Field operations, inlet receiving & natural gas compression

Constantinos Hadjistassou, PhD
Associate professor
Programme in Oil & Gas Engineering
University of Nicosia
Marine & Carbon Lab: www.carbonlab.eu

Oct., 2020

UNIVERSITY *of* NICOSIA

Overview

- Natural gas components & products
- Roles of gas plants
- Contract types
- Field operations: 1. Pipeline transport. 2. Compression stations 3. Pigging. 4. Flow assurance.
- Phase separation
- Natural gas compression

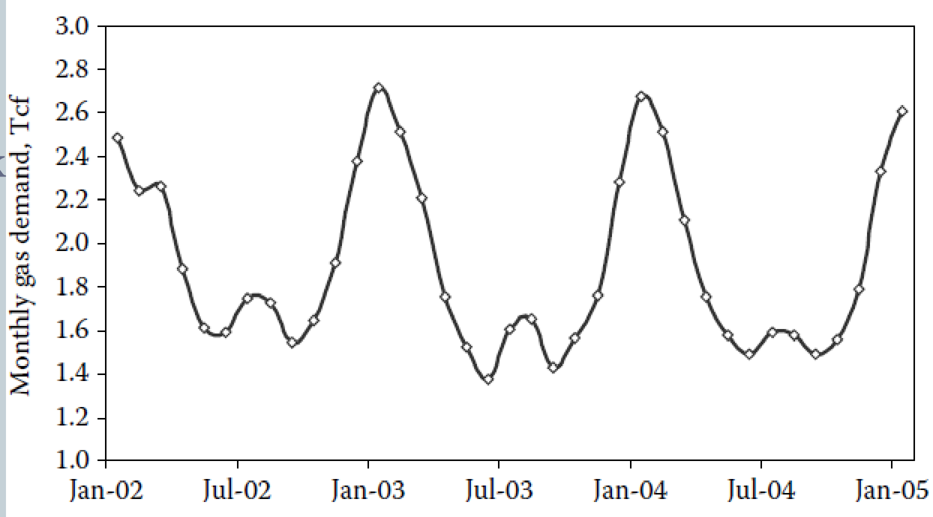
First LNG from Wheatstone

- Chevron has started producing first LNG
- Consortium: Chevron: 64.14%, Kuwait Petro: 13.4%; Woodside: 13%; Kyushu Electric Power: 1.46%; JERA 8%
- Plant consists of 2 LNG trains 8.9mtpa
- Wheatstone cost about $36bn
- Wheatstone video

Types of LNG plants

- Baseload LNG plants/storage:
  - Constant LNG supply
  - Usually >3MTPA
  - Produce most of the world's LNG

- Peakshaving storage facilities:
  - Smaller plants connected to gas network
  - LNG stored as a gas buffer
  - Liquefaction capacity: ~200t/d
  - Vaporization capacity: ~6000t/d



- Small scale plants:
  - Capacity of <500,000t/a
  - Linked to the gas network
  - LNG distributed by trucks or small LNG carriers
  - Examples in China & Norway

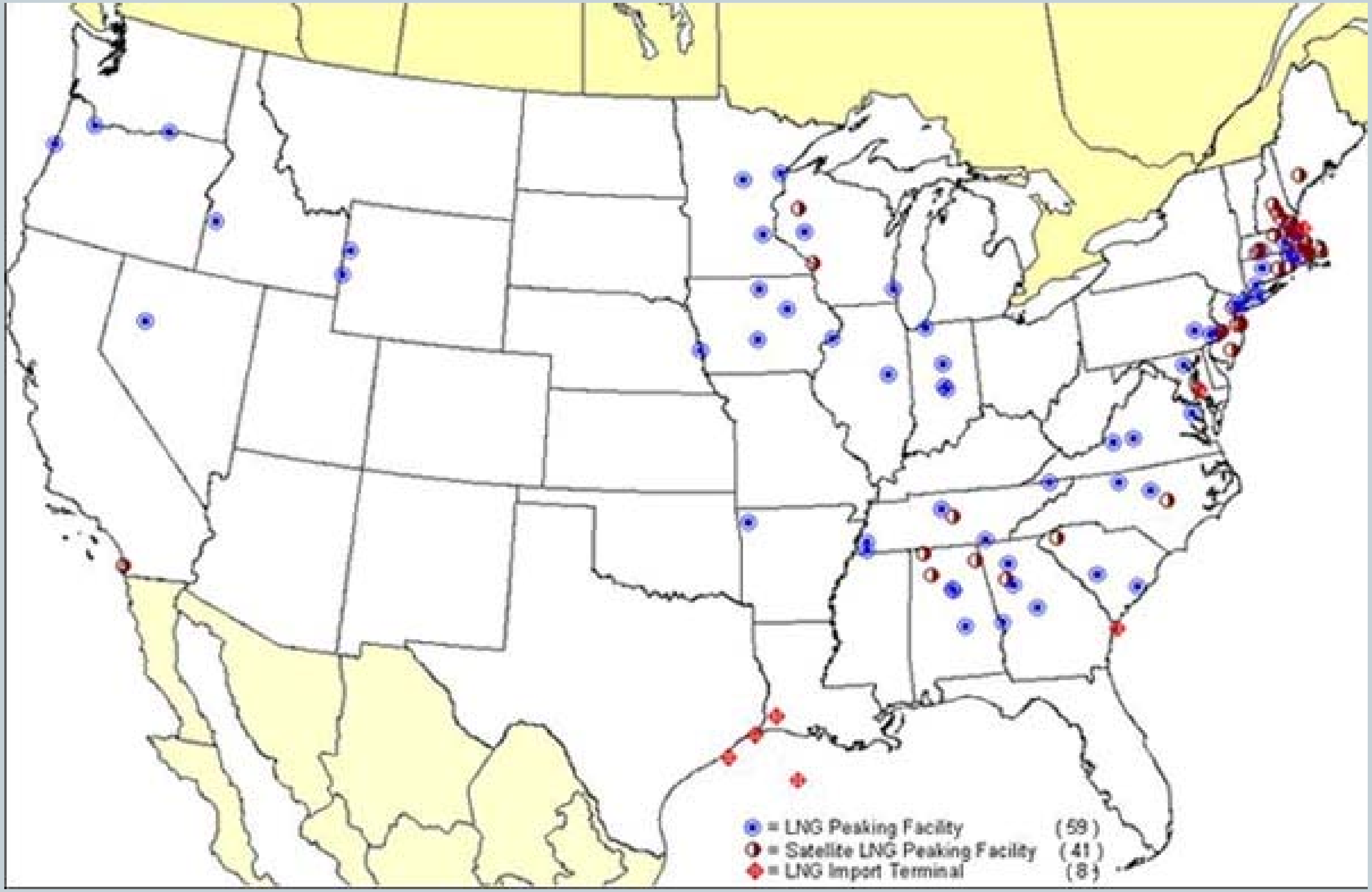
Peakshaving LNG storage

- Relatively high energy density of LNG can meet peak energy demand
- High demand needs (few days, weeks or few months)
- LNG tanks strategically sited close to cities, gas distribution networks
- A: High throughput conversion of LNG to NG
- A: Cost of liquefaction can be minimized
- A: Cost of pumps & vaporizers is relatively low
- D: LNG plant may cost x10 as much as storage
- D: Running costs of liquefaction are high
- However, high investment in extra transmission of network avoided
- Not all LNG peak shaving facilities do liquefaction

Memphis Peak LNG shaving facility

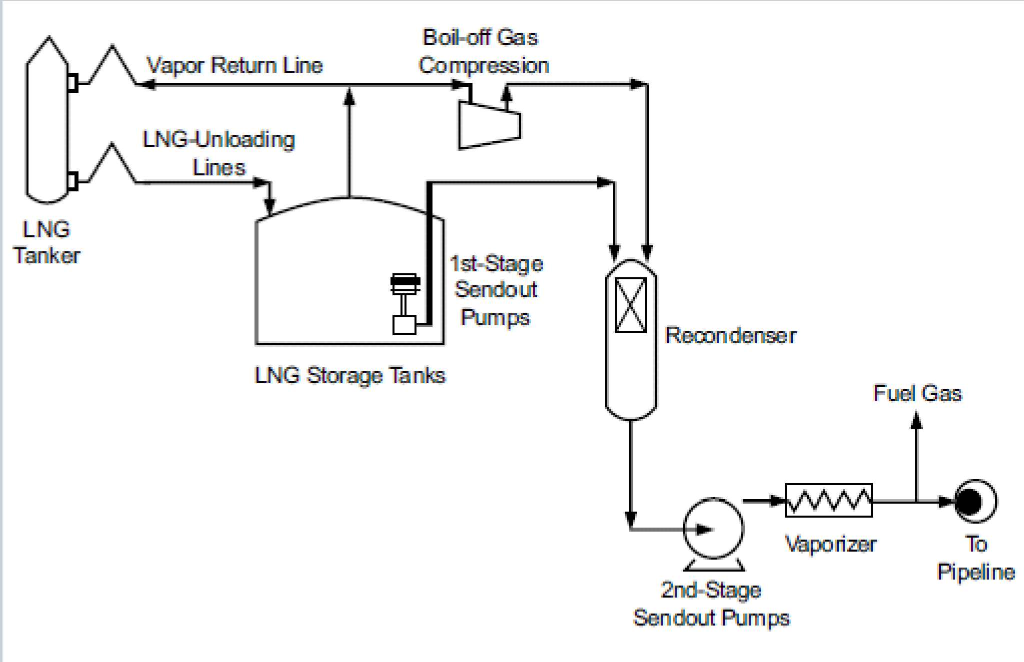
US LNG Peak shaving facilities (2008)

- Satellite facilities store & regasify LNG only



Baseload LNG receiving terminal

- Able to meet min. level of LNG demand (over 24hrs)
- A receiving terminal includes:
  - Tanker berthing
  - Storage tank
  - Regas facilities
  - High press. LNG pumps
  - Handle vapour
  - Handle boil-off gas
  - May include gas odourization



Natural gas composition

- Untreated natural gas consists predominantly of:
  - Nitrogen (N_2);
  - Carbon dioxide CO_2;
  - Traces of Sulphur species (H_2S, carbonyl sulfide, …);
  - Higher hydrocarbons
  - Impurities i.e. dust
  - Traces of Mercury (Hg) and occasionally
  - Helium (He)
  - Water vapour (H_2O)
  - Oxygen
  - Dilutents (92% CO_2, Col.; 88% H_2S, Alberta; 86% N_2, Tx)
- Gas condensates:
  - H_2S, CO_2, straight-chain alkanes, cyclohexane, napthenes
  - Thiols (mercaptants), aromatics (benzene, toluene)
- Natural Gas Liquids (NGLs)
  - Consist of low-molecular weigh H/Cs such as CH_4, C_2H_6, C_3H_8, & C_4H_{10}

Natural gas processing

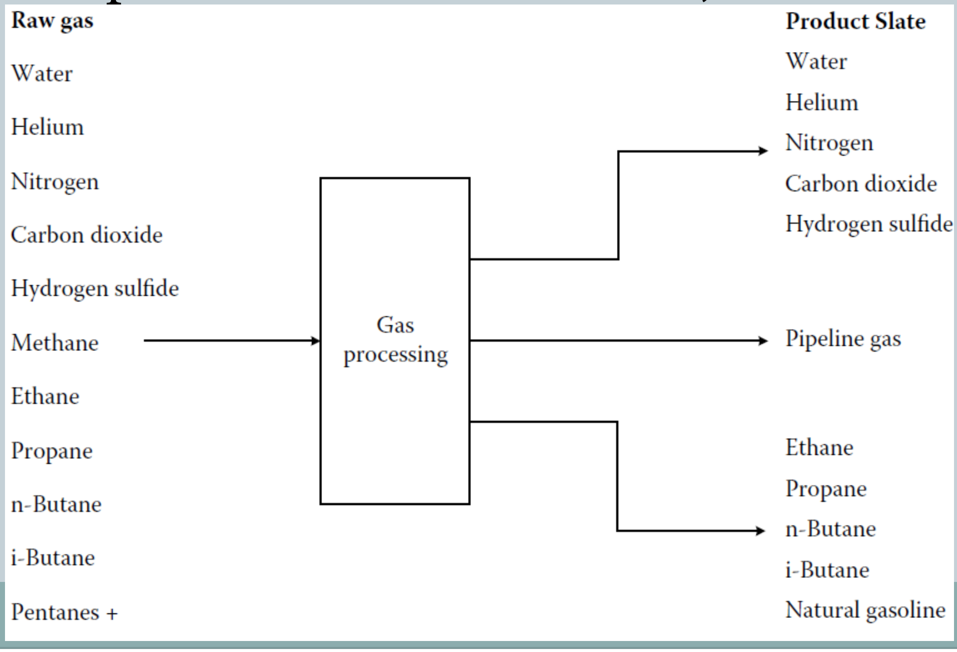
- Natural gas is mainly used as: a fuel & as a petrochemical feedstock
- Gas composition defines gas processing economics
- Reasons for raw gas processing:

- Purification. Remove substances that inhibit use of nat. gas for eg industrial or residential fuel

- Separation. Split components such as petrochemical feedstocks, fuels (propane), & industrial gases (He, C_2H_6)

- Liquefaction. Boost energy density for transportation (eg LNG) or storage

- Purification: small volume
- Separation: large volumes



Gas processing

- Meets transport or final gas specs
- Processing objectives:
  - Generate a sales gas stream which meets specs (Table below). These specs are designed to meet pipeline requirements & needs of industrial & domestic consumers
  - Maximize NGL share by producing lean gas stripped of most H/Cs other than CH_4
  - Deliver a commercial gas supply (distinguished by a range of gross heating value).

Natural Gas Specifications in the Salable Gas Stream (Goar and Arrington, 1978)

Characteristic	Specification
Water content	4–7 lb/MMscf (max)
Hydrogen sulfide content	1/4 grain/100 scf (max)
Gross heating value	950 Btu/scf (min)
Hydrocarbon dew point	15°F at 800 psig (max)
Mercaptan content	0.2 grain/100 scf (max)
Total sulfur content	1–5 grain/100 scf (max)
Carbon dioxide content	1–3 mole percent (max)
Oxygen content	0–0.4 mole percent (max)
Sand, dust, gums, and free liquid	Commercially free.
Typical delivery temperature	120°F
Typical delivery pressure	714.7 psia

Natural gas products (1)

- Methane (CH_4): used as a fuel. Main component of pipeline gas. Used as feedstock for the production of ammonia (NH_3) & methanol.
- Ethane (C_2H_6): used as fuel. Constituent of pipeline gas. Utilized in the production of ethylene; feedstock of polyethylene.
- Propane (C_3H_8): Uses as a petrochemical & residential fuel.
- Ethane-propane mix: also called an E-P mix is pumped to consumers, utilized as a chemical or refining feedstock.
- Isobutane: feedstock for MTBE (methyl tertiary butyl ether, phased out); production of reformulated gasoline & production of propylene oxide.

Natural gas products (2)

- n-Butane: predominantly used in gasoline as a blending. Mixtures of butanes & propane used as propellants in aerosols.
- Natural gas liquids (NGLs): H/Cs liquefied in the field or in processing plants, incl. ethane, propane, butanes & natural gasoline. Raw products
- Natural gasoline: consists of pentanes & heavier H/Cs; blended into gasoline & feedstock for C_3/C_6 isomerization and ethylene production.
- Sulphur: convert H_2S into elemental S. Used for rubber vulcalinization, production of sulphuric acid & black gunpowder.

Characteristics of natural gas

- Most of the gas used as fuel for domestic/industrial users
- NG is normally traded according to its heating value
- The more C_{2+} liquids the "richer" the gas
- Liquids: isobutane, n-Butane, isopentane, n-pentane, ... (see Kinday)
- Preceding fluids ($m^3/100m^3$ of gas) more valuable than CH_4

Sulphur content

- Sulphur is usually in the form of hydrogen sulphide (H_2S)
- H_2S has a tangent (rotten eggs) smell
- Sweet gas contains < 4 ppmv H_2S
- The presence of H_2O makes H_2S corrosive
- Pipeline-quality gas H_2S limit: 16 ppmv

Wobbe Index (WB)

- Interchangeability index i.e. Btw CH_4 & C_4H_{10}
- Maintenance of the same heat quantities at a gas burner btw gases
- If 2 gas compositions have same WB # are interchangeable
- Wobbe number or index (metric) defined by:

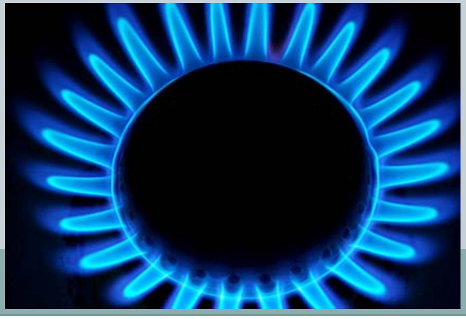
$$WB = \frac{\text{Gross heating value}}{\sqrt{\text{Specific gravity}}}$$

- Units: 51 MJ/m³ for CH_4 (or BTU/scf)
- Specific gravity = density (ρ) of gas/ρ of air
- Higher heating value (Gross heating or calorific value, liquid formed H_2O)
- Example

Families of gases

Units: MJ/m³

Family	Gas type	Approx. Wobbe no.
1st	Manufactured (town gas)	24–29
2nd	Natural	48–53
3rd	LPG	72–87



Example

- Calculate the Wobble Index (WI) of natural gas with a calorific value of 38.6MJ/m³ and specific gravity of 0.58.

$$WB = \frac{\text{Gross heating value}}{\sqrt{\text{Specific gravity}}} = \frac{38.6}{\sqrt{0.58}} = 50.68 MJ / m^3$$

The preceding value lies btw 48–53MJ/m³ which is acceptable for natural gas.

Roles of gas plants (1)

- Dehydration. Remove H_2O to reduce corrosion & prevent gas hydrates. Offshore plants. Associated gas dehydrated & reinjected into oil for piping.

- Associated oil stabilization. Remove gas from oil so that oil is safe to pump via pipeline. Example Prudhoe Bay Alaska. Gas reinjected in reservoir so as to maintain pressure.

- CO_2 or N_2 recovery. CO_2 and N_2 are separated for enhanced oil recovery (EOR). NG is sold.

- Upgrading inferior quality gas. Remove CO_2, H_2S & N_2. N_2 is the most difficult to remove as it requires cryogenic cooling for bulk quantities.

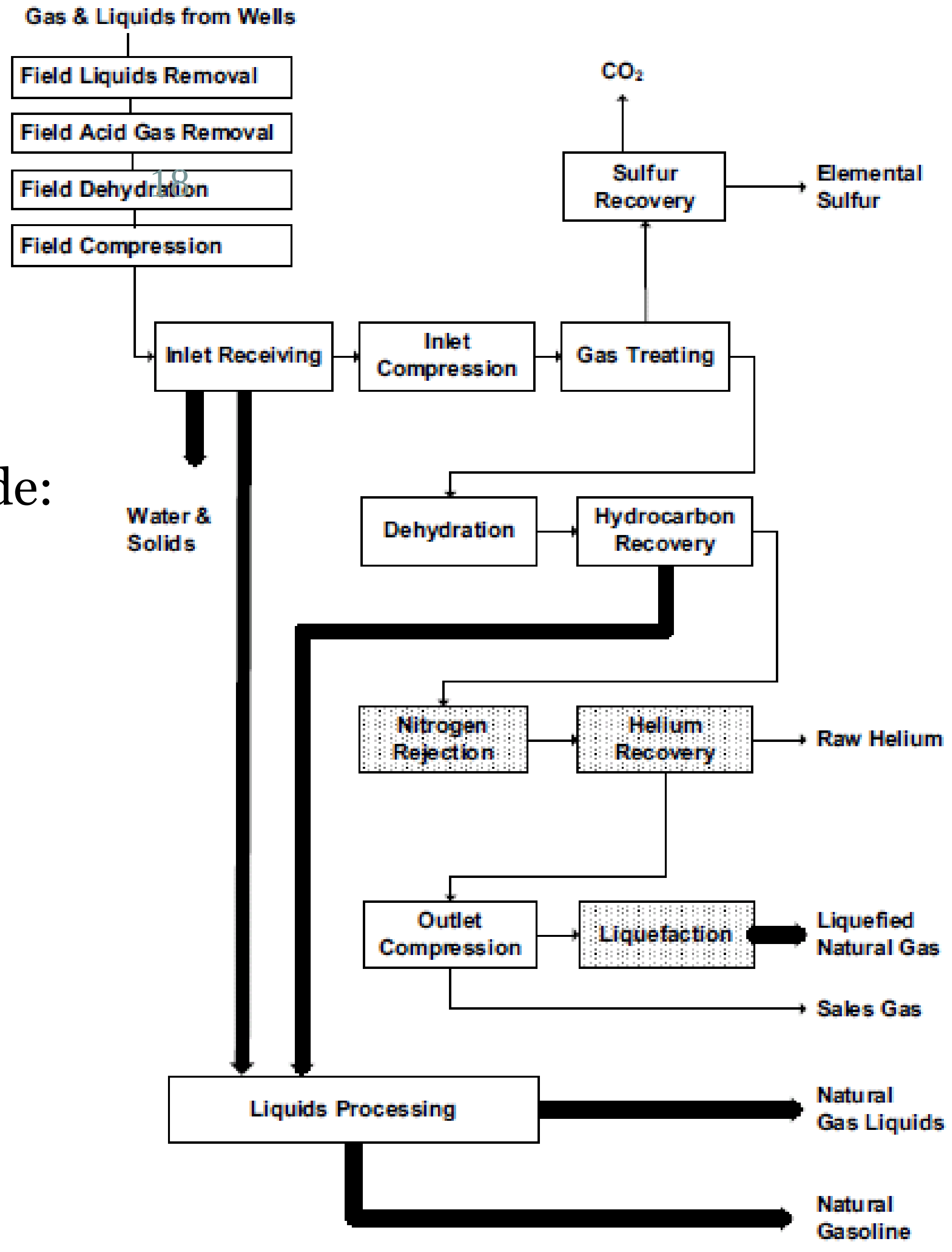
Roles of gas plants (2)

- Helium. NG is the major source of helium. He is used as cryogenic gas & for growing silicon wafers. An addition to a gas plant.

- Liquefaction. Gas plants which produce NG liquids & a gas stream for liquefaction. Usually serves large gas reserves with no pipelines to markets. LNG increasingly being used to store energy (peak shaving storage)

Gas processing

- Black lines denote liquids
- Less common processes appear in shaded color
- Field operations may include:
  - CO_2 removal
  - Dehydration
  - Compression
  - H_2S removal
- Inlet receiving removes:
  - Condensed H_2O
  - H/C liquids
  - Solids



Contract types btw producers & processors

- Common types of contracts:

1. Fee-based contract. Producer pays processor a fixed fee based on gas volumes produced. Processor extra income: field compression, pipeline transmission & marketing. Processor fee independent of NG price

2. % of proceeds contract (POP). Producer retains % of proceeds from gas sale. Typically, producer keeps 70% of earnings. Producer & processor earnings subject to NG & NGL price fluctuations.

3. Wellhead purchase contract. Processor buys gas from producer at wellhead based on MJ (or BTU) against an index.

Types of contracts (2)

4. Fixed efficiency contract. Processor receives a % recovery (efficiency) from producers from sale of heavier than methane gas components. Incentive for processor to extract higher recoveries.

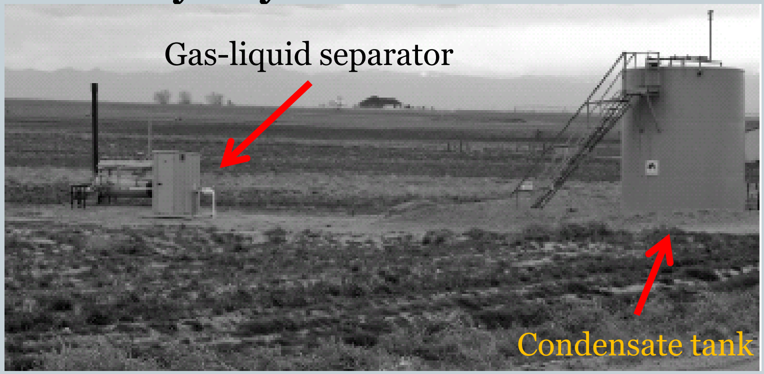
5. Keep whole contract. Processor processes all gas while compensates producer all energy for the NG (J or BTUs). Processor retains all NGLs extracted from gas stream. Risky for processor, favourable for producer

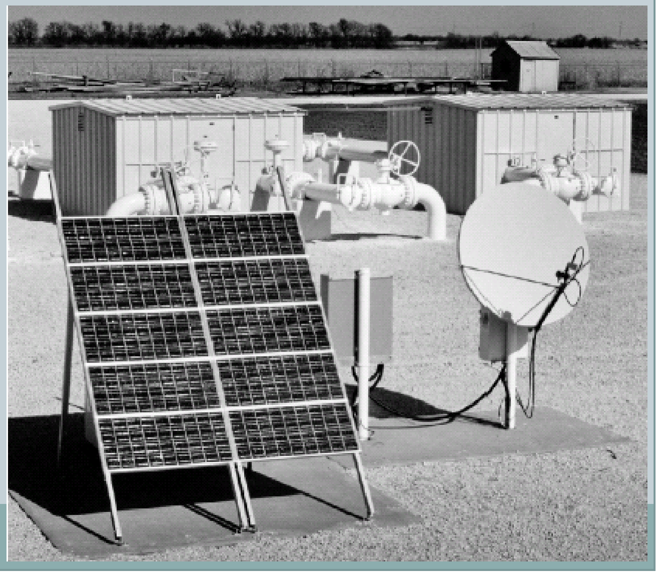
- Usually contracts are a combination of 2 or more of above types. Include penalties for deviations (eg liquid content, impurities).

- Maintenance, replacement, environmental costs borne by processor. Often producers cease operations.

Field operations

- Electronic meters quantify gas stream
- Gas processor buys gas from producer & lease royalty owner at meter
- Gas dehydration done onsite
- Heavier H/Cs split in field
- Offshore gas processing usually onshore
- If gas non-associated, H/C liquids mixed with gas or collected in tank & hauled by track
- Offshore several wells tied to one separator, meter & compressor



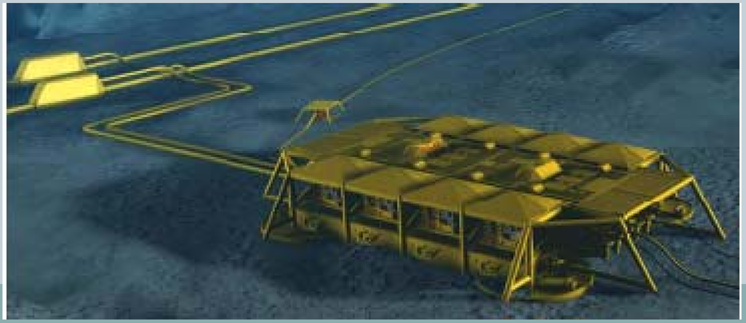


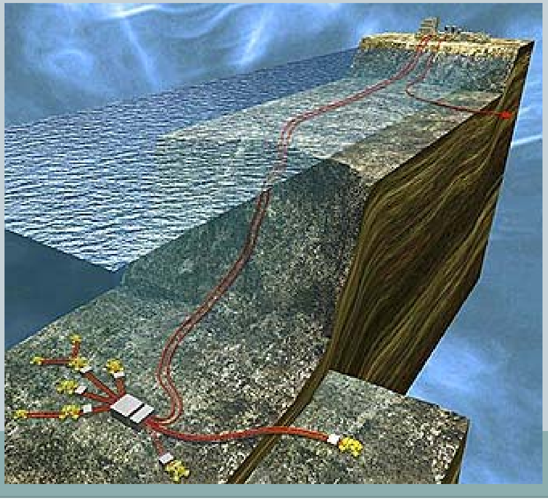
Onshore initial gas processing

- Min. purification at well-head
- Raw gas transmission
- Feed gas may contain: H_2O, CO_2, H_2S, higher H/Cs, impurities
- Need to pig regularly due to two-phase flow
- First stage treatment:
  - Traps
  - Collect liquids
- Depending on temp., H_2O content, press. drop:
  - Glycol or methanol prevents hydrate formation
  - Glycol/methanol removed using fractionation in H_2O/liquid separator
- Gas cooled close to freezing temp by heat exchanger
  - Removes more water
  - Heavy hydrocarbons in knock-out drum

Offshore gas processing

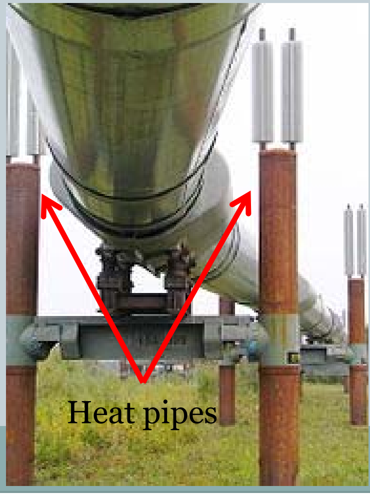
- Processing done onboard platform or subsea
- Remove:
  - Liquids (H_2O)
  - Carbon dioxide (CO_2)
  - Acid gases (eg, H_2S)
  - Dry gas from water
- Pump sweet natural gas to shore via submarine pipeline
- If natural gas is dry (pure gas) minimal processing
- Compression station pumps gas to shore
- CO_2 and water usually re-injected in gas field





Pipeline gas transport

- Offshore: gas plant usually located onshore
- Offshore: several wells tied to a platform, several rigs fed into single large diameter pipe
- Small lines (in length & diameter) aboveground or buried
- Large pipelines are *always* buried underground
- Aboveground pipelines easier to maintain but subject to elements
- Coatings, corrosion protection & possibly insulation needed



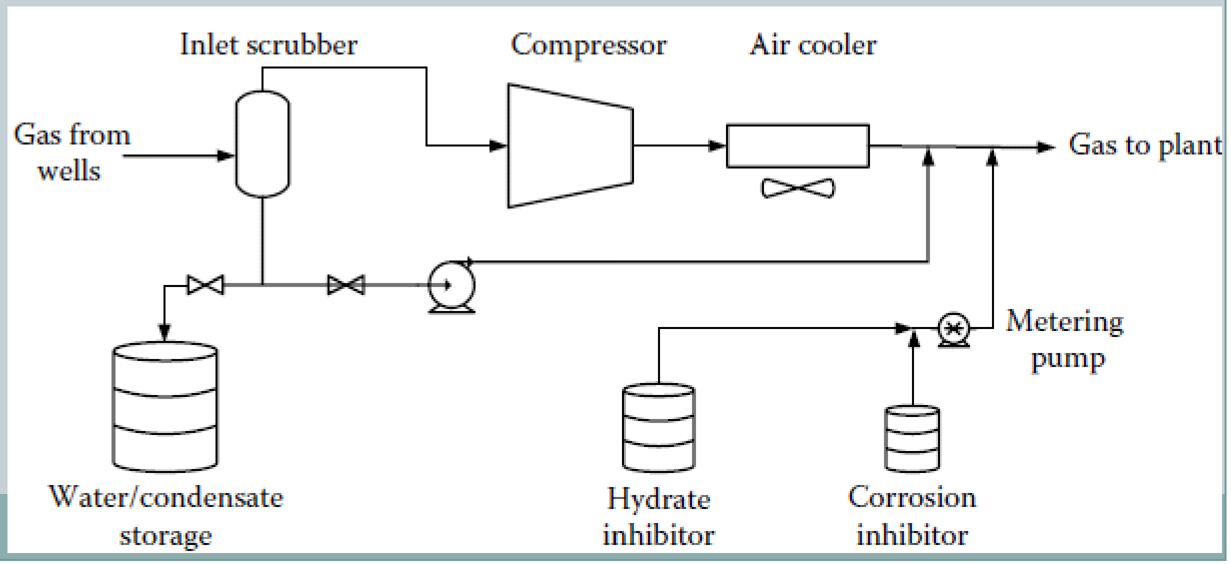
Pipeline gas transport (2)

- Small amounts of liquids usually emptied using “drip systems”
- As reservoir depletes pressure in pipelines reduce
- Subambient pressure is highly problematic for gas pipelines
- Air ingress in pipeline is undesirable
- Oxygen intake is unwelcome because:
  - Enhances corrosion
  - Interfere with other gas processes
  - Subquality sale gas ($[O_2]$>1 %vol)
- Air leaks detected and fixed
- SCADA (supervisory control and data acquisition) used to manage pipeline flow & control

Compressor stations

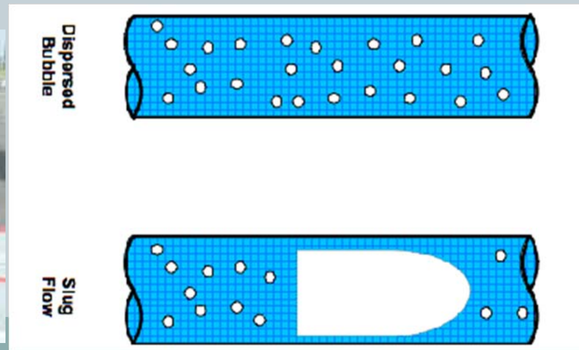
- Function of a pump (reciprocating/centrifugal) is to increase fluid pressure
- Inlet scrubber separates condensed liquids from gas
- Liquids either removed or re-injected in gas stream
- Booster stations re-pressurize gas at 65-160 km intervals
- Two-phase pressure is complex
- Compressors powered by ICE, gas turbines or electric motors

7 pumping stations



Pigging

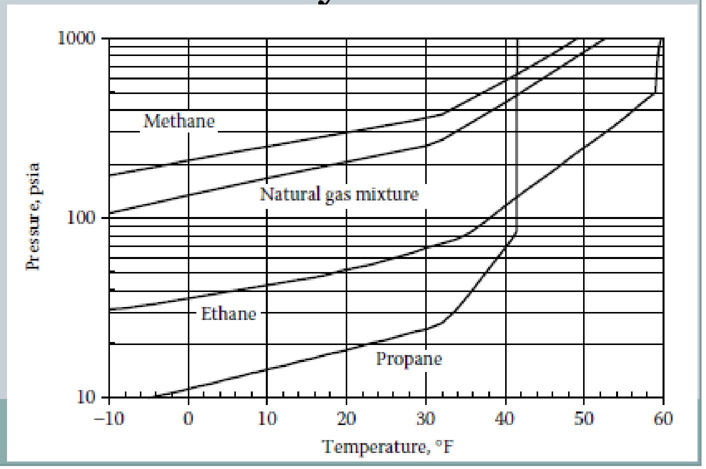
- Process of cleaning & inspecting the pipeline
- Done using ‘pigs’ using a pig launcher while pipeline in operation
- Pigging serves to:
  - Offers a barrier between different liquid products
  - Inspects wall thickness & detect damaged sections
  - Remove debris such as dirt & wax
  - Provide a calculated volume for flow meter calibration
  - Coat inner pipe walls with inhibitors
  - Eliminate condense H/C liquids & H_2O in 2-phase flows
- Liquid flow rate slower than gas flow rate
- Pigs made of polyurethane foam
- Nowadays, smart pigs are used



Flow assurance

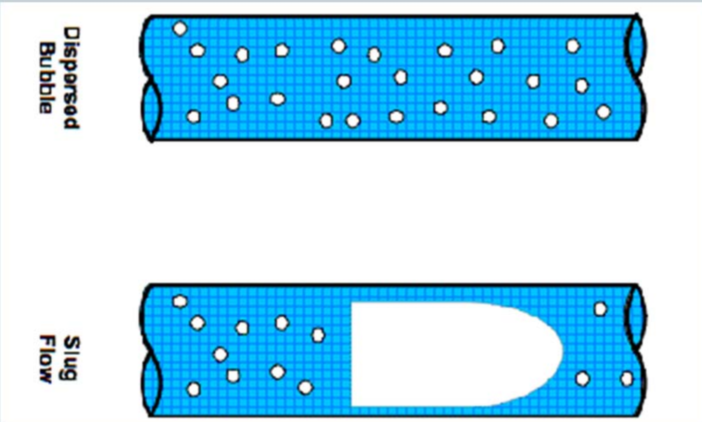
- H/Cs flow uninterrupted. Avoid formation of gas hydrates

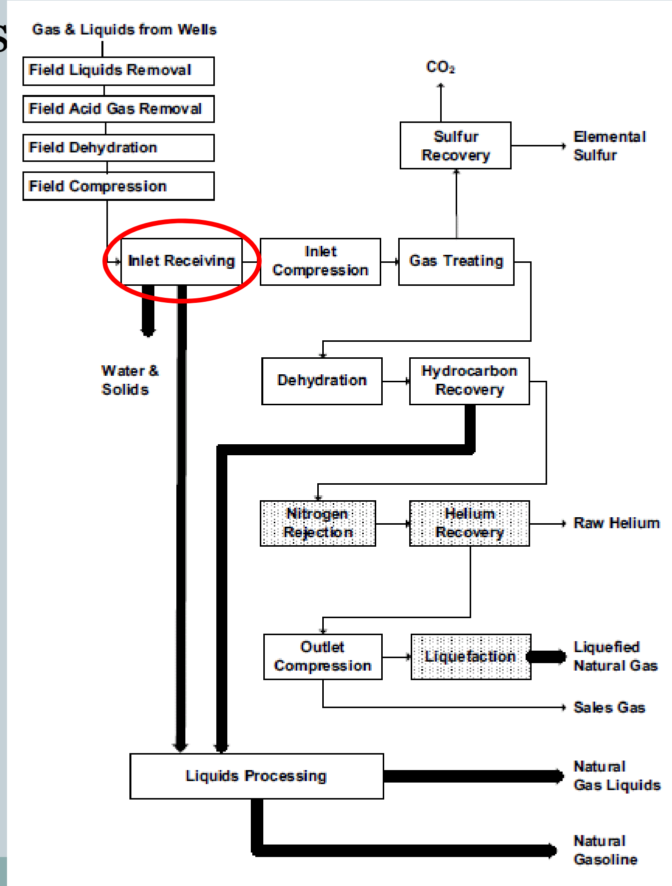
- Three considerations:
  - Wax and asphaltene solids deposition
  - Scale (inorganic salt) attachment
  - Gas hydrate solids formation
- Wax & asphaltene dealt with by pigging. Scale problem at wellhead
- Hydrate plugs perilous : 1) occur within minutes w/o notice, 2) Injection pump, separator failure & process upsets trigger gas hydrates
- Gas hydrate formation predicted using statistical thermodynamics
- Avoid gas hydrates:
  - Operate outside gas hydrates region (impractical)
  - Dehydrate gas (offshore)
  - Inject hydrate inhibitors (methanol, onshore vs ethylene glycol)



Inlet receiving

- Emergency shutdown valves: protection against pig receivers
- Glycol/methanol are recovered
- Natural gas liquids go to storage for proces
- NG stream directed to inlet compressors
- Gas devoid of liquids is critical





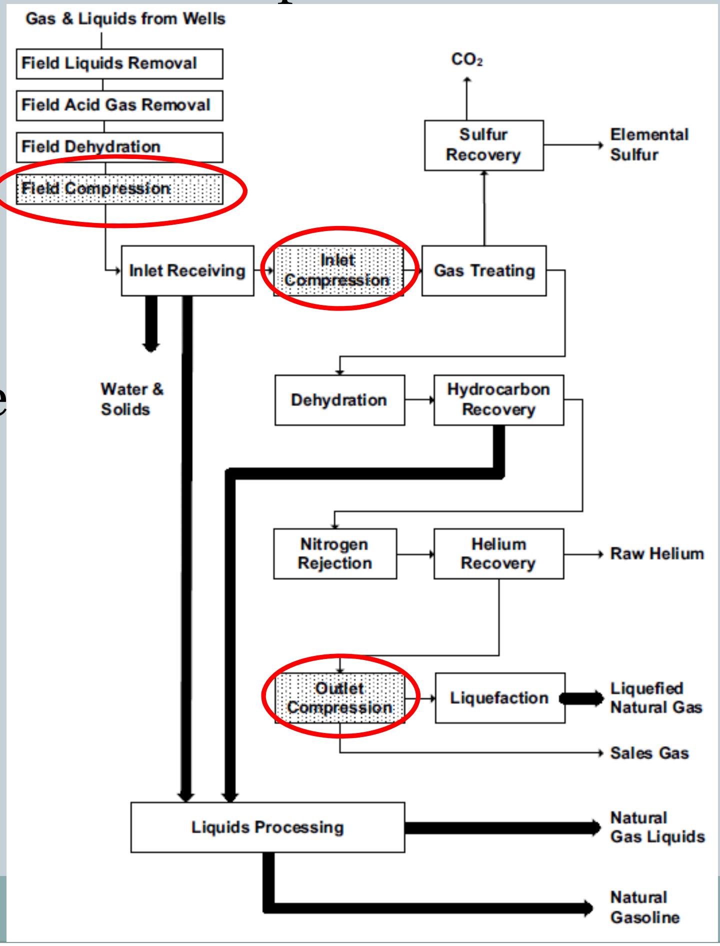
Field operations safety & environmental issues

- Pipeline leaks. Pose fire hazard & poisoning if high levels H_2S present
- Plugged pipelines. Gas hydrates or pigs may obstruct gas flow. Depressurisation is vital to avoiding pipeline damage. Dislodging a hydrate (clathrate) plug offshore may be a complicated undertaking.
- Environmentally pipe leaks are most serious issue.
- Methanol leak poses fire hazards.
- Emissions (NO_x, CO_2) from compression stations.
- Emergency release of gas may be flared or vented.

Compression

Compression

- Compression station responsible for gas transmission
- Principle: increase fluid pressure & force it to flow via press. difference
- Pressure triggers temperature drop via turbo-expander (centrifugal pump)
- Gas & refrigeration compressors typically the largest expenditure in gas plant; 50 to 60%, highest maintenance costs.
- Today tendency to operate at higher p/line pressures:
  - Squeeze more gas thru given pipeline diameter
  - Smaller transmission frictional losses
  - Fewer compression stations



Types of compressor stations

- There are 5 types of compression stations:

- 1. Field gas-gathering stations. Generally source gas from nearby wells in which pressure is insufficient to produce. These stations generally handle suction pressures. Capacity: several million cubic feet/day.

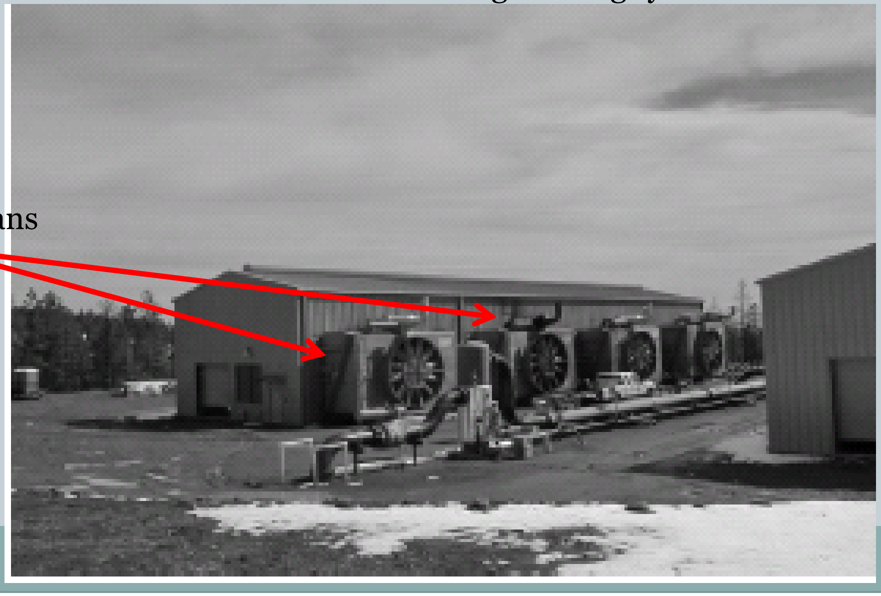
- 2. Relay or main line stations. Boost pressure in transmission lines. Generally compress large gas volumes at a pressure range: 14 to 90 bar

- 3. Repressuring or recycling stations. Develop high pressures (up to 415 bar) for processing or secondary oil recovery process.

Types of compressor stations (2)

- 4. Storage field stations. Compresses natural gas from trunk (main) line for injection into storage wells at pressures of about 275 bar.
- 5. Distribution gas compression stations. Pump gas from gas holder storage to medium-pressure (1.4 bar) & high-pressure (up to 7 bar), distribution lines or bottle storage (≈172 bar).

Booster station on gathering system.



Gas flow characteristics

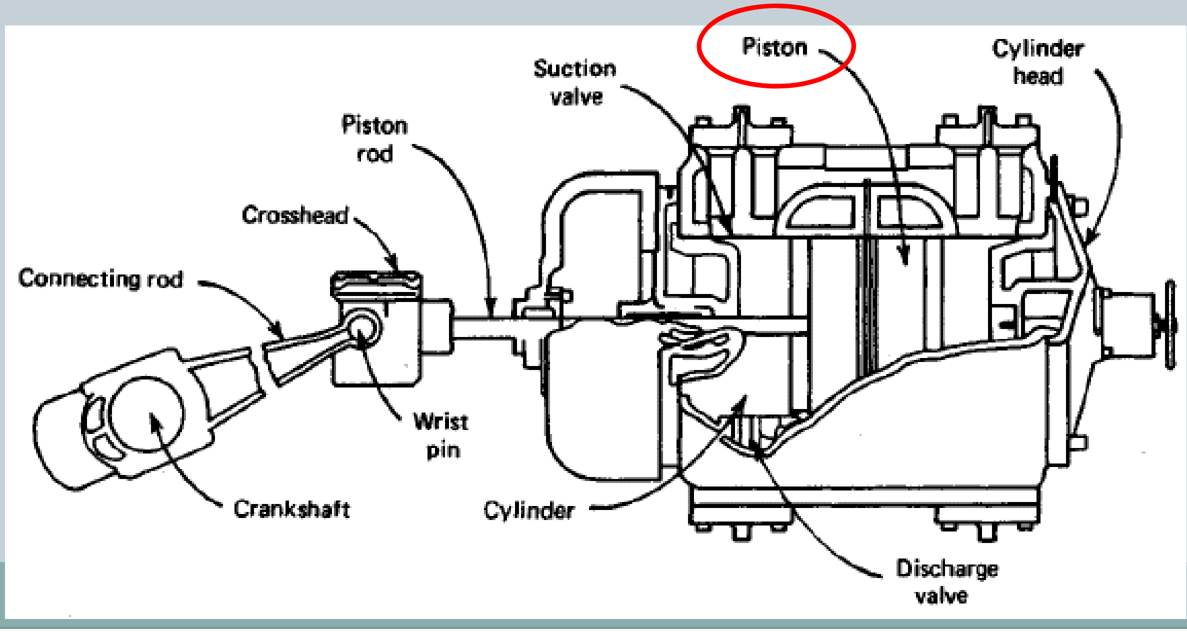
- Gas gathering pipelines (<30”, 76cm) & ‘trunklines’ (>30”)
- Gas streams to consumers carry single phase compressible NG mixture
- Onshore pipelines typically operate at: 700-1,100psi (~4,000 psi)
- Offshore pipelines typically operate at: 1,400-2,100psi
- Gas coolers installed at the discharge side of gas compressors. Why?
  - Protect pipeline inner & external coatings against high temps
  - Manage undue downstream pressure losses due to high temps

Selection criteria

- Most common types of compressors: a) reciprocating & b) rotary
- Selection variables:
  - Life cycle costs
  - Gas throughput (capacity)
  - Size of compressors
  - Efficiency & reliability
  - Capital expenditure
  - Maintenance costs incl. overhaul & spare parts
  - Running costs (fuel or energy costs)
  - Level of utilization
  - Gas demand fluctuations.
- Driver selected through a feasibility study:
  - Electric motors (requires electricity)
  - Gas engines (powered by natural gas)
  - Gas turbines (powered natural gas)

Reciprocating compressors

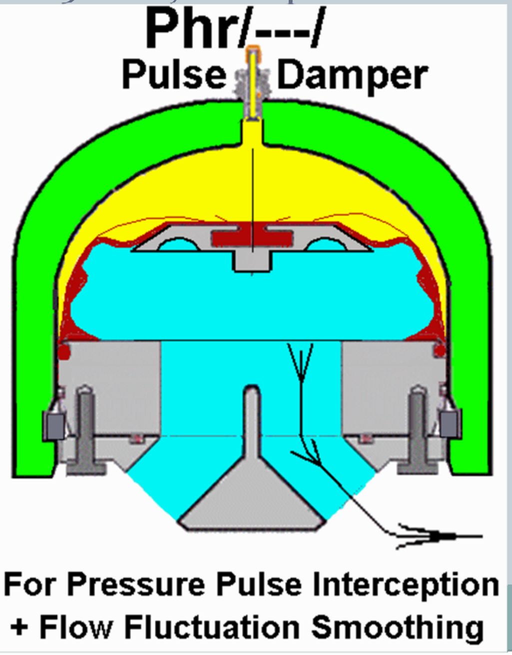
- Most popular; driven by gas engines or electric motors
- Flexible in throughput & pressure range
- Fit for practically all pressures (<415 bar) & volumetric capacities
- More moving parts & lower mechanical efficiency than rotary ones
- Convert rotary into reciprocating motion (+ displacement machine)
- Typical delivery volume 30,000ft³/min (cfm) [850 cmm] @ 10,000 psig [690 bar]



Reciprocating compressors (2)

- Risk of damaging equipment min. by:
  - *Pulsation dampeners* protect up- & down-stream equipment from pressure fluctuations

  https://www.youtube.com/watch?v=Dq3nHKoZbTc
- Divided into:
  - Slow-speed: 200-600 rpm
  - High-speed: 900-1,200 rpm



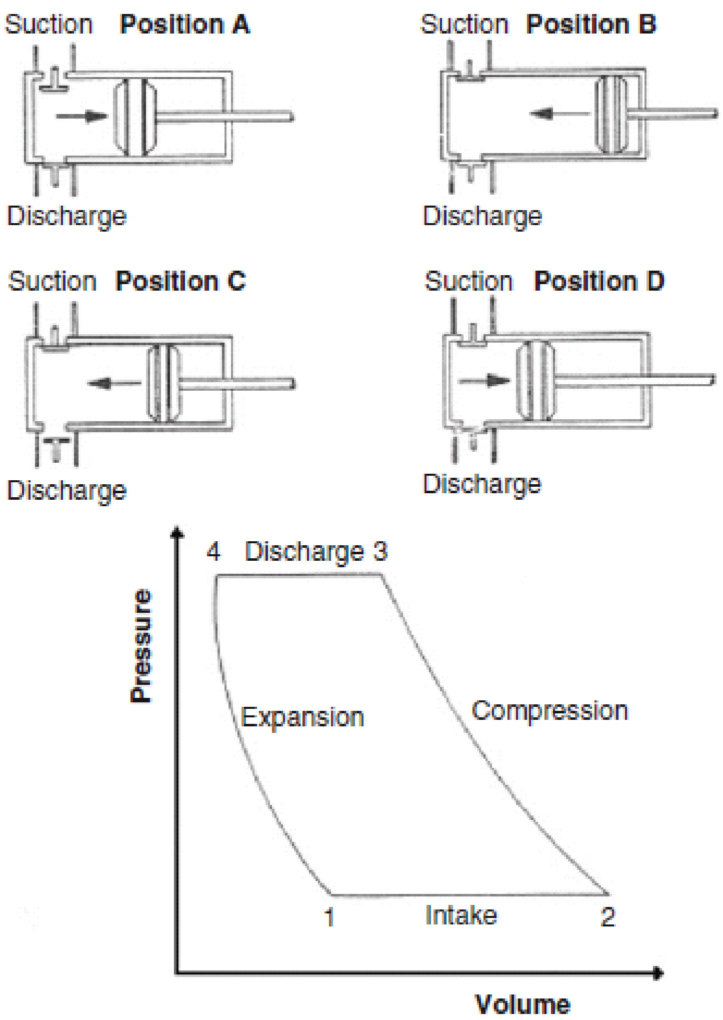
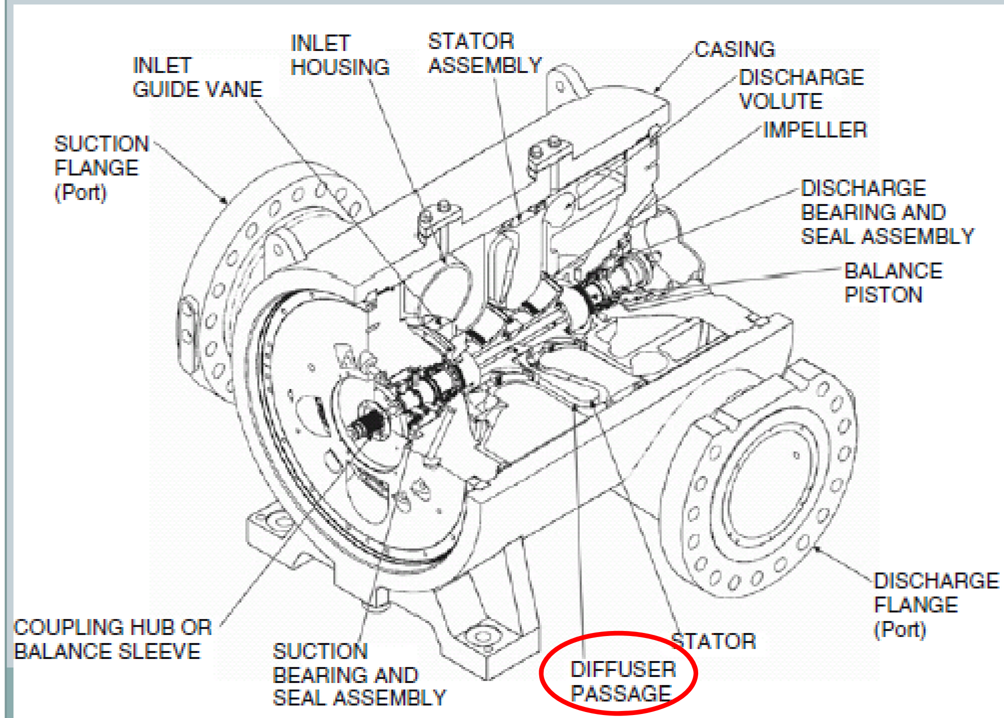
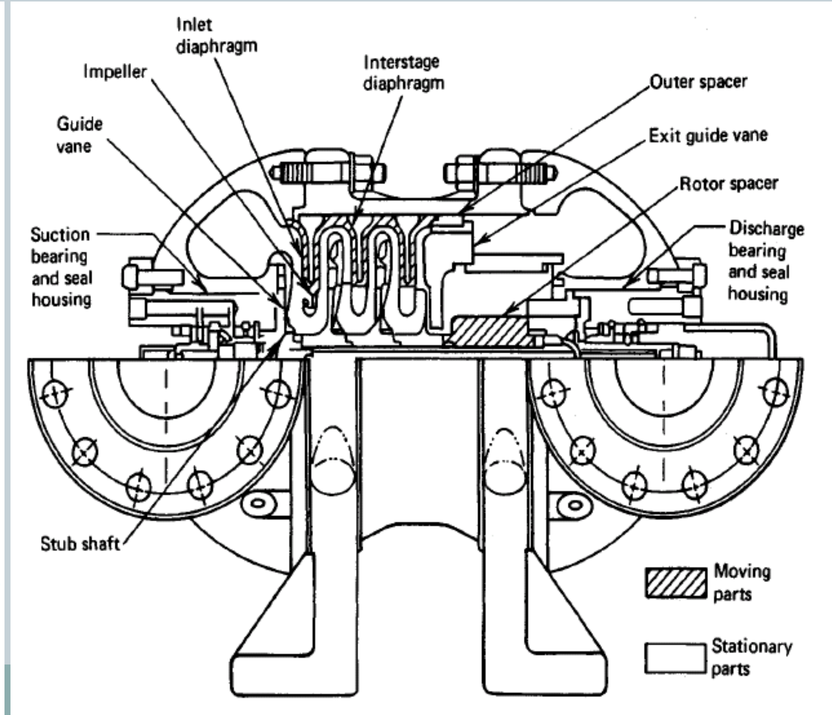


Figure 8-1. Reciprocating compressor compression cycle.

Rotary compressors

- Divided into two classes: centrifugal compressor & rotary blower
- Powered by gas turbines or electric motors
- Impeller increases gas velocity & static pressure
- Diffuser converts momentum into static pressure





Centrifugal compressors (2)

- A compressor stage is defined as one impeller
- A compressor body may house up to 8 or 10 stages (impellers)
- Typically pipeline compressors are single body trains of 1 or 2 stages
- Capacity: 100,000 cfm [≈2,800 cmm]; press.: 10,000 psia [≈690 bar]
- Operating speeds:
  - 5,000 hp @ 14,000 rpm
  - 20,000 hp @ 8,000 rpm

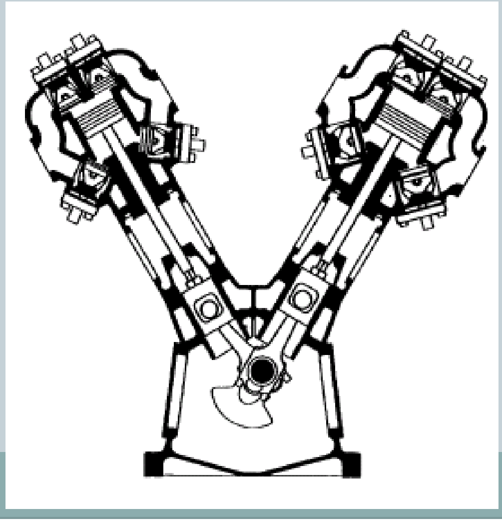
Reciprocating vs centrifugal compressors

- Reciprocating compressors advantages over centrifugal:
  - Ideal for low volume flow & high-pressure ratios
  - High efficiency at high-pressure ratios
  - Relatively low capital cost in small units (<3,000 hp)
  - Less sensitive to changes in composition and density of gas

- Centrifugal compressors merits over reciprocal:
  - Ideal for high volume flow & low head (pressure)
  - Simple construction with only one moving part
  - High efficiency over normal operating range
  - Low maintenance cost & high availability
  - Greater volume capacity per unit of plot area
  - No vibrations and pulsations

Other selection parameters

- Selection project specific, ie purchaser defines operating variable
- Considerations:
  - Flow rate
  - Gas composition
  - Inlet pressure and temperature
  - Outlet pressure
  - Train arrangement:
    - For centrifugal compressors: series, parallel, multiple bodies, multiple sections, etc, …
    - For reciprocating compressors: number of cylinders, cooling, & flow control strategy
  - Number of units
  - Environmental issues i.e. emissions
  - Terrain inclinations
  - etc.



Double acting reciprocating compressor.

Next…

- Thermodynamics of gas compression (compressor power calcs)
- Gas treating
- Acid gas treatment
- Natural gas dehydration
- Hydrocarbon recovery

Thanks for your attention!