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**MOVING THE MOLECULES TO MARKET: AN INTRODUCTION TO HYDROCARBON PROCESSING AND TRANSPORTATION**

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**Overview**

· Overview of hydrocarbon properties

· Hydrocarbon processing

- Gathering

- Separation

- Water handling

- Dehydration

- Sweetening

- Liquid extraction

- Compression

- Transportation

- Metering

· Measurement standards

**Hydrocarbon Properties**

· ***Oil*** and gas are the liquid and gaseous forms of petroleum

· Petroleum is any naturally-occurring hydrocarbon found beneath the earth



· Petroleum hydrocarbons are naturally-occurring organic compounds (carbon + hydrogen)

· Occur in a variety of states from solid to gaseous

**Increasing Hydrogen and Carbon Atoms**

· Increase in Carbon and Hydrogen → Increase in chemical bonds → Increase in energy content

**If only it were this simple** ........



**Hydrocarbon Processing**



**Gathering**

· Too expensive for each wellhead to have own processing unit; system of flowlines connect wells to central processing facility (field processing area or processing plant)

- Radial gathering system

- Trunk line gathering system → Used in larger fields

· All produced fluids flow through gathering lines

· If no gathering system in place, fluids can be trucked → Not for gas wells

**Hydrocarbon Processing**



**Separation**

· Operation where well stream passed through 2+ separators arranged in series

- First-stage separator, second-stage separator, etc.

· Purpose of multi-stage separation to maximize hydrocarbon liquid recovery and provide maximum stabilization to resultant phases leaving final separator

- Well stream must be separated into three phases → Gas and liquids (***oil*** and water)

· Operation mainly uses gravity segregation

- Inlet fluid flows against diverter plate that separates gas and liquid

- Mist extractor collects liquid droplets from gas stream before it leaves separator

· Separators can be vertical, horizontal, or spherical depending on requirements

· If water cut is high, free water knock out vessel used for primary separation

· Heater/Treater used to treat ***oil***-water emulsions



**Separation - Crude *Oil***

· ***Oil*** flows into sales pipeline or tanks for storage

· If tanks are used, producers sell ***oil*** to third-party, who subcontracts with trucking company

· Important to negotiate risk of loss during transport

- Indemnification language

**Separation - Water Handling**

· If separation occurs at wellsite, water flows into tanks and is trucked to a processing facility

· Water tank has skimmer to remove any residual ***oil*** that floats to the top

· Water from separators used for reinjection (enhanced ***oil*** recovery) or sent to disposal well



**Hydrocarbon Processing**



**Dehydration - Natural Gas**

· Even after separation, gas stream contains water vapor, which must be removed

- Water reduces value of product

- Corrosion problems

- Hydrate formation

· Formed by union of water with other substances

· Can form in gas gathering facilities at reduced temperatures and high pressures

· Can plug the pipelines and significantly affect production operations

· Operation used to remove water and water vapors from gas

- Glycol dehydrator uses liquid desiccant

· Glycols → Ethylene, diethylene, triethylene, etc.

- Dry-bed dehydrator uses solid desiccant

· Silica gel or calcium chloride (CaCl)

· Designed to handle only water and gas vapors



**Hydrocarbon Processing**



**Sweetening - Natural Gas**



· Amine unit



· Sulphur block

· Difficult to dispose of or sell

**Hydrocarbon Processing**



**Liquid Extraction**

· If natural gas liquids (NGLs) have higher value as separate products, liquids are removed from gas stream

· Removal process similar to dehydration process

- Absorption method

· Absorption method uses absorbing ***oil*** to attract NGLs

- Cryogenic expansion method

· Drop temperature to ~ -120F

· Gas chilled using turbo expander process

- Better at recovering lighter hydrocarbons (C+)

**Liquid Extraction - Absorption**



**Liquid Extraction - Cryogenic**



**Hydrocarbon Processing**



**Compression**

· Compression can be done at all stages of hydrocarbon processing → Interstage compression

- Before processing, pressure may need to be increased (e.g., flow from low wellhead pressure to high separator pressures)

· Two main types of compressors used in gas industry

- Reciprocating

- Centrifugal

· Usually most expensive item in an upstream processing facility



**Transportation**

· After processing, hydrocarbons taken to sales typically via large, interstate/intrastate transmission lines

· Point-of-transfer between producer/processor and third-party purchaser/pipeline is the sales meter at specified location

- Transfer of title also determined in purchase and sale agreement

· Natural gas pipeline



· Crude ***oil*** pipeline



**Metering**

· Common types of meters:

- Direct / Positive displacement

· Used for liquids

· Mechanically isolate and pass known volume of liquid with every revolution

- Inferential / Differential Pressure

· Used for gas

· Velocity (gas flow rate) inferred from pressure differential caused by flowing gas through a restriction in the line (orifice plate)

**Metering**

· Positive displacement meter



· Orifice meter



**Measurement Standards - Natural Gas**

· Terms set forth in gas purchase and sale contract

· Found within contract or as exhibit to contract (e.g., Standard/General Terms & Conditions)

· Terms usually address:

- Receipt and delivery pressure

- Gas quality

· Grains of sulphur and hydrogen sulphide

· Volume of oxygen and carbon dioxide

· Temperature

· Water vapor content

· Bacteria-free

**Measurement Standards - Crude *Oil***

· Terms set forth in purchase confirmation:

- Specific Gravity

· Scale developed by API for measuring relative density of petroleum liquids (degrees)

- Reid Vapor Pressure

· Common measure of and generic term for gasoline volatility

· Conoco Terms and Conditions (1993) usually attached to or referenced in crude ***oil*** contract

**Reference Material**

· American Petroleum Institute (API) Standards

· GPSA Engineering Data Books

· Appendices

- Appendix A: EIA Natural Gas Processing Overview

- Appendix B: Example of General Terms & Conditions

- Appendix C: Conoco General Provisions

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**Appendix A**

**Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market**

This special report examines the processing plant segment of the natural gas industry, providing a discussion and an analysis of how the gas processing segment has changed following the restructuring of the natural gas industry in the 1990s and the trends that have developed during that time. It focuses upon the natural gas industry and its capability to take wellhead quality production, separate it into its constituent parts, and deliver pipeline-quality natural gas (methane) into the nation's natural gas transportation network. Questions or comments on the contents of this article may be directed to James Tobin at James.Tobin@eia.doe.gov or (202) 586-4835, Phil Shambaugh at Phil.Shambaugh@eia.doe.gov or 202-586-4833, or Erin Mastrangelo at Erin.Mastrangelo@eia.doe.gov or (202)-586-6201.

The natural gas product fed into the mainline gas transportation system in the United States must meet specific quality measures in order for the pipeline grid to operate properly. Consequently, natural gas produced at the wellhead, which in most cases contains contaminants[[1]](#footnote-2)1 and natural gas liquids,[[2]](#footnote-3)2 must be processed, i-e., cleaned, before it can be safely delivered to the high-pressure, long-distance pipelines that transport the product to the consuming public. 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 (see Box, "Pipeline-Quality Natural Gas").[[3]](#footnote-4)3

Although the processing/treatment segment of the natural gas industry rarely receives much public attention, its overall importance to the natural gas industry became readily apparent in the aftermath of Hurricanes Katrina and Rita in September 2005. Heavy damage to a number of natural gas processing plants along the U.S. Gulf Coast, as well as to offshore production platforms and gathering lines, caused pipelines that feed into these facilities to suspend natural gas flows while the plants attempted to recover.[[4]](#footnote-5)4 While several processing plants in southern Mississippi and Alabama were out of commission for only a brief period following Katrina, 16 processing plants in Louisiana and Texas with a total capacity of 9-71 billion cubic feet per day (Bcf/d) and a pre-hurricane flow volume of 5.45 Bcf/d were still offline 1 month following the two storms.[[5]](#footnote-6)5 Consequently, a significant portion of the usual daily output that flowed into the interstate pipeline network from the tailgates of these plants was disrupted, in some cases indefinitely.

**Pipeline-Quality Natural Gas**

The natural gas received and transported by the major intrastate and interstate mainline transmission systems must meet the quality standards specified by pipeline companies in the "General Terms and Conditions (GTC)" section of their tariffs. These quality standards vary from pipeline to pipeline and are usually a function of a pipeline system's design, its downstream interconnecting pipelines, and its customer base. In general, these standards specify that the natural gas:

· Be within a specific Btu content range (1,035 Btu per cubic feet, +/- 50 Btu)

· Be delivered at a specified hydrocarbon dew point temperature level (below which any vaporized gas liquid in the mix will tend to condense at pipeline pressure)

· Contain no more than trace amounts of elements such as hydrogen sulfide, carbon dioxide, nitrogen, water vapor, and oxygen

· Be free of particulate solids and liquid water that could be detrimental to the pipeline or its ancillary operating equipment.

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. For instance, in some areas coalbed methane production falls below the pipeline's Btu standard, in which case a blend of higher btu-content natural gas or a propane-air mixture is injected to enrich its heat content (Btu) prior for delivery to the pipeline. In other instances, such as at LNG import facilities where the heat content of the regasified gas may be too high for pipeline receipt, vaporized nitrogen may be injected into the natural gas stream to lower its Btu content.

In recent years, as natural gas pricing has transitioned from a volume basis (per thousand cubic feet) to a heat-content basis (per million Btu), producers have tended, for economic reasons, to increase the Btu content of the gas delivered into the pipeline grid while decreasing the amount of natural gas liquids extracted from the natural gas stream. Consequently, interstate pipeline companies have had to monitor and enforce their hydrocarbon dew point temperature level restrictions more frequently to avoid any potential liquid formation within the pipes that may occur as a result of producers maximizing Btu content.

**Figure 1. Generalized Natural Gas Processing Schematic**



· Source: Energy Information Administration, Office of ***Oil*** and Gas, Natural Gas Division.

In 2004, approximately 24.2 trillion cubic feet (Tcf) of raw natural gas was produced at the wellhead.[[6]](#footnote-7)6 A small portion of that, 0-1 Tcf, was vented or flared, while a larger portion, 3.7 Tcf, was re-injected into reservoirs (mostly in Alaska) to maintain pressure. The remaining 20.4 Tcf of "wet"[[7]](#footnote-8)7 natural gas was converted into the 18.9 Tcf of dry natural gas that was put into the pipeline system. This conversion of wet natural gas into dry pipeline-quality natural gas, and the portion of the natural gas industry that performs that conversion, is the subject of this report.

**Background**

Natural gas processing begins at the wellhead (Figure 1). 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." In 2004, 75 percent of U.S. wellhead production of natural gas was 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). The natural gas extracted from coal reservoirs and mines (coalbed methane) is the primary exception, being essentially a mix of mostly methane and carbon dioxide (about 10 percent).[[8]](#footnote-9)8

Natural gas production from the deepwater Gulf of Mexico and conventional natural gas sources of the Rocky Mountain area is generally rich in NGLs and typically must be processed to meet pipeline-quality specifications- Deepwater natural gas production can contain in excess of 4 gallons of NGLs per thousand cubic feet (Mcf) of natural gas compared with 1 to 1.5 gallons of NGLs per Mcf of natural gas produced from the continental shelf areas of the Gulf of Mexico. Natural gas produced along the Texas Gulf Coast typically contains 2 to 3 gallons of NGLs per Mcf.[[9]](#footnote-10)9

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 (see Box, "Stages in the Production of Pipeline-Quality Natural Gas and NGLs"). 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. These natural gas hydrates are crystalline ice-like solids or semi-solids that can impede the passage of natural gas through valves and pipes.

The wells on a lease or in a field are connected to downstream facilities via a process called gathering, wherein small-diameter pipes connect the wells to initial processing/treating facilities. Beyond the fact that a producing area can occupy many square miles and involve a hundred or more wells, each with its own production characteristics, there may be a need for intermediate compression, heating, and scrubbing facilities, as well as treatment plants to remove carbon dioxide and sulfur compounds, prior to the processing plant (see Box "Other Key Byproducts of Natural Gas Processing"). All of these factors make gathering system design a complex engineering problem.

In those few cases where pipeline-quality natural gas is actually produced at the wellhead or field facility, the natural gas is moved directly to receipt points on the pipeline grid. In other instances, especially in the production of non-associated natural gas, field or lease facilities referred to as "skid-mount plants" are installed nearby to dehydrate and decontaminate raw natural gas into acceptable pipeline-quality gas for direct delivery to the pipeline grid. These compact "skids" are often specifically customized to process the type of natural gas produced in the area and are a relatively inexpensive alternative to transporting the natural gas to distant large-scale plants for processing.

Natural gas pipeline compressor stations,[[10]](#footnote-11)10 especially those located in production areas, may also serve as field level processing facilities- They often include additional facilities for dewatering natural gas and for removal of many hydrocarbon liquids. Some pipeline compressor stations located along the coast of the Gulf of Mexico, for instance, are set up to process offshore production to a degree permitting delivery of a portion of its natural gas throughput directly into the pipeline grid. The remaining portion is forwarded to a natural gas processing plant for further processing and extraction of heavy liquids.

Non-pipeline-quality production is piped to natural gas processing plants for liquids extraction and eventual delivery of pipeline-quality natural gas at the plant tailgate. A natural gas processing plant typically receives gas from a gathering system and sends out processed gas via an output (tailgate) lateral that is interconnected to one or more major intra- and inter-state pipeline networks. Liquids removed at the processing plant usually will be taken away by pipeline to petrochemical plants, refineries, and other gas liquids customers. Some of the heavier liquids are often temporarily stored in tanks on site and then trucked to customers.

Various types of processing plants have been utilized since the mid-1850s to extract liquids, such as natural gasoline, from produced crude ***oil***. However, for many years, natural gas was not a sought after fuel. Prior to the early 20 century, most of it was flared or simply vented into the atmosphere, primarily because the available pipeline technology permitted only very short-distance transmission.[[11]](#footnote-12)11

It was not until the early 1920s, when reliable pipe welding techniques were developed, that a need for natural gas processing arose- Yet, while a rudimentary network of relatively long-distance natural gas pipelines was in place by 1932, and some natural gas processing plants were installed upstream in major production areas,[[12]](#footnote-13)12 the depression of the 1930s and the duration of World War II slowed the growth of natural gas demand and the need for more processing plants.[[13]](#footnote-14)13

After World War II, particularly during the 1950s, the development of plastics and other new products that required natural gas and petroleum as a production component coincided with improvements in pipeline welding and pipeline manufacturing techniques- The increased demand for natural gas as an industrial feedstock and industrial fuel supported the growth of major natural gas transportation systems, which in turn improved the marketability and availability of natural gas for residential and commercial use.

**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 shown in Figure 1 may be integrated into one unit or operation, performed in a different order or at alternative locations (lease/plant), or not required at all. Among the several stages (as lettered in Figure 1) of gas processing/treatment are:

A) **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.

B) **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 (600 pounds per square inch gauge (psig) or greater) 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.

C) **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.

D) **Contaminant Removal:** Removal of contaminates includes the elimination of hydrogen sulfide, carbon dioxide, water vapor, helium, and oxygen. The most commonly used technique is to first direct the flow though 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.

E) **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.

F) **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.

G) **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.

\* Adsorption is the binding of molecules or particles to the surface of a material, while absorption is the filling of the pores in a solid. The binding to the surface is usually weak with adsorption, and therefore, usually easily reversible.

· Sources: Compiled from information available at the following Internet web sites: American Gas Association (http://www.naturalgas.org/naturalgas/naturalgas.asp), Environmental Protection Agency (http://www.cpa.gov/ttn/chicf/ap42/ch05/final/c05s03.pdf). Cooper Cameron Inc. (http://www.coopercameron.com/cgi-bin/petreco/products/products.cfm?pageid=gastreatment), AdvancedExtractionTechnologies, Inc. (http://www.aet.com/gtipl.htm#refriglean), SPM-3000 Gas ***Oil*** Separation Processing (GOSP) (http://www.simtronics.com/\_catalog/spm/spm3000.htm), and Membrane Technology and Research, Inc. (http://www.mtrinc.com/Pages/NaturalGas/ng.html#).

**Other Key Byproducts of Natural Gas Processing**

While natural gas liquids, such as propane and butane, are the byproducts most often related to the natural gas recovery process, several other products are also extracted from natural gas at field or gas treatment facilities.

**Helium (He)**

The world's supply of helium comes exclusively from natural gas production. The single largest source of helium is the United States, which produces about 80 percent of the annual world production of 3.0 billion cubic feet (Bcf). In 2003, U.S. production of helium was 2.4 Bcf, about two-thirds of which came from the Hugoton Basin in north Texas, Oklahoma, and Kansas (Figure 2). The rest mostly comes from the LaBarge field located in the Green River Basin in western Wyoming, with small amounts also produced in Utah and Colorado. According to the National Research Council, the consumption of helium in the United States doubled between 1985 and 1996, although its use has leveled off in recent years. It is used in such applications as magnetic resonance, imaging, semiconductor processing, and in the pressurizing and purging of rocket engines by the National Aeronautics and Space Administration.

Twenty-two natural gas treatment plants in the United States currently produce helium as a major byproduct of natural gas processing. Twenty of these plants, located in the Hugoton-Panhandle Basin, produce marketable helium which is sold in the open market when profitable, while transporting the remaining unrefined helium to the Federal Helium Reserve (FHR). The FHR was created in the 1950s in the Bush salt dome, underlying the Cliffside field, located near Amarillo, Texas. Sales of unrefined helium in the United States for the most part, come from the FHR.

**Carbon Dioxide (CO)**

While most carbon dioxide is produced as a byproduct of processes other than natural gas treatment, a significant amount is also produced during natural gas processing in the Permian Basin of western Texas and eastern New Mexico. A limited amount is also produced in western Wyoming. In 2004 about 6.2 Bcf of carbon dioxide was produced in seven plants in the United States.

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, uneconomic, amounts of carbon dioxide that are normally removed during the natural gas processing and treatment in the United States are vented to the atmosphere.

**Hydrogen Sulfide (HS)**

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.

Consequently, as the natural gas pipeline network itself became more efficient and regulated, the need for more and better natural gas processing increased both the number and operational efficiencies of natural gas processing plants.

**National Overview**

More than 500 natural gas processing plants currently operate in the United States (Table 1). Most are located in proximity to the major gas/***oil*** producing areas of the Southwest and the Rocky Mountain States (Figure 2).[[14]](#footnote-15)14 Not surprisingly, more than half of the current natural gas processing plant capacity in the United States is located convenient to the Federal offshore- Texas, and Louisiana. Four of the largest capacity natural gas processing/treatment plants are found in Louisiana while the greatest number of individual natural gas plants is located in Texas.

Although Texas and Louisiana still account for the larger portion of U.S. natural gas plant processing capability, other States have moved up in the rankings somewhat during the past 10 years as new trends in natural gas production and processing have come into play. For instance:

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Table 1. Natural Gas Processing Plant Capacity in the Lower 48 States, 1995 and 2004 |  |  |  |  |  |  |  |  |  |  |
| Natural Gas Processing Capacity (Million cubic feet per day) | Number of Natural Gas Processing/Treatment Plants | Percentage Change 1995 to 2004 |  |  |  |  |  |  |  |  |
| State | In 2004 | Percent of Total U.S. | In 1995 | Percent of Total U.S. | In 2004 | Percent of Total U.S. | In 1995 | Percent of Total U.S. | In Capacity | In Number |
| Louisiana | 16,512 | 27.3 | 15,569 | 28.0 | 61 | 11.5 | 87 | 12.0 | 6.1 | -29.9 |
| Texas | 15,825 | 26.1 | 18,259 | 32.9 | 166 | 31.3 | 278 | 38.2 | -13.3 | -40.3 |
| Wyoming | 6,920 | 11.4 | 4,730 | 8.5 | 45 | 8.5 | 53 | 7.3 | 46.3 | -15.1 |
| Kansas | 3,533 | 5.8 | 3,424 | 6.2 | 10 | 1.9 | 11 | 1.5 | 3.2 | -9.1 |
| New Mexico | 3,427 | 5.7 | 3,697 | 6.7 | 25 | 4.7 | 34 | 4.7 | -7.3 | -26.5 |
| Oklahoma | 3,438 | 5.7 | 4,220 | 7.6 | 59 | 11.1 | 100 | 13.8 | -18.5 | -41.0 |
| Illinois | 2,202 | 3.6 | 2 | -- | 2 | 0.4 | 1 | 0.1 | -- | 100.0 |
| Colorado | 2,093 | 3.5 | 1,490 | 2.7 | 43 | 8.1 | 40 | 5.5 | 40.5 | 7.5 |
| Mississippi | 1,572 | 2.6 | 40 | 0.1 | 6 | 1.1 | 5 | 0.7 | -- | 20.0 |
| Alabama | 1,310 | 2.2 | 468 | 0.8 | 15 | 2.8 | 12 | 1.7 | 179.9 | 25.0 |
| California | 1,037 | 1.7 | 925 | 1.7 | 24 | 4.5 | 31 | 4.3 | 12.1 | -22.6 |
| Utah | 970 | 1.6 | 779 | 1.4 | 16 | 3.0 | 13 | 1.8 | 24.5 | 23.1 |
| Michigan | 483 | 0.8 | 524 | 0.9 | 16 | 3.0 | 19 | 2.6 | -7.8 | -15.8 |
| West Virginia | 460 | 0.8 | 421 | 0.8 | 8 | 1.5 | 7 | 1.0 | 9.3 | 14.3 |
| North Dakota | 222 | 0.4 | 241 | 0.4 | 8 | 1.5 | 9 | 1.2 | -7.9 | -11.1 |
| Kentucky | 154 | 0.3 | 178 | 0.3 | 3 | 0.6 | 5 | 0.7 | -13.5 | -40.0 |
| Montana | 133 | 0.2 | 115 | 0.2 | 3 | 0.6 | 8 | 1.1 | 15.7 | -62.5 |
| Florida | 90 | 0.1 | 361 | 0.6 | 1 | 0.2 | 2 | 0.3 | -75.1 | -50.0 |
| Arkansas | 67 | -- | 70 | 0.1 | 7 | 1.3 | 6 | 0.8 | -4.3 | 16.7 |
| Pennsylvania | 62 | 0.1 | 20 | -- | 9 | 1.7 | 2 | 0.3 | 210.0 | 350.0 |
| Ohio | 23 | -- | 23 | -- | 3 | 0.6 | 3 | 0.4 | -- | 0.0 |
| Nebraska | 0 | -- | 10 | -- | 0 | 0.0 | 1 | 0.1 | NA | NA |
| Total Lower 48 States | 60,533 | 100.0 | 55,566 | 100.0 | 530 | 100.0 | 727 | 100.0 | 8.9 | -27.1 |
| Note: -- = less than .05 or greater than 999.99 percent. Although more than 8 billion cubic feet per day of gas processing capacity exists in the State of Alaska, almost all of the natural gas that is extracted does not enter any transmission system. Rather, it is reinjected into reservoirs. |  |  |  |  |  |  |  |  |  |  |
| Source: Energy Information Administration. Gas Transportation Information System, Natural Gas Processing Plant Database (Compiled from data available from the Form EIA-64A, Form EIA-816, PentaSul Inc's LPG Almanac, and Internet sources.) |  |  |  |  |  |  |  |  |  |  |

· **The Aux Sable natural gas plant, one of the largest natural gas processing plants in the Lower 48 States with an initial design capacity of 2.2 Bcf/d, was built in 2000 in Illinois, a State that has little or no natural gas production of its own.** Located at the receiving end of the Alliance Pipeline, which was built specifically to transport "wet" natural gas from British Columbia and Alberta, Canada, to Aux Sable, the plant currently processes about 1.5 Bcf daily, separating methane from natural gas liquids. The plant's northern Illinois location was selected to take economic advantage of extracting natural gas liquids in the Chicago (hub) area with its easy access to several hydrocarbon products pipelines, while delivering "dry" natural gas to the interstate pipeline system via the Chicago Hub. Four interstate, and two intrastate, pipelines receive natural gas at the Aux Sable plant tailgate.

· **Since 1995, average daily natural gas plant processing capacity in the United States increased by 49 percent as new and larger capacity plants were installed and a number of existing ones were expanded.** Over the past 10 years, average plant capacity increased from 76 million cubic feet per day (MMcf/d) to 114 MMcf/d and decreased in only 4 of the 22 States with natural gas processing plant capacity (Table 1). In Texas, although the number of plants and overall processing capacity decreased, the average capacity per plant increased from 66 MMcf/d to 95 MMcf/d as newer plants were added and old, less efficient plants were idled. In Alabama, Mississippi, and the eastern portion of South Louisiana, new larger plants and plant expansions built to serve new offshore production increased the average plant capacity significantly in those areas.

· **Expanding natural gas production in Wyoming in recent years led to the installation of seven new gas processing plants and the expansion of several more.** Since 1995, Wyoming's natural gas plant processing capacity increased by almost 46 percent, adding more than 2.2 Bcf/d (Table 1). Much of the activity has been focused in the southwestern area of Wyoming's Green River Basin where one of the nation's largest gas plants, the Williams Company's 1.1 Bcf/d Opal facility, is located. Increased natural gas development behind the plant and a significant expansion of pipeline capacity at the plant tailgate (***Kern*** River Transmission and Northwest Pipeline systems) necessitated two significant plant expansions at Opal since 2000, the last being a 350-MMcf/d increase in early 2004.

**Figure 2. Concentrations of Natural Gas Processing Plants, 2004**



Note: Eight Alaska plants not displayed, but count is reflected in the legend.

Source: Energy Information Administration, Gas Transportation Information System, Natural Gas Processing Plant Database.

· **Successful exploration and development in the Piceance Basin in western Colorado and increased natural gas production in the San Juan Basin in southern Colorado have contributed to the installation of 13 new or replacement plants in the State and the expansion of several existing facilities.** In part, these increases have supported the installation of new pipeline systems in the region such as the TransColorado Gas Transmission system built in 1999, which can transport up to 650 MMcf/d of Piceance and San Juan basin production to interstate pipeline connections with western markets.

Over the next several years, additional new natural gas processing plants and capacity can be expected to be installed in Wyoming and Colorado as exploration and development efforts in those States continue, especially if the prices of natural gas and natural gas liquids remain high. Increased exploration and development has increased the level of proved natural gas reserves in these two States by more than 45 percent, or 18.6 trillion cubic feet, since 1995 (Figure 3).

Moreover, it can be expected that new plant capacity will be needed in other areas currently undergoing increased exploration and development, such as the Fort Worth Basin in northeast Texas (gas shale), the Texas panhandle, and the east Texas area. Since 1995, growth in the level of proved natural gas reserves in these areas has been significant.

**Shift in Installation Patterns**

While a number of market factors can influence the location and level of gas processing capacity in the United States, shifts in exploration and development activity and subsequent changes in natural gas production levels have had the greatest impact during the past 10 years. The level of overall natural gas plant processing capacity in an area follows the development of new ***oil*** and gas fields (rise in supply) and the decline of older fields (fall in supply).

**Figure 3. Major Changes in Proved Natural Gas Reserves, 1995 to 2004 (Wet after lease separation)**



Source: Energy Information Administration, *U.S. Crude* ***Oil*** *and Natural Gas, and Natural Gas Liquids Reserves, 1995 and 2004 Annual Reports*: Table 9.

As natural gas production (Table 2) and annual added proved reserves (Figure 3) decreased significantly in southern Louisiana and the Gulf of Mexico (GOM) between 1995 and 2004,[[15]](#footnote-16)15 several natural gas processing plants in the region were idled, especially in the western portion of the region where older production fields are predominate- However, in the deepwater and eastern portion of the Gulf several substantial new natural gas deposits were developed and began producing during the period. Subsequently, new natural gas production facilities and new gathering pipelines were built to deliver this natural gas onshore. To accommodate these new natural gas flows, eight natural gas plants located in southern Louisiana were expanded. These expansions helped increase Louisiana's overall natural gas plant capability by 6 percent between 1995 and 2004, despite declining overall natural gas production both onshore and off. Increased deepwater natural gas development also affected the number and capacity of natural gas processing facilities in Alabama and Mississippi. In Alabama, two of the seven new processing plants installed after 1995 were principally dedicated to processing offshore production delivered via the Dauphin Island Gathering System and Transco's Mobile Bay lateral. Both were large 600-MMcf/d facilities located along Mobile Bay.[[16]](#footnote-17)16 In Mississippi, a new 500-MMcf/d plant was developed in the mid-1990s at Pascagoula, primarily to serve onshore production. The plant's capacity was doubled in 2000 in order to accept natural gas from the offshore via the new Destin Pipeline. Growth in natural gas processing demand owing to new offshore production brought Mississippi and Alabama, from a ranking (by overall capacity) of 18 and 11, respectively, in 1995, to 9th and 10th in 2004.

The Rocky Mountain States have seen expanding development of coalbed methane resources as well as steadily increasing exploration/development efforts and growing production from tight-sands and conventional natural gas sources. As a result, significant increases in natural gas plant processing capacity in Wyoming, Colorado, and Utah have occurred. While Montana has much less overall natural gas processing capacity than the other Rocky Mountain States, it too experienced an increase in processing capacity (Table 1) as natural gas production in the State rose by 16 percent and proved reserves grew by 27 percent during the past decade.

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Table 2. Major Lower 48 Natural Gas Producing States and Federal Offshore |  |  |  |  |  |  |  |
| (Volumes in Trillion Cubic Feet) |  |  |  |  |  |  |  |
| State | Wet Gas Production | Percentage Change | Processed Volume (Gas to Liquids) | Percent Processed |  |  |  |
| 1995 | 2004 | 1995-2004 | 1995 | 2004 | 1995 | 2004 |  |
| Texas | 5.11 | 5.66 | 10.8 | 0.39 | 0.35 | 7.6 | 6.2 |
| Federal Offshore | 4.67 | 4.01 | -14.0 | 0.04 | 0.09 | 0.9 | 2.3 |
| Oklahoma | 1.66 | 1.66 | -0.2 | 0.10 | 0.10 | 6.0 | 5.8 |
| New Mexico | 1.48 | 1.62 | 9.7 | 0.08 | 0.09 | 5.4 | 5.7 |
| Wyoming | 0.84 | 1.59 | 89.4 | 0.03 | 0.07 | 3.6 | 4.5 |
| Louisiana | 1.50 | 1.36 | -9.5 | 0.10 | 0.04 | 6.7 | 2.8 |
| Colorado | 0.54 | 1.09 | 101.1 | 0.03 | 0.04 | 5.6 | 3.3 |
| Kansas | 0.71 | 0.40 | -43.1 | 0.08 | 0.02 | 11.3 | 5.9 |
| Total | 18.51 | 17.39 | 5.3 | 0.85 | 0.80 | 5.1 | 4.6 |
| Source: Energy Information Administration, U.S. Crude ***Oil*** and Natural Gas, and Natural Gas Liquids Reserves: 1995 and 2004 Annual Reports. |  |  |  |  |  |  |  |

As mentioned earlier, the number of plants and the level of natural gas processing capacity in Texas decreased by 40 and 13 percent, respectively, between 1995 and 2004. While natural gas production within Texas increased overall during that time period, several areas such as the Permian Basin in the western part of the State experienced decreases. A number of natural gas plants in that area were idled while new processing plants were built in developing areas such as the Fort Worth Basin area in northeast Texas.

In most of the country, the increases and decreases in installed natural gas processing capacity have closely tracked the changes in proved natural gas reserves since 1995, Moreover, where significant new proved reserves have been added, the expectation is that eventually new natural gas production will follow, and new natural gas processing plants will need to be installed accordingly (Figure 3).

**Impact of Restructuring**

As the FERC-mandated restructuring of the natural gas industry[[17]](#footnote-18)17 took effect during the 1990s, changes also occurred in the economics of natural gas processing plant ownership- Before restructuring, many natural gas processing plants were owned and operated by natural gas and ***oil*** producers as part of their overall energy production and marketing business. With restructuring, many of these producers sold their natural gas processing facilities in order to focus on exploration and development activities.

Before restructuring, more than 310 individual companies owned and/or operated natural gas processing plants. By 1995 there were 270 companies, and by 2004 the number had dropped to 209. Yet, the amount of new processing capacity rose by 8.9 percent during the same 9-year period (Table 1). As competition increased and the economics of production and processing changed under restructuring, consolidation of plant ownership significantly increased. In 2004, for instance, the top 10 natural gas plant owner/operators had access to or owned about 74 percent (44.5 Bcf/d) of the total natural gas plant capacity in the United States. This compares with about half that much in 1995, although the percentage of plants owned/operated remained at about 36 percent.

Between 1995 and 2004, the type of companies owning/operating processing plants shifted from primarily ***oil***/gas producers to what are now referred to as "midstream" companies or operating divisions. These entities focus their efforts on the natural gas gathering, natural gas processing, and natural gas storage operations segments of the industry. In 1995 production companies such as Shell Western E&P, Texaco Production, Exxon Co USA, and Warren Petroleum controlled the largest share of natural gas plant processing capacity. In 2004, however, midstream operating companies such as Duke Energy Field Services (54 plants, 7.5 Bcf/d capacity). Enterprise Products Operating LP (26, 6.3 Bcf/d), Targa Resources[[18]](#footnote-19)18 (21, 3-4 Bcf/d), and BP PLC (13, 5.6 Bcf/d), predominate.[[19]](#footnote-20)19

**Natural Gas Processing Cost Recovery**

The primary role of a natural gas processing plant in today's marketplace is to produce pipeline-quality natural gas. The production of natural gas liquids and other products from the natural gas stream is secondary. The quantity and quality of the byproducts actually produced during a particular time period is, in many instances, a function of their current market prices. If the market value of a byproduct falls below the current production cost, a natural gas plant owner/operator may suspend its production temporarily. In some instances, a plant operator may increase the Btu content of its plant residue (plant tailgate) gas stream, as long as it remains within pipeline tolerances, in order to absorb some of the byproducts. In other cases the raw liquid stream (minus methane) is stored on-site temporarily or sold off.

As noted earlier, before restructuring of the natural gas industry in the 1990s, most natural gas processing was performed by an affiliate of the production company. The processor was reimbursed through what is commonly referred to as a keepwhole contract.[[20]](#footnote-21)20 Under such a contract the NGLs recovered at the facility are retained by the processor as payment, while the other party's delivery is "kept whole" by returning an amount of residue (plant tailgate) natural gas (equal on a Btu basis to the natural gas received at the plant inlet) at the tailgate of the plant-

In today's more competitive restructured marketplace, where supply/demand fluctuations are more commonplace, natural gas prices are more variable, and price levels are relatively high compared with other forms of energy, including NGLs. "keepwhole" arrangements tend to create income uncertainty for processors. Such arrangements are profitable when the value of the NGLs is greater as a separated liquid than as a portion of the residue natural gas stream; they are less profitable when the value of the NGLs is lower as a liquid than as a portion of the residue natural gas stream.

As a result, participants in the natural gas processing industry have been replacing keepwhole contracts with alternative arrangements as the contracts come up for renewal. Several unique types of natural gas processing arrangements are being offered in their place. Among them are: percent-of-liquids contracts, percent-of-index contracts, margin-band contracts, fee-based contracts, and hybrid contracts. In broad terms, they function as follows:

· ***Percent-of-liquids or percent-of-proceeds*.** With this type of contract the processor takes ownership of a percentage of the NGL mix extracted from a producer's natural gas stream. The producer either retains title to, or receives the value associated with, the remaining percentage of the NGL mix. The producer reimburses the processor for the costs involved in the liquids extraction operation.

· ***Percent-of-index contracts*.** Under this type of contract the processor generally purchases its natural gas at either a percentage discount to a specified index price, a specified index price less a fixed amount, or a percentage discount to a specified index price less an additional fixed amount. The processor then resells the natural gas at the index price or at a different percentage discount to the index price.

· ***Margin-band contracts*.** Under this type of arrangement the processor takes ownership of NGLs extracted from the natural gas stream delivered by the producer, while the producer is paid a return based on the energy value of the NGL mix that was extracted from the natural gas stream less the fuel consumed in the extraction process. Both parties accept specified floor and ceiling return levels which are intended to provide an acceptable return to each party when natural gas processing economics tend to become negative or the economic gains become excessive.

· ***Fee-based contracts*.** In these contracts a set fee is negotiated based on the anticipated volume of natural gas to be processed. The producer either retains title to, or receives the value associated with, any NGLs extracted and is responsible for all energy costs of processing.

· ***Hybrid contracts*.** Such arrangements usually provide processing services to a producer under a monthly percent-of-liquids arrangement initially, with the producer having the option of switching to either a fee-based arrangement or in certain cases to a keepwhole basis. The intent is to give both producer and processor the incentive to maintain operations during periods of natural gas price swings, especially during those periods when the price of natural gas is high relative to the economic value of NGLs.

Contracts for natural gas processing have terms ranging from month-to-month to the life of the producing lease. Intermediate terms of 1 to 10 years are also common.

**Outlook and Potential**

Since 1995, natural gas plant processing capacity has increased by almost 9 percent (Table 1), with most of this growth following new production field development. Based upon trends that have developed over the past several years, especially in the finding of newly proved reserves (Figure 3), or lack thereof, two areas of the country in particular could experience sizable shifts in natural gas processing plant resources, with increases expected in the Rocky Mountain area and decreases expected along the Gulf Coast.

Continuing a trend begun in the late 1990s, ongoing expansion of natural gas exploration and development in Colorado, Utah, and Wyoming could add to natural gas plant processing requirements over the next several years.[[21]](#footnote-22)21 Each of these States experienced a 25 percent or greater increase in installed natural gas processing plant capacity over the past decade- It is generally anticipated that the Unita Basin of eastern Utah and the Piceance Basin of western Colorado will become more actively developed over the next decade, with several new large-scale capacity natural gas pipelines scheduled to be installed to transport the produced natural gas to western and midwestern markets.[[22]](#footnote-23)22 These new pipelines will also need new processing plants to be installed to treat this natural gas prior to receipt.

New natural gas processing capacity will perhaps be needed in Texas as well. Despite a net decrease in natural gas plant capacity in the State of about 13 percent between 1995 and 2004 (Table 1), several new plants were added and others are planned as a result of increased development in the Barnett Shale Formation of the Fort Worth Basin in northeast Texas. The gas shales located in this area, which encompasses several counties north and west of Dallas, Texas, were once considered uneconomical to develop, but the advent of new technologies has greatly improved its potential and, thus, its attraction to natural gas producers.

In southern Louisiana and the Gulf of Mexico, on the other hand, decreasing natural gas production and a significant drop in the volume of new proved natural gas reserves found in the region during the past decade likely will slow growth of natural gas processing capacity along the Gulf Coast over the next several years. However, since the Gulf of Mexico and southern Louisiana will remain the largest natural gas producing area in the country for years to come, most existing natural gas processing plants in the region should remain active, although perhaps processing at lower daily flow rates.

The potential remains, nevertheless, for the discovery of some major natural gas finds in the deepwater regions of the Gulf, which could lead to expansion of some existing plants or even installation of an occasional new one. However, in the short term, this seems unlikely. No new offshore-to-onshore pipelines are scheduled for development through 2008, except for those related to LNG imports through the Gulf States.[[23]](#footnote-24)23 The lack of proposals for pipeline development would tend to indicate that existing plant capacity serving the Gulf of Mexico is adequate for the foreseeable future-

Although gross natural gas production in the United States has remained relatively level since 2000,[[24]](#footnote-25)24 rising natural gas wellhead prices can be expected to lead to increases in natural gas exploration and development efforts- Some increases in production could occur in the older production fields, but much of the additional natural gas production will probably come from newly developed reserves found in the areas mentioned above. Consequently, as new sources of production are developed, new processing facilities, or greater use of now-underutilized plant capacity, will follow suit, while some older facilities, particularly those taking gas from depleting areas, will be closed or relocated.

**Appendix B**

**SAMPLE PROVISIONS EXHIBIT A - GENERAL TERMS AND CONDITIONS to GAS PURCHASE AGREEMENT**

**A.1. DEFINITIONS**

As used in this Agreement, except in those certain instances where the context expressly states another meaning, the following terms and expressions shall have the following meanings:

**"Affiliate"** means any Person that directly or indirectly, through one or more intermediaries, controls or is controlled by or is under common control with the specified Person. For purposes of this definition, "control" shall mean (i) ownership, directly or indirectly, of either the outstanding voting stock of the controlled Person or any other ownership interest in the controlled Person if such interest has, directly or indirectly, the power to direct or cause the direction of the management and policies of such relevant Person or (ii) operational control of the controlled Person pursuant to an operating agreement, management agreement or other contractual rights.

**"Agreement"** shall mean this Gas Purchase Agreement, including the Commercial Terms and Conditions, the exhibits and schedules attached hereto or incorporated therein by reference, and any amendments to this Gas Purchase Agreement executed pursuant to the provisions of Section A.33 (9).

**"Btu"** shall mean British thermal unit or units and shall be defined as the quantity of heat required to raise the temperature of one (1) pound, avoirdupois, of pure water one (1) degree on the Fahrenheit temperature scale (58.5 degrees to 59.5 degrees) at a constant pressure of 14.73 psia.

**"Business Day"** shall mean any Day in which Federal Reserve member banks in Houston, Texas are open for business.

**"Claims"** shall mean any claim, demand, and causes of action of any kind and all losses, fines, penalties, damages liabilities, interest, costs, and expenses (including court costs, expert fees, expenses of investigation and reasonable attorneys' fees) relating thereto.

**"Commercial Terms and Conditions"** shall mean the terms and conditions appearing under the heading "Commercial Terms and Conditions" in the main body of this Agreement.

**"CPI-U Index"** shall be the Consumer Price Index, All Urban Consumers, U. S. city average, all items, as determined and published by the United States Department of Labor Statistics (the "BLS") or any successor agency thereto. The CPI-U Index shall be taken from the data published by the BLS, as of the date hereof, electronically at the internet address of ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt, or at any successor electronic address or as same is published in hardcopy form.

**"Cubic Foot of Gas"** shall mean the volume of Gas contained in one cubic foot of space at (1) a pressure base of (a) 15.025 pounds per square inch absolute if produced from lands or water bottoms situated in or off of the coast of Louisiana; or (b) 14.65 pounds per square inch absolute if produced from lands or water bottoms situated in or off of the coast of any other state; and (2) a temperature base of sixty degrees Fahrenheit (60°F). Whenever the conditions of pressure and temperature differ from the above, conversion of the volume from such conditions to the standard conditions shall be made in accordance with the Ideal Gas Laws, corrected for deviation due to supercompressibility by the methods set forth in the American Petroleum Institute Manual of Petroleum Measurement Standards ("API MPMS"), Chapter 14, Natural Gas Fluids Measurement, Section 3, Concentric, Square-Edged Orifice Meters, Parts 1, 2, 3 & 4, 1991 Edition or latest revision and as further detailed in the latest revision of American Gas Association (AGA) Report Number 8, "Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases."

**"Day"** or **"Daily"** shall mean the period of twenty-four (24) consecutive hours commencing at nine (9:00) o'clock a.m., in the time zone in which the Plant is located, on a calendar day and ending at nine (9:00) o'clock a.m., in that same time zone, on the next succeeding calendar day.

**"Dedicated Acreage"** shall mean those lands covered by the leases (including any extensions and renewals thereof) more particularly described on Exhibit B.

**"Dedicated Wells"** shall mean those well(s) and wellbore(s) described on Exhibit B, including any replacement(s) thereto and any other wells situated within the "Setoff Area" described in Exhibit B and completed within any of the same geological formations in which the well(s) described in Exhibit B are completed.

**"Delivery Point"** shall have the meaning set forth in the "Delivery Points" section of the Commercial Terms and Conditions.

**"Drip Liquids"** shall mean any liquid hydrocarbons accumulating in drips, separators, equipment and/or pipelines or otherwise recovered at any point between the Delivery Point and the initial inlet scrubber of the Plant (including liquid hydrocarbons recovered by the inlet scrubber); including, without limitation, dirty ***oil***, line drip, scrubber ***oil***, compression and separator liquids and condensate.

**"Effective Date"** shall have the meaning set forth in the "Term" section of the Commercial Terms and Conditions.

**"Fee"** shall have the meaning specified in the Commercial Terms and Conditions.

**"Fuel"** shall mean the Monthly volume of Gas, in Mcf or MMBtu, utilized for Plant and/or Gathering System operations.

**"Gallon"** shall mean one (1) U.S. Standard Liquid Gallon of two hundred thirty-one (231) cubic inches, adjusted to a temperature of sixty degrees Fahrenheit (60°F) and equilibrium pressure of the Product measured.

**"Gas"** or **"Natural Gas"** shall mean all gaseous elements and compounds and mixtures thereof comprising the effluent vapor stream produced from a well.

**"Gathering System"** shall mean the system of pipes and gathering lines upstream of the Plant which are or will be connected to the Plant and all related equipment and systems which are or will be connected to such pipes and gathering lines including, without limitation, meters, meter runs, compressors, separators, drips and pigging stations.

**"GPM"** shall mean U.S. Gallons per one thousand (1000) cubic feet of Gas or Gallons per Mcf.

**"Gross Heating Value"** or **"Heat Content"** shall mean the gross number of British Thermal Units produced by the complete combustion at constant pressure of the amount of dry Gas which would occupy a volume of one (1) Cubic Foot at a temperature of sixty (60) degrees Fahrenheit and under pressure equivalent to:

(1) 15.025 pounds per square inch absolute, if produced from lands or water bottoms situated in or off of the coast of Louisiana or

(2) 14.65 pounds per square inch absolute if produced from lands or water bottoms situated in or off of the coast of any other state,

and with air of the same temperature and pressure as the Gas, when the products of combustion are cooled to the initial temperature of the Gas and air, and when the water formed by combustion is condensed to the liquid state, corrected from the water vapor content of the Gas under testing conditions to the actual water vapor content of the Gas as received and delivered. Any Gas containing not more than seven (7) pounds of water vapor per one million (1,000,000) Cubic Feet of Gas is considered to be dry for purposes of correcting Heat Content. The number of Btus per unit volume of Gas, as determined above, shall be converted to the same pressure base as the Gas volume.

**"Interest Owners"** shall have the meaning ascribed to such term in Section A.8 below.

**"Mcf"** shall mean one thousand (1,000) cubic feet of Gas (1) at a pressure of (a) 15.025 pounds per square inch absolute, if produced from lands or water bottoms situated in or off of the coast of Louisiana or (b) 14.65 pounds per square inch absolute if produced from lands or water bottoms situated in or off of the coast of any other state, and (2) at a temperature of 60° Fahrenheit.

**"MMBtu"** shall mean one million British thermal units.

**"Month"** shall mean a period beginning at the start of the first Day (as set forth in the definition of "Day" above) of a calendar Month and ending at start of the first Day (also as set forth in the definition of "Day" above) of the next succeeding calendar Month, except that the period from the date of first deliveries to the first Day of the following calendar Month shall be deemed to be a Month, and the period between the termination date and the first Day of the calendar Month in which termination occurs shall be deemed to be a Month.

**"Party"** shall mean Company or Supplier individually. **"Parties"** shall mean Company and Supplier collectively.

**"Person"** means any individual, corporation, partnership, limited liability company, association, joint venture, trust, or other organization of any nature or kind.

**"Plant"** shall mean a gas processing plant and/or treating facility and other related facilities utilized for Processing Supplier's Gas. It is understood that Supplier's commitment of Gas to Company pursuant to this Agreement is not limited to a specific Plant, it being the intent that Company shall have the right to cause Supplier's Gas to be Processed in any Plant, whether or not owned by Company or its Affiliates, but in a manner consistent with the terms of this Agreement.

**"Plant Products"** or **"Products"** shall mean the liquid hydrocarbons and non-hydrocarbon components which are removed from Gas during Processing including ethane, propane, isobutane, normal butane, natural gasoline and/or any mixture thereof and methane, to the extent removal thereof is necessary in, or results from, removing other liquid hydrocarbons. Notwithstanding the foregoing, the term Plant Products or Products shall not include sulfur, Drip Liquids or methane.

**"Primary Term"** shall have the meaning set forth in Section 3 of the Commercial Terms and Conditions.

**"Proceeds"** shall mean the total proceeds received from the sale of Plant Products and/or Residue Gas, as applicable, adjusted to a F.O.B. Plant basis, unless a specific method for calculating Proceeds is set forth in the Commercial Terms and Conditions. Said adjustments shall include, but not be limited to, adjustments for

· fractionation costs incurred by Company, unless a fixed fractionation fee is specified in the Commercial Terms and Conditions, in which case, such fixed fee shall apply,

· actual storage and loading costs incurred by Company, if any,

· transportation costs incurred by Company, including pipeline tariff charges, pipeline losses, if any, rail car and truck transportation costs, unless a fixed transportation fee is specified in the Commercial Terms and Conditions, in which case, such fixed fee shall apply,

· any freight differentials received or allowed to Third Parties and

· Supplier's allocated share of electricity power charges, if any, allocated in accordance with Exhibit D.

Company shall have the right to sell Products and/or Residue Gas to its Affiliate at a fair and reasonable price and the price received from such sale shall be the basis for determining the Proceeds as provided above.

**"Process"** or **"Processing"** shall mean the removal of Plant Products and/or impurities from Supplier's Gas using mechanical separation, extraction, condensation, compression, absorption, stripping, refrigeration, cryogenic expansion or other Processing methods.

**"psia"** shall mean pounds per square inch absolute.

**"psig"** shall mean pounds per square inch gauge.

**"Redelivery Point"** shall mean the point at or near the tailgate of the Plant at which the Residue Gas is returned to Supplier or Supplier's designee if Supplier is taking its share of the Residue Gas in kind.

**"Residue Gas"** shall mean that gaseous portion of Supplier's Gas remaining after Processing (which includes a reduction for Fuel and for all losses or other uses of Gas, including without limitation, Gas which is flared and any Gas which is lost). Without limiting the foregoing, for purposes hereof, lost Gas shall be deemed to include any and all Gas that cannot be found or located, or that is otherwise unaccounted for.

**"Supplier's Gas"** shall mean all Gas owned or controlled by Supplier now or hereafter produced from the Dedicated Acreage (or any lands pooled, unitized or communitized therewith) and/or Dedicated Wells.

**"Supplier's Interest"** or **"Interest"** shall mean any ***oil*** and gas leasehold, mineral fee, royalty or other interest owned or controlled by Supplier.

**"Specifications"** shall mean the quality specifications set forth in Exhibit C hereto.

**"Taxes"** shall mean any and all ad valorem, property, occupation, severance, production, extraction, first use, conservation, Btu or energy, gathering, transport, pipeline, utility, gross receipts, gas or ***oil*** revenue, gas or ***oil*** import, privilege, sales, use, consumption, excise, lease, transaction, environmental, and other taxes, governmental charges, duties, licenses, fees, permits and assessments.

**"Term"** shall have the meaning set forth in the Commercial Terms and Conditions portion of this Agreement.

**"Third Party"** shall mean any Person other than Company or Supplier and their Affiliates.

**A.2. UNPROCESSED GAS**

Company shall have the exclusive right to Process Supplier's Gas for the extraction of Plant Products. Supplier agrees that prior to delivery to Company at the Delivery Point Supplier's Gas shall not be Processed other than in a conventional separator or separators operating with no internal piping for heat interchange and which operate without any prior chilling or refrigeration other than the cooling which takes place upon expansion of the Gas as it is produced across a choke and into such separator or separators. Furthermore, Supplier agrees not to utilize units designed to remove liquid hydrocarbons, including Products, by means of low temperature separation equipment, lean ***oil*** absorption, turbo-expander or mechanical refrigeration equipment, dry bed extraction equipment or any other type of equipment which would reduce the liquid hydrocarbon or Btu content of Supplier's Gas prior to delivery to Company at the Delivery Point.

**A.3. SPECIFICATIONS**

Supplier's Gas delivered to Company hereunder shall be merchantable, unprocessed Gas, at all times complying with the Specifications.

The determination as to conformity of Supplier's Gas with the Specifications shall be made by Company in accordance with generally accepted procedures of the Gas industry including chromatograph analysis. Such determinations shall be made as often as Company deems necessary and Supplier may witness such determinations or make joint determinations with its own appliances. If in Supplier's judgment the result of any such test or determination is inaccurate, Company, at Supplier's request, will again conduct the questioned test or determination, and the costs of such additional test or determination shall be borne by Supplier unless same shows the original test or determination to be materially inaccurate.

Failure to Meet Specifications: Should any of Supplier's Gas delivered by Supplier hereunder at a given Delivery Point fail to meet any of the Specifications, Company may at its option accept, or immediately discontinue or curtail receipt of Supplier's Gas at such Delivery Point until such time as Supplier's Gas meets the required Specification(s). Company may elect to take Supplier's Gas not meeting the Specification(s); however, Company's election to do so shall not constitute a waiver of the Specification(s) as to any other Supplier's Gas.

Should Supplier's operations or any of Supplier's Gas create a condition which in the judgment of Company tends to endanger the Plant or other property of Company or the lives or property of Company's employees or any Third Party, Company may discontinue receipt of Supplier's Gas so long as such condition exists.

Company shall notify Supplier of such failure of Supplier's Gas to meet the Specification(s) and Supplier shall make diligent effort to deliver such Gas conforming to the Specification(s). If Supplier fails and/or refuses to deliver Gas conforming to the Specifications, within a reasonable time following Supplier's receipt of Company's notice, Company shall have the right to terminate this Agreement as to the leases and/or wells producing Supplier's Gas which fails to meet the Specification(s) without any liability whatsoever to Supplier.

Fee: If Company accepts delivery of Supplier's Gas which does not meet the Specifications, Company may charge a treating fee to cover the reasonable costs incurred by Company to monitor Supplier's Gas quality and/or to bring Supplier's Gas within the Specification(s). In addition, Supplier agrees to indemnify, defend and hold Company harmless from and against any and all Claims arising out of, relating to or in any way connected with, the delivery of Supplier's Gas to Company which does not meet the Specifications.

**A.4. DELIVERY PRESSURE**

Supplier shall make delivery of Gas hereunder to Company at a pressure sufficient to enable Supplier's Gas to enter the Gathering System against the pressure maintained therein from time to time, it being understood that such operating pressures may fluctuate substantially over the term of this Agreement.

**A.5. PRODUCTION IN CONFORMANCE WITH FLOW SCHEDULE**

In order to maintain maximum Plant efficiency on a (twenty-four) 24-hour operating schedule, it is desired by the Parties hereto to maintain a reasonably uniform rate of flow of Gas to said Plant over each (twenty-four) 24-hour period. Accordingly, Supplier shall, at its option, either (1) regulate its producing schedule so that Supplier's Gas shall be supplied from Supplier's well or wells at a reasonably uniform rate of flow or (2) accept and follow a producing schedule to be established by Company from time to time. Company shall take into consideration the wishes of Supplier in establishing the producing schedule for Supplier's well or wells. Anything else contained in this Agreement to the contrary notwithstanding, Supplier hereby agrees that in the event it fails to comply with the above provisions of this Article, such failure shall give Company the right, at its option, to refuse to accept delivery of Supplier's Gas during any period of such non-compliance. Should Supplier produce and deliver Gas by intermitted or by stopcock production methods, Company shall have the option to change the measuring facility to insure a constant recording pattern for the delivery of Supplier's Gas. These methods may include installation of pressure restricting devices upstream of the facilities owned by Company or Company's designee. All costs associated with this conversion shall be borne by Supplier or Supplier shall provide Company or Company's designee with the appropriate equipment for such facilities. If Supplier elects to furnish the equipment, the operation of said equipment shall remain the responsibility of Company or Company's designee.

**A.6. FLUSH GAS AND CURTAILMENT CONDITIONS**

A "Flush Gas Condition" exists whenever the Gathering System, if any, utilized to deliver Gas to the Plant and/or the Plant is of insufficient capacity to gather and/or Process all of the Gas connected thereto. During any period when a Flush Gas Condition exists, Company shall only be obligated to take Supplier's Gas ratably as to quantity with all other Gas of the same quality connected to the Plant.

During any periods of curtailment by Residue Gas and/or Products purchasers or transporters (a "Curtailment Condition"), Company shall only be obligated to take Supplier's Gas to the extent that such Residue Gas and/or Product purchasers or transporters are taking Residue Gas and/or Products.

Notwithstanding anything in this Agreement to the contrary, Company shall not be obligated to expand the capacity of the Gathering System or Plant to accommodate Supplier's Gas. Supplier shall have the right to dispose of the excess Gas not taken by Company on a temporary basis during any Flush Gas or Curtailment Condition, subject to Company's right to take such Gas at any subsequent time upon giving Supplier at least ten (10) Days' written notice of its election to do so.

**A.7. SETTLEMENT TESTS**

In accordance with the testing schedule as set forth in the section entitled "Testing Schedule" of the Commercial Terms and Conditions, Company shall obtain a representative sample of Supplier's Gas at each Delivery Point and determine the composition in mole percent, theoretical Product content in GPM, Gross Heating Value in Btu per cubic foot on a water saturated basis, gasoline content (iC+), if required, specific gravity and hydrogen sulfide by means of Gas chromatography according to the latest edition of Gas Processors Association (GPA) Standard 2261, "Analysis of Natural Gas and Similar Gaseous Mixtures by Gas Chromatography" or other generally accepted methods in the industry. The Gas samples shall be taken at the actual flowing conditions, in accordance with the latest edition of GPA Standard 2166, "Obtaining Natural Gas Samples for Analysis by Gas Chromatography." The Gross Heating Values for various hydrocarbon components shall be determined from the latest edition of GPA Standard 2145, "Table of Physical Constants of Paraffin Hydrocarbons and other Components of Natural Gas." The specific gravity may be determined by the use of a gravitometer of the Ranarex type. The hydrogen sulfide content shall be determined according to the latest edition of GPA Standard 2377 entitled "Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes" or by Gas chromatography according to the latest edition of GPA Standard 2261. The calculations of Product GPM's determined from such analysis shall be made by utilizing applicable conversion factors (corrected to the measurement conditions herein stated) as contained in the latest edition of GPA Standard 2261. These methods may be replaced, at Company's discretion, by any method commonly used in the industry. All analysis results shall be utilized for settlement purposes beginning with the Month following the Month in which the results were obtained, and shall be effective until the next scheduled test. The settlements tests shall be made by Company in accordance with the Testing Schedule except when, in the opinion of either Party, a change in the method of operations of the lease will affect materially Supplier's Gas composition, Gross Heating Value, specific gravity and/or hydrogen sulfide content, in which event, the tests shall be made at the demand of either Party upon ten (10) Days' notice to the other Party. If the Supplier makes such demand, the reasonable cost for such settlement test shall be reimbursed by Supplier to Company. Company shall notify Supplier in writing at least ten (10) Days' prior to any settlement tests conducted hereunder in order that Supplier may have a representative present to witness such tests and/or make joint tests with its own appliances. If the Gas composition, Gross Heating Value, specific gravity and/or hydrogen sulfide content as revealed by any analysis made in accordance with the Testing Schedule is substantially the same as determined in the previous analysis, or if the volume of Gas delivered hereunder is less than fifty thousand cubic feet per Day (50 Mcf per Day), then Company, in its sole discretion, shall have the right to reduce the frequency of settlement tests. Notwithstanding the testing schedule set forth in the section entitled "Testing Schedule" of the Commercial Terms and Conditions, if a well subject to this Agreement produces less than a Monthly average rate of (a) one hundred thousand cubic feet (100 Mcf) per Day, if the GPM content of the Gas delivered from such well is 2 GPM or less or (b) twenty thousand cubic feet (20 Mcf) per Day, if the GPM content is 2 GPM or more, Company, in its sole discretion, shall have the right to suspend all or a portion of such tests until the well produces at the rates as set forth in (a) and (b) above, as applicable for at least two consecutive Months. If Company suspends any such testing, the most recent test that was made shall be utilized for settlement purposes unless Company subsequently elects to test such well, in which event, such test shall thereafter be used for settlement purposes.

**A.8. METERS AND MEASUREMENT**

Supplier's Gas delivered hereunder shall be measured by a suitable orifice meter, or meters, or other generally accepted measuring devices, of standard make near the Delivery Point. Such metering equipment shall be installed, operated and the volumes calculated in accordance with the prescribed recommendations of American Petroleum Institute Manual of Petroleum Measurement Standards ("API MPMS"), Chapter 14, Natural Gas Fluids Measurement, Section 3, Concentric, Square-Edged Orifice Meters, Parts 1, 2, 3 & 4, 1991 Edition or latest revision. Revisions to such Edition shall apply to computations and operation of meter installations but shall not be construed to require modifications to, or replacement of, said equipment. The computation of all Gas volumes measured by orifice meter shall also be made in accordance with API Chapter 20, as amended from time to time; provided, however, that all factors involved in the computation of Gas volumes measured hereunder shall be subject to and in accordance with applicable state laws. Company may, at its option, install an electronic flow recorder to record the static and differential pressures, flowing temperature and volume of such Gas. In the event the Gas is measured by positive displacement meters, such meters shall be installed, maintained and operated in accordance with AGA Report No. 7, 1985 edition (for turbine meters) or ANSI/ASC B109.3-1992 edition (for rotary meters), as such publications may be supplemented and amended from time to time. All of Supplier's Gas volumes measured hereunder shall be computed to a standard pressure base of (1) 15.025 pounds per square inch absolute, if the Gas is produced from properties situated in or off the coast of Louisiana; and (2) 14.65 pounds per square inch absolute, if produced from properties situated in or off the coast of any other State, at a standard base temperature of sixty (60) degrees Fahrenheit.

Company shall periodically, but no less frequently than the schedule agreed to for Settlement Tests which are performed as provided in the section entitled "Settlement Tests", test the accuracy of the measuring equipment operated by it hereunder using means and methods generally accepted in the Gas industry. If, at any time, the Gas measuring or testing equipment is found to be out of service or registering inaccurately in any percentage, it shall be adjusted at once to read accurately, within the limits prescribed by the manufacturer. In case any question arises as to the accuracy of the meter measurement, said meter or meters shall be tested upon the demand of either Party. The expense of such tests shall be borne by the Party demanding such test if the meter is found to be correct and by Company if found to be incorrect. Such equipment will be judged incorrect if inaccurate by an amount exceeding two percent (2%) at a reading corresponding to the average rate of flow for the period since the last test. If such equipment is out of service or incorrect, then any previous readings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon; but in case the period is not known definitely or agreed upon, such correction shall be for a period equal to one-half (½) of the time elapsed since the last test, which shall not exceed forty-five (45) Days. No correction will be made for prior periods for recorded inaccuracies of two percent (2%) or less. The volumes delivered during the period such measuring equipment is out of service or incorrect shall be estimated by the Parties on the basis of the best data available using the most feasible of the following methods:

· By using the registration of any check measuring equipment installed and accurately registering;

· By correcting the error if the percentage of error is ascertainable by calibration, test or mathematical calculations;

· By estimating the quantity of Gas delivered through the meter based on the quantity delivered through the same meter during the preceding period under similar conditions when the meter was registering accurately; or

· Using other mutually agreeable methods.

Each Party shall preserve all charts, volumetric data, meter test data and applicable Gas analyses for at least two years, unless a longer time period is prescribed by applicable regulations, including any charts or test data covering any check meters that are installed. Should such data be the property of Company's designee, Company and Supplier shall be subject to the retention practices (and availability of such data) of Company's designee. At any time within such period, upon reasonable advance written request by either Party, records and/or charts from the measuring equipment, together with calculations therefrom, will be submitted for such requesting Party's inspection and verification at the offices of the Party maintaining such records during normal business hours.

Supplier or Supplier's designee shall have the right to install, maintain, and operate such check measurement equipment as it may desire as long as such equipment does not interfere with or impede in any way the operation of Company's measurement or other equipment hereunder, and all calibrating and adjusting of check meters and changing of charts shall be done by Supplier or its designees and at its sole cost, risk and expense. Notice of the time and nature of each test shall be given by Supplier to Company sufficiently in advance to allow Company the opportunity to have a representative present during such tests, if Company so desires.

If Supplier elects to install compression near the measuring facilities installed by Company or Company's designee, it shall be the responsibility of Supplier to reduce or eliminate any sources of pulsation in such metering facilities. This may include installation of pulsation plates, acoustic filters, pulsation bottles or other types of pulsation dampening equipment prior to delivery of Gas into the metering facilities.

**Appendix C**

**GENERAL PROVISIONS**

**DOMESTIC CRUDE *OIL* AGREEMENTS**

**A. Measurement and Tests:** All measurements hereunder shall be made from static tank gauges on 100 percent tank table basis or by positive displacement meters. All measurements and tests shall be made in accordance with the latest ASTM or ASME-API (Petroleum PD Meter Code) published methods then in effect, whichever apply. Volume and gravity shall be adjusted to 60 degrees Fahrenheit by the use of Table 6A and 5A of the Petroleum Measurement Tables ASTM Designation D1250 in their latest revision. The crude ***oil*** delivered hereunder shall be marketable and acceptable in the applicable common or segregated stream of the carriers involved but not to exceed 1% S&W. Full deduction for all free water and S&W content shall be made according to the API/ASTM Standard Method then in effect. Either party shall have the right to have a representative witness all gauges, tests and measurements. In the absence of the other party's representative, such gauges, tests and measurements shall be deemed to be correct.

**B. Warranty:** The Seller warrants good title to all crude ***oil*** delivered hereunder and warrants that such crude ***oil*** shall be free from all royalties, liens, encumbrances and all applicable foreign, federal, state and local taxes.

Seller further warrants that the crude ***oil*** delivered shall not be contaminated by chemicals foreign to virgin crude ***oil*** including, but not limited to chlorinated and/or oxygenated hydrocarbons and lead. Buyer shall have the right, without prejudice to any other remedy available to Buyer, to reject and return to Seller any quantities of crude ***oil*** which are found to be so contaminated, even after delivery to Buyer.

**C. Rules and Regulations:** The terms, provisions and activities undertaken pursuant to this Agreement shall be subject to all applicable laws, orders and regulations of all governmental authorities. If at any time a provision hereof violates any such applicable laws, orders or regulations, such provision shall be voided and the remainder of the Agreement shall continue in full force and effect unless terminated by either party upon giving written notice to the other party hereto. If applicable, the parties hereto agree to comply with all provisions (as amended) of the Equal Opportunity Clause prescribed in 41 C.F.R. 60-1.4; the Affirmative Action Clause for disabled veterans and veterans of the Vietnam Era prescribed in 41 C.F.R. 60-250.4; the Affirmative Action Clause for Handicapped Workers prescribed in 41 C.F.R. 60-741.4; 48 C.F.R. Chapter 1 Subpart 19.7 regarding Small Business and Small Disadvantaged Business Concerns; 48 C.F.R. Chapter 1 Subpart 20.3 regarding Utilization of Labor Surplus Area Concerns; Executive Order 12138 and regulations thereunder regarding subcontracts to women-owned business concerns; Affirmative Action Complicance Program (41 C.F.R. 60-1.40); annually file SF-100 Employer Information Report (41 C.F.R. 60-1.7); 41 C.F.R. 60-1.8 prohibiting segregated facilities; and the Fair Labor Standards Act of 1938 as amended, all of which are incorporated in this Agreement by reference.

**D. Hazard Communication:** Seller shall provide its Material Safety Data Sheet ("MSDS") to Buyer. Buyer acknowledges the hazards and risks in handling and using crude ***oil***. Buyer shall read the MSDS and advise its employees, its affiliates, and third parties, who may purchase or come into contact with such crude ***oil***, about the hazards of crude ***oil***, as well as the precautionary procedures for handling said crude ***oil***, which are set forth in such MSDS and any supplementary MSDS or written warning(s) which Seller may provide to Buyer from time to time.

**E. Force Majeure:** Except for payment due hereunder, either party hereto shall be relieved from liability for failure to perform hereunder for the duration and to the extent such failure is occasioned by war, riots, insurrections, fire, explosions, sabotage, strikes, and other labor or industrial disturbances, acts of God or the elements, governmental laws, regulations, or requests, acts in furtherance of the International Energy Program, disruption or breakdown of production or transportation facilities, delays of pipeline carrier in receiving and delivering crude ***oil*** tendered, or by any other cause, whether similar or not, reasonably beyond the control of such party. Any such failures to perform shall be remedied with all reasonable dispatch, but neither party shall be required to supply substitute quantities from other sources of supply. Failure to perform due to events of Force Majeure shall not extend the terms of this Agreement.

Notwithstanding the above, and in the event that the Agreement is an associated purchase/sale, or exchange of crude ***oil***, the parties shall have the rights and obligations described below in the circumstances described below:

(1) If, because of Force Majeure, the party declaring Force Majeure (the "Declaring Party") is unable to deliver part or all of the quantity of crude ***oil*** which the Declaring Party is obligated to deliver under the Agreement or associated contract, the other party (the "Exchange Partner") shall have the right but not the obligation to reduce its deliveries of crude ***oil*** under the same Agreement or associated contract by an amount not to exceed the number of barrels of crude ***oil*** that the Declaring Party fails to deliver.

(2) If, because of Force Majeure, the Declaring Party is unable to take delivery of part or all of the quantity of crude ***oil*** to be delivered by the Exchange Partner under the Agreement or associated contract, the Exchange Partner shall have the right but not the obligation to reduce its receipts of crude ***oil*** under the same Agreement or associated contract by an amount not to exceed the number of barrels of crude ***oil*** that the Declaring Party fails to take delivery of.

**F. Payment:** Unless otherwise specified in the Special Provisions of this Agreement, Buyer agrees to make payment against Seller's invoice for the crude ***oil*** purchased hereunder to a bank designated by Seller in U.S. dollars by telegraphic transfer in immediately available funds. Unless otherwise specified in the Special Provisions of this Agreement, payment will be due on or before the 20th of the month following the month of delivery. If payment due date is on a Saturday or New York bank holiday other than Monday, payment shall be due on the preceding New York banking day. If payment due date is on a Sunday or a Monday New York bank holiday, payment shall be due on the succeeding New York banking day.

Payment shall be deemed to be made on the date good funds are credited to Seller's account at Seller's designated bank.

In the event that Buyer fails to make any payment when due, Seller shall have the right to charge interest on the amount of the overdue payment at a per annum rate which shall be two percentage points higher than the published prime lending rate of Morgan Guaranty Trust Company of New York on the date payment was due, but not to exceed the maximum rate permitted by law.

**G. Financial Responsibility:** Notwithstanding anything to the contrary in this Agreement, should Seller reasonably believe it necessary to assure payment, Seller may at any time require, by written notice to Buyer, advance cash payment or satisfactory security in the form of a Letter or Letters of Credit at Buyer's expense in a form and from a bank acceptable to Seller to cover any or all deliveries of crude ***oil***. If Buyer does not provide the Letter of Credit on or before the date specified in Seller's notice under this section. Seller or Buyer may terminate this Agreement forthwith. However, if a Letter of Credit is required under the Special Provisions of this Agreement and Buyer does not provide same, then Seller only may terminate this Agreement forthwith. In no event shall Seller be obligated to schedule or complete delivery of the crude ***oil*** until said Letter of Credit is found acceptable to Seller. Each party may offset any payments or deliveries due to the other party under this or any other agreement between the parties.

If a party to this Agreement (the "Defaulting Party") should (1) become the subject of bankruptcy or other insolvency proceedings, or proceedings for the appointment of a receiver, trustee, or similar official, (2) become generally unable to pay its debts as they become due, or (3) make a general assignment for the benefit of creditors, the other party to this Agreement may withhold shipments without notice.

**H. Liquidation:**

(1) Right to Liquidate. At any time after the occurrence of one or more of the events described in the third paragraph of Section G, Financial Responsibility, the other party to the Agreement (the "Liquidating Party") shall have the right, at its sole discretion, to liquidate this Agreement by terminating this Agreement. Upon termination, the parties shall have no further rights or obligations with respect to this Agreement, except for the payment of the amount(s) (the "Settlement Amount" or "Settlement Amounts") determined as provided in Paragraph (3) of this section.

(2) Multiple Deliveries. If this Agreement provides for multiple deliveries of one or more types of crude ***oil*** in the same or different delivery months, or for the purchase or exchange of crude ***oil*** by the parties, all deliveries under this Agreement to the same party at the same delivery location during a particular delivery month shall be considered a single commodity transaction ("Commodity Transaction") for the purpose of determining the Settlement Amount(s). If the Liquidating Party elects to liquidate this Agreement, the Liquidating Party must terminate all Commodity Transactions under this Agreement.

(3) Settlement Amount. With respect to each terminated Commodity Transaction, the Settlement Amount shall be equal to the contract quantity of crude ***oil***, multiplied by the difference between the contract price per barrel specified in this Agreement (the "Contract Price") and the market price per barrel of crude ***oil*** on the date the Liquidating Party terminates this Agreement (the "Market Price"). If the Market Price exceeds the Contract Price in a Commodity Transaction, the selling party shall pay the Settlement Amount to the buying party. If the Market Price is less than the Contract Price in a Commodity Transaction, the buying party shall pay the Settlement Amount to the selling party. If the Market Price is equal to the Contract Price in a Commodity Transaction, no Settlement Amount shall be due.

(4) Termination Date. For the purpose of determining the Settlement Amount, the date on which the Liquidating Party terminates this Agreement shall be deemed to be (a) the date on which the Liquidating Party sends written notice of termination to the Defaulting Party, if such notice of termination is sent by telex or facsimile transaction; or (b) the date on which the Defaulting Party receives written notice of termination from the Liquidating Party, if such notice of termination is given by United States mail or a private mail delivery service.

(5) Market Price. Unless otherwise provided in this Agreement, the Market Price of crude ***oil*** sold or exchanged under this Agreement shall be the price for crude ***oil*** for the delivery month specified in this Agreement and at the delivery location that corresponds to the delivery location specified in this Agreement, as reported in Platt's Oilgram Price Report ("Platt's") for the date on which the Liquidating Party terminates this Agreement. If Platt's reports a range of prices for crude ***oil*** on that date, the Market Price shall be the arithmetic average of the high and low prices reported by Platt's. If Platt's does not report prices for the crude ***oil*** being sold under this Agreement, the Liquidating Party shall determine the Market Price of such crude ***oil*** in a commercially reasonable manner, unless otherwise provided in this Agreement.

(6) Payment of Settlement Amount. Any Settlement Amount due upon termination of this Agreement shall be paid in immediately available funds within two business days after the Liquidating Party terminates this Agreement. However, if this Agreement provides for more than one Commodity Transaction, or if Settlement Amounts are due under other agreements terminated by the Liquidating Party, the Settlement Amounts due to each party for such Commodity Transactions and/or agreements shall be aggregated. The party owing the net amount after such aggregation shall pay such net amount to the other party in immediately available funds within two business days after the date on which the Liquidating Party terminates this Agreement.

(7) Miscellaneous. This section shall not limit the rights and remedies available to the Liquidating Party by law or under other provisions of this Agreement. The parties hereby acknowledge that this Agreement constitutes a forward contract for purposes of Section 556 of the U.S. Bankruptcy Code.

**I. Equal Daily Deliveries:** For pricing purposes only, unless otherwise specified in the Special Provisions, all crude ***oil*** delivered hereunder during any calendar month shall be considered to have been delivered in equal daily quantities during such month.

**J. Exchange Balancing:** If volumes are exchanged, each party shall be responsible for maintaining the exchange in balance on a month-to-month basis, as near as pipeline or other transportation conditions will permit. In all events upon termination of this Agreement and after all monetary obligations under this Agreement have been satisfied, any volume imbalance existing at the conclusion of this Agreement of less than 1,000 barrels will be declared in balance. Any volume imbalance of 1,000 barrels or more, limited to the total contract volume, will be settled by the underdelivering party making delivery of the total volume imbalance in accordance with the delivery provisions of this Agreement applicable to the underdelivering party, unless mutually agreed to the contrary. The request to schedule all volume imbalances must be confirmed in writing by one party or both parties. Volume imbalances confirmed by the 20th of the month shall be delivered during the calendar month after the volume imbalance is confirmed. Volume imbalances confirmed after the 20th of the month shall be delivered during the second calendar month after the volume imbalance is confirmed.

**K. Delivery, Title, and Risk of Loss:** Delivery, title, and risk of loss of the crude ***oil*** delivered hereunder shall pass from Seller to Buyer as follows:

For lease delivery locations, delivery of the crude ***oil*** to the Buyer shall be effected as the crude ***oil*** passes the last permanent delivery flange and/or meter connecting the Seller's lease/unit storage tanks or processing facilities to the Buyer's carrier. Title to and risk of loss of the crude ***oil*** shall pass from Seller to Buyer at the point of delivery.

For delivery locations other than lease/unit delivery locations, delivery of the crude ***oil*** to the Buyer shall be effected as the crude ***oil*** passes the last permanent delivery flange and/or meter connecting the delivery facility designated by the Seller to the Buyer's carrier. If delivery is by in-line transfer, delivery of the crude ***oil*** to the Buyer shall be effected at the particular pipeline facility designated in this Agreement. Title to and risk of loss of the crude ***oil*** shall pass from the Seller to the Buyer upon delivery.

**L. Term:** Unless otherwise specified in the Special Provisions, delivery months begin at 7:00 a.m. on the first day of the calendar month and end at 7:00 a.m. on the first day of the following calendar month.

**M. Governing Law:** This Agreement and any disputes arising hereunder shall be governed by the laws of the State of Texas.

**N. Necessary Documents:** Upon request, each party agrees to furnish all substantiating documents incident to the transaction, including a Delivery Ticket for each volume delivered and an invoice for any month in which the sums are due.

**O. Waiver:** No waiver by either party regarding the performance of the other party under any of the provisions of this Agreement shall be construed as a waiver of any subsequent performance under the same or any other provisions.

**P. Assignment:** Neither party shall assign this Agreement or any rights hereunder without the written consent of the other party unless such assignment is made to a person controlling, controlled by or under common control of assignor, in which event assignor shall remain responsible for nonperformance.

**Q. Entirety of Agreement:** The Special Provisions and these General Provisions contain the entire Agreement of the parties; there are no other promises, representations or warranties. Any modification of this Agreement shall be by written instrument. Any conflict between the Special Provisions and these General Provisions shall be resolved in favor of the Special Provisions. The section headings are for convenience only and shall not limit or change the subject matter of this Agreement.

**R. Definitions:** When used in this Agreement, the terms listed below have the following meanings:

"API" means the American Petroleum Institute.

"ASME" means the American Society of Mechanical Engineers.

"ASTM" means the American Society for Testing Materials.

"Barrel" means 42 U.S. gallons of 231 cubic inches per gallon corrected to 60 degrees Fahrenheit.

"Carrier" means a pipeline, barge, truck, or other suitable transporter of crude ***oil***.

"Crude ***Oil***" means crude ***oil*** or condensate, as appropriate.

"Day," "month," and "year" mean, respectively, calendar day, calendar month, and calendar year, unless otherwise specified.

"Delivery Ticket" means a shipping/loading document or documents stating the type and quality of crude ***oil*** delivered, the volume delivered and method of measurement, the corrected specific gravity, temperature, and S&W content.

"Invoice" means a statement setting forth at least the following information: The date(s) of delivery under the transaction; the location(s) of delivery; the volume(s); price(s); the specific gravity and gravity adjustments to the price(s) (where applicable); and the term(s) of payment.

"S&W" means sediment and water.

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**End of Document**

1. 1Includes non-hydocarbon gases such as water vapor, carbon dioxide, hydrogen sulfide, nitrogen, oxygen, and helium. [↑](#footnote-ref-2)
2. 2Ethane, propane, and butane are the primary heavy hydrocarbons (liquids) extracted at a natural gas processing plant, but other petroleum gases, such as isobutane, pentanes, and normal gasoline, also may be processed. [↑](#footnote-ref-3)
3. 3For a detailed examination of the subject see Joseph Wardzinski, et al., "Interstate Natural Gas - Quality Specifications & Interchangeability," Center for Energy Economics, Bureau of Economic Geology, The University of Texas at Austin (Houston. Texas. December 2004). http://www.beg.utexas.edu/energyecon/lng/ [↑](#footnote-ref-4)
4. 4Some of these feeder pipelines also had to suspend operations because they themselves suffered damage, the production platforms that they serviced were damaged, or the connecting pipelines were damaged. [↑](#footnote-ref-5)
5. 5Department of Energy. "DOE's Hurricane Response Chronology" provided by Secretary Samuel Bodman at Senate Energy and Natural Resources Committee Hearing, October 27, 2005. [↑](#footnote-ref-6)
6. 6Energy Information Administration, *Natural Gas Annual 2004* (December 2005), Table 1. http://www.eia.doe.gov/***oil***\_gas/natural\_gas/data\_publications/natural\_gas\_annual/nga.html. [↑](#footnote-ref-7)
7. 7Wet gas is defined as the volume of natural gas remaining after removal of condensate and uneconomic nonhydrocarbon gases at lease/field separation facilities and less any gas used for repressurization. [↑](#footnote-ref-8)
8. 8The Energy Information Administration estimates that about 9 percent of 2004 U.S. dry natural gas production, or about 1.7 Tcf, came from coalbed methane sources, which do not contain any natural gas liquids. *U.S. Crude* ***Oil*** *and Natural Gas, and Natural Gas Liquids Reserves: 2004 Annual Report*, http://www.eia.doe.gov/***oil***\_gas/natural\_gas/data\_publications/ [↑](#footnote-ref-9)
9. 9Enterprise Products Partners LP, Annual SEC 10K filing, 2004. p. 18. [↑](#footnote-ref-10)
10. 10All compressor stations contain some type of separation facilities which are designed to filter out. before compression, any water and/or hydrocarbons that may form in the gas stream during transport. [↑](#footnote-ref-11)
11. 11William L. Leffler, "The Technology and Economic Behavior of the U.S. Propane Industry" (Tulsa, Oklahoma, 1973, The Petroleum Publishing Company), Chapter 1. [↑](#footnote-ref-12)
12. 12Most of these pipelines extended from the Texas Panhandle and Louisiana to the Midwestern United States. Gas processing plants for these systems were located primarily in the Houghton Basin of northern Texas/Oklahoma/Kansas and the Katy area of eastern Texas. [↑](#footnote-ref-13)
13. 13Arlon R. Tusing & Bob Tippee, "The Natural Gas Industry: Evolution, Structure, and Economics" (Tulsa, Oklahoma. 1995, Pennwell Publishing Company). [↑](#footnote-ref-14)
14. 14The largest gas producing areas and States in 2004 were Texas onshore, the Federal offshore (waters off Texas, Louisiana, Alabama, and Mississippi). Oklahoma, New Mexico, Wyoming, Louisiana onshore. Colorado, and Kansas. [↑](#footnote-ref-15)
15. 15In 1995, proved gas reserve additions from new fields and new reservoir discoveries in old fields in southern Louisiana and the Gulf of Mexico amounted to 3.174 Bcf (wet basis) with gas production at 5.827 Bcf. while the corresponding figures in 2004 were 991 Bcf and 4,866 Bcf. respectively, Energy Information Administration, *U.S. Crude* ***Oil****, Natural Gas and Natural Gas Liquids Reserves*, 1995 and 2004 Annual Reports, Table 9. [↑](#footnote-ref-16)
16. 16In 2004, a co-owner of one of the facilities removed one processing train (300 MMcf/d) from the plant and moved it to Louisiana. [↑](#footnote-ref-17)
17. 17FERC Order 636, issued in 1993, primarily dealt with revising how interstate pipeline companies did business. Order 636 required interstate pipeline companies to change from buying and selling the natural gas they transported to selling the transportation service only. [↑](#footnote-ref-18)
18. 18In late 2005. Targa Resources, Inc., acquired the gas processing plant interests of Dynegy Midstream Services LP in Louisiana, Texas, and New Mexico. In combination with its existing gas plant assets, the acquisition moved Targa Resources significantly higher in the rankings of midstream companies. [↑](#footnote-ref-19)
19. 19In those cases where a gas plant is not fully owned by the party, a percentage of the total capacity of the plant equal to the ownership percentage was included in the Bcf/d capacity item. [↑](#footnote-ref-20)
20. 20Much of the background material used in this section is based on information and discussions of gas processing contracts found in the 2004 SEC 10K filings of Enterprise Products Partners LP and MarkWest Energy Partners LP. [↑](#footnote-ref-21)
21. 21On November 30, 2005, EnCana Ltd announced that it has begun construction of a new 650 MMcf/d natural gas processing plant in northwestern Colorado to accommodate increasing natural gas production in the Piceance Basin. The plant is scheduled to be in service in early 2007. Platts Inc., *Gas Dally*, December 1, 2005, p. 4. [↑](#footnote-ref-22)
22. 22Energy Information Administration, Gas Transportation Information System. Natural Gas Pipeline Projects Database, as of December 2005. [↑](#footnote-ref-23)
23. 23Imported LNG supplies often have higher Btu content than domestic natural gas supplies and may need to be processed to meet U.S pipeline quality specifications. The introduction of additional LNG volumes into the Gulf area may increase processing plant utilization beyond what is required for domestic natural gas production. However, this need is uncertain and depends on the construction of new facilities and the quality of the future LNG imports. [↑](#footnote-ref-24)
24. 24See Energy Information Administration. *Natural Gas Annual 2004*, (Washington, D.C. December 2005), Table 1, http://www.eia.doe.gov/***oil***\_gas/natural\_gas/data\_publications/natural\_gas\_annual/nga.html [↑](#footnote-ref-25)