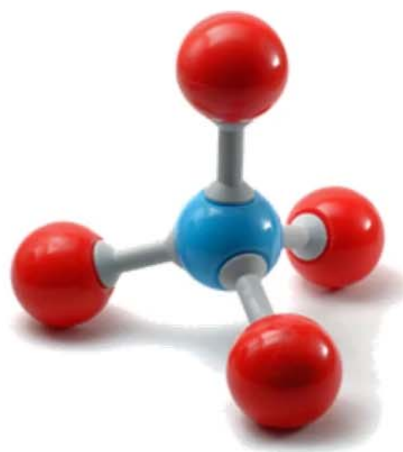
Sour components in Natural Gas

H2S

NH3

CO2



RSH

CS2

COS

Natural gas Sweetening

Purification processes which is employed to remove acidic contaminants from natural gases

H2S	Hydrogen Sulfide 4ppmv	COS	Carbonyl sulfide	RSH	Mercaptans
CO2	Carbon dioxide	NOS	Nitrox ide	RSSR	Disulfide

the gas is usually considered sour if the hydrogen sulfide content exceeds 5.7 mg of H2S per cubic meter of natural gas.

TYPES OF CONTAMINANTS

Ammonia (NH_3)
Hydrogen sulfide (H_2S)
Hydrogen cyanide (HCN)
Carbon dioxide (CO_2)
Carbonyl sulfide (COS)
Carbon disulfide (CS_2)
Mercaptan (RSH)

Nitrogen (N_2)
Water (H_2O)
Sulfur dioxide (SO_2)
Elemental sulfur
Mercury and arsenic
Oxygen

Natural gas Sweetening

- **Acid Gases**

  H_2S + water ➡ sulfuric acid weak, corrosive acid

  CO_2 + water ➡ carbonic acid.

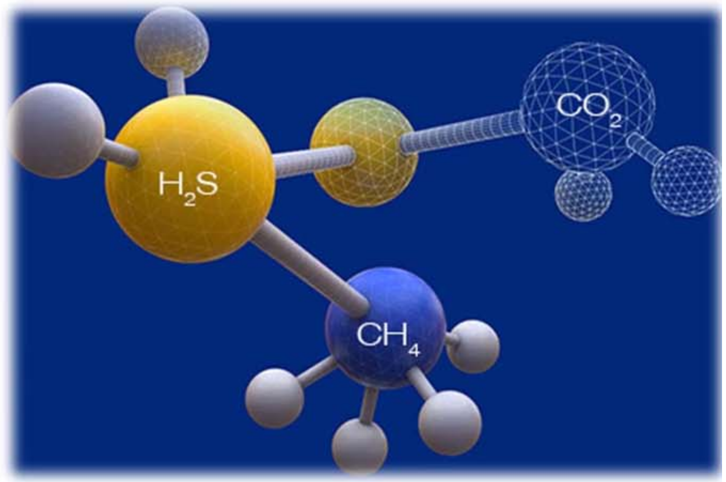
  Both are undesirable because they cause corrosion and reduce heating value and sales value.

- **Sour Gas**

  Sour gas is defined as natural gas with H2S and other sulfur compounds.

- **Sweet Gas**

  Sweet gas is defined as natural gas without any acidic impurities.



Natural Gas Pipeline Specifications

Characteristic	Specification
Water content	4–7 lb/MMSCF maximum
Hydrogen sulfide content	0.25 grain/100 SCF maximum
Gross heating value	950 Btu/SCF minimum
Hydrocarbon dew point	15°F at 800 psig maximum
Mercaptan content	0.2 grain/100 SCF maximum
Total sulfur content	1–5 grain/100 SCF maximum
Carbon dioxide content	1–3 mol% maximum
Oxygen content	0–0.4 mol% maximum
Sand, dust, gums, and free liquid	Commercially free
Delivery temperature (°F)	120°F maximum
Delivery pressure (psia)	700 psig minimum

Typical Product Specifications

WNTS SALES

GAS SPECIFICATIONS

Specifications	
Heating Value, GHV (BTU/SCF)	950-1350
Wobbe Index (BTU/SCF)	1325 +/- 8%
Hydrocarbon Dew point (oF at 725 psia)	55
Water Dew point (oF at 725 psia)	55
Particulate Size (microns, max)	400
Carbon Dioxide (mole%, max)	10
Total Inerts (mole%, max)	12
Hydrogen Sulfide, H_2S (ppmv, max)	10
Total Sulfur (ppmv, max)	30
Oxygen (mole%, max)	0.1
Methane as reactant species (mole%, min)	80
WNTS Pipeline Entry Pressure (psig at SSTI-S)	1800
WNTS Delivery Pressure (psig at Singapore)	550
Free Liquids	0
Delivery Temperature (oF, min above dew pt)	5
Delivery Temperature (oF, min absolute)	32

PROPANE PRODUCT

Specifications	
Vapor Pressure (psig at 100 F, max)	200
Ethane (volume%, max)	2.0
Propane (volume%, min)	95
Butane (volume%, max)	4.0
Copper Strip	1b
Hydrogen Sulfide (ppmw , max)	5.0
Total Sulfur (ppmw , max)	30
Water Content (ppmw , max)	10

BUTANE PRODUCT

Specifications	
Vapor Pressure (psig at 100 F, max)	70
Propane (volume%, max)	2.0
Butane (volume%, min)	97
Pentane (volume%, max)	1.0
Copper Strip	1b
Hydrogen Sulfide (ppmw , max)	5.0
Total Sulfur (ppmw , max)	30
Water Content (ppmw , max)	10

NACE TM0187

PASSED

TESTED

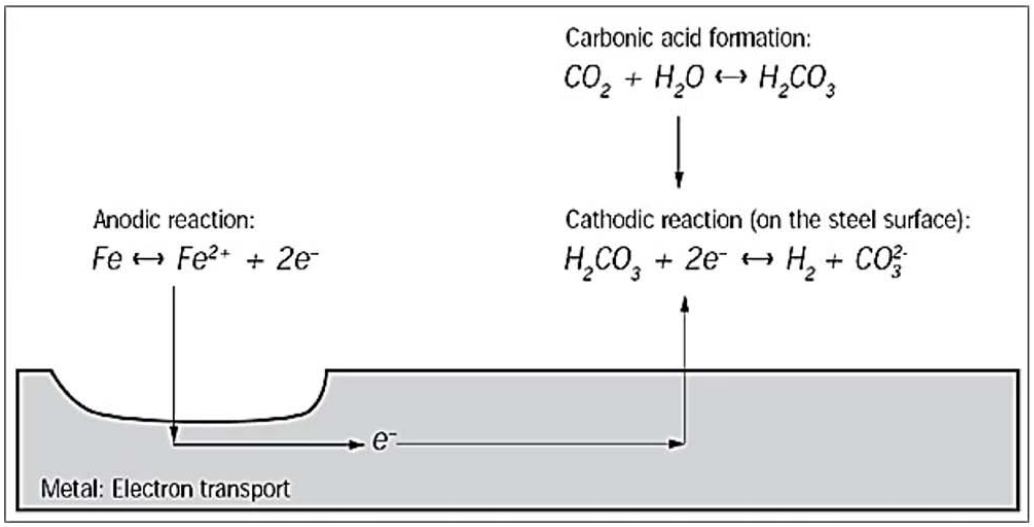
Typical Product Specifications

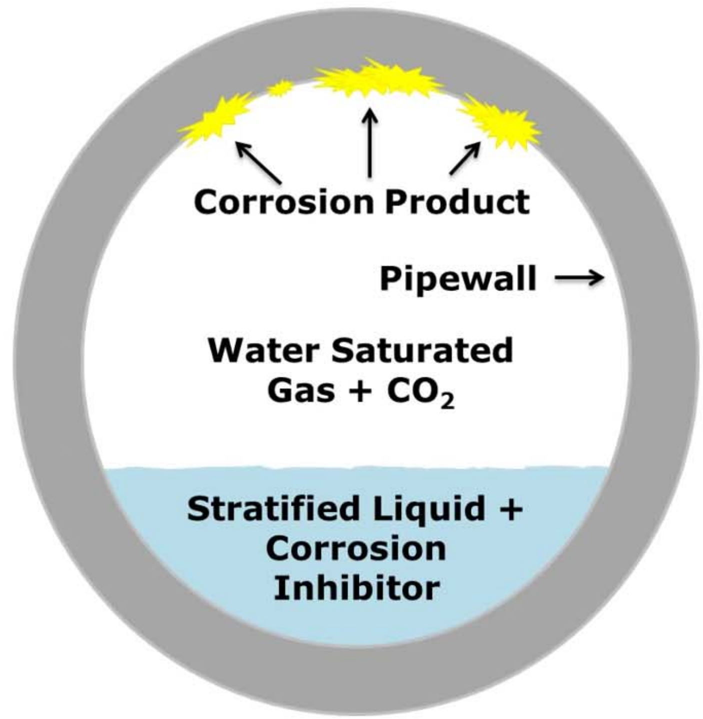
	Treated Gas Specs For:			Liquid Specs
	Pipeline	LNG	GTL	LPG
H_2S, ppmv	<4	< 2 -4	< 2 -4	<1 - 10
Total Sulfur, ppmv	< 20 - 50	< 10 -50	< 10 - 50	< 50
CO_2	<2% - 8%	< 50 ppmv	< 50 -1000 ppmv	< 500
Hg, pg/Nm^3	< 0.01	< 0.01	< 0.01	NA
H_2O, ppmv	<7 lb/ MMSCFD	< 0.1 ppm	< 1 ppm	< 5

Gas Sales Contracts Limit Concentration of Acid Compounds

1. CO_2
   - ❑ 2–4% for pipelines.
   - ❑ Lowers Btu content.
   - ❑ $CO_2$is corrosive.
   - ❑ 20 ppm for LNG plants.
2. H_2S
   - ❑ ¼ grain sulfur per 100 scf (approximately 4 ppm).
   - ❑ 0.0004% H_2S.
   - ❑ 2 ppm for LNG plants.
   - ❑ H_2S is toxic.
   - ❑ H_2S is corrosive (refer to NACE MR-01-75).

Hazards of CO2





Properties of H2S

Soluble in water and dissolves in drilling fluids

Highly Toxic and hazardous to health

Colorless or transparent

Corrosive to certain metals and elastomers

H2S

Generates **680 BTU/HR** during burning

Readily dispersed by wind movement or air currents

Heavier than air (Vapor Density = 1.1895) and accumulates in low-lying areas

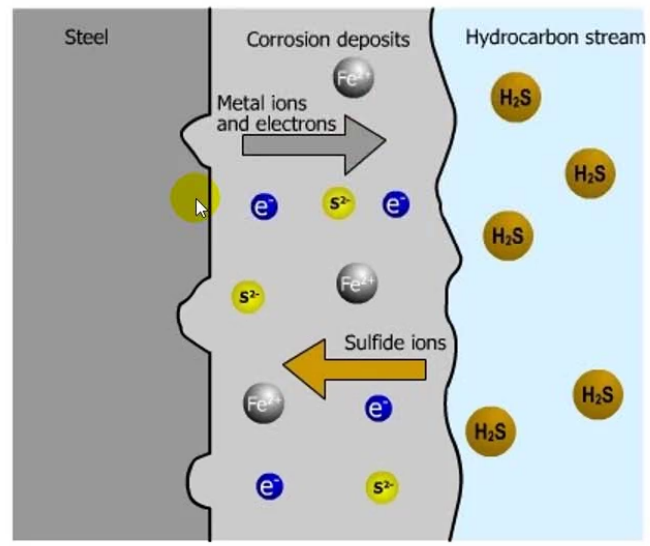
Flammable

in concentrations between 4.3% and 46.0% and auto ignites at 500°F (260°C)

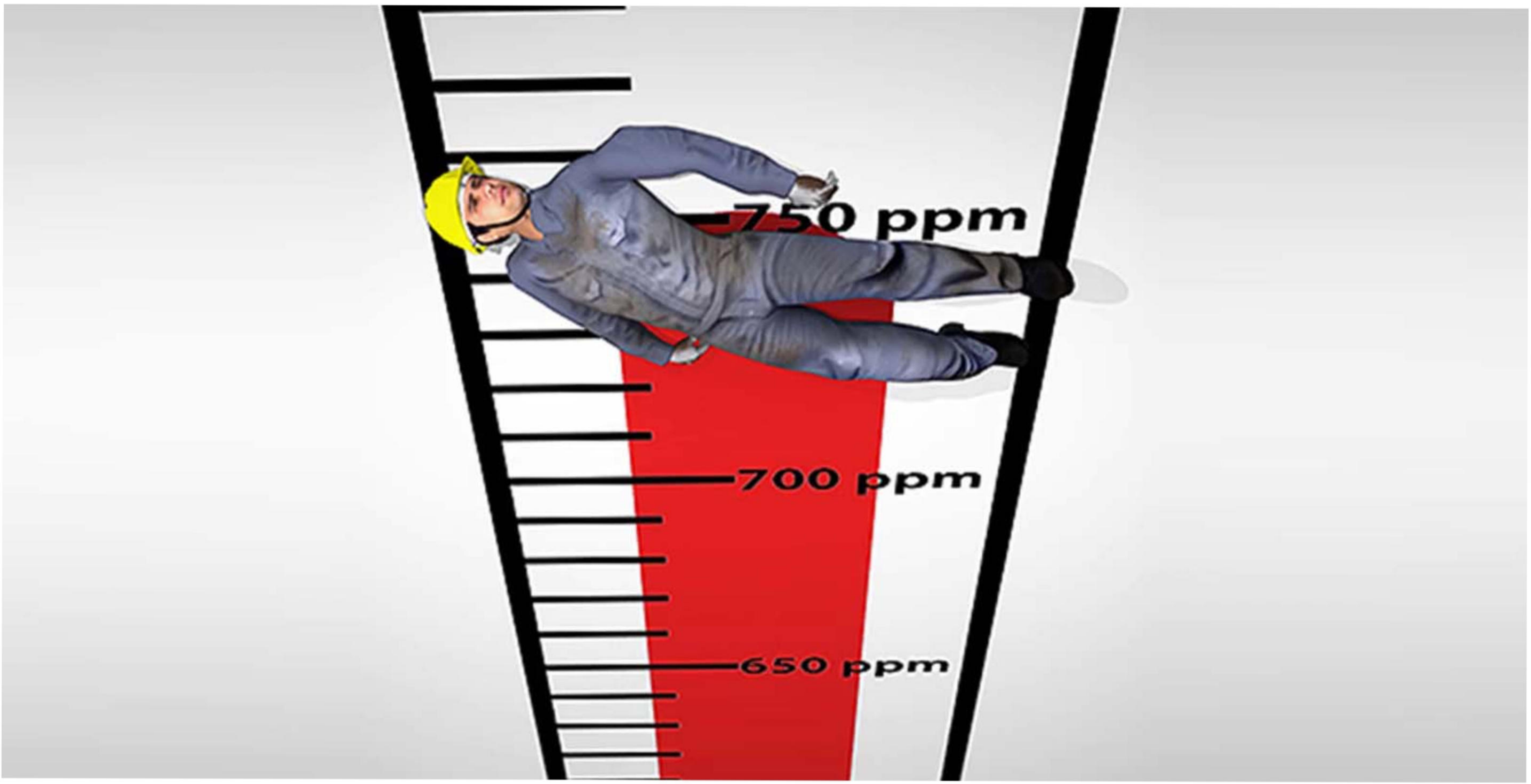
TOTALSAFETY

Hazards of H2S

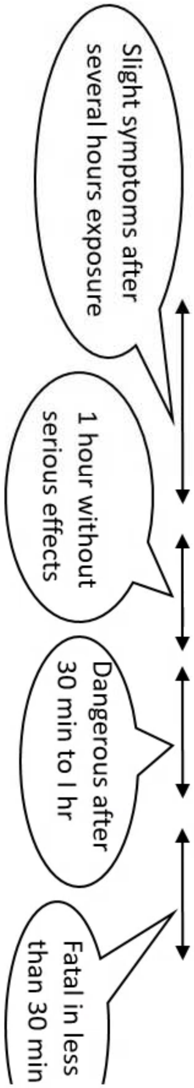
- Highly toxic colorless and flammable gas.
- Heavier than air.
- At low concentration, it smells like “rotten eggs”.
- Human sense of smell cannot be relied on to detect hazardous concentration of it.



Mechanism of sulfide stress corrosion cracking.


750 ppm
700 ppm
650 ppm

Concentration & Reaction by Human body



ppm	%	Symptoms
1	0.0001	Detected by odor
10	0.001	Occupational Exposure Level, Threshold Limit Value (TLV)
100	0.01	Kills sense of smell in 3 to 5 minutes. May burn eyes and throat.
200	0.02	Kills sense of smell rapidly. Burns eyes and throat after one hour.
500	0.05	Dizziness, loses sense of reasoning, breathing ceases in few minutes. Needs prompt artificial resuscitation
700	0.07	Will become unconscious quickly. Breathing will stop, death will result if not rescued promptly. Immediate artificial resuscitation
1000	0.1	Unconscious at once; followed by death

Concentration & Reaction by Human body

TOXICITY OF HYDROGEN SULPHIDE GAS	
10 ppm (1/1000 of 1%)	Can smell. Safe for 8 hours exposure
100 ppm (1/100 of 1%)	Kills smell in 3 to 15 minutes. May sting eyes and throat.
200 ppm (2/100 of 1%)	Kills smell rapidly. Stings eyes and throat
500 ppm (5/100 of 1%)	Loses sense of reasoning and balance. Respiratory paralysis in 2 to 15 minutes. Needs prompt artificial resuscitation.
700 ppm (7/100 of 1%)	Breathing will stop and death result if not rescued promptly. Requires immediate artificial resuscitation.
1,000 ppm (1/10 of 1%)	Unconscious at once. **PERMANENT BRAIN DAMAGE MAY RESULT UNLESS RESCUED PROMPTLY.**

GAS RESERVOIR CLASSIFICATION

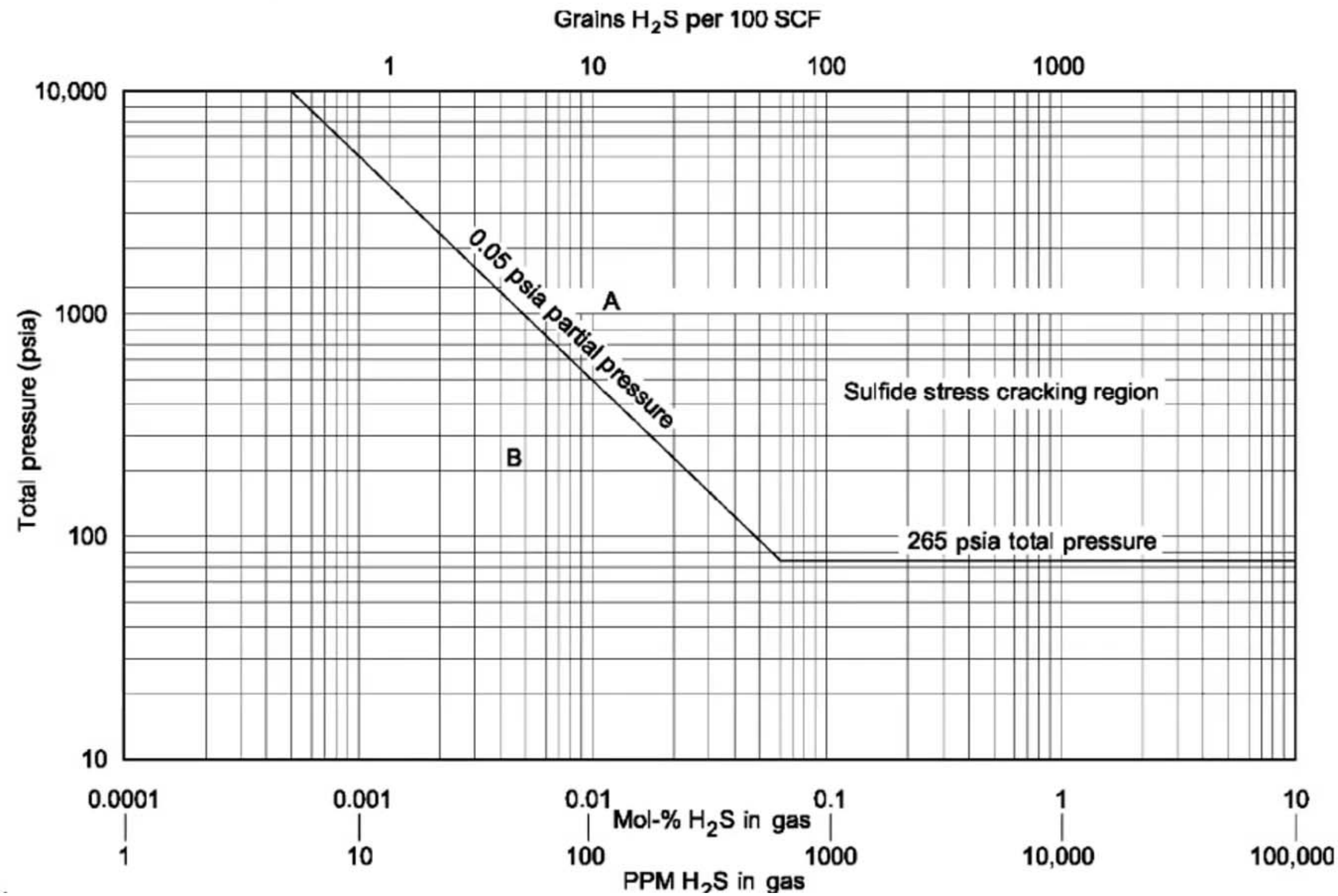
Number	Type	Content of H_2S
1	Non-sour gas reservoir	<0.0014%
2	Low sour gas reservoir	0.0014- 0.3%
3	sour gas reservoir	0.3—1.0%
4	Medium gas reservoir	1.0—5.0%
5	high sour gas reservoir	>5.0%

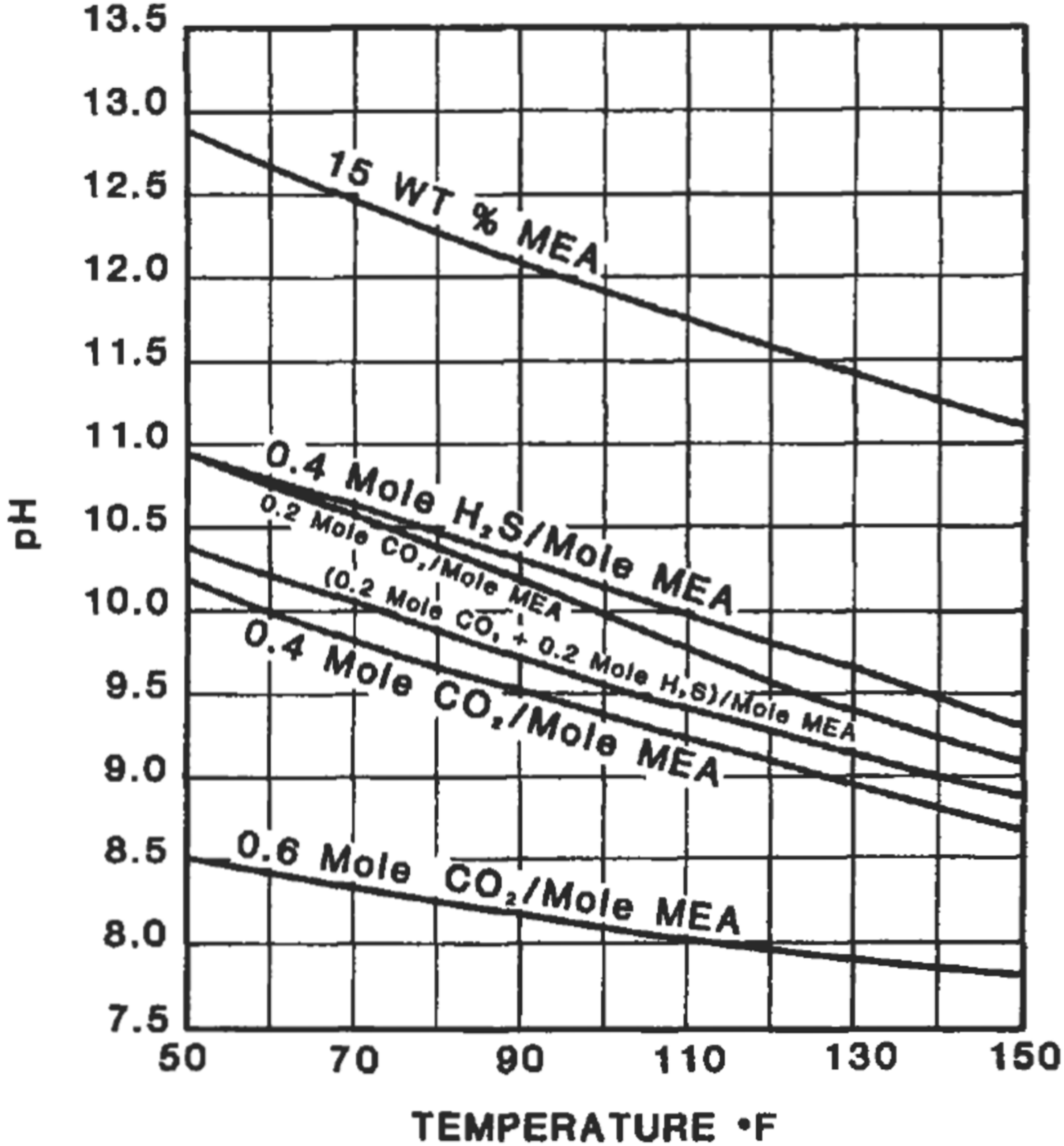
Partial Pressure

Partial pressure is used as an indicator if treatment is required.

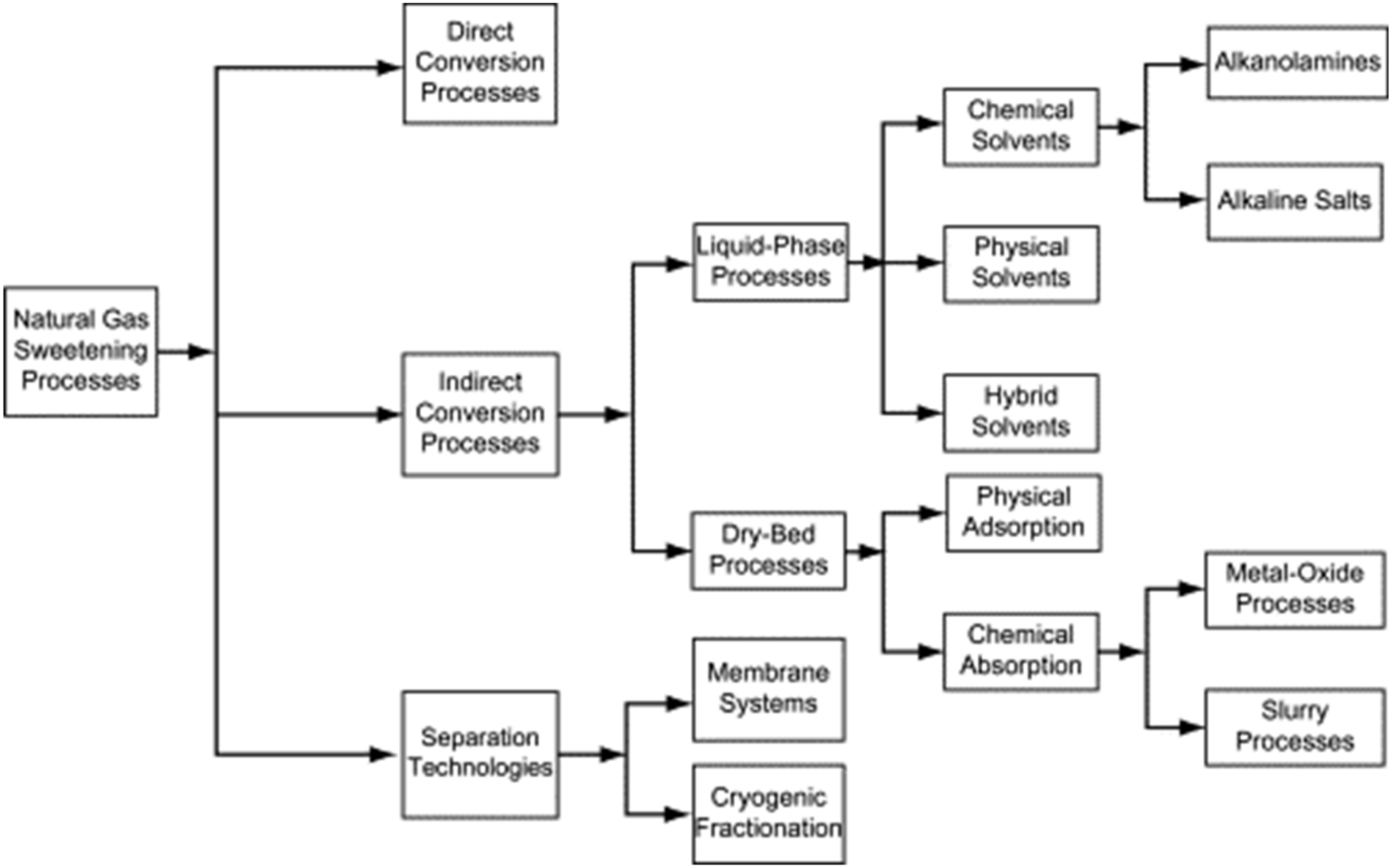
- where CO_2 is present with water, a partial pressure >30 psia would indicate CO_2 corrosion might be expected.
- Below 15 psia would indicate CO_2corrosion would not normally be a problem although inhibition may be required
- Factors that influence CO_2 corrosion are those directly related to solubility, that is, temperature, pressure, and composition of the water.
- Increased pressure increases solubility and increased temperature decreases solubility.

Sulfide stress cracking regions in sour gas systems.





13.5
13.0
12.5
12.0
11.5
11.0
10.5
10.0
9.5
9.0
8.5
8.0
7.5
pH
15 WT % MEA
0.4 Mole H_2S/Mole MEA
0.2 Mole CO_2/Mole MEA
(0.2 Mole CO_2 + 0.2 Mole H_2S)/Mole MEA
0.4 Mole CO_2/Mole MEA
0.6 Mole CO_2/Mole MEA
50
70
90
110
130
150
TEMPERATURE °F



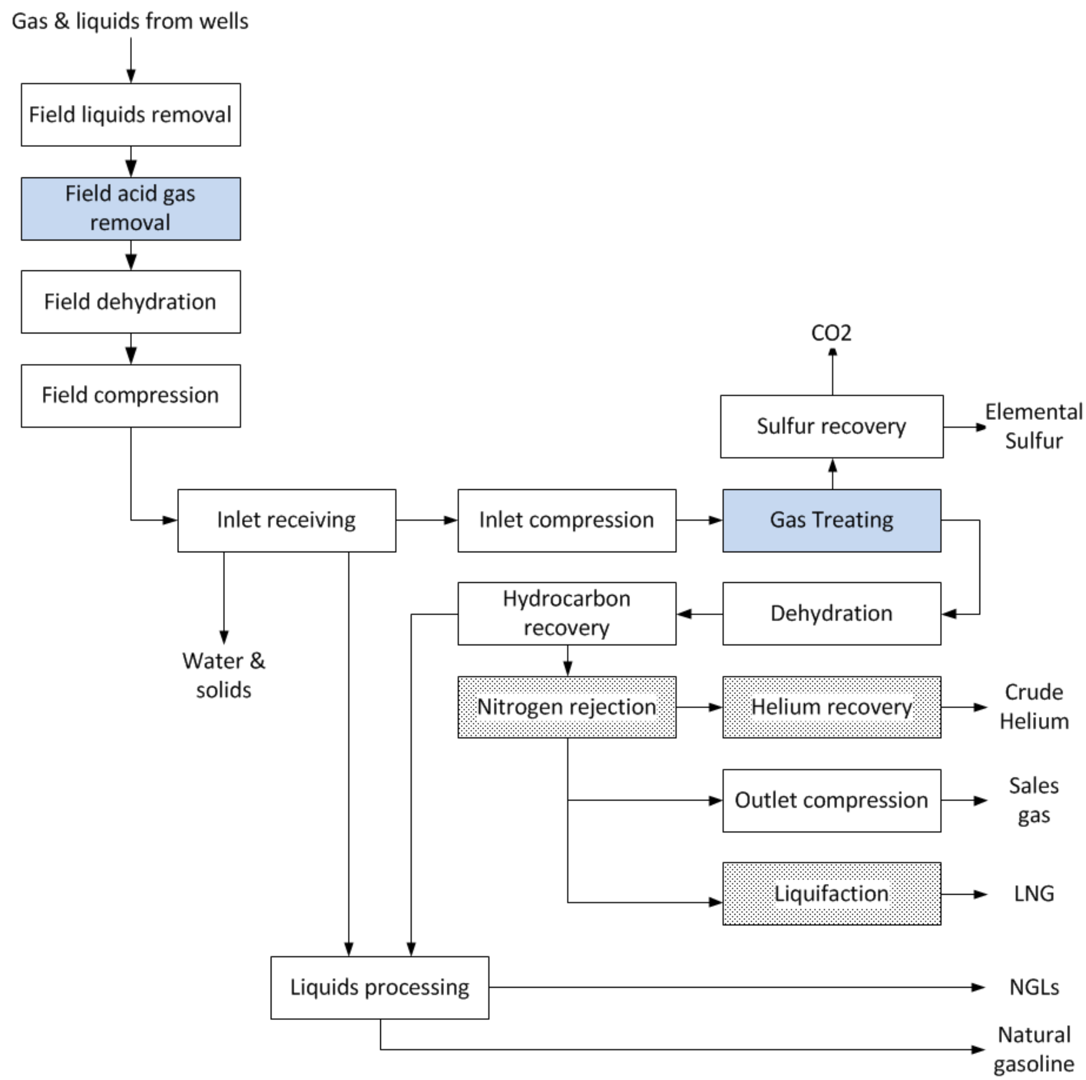
Natural Gas Sweetening Processes
Direct Conversion Processes
Indirect Conversion Processes
Separation Technologies
Liquid-Phase Processes
Dry-Bed Processes
Membrane Systems
Cryogenic Fractionation
Chemical Solvents
Physical Solvents
Hybrid Solvents
Physical Adsorption
Chemical Absorption
Alkanolamines
Alkaline Salts
Metal-Oxide Processes
Slurry Processes

PURIFICATION PROCESSES

- **More than 30 purification process are available**

1. ***Batch process***
2. ***Aqueous Amine***
3. ***Mixed Solution***
4. ***Physical Solvents***
5. ***Hot Potassium***
6. ***Direct Oxidation***
7. ***Adsorption***
8. ***Membrane***

Plant Block Schematic



Topics

- Chemical Absorption Processes
- Physical Absorption
- Adsorption
- Cryogenic Fractionation
- Membranes
- Nonregenerable H_2S Scavengers
- Biological Processes
- Safety and Environmental Considerations

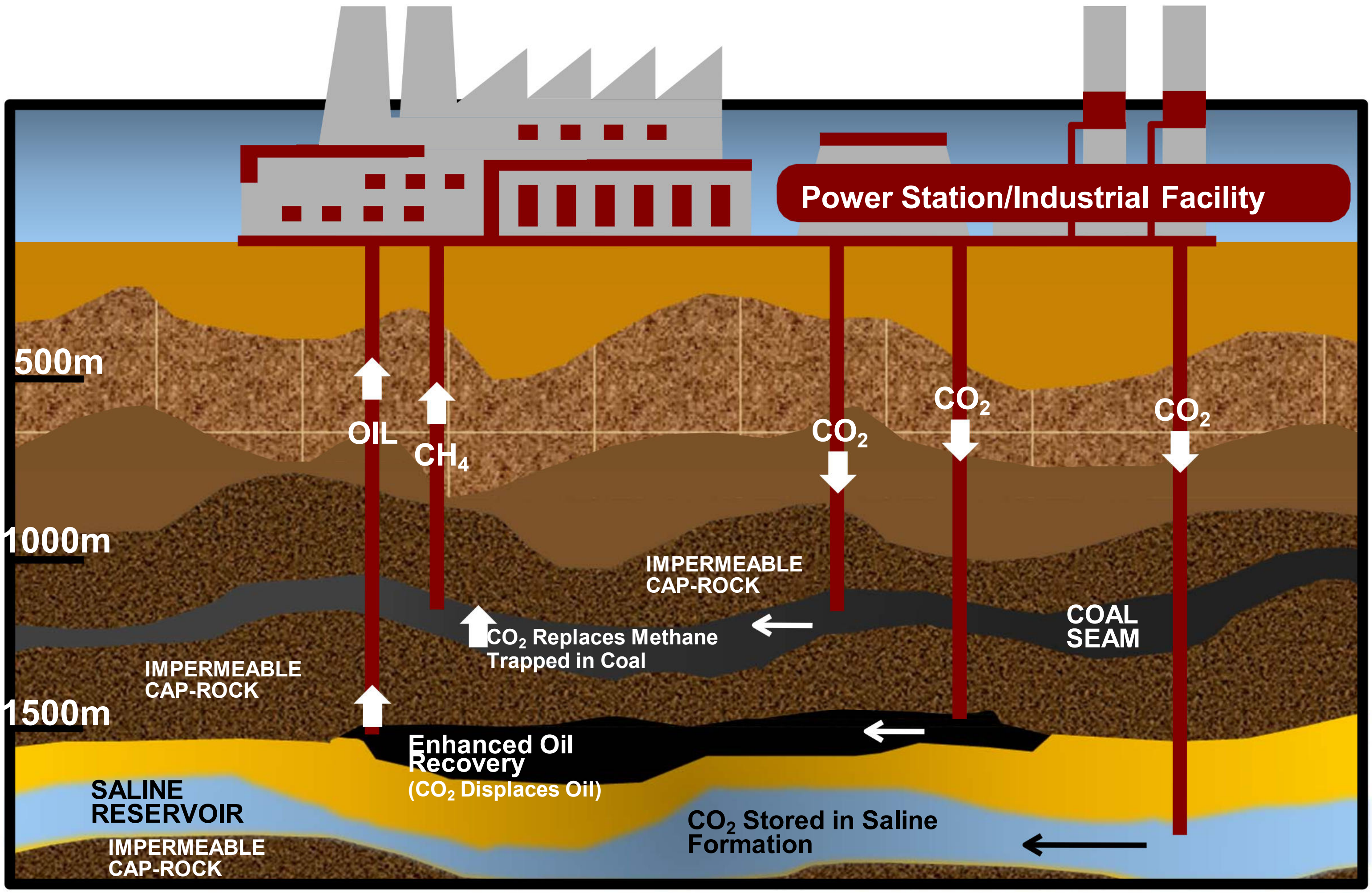
Gas treating

- Gas treating involves removing the ”acid gases” to sufficiently low levels to meet contractual specifications
  - Carbon dioxide (CO_2)
  - Hydrogen sulfide (H_2S)
  - Plus other sulfur species
- The problems
  - H_2S is highly toxic
  - H_2S combustion gives SO_2 – toxic & leads to acid rain
  - CO_2 is a diluent in natural gas – corrosive in presence of H_2O
- 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
  - CO_2
    - Vent to atmosphere
    - EOR – Enhanced Oil Recovery
    - Sequestration
  - H_2S
    - Incineration or venting (trace amounts)
    - React with scavengers (e.g. iron sponge)
    - Convert to elemental sulfur
    - Injection into suitable underground formation

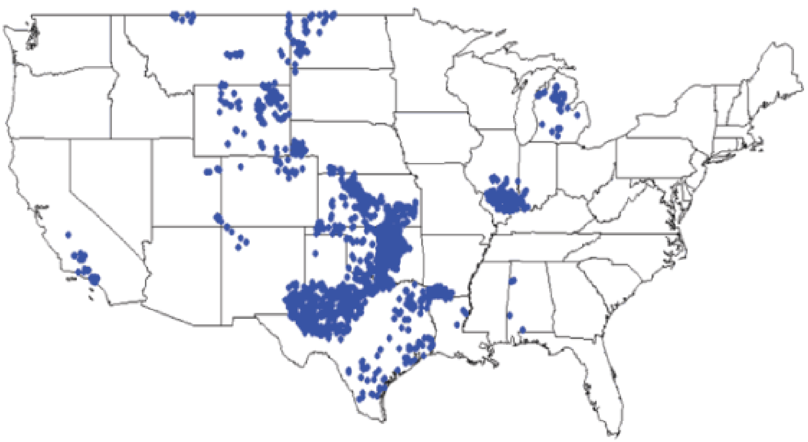
CO2 Capture and Sequestration



CO2 Sources & Disposition Options

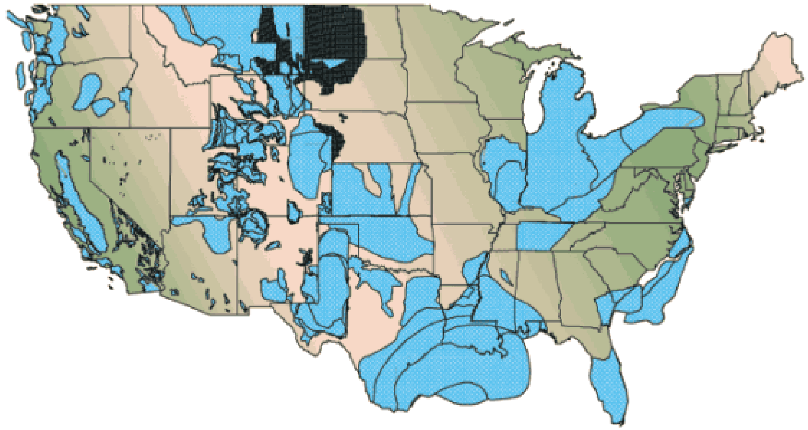
CANDIDATE US CO_2 EOR FIELDS

Fig. 8



DEEP SALINE AQUIFERS

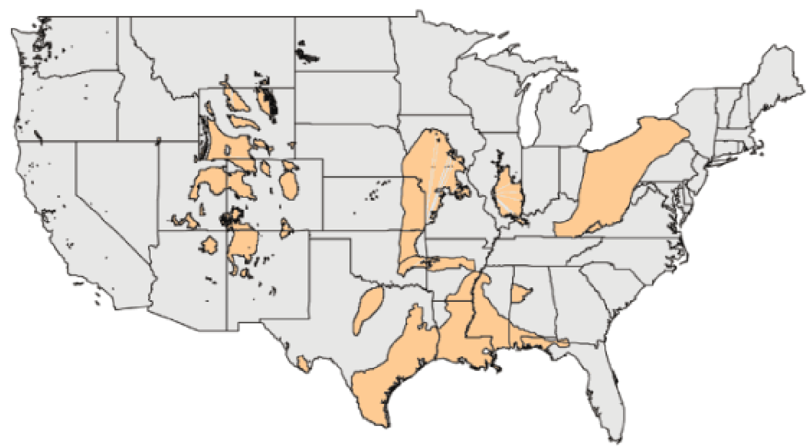
Fig. 6



Source: NatCarb

UNMINABLE COAL SEAMS

Fig. 9



"Study places CO2 capture cost between $34 and $61/ton"
Oil & Gas Journal, Oct. 12, 2009

Processes for acid gas removal

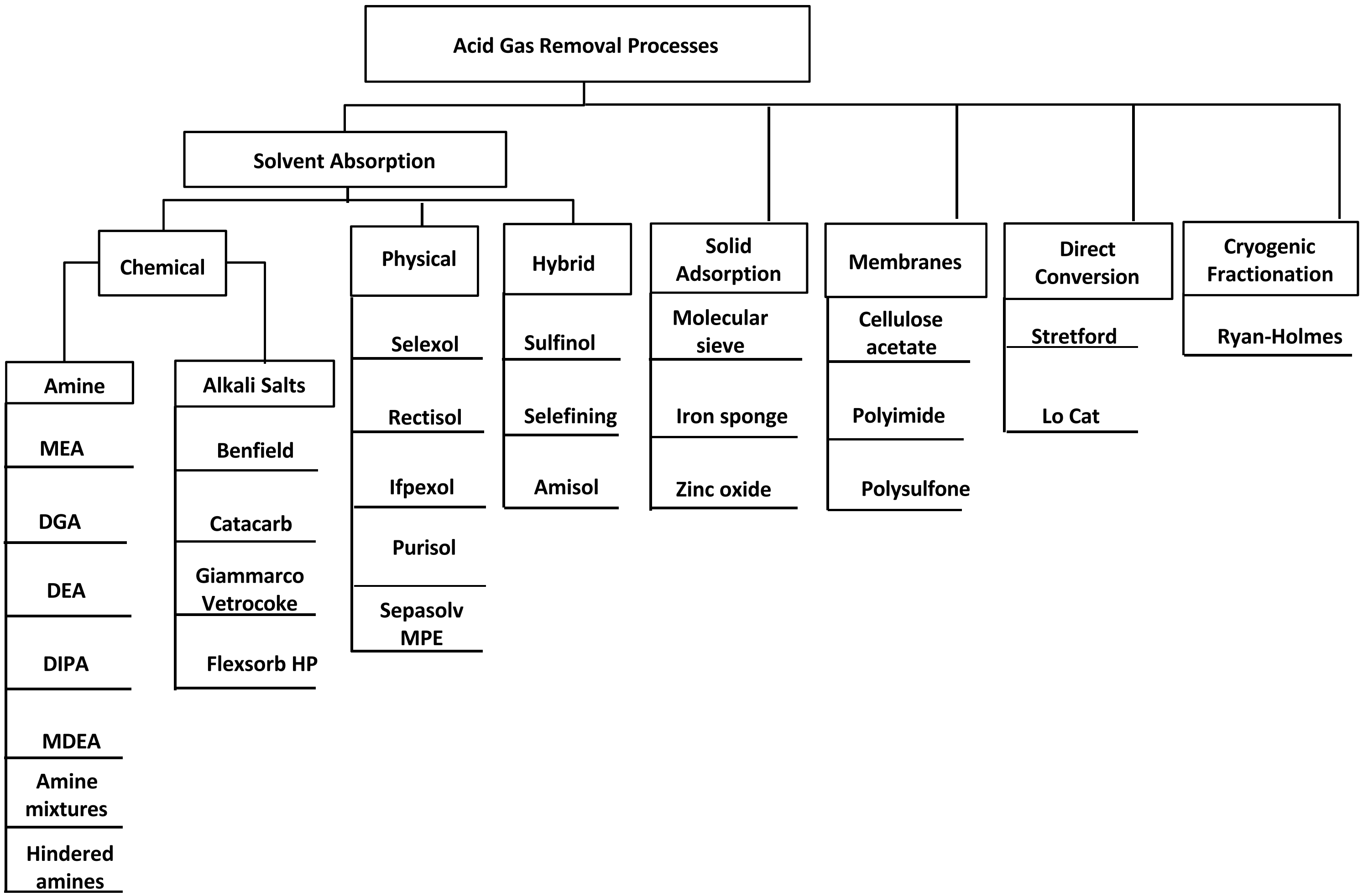


Figure 10.1, *Fundamentals of Natural Gas Processing*, 2nd ed., Kidnay, Parrish, & McCartney, 2011

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_2S
  - Both CO_2 and H_2S
  - Both CO_2 and H_2S present <u>but</u> selectively remove H_2S
    - Allow CO_2 <u>slip</u>

Selecting a process

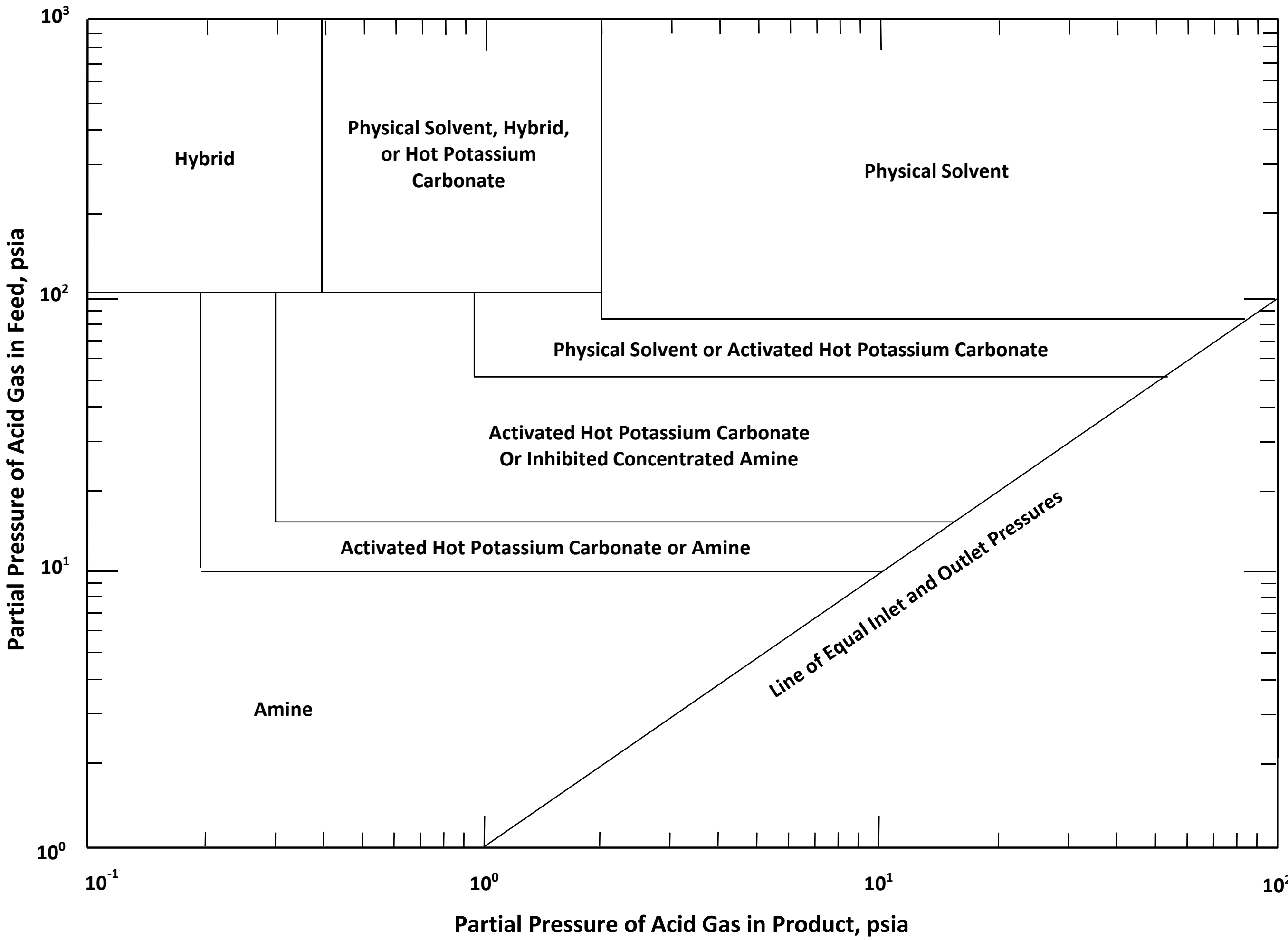


Table 1-3 Gases removed by various processes

Process	GASES REMOVED				
	CO_2	H_2S	RHS	COS	CS_2
Solid Bed					
Iron sponge		X			
Sulfa-Treat		X			
Zinc Oxide		X			
Molecular Sieves	X	X	X	X	X
Chemical Solvents					
MEA—MonoEthanolAmine	X	X		X[a]	X
DEA—DiEthanolAmine	X	X		X	X
MDEA—MethylDiEthanolAmine		X			
DGA—DiGlycolAmine	X	X		X	X
DIPA—DiIsoPropanolAmine	X	X		X	
Hot potassium carbonate	X	X		X	X
Physical Solvents					
Fluor Solvent	X	X	X	X	X
Shell Sulfinol®	X	X	X	X	X
Selexol®	X	X	X	X	X
Rectisol		X			
Direct Conversion of H_2S to Sulfur					
Claus		X			
LO-CAT®		X			
SulFerox®		X			
Stretford		X			
Sulfa-Check		X			
Nash		X			
Gas Permeation	X	X			

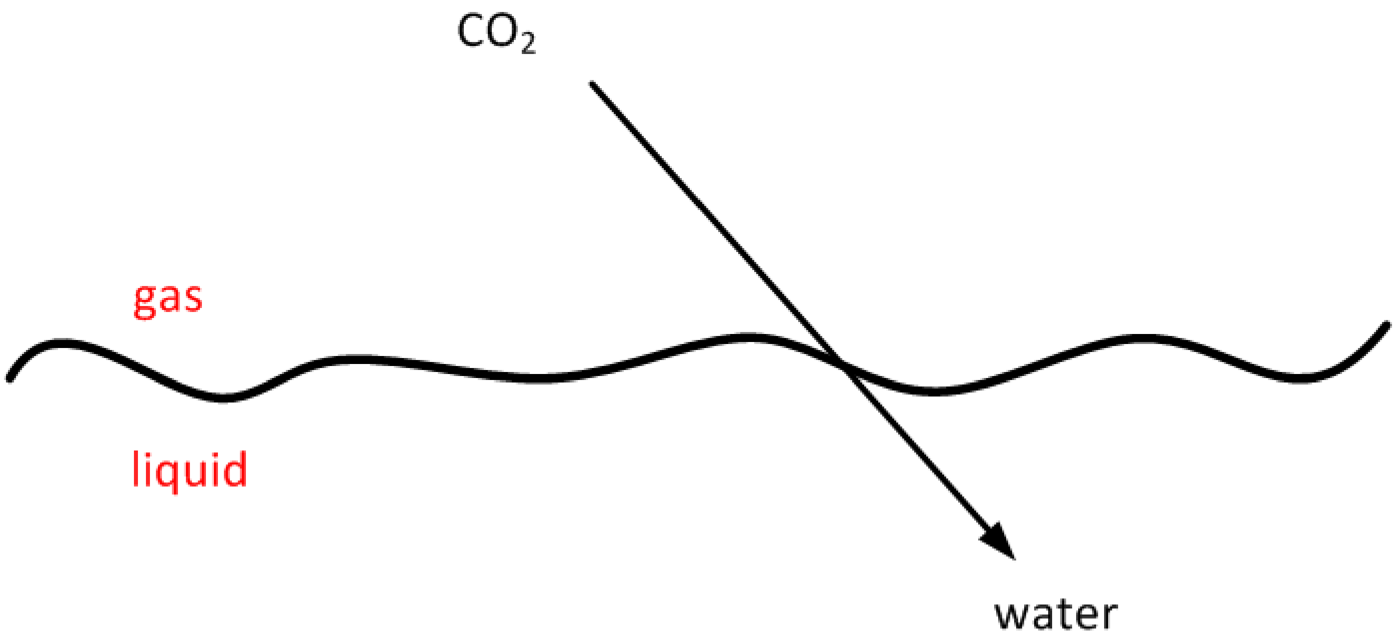
[a]MEA reacts nonreversibly with COS (carbonyl sulfide), and, therefore, should not be used to treat gases with a large concentration of COS.

Topics

- Chemical Absorption Processes
- Physical Absorption
- Adsorption
- Cryogenic Fractionation
- Membranes
- Nonregenerable H_2S Scavengers
- Biological Processes
- Safety and Environmental Considerations

Physical absorption

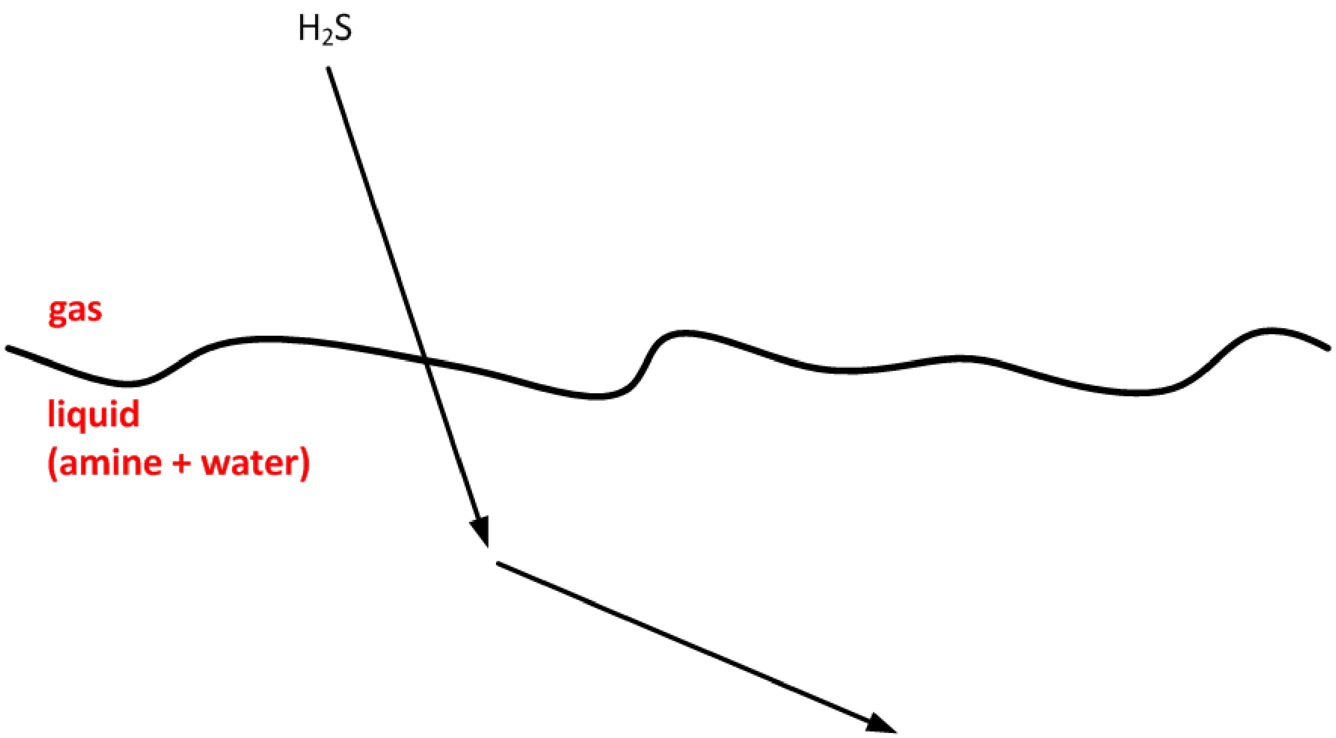
(Examples: carbonated water, soft drinks, champagne)



high P, low T = absorption

low P, high T = desorption

Chemical absorption



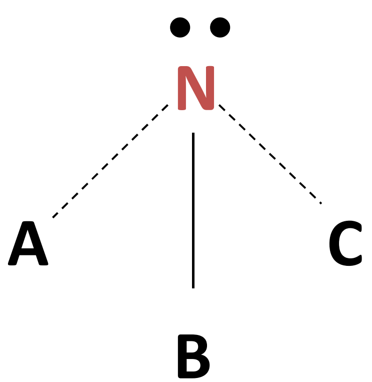
$$H_2S + R_1R_2R_3N = R_1R_2R_3NH^+S$$

(soluble salt)

reversible exothermic reaction

Amine Chemistry

AMINE



Primary amine (MEA)
A = CH_2CH_2OH
B = H
C = H

Secondary amine (DEA)
A = CH_2CH_2OH
B = CH_2CH_2OH
C = H

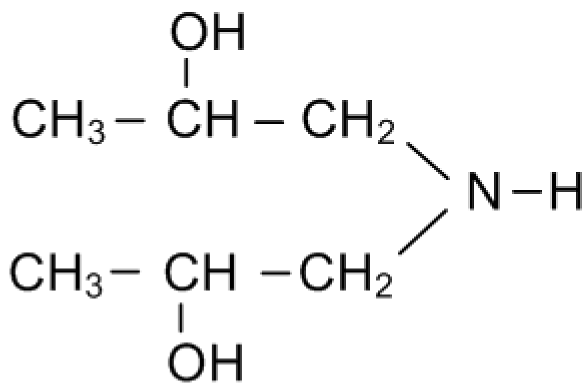
Tertiary amine (MDEA)
A = CH_2CH_2OH
B = CH_2CH_2OH
C = CH_3

- Gas treating amines are:
  - Weak Lewis Bases
  - 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

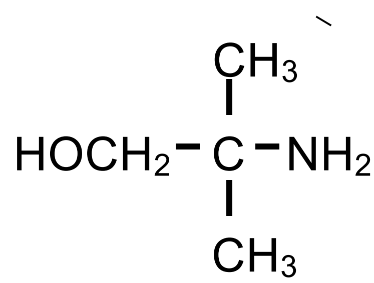
Dow Oil & Gas – Gas Treating Technology Presentation to URS Washington Division, August 2009 Rich Ackman – ackmanrb@dow.com

Sterically hindered amines – selective H_2S absorbers

Diisopropanolamine (DIPA)



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



Amines

- Amines remove H_2S and CO_2 in two step process:
  - Gas dissolves in solvent (physical absorption)
  - Dissolved gas (a weak acid) reacts with weakly basic amines
- H_2S reaction

$$R_1R_2R_3N + H_2S \leftrightarrow R_1R_2R_3NH + HS^-$$

- CO_2 reacts two ways with amine:
  - With water

$$CO_2 + H_2O + R_1R_2R_3N \leftrightarrow R_1R_2R_3NH^+ \; HCO_3^-$$

    - Much slower than H_2S reaction
  - Without water

$$CO_2 + 2\ R_1R_2NH \leftrightarrow R_1R_2NH_2 + R_1R_2NCOO^-$$

    - Faster but requires one H attached to the N
    - Use tertiary amines to "slip" CO_2

Comparison of acid gas removal solvents

Process	Capable of meeting H_2S spec?	Removes COS, CS_2, & mercaptans	Selective H_2S removal	Minimum CO_2 level obtainable	Solution subject to degradation? (degrading species)
Monoethanolamine (MEA)	Yes	Partial	No	100 ppmv at low to moderate pressures	Yes (COS, CO_2 , CS_2, SO_2 , SO_3 and mercaptans)
Diethanolamine (DEA)	Yes	Partial	No	50 ppmv in SNEA-DEA process	Some (COS, CO_2 CS_2, HCN and mercaptans)
Triethanolamine (TEA)	No	Slight	No	Minimum partial pressure of 0.5 psia (3 kPa)	Slight (COS, CS_2 and mercaptans)
Methyldiethanolamine (MDEA)	Yes	Slight	Some	Bulk removal only	No

Representative operating parameters

	MEA	DEA	DGA	MDEA
Weight % amine	15 to 25	25 to 35	50 to 70	40 to 50
Rich amine acid gas loading mole acid gas / mole amine	0.45 to 0.52	0.43 to 0.73	0.35 to 0.40	0.4 to 0.55
Acid gas pickup mole acid gas / mole amine	0.33 to 0.40	0.35 to 0.65	0.25 to 0.3	0.2 to 0.55
Lean solution residual acid gas mole acid gas / mole amine	~0.12	~0.08	~0.10	0.005 to 0.01

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)

	Wt%	**Mol%**	**Load Range**	**Relative Capacity**
MEA	18%	6.1%	0.35	1
DGA	50%	14.6%	0.45	3.09
DEA	28%	6.3%	0.48	1.41
MDEA	50%	13.1%	0.49	3.02
CompSol 20	50%	10.4%	0.485	2.37
CR 402	50%	14.7%	0.49	3.38
AP 814	50%	13.9%	0.485	3.16

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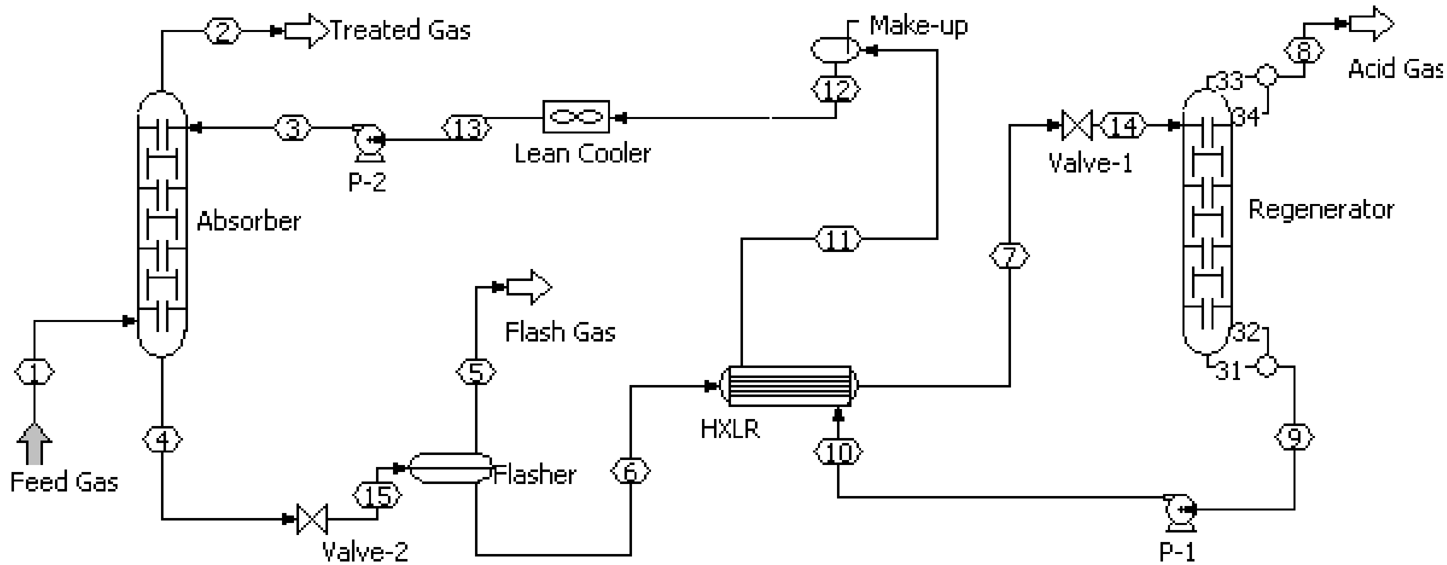
Heats of reaction in amine solutions

Amine	H_2S, Btu/lb (kJ/kg)	CO_2, Btu/lb (kJ/kg)
DGA®	674 (1570)	850 (1980)
MEA	610 (1420)	825 (1920)
DEA	555 (1290)	730 (1700)
MDEA	530 (1230)	610 (1420)

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 H_2S
  - 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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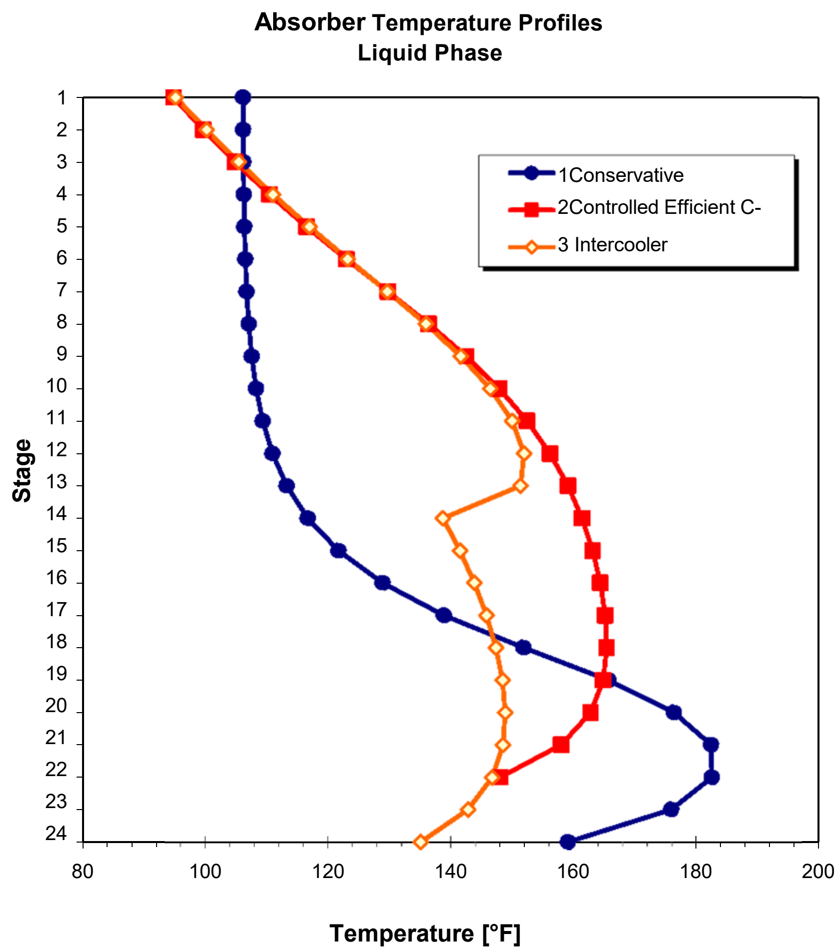
Amine Tower Parameters

- 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



Simplified Design Calculations

- Estimate amine circulation rate

$$\mathrm{GPM} = C \cdot \left(\frac{Qy}{x} \right)$$

C	=	41 if MEA
		45 if DEA
		32 if DEA (high loading)
		55.8 if DGA
Q	=	Sour gas to be processed [MMscfd]
y	=	Acid gas concentration in inlet gas [mol%]
x	=	Amine concentration in liquid solution [wt%]

- Use only if combined H_2S + CO_2 in gas below 5 mol%
- Amine concentration limited to 30 wt%

Amine Approximate Guidelines

		MEA	DEA	DGA
Acid gas pickup	scf/gal @ 100°F	3.1 - 4.3	6.7 - 7.5	4.7 - 7.3
Acid gas pickup	mol/mol amine	0.33 - 0.40	0.20 - 0.80	0.25 - 0.38
Lean solution residual acid gas	mol/mol amine	0.12	0.01	0.06
Solution concentration	wt%	15 - 25	30 - 40	50 - 60
Reboiler duty	BTU/gal lean solution	1,000 - 2,000	840 - 1,000	1,100 - 1,300
Steam heated reboiler tube bundle flux	Btu/hr-ft^2	9,000 - 10,000	6,300 - 7,400	9,000 - 10,000
Direct fired reboiler tube bundle flux	Btu/hr-ft^2	8,000 - 10,000	6,300 - 7,400	8,000 - 10,000
Reclaimer steam bundle or fire tube flux	Btu/hr-ft^2	6 - 9	N/A	6 - 8
Reboiler temperature	°F	225 - 260	230 - 260	250 - 270
Heat of reaction	Btu/lb H_2S	610	720	674
	Btu/lb CO_2	660	945	850

Operating issues with amine units

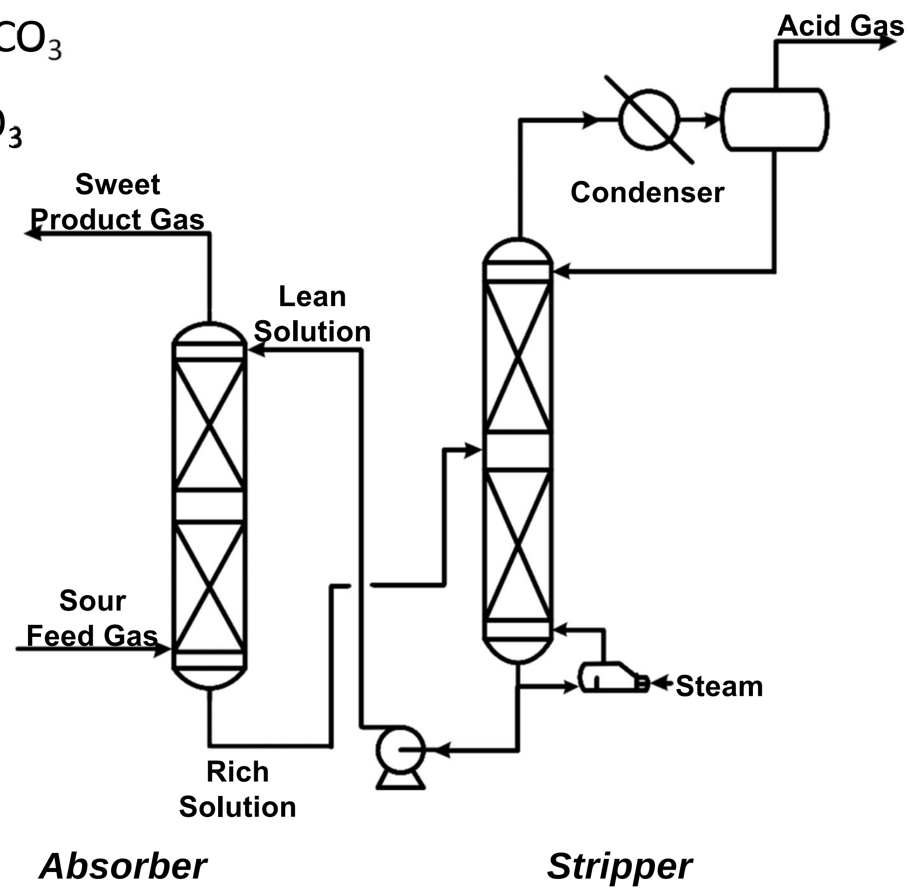
- Corrosion – caused by:
  - High amine concentrations
  - Rich amine loadings
  - Oxygen
  - Heat stable salts (HSS)
- Foaming – caused by
  - Suspended solids
  - Surface active agents
  - Liquid hydrocarbons
  - Amine degradation products (heat stable salts)

Hot potassium carbonate process (Hot Pot)

- Major reactions

$$K_2CO_3 + CO_2 + H_2O \leftrightarrow 2\ KHCO_3$$

$$K_2CO_3 + H_2S \leftrightarrow KHS + KHCO_3$$

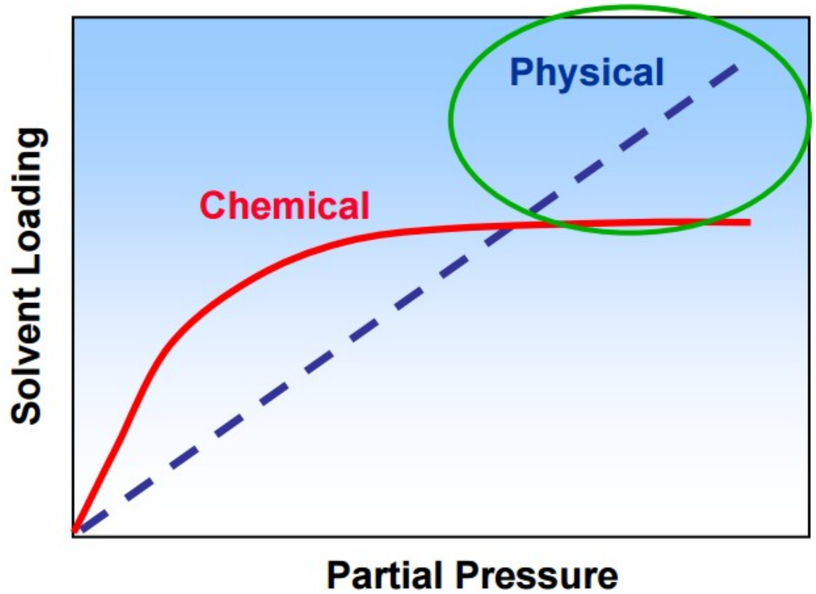


Topics

- Chemical Absorption Processes
- Physical Absorption
- Adsorption
- Cryogenic Fractionation
- Membranes
- Nonregenerable H_2S Scavengers
- Biological Processes
- Safety and Environmental Considerations

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



High acid gas partial pressures in syngas are ideal for physical solvent application

Figure from *UOP Selexol™ Technology for Acid Gas Removal*, UOP, 2009
Retrieved March 2016 from
http://www.uop.com/?document=uop-selexol-technology-for-acid-gas-removal&download=1

- Partial dehydration occurs along with acid gas removal

Comparison of chemical and physical solvents

	Advantages	Disadvantages
Chemical Solvent (e.g., amines, hot potassium carbonate)	Relatively insensitive to H_2S and CO_2 partial pressure	High energy requirements for regeneration of solvent
	Can reduce H_2S and CO_2 to ppm levels	Generally not selective between CO_2 and H_2S
		Amines are in a water solution and thus the treated gas leaves saturated with water
Physical solvents (e.g., Selexol, Rectisol)	Low energy requirements for regeneration	May be difficult to meet H_2S specifications
	Can be selective between H_2S and CO_2	Very sensitive to acid gas partial pressure

Physical Solvents – Selexol

- Characteristics
  - Poly (Ethylene Glycol) Dimethyl Ether

$$CH_3 - O - (CH_2 - CH_2 - O)_n - CH_3 \quad \text{where n is from 3 to 10}$$

  - Selexol is a mixture of homologues so the physical properties are approximate
  - Clear fluid that looks like tinted water
- Capabilities
  - H_2S selective or non selective removal – very low spec. - 4 ppm
  - 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_2S & 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 70ºF (21ºC)

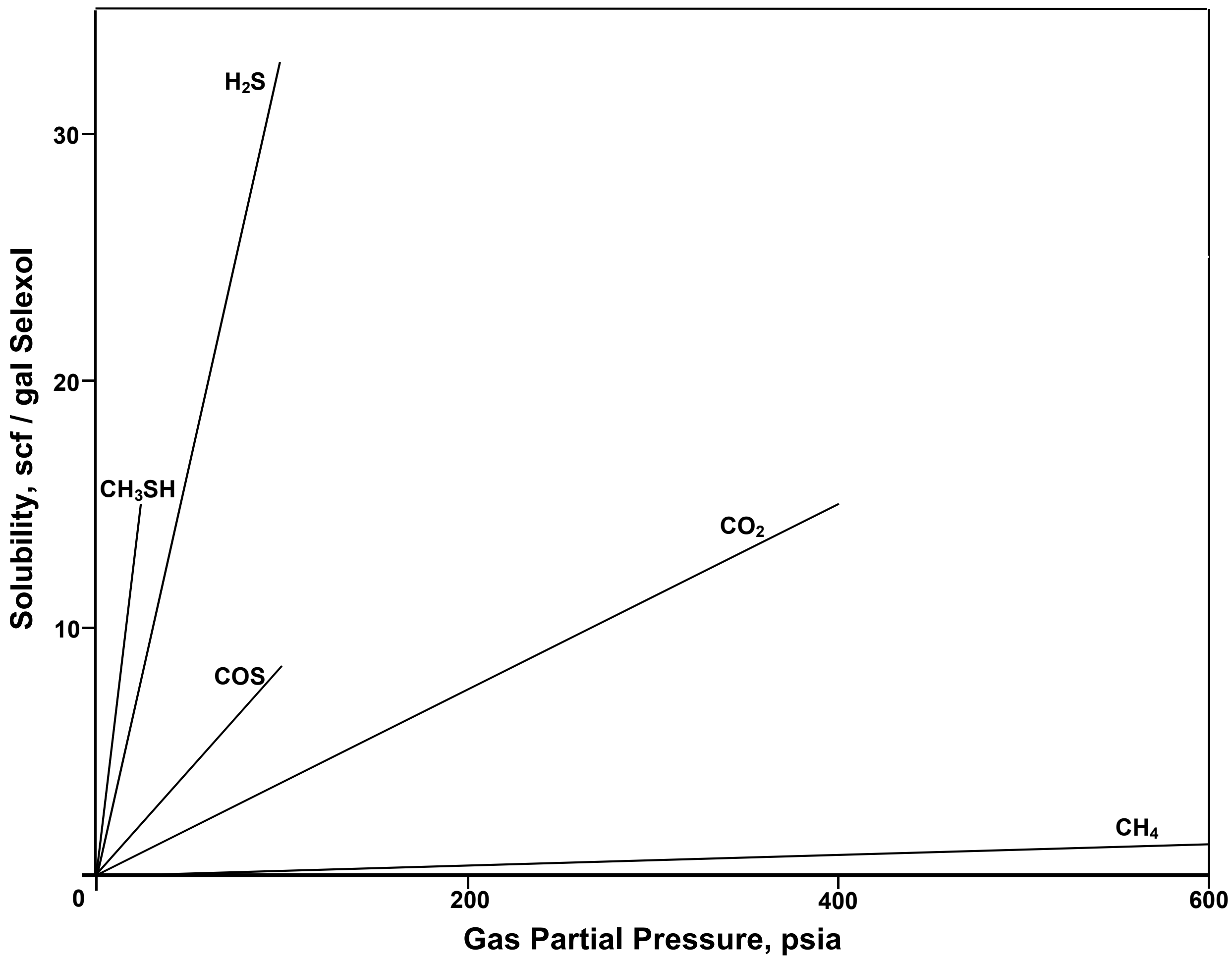
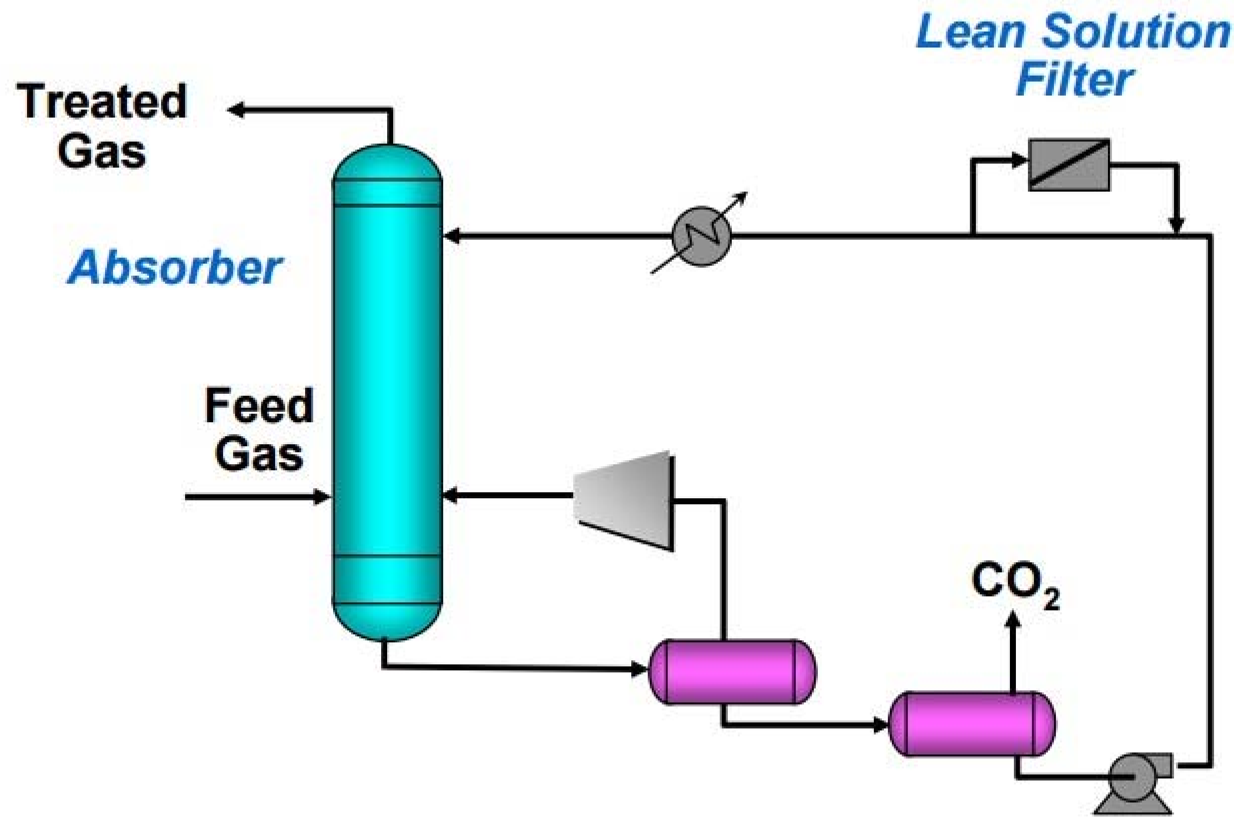


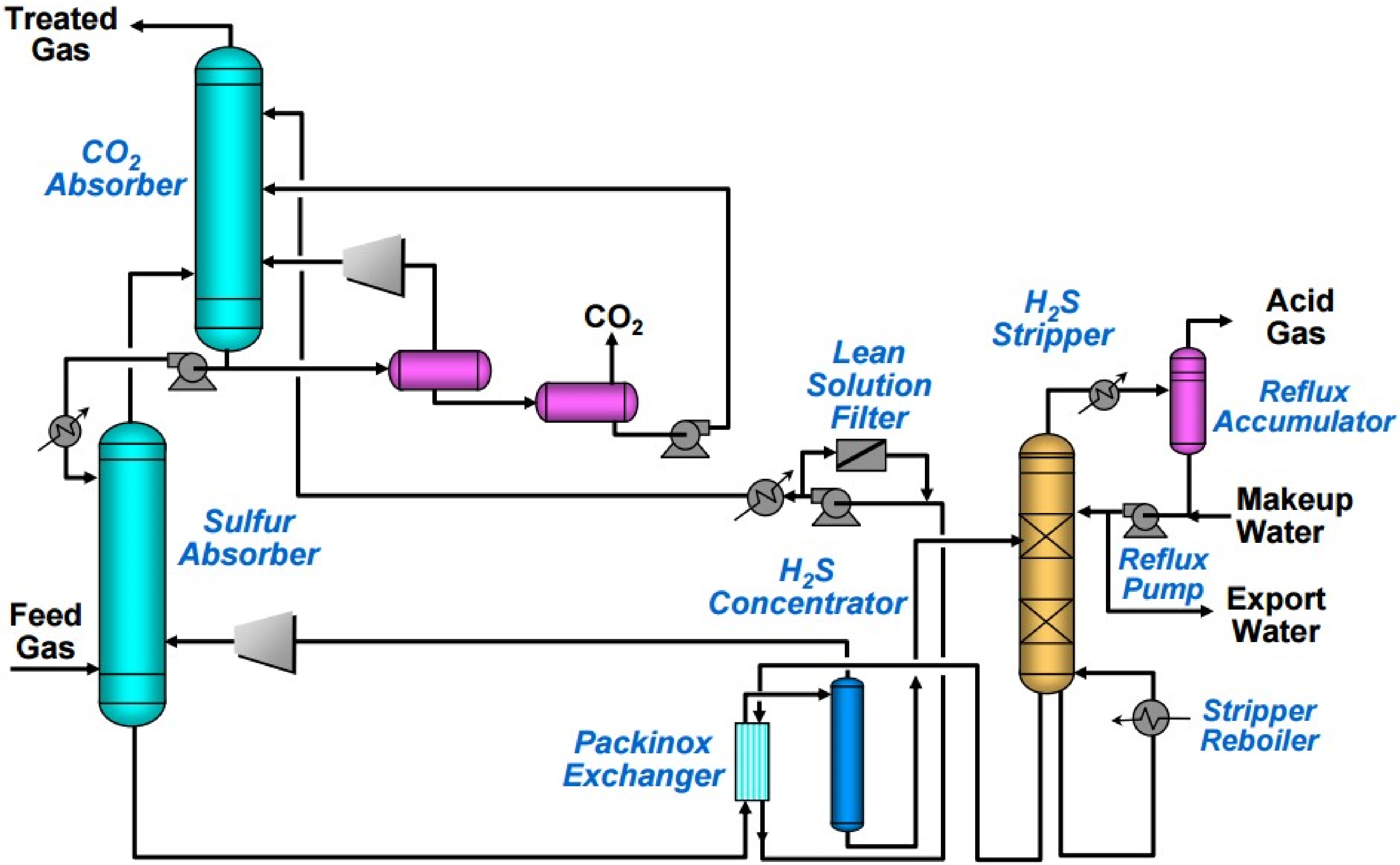
Figure 10.6, *Fundamentals of Natural Gas Processing*, 2nd ed., Kidnay, Parrish, & McCartney, 2011

Selexol process – CO_2 separation



UOP Selexol™ Technology for Acid Gas Removal, UOP, 2009
Retrieved March 2016 from http://www.uop.com/?document=uop-selexol-technology-for-acid-gas-removal&download=1

Selexol process – sulfur removal & CO_2 capture



UOP Selexol™ Technology for Acid Gas Removal, UOP, 2009
Retrieved March 2016 from http://www.uop.com/?document=uop-selexol-technology-for-acid-gas-removal&download=1

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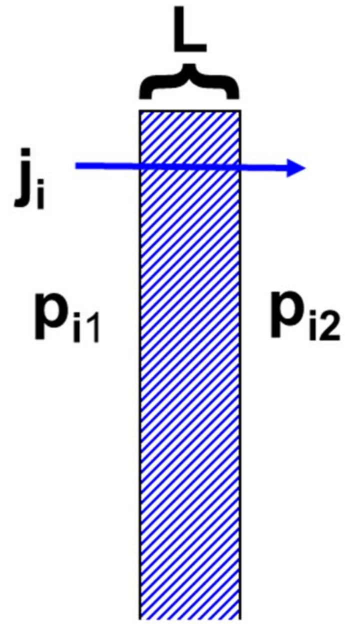
Membrane systems

- 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
Δp_i is the partial pressure difference across the membrane
L is the thickness of the membrane



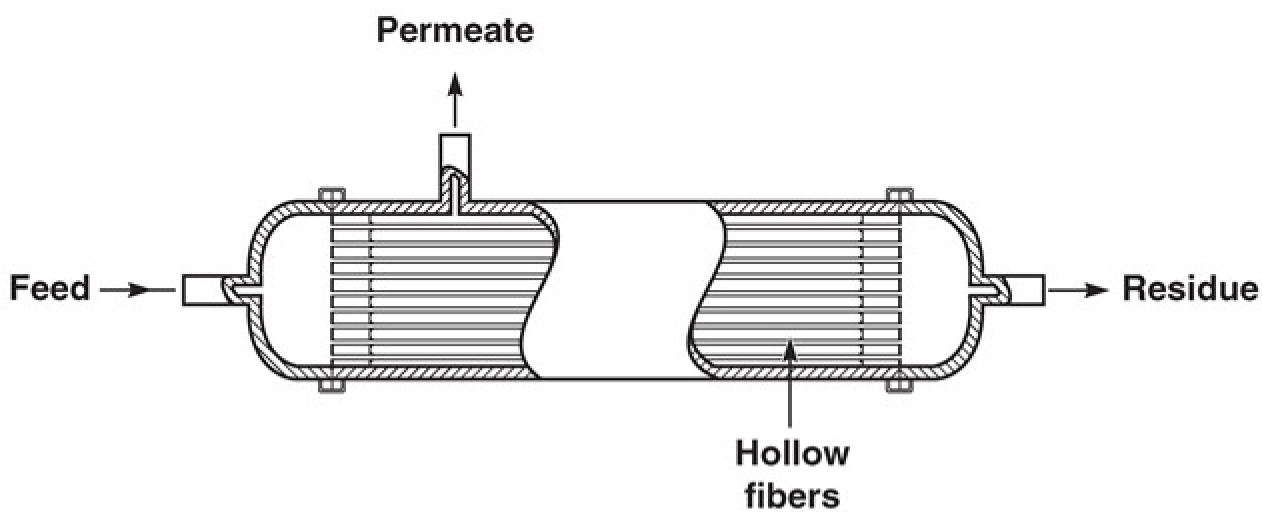
- The permeability combines the properties of solubility & diffusion
  - Differs for each compound
  - Provides selectivity

$$y_{i,\text{permeate}} \propto \left(\frac{P_{\text{feed}}}{P_{\text{permeate}}} \right) y_{i,\text{feed}}$$

Module configurations – hollow fiber

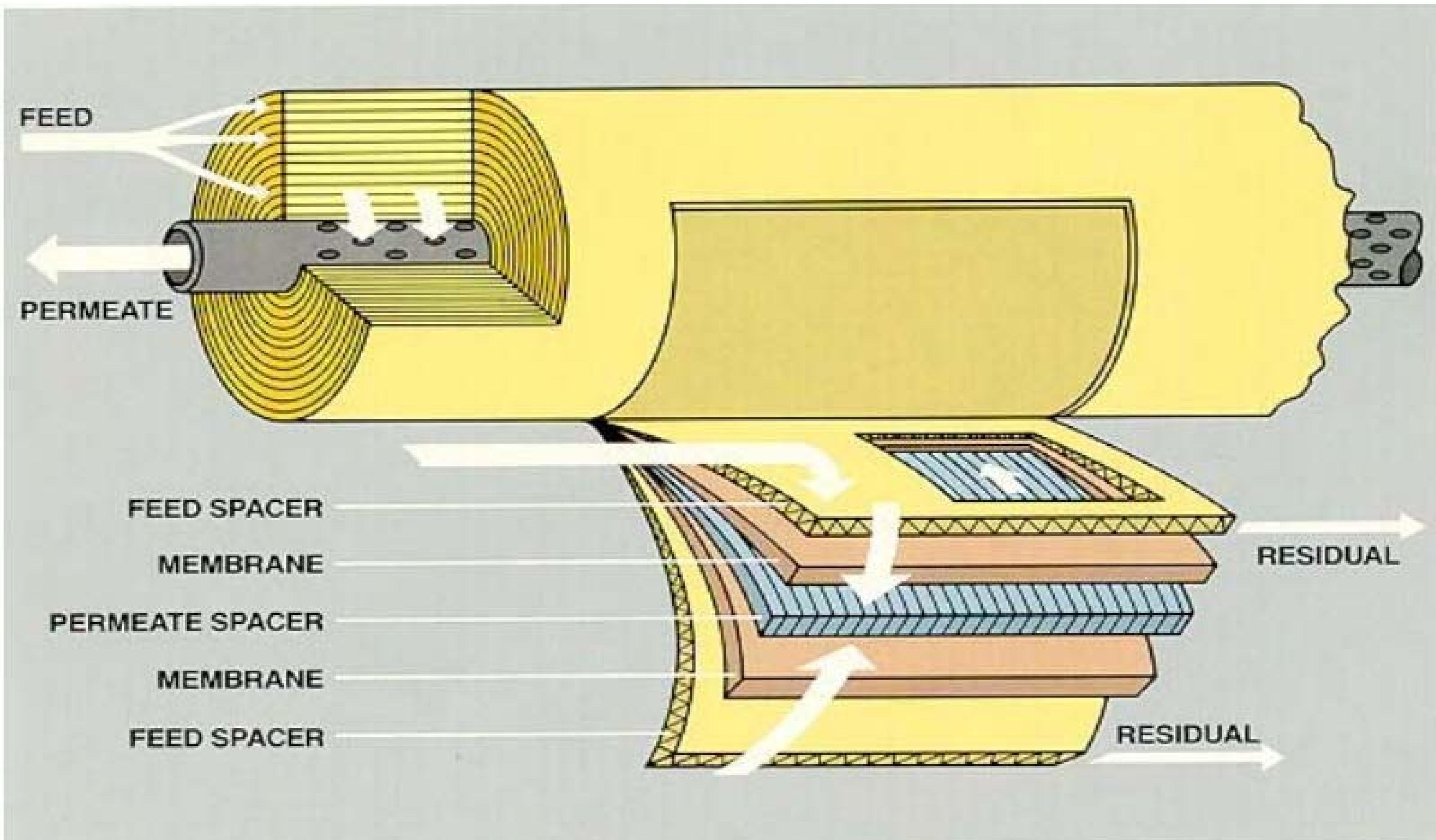
- Approximately 70% of membrane systems are hollow fiber

Low Pressure, Bore-Side Gas Feed Module



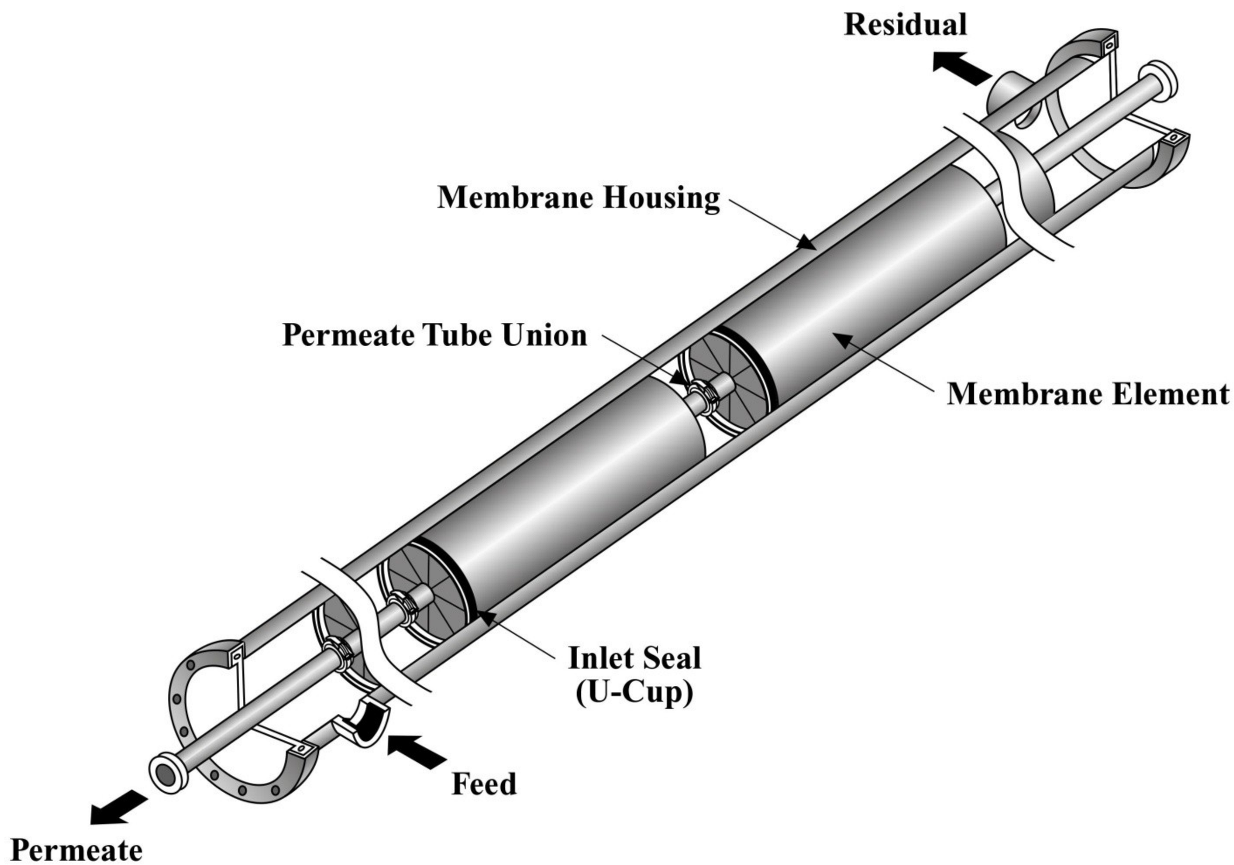
Courtesy MTR

Module configurations – spiral wound

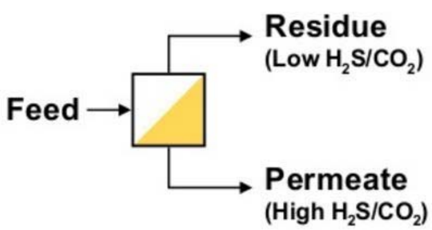


Continued Development of Gas Separation Membranes for Highly Sour Service, Cnop, Dormndt, & schott, UOP
Retrieved March 2016 from http://www.uop.com/?document=uop-continued-development-of-gas-separation-membranes-technical-paper&download=1

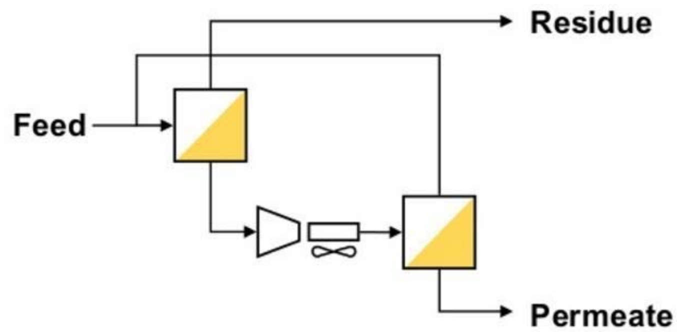
Module configurations – spiral wound



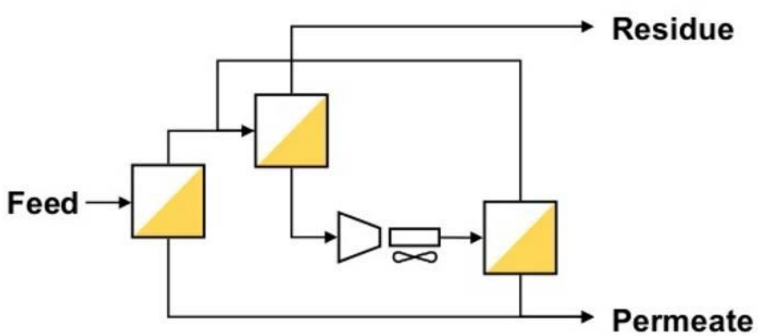
Membrane module flow schemes



- No moving parts
- Simple, reliable operation
- Low hydrocarbon recovery



- Allows for greater CO2 removal
- High hydrocarbon recovery
- Requires recycle compressor

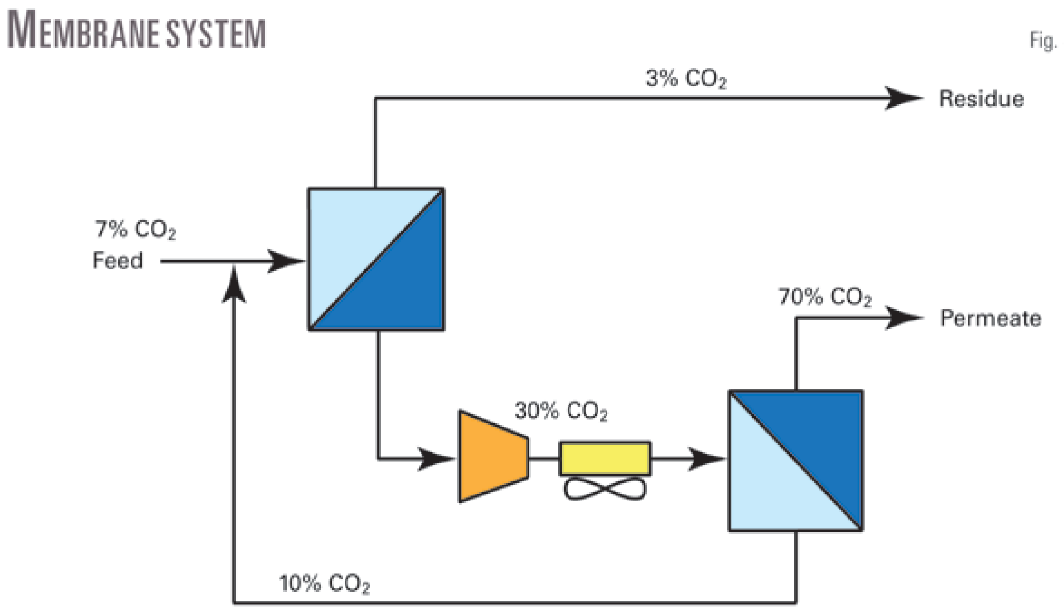


- Feed with high CO2
- Intermediate hydrocarbon recovery
- Reduced compression

UOP Separex™ Membrane Technology, UOP, 2009
Retrieved March 2016 from http://www.slideshare.net/hungtv511/uop-separex-membrane-technology

CO_2/CH_4 separation

Two stage process (non-optimized)



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Acid gas removal by adsorption (mole sieves)

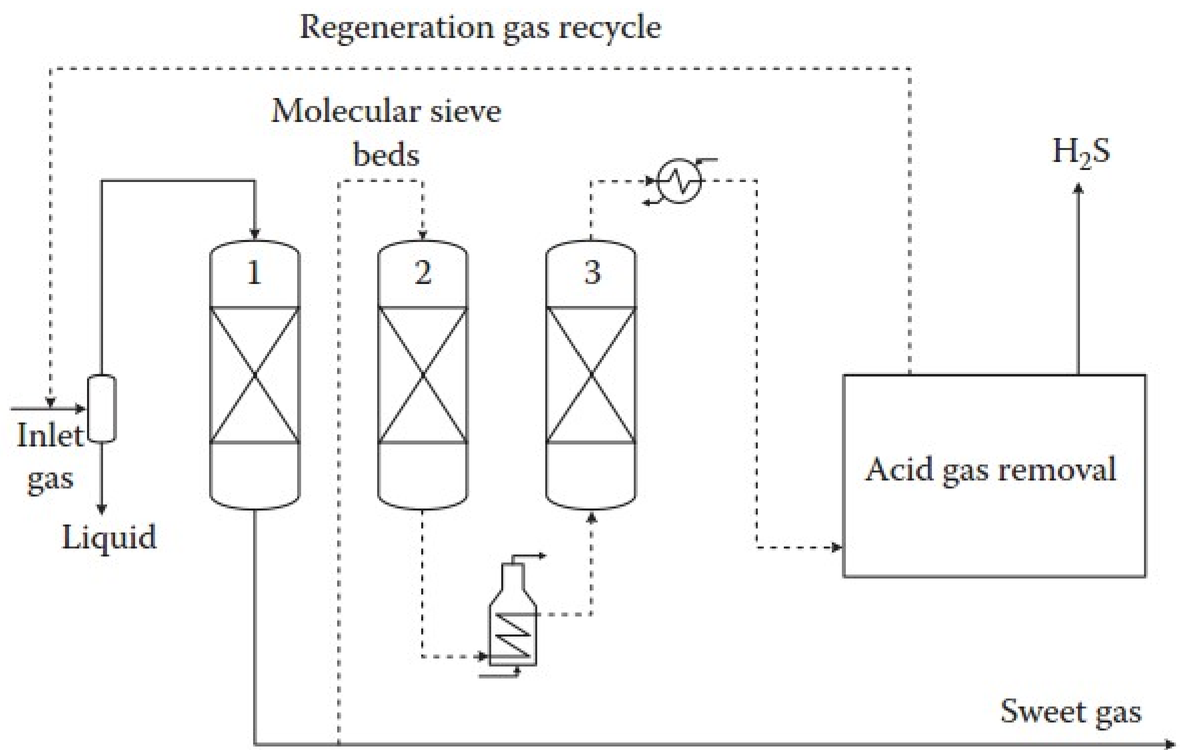

Figure 10.10, *Fundamentals of Natural Gas Processing*, 2nd ed., Kidnay, Parrish, & McCartney, 2011

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Nonregenerable H2S scavengers

Process Phase	Process
Solid-based processes	Iron oxides Zinc oxides
Liquid-based processes	Amine-aldehyde condensates Caustic Aldehydes Oxidizers Metal-oxide slurries

Table 10.9, *Fundamentals of Natural Gas Processing*, 2nd ed., Kidnay, Parrish, & McCartney, 2011

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