14. Natural Gas Liquids Recovery (NGL)

- The hydrocarbon liquids can be grouped into natural gas liquids (C_2 to C_4) and natural gas condensate (C_5^+). Usually, there is a commercial benefit to recovering these hydrocarbon liquids in greater amounts than required for pipeline specifications. The majority of the C_5^+ condensate is separated in the condensate stabilization unit.
- The richness of the NGL components can be expressed by the term “GPM”, that is, gallons of C_2^+ liquids per 1000 standard cubic feet of gas.
- The C_2^+ NGL mixture recovered from an NGL recovery unit is sometimes referred to as “Y-grade NGL” or “raw NGL mix”.
- The Y-grade NGL is typically transported to a centralized facility for fractionation where the mixed NGLs are separated into discrete NGL products: ethane, ethane propane mix, propane, normal butane, iso-butane, and natural gasoline.

14.1. Refrigeration Processes

- Refrigeration units are designed to meet the process cooling temperature requirements.
- In NGL recovery or a natural gas liquefaction plant, a two or three-stage propane compressor is common, typically designed to meet the process chilling temperature of about -20 to -30°F.
- If lower temperatures are required, ethane refrigeration or mixed refrigeration system can be used.
- Alternatively, gas expander or Joule-Thomson (J-T) cooling can also produce deeper refrigeration using feed gas as the working fluid.

14.1.1. Propane Refrigeration

- Propane is a common refrigerant and has a lower environmental impact compared to the fluorocarbon refrigerant.
- A refrigeration system operates on a vapor-compression refrigeration cycle principle.

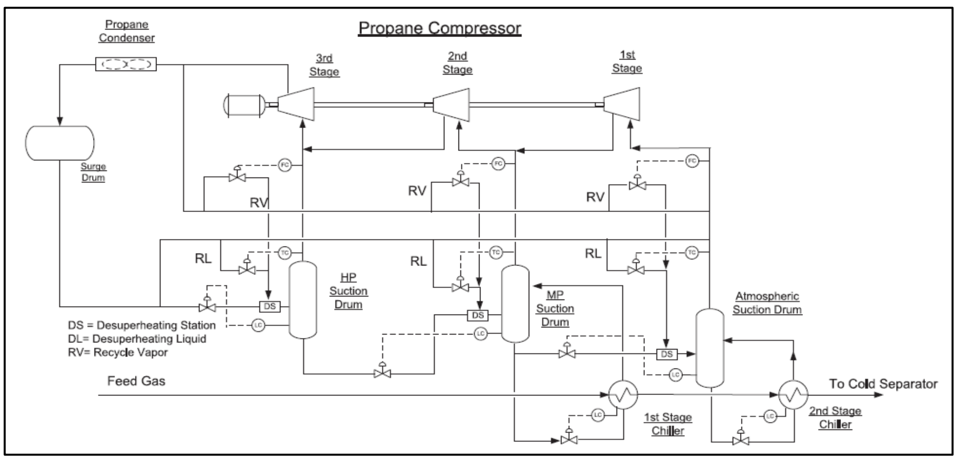
❖ In a gas processing plant, propane refrigerant is typically condensed by cooling water or ambient air.

❖ A refrigeration unit, which is typically designed for the summer operation, would have more cooling capacity during winter.

❖ Propane refrigeration can provide coolant at -40 °F at atmospheric pressure.

❖ Lower chilling temperatures could be achieved with a fourth stage compression operating under vacuum pressure.

❖ The more efficient gas plants typically use a three-stage propane compression system as shown in Fig. below.



Process flow schematic of a three-stage propane refrigeration system.

❖ For a three-stage compression system, the feed gas cooling system typically consists of two chillers operating in series.

❖ The first chiller uses the refrigerant from the MP drum while the second chiller uses the atmospheric drum liquid.

❖ The chillers are typically kettle-type exchangers with propane evaporating on the shell side.

❖ The propane compressor also has a third stage that receives vapor from the HP suction drum.

14.1.2. Cascade Refrigeration

- For rich gas, such as shale gas, with a higher ethane content, a lower refrigerant temperature is required.
- Alternatively, when ethane and propane recoveries are attractive, lower temperature cooling is also necessary.
- Cascade refrigeration can be an option to generate a low temperature refrigerant.
- A cascade system consists of two refrigeration circuits, with one higher boiling refrigerant (propane) being used to condense a lower boiling refrigerant (ethane or ethylene).
- The propane condenser is cooled by ambient air or cooling water and the ethane condenser is cooled by evaporating propane at -40 °F.
- With such an arrangement, an ethane refrigerant at -120 °F can be produced for cooling in the demethanizer in a gas plant.

14.1.3. Mixed Refrigerants

- An alternative to the multistage cascade refrigeration is to use a single mixed refrigerant.
- The mixed refrigerant composition must be varied such that the evaporating heat curve of the mixed refrigerant matches closely with the gas cooling and condensing heat curve.
- However, when feed gas pressure is low, such as 300 to 400 psig, refrigeration generated by a J-T valve or turboexpander is limited, mixed refrigerant is an alternate solution to generate cold temperature refrigeration.

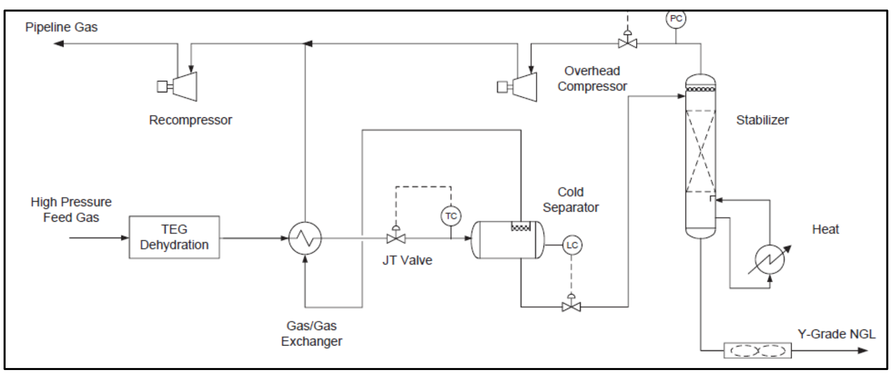
14.2. Liquid Recovery Processes

- There are various processes in natural gas liquids recovery, depending on the feed gas compositions, the recovery levels, and the product target specifications.

- It can vary from the simple hydrocarbon dewpoint controlling unit to the more complex cryogenic turboexpander units.

14.2.1. Hydrocarbon Dew Point Controlling with Joule-Thomson Cooling

- When the feed gas is available at high pressure, the gas high pressure can be used to generate cooling by isenthalpic expansion or Joule-Thomson cooling.
- The gas cooling effect will cause heavy hydrocarbons to drop out. Removal of the heavy hydrocarbons can then meet the hydrocarbon dew point specification.
- The chilled gas is reduced in pressure using a Joule-Thomson (J-T) valve. The J-T letdown operation cools the gas further, producing a liquid condensate in the cold separator.
- The conventional dew pointing unit is designed to recover condensate hydrocarbons and can only recover a moderate level of the propane C_3^+ product.

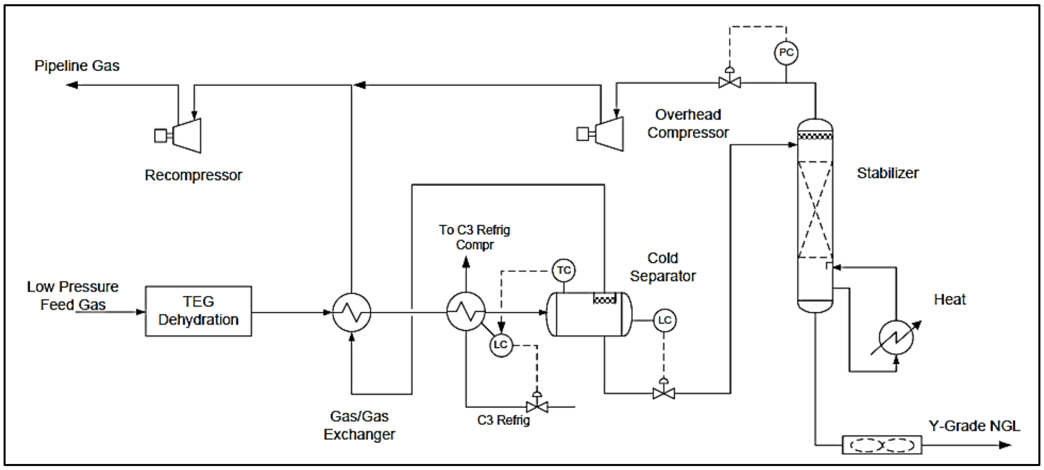


Hydrocarbon dew point controlling using the J-T process.

14.2.2. Hydrocarbon Dew Point Controlling with a Mechanical Refrigeration Unit

- When feed gas is supplied at low pressures, there will not be sufficient pressure differential to operate the J-T process.
- In this situation, the feed gas can be chilled at pressure using a Mechanical Refrigeration Unit (MRU) where the J-T valve is replaced by the propane refrigeration chiller.

- ❖ The chiller is a kettle-type exchanger with propane evaporating on the shell side.
- ❖ Typically, rich gas would require higher refrigeration duty which can be supplied by a mechanical refrigeration system.



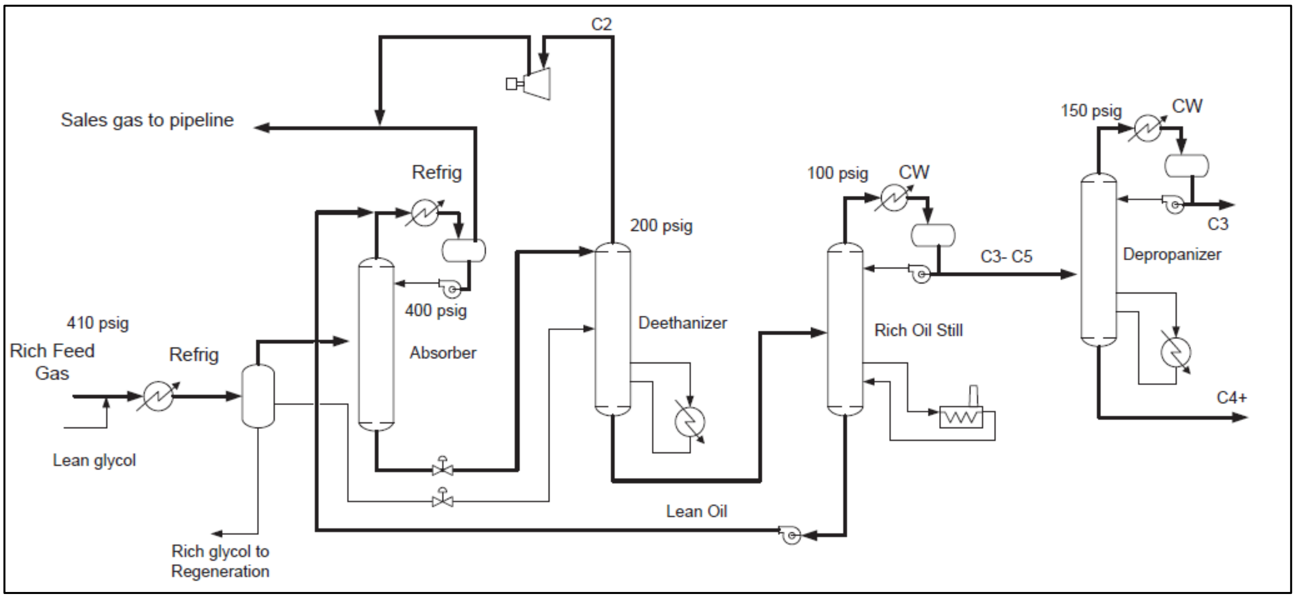
Hydrocarbon dew point controlling using propane refrigeration

14.2.3. Deep Hydrocarbon Dew Point unit

- ❖ a deep hydrocarbon dew pointing process (DDP) that can achieve over 95% propane recovery.
- ❖ The process uses propane refrigeration and J-T expansion. With propane refrigeration and J-T cooling, the process can recover or remove most of the propane and heavier components.
- ❖ The main advantage of the deep hydrocarbon dew point unit is the flexibility to produce NGL with varying ethane content. The ethane content can be lowered to 1 vol% as needed to meet specification of the propane product. Alternatively, the ethane content can be increased to meet the Y-grade NGL specifications if there is an ethane demand.

14.2.4. Lean Oil Absorption

The absorption unit uses a lean oil to absorb the C_3^+ components followed by a deethanizer, and a rich oil still to regenerate the rich oil. Propane and butane products can be produced. A typical refrigerated lean oil absorption process is shown in Fig. 11.12.



A typical lean oil absorption process.

14.3. NGL Recovery Unit Operating Problems

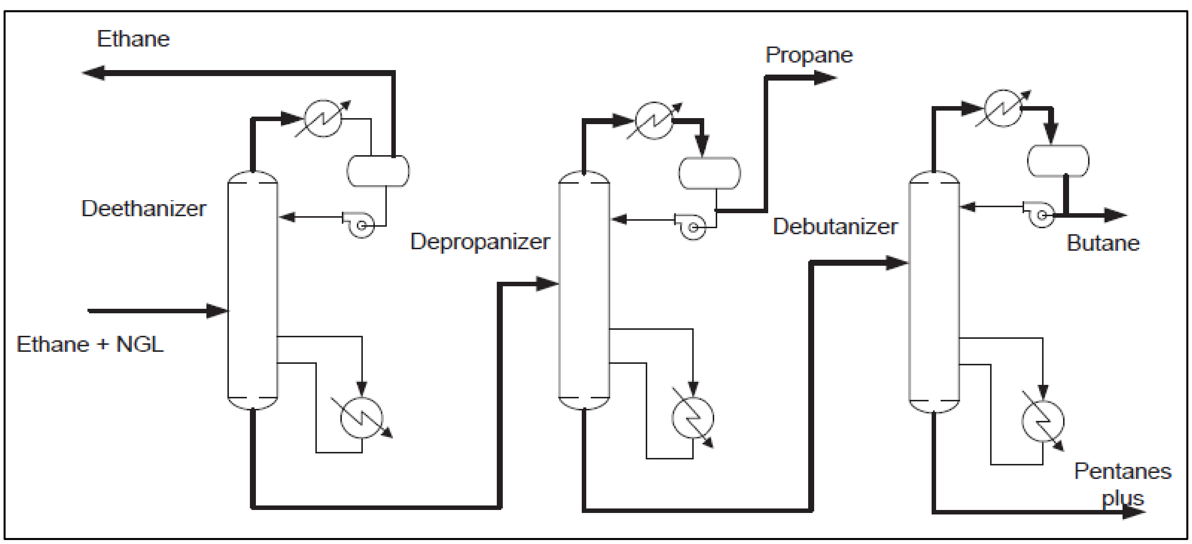
The operating problems in an NGL recovery unit are unstable operation and failure to meet NGL recovery targets and product specifications. The following checklists can be used to identify the root cause of the problems.

- If a high pressure drop occurs in the unit, check the CO_2 content in the feed gas. This may be due to CO_2 freezing. Check the performance of the amine unit and check the moisture content in the dried gas from the molecular sieve unit. Methanol injection can be started to temporarily relieve the problems.
- If the unit fails to achieve the design capacity, check the feed gas compositions. If the feed gas is leaner and contains more nitrogen, vapor loading on the demethanizer will increase, reducing the capacity of the unit.

- Check the temperature and pressure profile of the NGL unit. If the deethanizer operates at high temperature, propane recovery will be reduced. If the column pressure is too high, separation may become difficult, resulting in lower recovery.
- If the exchanger fails to achieve design performance, check the temperature profile of the NGL unit to determine if there is a temperature pinch on heat exchangers.
- Check the refrigeration system performance.
- Check the contaminant levels in the propane refrigeration system.
- Sometimes, leakage of lube oil into the propane system can be a problem.

14.4. NGL Fractionation

- The NGL stream exiting an NGL recovery unit consists of a combination of components that must be separated into marketable products.
- This separation process occurs in a series of fractionators, which can include deethanizers, depropanizers, debutanizers, and butane splitters.
- A simplified NGL fractionation flow schematic is shown in Fig. below.



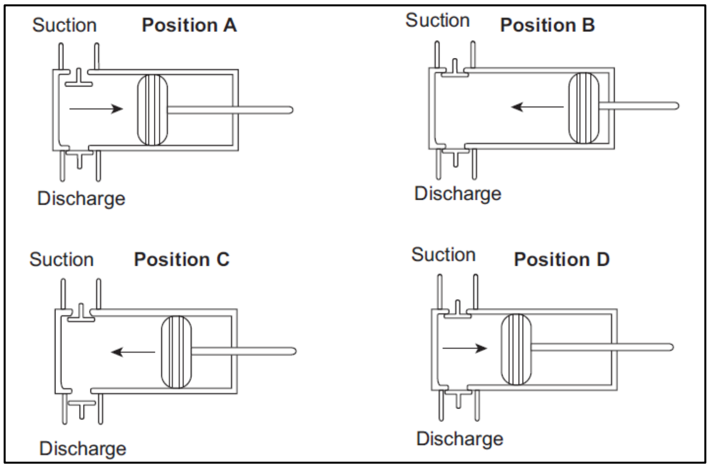
Typical NGL fractionation flow schematic.

15. Natural Gas Compression

- "Compression" is used in all aspects of the natural gas industry including gas lift, reinjection of gas for pressure maintenance, gas gathering, gas processing operations (gas loading and discharge), transmission and distribution systems, and boil-off system (gas storage in tankers for vapor control and to avoid releasing gas into the atmosphere).
- In gas transmission, two basic types of compressors are used: (1) **reciprocating** and (2) **centrifugal compressors**.
- Reciprocating compressors are usually driven by either electric motors or gas engines, whereas centrifugal compressors use gas turbines or electric motors as drivers.

15.1. Reciprocating Compressors

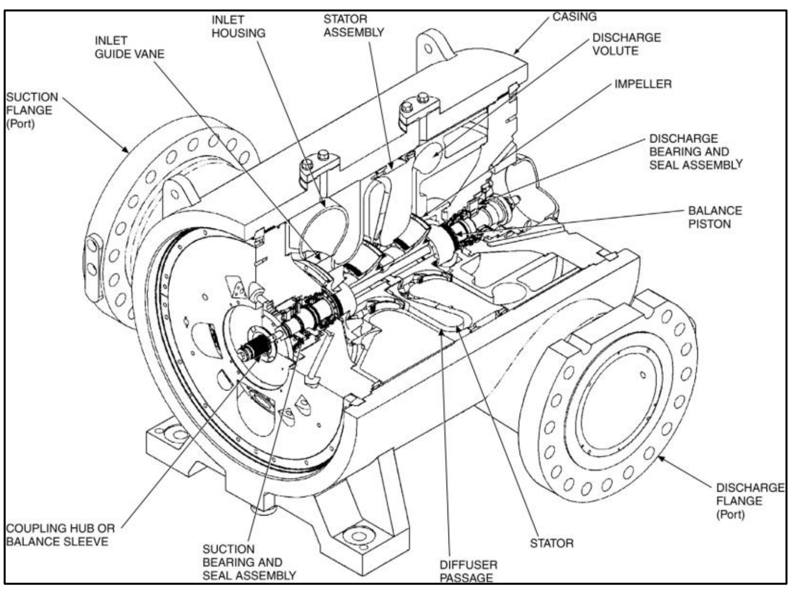
A reciprocating compressor is a positive displacement machine in which the compressing and displacing element is a piston moving linearly within a cylinder. The reciprocating compressor uses automatic spring-loaded valves that open when the proper differential pressure exists across the valve. Fig. below describes the action of a reciprocating compressor. The flow to and from reciprocating compressors is subject to significant pressure fluctuations due to the reciprocating compression process. Therefore, pulsation dampeners have to be installed upstream and downstream of the compressor to avoid damages to other equipment. Reciprocating compressors are widely used in the gas-processing industries because they are flexible in throughput and discharge pressure range. Reciprocating compressors are classified as either "high speed" or "slow speed." Typically, high-speed compressors operate at speeds of 900-1200 rpm and slow speed units at speeds of 200-600 rpm.



Reciprocating compressors

15.2. Centrifugal Compressors

A centrifugal compressor achieves the compression task by converting the mechanical energy from the driver to kinetic energy in the gas, using the forces that moving and stationary airfoils exert on this gas.



A compressor stage is defined as one impeller, with the subsequent diffuser and (if applicable) return channel. A compressor body may hold one or several (up to 8 or 10) stages. Centrifugal compressors are used in a wide variety of applications in chemical plants, refineries, onshore and offshore gas lift and gas injection applications, gas gathering, and in the transmission and storage of natural gas. Centrifugal compressors can be used for outlet pressures as high as 10,000 psia, thus overlapping with reciprocating compressors over a portion of the flow-rate/pressure domain. Typical operating speeds for centrifugal compressors in gas transmission applications are about 14,000 rpm for 5000 hp units and 8000 rpm for 20,000 hp1 units.

15.3. Comparison Between Compressors

The advantages of a reciprocating compressor over a centrifugal machine include:

- ideal for low volume flow and high pressure ratios
- high efficiency at high pressure ratios
- relatively low capital cost in small units (less than 3000 hp)
- less sensitive to changes in composition and density

The advantages of a centrifugal compressor over a reciprocating machine include:

- ideal for high volume flow and low head
- simple construction with only one moving part
- high efficiency over normal operating range
- low maintenance cost and high availability
- greater volume capacity per unit of plot area
- no vibrations and pulsations generated

15.4. Thermodynamics of Gas Compression

For an isentropic compression, the discharge temperature (T_2) is determined by the pressure ratio as:

$$\frac{T_2}{T_1} = \left(\frac{p_2}{p_1}\right)^{\frac{k-1}{k}}$$

where k (isentropic exponent) is ratio of the heat capacities of gas at constant pressure and temperature (k= Cp/Cv), p_1 is suction pressure, and p_2 is discharge pressure.

Note that the heat capacities of real gases are a function of the pressure and temperature; however, they are functions of temperature only for ideal gases and can be related together with CP- CV =R,

where R is universal gas constant. The isentropic exponent (k) for ideal gas mixtures can therefore be determined as:

$$k = \frac{\sum y_i \, C_{Pi}}{[\sum y_i \, C_{Pi}] - R}$$

where CP_i is the molar heat capacity of the individual component at constant pressure, and y_i is the molar concentration of the component. Because the temperature of the gas increases as it passes from suction to discharge in the compressor, common practice is to determine the heat capacities of gas at the average of suction and discharge temperatures.

15.5. Compression Ratio (CR)

❖ Compression ratio (CR) is the ratio of absolute discharge pressure to the absolute suction pressure. Mathematically this can be shown as:

$$CR = \frac{p_2}{p_1}$$

❖ By definition, the compression ratio is always greater than one. If there are "n" stages of compression and the compression ratio is equal on each stage, then the compression ratio per stage is given by the equation:

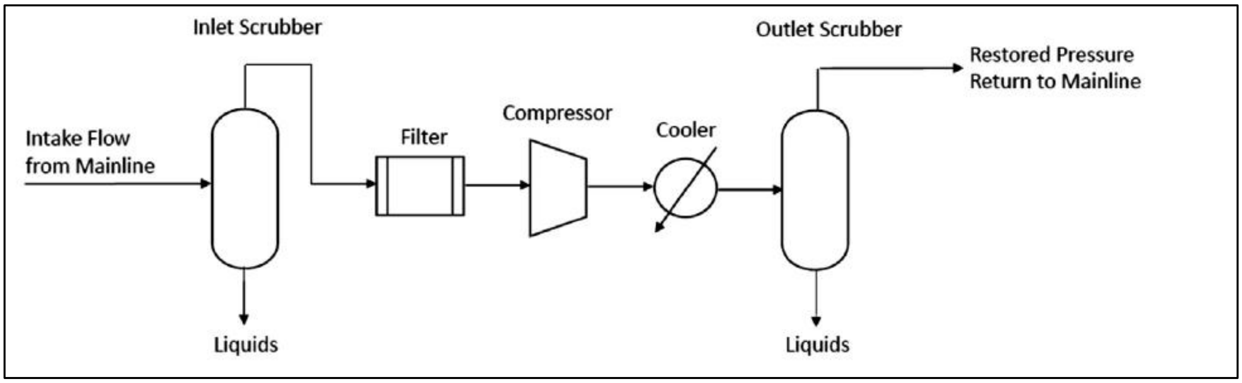
$$CR_{stage} = \left(\frac{p_2}{p_1}\right)^{1/n}$$

❖ The compression ratio for typical gas pipeline compressors is rather low (usually below 2). Low pressure ratios can be covered in a single compression stage for reciprocating compressor and in a single body (with 1 or 2 impellers) in a centrifugal compressor. For natural gas (with specific gravity in the range of 0.58-0.70), a single centrifugal stage can provide a pressure ratio of 1.4.

- The pressure ratio per stage is usually lower than the aforementioned values for multistage machines.
- A multistage centrifugal compressor (i.e., a machine with multiple stages) can achieve, with natural gas, a pressure ratio of about 4-5.
- Reciprocating compressors can achieve cylinder pressure ratios of 3-6.
- Whenever any limitation is involved, it becomes necessary to use multiple compression stages in series and intercooling.
- For pressure ratios higher than 3, it may be advantageous to install intercoolers between the compressors.
- Intercoolers are generally used between the stages to reduce the power requirements as well as to lower the gas temperature that may become undesirably high. Interstage cooling is usually achieved using gas-to-air coolers.

15.6. Compressor Station

- As natural gas flows through a pipeline, it loses pressure due to friction against the inside of the pipe. Therefore, compressor stations are installed along the pipeline to boost the gas pressure in the pipeline to maintain required delivery pressure and flow.
- A given gas transmission system may have anywhere from a few stations up to well over 50 depending on feasibility studies.
- Most compressors are powered by natural gas taken directly from the pipeline, but electric powered compressors are becoming more common.
- A typical single-stage compressor station design, as shown in Fig. below,



Schematic process diagram of single-stage gas compressor station.

15.7. Compressor Arrangement

- The decision on the compressor arrangement whether **series** or **parallel** is mostly based on economics and on simulation of failure analysis.
- While series arrangement may present some advantages when standby compressor units are not required, parallel arrangement provides better results when standby units are required and also provides more operating flexibility under failure scenario analysis.

15.8. Pipeline Sizing Criteria

- The pipe size generally is based on the acceptable pressure drop, compression ratio, and allowable gas velocities. In fact, a large pressure drop between stations will result in a large compression ratio.
- Experience has shown that the most cost-effective pipeline should have a pressure drop in the range between 3.50 and 5.83 psi/mile.
- However, for those pipelines (short ones) in which pressure drop is of secondary importance, the pipe could be sized based on fluid velocity only.
- The flow velocity must be kept below maximum allowable velocity to prevent pipe erosion, noise, or vibration problems, especially for gases that may have a velocity exceeding 70 ft/s.

- In systems with CO_2 fractions of as low as 1%- 2%, field experiences indicate that the flow velocity should be limited to less than 50 ft/s because it is difficult to inhibit CO_2 corrosion at higher gas velocities.
- The recommended value for the gas velocity in the transmission pipelines is normally 40%-50% of the erosional velocity.

15.9. Compressor Station Spacing

For a given pipe diameter, the distance between compressor stations may be computed from the gas flow equation, assuming a value of pipeline operating pressure (station discharge pressure) and a next compressor station suction pressure limited to the maximum compression ratio adopted for the project.