Acid Gas Treating

Chapter 10

Based on presentation by Prof. Art Kidnay
Plant Block Schematic

Gas & liquids from wells
- Field liquids removal
  - Field acid gas removal
  - Field dehydration
  - Field compression

- Inlet receiving
  - Water & solids
- Inlet compression
- Gas treating
- Hydrocarbon recovery
  - Nitrogen rejection
  - Helium recovery
- Dehydration
- Outlet compression
- Liquifaction
- Liquids processing

- CO2
  - Sulfur recovery
    - Elemental Sulfur
  - Crude Helium
  - Sales gas
  - LNG
  - NGLs
  - Natural gasoline
Topics

Chemical Absorption Processes
Physical Absorption
Adsorption
Cryogenic Fractionation
Membranes
Nonregenerable H2S Scavengers
Biological Processes
Safety and Environmental Considerations
Gas treating

Gas treating involves removing the "acid gases" to sufficiently low levels to meet contractual specifications

- Carbon dioxide (CO₂)
- Hydrogen sulfide (H₂S)
- Plus other sulfur species

The problems

- H₂S is highly toxic
- H₂S combustion gives SO₂ – toxic & leads to acid rain
- CO₂ is a diluent in natural gas – corrosive in presence of H₂O

Purification levels

- H₂S: Pipeline quality gas requires 0.25 grains/100 scf (4 ppmv)
- CO₂: pipeline quality gas may allow up to 4 mole%
  - Cryogenic applications need less than 50 ppmv
Two step process

Two steps

- Remove the acid gases from natural gas
- Dispose of the acid gases

Disposition

- CO₂
  - Vent to atmosphere
  - EOR – Enhanced Oil Recovery
  - Sequestration

- H₂S
  - Incineration or venting (trace amounts)
  - React with scavengers (e.g. iron sponge)
  - Convert to elemental sulfur
  - Injection into suitable underground formation
Power Station/Industrial Facility

- CO2 Capture and Sequestration

- CO2 Replaces Methane Trapped in Coal
- CO2 Replaces Methane Trapped in Coal
- Enhanced Oil Recovery (CO2 Displaces Oil)
- CO2 Stored in Saline Formation
- CO2 Indicates Power Station/Industrial Facility

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Processes for acid gas removal

Figure 10.1, *Fundamentals of Natural Gas Processing, 2nd ed.*, Kidnay, Parrish, & McCartney, 2011
Selecting a process

Factors for selecting process
- Type & concentration of impurities
- Hydrocarbon composition of the gas
- Pressure & temperature of the gas
- Specifications for outlet gas
- Volume of gas to be processed

Four possible scenarios
- Only CO$_2$
- Only H$_2$S
- Both CO$_2$ and H$_2$S
- Both CO$_2$ and H$_2$S present but selectively remove H$_2$S
  - Allow CO$_2$ slip
Selecting a process

- Hybrid
- Physical Solvent, Hybrid, or Hot Potassium Carbonate
- Physical Solvent or Activated Hot Potassium Carbonate
- Activated Hot Potassium Carbonate or Amine
- Amine

Partial Pressure of Acid Gas in Feed, psia

Partial Pressure of Acid Gas in Product, psia

Line of Equal Inlet and Outlet Pressures
Chemical Absorption Processes
Physical vs. Chemical Absorption

(Examples: carbonated water, soft drinks, champagne)

\[
\text{CO}_2 \quad \text{gas} \quad \text{liquid} \quad \text{water}
\]

- high P, low T = absorption
- low P, high T = desorption

\[
\text{H}_2\text{S} + \text{R}_1\text{R}_2\text{R}_3\text{N} = \text{R}_1\text{R}_2\text{R}_3\text{NH}^+\text{S} \quad \text{(soluble salt)}
\]

reversible exothermic reaction
Amine Chemistry

Gas treating amines are:
- Weak Lewis Bases
- $\text{H}^+$ from weak acids react with the electrons on N:

ABC substituents influence:
- How fast acids react with N:
- Temperature bulge in absorber
- Energy required in regenerator
- Chemical Stability
- Unwanted reactions

---

Primary amine (MEA)
A = CH$_2$CH$_2$OH
B = H
C = H

Secondary amine (DEA)
A = CH$_2$CH$_2$OH
B = CH$_2$CH$_2$OH
C = H

Tertiary amine (MDEA)
A = CH$_2$CH$_2$OH
B = CH$_2$CH$_2$OH
C = CH$_3$

---

*Dow Oil & Gas – Gas Treating Technology*
Presentation to URS Washington Division, August 2009
Rich Ackman – ackmanrb@dow.com
Sterically hindered amines – selective \( \text{H}_2\text{S} \) absorbers

Diisopropanolamine (DIPA)

\[
\begin{array}{c}
\text{CH}_3 \quad \text{CH} \quad \text{CH}_2 \\
\text{OH} \\
\text{N} - \text{H} \\
\text{CH}_3 \quad \text{CH} \quad \text{CH}_2 \\
\text{OH}
\end{array}
\]

2-amino,2-methyl,1-propanol (AMP)

\[
\begin{array}{c}
\text{CH}_3 \\
\text{HOCH}_2 \quad \text{C} \quad \text{NH}_2 \\
\text{CH}_3
\end{array}
\]
Amines

Amines remove $\text{H}_2\text{S}$ and $\text{CO}_2$ in a two-step process:

- Gas dissolves in solvent (physical absorption)
- Dissolved gas (a weak acid) reacts with weakly basic amines

**H$_2$S reaction**

$$R_1R_2R_3\text{N} + \text{H}_2\text{S} \leftrightarrow R_1R_2R_3\text{NH}^+\text{HS}^-$$

**CO$_2$ reacts two ways with amine:**

- With water
  
  $$\text{CO}_2 + \text{H}_2\text{O} + R_1R_2R_3\text{N} \leftrightarrow R_1R_2R_3\text{NH}^+\text{HCO}_3^-$$
  
  - Much slower than $\text{H}_2\text{S}$ reaction

- Without water
  
  $$\text{CO}_2 + 2R_1R_2\text{NH} \leftrightarrow R_1R_2\text{NH}_2 + R_1R_2\text{NCOO}^-$$
  
  - Faster but requires one H attached to the N
  - Use tertiary amines to “slip” CO$_2$
## Comparison of acid gas removal solvents

<table>
<thead>
<tr>
<th>Process</th>
<th>Capable of meeting ( \text{H}_2\text{S} ) spec?</th>
<th>Removes ( \text{COS}, \text{CS}_2, ) &amp; mercaptans</th>
<th>Selective ( \text{H}_2\text{S} ) removal</th>
<th>Minimum ( \text{CO}_2 ) level obtainable</th>
<th>Solution subject to degradation? (degrading species)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Monoethanolamine (MEA)</td>
<td>Yes</td>
<td>Partial</td>
<td>No</td>
<td>100 ppmv at low to moderate pressures</td>
<td>Yes (( \text{COS}, \text{CO}_2, \text{CS}_2, \text{SO}_2, \text{SO}_3 ) and mercaptans)</td>
</tr>
<tr>
<td>Diethanolamine (DEA)</td>
<td>Yes</td>
<td>Partial</td>
<td>No</td>
<td>50 ppmv in SNEA-DEA process</td>
<td>Some (( \text{COS}, \text{CO}_2, \text{CS}_2, \text{HCN} ) and mercaptans)</td>
</tr>
<tr>
<td>Triethanolamine (TEA)</td>
<td>No</td>
<td>Slight</td>
<td>No</td>
<td>Minimum partial pressure of 0.5 psia (3 kPa)</td>
<td>Slight (( \text{COS}, \text{CS}_2 ) and mercaptans)</td>
</tr>
<tr>
<td>Methyl-diethanolamine (MDEA)</td>
<td>Yes</td>
<td>Slight</td>
<td>Some</td>
<td>Bulk removal only</td>
<td>No</td>
</tr>
</tbody>
</table>

Part of Table 10.1, *Fundamentals of Natural Gas Processing, 2nd ed.*, Kidnay, Parrish, & McCartney, 2011
Representative operating parameters

<table>
<thead>
<tr>
<th></th>
<th>MEA</th>
<th>DEA</th>
<th>DGA</th>
<th>MDEA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weight % amine</td>
<td>15 to 25</td>
<td>30 to 40</td>
<td>50 to 60</td>
<td>40 to 50</td>
</tr>
<tr>
<td>Rich amine acid gas loading</td>
<td>0.45 to 0.52</td>
<td>0.21 to 0.81</td>
<td>0.35 to 0.44</td>
<td>0.20 to 0.81</td>
</tr>
<tr>
<td>mole acid gas / mole amine</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Acid gas pickup</td>
<td>0.33 to 0.40</td>
<td>0.20 to 0.80</td>
<td>0.25 to 0.38</td>
<td>0.20 to 0.80</td>
</tr>
<tr>
<td>mole acid gas / mole amine</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lean solution residual acid</td>
<td>~0.12</td>
<td>~0.01</td>
<td>~0.06</td>
<td>0.005 to 0.01</td>
</tr>
<tr>
<td>gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>mole acid gas / mole amine</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>


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Gas Treating Amines

Generic Amines

- **MEA (monoethanolamine)**
  - 15 – 18% wt. (5 – 6.1% mol)

- **DEA (diethanolamine)**
  - 25 – 30% wt. (5.4 – 6.8% mol)

- **DIPA (diisopropanolamine)**
  - 30% - 50% wt. (5.5 – 11.9% mol)

- **MDEA (methyldiethanolamine)**
  - 35% - 50% wt. (7.5 – 13.1% mol)

---

<table>
<thead>
<tr>
<th></th>
<th>Wt%</th>
<th>Mol%</th>
<th>Load Range</th>
<th>Relative Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>MEA</td>
<td>18%</td>
<td>6.1%</td>
<td>0.35</td>
<td>1</td>
</tr>
<tr>
<td>DGA</td>
<td>50%</td>
<td>14.6%</td>
<td>0.45</td>
<td>3.09</td>
</tr>
<tr>
<td>DEA</td>
<td>28%</td>
<td>6.3%</td>
<td>0.48</td>
<td>1.41</td>
</tr>
<tr>
<td>MDEA</td>
<td>50%</td>
<td>13.1%</td>
<td>0.49</td>
<td>3.02</td>
</tr>
<tr>
<td>CompSol 20</td>
<td>50%</td>
<td>10.4%</td>
<td>0.485</td>
<td>2.37</td>
</tr>
<tr>
<td>CR 402</td>
<td>50%</td>
<td>14.7%</td>
<td>0.49</td>
<td>3.38</td>
</tr>
<tr>
<td>AP 814</td>
<td>50%</td>
<td>13.9%</td>
<td>0.485</td>
<td>3.16</td>
</tr>
</tbody>
</table>

*Dow Oil & Gas – Gas Treating Technology*
Presentation to URS Washington Division, August 2009
Rich Ackman – ackmanrb@dow.com
Amine Solution Densities

Lean amine composition will dictate volumetric circulation rate & pumping power required

\[
W_{BHP} = \frac{\dot{V}(\Delta P)}{\eta_{pump}} = \frac{\dot{V} \rho g H}{\eta_{pump}}
\]

FIG. 21-9
Specific Gravity of Aqueous Amine Solutions

GPSA Engineering Data Book, 13th ed.
### Heats of reaction in amine solutions

<table>
<thead>
<tr>
<th>Amine</th>
<th>$H_2S$, Btu/lb (kJ/kg)</th>
<th>$CO_2$, Btu/lb (kJ/kg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DGA®</td>
<td>674 (1570)</td>
<td>850 (1980)</td>
</tr>
<tr>
<td>MEA</td>
<td>610 (1420)</td>
<td>825 (1920)</td>
</tr>
<tr>
<td>DEA</td>
<td>555 (1290)</td>
<td>730 (1700)</td>
</tr>
<tr>
<td>MDEA</td>
<td>530 (1230)</td>
<td>610 (1420)</td>
</tr>
</tbody>
</table>

Includes heat of solution & heat of reaction

Can give rise to temperature “bulges” in the absorbing column

Typical Amine Treating Plant

Typical plant configuration

- Broad range of treating applications
- Low to intermediate specifications
- Selective treating, low H₂S
- Low installed cost
Amine Tower Parameters

Tower Design Considerations

- Gas Composition
- Trays
  - System Factor Bubble Area
    - MEA/DEA – 0.75 abs (0.85 reg)
    - MDEA & Formulated Solvents – 0.70 abs (0.85 reg)
  - System Factor Downcomer
    - MEA/DEA – 0.73 abs (0.85 reg)
    - MDEA & Formulated Solvents – 0.70 abs (0.85 reg)
    - Standard Cross Flow vs. High Capacity
      - Calming Section, MD Trays
- Packings
  - Random Packing
    - Capacity vs. efficiency, GPDC overlay
  - Structured Packing

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    - MDEA & Formulated Solvents – 0.70 abs (0.85 reg)
  - System Factor Downcomer
    - MEA/DEA – 0.73 abs (0.85 reg)
    - MDEA & Formulated Solvents – 0.70 abs (0.85 reg)
  - Standard Cross Flow vs. High Capacity
    - Calming Section, MD Trays

- Packings
  - Random Packing
  - Capacity vs. efficiency, GPDC overlay
  - Structured Packing
Amine Tower Parameters

Absorber design considerations

- Pinch points limit
  - Top of tower lean pinch
  - Temperature bulge maximum
  - Bottom of tower rich pinch
  - Confidence level in VLE
- Temperature profile indicator
# Amine Approximate Guidelines

<table>
<thead>
<tr>
<th></th>
<th>MEA</th>
<th>DEA</th>
<th>DGA</th>
<th>MDEA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acid gas pickup, scf/gal @ 100°F</td>
<td>3.1 – 4.3</td>
<td>6.7 – 7.5</td>
<td>4.7 – 7.3</td>
<td>3 – 7.5</td>
</tr>
<tr>
<td>Acid gas pickup, mols/mol amine</td>
<td>0.33 – 0.40</td>
<td>0.20 – 0.80</td>
<td>0.25 – 0.38</td>
<td>0.20 – 0.80</td>
</tr>
<tr>
<td>Lean solution residual acid gas, mol/mol amine</td>
<td>~ 0.12</td>
<td>~ 0.01</td>
<td>~ 0.06</td>
<td>0.005 – 0.01</td>
</tr>
<tr>
<td>Rich solution acid gas loading, mol/mol amine</td>
<td>0.45 – 0.52</td>
<td>0.21 – 0.81</td>
<td>0.35 – 0.44</td>
<td>0.20 – 0.81</td>
</tr>
<tr>
<td>Max. solution concentration, wt%</td>
<td>25</td>
<td>40</td>
<td>60</td>
<td>65</td>
</tr>
<tr>
<td>Approximate reboiler heat duty, Btu/gal lean solution</td>
<td>1,000 – 1,200</td>
<td>840 – 1,000</td>
<td>1,100 – 1,300</td>
<td>800 – 900</td>
</tr>
<tr>
<td>Heats of reaction (approximate)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Btu/lb H₂S</td>
<td>610</td>
<td>555</td>
<td>674</td>
<td>530</td>
</tr>
<tr>
<td>Btu/lb CO₂</td>
<td>825</td>
<td>730</td>
<td>850</td>
<td>610</td>
</tr>
</tbody>
</table>

*GPSA Engineering Data Book, 13th ed., portion of Figure 21-4*
Amine System Initial Design

Amine solvent considerations

- Lean amine concentration (wt% amine in water)
- Rich & lean amine loadings (mole acid gas per mole amine) — difference is the allowed amine pick-up

Determine amount of acid gas to be absorbed

- Difference between what can be contained in the treated gas & what is in the feed gas

Determine rate of lean amine to the absorber

- Molar rate amine based on the allowed pick-up
- Total mass rate amine+water based on the allowed lean amine concentration
- Total volumetric flowrate (standard conditions) based on lean amine concentration

Determine the reboiler duty for regeneration

- Based on heat of regeneration for each amine & acid gas (CO₂ & H₂S)
GPSA Data Book example 21-1

30.0 MMscfd of gas available at 850 psig and containing 0.6% H2S and 2.8% CO2 is to be sweetened using 20 wt% DEA solution. If a conventional DEA system is to be used, what amine circulation rate is required, and what will be the principal parameters for the DEA treating system?

DEA circulation rate

- Loading considerations:
  - Moderate loading, 0.50 mol acid gas/mol DEA rich loading
  - Lean loading, assume essentially 0 mol acid gas/mol DEA

- Acid gas to be removed: \((0.028 + 0.006)(30 \text{ MMscfd}) = 1.02 \text{ MMscfd} \Rightarrow 1.87 \text{ lb.mol/min}\)

- DEA required: \(\frac{1.87 \text{ lb.mol/min}}{0.50 \text{ mol/mol DEA}} = (3.73 \text{ lb.mol/min})(105.14 \text{ lb/lb.mol}) = 392 \text{ lb/min}\)

- 20% DEA solvent required: \(\frac{392 \text{ lb/min}}{0.20} \times \frac{1}{8.54 \text{ lb/gal}} = 230 \text{ gal/min}\)
Operating issues with amine units

Corrosion – caused by:
- High amine concentrations
- Rich amine loadings
- Oxygen
- Heat stable salts (HSS)

Foaming – caused by
- Suspended solids
- Surface active agents
- Liquid hydrocarbons
- Amine degradation products (heat stable salts)
Hot potassium carbonate process (Hot Pot)

Major reactions

\[
\begin{align*}
K_2CO_3 + CO_2 + H_2O & \leftrightarrow 2 KHCO_3 \\
K_2CO_3 + H_2S & \leftrightarrow KHS + KHCO_3
\end{align*}
\]
Physical Absorption
Characteristics of physical absorption processes

- Most efficient at high partial pressures
- Heavy hydrocarbons strongly absorbed by solvents used
- Solvents can be chosen for selective removal of sulfur compounds
- Regeneration requirements low compared to amines & Hot Pot
- Can be carried out at near-ambient temperatures
- Partial dehydration occurs along with acid gas removal

Figure from UOP Selexol™ Technology for Acid Gas Removal, UOP, 2009
## Comparison of chemical and physical solvents

<table>
<thead>
<tr>
<th></th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Chemical Solvent</strong></td>
<td>Relatively insensitive to $\text{H}_2\text{S}$ and $\text{CO}_2$ partial pressure</td>
<td>High energy requirements for regeneration of solvent</td>
</tr>
<tr>
<td>(e.g., amines, hot potassium carbonate)</td>
<td>Can reduce $\text{H}_2\text{S}$ and $\text{CO}_2$ to ppm levels</td>
<td>Generally not selective between $\text{CO}_2$ and $\text{H}_2\text{S}$</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Amines are in a water solution and thus the treated gas leaves saturated with water</td>
</tr>
<tr>
<td><strong>Physical solvents</strong></td>
<td>Low energy requirements for regeneration</td>
<td>May be difficult to meet $\text{H}_2\text{S}$ specifications</td>
</tr>
<tr>
<td>(e.g., Selexol, Rectisol)</td>
<td>Can be selective between $\text{H}_2\text{S}$ and $\text{CO}_2$</td>
<td>Very sensitive to acid gas partial pressure</td>
</tr>
</tbody>
</table>
Physical Solvents – Selexol

Characteristics

- Poly (Ethylene Glycol) Dimethyl Ether
  \[ \text{CH}_3 - \text{O} - (\text{CH}_2 - \text{CH}_2 - \text{O})_n - \text{CH}_3 \] where \( n \) is from 3 to 10
- Selexol is a mixture of homologues so the physical properties are approximate
- Clear fluid that looks like tinted water

Capabilities

- \( \text{H}_2\text{S} \) selective or non selective removal – very low spec. - 4 ppm
- \( \text{CO}_2 \) selective or non selective removal – 2% to 0.1%
- Water dew point control
- Hydrocarbon dew point control
  - See relative solubilities; more efficient to remove hydrocarbon vs. refrigeration
- Organic sulfur removal – mercaptans, disulfides, COS
Selexol Processes

Physical solvent which favors high pressure & high partial pressure

Configurations

- H$_2$S & organic sulfur removal
  - Steam stripping for regeneration
- CO$_2$ removal
  - Flash regeneration
  - Chiller for low CO$_2$

Special applications

- Siloxanes are removed from landfill gas
- Metal carbonyl are removed from gasifier gas
Solubility in Selexol at 70°F (21°C)

Figure 10.6, Fundamentals of Natural Gas Processing, 2nd ed., Kidnay, Parrish, & McCartney, 2011
Selexol process – CO$_2$ separation

UOP Selexol™ Technology for Acid Gas Removal, UOP, 2009
Selexol process – sulfur removal & CO₂ capture

UOP Selexol™ Technology for Acid Gas Removal, UOP, 2009

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Membranes
Membrane systems

Based on Fick’s law of diffusion through the membrane

\[ J_i = \frac{S_i D_i (\Delta p_i)}{L} \]

where:  
- \( J_i \) is the molar flux of component \( i \) through the membrane  
- \( S_i \) is the solubility term  
- \( D_i \) is the diffusion coefficient  
- \( \Delta p_i \) is the partial pressure difference across the membrane  
- \( L \) is the thickness of the membrane

The permeability combines the properties of solubility & diffusion

- Differs for each compound
- Provides selectivity

\[ y_{i,\text{permeate}} \propto \left( \frac{p_{\text{feed}}}{p_{\text{permeate}}} \right) y_{i,\text{feed}} \]
Module configurations – hollow fiber

Approximately 70% of membrane systems are hollow fiber
Module configurations – spiral wound

Continued Development of Gas Separation Membranes for Highly Sour Service, Cnop, Dormndt, & schott, UOP
Module configurations – spiral wound

- Membrane Housing
- Permeate Tube Union
- Membrane Element
- Inlet Seal (U-Cup)
- Feed
- Permeate
- Residual
Membrane module flow schemes

No moving parts
Simple, reliable operation
Low hydrocarbon recovery

Allows for greater CO$_2$ removal
High hydrocarbon recovery
Requires recycle compressor
Feed with high CO$_2$
Intermediate hydrocarbon recovery
Reduced compression

UOP Separex™ Membrane Technology, UOP, 2009
CO₂/CH₄ separation

Two stage process (non-optimized)
**CO₂/CH₄ separation**

**Composition (mole %)**

<table>
<thead>
<tr>
<th></th>
<th>A</th>
<th>B</th>
<th>C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane</td>
<td>93.0</td>
<td>98.0</td>
<td>63.4</td>
</tr>
<tr>
<td>Carbon dioxide</td>
<td>7.0</td>
<td>2.0</td>
<td>36.6</td>
</tr>
<tr>
<td>Flow rate (MMscfd)</td>
<td>20.00</td>
<td>17.11</td>
<td>2.89</td>
</tr>
<tr>
<td>Pressure (psig)</td>
<td>850</td>
<td>835</td>
<td>10</td>
</tr>
</tbody>
</table>

Methane recovery = 90.2%

**Composition (mole %)**

<table>
<thead>
<tr>
<th></th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane</td>
<td>93.0</td>
<td>98.0</td>
<td>18.9</td>
<td>63.4</td>
<td>93.0</td>
</tr>
<tr>
<td>Carbon Dioxide</td>
<td>7.0</td>
<td>2.0</td>
<td>81.1</td>
<td>36.6</td>
<td>7.0</td>
</tr>
<tr>
<td>Flow Rate (MMscfd)</td>
<td>20.00</td>
<td>18.74</td>
<td>1.26</td>
<td>3.16</td>
<td>1.90</td>
</tr>
<tr>
<td>Pressure (psig)</td>
<td>850</td>
<td>835</td>
<td>10</td>
<td>10</td>
<td>850</td>
</tr>
</tbody>
</table>

Methane Recovery = 98.7%
Adsorption
Acid gas removal by adsorption (mole sieves)

Figure 10.10, *Fundamentals of Natural Gas Processing, 2nd ed.*, Kidnay, Parrish, & McCartney, 2011
Nonregenerable H$_2$S Scavengers
## Nonregenerable H$_2$S scavengers

<table>
<thead>
<tr>
<th>Process Phase</th>
<th>Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solid-based processes</td>
<td>Iron oxides</td>
</tr>
<tr>
<td></td>
<td>Zinc oxides</td>
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<tr>
<td>Liquid-based processes</td>
<td>Amine-aldehyde condensates</td>
</tr>
<tr>
<td></td>
<td>Caustic</td>
</tr>
<tr>
<td></td>
<td>Aldehydes</td>
</tr>
<tr>
<td></td>
<td>Oxidizers</td>
</tr>
<tr>
<td></td>
<td>Metal-oxide slurries</td>
</tr>
</tbody>
</table>

Summary
Summary

Appropriate technology based on...

- Amount of acid gas to be removed
- Concentration of acid gas in feed gas
- Pressure of feed gas

Very typical to find an amine treating system to remove $\text{H}_2\text{S}$ and/or $\text{CO}_2$

- May be able to “slip” CO2 into treated gas depending on the final specs
Supplemental Slides
“Study places CO2 capture cost between $34 and $61/ton”
Oil & Gas Journal, Oct. 12, 2009