

Aspen-HYSYS Simulation of Natural Gas Processing Plant

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Abstract

In this time of energy crisis low production rate against the increasing demand of the gas production regularly hampers both the domestic and industrial operations since natural gas is the major power source of this country. Unless other power source is developed, natural gas is our only hope. Almost all the existing processing plants are now operating beyond their capacities. Nonetheless there has been a dwindling situation in the gas production. Besides political indecision regarding new establishment of gas plant and other power source have made the situation nothing but complicated. In such a case an idea of optimization of the gas processing plant will surely pave a way to a sustainable solution. This project has the intention to carry out the simulation of the Bakhrabad gas processing plant (at Sylhet) using the Aspen-HYSYS process simulator. The steady state simulation of the gas processing plant shall be performed based on both the design and physical property data of the plant.

Keywords

natural gas; aspen-hysys; gas processing; separation; simulation..

Introduction

The global use of natural gas is growing rapidly. This is primarily attributed to the environmental advantages it enjoys over other fossil fuels such as oil and coal. There is worldwide drive towards increasing the utilization of natural gas and the need to minimize energy consumption and increase profit associated with the process. These objectives can be achieved by reducing time required to get products to market, increasing the quantity and quality of product produced and designing plants for an optimum performance along their life cycle. In industries these complicated problems are often not solved by hand for two reasons.

- Human error
- Time constraints

There are many different simulation programs used in industry depending on the field of application and desired simulation product. When used to its full capability "ASPEN" can be a very powerful tool for an engineer to achieve major business benefits.

- Ensuring more efficient and profitability design.
- Improving plant control, operability.
- Eliminating process bottle necks and minimizing process network.
- Reducing human error and time requirement.

The inherent flexibility contributes through its design, combined with the unparallel accuracy and robustness provided by it, leads to represent a more realistic model. It can be used for variety of field including gas production.

In order to reduce the operating costs of a plant, much effort is put to find the optimal design condition of the process through optimization studies. Optimization has many applications in chemical, mineral processing, oil and gas, petroleum, pharmaceuticals and related industries. Not surprisingly, it has attracted the interest and attention from many chemical engineers for several decades. Optimization of chemical and related processes requires a process modeling and optimization along with control characterizes the area of process systems

engineering (PSE), important in chemical engineering with a wide range of applications.

Natural Gas Processing

The natural gas product fed into the mainline gas transportation system must meet specific quality measures in order for the pipeline grid to operate properly. Natural gas produced at the wellhead, which in most cases contains contaminants and natural gas liquids, must be processed and cleaned, before it can be safely delivered to the high-pressure, long-distance pipelines that transport the product to the consumers. Natural gas that is not within certain specific gravities, pressures, Btu content range, or water content levels will cause operational problems, pipeline deterioration, or can even cause pipeline rupture.

Gas processing equipment, whether in the field or at processing/treatment plants, assures that these tariff requirements can be met. While in most cases processing facilities extract contaminants and heavy hydrocarbons from the gas stream, in some cases they instead blend some heavy hydrocarbons into the gas stream in order to bring it within acceptable Btu levels.

Natural gas processing begins at the wellhead. The composition of the raw natural gas extracted from producing wells depends on the type, depth, and location of the underground deposit and the geology of the area. Oil and natural gas are often found together in the same reservoir. The natural gas produced from oil wells is generally classified as "associated-dissolved," meaning that the natural gas is associated with or dissolved in crude oil. Natural gas production absent any association with crude oil is classified as "non-associated."

Most natural gas production contains, to varying degrees, small (two to eight carbons) hydrocarbon molecules in addition to methane. Although they exist in a gaseous state at underground pressures, these molecules will become liquid (condense) at normal atmospheric pressure. Collectively, they are called condensates or natural gas liquids (NGLs).

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The processing of wellhead natural gas into pipeline-quality dry natural gas can be quite complex and usually involves several processes to remove: (1) oil; (2) water; (3) elements such as sulfur, helium, and carbon dioxide; and (4) natural gas liquids. In addition to those four processes, it is often necessary to install scrubbers and heaters at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the natural gas does not drop too low and form a hydrate with the water vapor content of the gas stream.

Stages in the Production of Pipeline-Quality Natural Gas and NGLs

The number of steps and the type of techniques used in the process of creating pipeline-quality natural gas most often depends upon the source and makeup of the wellhead production stream. In some cases, several of the steps may be integrated into one unit or operation, performed in a different order or at alternative locations, or not required at all. Among the several stages of gas processing/treatment are:

Gas-Oil Separators: In many instances pressure relief at the wellhead will cause a natural separation of gas from oil (using a conventional closed tank, where gravity separates the gas hydrocarbons from the heavier oil). In some cases, however, a multi-stage gas-oil separation process is needed to separate the gas stream from the crude oil. These gas-oil separators are commonly closed cylindrical shells, horizontally mounted with inlets at one end, an outlet at the top for removal of gas, and an outlet at the bottom for removal of oil. Separation is accomplished by alternately heating and cooling (by compression) the flow stream through multiple steps. Some water and condensate, if present, will also be extracted as the process proceeds.

Condensate Separator: Condensates are most often removed from the gas stream at the wellhead through the use of mechanical separators. In most instances, the gas flow into the separator comes directly from the wellhead, since the gas-oil separation process is not needed. The gas stream enters the processing plant at high pressure through an inlet slug catcher where free water is removed from the gas, after which it is directed to a condensate separator. Extracted condensate is routed to on-site storage tanks.

Dehydration: A dehydration process is needed to eliminate water which may cause the formation of hydrates. Hydrates form when a gas or liquid containing free water experiences specific temperature/pressure conditions. Dehydration is the removal of this water from the produced natural gas and is accomplished by several methods. Among these is the use of ethylene glycol (glycol injection) systems as an absorption mechanism to remove water and other solids from the gas stream. Alternatively, adsorption dehydration may be used, utilizing dry-bed dehydrators towers, which contain desiccants such as silica gel and activated alumina, to perform the extraction.

Contaminant Removal: Removal of contaminants includes the elimination of hydrogen sulfide, carbon dioxide, water vapor, helium, and oxygen. The most commonly used technique is to first direct the flow through a tower containing an amine solution. Amines absorb sulfur compounds from natural gas and can be reused repeatedly. After desulphurization, the gas flow is directed to the next section, which contains a series of filter tubes. As the velocity of the stream reduces in the unit, primary separation of remaining contaminants occurs due to gravity. Separation of smaller particles occurs as gas flows through the tubes, where they combine into larger particles which flow to the lower section of the unit. Further, as the gas stream continues through the series of tubes, a centrifugal force is generated which further removes any remaining water and small solid particulate matter.

Nitrogen Extraction: Once the hydrogen sulfide and carbon dioxide are processed to acceptable levels, the stream is routed to a Nitrogen Rejection Unit (NRU), where it is further dehydrated using molecular sieve beds. In the NRU, the gas stream is routed through a series of passes through a column and a brazed aluminum plate fin heat exchanger. Using thermodynamics, the nitrogen is cryogenically separated and vented. Another type of NRU unit separates methane and heavier hydrocarbons from nitrogen using an absorbent solvent. The absorbed methane and heavier hydrocarbons are flashed off from the solvent by reducing the pressure on the processing stream in multiple gas decompression steps. The liquid from the flash regeneration step is returned to the top of the methane absorber as lean solvent. Helium, if any, can be extracted from the gas stream in a Pressure Swing Adsorption (PSA) unit.

Methane Separation: The process of demethanizing the gas stream can occur as a separate operation in the gas plant or as part of the NRU operation. Cryogenic processing and absorption methods are some of the ways to separate methane from NGLs. The cryogenic method is better at extraction of the lighter liquids, such as ethane, than is the alternative absorption method. Essentially, cryogenic processing consists of lowering the temperature of the gas stream to around -120 degrees Fahrenheit. While there are several ways to perform this function the turbo expander process is most effective, using external refrigerants to chill the gas stream. The quick drop in temperature that the expander is capable of producing condenses the hydrocarbons in the gas stream, but maintains methane in its gaseous form. The absorption method, on the other hand, uses a "lean" absorbing oil to separate the methane from the NGLs. While the gas stream is passed through an absorption tower, the absorption oil soaks up a large amount of the NGLs. The "enriched" absorption oil, now containing NGLs, exits the tower at the bottom. The enriched oil is fed into distillers where the blend is heated to above the boiling point of the NGLs, while the oil remains fluid. The oil is recycled while the NGLs are cooled and directed to a fractionator tower. Another absorption method that is often used is the refrigerated oil absorption method where the lean oil is chilled rather than heated, a feature that enhances recovery rates somewhat.

Fractionation: Fractionation, the process of separating the various NGLs present in the remaining gas stream, uses the varying boiling points of the individual hydrocarbons in the stream, by now virtually all NGLs, to achieve the task. The process occurs in stages as the gas stream rises through several towers where heating units raise the temperature of the stream, causing the various liquids to separate and exit into specific holding tanks.

Carbon Dioxide (CO₂)

While most carbon dioxide is produced as a by-product of processes other than natural gas treatment. The carbon dioxide produced at these natural gas treatment plants is used primarily for re-injection in support of tertiary enhanced oil recovery efforts in the local production area. The smaller and uneconomic amounts of carbon dioxide are normally removed during the natural gas processing and treatment.

Hydrogen Sulfide (H₂S)

Almost all the elemental sulfur today is sulfur recovered from the desulfurization of oil products and natural gas. Hydrogen sulfide is extracted from a natural gas stream, or condensate, that is referred to as "sour." It is passed through a chemical solution that removes hydrogen sulfide and carbon dioxide, which are then fed to plants where the hydrogen sulfide is converted to elemental sulfur. The small quantities of non-sulfur components are incinerated and vented into the atmosphere. "Sour" condensate from plant inlet separators is fed to a condensate stabilizer where hydrogen sulfide and lighter hydrocarbons are removed, compressed, and then cycled to sulfur plants.

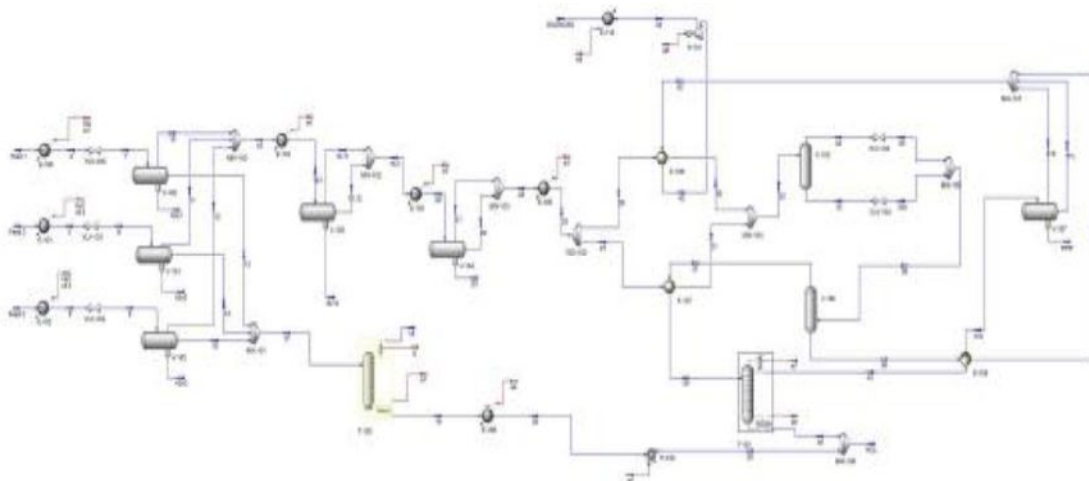


Fig: Simulation model of gas processing plant.

Simulation of gas processing plant

In simulating the processing plant, gas is drawn from three wells: feed 1, feed 2, feed3 respectively. This data are chosen randomly. Due to limitation and industrial visit the used data are assumed. If the industrial data are obtained the simulation can be done with real plant data of "Bakhrabad" and "Bibiana" gas processing plant and can be compared with industry. Composition of the feed can be found in datasheet. Then the gas is passed through three heaters (E-100, E-101, E-102) to heat the gas. Then the outlet streams of the heaters are passed through the inlet separators (V-100, V-101, V-102). The pressure control valves (VLV-100, VLV-101 and VLV-102)

control the pressure of the separators (three phase separators).

The vapor phases (stream 10, 11, 12) from the separators are mixed in a mixer and then the mixed stream (stream 16) is passed through the dehydration unit to dehydrate the gas. HYSYS no dehydration unit is available, so it carried out is a different way. First the gas is cooled by passing through a cooler (E-103). The cooled stream is passed the three phase separator (V-103) to separate the water and then the mixed stream of vapor and condensate phase is again passed through a second cooler (E-104) to cool the gas followed by the second three phase separator (V-104) and finally the mixed stream of vapor and

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condensate phase is passed through a heater (E-105) to heat the gas to the required temperature.

On the other hand the condensate phases (stream 13, 14, 15) are mixed in a mixer (MIX-101) and the mixed stream (stream 17) is taken to a stabilizer (T-100) to stabilize the gas. The top product (stream 18) from the stabilizer (stream 16) is used as fuel gas and the bottom product (stream 19) from the stabilizer is passed through the stabilizer product cooler (E-109). Then the product from the cooler is pumped (P-100) and mixed (MIX-106) with the bottom product of the deethanizer (stream 46) and stored in a storage tank and supply the condensate to the LPG plant.

The overhead gas stream (stream 20) from the water separators is then divided into two streams stream 26 and stream 27. Then the stream 26 is passed through the gas-gas exchanger (E-106) and stream 27 is passed through the de-ethanizer feed heater. Then the streams 30 and 31 are mixed (MIX 104) and the mixed stream is passed through the cold separator (V-105). The top stream (stream 34) from the cold separator is passed through the J-T valve and the bottom stream (stream 33) is passed through a valve to reduce the pressure and the output streams (stream 33a, 35) are then mixed (MIX-105). This mixed stream (stream 36) is a two-phase stream. This stream 36 is then passed through the expander separator (V-106). The bottom stream (stream 38) from the expander separator is passed through the heat exchanger (E-108). The top stream is passed through the de-ethanizer feed heater (E-107) and fed to the de-ethanizer (T-101)

The top product (stream 41) of the de-ethanizer is passed through the heat exchanger (E-108) and then the output streams (streams 41b, 41c) is mixed in a mixture (MIX-107) and then the mixed stream (stream 42) is passed through the gas-gas exchanger (E-106). Then the output stream (stream 43) is passed through the residue gas compressor (K-101) and then the residue gas cooler (E-

110). Finally the gas (stream sales gas) is taken to the pipeline as sales gas.

Conclusion

In this paper a simulation model of natural gas processing plant is developed. Simulation result will be compared further with natural gas processing plant equipment. Process optimizes the operating conditions that maximize the overall profit for the process with reduction of loss and modification in present plant equipment.

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