claus Steam Reheaters (Process Side)

Process Conditions and Corrosion Mechanisms
- 350 – 475 °F and 15 – 25 psia
- H₂S, CO₂, SO₂, NH₃, COS, CS₂, H₂O(V), elemental sulfur, reducing
- Sulfide corrosion (>650 °F); low temperature acid attack

Corrosion Mitigation Strategies
- Carbon steel construction is adequate

Typical Industry Practice
- Design 650 °F and 15 – 50 psig
- Shell: SA-516-70, 0.25” CA; Tubes: SA-179
Claus Converters

Process Conditions and Corrosion Mechanisms

- Up to 475 – 650 °F and 15 – 25 psia
- \( \text{H}_2\text{S}, \text{CO}_2, \text{SO}_2, \text{NH}_3, \text{COS}, \text{CS}_2, \text{H}_2\text{O(V)}, \) elemental sulfur, reducing
- Sulfide corrosion (>650 °F); low temperature acid attack

Corrosion Mitigation Strategies

- Carbon steel construction is adequate
- Provide refractory lining and full external insulation

Typical Industry Practice

- Design 650 °F and 15 – 50 psig; refractory lined
- SA-516-70, 0.125” – 0.25” CA; 304 removable SS internals
Final Condenser Piping to TGU

Process Conditions and Corrosion Mechanisms
- 250 – 300°F and 15 – 16 psia
- $\text{H}_2\text{S}$, $\text{CO}_2$, $\text{SO}_2$, $\text{H}_2\text{O(}\text{V}\text{)}$, trace elemental sulfur
- Low temperature acid attack

Corrosion Mitigation Strategies
- Carbon steel construction is adequate
- Heat tracing to prevent sulfur and water condensation

Typical Industry Practice
- Design 300 – 350 °F and 15 – 50 psig with heat tracing
- A-106 Gr. B, 0.125” CA
Specific Applications – Tail Gas Treating
Direct Fired Tail Gas Heater (Process Side)

Process Conditions and Corrosion Mechanisms

- 200 – 650 °F and 15 – 20 psia
- H₂S, CO₂, SO₂, NH₃, COS, CS₂, H₂O(V+L), elemental sulfur, reducing
- Sulfide corrosion (>650 °F); low temperature acid attack

Corrosion Mitigation Strategies

- Use CS and keep the shell temperature between 400 °F and 650 °F
- Internal refractory lining + external thermal shroud

Typical Industry Practice

- 650 °F and 50 psig
- SA-516-70, 0.125” – 0.25” CA, refractory lined
Steam Heated Tail Gas Heater (Process Side)

Process Conditions and Corrosion Mechanisms

- 200 – 500 °F and 15 – 20 psia
- H₂S, CO₂, SO₂, NH₃, COS, CS₂, H₂O(V+L), elemental sulfur, reducing
- Sulfide corrosion (>650 °F); low temperature acid attack

Corrosion Mitigation Strategies

- Carbon steel construction is adequate
- Very high temperature steam (>650 °F) may require 304L SS

Typical Industry Practice

- Design 650 °F and 50 psig
- SA-516-70, 0.25” CA, NACE applies to inlet channel
TGU Reactor Inlet Piping

Process Conditions and Corrosion Mechanisms
- 450 – 550 °F and 15 – 20 psia
- H₂S, CO₂, SO₂, NH₃, COS, CS₂, H₂O(V), elemental sulfur, reducing
- Sulfide corrosion (>650 °F); low temperature acid attack

Corrosion Mitigation Strategies
- Carbon steel with refractory lining for temperature excursion
- Optional: 304L SS with no refractory (0.0625” CA)

Typical Industry Practice
- Design 650 °F and 50 psig
- A-106 Gr. B, 0.125” – 0.25” CA, refractory lined (after Fired Heater)
### TGU Reactor

<table>
<thead>
<tr>
<th>Process Conditions and Corrosion Mechanisms</th>
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</thead>
<tbody>
<tr>
<td>• 540 – 650 °F and 15 – 20 psia</td>
</tr>
<tr>
<td>• H₂S, CO₂, SO₂, NH₃, COS, CS₂, H₂O(V), elemental sulfur, reducing</td>
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<tr>
<td>• Sulfide corrosion (&gt;650 °F); low temperature acid attack</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Corrosion Mitigation Strategies</th>
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</thead>
<tbody>
<tr>
<td>• Carbon steel with refractory lining for temperature excursion</td>
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<tr>
<td>• Keep steel wall temperature between 350 – 650 °F</td>
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<table>
<thead>
<tr>
<th>Typical Industry Practice</th>
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</thead>
<tbody>
<tr>
<td>• Design 650 °F and 50 psig; refractory lined</td>
</tr>
<tr>
<td>• SA-516-70, 0.25” CA, 304 SS removable internals</td>
</tr>
</tbody>
</table>
TGU Reactor Outlet Piping

Process Conditions and Corrosion Mechanisms

- 650 °F and 15 – 20 psia
- H₂S, CO₂, NH₃, trace COS, H₂O(V)
- Sulfide corrosion (>650 °F); low temperature acid attack

Corrosion Mitigation Strategies

- Carbon steel with refractory lining for temperature excursion
- Optional 1-¼ Cr, ½ Mo without refractory (A-335), 0.125” CA

Typical Industry Practice

- Design 650 °F and 50 psig
- A-106 Gr. B, 0.125” – 0.25” CA, refractory lined
TGU Waste Heat Boiler (Process Side)

Process Conditions and Corrosion Mechanisms
- 650 °F and 15 – 20 psia
- \( \text{H}_2\text{S}, \text{CO}_2, \text{NH}_3, \text{trace COS, H}_2\text{O(V)} \)
- Sulfide corrosion (>650 °F); low temperature acid attack

Corrosion Mitigation Strategies
- Carbon steel construction is adequate
- Refractory lined inlet channel for temperature excursions

Typical Industry Practice
- Design 650 °F and 50 psig; refractory lined
- Shell: SA-516-70, 0.125” – 0.25” CA; Tubes: SA-179 0.134” wall
Quench Tower

Process Conditions and Corrosion Mechanisms

- 100 – 350 °F and 15 – 20 psia
- H₂S, CO₂, NH₃ or NaOH, trace COS, H₂O(V)
- Sulfide stress cracking, acid corrosion, HIC

Corrosion Mitigation Strategies

- CS with hardness control is adequate; 304L SS is optional
- Caustic (or ammonia) injection for pH control

Typical Industry Practice

- Design 400 °F and 50 psig
- SA-516-70 + 0.25” CA, 304 SS internals, NACE applies
Quench Water Pumps

Process Conditions and Corrosion Mechanisms
- 150 °F and 150 psia
- H₂O(L), NH₃ or NaOH, trace CO₂ and H₂S
- Sulfide stress cracking

Corrosion Mitigation Strategies
- Stainless steel construction

Typical Industry Practice
- Design 250 °F and 150 psig
- API A-8, 316SS case and impeller, NACE applies
Quench Water Piping

Process Conditions and Corrosion Mechanisms

- 100 – 175 °F and <150 psia
- H₂O(L), NH₃ or NaOH, trace CO₂ and H₂S
- Sulfide stress cracking, acid corrosion

Corrosion Mitigation Strategies

- CS with hardness control is adequate; 304L SS is optional
- Caustic (or ammonia) injection for pH control

Typical Industry Practice

- Design 250 – 350 °F and 150 psig
- A-106 Gr. B, 0.125” – 0.25” CA, NACE applies
### Quench Water Filters

**Process Conditions and Corrosion Mechanisms**
- <150 °F and <150 psia
- H₂O(L), NH₃ or NaOH, trace CO₂ and H₂S
- Sulfide stress cracking, acdi corrosion, HIC

**Corrosion Mitigation Strategies**
- Carbon steel with hardness control

**Typical Industry Practice**
- Design 250 – 350 °F and 150 psig
- SA-516-70, 0.125” – 0.25” CA, NACE applies
Quench Water Cooler, Water (Process Side) or Air-Cooled

Process Conditions and Corrosion Mechanisms
- 100 – 150 °F and 75 psia
- $\text{H}_2\text{O(L)}, \text{NH}_3$ or $\text{NaOH}$, trace $\text{CO}_2$ and $\text{H}_2\text{S}$
- Sulfide stress cracking, alkaline stress cracking, acid corrosion, HIC

Corrosion Mitigation Strategies
- Carbon steel, Austenitic (304L or 316L) Stainless Steel or more exotic
- Actual selection varies widely

Typical Industry Practice
- Design 250 °F and 150 psig
- NACE applies
## TGU Absorber

### Process Conditions and Corrosion Mechanisms
- 100 – 120 °F and 15 – 16 psia
- $\text{H}_2\text{O (V+L)}, \text{CO}_2, \text{H}_2\text{S}, \text{trace COS, and amine}$
- Amine stress corrosion cracking, HIC

### Corrosion Mitigation Strategies
- Carbon steel with hardness control; 304L SS cladding optional

### Typical Industry Practice
- 200 – 250 °F and 50 psig
- SA-516-70, 0.125” – 0.25” CA, NACE applies
TGU Absorber Overhead Piping

Process Conditions and Corrosion Mechanisms
- 100 °F and 15 – 16 psia
- H₂O (V), CO₂, trace H₂S, and trace COS
- Low temperature acid attack

Corrosion Mitigation Strategies
- No pockets
- Consider heat tracing to prevent condensation

Typical Industry Practice
- 200 – 250 °F and 50 psig
- A-106 Gr. B, 0.125” – 0.25” CA
Incinerator Chamber

Process Conditions and Corrosion Mechanisms

- 1000 – 1800 °F and 16 psia
- H₂O (V), CO₂, H₂S, SO₂, and trace elemental sulfur
- High temperature sulfide attack, low temperature acid attack

Corrosion Mitigation Strategies

- Carbon steel is adequate
- Control shell temperature with refractory lining and thermal shield

Typical Industry Practice

- Design up to 1800 °F and 50 psig
- SA-516-70, 0.125” CA
Incinerator Stack

Process Conditions and Corrosion Mechanisms
- 600 – 1200°F and atmospheric pressure
- H₂O (V), CO₂, and SO₂
- Low temperature acid attack

Corrosion Mitigation Strategies
- 304L SS (tip section)
- Refractory lined (if no Incinerator Waste Heat Boiler)

Typical Industry Practice
- 750 – 1500°F and 50 psig
- SA-516-70, 0.125” CA, 304L stainless steel tip section
Specific Applications – Sour Water Stripping
General Discussion

- Refinery sour water strippers (which must deal with ammonia) experience significantly more corrosion than gas plant sour water strippers.
- In general, gas plant sour water strippers can be constructed of carbon steel, following NACE MR0175 as appropriate and using HIC resistant plate.
- For refinery sour water strippers, follow NACE MR0103 as appropriate and use HIC resistant plate.
- API Publication 950 “Survey of Construction Materials and Corrosion in Sour Water Strippers – 1978” is a valuable resource. According to API, the addition of acid to fix ammonia in the sour water – which decreases corrosion in the overhead – is now seldom used.
- The following discussion is relevant to non-acidified sour water strippers which contain both H₂S and NH₃ (i.e. refinery applications)
Sour Water Tank

Process Conditions and Corrosion Mechanisms

- 80 – 100 °F and atmospheric pressure
- \( \text{H}_2\text{O} \text{ (L), H}_2\text{S, NH}_3, \text{trace HCN and phenols, sour liquid hydrocarbons} \)
- Sulfide stress cracking, HIC is possible

Corrosion Mitigation Strategies

- Use carbon steel with hardness control to avoid cracking

Typical Industry Practice

- Design and fabricate in accordance with API 650
- SA-516-70N, 0.125” CA, NACE MR0103 applies
### Sour Water Feed Surge Drum

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<tbody>
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<tbody>
<tr>
<td>• Design 300 °F and 50 psig</td>
</tr>
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<td>• SA-516-70N, 0.125” CA, NACE MR0103 applies</td>
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</tbody>
</table>
SWS Feed/Bottoms Exchanger – Feed Side

Process Conditions and Corrosion Mechanisms

- 100 – 220 °F and 50 – 75 psia
- H₂O (V+L), H₂S, NH₃, phenols
- Sulfide stress cracking, HIC

Corrosion Mitigation Strategies

- Cold shells: hardness control / Hot shell: Austenitic stainless steel
- Minimize vaporization by downstream control valve (at tower inlet)

Typical Industry Practice

- Cold: 250 °F and 150 psig / Hot: 350 °F and 150 psig
- Cold: SA-516-70N / Hot: 304L SS, NACE MR0103 applies to both
SWS Hot Feed Piping

Process Conditions and Corrosion Mechanisms
- 200 – 220 °F and 30 – 50 psia
- H₂O (V+L), H₂S, NH₃, trace HCN and phenols
- Sulfide stress cracking, corrosion-erosion, HIC (welded piping)

Corrosion Mitigation Strategies
- Use Austenitic stainless steel to reduce corrosion
- Limit temp to reduce corrosion; minimize velocity to reduce erosion

Typical Industry Practice
- 250 °F and 75 psig
- 304L SS, 0.125” CA, NACE MR0103 applies
Sour Water Stripper

Process Conditions and Corrosion Mechanisms
- 200 – 260 °F and 25 – 30 psia
- H₂O (V+L), H₂S, NH₃, trace HCN and phenols
- Sulfide stress cracking, HIC

Corrosion Mitigation Strategies
- Use carbon steel with hardness control to avoid cracking
- Austenitic stainless steel cladding above the feed tray

Typical Industry Practice
- 350 °F and 50 – 75 psig
- SA-516-70N, 0.25” CA, NACE MR0103 applies
Discussion of SWS Condensing Systems

There are two types of SWS condensing systems:

1. External condenser with reflux drum and pumps;
2. Internal condensing section with an external pumparound cooler.

Some key points to remember:

- External condensing systems experience significantly greater corrosion
- Internal condensing systems are more expensive
- Operating problems with internal condensing systems are usually due to either (a) insufficient condensing height or (b) inadequate control of tower overhead temperature
Sour Water Stripper Condensing Section (Internal)

Process Conditions and Corrosion Mechanisms
- 180 – 200 °F and 25 - 30 psia
- H$_2$O (V+L), H$_2$S, NH$_3$, HCN and phenols may concentrate
- Ammonium bicarbonate corrosion, sulfide stress cracking, HIC

Corrosion Mitigation Strategies
- Use Austenitic stainless cladding to reduce corrosion
- High liquid rates minimize dry areas for condensation to occur

Typical Industry Practice
- 350 °F and 50 – 75 psig
- SA-516-70N + 0.125” SS clad, NACE MR0103 applies
SWS Pumparound Cooler

Process Conditions and Corrosion Mechanisms

- 140 – 180 °F and 20 – 30 psia
- $\text{H}_2\text{O (L), H}_2\text{S, NH}_3$, 
- Ammonium bicarbonate corrosion, sulfide stress cracking, HIC

Corrosion Mitigation Strategies

- Austenitic stainless steel to minimize corrosion
- Low temperature reduces corrosion but increases cracking concern

Typical Industry Practice

- 250 °F and 50 – 75 psig
- 304L SS, 0.0675” CA, NACE MR0103 applies
SWS Condenser (External, Process Side)

Process Conditions and Corrosion Mechanisms

- 180 – 240 °F and 20 – 30 psia
- \( \text{H}_2\text{O (V+L), H}_2\text{S, NH}_3, \text{HCN and phenols may concentrate} \)
- Ammonium bicarbonate corrosion, sulfide stress cracking, HIC

Corrosion Mitigation Strategies

- Corrosion resistant alloys required

Typical Industry Practice

- 300 °F and 50 – 75 psia
- Titanium tubes, 316L SS, 0.125” CA, NACE MR0103 applies
SWS Overhead Piping

Process Conditions and Corrosion Mechanisms

- 180 – 190 °F and 25 – 30 psia
- H$_2$O (V), H$_2$S, NH$_3$, trace HCN and phenols
- Ammonium bicarbonate corrosion, sulfide stress cracking

Corrosion Mitigation Strategies

- Use carbon steel with hardness control to limit cracking
- Prevent condensation with effective heat trace to 190 °F

Typical Industry Practice

- 250 °F and 50 – 75 psig
- A-106B, 0.25” CA, NACE MR0103 applies
References


