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THE NATURAL GAS SUPPLY CHAIN:

An Integrated Process Framework

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Contents

List of Figures

List of Tables

Appendix Figures and Tables

Introduction

Unconventional natural gas has rapidly moved to the forefront of the US and global energy scene over the course of the past several years. The magnitude of its forces has been portrayed in media and related discussion as "new era," "golden age," "paradigm shift," "inflection point," "game changer," and "most significant energy innovation," among other momentous-defining locution. Amid this phenomenon, the United States is globally recognized for its revolutionary progress in unconventional gas area, particularly shale gas. In fact, the United States has emerged as the largest producer of natural gas in the world since 2009, with a significant portion of its production comes from shale (C2ES 2011; EIA 2014c). Shale gas is expected to remain the main source of growth in overall gas supply in the United States in the coming decades (IEA 2012b).

The Rise of US Shale Gas Phenomenon

The unprecedented growth of shale gas production in the United States is by no means a meteoric enterprise. Shale gas has been produced in the United State for many decades. However, it was neither considered to be a significant resource, nor deemed economically feasible to produce because of its impermeable geological formation features (IEA 2012b; Ratner and Tiemann 2014). Briefly speaking, while conventional gas is found in large permeable sandstone reservoirs (Origin Energy n.d.; Ratner and Tiemann 2014), unconventional sources of gas are trapped underground by impermeable rocks, such as coal, sandstone and shale which cannot migrate to a trap and form a conventional gas deposit (IEA 2015; NTG 2012). The latter are also called "continuous-type deposits" or "tight formations." The lack of permeability means that the unconventional gas typically remains in the source rock unless natural or artificial fractures occur (Ratner and Tiemann 2014).

Such a state of affairs has changed, however, when a significant milestone for large-scale shale gas extraction was realized in the mid-2000s with the application of horizontal drilling[1] and hydraulic fracturing technology (often referred to simply as

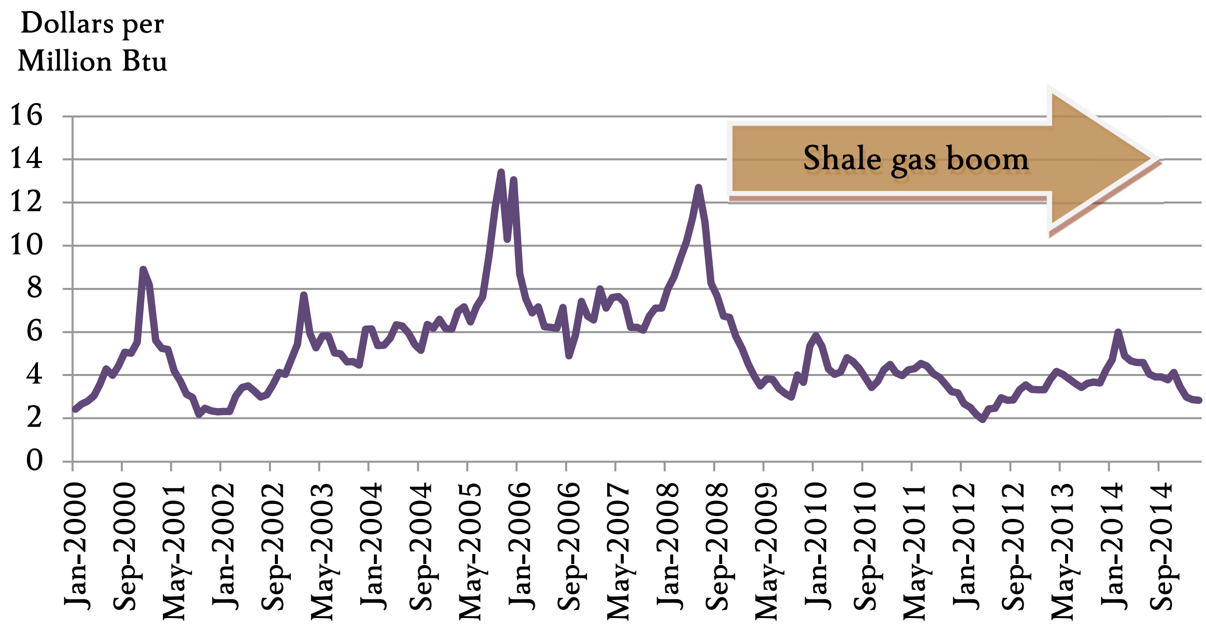
[1] The more generic term, "directional drilling" is sometimes used to refer to any non-vertical well (Office of Fossil Energy 2013).

"fracking") (England and Mittal 2014; IEA 2015; Maring and Mintz 2014; Ratner and Tiemann 2014). The technological advances, coupled with soaring gas prices in the early 2000s partly due to the declining production of conventional natural gas, have stimulated exploration and production (E&P) companies in the United States to pursue development of unconventional gas types even more vigorously (IEA 2015; Wang and Krupnick 2013).

To put US shale gas phenomenon in perspective, at the start of the 21st century, natural gas production from shale accounted for 2 percent of US total natural gas output (API 2014a). Since mid-2000s, US natural gas production increased almost every month on a year-on-year basis, resulting in shale gas production more than quadrupled from 2005 to 2009 (England and Mittal 2014; IEA 2015; Ratner and Tiemann 2014). By the end of the 2000–10 decade, shale gas production share comprised approximately 34 percent of total US production (C2ES 2011; PwC 2013). Astonishing surge continued as shale gas production grew by more than 7 percent in 2011, making it the largest year-to-year (2010–11) increase in the history of US production volume (C2ES 2011; Ratner and Tiemann 2014). Shale gas share of total natural gas production rose to 40 percent in 2013, surpassing production from non-shale natural gas wells, according to the *Natural Gas Annual* (API 2014b; Tran 2014). This figure is projected to rise to 50 percent by 2040, according to the US Energy Information Administration (EIA) forecasts (PwC 2013).

As a result of US shale gas production boom, natural gas prices have been on a decline to the historical lows in 2012. As shown in Figure 1, Henry Hub spot price dropped below $2 per one million British thermal units (MMBtu) in April 2012—a steep decline from over $13 per MMBtu in 2008 (Andreoli 2013; Deloitte 2014; Ratner and Tiemann 2014; Wang and Krupnick 2013).

Figure 1 / Monthly Henry Hub Natural Gas Spot Price (January 2000–March 2015)



Source: US Energy Information Administration, released on April 22, 2015

The Great Expectation of Natural Gas

The speed and scale of shale gas development that has ensued in the past decade is transforming US natural gas E&P patterns, with shale gas deemed to be integral to future US natural gas production (PwC 2011). It is estimated that the United States hold about 2,400 trillion cubic feet (Tcf) of technically recoverable[2] natural gas in shale formations, equivalent to approximately 100 years of supply at present levels of demand (DOE 2015). In effect, natural gas holds a great prospect as a long-term, low-cost, reliable resource that could transform the United States from import-dependent, oil-based economy to energy self-sufficient, net-export one. It also holds

[2] **Recoverable** gas resources refer to volumes that analysts are confident will be discovered or technologically developed to produce them. They are larger than **proven** gas reserves, volumes that have been discovered and can be produced economically with existing technology at current gas prices (IEA 2015). In other words, the term "proven" signifies that the reserves are both technically and economically recoverable. Currently, the extent to which global technically recoverable shale resources will prove to be economically recoverable is not yet clear (EIA 2014d).

immense opportunities in enabling the revitalization of energy-driven petrochemical and manufacturing industry (Deloitte 2014).

Markets for natural gas are growing both in terms of demand volume and market bases. Natural gas consumption in the United States and Canada is projected to increase by an average of 1.2 percent annually through 2035. Total natural gas use across all sectors is projected to rise to an average of roughly 106 billion cubic feet per day (Bcfd) in 2035 from around 80 Bcfd in 2013, according to INGAA Foundation (2014).

Among traditional markets, the electric power generation and heating markets is witnessing increased substitution of incumbent fuels (e.g. coal and oil) with natural gas (AEP 2015). In anticipation of industrial renaissance, particularly for the chemical and petrochemical industries (Liss 2012), natural gas is being explored as feedstock, in addition to its traditional combustion applications. Transportation markets are showing a renewed interest in natural gas as fuels, in relation to incumbent gasoline and diesel counterparts (IHS CERA 2010).

Meanwhile, the number and geographic spread of countries importing natural gas is growing, many of which were not considered to be potential importers a decade ago (IGU 2014). Soaring unconventional gas production in the United States led to a sharp drop in import requirements that are accompanied by the favorable competitive position of the United States in the international gas trade (IEA 2015). In fact, it is projected that within the next several years, the United States may become a much larger natural gas exporter, particularly in the form of liquefied natural gas (LNG) (Ratner et al. 2015).

Overall, it is foreseeable that natural gas has an opportunity to play a much greater role in the future of US energy mix and industrial resurgence. It could replace coal in the electric power generation market, petroleum in the transportation fuel market, fuel oil in the commercial and residential markets, and oil-derived feedstock in the chemical and petrochemical manufacturing markets.

Continued Challenges and Uncertainties

However, the great prospect of natural gas does not come without challenges. On the one hand, while the abundant supply of price-competitive natural gas is changing the perception of natural gas applications and corresponding demand markets, many large-scale market opportunities remain in the early stages of development (IHS CERA 2010). To wit, natural gas–fueled power plants, liquefaction/export terminals, chemical and petrochemical plants (notably ethane cracking plants), natural gas transport vehicles and fueling stations, and receiving terminals in international markets are all in an early and varying stage of development. Uncertainties remain as to the speed and manner that these markets will evolve.

On the other hand, the rest of natural gas supply systems are still in the verge of reconfiguration spurred by the revolutionary leap made in E&P of shale gas. For a start, many large shale deposits in the United States are located outside the regions where natural gas is historically produced and served by well-established pipeline systems. There is a pressing need for the development of gas and gas product pipeline systems, along with processing and storage facilities, in order to bring the newfound gas supply to markets (DOE 2015; Ulama 2015).

Moreover, unconventional resources are less geographically concentrated than conventional deposits (IEA 2012b), and while large gas deposits can justify dedicated pipelines, smaller deposits often do not (IEA 2011). The quandary of gas producers with smaller discoveries has led to efforts aimed to make transporting smaller volumes of natural gas more viable, and to help speed up development of smaller gas deposits. Notable technologies are liquefaction and gas-to-liquid technologies (Deloitte 2013b; Raman, Jajur, and Valsan n.d.).

Similar efforts are also essential to realize growth in the global market. In this respect, while most of the world's gas supply continues to be traded and transported regionally via pipeline, seaborne LNG trade at the global level is rapidly growing (C2ES 2011; Crompton 2014a). Development in export liquefaction facilities and marine LNG vessels will be vital to compete in this growing market.

The Essence of End-to-end Panorama of Natural Gas Supply Chain

As the changing dynamics in the natural gas industry and commercial marketplace begins to unfold, it provides a compelling memento that success in shale gas development hinges on the harmonious development of all links and nodes of the natural gas supply system. Fundamental to this undertaking is the holistic understanding of the natural gas supply chains.

Natural gas supply chains are complex, comprising of multiple interrelated subsystems and various types of customers—each of which, while operates under its own business environments, impacts and is impacted by others. Because of the complexities, research studies and business analysis thus far largely focus either on individual industry sectors (generally classified as upstream, midstream, and downstream sectors), or on particular natural gas products (e.g. dry natural gas, LNG, and natural gas liquids [NGLs]). What is lacking, however, is an understanding of the full panorama of natural gas supply chains and the interrelationships among these systems within the context of the broader end-to-end supply chain.

This study aims to provide a framework for comprehensive, structural understanding of shale gas supply chain within the context of broader natural gas supply network. Instead of taking industry sector perspective, this study focuses on identifying key processes, underlying activities, participants, and the end-to-end sequence and interplay within the system. The framework provides a fundamental knowledge, a common basis for dialogue, and holistic frame of reference for business professionals and academic researchers working in specific systems of the natural gas supply chain. A global understanding of the entire system enables both professionals and disciplinary researchers to gauge the potential impact of their work on the broader natural gas supply chain.

It is acknowledged that supply chain excellence is one of multi-faceted constituents of shale gas development. Others include economic, environment, public health, government policy and regulations, security, commodity trade and pricing mechanism, and technological and engineering, among others. While each of these aspects merits further research, they are beyond the scope of this study.

In the balance of this report, the premises of the proposed framework are described. Next, the natural gas supply chain framework is presented, beginning with the discussion of system-wide infrastructure, namely natural gas pipeline network and storage fields, followed by a bird eye's view description of the framework. In turn, key processes, related activities, and trends are discussed in more details.

The Premises of the Natural Gas Supply Chain Framework

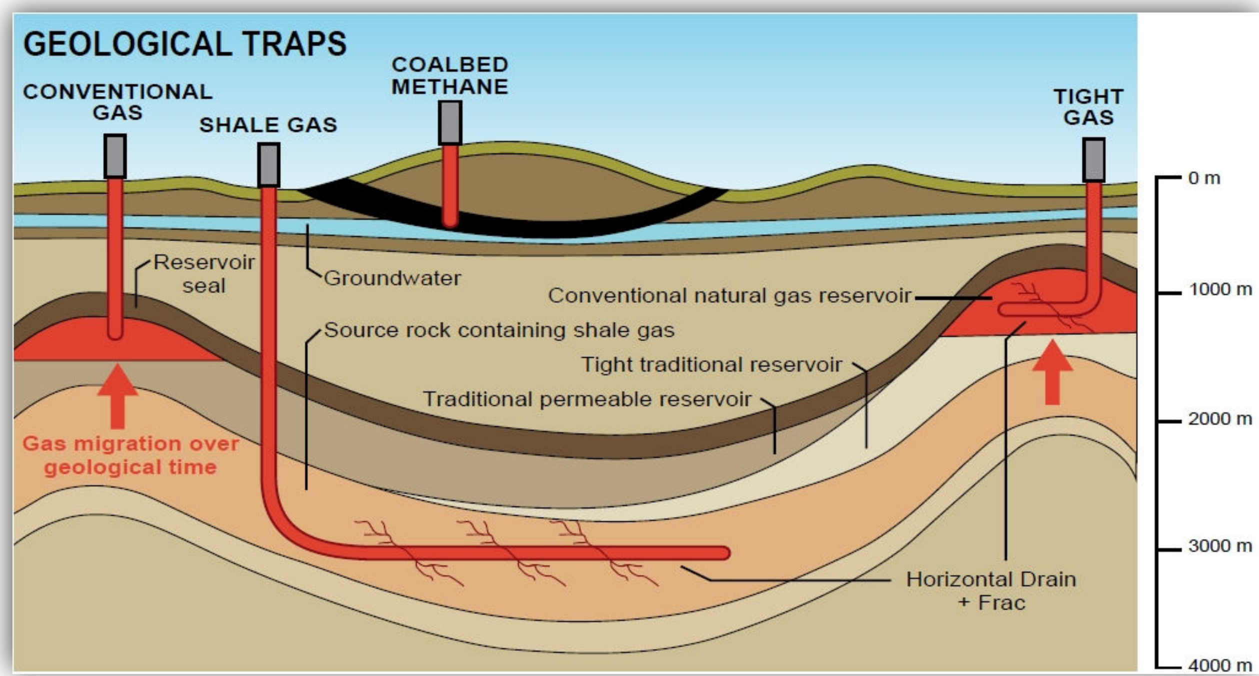
The fundamental premises of the proposed framework are threefold: (1) Natural gas resource base is diverse; (2) Raw natural gas outputs are essentially comparable; and (3) Different natural gas components render different natural gas products.

Natural Gas Resource Base Is Diverse

The framework takes into account that natural gas resource base is diverse. Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that is produced in association with crude oil from oil wells is typically termed *associated gas*. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas wells and condensate wells in which there is little or no crude oil, thus producing only hydrocarbons in gaseous form, is termed *non-associated gas*. Gas wells typically produce raw natural gas by itself, while condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate (IEA 2015; NaturalGas.org 2013c). The majority (89%) of US gas is extracted as the primary, non-associated product (C2ES 2011).

Natural gas resource base also differ in terms of formation. It comprises onshore and offshore reservoirs of conventional and unconventional gas resource. Conventional gas is found in large permeable sandstone reservoirs (NTG 2012; Origin Energy n.d.), whereas unconventional gas can be further distinguished into four types (see Figure 2), namely: (1) **shale gas** found in shale rock deposits; (2) **coal bed methane**, or CBM (also known as coal seam gas [CSG] in Australia) found in coal deposits; (3) **tight gas** trapped underground in impermeable rock formations; and (4) **gas hydrates**, a lesser known unconventional gas resource, are an ice-like solid formed from a mixture of water and natural gas in cold northern regions or in deepwater offshore sediments. Among the unconventional gas types, gas hydrates are least developed. Only a handful of experimental tests have been conducted thus far, and the exploitation on any significant scale is projected to be more than two decade away (IEA 2011, 2015; Origin Energy n.d.).

Figure 2 / Geology of Natural Gas Resource



Source: *Gas Fact Sheet – Gas Resource Types.* Department of Mines and Petroleum, Government of Western Australia (cited in NTG 2012)

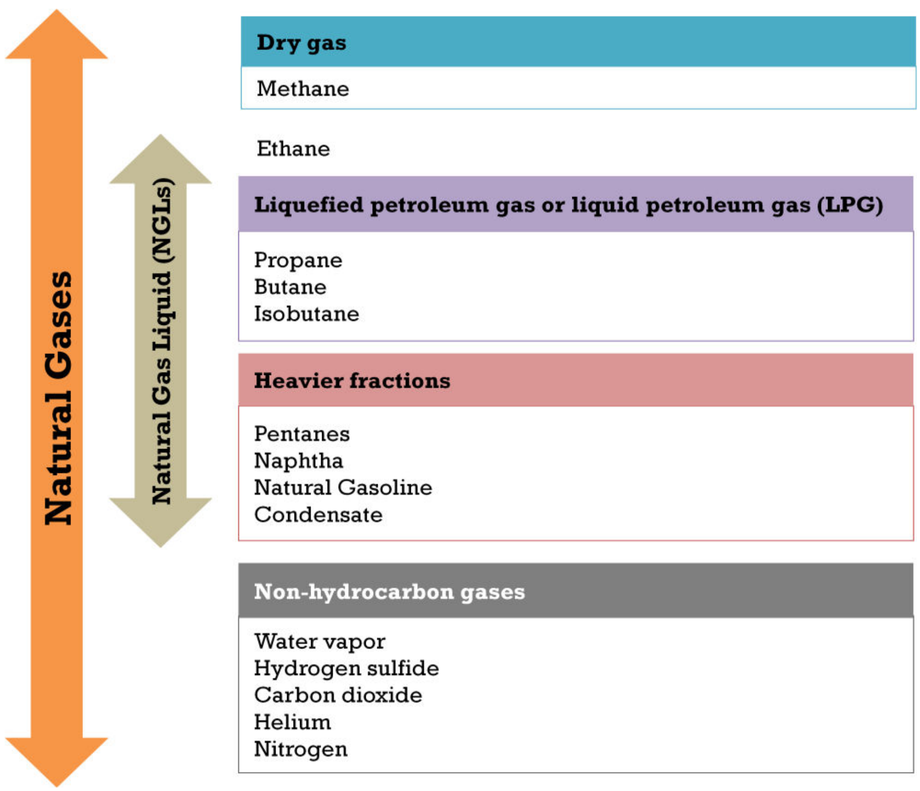
While this study focus on onshore shale gas resource, it is imperative to examine shale gas supply chains in the context of broader natural gas resource base. This is because natural gas producers—whether they are pure-play gas producers, independent oil and gas companies, or integrated oil and gas companies—take such diversity into account in devising their asset portfolio and resource development strategies. Hence, investment in shale gas depends on its relative position within the dynamic of natural gas resource base relations.

Raw Natural Gas Outputs Are Essentially Comparable

Raw natural gas extracted from unconventional reserves is comparable to their conventional counterparts in terms of essential properties. The term *unconventional* simply refers to the geological formation described above, and not the gas outputs per se (EKT Interactive 2015a; Origin Energy n.d.; Ratner and Tiemann 2014). Regardless of the source of the natural gas, once separated from crude oil (if present), dry natural gas (methane) commonly exists with mixtures with other hydrocarbons (known as natural gas liquids or NGLs), principally ethane, propane, butane, and pentanes. In addition, natural gas contains some impurities such as water vapor, hydrogen sulfide/sulfur (H2S), carbon dioxide, helium, nitrogen, and other non-hydrocarbon compounds (see Figure 3).

Natural gas produced from wells is called *raw gas*. Raw gas that is mostly methane is called *dry gas*, while raw gas with a mixture of methane and NGLs is called *wet gas, rich gas,* or *hot gas* (IEA 2015; NaturalGas.org 2013c; Pan 2014; Ratner and Tiemann 2014; Ratner et al. 2015; Tortoise Capital Advisors 2014). Raw gas that contains significant amounts of sulfur is called *sour gas* (Adventures in Energy 2015b; IEA 2015). That natural gases from all sources (conventional, unconventional, onshore, offshore) are destined to and compete in the same market bases further accentuates that shale gas supply chain framework be depicted in the context of broader natural gas resource.

Figure 3 / Natural Gas Components



Source: Created based on IEA (2010)

NOTE: Natural gasoline is equivalent to pentanes plus and nearly chemically identical to plant condensates, which are mostly pentane.

Different Natural Gas Components Render Different Natural Gas Products

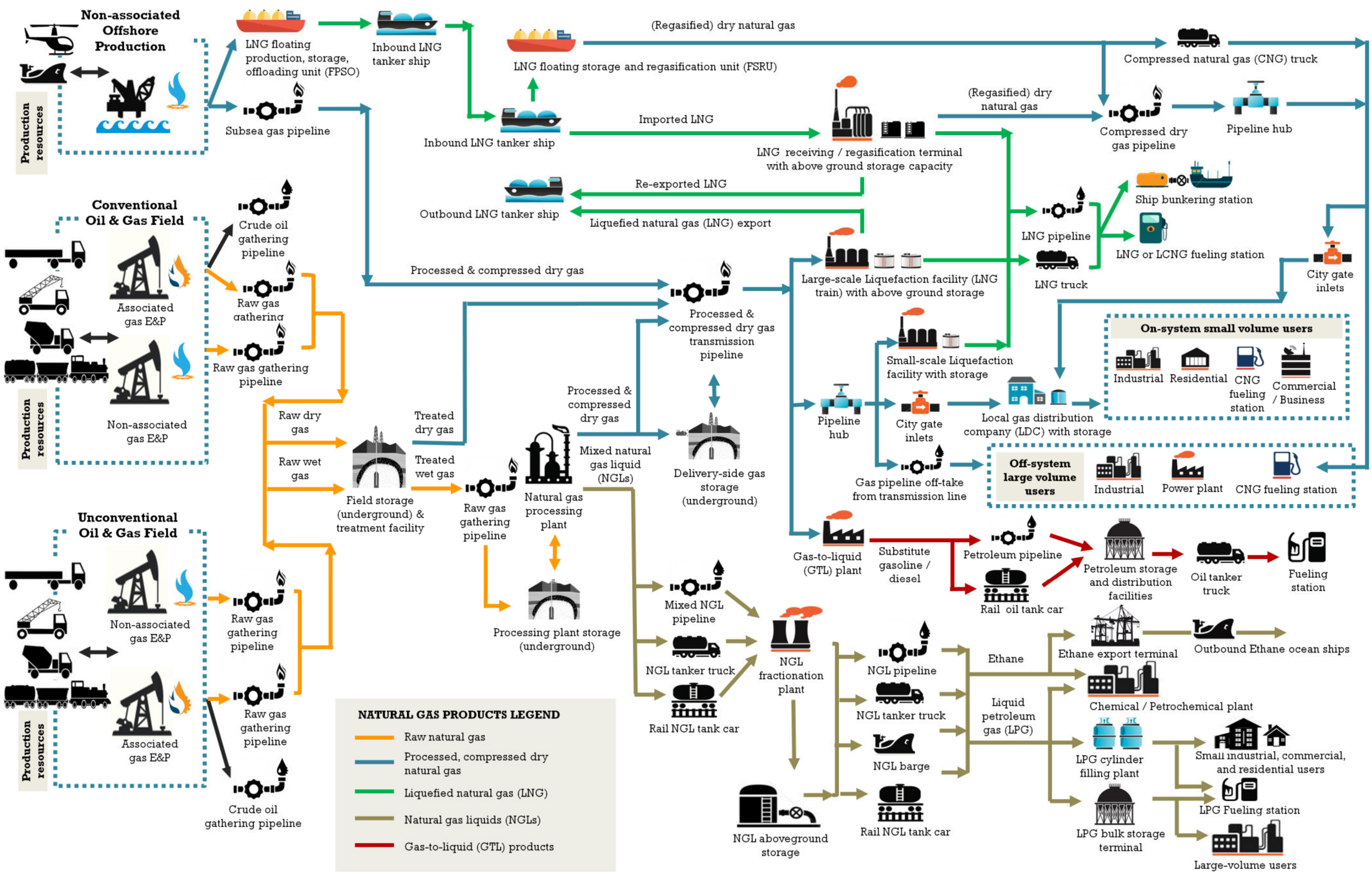
While raw gas is essentially the same across the resource types, the same does not hold true across its different components. Dry gas (methane) can be compressed and sold as compressed natural gas (CNG), liquefied to produce liquefied natural gas (LNG), or converted into liquid fuels (gas-to-liquids or GTL) such as gasoline, jet fuel, and diesel (EIA 2014e; Shell Global 2015). Similarly, individual NGL products go through different processes before reaching end-use markets. Ethane, for instance, is *cracked* to produce various ethane derivatives; while LPGs are cylinder filled before further distribution.

The processes, technologies, and infrastructure requirements differ across these natural gas products. That is, they have their own supply systems that are embedded within the natural gas supply chain. It is also worth noting that some of them are competing in the same end-use markets, although may possess different comparative advantages/disadvantages and stage of market acceptance. To wit, GTL gasoline and diesel (called substitute gasoline/diesel) compete in the same transportation fuel markets as CNG, LNG, and LPG. The framework incorporates these subsystems and markets served accordingly.

The Natural Gas Supply Chain: A Process Framework

The natural gas supply chain framework is illustrated in Figure 4. In the following pages, supply chain–wide pipeline and storage infrastructure is discussed, followed by a bird's eye view description of key processes and general characteristics.

Figure 4 / The Natural Gas Supply Chain: A Process Framework



Natural Gas Pipeline Network

Pipelines provide vital linkages throughout the natural gas supply system. In fact, 99 percent of natural gas used in the United States moves from well to market entirely via pipeline (Adventures in Energy 2015b).

Natural Gas Pipeline Companies

Natural gas pipeline companies have customers on both ends of the pipeline. On the one end, the gas producers and processing plant operators input natural gas into the pipeline. On the other end, end-use customers and local distribution companies (LDCs) take out the gas from the pipeline. The former via outlet points for use in their processes, and the latter for resale and distribution to end-use customers via LDCs' low-pressure distribution lines (Eastern Shore 2015; Naturalgas.org 2013b).

Pipeline companies neither participate in the buying and selling of natural gas, nor own natural gas that they transport.[3] Their roles are to provide transportation and storage services, and earn revenue from a fee charged for their services. Most of the major natural gas pipelines are federally regulated interstate pipelines.
Their service charges are established by the Federal Energy Regulatory Commission (FERC) that generally sets rates on a pipeline-by-pipeline basis and a maximum allowable rate is usually established (API 2014b; Ulama 2015).

Pipelines are owned and operated by private companies, some of which are subsidiaries of oil and/or gas companies, while others are third-party pipeline companies that do not engage in oil and/or gas production (Phillips 2012). Major natural gas pipeline companies in the United States and their business description is summarized in Table 1.

[3] This is a result of the open access policy in adherence to a series of Federal Energy Regulatory Commission (FERC) orders in the 1980s and early 1990s. Interstate natural gas pipelines previously sold pipeline transportation and natural gas as a bundled product. The open access policy mandated that interstate natural gas pipeline companies transform themselves from buyers and sellers of natural gas to strictly natural gas transporters and storage service providers. The unbundling of services in the natural gas industry also extends to distribution pipelines owned and operated by local distribution companies (EIA n.d., 2014a; Wang and Krupnick 2013).

Table 1 / Major US Natural Gas Pipeline Companies

Companies (Market Share 2014)	Description
Kinder Morgan (34.8%)	Kinder Morgan operates 82,000 miles of energy pipelines and 180 terminals. Its extensive pipeline infrastructure transports natural gas, refined petroleum products, crude oil and carbon dioxide. Its terminals handle a variety of products, including gasoline, jet fuel, ethanol, coal, petroleum coke and steel. The company operates in the Gas Pipeline Transportation industry under Kinder Morgan Energy Partners LP (KMP) and El Paso Pipeline Partners. Combined, the company's natural gas pipelines total about 70,000 miles in the United States, securing Kinder Morgan's place as the industry's leader. Kinder Morgan's natural gas pipelines are connected to several important gas sources, including Eagle Ford, Marcellus, Utica, Uinta, Haynesville, Fayetteville, Barnett, Mississippi Lime and Woodford.
The Williams Companies Inc. (6.9%)	Headquartered in Tulsa, OK, The Williams Companies Inc. is an energy infrastructure company that produces, gathers, processes and transports natural gas, with growing presence in the Marcellus Shale region. Within the gas pipeline transportation industry, Williams Companies has a combined total of 13,700 miles of natural gas pipelines. The gas-pipeline division consists of Transcontinental Gas Pipe Line Corporation (Transco), Northwest Pipeline GP, a 50 percent interest in Gulfstream Natural Gas System LLC, and a 51 percent interest in Constitution Pipeline Company LLC. Williams Companies also has a master limited partnership, Williams Pipeline Partners, LP, which owns and operates the natural gas transportation and storage assets. The Transco pipeline totals 9,800 miles and delivers natural gas from south Texas to customers in Texas, and 12 southeast and Atlantic seaboard states. Transco pipeline system has a capacity of 8.5 billion cubic feet per day.
Spectra Energy Corporation (5.9%)	Spectra Energy Corporation, based in Houston, is involved in the processing, transmission, storage and distribution of natural gas in the United States and Canada. Spectra split from Duke Energy in 2006 to become its own company. The energy company operates more than 22,000 miles of natural gas, natural gas liquids, and crude oil pipelines. In addition to its transmission networks, Spectra own a 50 percent interest in DCP Midstream, LLC, one of the largest natural gas gatherers in the United States. Spectra Energy's US pipeline systems consist of more than 14,600 miles of transmission pipelines with eight primary transmission systems: Texas Eastern Transmission LP (Texas Eastern); Algonquin Gas Transmission LLC (Algonquin); East

Companies (Market Share 2014)	Description
	Tennessee Natural Gas LLC (East Tennessee); Maritimes & Northeast Pipeline LLC and Maritimes & Northeast Pipeline LP; Ozark Gas Transmission LLC; Big Sandy Pipeline LLC; Southeast Supply Header LLC; and Gulfstream Natural Gas System LLC.
Energy Transfer Equity (4.9%)	The acquisition of Southern Union in March 2012 marks Energy Transfer Equity (ETE)'s entrance into the gas pipeline industry. Currently, Southern Union Company is headquartered in Houston, and is mainly engaged in the gathering, processing, transportation, storage and distribution of natural gas in the United States. Southern Union has interests in gas storage facilities and nearly 10,000 miles of pipeline throughout the United States. The company's transportation and storage segment is primarily engaged in the interstate transportation and storage of natural gas to markets in the Midwest, Southwest and Florida state.

Source: Cohen & Steers (2014); IBISWorld (Ulama 2015)

Natural Gas Pipeline Network

Natural gas is transported in high-pressure pipelines, usually through more than one pipelines or pipeline systems. Natural gas pipeline networks are generally categorized into three systems, including *gathering* systems, *(mainline) transmission* systems, and *local distribution* systems. They vary in length from several hundred miles or less, to over a thousand miles seen in major intra- and interstate transmission pipelines (Adventures in Energy 2015a; DOE 2015). Natural gas pipelines are generally smaller in diameter than petroleum pipelines. Pipelines in the gathering and distribution systems range from 6" to 16" in diameter, with certain segments as narrow as 1/2". The pipelines making up the interstate transmission system range in diameter from 16" to 48" (Adventures in Energy 2015a; EIA n.d.).

Gathering Systems

Gathering systems consist of small-diameter pipelines that are connected to a producing well and converged with pipelines from other wells in the producing region. There are two types of gathering systems, *radial* and *trunk line*. The radial type brings all the flow lines to a central header, while the trunk-line system uses several remote headers to collect oil and gas. The latter is used most often in large fields that cover a large geography. Gathering systems collectively move raw natural gas from the wellhead to the natural gas processing plant, or to an interconnection with a larger mainline transmission pipeline. As onshore production expanded, gathering pipelines became much longer and more sophisticated, built with high-strength steel pipe, and equipped with compression, measuring, and pressure regulation devices (Adventures in Energy 2015a; EIA n.d.; EKT Interactive 2015a).

Transmission Systems

Transmission systems consist of wide-diameter, long-distance pipelines that transport natural gas from the producing area to export, to large industrial users that directly connected to the systems through lateral pipelines,[4] and to local distribution systems in market areas around the country. They are located between the gathering system, natural gas processing plant, market hubs, and local distribution networks (Adventures in Energy 2015a; EIA n.d.; EKT Interactive 2015).

Many large transmission routes are generally referred to as *looped*. Looping is when one pipeline is laid parallel to another. It is often used as a way to increase capacity along a right-of-way beyond what is possible on one line, or an expansion of an existing pipeline(s). Some very large pipeline systems have five or six large diameter pipelines laid along the same right-of-way (EIA n.d.; Goellner 2012).

A natural gas transmission system is typically designed as either a *grid* system or a *trunkline* system (EIA n.d.). A trunkline transmission system links a major supply source with a market area or with a large pipeline/LDC serving a market area. Trunklines tend to have fewer receipt points (usually at the beginning of its route), fewer delivery points, and fewer interconnections with other pipelines and associated lateral lines. A grid-type transmission system is usually characterized by a large number of laterals or branches from the mainline. Grid transmission systems tend to form a network of integrated receipt, delivery, and pipeline interconnections that operate in and serve major market areas (EIA n.d.).

[4] **Lateral pipelines**, typically between 6 and 16 inches in diameter, deliver natural gas to or from the mainline transmission pipelines (Naturalgas.org 2013b).

Local Distribution Systems

Local distribution systems consist of low-pressure, small-diameter pipelines buried under the city that deliver natural gas into residential and commercial buildings, and other end-users' facilities. LDCs are usually utility companies, ranging in size from small municipally-owned companies with hundreds of customers to large multinational companies with hundreds of thousands of customers (Adventures in Energy 2015a; Eastern Shore 2015; EKT Interactive 2015).

Pipeline System Facilities

In addition to pipelines, there are a number of facilities and devices needed in the transportation of natural gas, including compressor stations, meter stations, mainline valves, centralized control (monitoring) stations, city gate stations, and market hubs/centers.

Compressor stations

Natural gas moves along pipelines due to the exertion of force (pressure). To ensure that the natural gas flowing through any one pipeline remains pressurized, compression of the natural gas is required periodically along the pipe. This is accomplished by compressor stations usually placed at 40–100 mile intervals along the pipeline, depending on terrain features. In hilly terrain, pressure increases are required more frequently than on flat terrain (Adventures in Energy 2015a; DOT 2011; EIA n.d.; Naturalgas.org 2013b).

The size of a station and the number of compressors varies, depending on the diameter of the pipe and the volume of gas to be moved (INGAA Foundation 2015). Compressor units used on a natural gas mainline transmission system are usually rated at 1,000 horsepower (hp) or more. The larger compressor stations may have as many as 10–16 units, with an overall horsepower rating of 50,000–80,000 hp and a throughput capacity exceeding 3 billion cubic feet (bcf) of natural gas per day. Most compressor units operate on natural gas (extracted from the pipeline flow). However, in recent years, and mainly for environmental reasons, the use of electricity-driven compressor units has been growing (EIA n.d.).

In addition to compressing natural gas, compressor stations also usually contain some type of liquid separators. Though the pipeline is carrying dry gas, some water and hydrocarbon liquids may condense out of the gas stream as the gas cools and moves through the pipeline. Liquid separators are vessels designed to remove any free liquids or dirt particles from the gas, much like the ones used to dehydrate natural gas during its processing before it enters the compressors (Adventures in Energy 2015a; INGAA Foundation 2015; Naturalgas.org 2013b).

Meter stations

In addition to compressor stations, meter stations are placed periodically along interstate natural gas pipelines to measure all natural gas entering or exiting the pipeline system. These meter stations employ specialized meters to measure the natural gas as it flows through the pipeline without impeding its movement. Some meter stations also regulate gas pressure and delivery volumes, and are called *meter and regulator stations (M&R)*. Pressure regulation equipment ensures that gas delivered into or out of a pipeline system is maintained within a specified pressure range. This is important for safety reasons because engineers design transmission and distribution systems to operate within specific pressure ranges (INGAA Foundation 2015; Naturalgas.org 2013b).

Mainline valves

Pipeline companies install valves along a gas pipeline system to provide a means of controlling flow. The valves may be spaced as close together as every 5 miles or as far apart as 20 miles, depending on standards established by applicable safety codes. The valves normally are open. However, when a section of pipeline requires maintenance, operational engineers close the valves to isolate that section of the pipeline. Once isolated, the maintenance crew can vent the gas from that section of the pipeline and proceed with their work (INGAA Foundation 2015).

Centralized control stations

Centralized gas control (monitor) stations collect, assimilate, and manage data received from meter stations and compressor stations all along the pipeline system. Monitoring the pipeline as a whole is an apparatus known as *Systems Control and Data*

Acquisition (SCADA) systems. SCADA systems provide monitoring staff the ability to direct and control pipeline flows, and maintain pipeline integrity and pressures as natural gas is received and delivered along numerous points on the system, including flows into and out of storage facilities. These capabilities help to ensure that all customers receive timely delivery of their portion of the gas. They also enable pipeline engineers to take quick actions to equipment malfunctions, leaks, or any other unusual activity along the pipelines (EIA n.d.; Naturalgas.org 2013b).

City gate stations

City gates are a point at the end of transmission pipeline that distribution system connects to the interstate transmission pipeline. There, city gate stations reduce the pressure of the natural gas from its transmission rate (200–1,500 pounds per square inch [psi]) down to a rate more appropriate to consumer usage (e.g. as low as 3 psi). The city gate stations also add sour-smelling Mercaptan to the naturally odorless gas to make it easier to detect a natural gas leak (Adventures in Energy 2015a; Eastern Shore 2015).

Market hubs/centers

Market hubs or market centers are the locations where major pipeline systems intersect and flows are transferred. There are over 30 major market hubs in the United States, but the principle hub is the Henry Hub located in Louisiana (Ivanenko 2011; Naturalgas.org 2013e). Top 25 natural gas trading locations are displayed in Figure 5.

Pipeline Regulatory Oversight

The location, construction, and operation of pipeline systems are generally regulated by federal and state regulations. The Pipeline and Hazardous Materials Safety Administration (PHMSA), an agency within the US Department of Transportation (US DOT), is responsible for conducting inspections on pipelines that cross state boundaries. Its regulatory oversight is to ensure safety in the design, construction, operation and maintenance, and spill response planning. Jurisdictional pipelines, which are situated wholly within one state, are often overseen by the relevant state pipeline safety agency under a delegation agreement between the PHMSA and the state. When intrastate pipelines are regulated by these agencies through adoption and enforcement of PHMSA safety standards, PHMSA's role is to oversee state agency performance. The state maintains direct regulatory authority (Henderson 2012; PHMSA n.d.). As noted earlier, the FERC generally has jurisdiction over the interstate transmission in terms of pipeline service rates, and sale of natural gas for resale. The FERC does not have jurisdiction over the location and construction of gathering lines (Henderson 2012).

Figure 5 / Top 25 North American Natural Gas Trading Locations

Source: API (2014b)

It is worth noting that there are approximately 200,000 miles or more *on-shore gathering lines* within the United States, most of which begin and end in the same state. Up to 90 percent of these pipelines are classified as "Class 1" gathering lines, which do not fall under federal safety or construction regulations. These Class 1 gathering pipelines are not regulated because the safety risks of these low pressure, small diameter rural pipelines are generally considered to be lower than those of other types of pipelines (e.g. high pressure, large diameter transmission pipelines and populate proximity local distribution pipelines) (Henderson 2012; Sadasivam 2013).

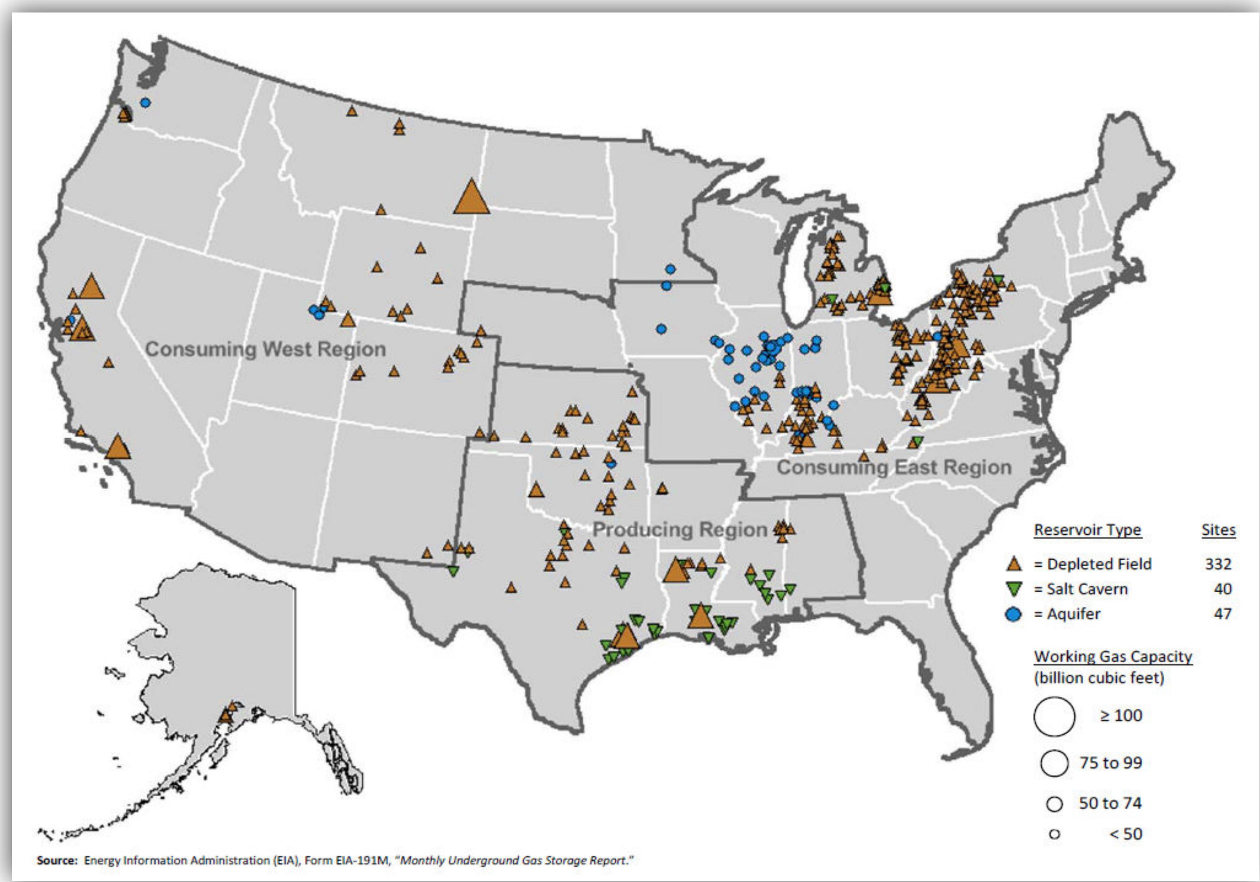
Under current regulations, whether or not a gathering line is regulated is determined by how close it is to a populated area. If there are more than 10 buildings within 220 yards of a line, the gathering line must be regulated. If the buildings are outside the 220-yard radius, the line is not regulated. Operators of regulated lines must give state or federal regulators details about their operations, including pipeline diameter, exact location, and maximum operating pressure. They must also inspect and maintain their lines and report details of any accidents, including fatalities, injuries, and property damages. None of these requirements are mandatory for unregulated pipelines (Sadasivam 2013).

Natural Gas Storage Field

At the end of the transmission system, and sometimes at its beginning and in between, natural gas can be stored either above ground or underground. *Above ground storage* can be in liquid form in LNG tanks on LNG terminal sites, or in gaseous form, generally in spherical tanks. *Underground storage* in gaseous form is executed by injecting natural gas into three types of subsurface facilities, including salt cavern formation, aquifers (water-bearing sands topped by an impermeable cap rock), and depleted (empty) reservoirs in oil or gas fields. Underground storage is by far the most effective and economical technique for the large-scale storage of natural gas (C2ES 2011; EIA n.d., 2014a; Gas in Focus 2013b; MarketsandMarkets 2014).

As shown in Figure 6, depleted natural gas or oil fields are most widely used to store natural gas in the United States (Adventures in Energy 2015a; MarketsandMarkets 2014; Spectra Energy 2015). However, during the past 20 years, the number of salt cavern storage sites has grown significantly because of its rapid cycling (inventory turnover) capability, coupled with its high injection and withdrawal flow rates that enable quick respond to daily, even hourly, variations in customer needs. Unlike gas storage in depleted fields or aquifers, which generally cycle in and out once a year, salt dome storage can cycle many times a year. Salt cavern storage typically operates at higher pressures and stores much lower volumes than depleted gas reservoirs and aquifers (EIA n.d., 2015; Gas in Focus 2013b).

Figure 6 / Locations of Existing Natural Gas Underground Storage Fields in the United States (2013)



Source: *Natural Gas Annual 2013* (EIA 2014a)

NOTE: Gas in an underground storage facility is divided into two categories, working gas (top gas) and cushion gas (base gas). Working gas is the volume of gas in the reservoir above the designed level of cushion gas. Cushion gas is the volume of gas needed as a permanent inventory in a storage reservoir to maintain adequate reservoir pressure and deliverability rates throughout the withdrawal season (FERC 2010; Gas in Focus 2013b).

Owners and Users of Underground Gas Storage Facilities

Underground storage facilities in the United States are principally owned and operated by inter- and intrastate pipeline companies, large LDCs, and independent storage merchants/service providers. Compared to pipeline companies, independent storage merchants are often smaller, more nimble and focused companies that recognized the potential profitability for these specialized facilities. Many salt formation and other high deliverability sites have been initiated by independent storage service providers (EIA 2004).

These owners of underground storage fields often lease the storage space to shippers, mostly the pipeline's major customers such as gas marketers and electric power generation plants (EIA 2004; EKT Interactive 2015c). The leaseholder has the right to inject into or withdraw from the storage facility for a pre-specified period of time, usually between each April 1 and the following March 31, and within pre-specified volume constraints, which are described through a *ratchet schedule.* As the leaseholder injects or withdraws, two types of transaction costs typically incur: (1) a *fuel charge* expressed in a percentage of injected or withdrawn gas, and (2) a *commodity charge* expressed in a dollar amount per unit of injected or withdrawn gas. These two charges are used to cover variable costs of operating the storage facility, the chief of which is compressor operation for pushing more natural gas into or out of the facility (Parsons 2013).

Uses of Natural Gas Storage

Natural gas storage is used for several purposes and can vary by entities using the facilities. Intra- and interstate pipeline companies and LDCs use storage for *operation flexibility and reliability*. They rely heavily on underground storage to: (1) meet seasonal demand (store during low demand in summer and withdrawn during high demand in winter), (2) facilitate load balancing in transmission pipeline system, (3) handle short-term surges in customer demands (called *peak shaving*), and (4) provide for supply backup in the events of natural- or human-caused disruptions of gas production or transportation (Ariel Corporation 2015; C2ES 2011; EIA n.d., 2004; EKT Interactive 2015b; Gas in Focus 2013b; INGAA Foundation 2015; Spectra Energy 2015).

Leaseholders of storage space may use storage to *hedge* against natural gas price increases, or to *arbitrage* gas price differences. Gas can be bought when prices are relatively low (e.g. during the shoulder months between the winter and summer peaks), put into storage, and then withdrawn to be sold or consumed when prices rise. Storage fields in both production areas (e.g. processing plants) and market areas (LDCs, marketers, and large-volume consumers) can be used for the arbitrage purpose (C2ES 2011; EKT Interactive 2015b; Gas in Focus 2013b; Parsons 2013).

A Bird's Eye View Process Description

Exploration

Natural gas supply chain begins with exploration processes, the heart of which involves specialists who analyze geological structure to identify areas that may contain hydrocarbons, called *reserves*. Today they are often located in remote areas, deep water, and tens of thousands of feet below the surface (EKT Interactive 2015d). Exploration can be natural gas–focused or oil-directed, the former of which is related to non-associated gas production and the latter associated gas production (Hanson and Simko 2015). The exploration team carries out special tests, such as seismic analysis, to confirm the initial assessments. Drilling of an exploratory well is undertaken when there is a high probability of discovering gas. After a series of tests, measurements, and additional drilling, the well is determined whether there is enough natural gas (and oil) in the reservoir to make it commercially viable for production (EKT Interactive 2015d; Gas in Focus 2013a).

Production

Once the well is determined to be viable, it goes into production (also called *lifting operations* that bring gas to the surface). Production technology, equipment, and processes focus not only on lifting operations, but also on maintaining the well throughout its economic life and the necessary infrastructure (e.g. gathering pipelines and road access) and treatment and storage facilities (EKT Interactive 2015).

While conventional gas is relatively easy to get out of the ground through traditional, vertical well-drilling techniques (NTG 2012; Origin Energy n.d.), shale gas requires more complex hydraulic fracturing/horizontal drilling (or fracking) techniques (IEA 2015). During fracking operations, it requires intensive coordination of dozens of large trucks, roughly the same number of highly skilled engineers and technicians, a mobile laboratory for real-time quality assurance, and powerful integrated computers (EKT Interactive 2015). Raw gas produced from the wells and large amount of waste streams also have to be managed (IEA 2012b).

Added to the production complexities is the fact that, unlike the conventional well where production might last 30 years or more, shale gas production occurs over a more compressed timeframe (Allegro 2013; IEA 2012b). Shale gas wells typically exhibit a burst of initial production and then a steep decline, followed by a long period of relatively low production. Output typically declines by between 50 percent and 75 percent in the first year of production. That is, by the end of second year, the well may be producing at less than 50 percent, driving operations quickly to a close (Allegro 2013; IEA 2012b; KPMG GEI 2011).

Due to the short-lasting yields, a greater number of wells are drilled (Wisniewski 2011). In fact, in North America, there has recently been a move towards *pad drilling*, the practice of drilling multiple wells from a single site (pad). In 2011, around 30 percent of all new shale and tight gas wells in the United States and Canada were multiple wells drilled from pads (IEA 2012b). As more wells are drilled, above-ground efficiencies, such as asset utilization rates, inventory management, and logistics management of production resource, equipment, and wastes become more important (Deloitte 2013a).

Gathering

After natural gas is produced, it is gathered at a collection point from numerous land-based (onshore) wells via gathering pipelines. In case of dissolved associated gas, separation of natural gas from oil is most often done using a separator, equipment installed at or near the wellhead (NaturalGas.org 2013c). Once gathered and separated, the gas is moved via gathering pipelines to a field treatment facility or a central processing plants (Adventures in Energy 2015a; EKT Interactive 2015b).

Field Processing and Storage

A field treatment facility located at or near the wellhead varies in sophistication, depending on the need for processing as determined by the composition of the hydrocarbon stream. Field processing (also known as *lease processing* and *wellhead processing*) generally involves splitting the well stream into water, stable liquids, and gas. The liquids from the well are said to be *stable* because the components in the liquid are practically all liquid under atmospheric pressure and prevailing surface temperatures (Goellner 2012; IEA 2010). Here, all raw gas, wet and dry, is treated to remove any solids, water vapor, and/or contaminants (EKT Interactive 2015b).

Some portion of treated gas is injected into underground field storage for later withdrawal. The storage withdrawal process is similar to a natural gas gathering application. The natural gas is withdrawn through the same well in which it was originally stored. Once the natural gas is withdrawn, it is compressed and sent through pipelines to its destination (Ariel Corporation 2015).

Depending upon the quality of the gas, treated natural gas is either moved to a central processing plant for further processing, or to shipping points of the transmission pipeline system (EKT Interactive 2015a; EIA n.d.; NaturalGas.org 2013c; Spectra Energy 2015). The latter is often seen in the non-associated gas production environment. Dry non-associated gas, in particular, requires less processing than wet gas and is sometimes of pipeline quality after field treatment. Thus, it does not need to flow through a processing plant prior to entering the transmission system (EIA n.d.; IEA 2012b; NGI n.d.). Meanwhile, crude oil (often along with condensate) that exists in the associated gas production environment is transported from the well site and proceeds along petroleum supply chain (England and Mittal 2014).

Treated Natural Gas Transportation

While some of the needed processing can be accomplished at the field treatment facility, the complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region (EIA n.d.; NaturalGas.org 2013c; Spectra Energy 2015). Hence, transportation of treated natural gas from the production site to the processing plant is generally required.

Unlike oil and condensate that can be relatively easily transported via shuttle tankers, oil pipelines, or rail cars, natural gas relies heavily on pipelines (IEA 2010). The treated natural gas is transported to the processing plant through a network of gathering pipelines. If pipeline infrastructure does not exist, associated gas streams are vented or flared, and/or returned to the reservoir in cycling, repressuring, or conservation operations (CAPP 2012; EIA n.d.; IEA 2010; NaturalGas.org 2013c; Spectra Energy 2015).

Plant Processing

At a central processing plant, treated wet gas is processed to remove impurities, and split natural gas liquids (NGLs) from the natural gas. The natural gas that is now stripped of NGLs is referred to as *dry gas, pipeline-quality dry natural gas, consumer-grade natural gas*, or *sales gas* and consists mainly of methane (95–98% methane). The dry gas might need further processing or purification to conform to the specification of the pipeline companies and target markets. The *spec* will regulate the heat content measured in Btu per cubic foot, acidity, dew point, and other characteristics of the gas (API 2014b; BP 2015b; CAPP 2012; Eastern Shore 2015; EIA n.d., 2014a, 2014c; EKT Interactive 2015b; IEA 2010; NaturalGas.org 2013c; Ratner and Tiemann 2014; Ratner et al. 2015; Tortoise Capital Advisors 2014).

In addition, *sweetening*, the process of removing sulfur, may be required for sour gas. Sour gas is undesirable because the sulfur compounds it contains can be extremely harmful, even lethal, to breathe. This process may be done at the processing plant, or at a specialized sweetening and treating plant, from where extracted sulfur may be marketed on its own (Adventures in Energy 2015b; DCP Midstream 2014; IEA 2015; NaturalGas.org 2013c).

Processed Dry Gas and NGL Transportation

From the processing plant, mixed NGLs are transported via mixed NGL pipeline for further processing (called *fractionation*) and/or put into storage for future use. Meanwhile, processed dry natural gas is compressed and injected at the inlet points that are connected to transmission pipelines to be transported to markets (INGAA Foundation 2011). Some amount of processed dry gas may be put into underground storage for future use. During in-transit along the transmission pipeline system, the processed dry gas may also be injected and withdrawn from an underground storage field as needed (API 2014b; EKT Interactive 2015b; IEA 2010).

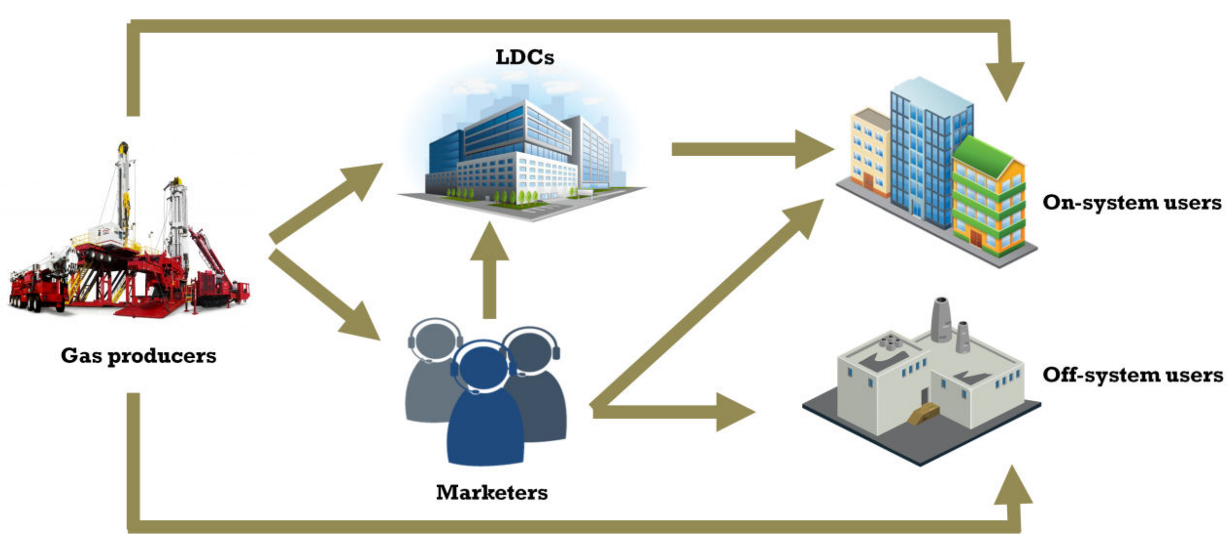
From this point onwards, processed dry gas and NGLs enter four separate subsystems, one of which is associated with NGLs and three of which are associated with processed dry gas, namely compressed dry natural gas, LNG, and GTLs.

Natural Gas Product Subsystems

Compressed Dry Natural Gas Subsystem

Compressed dry natural gas is transacted under a number of commercial arrangement as depicted in Figure 7, including direct-to-user, market centers or hubs, and city gates. Marketers buy or sell gas through individually negotiated contracts or on a spot commodity exchange. At the market hub, the title to natural gas is transferred between buyers and sellers (Ivanenko 2011). At city gate, natural gas leaves the transmission pipeline network and enters the city gate station where LDCs add odorant and lower the pressure before distributing it via local distribution pipelines to residential and commercial customers (Adventures in Energy 2015a; C2ES 2011). Some commercial and industrial end-users, typically large-volume users, bypass the LDC and arrange the *wholesale* purchase of dry natural gas from marketers. A natural gas marketer can be a producer of natural gas, pipeline marketing affiliate, distribution utility marketing affiliate, or independent marketer (Naturalgas.org 2013e). The physical delivery (distinguished from commercial arrangements) of the purchased gas may be executed via LDC's local distribution systems (*on-system* users). On the other hand, *off-system* users have pipeline laterals that are connected to transmission pipelines, thus receive purchased natural gas directly at the outlet points without relying on LDC's distribution pipelines (Adventures in Energy 2015a; API 2014b; Eastern Shore 2015; EKT Interactive 2015a, 2015b; Naturalgas.org 2013b).

Figure 7 / Compressed Dry Natural Gas Commercial Arrangement



Source: Created based on API (2014b)

Liquefied Natural Gas (LNG) Subsystem

Via transmission pipelines, dry natural gas is transported to a large-scale liquefaction facility where LNG is produced. Large-scale LNG facility is distinguished from a number of smaller scale facilities that operate at a more local level further downstream of the supply chain (Strande and Johns 2013). LNG is then transported by LNG pipelines or LNG tanker trucks to *domestic market* destinations such as ship bunkering stations and LNG fueling stations.

LNG destined to *international markets* is transported on marine LNG ships to a receiving terminal at the destination countries. Note that natural gas produced from offshore wells also converges in this subsystem. Gas extracted from subsea resource is processed at a central offshore processing platform, from where dry natural gas is loaded onto an LNG floating production, storage, offloading unit (FPSO). FPSO liquefies dry natural gas into LNG that is, in turn, transferred to LNG tanker ship for transportation to the receiving terminal at the destination countries.

At the receiving terminal, LNG is either regasified to turn back into gaseous form, put into above-ground storage for later use, or transported via LNG tanker trucks to end-use markets. In some markets, a floating storage and regasification unit (FSRU) is employed. In this case, LNG is ship-to-ship transferred from an LNG carrier ship to an FSRU where it is temporary stored and regasified.

Once regasified, whether at the onshore receiving terminal or on FSRU, dry natural gas is compressed and moved through pipeline laterals that connect to main natural gas pipeline systems (Ulama 2015). Afterwards, distribution processes are much like those of the compressed dry natural gas subsystem described previously.

Gas-to-Liquid (GTL) Subsystem

Compressed dry natural gas, transported via transmission pipelines, is delivered to a facilities equipped with GTL technologies that use chemical processes to convert gas to liquid fuels such as gasoline, jet fuel, and diesel. A range of other products that would otherwise be produced from oil can also be produced from dry natural gas, such as naphtha, kerosene, waxes, and lubricating products (EIA 2014e, IEA 2011; Shell Global 2015). Transportation fuel has been a targeted market for GTL products, notably substitute gasoline and diesel that can be used in existing vehicles and moved through existing infrastructure used for petroleum-based gasoline and diesel (C2ES 2011).

NGL Subsystem

By-products of natural gas processing, mixed NGLs are transported via long-distance, typically interstate, NGL transmission pipeline to a specialized fractionation plant, often located close to LPG export terminals or petrochemical facilities. These long distance pipelines are usually common carrier systems which aggregate mixed NGL from dozens of individual gas processing plants (IHS 2013). However, in locations where pipelines are not available, mixed NGLs may be transported by trucks, rails, or barges (BP 2015a; INGAA Foundation 2014). At the fractionation plant, mixed NGLs are further processed to extract individual base components (Follette and He 2012; IEA 2010; NaturalGas.org 2013c; Pan 2014). Note that fractionation can also be done at the central processing plant co-located with the fractionation facilities (EIA 2014f; Tortoise Capital Advisors 2014).

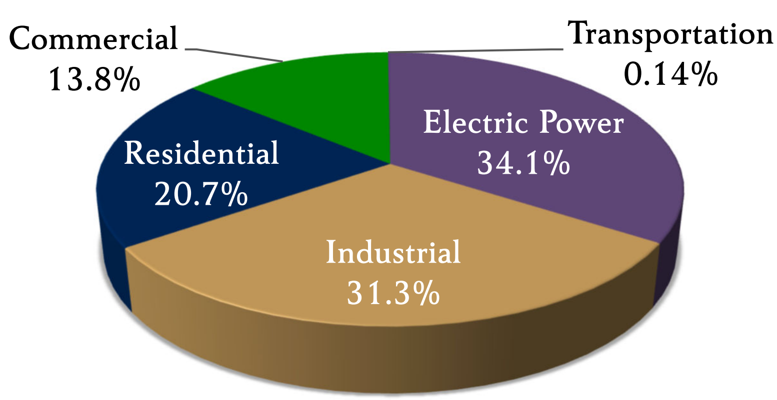
Once fractionated, the individual components have their own applications and are sold separately. Selling prices of individual NGL products are set against that of oil, except for ethane that is priced against that of natural gas (Ratner and Tiemann 2014). In terms of applications, NGL products have a variety of different uses much like petroleum products, including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy. For instance, majority of LPG (propane or butane) demand comes from residential and commercial markets for heating and cooking in homes and businesses. LPG can also be used in the manufacturing of olefins and fertilizers, and as fuel for vehicles fitted with an engine that can handle LPG. They can be transported via rail cars, shipping barges, tankers, and pipelines to their corresponding destinations where they are further processed (e.g. ethylene cracking, LPG cylinder filling), marketed, and/or stored (Allegro 2013; API 2014b; EKT Interactive 2015b; Goellner 2012; IEA 2010; Ivanenko 2011; NaturalGas.org 2013c; Pan 2014).

Among the NGL individual products, propane and ethane are dominating products, accounting for approximately 70 percent of all hydrocarbon gas liquid products produced each year since 2008. Propane is currently the largest-volume and highest-revenue product, while ethane is a fast growing product sought by the petrochemical industry (EIA 2014f). This report focuses on these two NGL products in examining pertinent subsystem processes.

End-use Markets

Natural gas is a flexible fuel that is consumed extensively in the United States for a multitude of uses (C2ES 2011; IEA 2011). Through the four subsystems, a variety of natural gas products are distributed to end-use markets that are generally classified into five sectors, including residential sector, commercial sector, industrial sector, electric power generation sector, and transportation sector. The market-sector share of natural gas delivered to consumers in 2013 (23,794,011 million cubic feet) is shown in Figure 8. Natural gas end-use market consumption is distinguished from natural gas consumed in well, field, and/or field (lease) operations (e.g. drilling operations, heaters, dehydrators, and field compressors); natural gas used as fuel in natural gas processing plants; and natural gas used in the operation of pipelines, primarily in compressors (EIA 2014a).

Figure 8 / Natural Gas Delivered to Consumers in the United States (2013)



Source: Natural Gas Annual 2013 (EIA 2014a)

Residential and commercial sectors

Natural gas is traditionally consumed in the residential and commercial sectors, mostly for space heating needs (IEA 2015). Residential sectors refer to private dwellings, including apartments, which use gas for heating, air-conditioning, cooking, water heating, and other household uses. Commercial sectors refer to non-manufacturing establishments or agencies primarily engaged in the sale of goods or services. Included are such establishments as hotels, restaurants, wholesale and retail stores, and local, State, and Federal agencies (EIA 2014a). Demand trend in these two sectors has been relatively flat over the past several years, and this trajectory is expected to continue into 2020 (Hanson and Simko 2015; Liss 2012).

Industrial sector

Industrial sector refers to manufacturing establishments or those engaged in mining or other mineral extraction as well as consumers in agriculture, forestry, and fisheries. However, industrial consumption is concentrated in a relatively small number of industries, primarily in the chemicals, pulp and paper, metals, petroleum refining, stone, clay and glass, plastic, and food processing industries (NaturalGas.org 2013f). Demand for natural gas in industrial sector has been strong, using gas both as an intermediary material and as an energy source in manufacturing. The former includes natural gas usage as a feedstock to make chemical products, fertilizers, plastics, and other materials. The latter includes natural gas usage for heating and cooling; for process heat to melt glass, process food, preheat metals, and dry various products; and for on-site generators that produce electricity and/or useful thermal output primarily to support the industrial activities. In fact, natural gas is the second most used energy source in industry, trailing only electricity (C2ES 2011; EIA 2014a; Harris 2014; IEA 2015; NaturalGas.org 2013f).

Electric power generation sector

The electric power sector includes electricity-only, and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public (EIA 2014a). Electric power generation represents the largest market by consumption volume, consuming an estimated 33.7 percent of the total quantity of US natural gas consumed in 2014, according to US Energy Information Administration (EIA) (Harris 2014). The electric power generation sector is expected to contribute to the most significant natural gas demand growth into 2040 (Cohen & Steers 2014; EIA 2014b; IHS CERA 2010).

Transportation sector

Historically, natural gas has not been widely used as an energy source for transportation. This non-traditional natural gas end-use sector is currently a small consumer sector, but has shown a strong growth as interest in promoting natural gas vehicles (NGVs) is growing in the United States. Already, gas demand in road transport grew tenfold between 2000 and 2010 (Kent 2013; NGVAmerica 2015). It is projected that this sector, including motor vehicles, trains, and ships, will consume almost 100 billion cubic metres (bcm) by 2018 or 2.5 percent of US natural gas consumption (C2ES 2011; EIA 2014b; IEA 2015; Marbek 2010).

The Natural Gas Supply Chain: An Expatiation of Processes, Activities, and Participants

Each key process of the natural gas supply chain comprises of an assortment of underlying activities and parties involved in executing them. This section provides an expatiation on these activities and key participants.

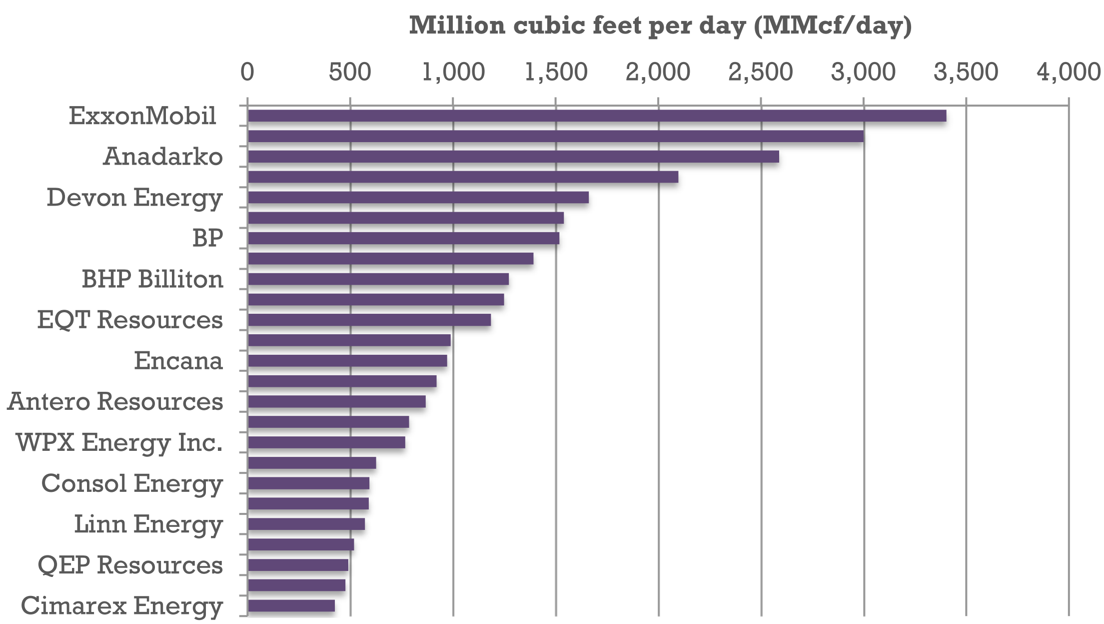
Exploration

Natural gas *exploration and production (E&P) operators* initiate and monitor the work leading to the commissioning of a natural gas well (Ivanenko 2011). The companies that focus solely on E&P are called *Independents* (EKT Interactive 2015a). Top 25 natural gas companies in United States by production volume at the end of 2014 are shown in Figure 9.

An E&P operator may operate gas wells on its own, with partners using a Joint Operating Agreement (JOA), or operate using a form of agreement called a *Farmout*. JOA, often used in large projects, involves several firms that pool their resources. The leading company is designated as an operator who controls day-to-day activities for the partnership, with other companies retaining their shares in production.

Farmouts are agreements under which the owner of a working interest in a natural gas lease assigns the working interest (or a portion of the working interest) to another party in exchange for certain contractually agreed services. Typically these services include drilling a well to a certain depth, in a certain location, and in a certain timeframe. The agreement also typically stipulates that the well must obtain commercial production. After this contractually agreed service is rendered, the assignee is said to have "earned" an assignment. The assignor usually retains a royalty interest[5] or reversionary interest[6] in the lease (Brister 2013; Crompton 2015b; EKT Interactive 2015a; Ivanenko 2011).

Figure 9 / Top 25 Natural Gas Producers in United States (2014)



Source: NGSA (2015)

[5] In the oil and gas industry, a **royalty interest** refers to ownership of a portion of the resource (e.g. natural gas) or revenue that is produced (e.g. cash earned from selling the extracted natural gas). A company that owns a royalty interest does not bear the costs of the operations needed to produce the resource (Investopedia).

[6] **Reversionary interest** is an interest in a well property that becomes effective at a specified time in the future or on the occurrence of a specified future event (Texas Energy Group).

Initial Exploration

Exploration for natural gas typically begins with non-invasive exploration activities performed by an *exploration service company*, a company specializing in geophysical services, either independently or on behalf of firms interested in the area. Geologists and geophysicists, known as explorationists, examine the surface structure of the earth, and determining areas where it is geologically likely that gas deposits might exist. Explorationists use detailed *Landsat data*,[7] or satellite images of Earch surfaces, as a cost-effective starting point to understand high-level surface geological details (EKT Interactive 2015d; Ivanenko 2011; NaturalGas.org 2013g).

Land Access Permit

After establishing an initial interest in a particular area, the next step is to determine who owns the land. A *permit man* contacts the *surface/land owner* to obtain permission for access to the land by the exploration company for the purpose of conducting seismic exploration activities in the search for gas deposits. The permit man also informs the exploration company of the location of streams, wells, buildings, and other improvements designated by the surface owner as being sensitive to geophysical survey. Upon the completion of the seismic crews' work, the permit man negotiates a final fee and **compensation** for any damages caused by the seismic exploration activities with the surface owner (NDSU 2013; The Workers' Compensation Board 2009).

Surface and Subsurface Geophysical Survey

With initial exploration and land access permit completed, the exploration company can begin more advanced phases of exploration. Geophysical survey begins with *surface* geophysical survey, and then *subsurface* geophysical survey to gain more detailed data about the potential reservoir area. These surveys allow for the more accurate mapping of underground formations, most notably those formations that are

[7] Landsat scenes can be requested and downloaded from: Glovis (http://glovis.usgs.gov) or Earth Explorer (http://earthexplorer.usgs.gov) (EKT Interactive 2015d).

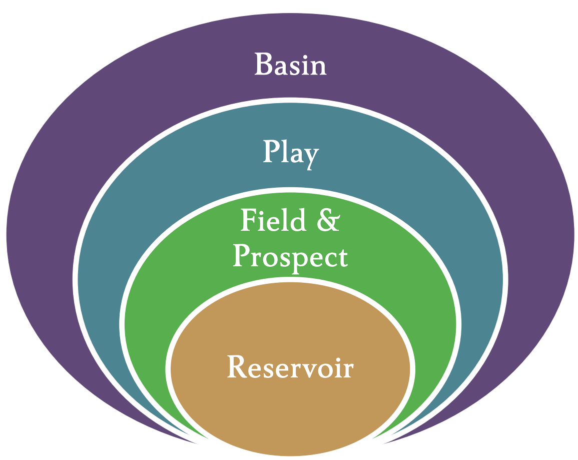
commonly associated with natural gas reservoirs (Adventures in Energy 2015c; NaturalGas.org 2013g).

See Figure 10 for basic natural gas geological terms, and Figure 11 for geographic location of US shale plays. The latter shows that shale gas are located in a number of different basins stretching across large parts of the United States, some of which are shared with Canada and Mexico (IEA 2012b). More details on top US shale producing states and plays can be found in Appendix 1.

Surface Geophysical Survey: Aeromagnetic Survey

A high-resolution *aeromagnetic survey* is conducted using a magnetometer aboard or towed by a helicopter or an aircraft. The aircraft typically flies in a grid-like pattern, with height and line spacing determining the resolution of the data and cost of the survey per unit area. As the aircraft flies, the magnetometer records tiny variations in the intensity of the earth's magnetic field. The aeromagnetic survey data, once processed, allow a three dimensional (3-D) visualization of the subsurface geological structure of the Earth's upper crust. A play with geological promise can be determined for more detailed surveys of the subsurface geology (Adventures in Energy 2015c; EKT Interactive 2015d).

Figure 10 / Geological Terms and Relations



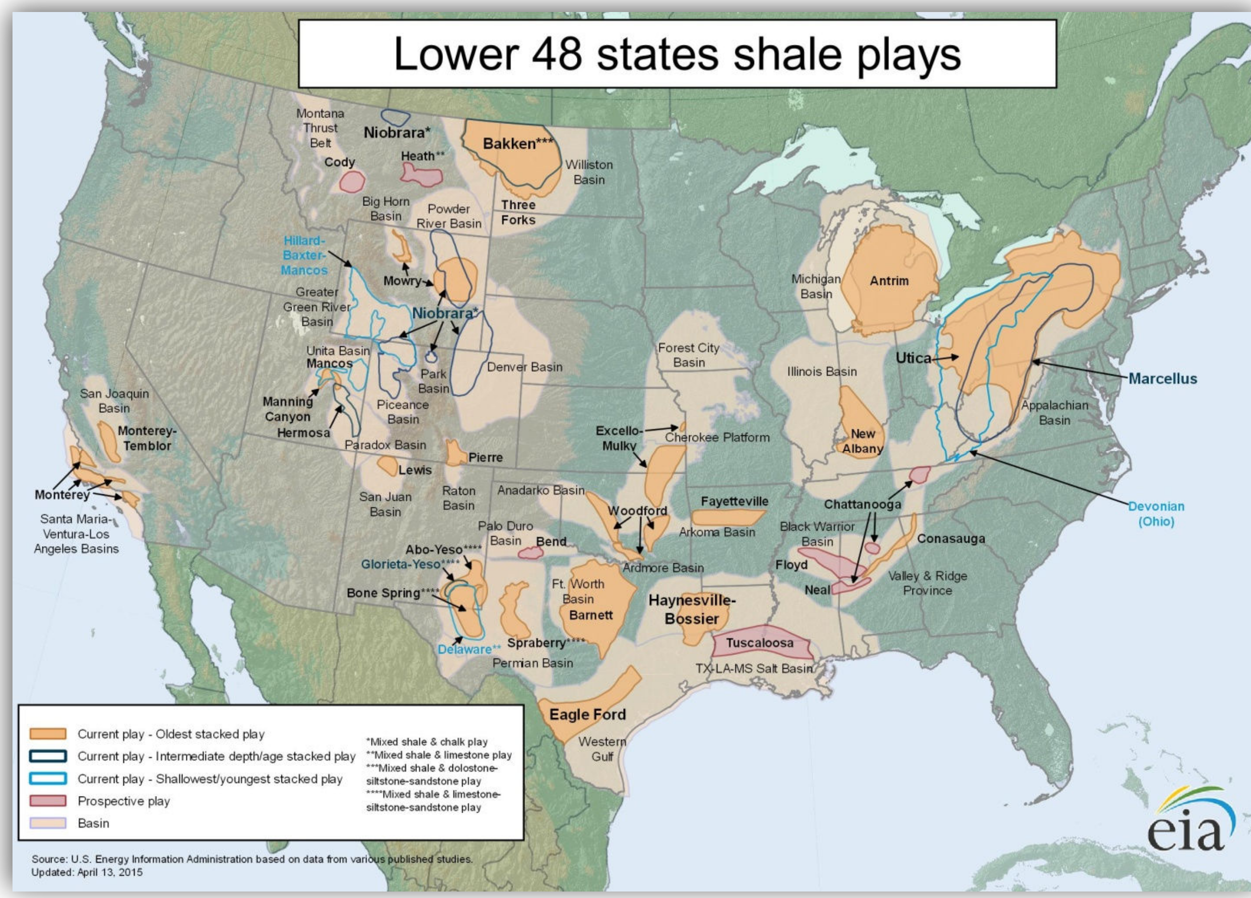
Source: Created based on Office of Fossil Energy (2013) and Schlumberger (2015)

NOTE:

1. **Reservoir** is a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids.

2. **Field** is an accumulation, pool, or group of pools of hydrocarbons or other mineral resources in the subsurface. A single field may include several reservoirs.
3. **Prospect** is an area of exploration in which hydrocarbons have been predicted to exist in economic quantity. A group of prospects of a similar nature constitutes a play.
4. **Play** is a set of discovered, undiscovered or possible natural gas accumulations that exhibit similar geological characteristics. Plays are located within basins.
5. **Sedimentary basin**, or simply **basin**, is a large-scale geologic depression in the crust of the Earth, often hundreds of miles across, in which sediments accumulate. A basin can vary from bowl-shaped to elongated troughs. If rich hydrocarbon source rocks occur in combination with appropriate depth and duration of burial, hydrocarbon generation can occur within the basin.

Figure 11 / Lower 48 Shale Plays



Source: Energy Information Administration (2015a)

Subsurface Geophysical Survey: Seismic Survey

Originally developed to measure earthquakes, seismology refers to the study of how energy, in the form of seismic waves, moves through the Earth's crust and interacts differently with various types of underground formations. In application to onshore natural gas exploration, seismology yields extremely useful data for explorationists and engineers. However, a seismic program is expensive and time consuming. Collecting and processing the data can take 12–18 months (EKT Interactive 2015d; NaturalGas.org 2013g).

Using seismic survey for natural gas exploration involves artificially creating seismic waves, either by an explosion or use of a large piece of equipment called a *thumper truck* (also called *Vibroseis truck*). Due to environmental concerns and improved technology, the non-explosive seismic technology is more widely used to generate the required data, with approximately 30 percent of seismic surveys using explosives and the rest using thumper trucks (Adventures in Energy 2015c; EKT Interactive 2015d; NaturalGas.org 2013g).

The reflection of seismic waves is then picked up by sensitive pieces of equipment called *geophones* or *hydrophones* that are embedded in the ground. The data picked up by these geophones is then transmitted to a seismic recording truck (see Figure 12) (Adventures in Energy 2015c; EKT Interactive 2015d; NaturalGas.org 2013g).

Figure 12 / Seismic Surveys

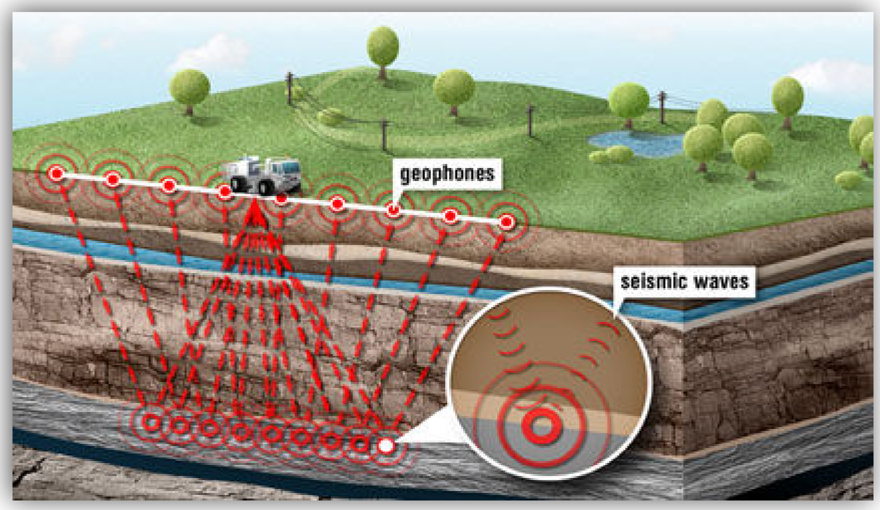


Image courtesy of EarthSky (2013)

The recorded seismic data, which can be reused many times and over a long period, then undergo elaborate computer processing, referred to as *CAEX (computer assisted exploration)*, to create a visual interpretation of an underground formation. These imaging techniques, relying mainly on seismic data acquired in the field, are becoming more and more sophisticated. There are three main types of CAEX models: two-dimensional (2-D), three-dimensional (3-D), and most recently, four-dimensional (4-D) (NaturalGas.org 2013g). Their descriptions are provided in Table 2.

Table 2 / Three Types of Computer-assisted Exploration (CAEX) Models

CAEX Model	Description
2-D seismic	A 2-D seismic shoot is recorded using straight lines of receivers crossing the surface of the earth. Data gathering and analysis of 2-D seismic information requires much less permitting, surveying, and processing time than that of 3-D and 4-D. A 2-D seismic survey works well for imaging major structures. It is normally used to map underground formations, and to make estimates based on the geologic structures to determine where it is likely that deposits may exist.
3-D seismic	In onshore 3-D seismic, many lines of receivers are used and recorded across the earth's surface, not just a vertical cross-section. The area of receivers recorded is known as a *patch*. A 3-D model is considerably more elaborate than 2-D counterparts, requiring data to be collected from several thousand locations compared to several hundred data points required for 2-D imaging. The daily cost of the crew and time required to gather 3-D seismic data is substantially higher. Large 3-D seismic shoots may take one to two years to acquire, three to four months to process the information, and can cost hundreds of thousands of dollars per square mile.
4-D seismic	Time-lapse or 4-D seismic is the process of using 3-D seismic data acquired at different times, over the same area. It is used to assess changes in a producing hydrocarbon reservoir over time (the fourth dimension).

Source: EKT Interactive (2015d) and Naturalgas.org (2013h)

In terms of usages, due to cost and time required, a 3-D seismic operation may not be cost-effective in the early stages of exploration. Rather, explorationists use a 2-D modeling and examination of geologic features described previously to determine if there is a probability of the presence of natural gas. Then, 3-D seismic imaging is used in the areas that have a high probability of containing reservoirs. The more elaborated data of 3-D seismic enable fewer dry holes, more optimized well locations, more complete evaluation of mineral rights, and better understanding the nature of prospects (Adventures in Energy 2015c; EKT Interactive 2015d; NaturalGas.org 2013g).

Engineers use 3-D seismic images as guidance for horizontal drilling projects to plan the safest, most cost-effective well path to the reservoir which increases the productivity of successful wells (allow for more natural gas to be extracted from the ground). In fact, 3-D seismic can increase the recovery rates[8] of productive wells to 40–50 percent or greater, as opposed to 25–30 percent with 2-D exploration techniques (Adventures in Energy 2015c; EKT Interactive 2015d; NaturalGas.org 2013g).

Once a reservoir has been located and put into production, a series of 3-D seismic surveys can be taken over time (time-lapse seismic or 4-D seismic) to evaluate the properties of a reservoir and how it is expected to deplete once extraction has begun. Using 4-D imaging on a reservoir can increase recovery rates (65–70%) above what can be achieved using 2-D or 3-D imaging (Adventures in Energy 2015c; EKT Interactive 2015d; NaturalGas.org 2013g).

Lease Acquisition

When the data indicate a likely site for natural gas reserves, the gas operator acquires (purchase or lease) the rights to allow further exploration. A unique characteristic of the United States in this respect is that, unlike in all other countries, the government does not own the subsurface mineral resources. Rather, landowners, which can be private or public entities,[9] often hold ownerships of mineral resources found in the subsurface of the land. Shale gas development in the United States has essentially

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[8] Recovery rate is a percentage of oil or gas that can be recovered from the deposit during production versus the total amount contained (Planete-Energies Glossary).

[9] There are a number of regional authorities that manage mineral leasing for US public lands—States administer any state trust lands; The US Bureau of Land Management administers public lands (including National Forest lands); and The Bureau of Indian Affairs administers Indian land in cooperation with individual Indian Nations (EKT Interactive 2015a; NDSU 2013; Wisniewski 2011).

taken place in areas with private land and minerals ownership, not in public-ownership areas (EKT Interactive 2015a; NDSU 2013; Wisniewski 2011).

A well cannot be drilled legally unless an operator is a mineral owner or has a valid lease. The common practice is a *mineral lease*, rather than a purchase of the mineral rights. A mineral lease is a contract that temporarily conveys a property right to the company. In this case, the operator that leases the mineral rights acquires the right to explore and drill, extract, remove, and dispose of any oil or gas that may be found on the leased land. Each lease is negotiated and agreed upon individually. The lease typically includes a per-acre signing bonus for a specified number of years, and an agreed upon royalty payment to the mineral owner if a well produces natural gas. Leases also include provisions to allow for the construction of underground gathering lines to transport natural gas from wells to larger transmission pipelines and processing plants. Leases are valid as long as annual rental (lease) payments are made, and can be extended for as long as oil or gas is produced (EKT Interactive 2015a; MSC 2014; NDSU 2013).

A *landman* or *land administrator* is usually involved in conducting due diligence and research in county courthouses for information on property records in order to determine mineral ownership as well as land ownership. Unlike permit man who contracts his/her services primarily to seismic exploration companies, a landman works primarily for oil and gas companies. The landman has the duty of negotiating and securing a lease agreement with the *mineral owners* for permission to drill and produce gas. Thus, the landman represents the gas company and interact extensively with internal business units, public, and regulatory stakeholders (CSUR n.d.; Ivanenko 2011; MSC 2014; NDSU 2013; The Workers' Compensation Board 2009).

The landman also provides administrative services such as preparing documentation, maintaining land records, obtaining operation permits, and paying annual lease fees. Federal and/or state and municipal licenses and permits are required for lease site construction, and will vary depending on the location of the well. Examples of the permits required in Pennsylvania are shown in Figure 13. Moreover, the landman monitors activity on a lease site to ensure that the gas company is meeting its obligations to the landowner. However, the landman does not become involved in supervising or controlling drilling or construction programs.

Note that a landowner who does not own mineral rights cannot stop a mineral owner or a company that has leased the mineral rights from entering onto the land to perform their activities (CSUR n.d.; Ivanenko 2011; NDSU 2013; The Workers' Compensation Board 2009).

Figure 13 / Examples of the Permits Required in Pennsylvania

1	Well drilling permit (w/ well location plat, casing and cementing plan, PNDI for threatened or endangered species, landowner/water well owner notifications, coal owner or operator notification and gas storage field owner notification)
2	Water management plan for Marcellus Shale wells
3	Proposed alternate method of casing, plugging, venting or equipping a well
4	Bond for Oil and Gas Well(s) (individual or blanket, various bond types allowed)
5	Waiver of distance requirements from spring, stream, body of water, or wetland (to put the well closer than 200 feet)
6	Variance from distance restriction from existing building or water supply (to put the well closer than 100 feet)
7	Proposed alternate method or material for casing, plugging, venting or equipping a well
8	Approval for alternative waste management practices
9	Approval of a pit for control, handling or storage of production fluids
10	Use of alternate pit liner
11	NPDES GP-1 for discharges from stripper oil wells
12	Water Quality Management Permit for treatment facilities
13	Alternative pit liners
14	Inactive status
15	Roadspreading plan approval
16	Transfer of well permit or registration
17	Orphan well classification
18	Off-site solids disposal
19	Residual waste transfer stations and processing facilities
20	Transportation of residual waste
21	Road use permit – construction of access to state roadway
22	Road use bond (PennDOT or municipality)
23	Surface use permit (if in the Allegheny National Forest)
24	PASPGP-3 or PASPGP-4 for pipelines crossing streams (if < 1 acre)
25	Water Obstruction – Encroachment – US Army Corps of Engineers Section 404 Joint Permit
26	Dam permit for a centralized impoundment dam for Marcellus Shale gas wells
27	GP-11 for non-road engine air emissions
28	GP-05 for natural gas compression facilities emissions
29	Earth disturbance permit (if > 5 acres)
30	Erosion and sedimentation control permit (if > 25 acres)
31	NPDES storm water for construction activities
32	Water allocation (SRBC, DRBC or DEP for Ohio River basin)
33	GP-3 for bank rehabilitation, bank protection, and gravel bar removal
34	GP-4 for intake and outfall structures
35	GP-5 for utility line stream crossings
36	GP-7 for minor road crossings
37	GP-8 for temporary road crossings
38	GP-11 Maintenance, Testing, Repair, Rehabilitation or Replacement of Water Obstructions and Encroachments

Source: API (2014a)

Exploratory Drilling

When the natural gas company get encouraging data for natural gas reserves and obtain all administrative permits, an exploration well (also called a *wildcat well* and a *test well*) is often drilled and evaluated to determine if there is enough natural gas in the reservoir to make it economically feasible to initiate recovery operations (Adventures in Energy 2015c; EKT Interactive 2015a; NaturalGas.org 2013g).

Exploratory drilling is the most expensive part of exploration. Examples of exploratory drilling techniques are *exploratory wells* and *core holes*. Exploratory wells involve digging into the Earth's crust to allow explorationists to study the composition of the underground rock layers in detail. For example, the drill cuttings (pulverized rock) are separated from drilling fluid (or mud, consisting of water, special chemicals, and clays) to allow physical examination of the subsurface rock. Fluid samples are also analyzed to determine the amount and type of hydrocarbon present in the rock. Another technique, a core hole is a well that is drilled using a hallow drill bit coated with synthetic diamonds for the purposes of extracting whole rock samples from the well. Taking core samples allows the various layers of rock and their thickness to be analyzed to determine the exact porosity and permeability (Adventures in Energy 2015c; NDSU 2013; NaturalGas.org 2013g; OpenEI 2013).

In most cases, E&P companies (well operators) do not possess the technology, manpower or equipment to do their own drilling. Rather, most wells are drilled by independent *drilling and field service companies* that provide experienced personnel, specialized equipment, and general support services. The E&P company awards contracts to these companies through a competitive bidding, with the terms of drilling and well service contracts that maintain the well operator's control of the well. Because of rig design and operating complexity, these contractors tend to focus their efforts on either onshore or offshore, with a few companies participating in both markets. Examples of land rig contractors are Nabors Drilling, Helmerich & Payne, Patterson UTI, Grey Wolf Drilling, Unit Drilling (EKT Interactive 2015a).

Pilot Testing

If promising amounts of oil and gas are confirmed, pilot testing (or appraisal drilling) is performed. A commonly used tool, *well logging* entails a process of performing tests during or after the drilling process to examine the porosity and fluid content of the subsurface rock, as well as to gain a better understanding of the earth in which the well is being drilled. Standard logging consists of examining and recording the physical aspects of a well. This information gives a good indication of how well natural gas would flow through the rock. If an exploratory well is considered to have commercial quantities, it is called a *discovery well*; otherwise it is called *dry hole* which will be plugged with cement and abandoned (Adventures in Energy 2015c; Cairn Energy 2015; EKT Interactive 2015a; NDSU 2013; NaturalGas.org 2013g).

Development

Development Planning

If appraisal wells show technically and commercially viable quantities of gas, a field development plan (FDP) is prepared and submitted to the relevant authorities for approval. An FDP comprises all activities and processes required to develop a field, namely: geophysics, geology, reservoir and production engineering, infrastructure, well design and construction, completion design, surface facilities, a rigorous assessment of all the potential risks, and a long-term assessment of environmental and social impacts covering between 10 and 30 year timeframe (EKT Interactive 2015a; IEA 2012b).

Once the development plan is approved, additional equipment is brought to the discovery well site to develop and complete the well. In general, more technical and construction services are required during site preparation, drilling, and completing a shale gas well than for a similar onshore conventional gas well (IEA 2012b).

Site Preparation

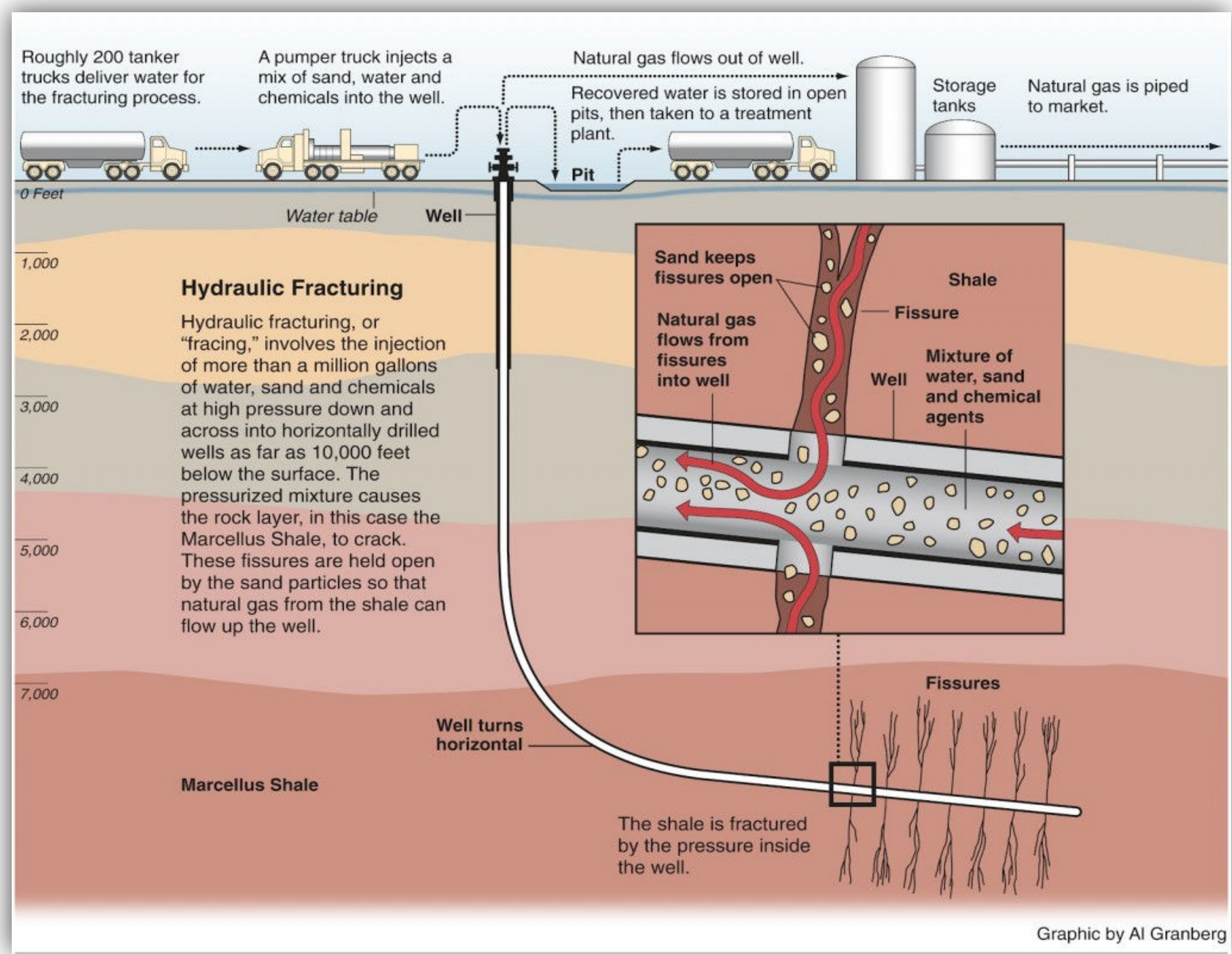
The site preparation phrase typically includes the followings (CSUR n.d.; **Dunn 2014**; GWPC & IOGCC 2015; Marathon Oil Corporation n.d.; MSC 2014):

- Roadways in areas that have active operations must be capable of supporting transportation of heavy equipment such as the drill rig, and the additional traffics of inbound and outbound material movements. These roadways are often upgraded and repaired at the expense of the well operator.
- The clearing and leveling of the site. As part of the clearing process, topsoil is removed and typically stored on site for use in the reclamation of the pad at a later date.
- The installation of structures for erosion control
- The excavation of pits to hold drilling fluids and drill cuttings
- The installation of several 500-barrel tanks for water storage, or a massive 40,000-barrel pool erected on the periphery of the site to store water
- The placement of racks to hold the drill pipe and casing strings
- The installation of oil and gas separators (in the case of associated production)
- The construction of gathering pipelines
- The construction of surface facilities, typically including: wellhead, data monitoring van, fracture fluid storage tanks, sand storage units, chemical storage trucks, frac blending equipment, and pumping equipment

Development Drilling and Completion

Development drilling for shale formation requires both vertical and horizontal drilling, combined with hydraulic fracturing (fracking). Producing gas and oil from shale using hydraulic fracking techniques takes 4–8 weeks from preparing the site to production itself (API 2014a), of which fracking takes about 2–3 days and drilling and completing a well takes roughly 10–14 days (Dunn 2014). The cost of developing a single well could add up to between $5 and $6 million (MSC 2014). Figure 14 demonstrates a typical fracking operation in a horizontal well. More detailed descriptions follow.

Figure 14 / A Typical Fracking Operation



Source: California Energy Commission (2015a)

1. **Vertical drilling and well casing.** To ensure that neither the fluid that will eventually be pumped through the well, nor the gas that will eventually be collected enters the water supply, steel surface or intermediate casings are inserted vertically into the well to depths of between 1,000 and 4,000 feet. The space between these casing "strings" and the drilled hole (wellbore) called the annulus is filled with cement. Once the cement has set, the vertical drilling continues to the next depth. This process is repeated, using smaller steel casing each time, until the gas-bearing reservoir is reached, generally 6,000 to 10,000 feet (see Figure 15) (Energy From Shale 2014). This process can take from 7 to 10 days, depending on the site (**Dunn 2014**).

Figure 15 / Well Casing

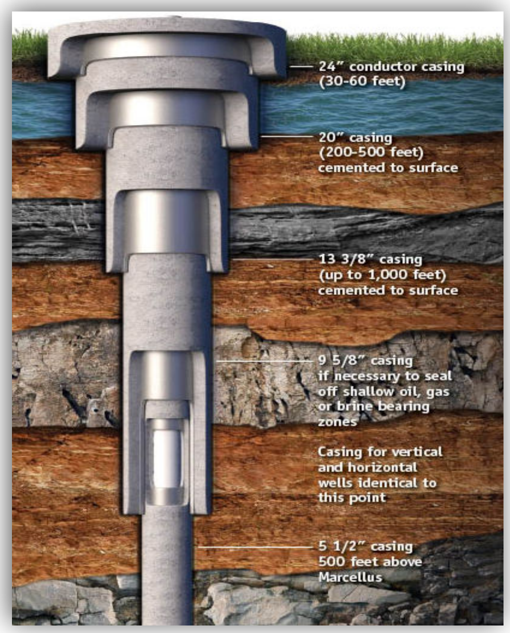


Image courtesy of the Marcellus Shale Coalition (2014)

2. **Horizontal drilling.** The point where the curve begins and the horizontal section is drilled is called *kick-off point*, which could take up to two days to drill (**Dunn 2014**). The drill runs horizontally at 6,000–10,000 feet to up to 2 miles long into the shale formation. The horizontal segment is called the *lateral*. The horizontal drilling enables the well to penetrate significantly more rock in the gas bearing strata, increasing the chances of gas being able to flow into the well (IEA 2015).
3. **Completion – Perforation.** The first stage in the completion process involves perforating the well casing in the horizontal portion of the well (MSC 2014). The steel casing that is inserted into the borehole is perforated with a tool that creates small holes for water and tiny particles to escape (Energy From Shale 2014; IEA 2015; Penn State Public Broadcasting 2014).
4. **Completion – Simulation (commonly by hydraulic fracturing method).** In the second stage of the completion process, a pumper truck injects a large volume of fracturing fluids called *slickwater* (generally consist of 90% water, 9.5% sand, and 0.5% chemicals) into the well under high pressure. The fluid shots through the holes and factures the rock. Chemical-based additives and proppant agents (e.g.

sand and ceramic particles) found in the fluid hold open these fissures, allowing the gas to escape and flow into the wellbore. After the newly created cracks create a pathway for the gas to enter the casing, a plug is inserted to prevent fracturing fluids from entering this zone. Additional sections of the casing are perforated, fracked, and plugged, dividing the horizontal section of the well into several sections. This process is repeated in roughly 1,000-foot segments throughout the horizontal distance of the well. Throughout the fracturing process, constant measurements of fluid level, pumping rates, and pumping times are performed to maximize the fracture zone, and to minimize any damage to the formation (EKT Interactive 2015a; Energy From Shale 2014; IEA 2015; Penn State Public Broadcasting 2014).

5. **Completion – Production testing.** After all sections have been fracked, the downward pressure needed to pump down fracturing fluids is removed from the well and the plugs are drilled out. Within a couple of days, the release of that pressure will reverse the flow stream, allowing gas and some of the water to flow up from downhole to the surface (lift). The surfaced gas from production testing is commonly flared in situations where no pipeline is available; otherwise it is separated from the water and put to pipeline to flow the gas for sales. The latter method is called *cleaning up into sales* by the natural gas industry, *reduced emissions completions* by regulators, and *green completions* by others. Typically, the production testing is monitored for a few weeks to evaluate its performance. Once the testing has been completed, all equipment, except the valves on top of the wellbore itself, will be removed. The well then enters the production phase (Dunn 2014; Energy From Shale 2014; Marathon Oil Corporation n.d.; MSC 2014; Natural Gas Now 2014; Penn State Public Broadcasting 2014).

As in exploratory drilling, development drilling is typically executed by *drilling and field service contractor*. The role of the well's operator should be noted, however. While most of the day-to-day activities of the drilling programs are executed by drilling contractors, it is the operator's *drilling department* (via the onsite drilling supervisor) that oversees the operations and performance of well site personnel and activities (EKT Interactive 2015a; Ivanenko 2011).

Well Production / Lift Operations

Once wells are completed and connected to processing facilities that usually serve several wells, the main production phase can begin (IEA 2012b). Gas is brought up (lift) to the surface in the water that is pumped up (called flowback). Most sites will have equipment to separate the oil, gas, and water produced from the well into distinct flow paths. Extracted gas is either put directly to the pipeline if the development areas have a pipeline ready, or put into storage tanks, then piped for further processing or to markets (Energy From Shale 2014; Marathon Oil Corporation n.d.; MSC 2014; Penn State Public Broadcasting 2014).

Meanwhile, recovered water is stored in open pits before being taken to a treatment plant (Energy From Shale 2014; MSC 2014; Penn State Public Broadcasting 2014). Flowback rates during first two weeks of fracking average 3,000–5,000 barrels/day (bpd) (357,000 to 595,000 litres), then declining rapidly to a few 100 bpd. Further decline is gradual, estimated at 10–20 bpd after a few months. Service companies specialized in wastewater treatment may be employed to perform these activities (Deloitte 2013a; Water World 2011).

Production processes, along with associated technology and equipment, also focus on maintaining the well throughout its economic life. Periodically, wells will undergo some type of servicing and repairs, called a *workover* to insure efficient operation of the well. Work-over crews clean the well by getting rid of fluids and sands which may have gathered in the hole. In some cases, the operator may repeat the hydraulic fracturing procedure at later times in the life of the producing well, a procedure called *re-fracturing* or *refracking*, to open cracks in the formation to allow the oil or gas to flow more freely. However, this procedure is relatively rare in horizontal wells, occurring in less than 10 percent of the horizontal shale-gas wells drilled in the United States (EKT Interactive 2015a; IEA 2012b; NDSU 2013).

The tasks of well maintenance described above involve operations that are technologically similar to drilling. As such, maintenance can be conducted by the same *drilling contractors*, but using simpler, mostly very mobile, service rigs. However, well maintenance service is typically negotiated separately from the drilling contract. As in drilling operations, while day-to-day production activities are performed by the contractors, well operators perform daily checks of producing wells, tank batteries, and contractor progress on workovers and other maintenance work to control the operating costs. Today, smart well technology is used, which results in dramatic increases of overall production efficiency of the well. The *smart wells* are completed with valves and/or chokes located downhole in the reservoir and tied to sensing equipment which can be operated, even remotely, from the surface. The technology makes it possible to control multiple well functions (e.g. production flow rates, and measuring and testing operations) at the surface with a push of a button (EKT Interactive 2015a; Ivanenko 2011).

Well Site Logistics

Well site logistics management plays an important role from the start of site preparation to well development and completion, and throughout the well production life. Well site logistics is complex, encompassing various services required to support numerous drilling locations operating in parallel, typically with high drilling frequency. Moreover, the logistics of supplies needed to sustain life and protect health of workers, and the logistics of the people themselves (e.g. managing the transportation of drilling crews into and out of the production site in line with their rotation schedules) need to be managed (Harrington 2014). Summary of material volume used in shale fracking operations is provided in Table 3.

Table 3 / Key Materials Used in Shale Fracking Operations

Materials	Estimated Volume
Fresh water	Average of 3–7 million gallons of water per well[1]
Propping agents (e.g. sand, ceramic beads)	1.5–6 million pounds of sand per frac job; a typical well can have as many as 20 fracs[2]
Chemicals	Average of 150,000–350,000 gallons of chemicals per well[1]

[1] Intermountain Oil and Gas Best Management Practices (BMPs) Project (2015)
[2] **Dunn (2014)**

In general, *rails* and *trucks* are used, either individually or in conjunction, to haul fresh water, the special sand known as frac sand, pipes, acids and other chemicals, waste products, and heavy equipment. Site preparation might involve between 100 and 200 truck movements to deliver all the equipment, while further truck movements will be required to deliver supplies during drilling and completion of the well (IEA 2012b; OpenEI 2013). Railroads play a particularly important role at new well sites that do not have existing pipelines. In fact, in some shale-producing regions, the railroads have had to build additional infrastructure to keep up with demand. A case in point is the Bakken shale field in North Dakota where rail has become the favored mode of transportation because it is cheaper than trucking and more flexible than pipeline (PwC 2013).

Thus far, well site logistics have been an afterthought in the unconventional space. There are low levels of coordination and visibility at the field level for the large volume of materials required for fracking operations and pad drilling. Demand for these movements is largely met by a combination of mom-and-pop transport operators, and equipment controlled by traditional field service companies (O'Reilly 2015; *SupplyChainBrain* 2012). Added to the challenges is the dynamic nature of drilling operations with frequent changes of plan to reflect current drilling performance. The frequent changes, in turn, impact materials demand and service requirements, as well as corresponding materials monitoring and procurement (Harrington 2014).

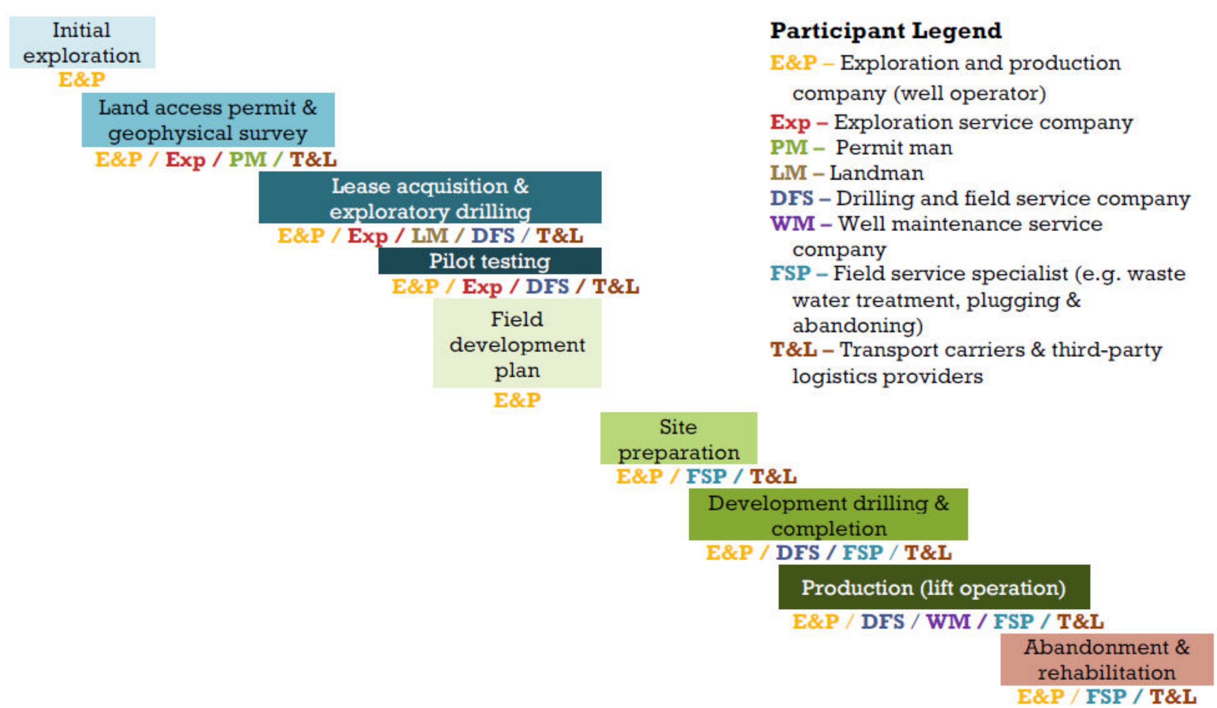
The challenges and current inefficiency has led to gas producers looking to partner with third-party logistics providers (3PLs) to achieve more efficient logistics management, and enable better asset utilization and production productivity. Among 3PLs that enter unconventional oil and gas markets are Ryder, Dupré Logistics, C.H. Robionson, and DHL (Harrington 2014; *Inbound Logistics & Chemical Week* 2013; O'Reilly 2015).

Well Abandonment and Rehabilitation

A well reaches its *end of economic life* when it costs more to operate than the revenue that it brings in. The term used when a well is taken out of service is called *plugging and abandoning (P&A)*. The well operator's plan for plugging a well is a legal obligation in every region with producing assets. The P&A plan is reviewed and approved by the regional body that governs oil and gas well approvals and permitting. In the United States and Canada, these government bodies are the states or provinces. The objectives of each abandonment are to: (1) protect any remaining reserves and particularly, ground water reserves, (2) limit fluid movement within the wellbore until nature restores the pressure balance that existed before the well was drilled, and (3) restore the surface area, involving dismantling facilities, and returning land to its natural state or putting it to new appropriate productive use (EKT Interactive 2015a; IEA 2012b).

Proper P&A is important because unplugged or poorly plugged wells are an environmental hazard as they provide potential conduits for fluids to migrate between formations and potentially into the fresh water zones. Poorly plugged wells also might provide pathways for natural gas to seep to the surface and potentially cause fire or be a health hazards. In general, the types of materials used for plugging abandoned wells have not changed significantly over the last 100 years. Cement is the most common plugging material used to seal the abandoned wells. However, drilling mud, bentonite, and mechanical plugs are also used frequently in conjunction with cement. The plugging process can take two days to a week, depending on the number of plugs to be set in the well (Technology Subgroup 2011). Figure 16 provides a recap of exploration and production activities discussed thus far.

Figure 16 / Exploration and Production Activity Recap



Gathering

After natural gas is produced, it is gathered at a collection point from numerous land-based (onshore) wells via gathering pipelines for further transportation to a field treatment facility or a central processing plants (Adventures in Energy 2015a; EKT Interactive 2015b).

The gathering pipeline transport services are provided either by subsidiaries of natural gas production companies, or third-party pipeline companies. In a circumstance where there is no existing pipeline in the production area, the natural gas production company may consider constructing gathering pipelines (through its pipeline subsidiary) or negotiate with a pipeline company to build ones. In both cases, the construction of gathering lines is subject to applicable state and federal permitting requirements, and depends on the consent of the property owners over whose property the pipeline will traverse (Henderson 2012; PHMSA n.d.; Sadasivam 2013).

Pipeline Construction Permits

As discussed earlier (see bird-eye view section), only about 10 percent of the approximately 200,000 miles or more on-shore gathering lines within the United States are regulated lines. However, unlike traditional rural gas gathering lines, the gathering pipelines that are put into service in the various shale plays are generally of much larger diameter and operating at higher pressure, raising safety concerns over these largely unregulated pipelines. Gathering lines in these areas are 12 to 36 inches in diameter, instead of 2 to 12 inches. Moreover, compared to gathering lines in the past that operated at pressures of between 5 and 800 pounds per square inch (psi), shale gas gathering lines typically handle a maximum operating pressure of 1,480 psi as estimated by the PHMSA advisory committee. Given the growing safety concerns, the PHMSA is presently contemplating extending federal jurisdiction to the currently unregulated gathering lines (Henderson 2012; PHMSA n.d.; Sadasivam 2013).[10]

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[10] In Pennsylvania, although Class 1 gathering lines are not required to register with PA One Call, many gathering line operators voluntarily comply with registration provisions of PA One

Right-of-way Acquisition

Gathering pipelines are generally buried 3–5 feet below the surface or deeper if an operator is boring underneath roadways, rail lines, or waterways. The width of a right-of-way can vary depending on the negotiation with the landowner. Typically, a temporary right-of-way will have a width of 60–100 feet, with a corresponding permanent right-of-way having a width of 50–75 feet. Additionally, property owners willing to host a pipeline may specify where on their property they are willing to permit a pipeline. Landowners who agree to host a pipeline sign a *right-of-way agreement* or *easement*, which grants a limited property right to the pipeline operator. The pipeline is then placed underground after excavation. The right-of-way must be cleared of trees, brush, and other obstructions. Similar to leases for oil or natural gas E&P, pipeline right-of-way agreements may involve an upfront "bonus" payment to the landowner in addition to a fixed dollar payment per linear foot (Henderson 2012; Phillips 2012).

Field (Lease) Processing

Traversing through gathering pipelines from well sites, raw natural gas arrives at a field (lease) processing facility. The first step at the field processing facility is to remove any water and natural gas condensate. Any wastewater that has been removed is typically collected and treated before being sent back to the well or offsite for wastewater disposal (EKT Interactive 2015b). The condensate recovered at field level is referred to as *field condensate* (also called *lease condensate* or *license condensate*). Field condensate is a mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas. They differ from natural gas plant liquids such as butane and propane (or LPG) that are typically recovered at downstream natural gas processing plants (EIA n.d., 2014c; England and Mittal 2014).

Field condensate is often blended into other crude oil to lighten and sweeten crude supply, thus enhancing the quality of the blend for refinery operators. In these

Call as a prudent standard business practice to enhance public safety and better protect against damage or compromise of the underground pipeline (Henderson 2012).

cases the condensate is known as *spiked condensate*. They also have an important application in dilution of bitumen, a technology that facilitates the pipeline transportation of otherwise viscous and heavy oil streams. Alternatively, the field condensate might be transported as *segregated condensate* and sold as is to purpose built condensate splitters and petrochemical facilities. Given the valuable applications in oil refining sector, large gas condensate deposits have been targeted for development by International Oil Companies (IOCs) over recent years (IEA 2010).

Plant Processing

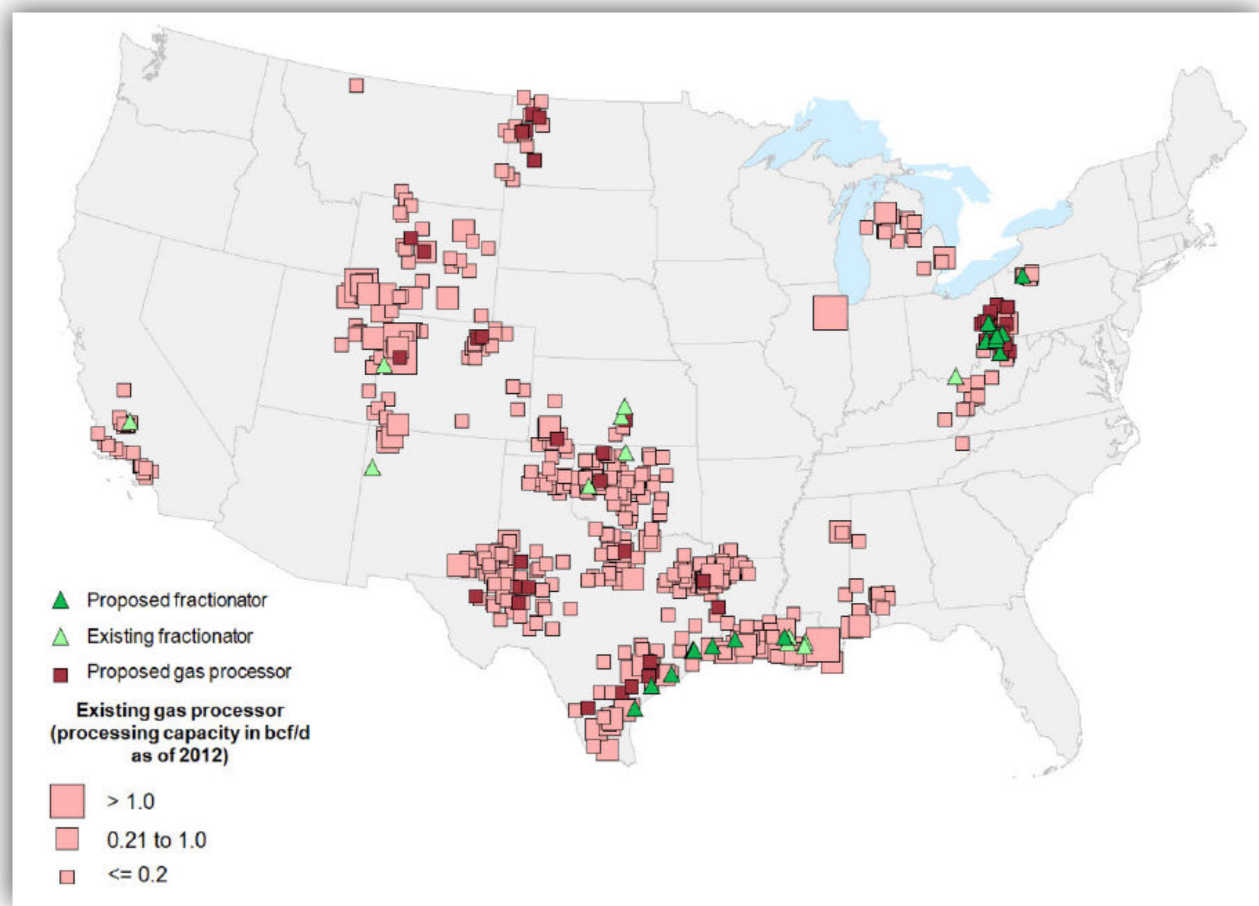
While some of the needed processing can be accomplished at field processing facilities, the complete processing of natural gas takes place at a processing plant, usually located in a natural gas producing region (NaturalGas.org 2013c). There are some 500 gas processing plants in the United States as of 2012. However, a group of 10 processing companies leads the nation in processing natural gas. These companies are often midstream energy master limited partnerships (MLP) companies that own pipelines and other midstream infrastructure (Pan 2014; Stell 2014). The top ten US gas processors and estimated gas processing volume in 2012 are listed as follows (Stell 2014). More detailed profile of the top five gas processors can be found in Appendix 2.

- DCP Midstream 6.10 Bcfd
- Enterprise Products Partners 6.05 Bdfd
- Williams Companies Inc. 4.45 Bdfd
- Targa Resources 2.10 Bdfd
- MarkWest Energy Partners 1.68 Bdfd
- Encana 1.63 Bdfd
- Crosstex Energy Services 1.35 Bdfd
- Western Gas Partners 1.19 Bdfd
- Shell Oil Co. 1.06 Bdfd
- Devon Energy 1.05 Bdfd

A central processing plant separates NGLs from a stream of raw natural gas using three main methods, namely absorption, refrigeration, and cryogenics. Of the three methods, the cryogenic method is most efficient, removing the highest percentage of NGL from the natural gas stream. However, it is also the most energy and capital intensive method. In addition to separation of NGLs, a gas processing plant also controls the quality of dry gas stream produced to meet industry standards for transportation in high-pressure transmission pipelines (API 2014b; EIA 2014c; Pan 2014). The main processes of plant processing are summarized as the followings:

- **Water removal.** In addition to separating oil and some condensate from the wet gas stream, it is necessary to remove most of the associated water. Most of the liquid, free water associated with extracted natural gas is removed by simple separation methods at or near the wellhead. However, the removal of the water vapor that exists in solution in natural gas requires a more complex treatment at a processing plant (NaturalGas.org 2013c).
- **Separation of NGLs.** There are two basic steps to the treatment of natural gas liquids in the natural gas stream. First, the liquids must be extracted from the natural gas. Second, the extracted, mixed natural gas liquids must be separated down to their base components. As shown in Figure 17, some gas processing plants may be co-located with NGL fractionation plants, allowing both processes to be completed at the same locations. However, more often, processing plants' primary objective is the production of dry gas (demethanizing), with the extracted, mixed NGL stream directed to a specialized, stand-alone fractionation plant (DCP Midstream 2014; EIA n.d., 2014f; IEA 2010; IHS 2013; NaturalGas.org 2013c).
- **Sulfur and carbon dioxide removal.** In addition to water, oil, and NGL removal, one of the most important parts of gas processing involves the removal of sulfur and carbon dioxide. This process may be performed at the centralized processing plant or at a specialized sweetening plant (NaturalGas.org 2013c).

Figure 17 / Existing and Proposed Natural Gas Processing Plants and Fractionation Plants (2012)



Source: EIA (2014f)

NOTE:

(1) As of 2012, EIA identified 516 natural gas processing plant and 122 fractionation plants, 16 of which are stand-alone fractionation facilities and 106 of which are co-located with natural gas processing plants (EIA 2014f).

(2) According to Bentek NGL Facilities Databank, US gas processing capacity is approximated at 74Bcf/d in 2013 and set to potentially increase by 14 Bcf/d by end of 2016. US fractionation capacity is approximated at 4 MMb/d in 2013 and set grow by 40 percent to 5.6 MMb/d by end of 2016 (Minter 2014).

After raw natural gas is processed, a stream of processed dry gas and a stream of NGLs are produced (Pan 2014). The natural gas that is now stripped of NGLs is referred to as *dry gas, pipeline-quality dry natural gas, consumer-grade natural gas,* or *sales gas* and consists mainly of methane (95–98% methane). The dry gas might need further processing or purification to conform to the specification of the pipeline companies and target markets. The spec will regulate the heat content measured in Btu per cubic foot, acidity, dew point, and other characteristics of the gas (API 2014b; BP 2015b; CAPP 2012; Eastern Shore 2015; EIA n.d., 2014a, 2014c; EKT Interactive 2015b; IEA 2010; NaturalGas.org 2013c; Ratner and Tiemann 2014; Ratner et al. 2015; Tortoise Capital Advisors 2014).

Line-haul Transportation

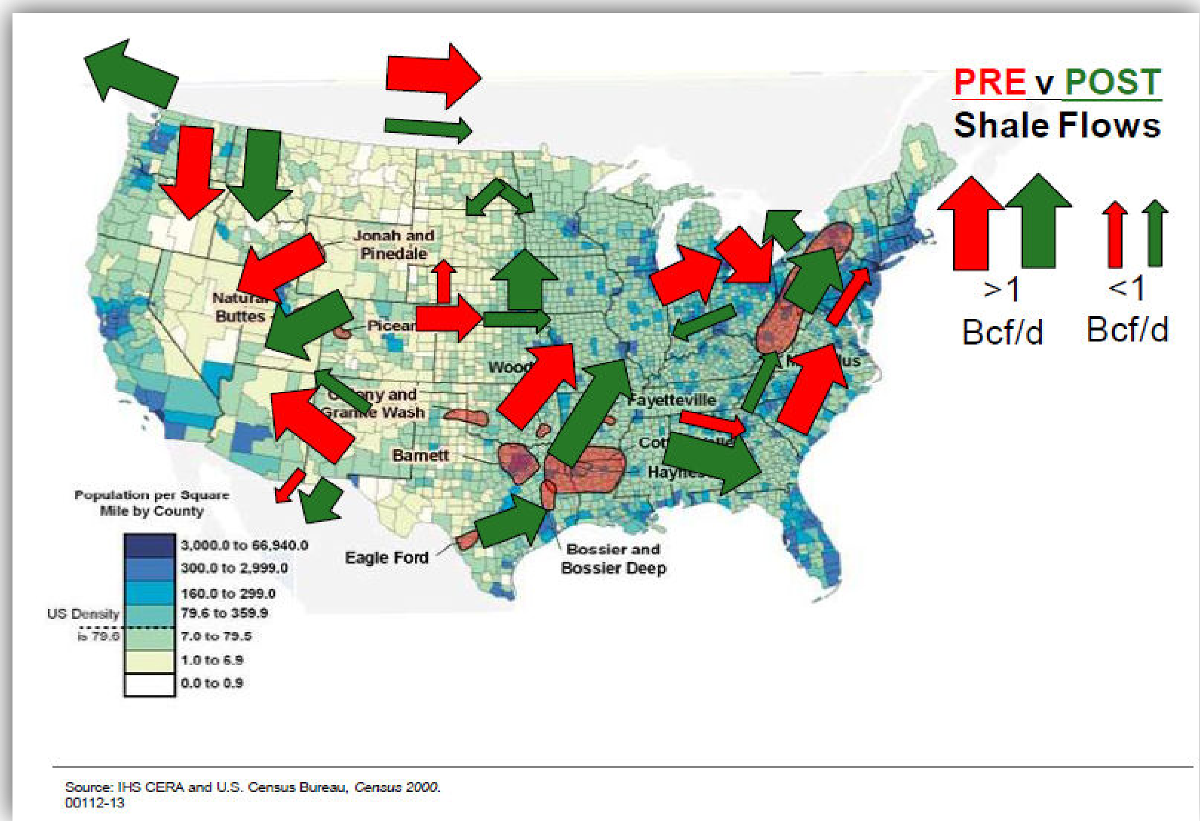
The two streams of natural gas products, dry gas and mixed NGLs, produced at the processing plant are then transported line-haul or regionally via transmission pipelines to markets.

Dry Natural Gas Line-haul Transportation

Pipeline is a primary mode of dry natural gas line-haul transportation. Using pipeline transportation, the processed dry natural gas is compressed and injected at the inlet points that are connected to transmission pipelines (INGAA Foundation 2011). Some amount of processed dry gas may be put into underground storage for future use. During in-transit along the transmission pipeline system, the dry gas may also be injected and withdrawn from an underground storage field as needed (API 2014b; EIA n.d.; EKT Interactive 2015b; IEA 2010).

However, in certain areas where waterway is accessible, compressed natural gas (CNG) ships can be used. For this purpose natural gas is simply mechanically compressed, as it is in a pipeline. CNG marine transportation can provide an economic alternative for small- to medium-sized, regional gas delivery applications, notably: (1) to markets located beyond pipeline, but within medium distances (less than about 3,000 kms); (2) for supply sources not large enough to justify the high capital investment required for liquefaction projects; (3) to transport gas from early production systems; and (4) to offtake gas directly from offshore production facilities, including deep and ultra-deep waters (Enersea 2014; Sea NG n.d.).

Figure 18 / Gas Pipeline Flows Pre- versus Post-Shale Revolutions



Source: IHS (2013)

It is worth noting that the growth in shale gas production has resulted in shifting flows on the US interstate pipeline network. In particular, natural gas that was once imported from other states into eastern markets has been increasingly displaced by Marcellus production. The growing Marcellus shale production in Pennsylvania and West Virginia has required substantial investment in new pipeline infrastructure to allow these supplies to be delivered to the major east coast consuming markets. At the same time, other pipelines that provided long-haul transportation of natural gas supplies from traditional supply areas, such as Canada and the Gulf Coast, have become less utilized as the region shifts to consuming local Marcellus natural gas production (API 2014b; DOE 2015).

Similar shifts have also occurred in import/export pipeline flows. Historically, the vast majority of US natural gas imports, almost 90 percent in 2012, arrived via pipeline from Canada (EIA 2014c). The increased supply from the Marcellus has not only reduced the need for Canadian exports to the US Northeast, but also led to increasing imports into Canada from the United States (Navigant 2014). Figure 18 provides a snapshot of the gas pipeline flows both in domestic and export markets. Observations of pipeline development trends in responding to changing flows are discussed in Appendix 3.

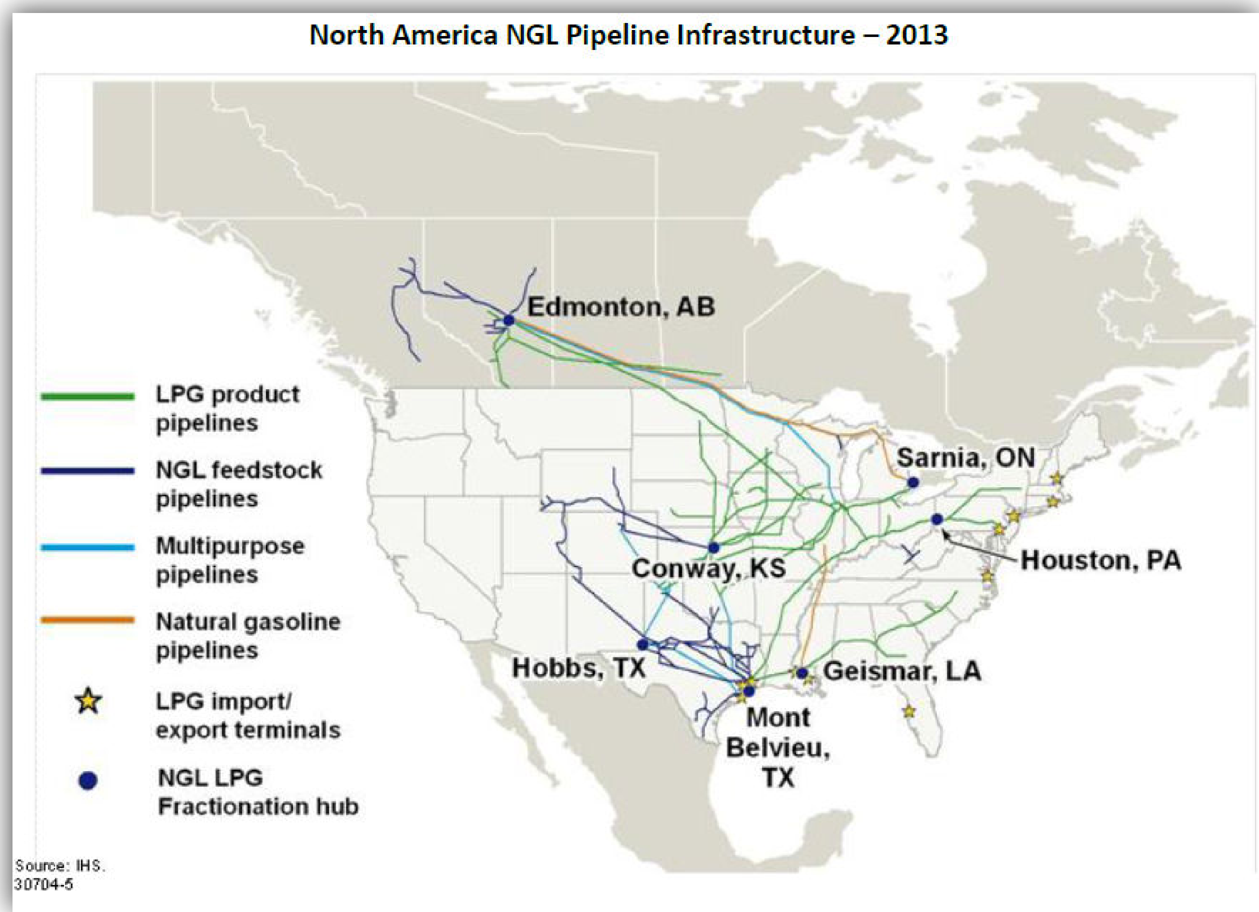
Mixed NGLs Line-haul Transportation

By-products of natural gas processing, mixed NGLs are transported via long-distance, typically interstate, NGL transmission pipeline for further processing and/or put into storage for future use. These long-distance pipelines are usually common carrier systems which aggregate mixed NGL from dozens of individual gas processing plants, and operate with limitations on methane content and minimum ethane content (EIA 2014f; IHS 2013; INGAA Foundation 2011).

It should be noted that mixed NGL stream (called Y-grade) is one of many forms of hydrocarbon gas liquids (distinguished from dry natural gas pipeline discussed above) moved via pipelines. Other forms are, for instance, purity products (individual base component streams such as ethane, propane, normal butane, isobutane, and natural gasoline), E-P mix (80% ethane and 20% propane), and LPG (mixture of propane, normal butane, and isobutane). Among these various forms, mixed NGLs account for the majority of all hydrocarbon gas liquids transported by pipeline (EIA 2014f). Figure 19 shows NGL pipeline infrastructure in North America as of 2013.

Several large NGL pipeline projects are currently under construction linking the gas processing facilities of Western Pennsylvania and Ohio to both the Gulf Coast and marine terminals along the Delaware River. Additional corridors are being expanded or established between West Texas and East Texas picking up NGL production from Eagle Ford along the way and between gas processing in the Rocky Mountains and the US Gulf Coast. As additional natural gas is recovered from the Bakken, production investment in NGL development will be made there as well (IHS 2013).

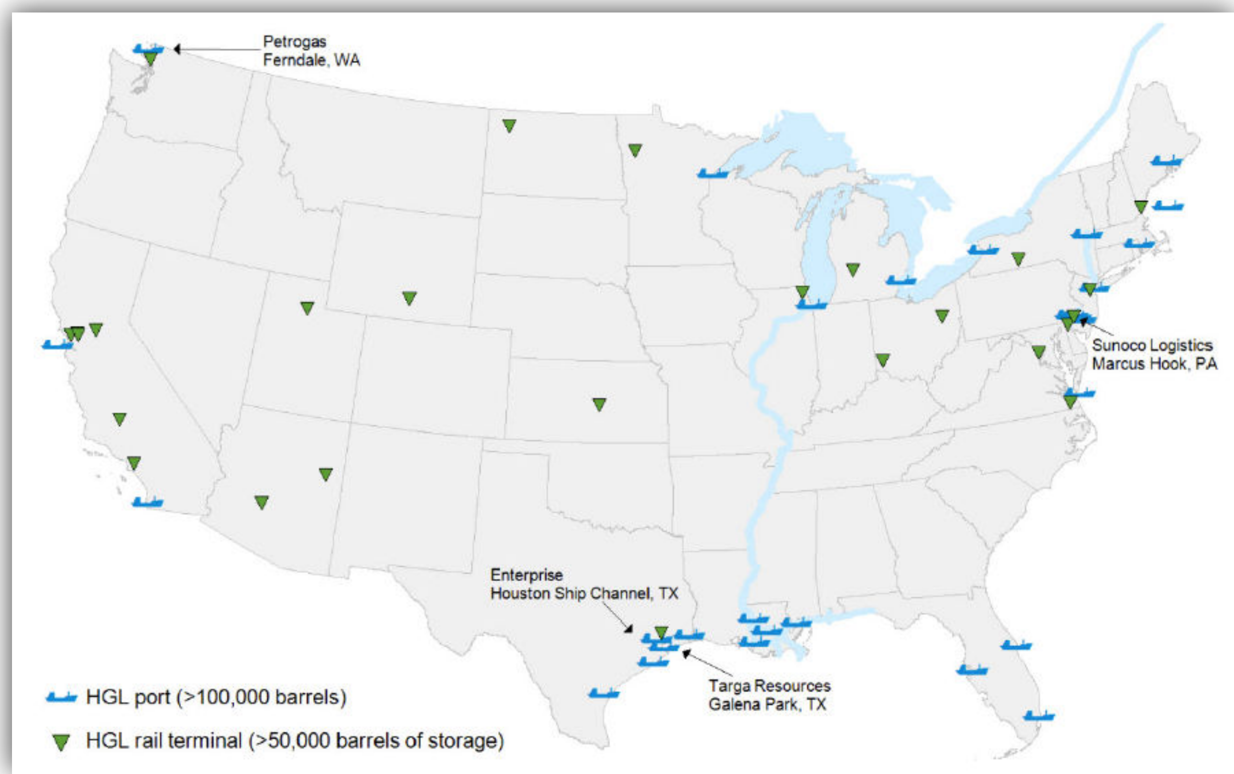
Figure 19 / North America NGL Pipeline Infrastructure (2013)



Source: (IHS 2013)

In locations where pipelines are not available, mixed NGLs may be transported refrigerated or under pressure by trucks, rail cars, or tanker/barges. Note that in North America, truck transportation of NGL is limited to 250 miles by safety restrictions. In addition, according to the 1920s Merchant Marine Act, also known as the Jones Act, only American-made, American-flagged, and American-manned ships can be used to deliver goods between US ports (BP 2015a; Chiaramonte 2013; EIA 2014f; IEA 2010; INGAA Foundation 2014). Figure 20 depicts existing rail terminals, waterways, and ports capable of handling hydrocarbon gas liquids.

Figure 20 / Existing US Rail Terminals, Waterways, and Ports Handling Hydrocarbon Gas Liquid (2014)



Source: EIA (2014f)

NOTE:

(1) EIA has identified 31 ports capable of loading and unloading HGL with greater than 100,000 barrels of storage capacity co-located at the port.

(2) LPG tankers come in a few varieties, with variation in size. The tankers can be fully pressurized, fully refrigerated, or a combination of pressurized and refrigerated, and they come in four size categories, including Very Large Gas Carrier (> 60,000 m^3), Large Gas Carrier (40,000—60,000 m^3), Medium Gas Carrier (20,000—40,000 m^3), and Small Gas Carrier (< 20,000 m^3).

(3) There are a limited number of marine terminals able to handle Very Large Gas Carrier (VLGC) in the United States. Ports configured for either cooled pressurized or fully pressurized gases typically load smaller ships destined for US and Latin American ports.

(4) Several companies such as Phillips 66, Targa Resources Partners, Sunoco Logistics, and Enterprise Products Partners have announced plans to expand or build new HGL export facilities, mostly along the Gulf Coast to take advantage of a growing excess supply of propane, normal butane, and ethane.

(5) EIA identified 26 rail terminals handling HGL with more than 50,000 barrels of aboveground storage. Rail movements of HGL are performed on manifest trains (i.e., trains

consisting of carloads of various products, not a single class of product, like unit trains). Because of the staging required to load a few tank cars of HGL, adequate underground or aboveground storage is needed. A tank car used to transport Y-grade must be able to withstand high pressures.

From this point onwards, processed dry gas and NGLs enter four separate subsystems, one of which is associated with NGLs and three of which are associated with processed dry natural gas, namely compressed dry natural gas (CNG), liquefied natural gas (LNG), and gas-to-liquids (GTLs).

Compressed Dry Natural Gas (CNG) Subsystem

Compressed dry natural gas (CNG) delivered via transmission pipelines is distributed to end-use markets primarily via local distribution pipeline systems. Compressed dry natural gas is transacted under a number of commercial arrangements, including direct-to-user, at market centers or hubs, and at city gates. Gas physical transfer and points of delivery associated with these arrangements differ as to be discussed as follows.

City Gate Transaction Process

At city gate, natural gas leaves the transmission pipeline network and enters the city gate station where *local distribution companies (LDCs)* add odorant and lower the pressure before distributing it via local distribution pipelines to residential and commercial customers (Adventures in Energy 2015a; C2ES 2011). Some LDCs have long-term gas supply and long-haul pipeline capacity contracts from the Gulf Coast, thus precluding them from taking advantage of abundant Marcellus and Utica shale gas supplies (Black & Veatch 2014).

Regardless of their supply sources, LDCs owned and operated distribution networks that include the networks of piping, stations, and meters. The networks of pipelines consist of larger distribution pipelines (called mains) and individual service lines branch off of the mains to reach each consumer. Services performed by LDCs also include billing, safety inspection, and providing natural gas hookups for new customers. Natural gas LDCs usually operate at a local or regional level and are typically *regulated* as monopoly utilities in their operating areas in which the rates charged are regulated at the federal and state level (API 2014b; C2ES 2011; EIA 2014a; Harris 2014; Marbek 2010; Naturalgas.org 2013d). Major LDCs in the United States are summarized in Table 4.

Table 4 / Major Gas Distribution Companies in the United States

Local Distribution Companies	Business Profile
Sempra Energy	San Diego based Sempra Energy is an energy services holding company with eight subsidiaries. Sempra's two largest subsidiaries, SoCalGas and SDG&E, distribute natural gas to more consumers than any other utilities company in the United States. As of December 2013, SoCalGas and SDG&E distribute natural gas to 21.3 and 3.2 million consumers, respectively, across Southern California.
Atmos Energy Corporation	Headquartered in Dallas, Atmos Energy Corporation distributes natural gas to more than 3.0 million residential, commercial, public authority and industrial customers across eight states in the southern United States. The areas that Atmos serves include large portions of West and Middle Texas, Kentucky, Tennessee, Virginia, Louisiana, Mississippi, Colorado and Kansas.
Pacific Gas & Electric Company	San Francisco-based Pacific Gas and Electric Company is a wholly owned subsidiary of PG&E Corporation. Pacific Gas and Electric provides 5.2 million customers electricity and 4.4 million customers with natural gas across Northern and Central California. As of December 2013, the company's natural gas system consists of 42,559 miles of distribution pipelines, over 6,000 miles of transmission pipelines, and a number of storage facilities, including eight natural gas compressor stations.
NiSource Inc.	NiSource Inc. is a holding company headquartered in Merrillville, IN. The company's natural gas distribution operations supply an estimated 3.4 million customers in a corridor running from the Gulf Cost throughout the Midwest to New England via 58,000 miles of pipeline. The majority of this distribution is done through the company's wholly owned subsidiary NiSource Gas Distribution Group, Inc. NiSource also owns six distribution subsidiaries that provide natural gas to another 2.6 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland and Massachusetts. NiSource distributes natural gas to its remaining 803,000 customers, located in northern Indiana, through other subsidiary NIPSCO.

Source: Harris (2014a)

Hub Transaction Process

Prior to the deregulation of the natural gas commodity market and the introduction of open access for everyone to natural gas pipelines, there was no role for natural gas marketers and market hubs/centers. Gas producers sold natural gas to pipeline operators who, in turn, sold the natural gas to LDCs and other large-volume natural gas users. LDCs sold the natural gas purchased from the pipeline operators to retail end-users. However, gradually over the past 15 years, natural gas marketing has become an integral component of the natural gas industry (Naturalgas.org 2013e). Natural gas marketers and brokers are less regulated by state agencies, allowing them to set prices according to market conditions (Harris 2014).

Physical marketing and trading markets

There are two distinct physical marketing and trading markets[11] for natural gas at natural gas hubs/centers, namely the *spot commodity market* and the *futures market*. The futures market consists of buying and selling natural gas under contract at least 1 month and up to 36 months in advance. Natural gas futures are traded on the New York Mercantile Exchange (NYMEX). The futures contracts that are traded on the NYMEX are Henry Hub contracts, meaning they reflect the price of natural gas for *physical delivery* at this hub. The price at which natural gas trades differs across the major hubs, depending on the supply and demand for natural gas at that particular point. The difference between the Henry Hub price and another hub is called the *location differential* (EIA 2014c; Naturalgas.org 2013e).

The spot market is the daily market in which natural gas is bought and sold through individually negotiated contracts for immediate or very near-term delivery, usually for a period of 30 days or less. Spot market contracts comprise mutual obligations to sell and buy a standard quantity of gas to be delivered and taken at a

[11] Physical marketing and trading of natural gas is distinguished from financial trading that involves derivatives and sophisticated financial instruments in which the buyer and seller never take physical delivery of the natural gas. There are two possible objectives to trading in financial natural gas markets: hedging and speculation. Some marketers who actively buy and sell in either the physical or financial markets are referred to as natural gas "traders" (Naturalgas.org 2013e). Financial trading of natural gas is outside the scope of this paper.

specific location at a uniform daily flow rate over the contract period. The Henry Hub in southern Louisiana is the best-known spot market for natural gas (API 2014b; EKT Interactive 2015b; Naturalgas.org 2013e). At the market hub, the title to natural gas is transferred between buyers and sellers (Ivanenko 2011).

The role of market centers/hubs in these trading markets involves two key services, including transportation between interconnections with other pipelines, and the physical coverage of short-term receipt/delivery balancing needs. Many of these centers also provide unique services that help expedite and improve the overall natural gas transportation processes, such as Internet-based access to natural gas trading platforms and capacity release programs. Most centers also provide title transfer services between parties that buy, sell, or move their natural gas through the centers (EIA n.d.).

Natural gas marketers

A natural gas marketer can be a producer of natural gas, pipeline marketing affiliate, distribution utility marketing affiliate, and independent marketer (Naturalgas.org 2013e).

Producer marketers are those entities generally concerned with selling their own natural gas production, or the production of their affiliated natural gas production companies. Today, producer marketers actively participate in gas spot and futures markets to manage their financial risks (EKT Interactive 2015b).

Non-producer marketers purchase gas from gas producers who may sell the gas at the wellhead or at the outlet of a gas processing plant (Harris 2014; Ivanenko 2011). These marketers may be large or small, and sell to LDCs, or to commercial or industrial customers that are either connected directly to pipelines or served by LDCs. Many marketing entities affiliated with LDCs focus on marketing gas for the geographic area in which their affiliated distributor operates; while major nationally integrated marketers operate on a nationwide basis (API 2014b; NaturalGAs.org 2013a, 2013e).

Regardless of the types of entities, marketers arrange the purchases and sales of natural gas either to resellers (other marketers and distribution companies), or to end-users without owning physical assets commonly used in the supply of natural gas, such as pipelines or storage fields. In states with residential choice programs, marketers serve as alternative suppliers to residential users of natural gas, which is delivered by an LDC in the areas (EIA 2014a). Marketers may own the natural gas being transferred, or may act as a broker without taking ownership of the natural gas. In the latter case, brokers simply act as facilitators, bringing buyers and sellers of natural gas together and facilitating its transportation and storage for a commission when the deal is executed (API 2014b; NaturalGAs.org 2013a, 2013e).

Direct Purchase Transaction Process

Some commercial and industrial end-users, typically large-volume users, bypass the LDC and arrange the *wholesale* purchase of dry natural gas from gas producer marketers or non-producer marketers. Today, gas producer marketers not only actively participate in gas spot and futures markets, but also directly negotiate long-term sales agreements with wholesale end-users. Some take it a few steps further by also marketing gas directly to small, retail end-users. The physical delivery (distinguished from commercial arrangements) of the wholesale purchased gas may be executed via LDC's local distribution systems (*on-system* users) in which the LDC is paid for the use of its pipeline to deliver the gas. Gas transported via LDC's system, but not purchased from that LDC is referred to as *transported gas*. In contrast, *off-system* users have pipeline laterals that are connected to transmission pipelines, thus receive purchased natural gas directly at the outlet points (Adventures in Energy 2015a; API 2014b; Eastern Shore 2015; EIA 2014a; EKT Interactive 2015a, 2015b; Naturalgas.org 2013b). About 55 percent of gas consumed by industrial users, such as chemical plants, is supplied off-system via mainline gas transmission systems (Ulama 2015).

NGL Subsystem

Mixed NGLs from processing plants arrived at specialized fractionation facilities that are concentrated in well-established formations near refinery and petrochemical facilities and ports along the US Gulf Coast. In this area, the long established fractionation hub of Mont Belvieu, Texas, currently has 8 major expansion projects under development with completion slated for the 2013–15 timeframe and an expected capacity addition of almost 700,000 b/d of fractionation capacity (EIA 2014f; IHS 2013).

New proposed facilities are concentrated in the major shale gas and tight oil formations, particularly the Marcellus-Utica, Eagle Ford, Bakken, and Permian (EIA 2014f). Amid this area emerges a new hub located at the intersection of the Pennsylvania, Ohio, and West Virginia borders, essentially in the heart of the Marcellus and Utica shale development. Nationally identified as the Houston, Pennsylvania hub is actually a complex of some 16 de-ethanizer and de-propanizer plants which will likely grow to become an interconnecting network of 25 individual facilities involved in the fractionation of NGLs. Meanwhile, smaller debottlenecks[12] are under way at the traditional fractionation hubs of Conway, Kansas, and Geismar, Louisiana (IHS 2013).

NGL Fractionation

At the fractionation plant, mixed NGL streams received from one or more gas processing plants are processed using distillation techniques (fractionation) to separate them into individual streams of marketable *base components* or *purity products* such as ethane, propane, normal butane, isobutane, and natural gasoline (EIA 2014f). Pentane and butane are liquid at normal temperatures, thus separating them from the natural gas stream is relatively inexpensive. In contrast, propane and especially ethane can only be separated by deep refrigeration which is energy intensive, thus more costly. *Shallow cut* fractionation facilities aim to recover most of the butane, pentane, and heavier molecules; while *deep cut* facilities recover these heavier molecules as well as propane and most of the ethane by expensive extra refrigeration (Kemp 2012). Once fractionated, the individual components have their own applications (see Figure 21) and are sold separately (Follette and He 2012; IEA 2010; NaturalGas.org 2013c; Pan 2014). Overview of NGL production and price trends are provided in Appendix 4.

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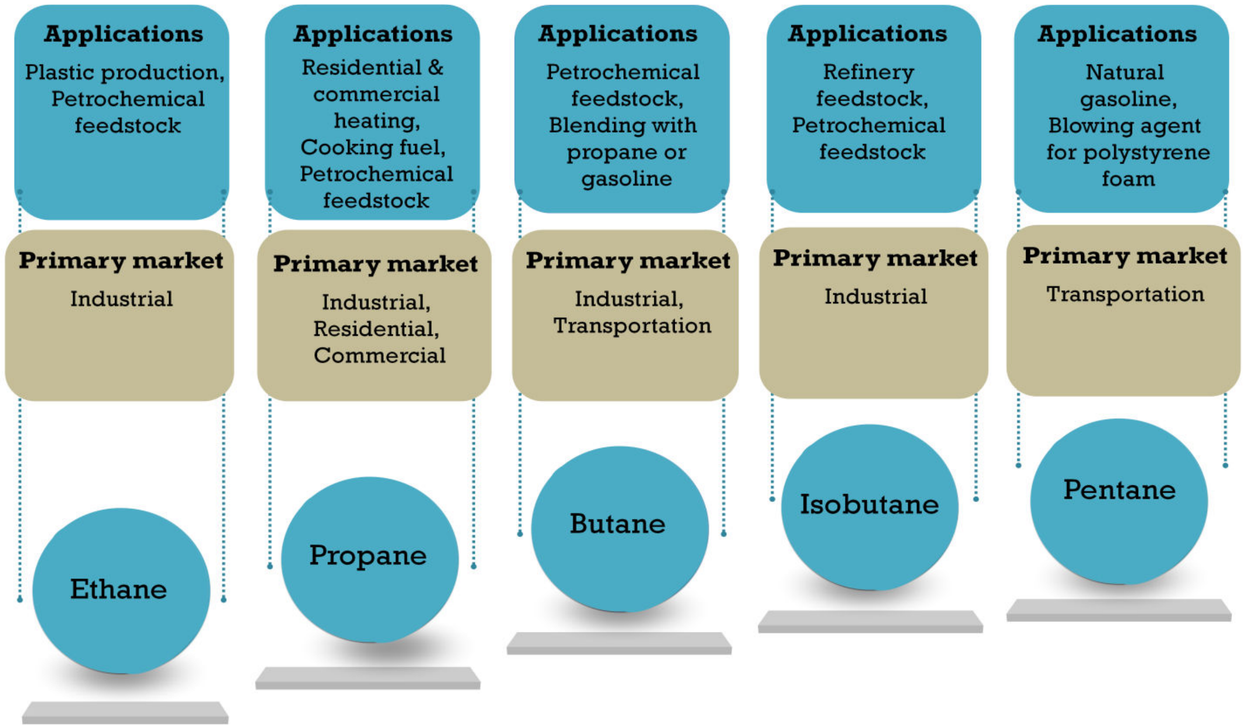
[12] **Debottlenecking** refer to increasing production capacity of existing facilities through the modification of existing equipment to remove throughput restrictions. Debottlenecking generally increases capacity at a much lower cost than that of building new facilities (www.encyclo.co.uk).

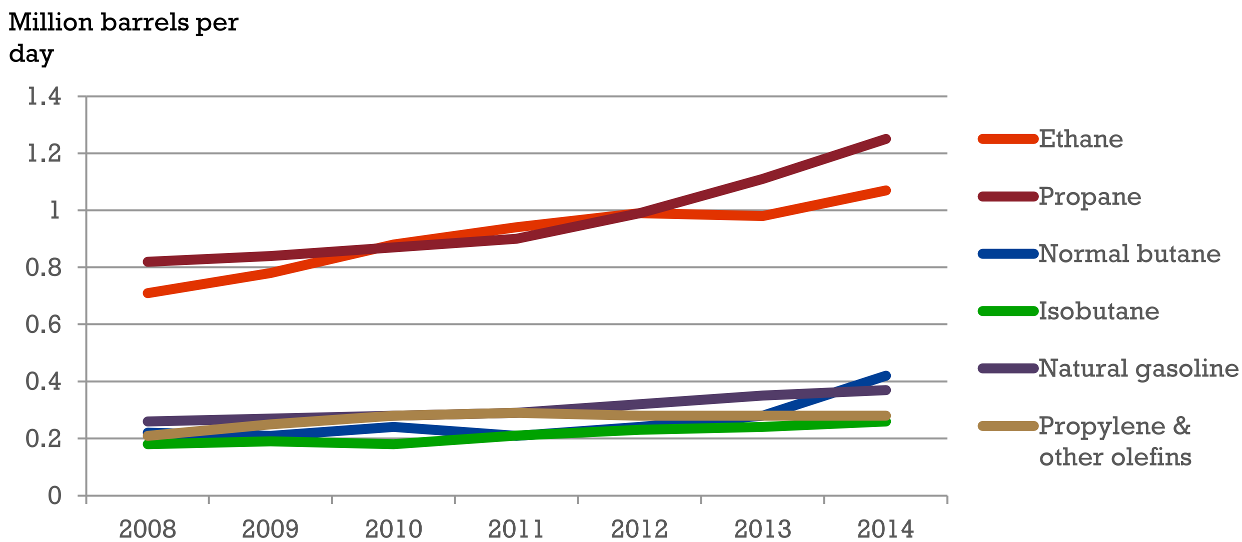
Figure 21 / Individual Natural Gas Liquid Product Applications



Source: Created based on Tortoise Capital Advisors (2014)

Among the NGL individual products, propane and ethane are dominating products, accounting for approximately 70 percent of all hydrocarbon gas liquid products produced each year since 2008 (see Figure 22**Error! Not a valid bookmark self-reference.**). Currently, total propane produced by gas processing plants and oil refineries remains the largest-volume and highest-revenue product. However, ethane production levels are increasing as US and Canadian petrochemical companies are shifting their feedstock slates toward ethane. Petrochemical companies are investing in additional ethylene capacity with the expectation of continued low ethane prices and increasing demand for ethylene intermediate product exports. Associated investment in ethane pipelines and export terminals also continues (EIA 2014f). This report focuses on these two key NGL products in examining subsequent subsystem processes. Corresponding market trends are discussed in Appendix 5.

Figure 22 / US Production of Hydrocarbon Gas Liquids (2008–14)



Source: Created based on EIA (2014f)

NOTE: 2014 includes January–August.

Ethane: Storage, Transportation, and Distribution

Ethane storage

Ethane (and its derivative ethylene) storage costs are higher than those for other NGL products because of their higher vapor pressures that usually require either cryogenic cooling to store as a liquid or large volumetric storage as a gas. Small volumes of liquid ethane and ethylene are typically stored temporarily (days to weeks) in bullet-shaped, cryogenically cooled aboveground tanks specifically built to manage higher pressures. These aboveground storage tanks are usually part of an import/export facility or petrochemical complex. However, for large-volume, relatively long periods (months) storage, ethane and ethylene are usually stored as a gas in underground salt caverns (both bedded and salt domes) (EIA 2014f).

Ethane transportation and distribution

Because ethane is relatively difficult to liquefy and transport in bulk, it has traditionally not been traded in global markets, but finding a home instead in facilities adjacent to where it is processed. For these domestic markets, ethane is transported over land primarily by pipeline. To be transported by sea, ethane must be refrigerated to a low temperature, compressed to a high pressure, or a combination of both. These factors limit the types of vessels that are capable of transporting the product in its liquid state (EIA 2014f; Janssens 2015).

At present, ethane-capable ships suitable for long-haul transport are in very short supply, all of which are small-scale vessels that have only been used in miniscule volumes on short-haul North Sea routes. The latest figures from IHS SeaWeb show that there are 141 ethane and ethylene carriers worldwide with capacities ranging from 918 m^3 to 22,000 m^3 (Janssens 2015; Lloyd's Register 2014). However, recent development suggests that the wide-scale ocean shipping of ethane aboard purpose-built tankers of much larger size called Very Large Ethane Carrier (VLEC) with a projected capacity of between 84k and 90k cubic meter (cbm), is becoming a reality (Lloyd's Register 2014; Miller 2014).

Both transportation processes, namely ethane pipeline and marine shipping, are faced with challenges in realizing ethane growth opportunities in the chemical markets. We discuss these challenges and associated trends as follows.

Ethane pipeline transportation challenges

In over land movements, ethane which is produced in growing volume from the liquid-rich Marcellus shale plays faced a unique transportation challenges compared to other NGL products. Ethane demand is highly dependent on the North American petrochemical industry, which consumes virtually all of the ethane produced in the United States. Thus, the ability to cost-effectively transport ethane from Marcellus shale plays to petrochemical demand centers could make ethane a valuable commodity for gas producers. There are two potential petrochemical markets for Marcellus ethane, including Gulf Coast plants (the largest NGL market in North America), and the "northern tier" petrochemical markets of Chicago, IL, and Sarnia, Ontario. However, challenges arise for three reasons: (1) Marcellus ethane is not located where the demand is; (2) there are essentially no regional ethane markets in the Northeast; and (3) the infrastructure does not yet exist to move ethane to markets outside the region (Braziel 2011).

To address the foregoing challenges and garner potentials in petrochemical markets, a number of proposed projects are announced to move ethane, mixed NGL stream (Y-grade), or some other mix of ethane and heavier NGL products to the petrochemical markets. Among the proposed projects are the followings (Braziel 2011):

- **El Paso Midstream Group's Marcellus Ethane Pipeline System (MEPS)** is designed to transport up to 60,000 b/d of ethane to interconnect points with third-party ethane pipelines and storage facilities in the Baton Rouge, Louisiana, area. The transportation rate on MEPS would be $7.56/barrel on a committed basis.
- **Mariner,** a joint venture between MarkWest Liberty Midstream and Sunoco Logistics, uses marine vessels to move as much as 50,000 b/d of ethane to the Gulf Coast. It includes a 45-mile pipeline from a fractionation plant in MarkWest's Houston, Pennsylvania, to an interconnect with a Sunoco Logistics pipeline at Delmont, Pennsylvania, where it connects to pipelines to new refrigerated storage facilities at a Sunoco Delaware River marine port. The ethane would then be loaded on vessels to ship to unspecified unloading facilities on the Gulf Coast (possibly also to international ports). Many project details have yet to be specified, but costs are expected to be in the $6.30–$6.70 per barrel range.
- **Kinder Morgan's Cochin Marcellus Lateral Expansion** would move NGLs from Marcellus fractionation plants to chemical markets near Sarnia and Chicago using the Cochin Pipeline. It includes a new 230-mile NGL pipeline from the Marcellus to the Cochin interconnect at Riga, Michigan. Initial throughput capacity is 75,000 b/d (expandable to 175,000 b/d), and project costs are estimated to be between $3.78 and $7.14 per barrel, depending on total firm commitments.
- **Buckeye and Nova Chemicals Corp.'s Marcellus Union Pipeline** is designed to ship Marcellus NGLs to the NOVA Chemicals Corunna olefins cracker near Sarnia. It consists of building a 12- or 16-inch pipeline either to Detroit (and

a 12-inch pipeline to Sarnia), or to Windsor, Ontario (using an existing pipeline to Sarnia). The estimated tariff is $5.04–$5.88 per barrel.

- **The private-equity funded Cumberland Plateau Pipeline** includes constructing a pipeline to transport 75,000–125,000 b/d of ethane initially (then, possibly other NGLs in the future) to the Gulf Coast. The pipeline would originate at fractionators in Pennsylvania and West Virginia, and deliver into Dow, Williams, and PetroLogistics connections near Baton Rouge at an approximate transportation cost of $0.17 per gallon.

Ethane ocean shipping challenges

At present, ethane ocean shipping challenges arise due to the short supply of ethane-capable ships suitable for long-haul transportation. Nevertheless, first began to take shape in early 2013, the Very Large Ethane Carrier (VLEC) shipping model in the United States is developing, with shale gas production boom deemed to be a significant driver (Janssens 2015; Lloyd's Register 2014).

Another significant driver for the US ethane shipping model comes from the unexpected announcement in April 2014 by Enterprise Products Partners to build a fully refrigerated ethane export facility on the Houston Ship Channel. The terminal is designed to have an aggregate loading rate of up to 240,000 barrels per day. An 18-mile, 24-inch diameter ethane pipeline will be constructed from Mont Belvieu to supply the terminal which will be integrated with Enterprise's existing natural gas liquids complex at Mont Belvieu, Texas. The terminal is expected to begin operations in the third quarter of 2016. Firm, long-term contracts for ethane storage, transportation, refrigeration, and loading services at the terminal as of 2014 suggest that the capacity is about 85 percent sold (Fisher 2014; Janssens 2015; Miller 2014).

The new ocean trade would be long haul, from the US East and Gulf Coasts to Northwest Europe initially, and then from the United States to Asia in the intermediate term. Special-built for ethane shipping, Evergas' 27,500 cubic metre (cbm) newbuilds are due for delivery in 2015, when ethane is expected to be available for export via Sunoco Logistics' terminal in Marcus Hook, Pennsylvania. Beyond Evergas, four 35,000cbm ethane marine carriers are being built for delivery in 2016 to Navigator Holdings. The new VLECs will use existing terminals that are currently capable of accommodating Very Large Gas Carriers (VLGCs) as they have similar dimensions, and could be easily adapted for ethane handling (Lloyd's Register 2014; Miller 2014).

These oceangoing ethane trades will be like that of a pipeline ethane trade, featuring supply contracts of 10 years-plus duration. The underlying factor for such a practice is that individual VLECs cost in excess of US$100 million per unit, resulting in most owners seeking to lessen the risk by having confirmed decade-plus export contracts. The long-term contracts can be used by shipowners to back newbuild financing and support new publicly listed Master Limited Partnerships (MLPs). This feature differs from LPG vessel market where spot market is available. In fact, experts do not expect a spot trade in ethane anytime soon (Janssens 2015; Miller 2014).

Propane: Transportation, Storage, Bottling, and Distribution

Propane transportation and storage

Propane can be transported via LPG rail cars, barges, tanker trucks, and pipelines to *intermediate storage centers* and *cylinder filling plants* (Allegro 2013; API 2014b; EKT Interactive 2015b; Goellner 2012; IEA 2010; Ivanenko 2011; McAllister 2014; NaturalGas.org 2013c; Pan 2014; WLPGA n.d.).

An intermediate storage center is built for storage of LPG in large, bulk volumes. Storage is critical for seasonal product like propane. Propane can be stored as pressurized liquids at surface temperatures in aboveground, standard welded steel tanks (similar to petroleum tank farms), which is used for short-duration storage and rapid delivery. For larger long-term storage, underground storage is the least expensive option. Underground caverns—primarily located in salt formations, both bedded and domed formations—are most commonly used in the United States. EIA identified 28 large storage facilities (>5 million barrels capacity) that are underground caverns, and another 20 mid-sized storage facilities (>1 million barrels capacity) that are mostly underground caverns. EIA also identified 47 smaller underground storage facilities (0.3–1 million barrels capacity), many of which are complemented by co-located aboveground storage or are in proximity to refineries, splitters, gas processors, fractionators, ports, rail terminals, and in-transit pipeline stocks (EIA 2014f).

From the storage centers, bulk trucks distribute propane (and/or other LPGs) to various bulk-volume buyers such as petrochemical plants, LPG export terminals, and LPG cylinder filling plants (BNH Gas Tanks n.d.; WLPGA n.d.).

Propane bottling and distribution

At cylinder filling/bottling plants, cylinders are filled with the intended product such as butane, propane, or specific LPG mixtures. LPG is sold and filled by weight (e.g. by reference to individual tare weights and a specified fill or weight of LPG) in pressured cylinders (BNH Gas Tanks n.d.; WLPGA n.d.).

Cylinder filling plants vary in scale and sophistication. Some plants are simple manual, single-station operations with stationary LPG cylinder filling scales that fill small numbers of cylinders per day. Others are high-technology, semi- or fully automatic plants for fast filling in large quantities like 5,000–10,000 cylinders per day, and serve hundreds of thousands of consumers. From the cylinder filling plants, trucks transport propane cylinders to retailers, private residence, commercial stores, and LPG vehicle fueling stations (BNH Gas Tanks n.d.; WLPGA n.d.).

LNG Subsystem

Via transmission pipelines, dry natural gas extracted from onshore gas well is transported to a large-scale liquefaction facility, which can be land-based or floating facilities, where LNG is produced. This large-scale LNG facility is distinguished from a number of smaller scale facilities that operate at a more local level further downstream of the natural gas supply chain (IEA 2010; Strande and Johns 2013). Key sequential processes involved in the LNG subsystem are: liquefaction and storage, LNG transportation, receiving/offloading and storage, regasification, and market distribution.

Liquefaction and Storage: Onshore and Floating Systems

Dry natural gas delivered either from processing plants or from field treatment facilities is first liquefied at an onshore or floating LNG (FLNG) liquefaction facility.

Onshore liquefaction system

Onshore liquefaction facilities often consist of several standardized installations arranged in parallel, called *liquefaction trains*. LNG trains condense dry natural gas into a liquid at atmospheric pressure by cooling it to -260° F. This liquefied state enables the natural gas to be shrunk to 1/600th of its original gaseous volume. This reduction in volume enables natural gas to be transported economically over long distances (Eaton 2014; ExxonMobil 2011; IEA 2015; Office of Fossil Energy n.d.; Origin Energy n.d.; Pettit, Darner, and Jelinek 2013).

A significant reorientation of liquefaction facilities and connecting pipeline systems to accommodate export is underway in the United States. For many decades, the United States is LNG net importers. Most US pipelines that bring regasified LNG imports originate in the Gulf of Mexico, and move the products toward the industrial heartland. Today, an increasing number of export-oriented LNG projects are proposed in the United States, principally, but not exclusively, on the Gulf Coast. The already attractive investment in a Gulf of Mexico LNG export facility will become even more so by the potential transit-time reductions upon completion of the Panama Canal expansion[13] (e.g. estimated transit time savings of 11.4 days and shipping cost savings of $1.50 per million British Thermal Units (MMBtu) from the Gulf Coast to Japan). The expanded channel will be able to accommodate ships with twice the cargo capability of vessels that currently traverse the existing canal, including a majority of world's LNG tankers. Currently, only 21 of the existing global fleet of 370 LNG tankers can traverse through the Panama Canal, but no LNG trade is conducted through the canal (Andreoli 2013; Andrew and Vukmanovic 2013; IHS 2013; IEA 2014; INGAA Foundation 2014; Ratner et al. 2015).

Export-oriented LNG projects proposed in the United States include both new LNG export facilities, and LNG regasification facilities historically used to receive LNG imports that are repurposed into liquefaction facilities for exports. As of the

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[13] The major expansion of the Panama Canal was previously scheduled expected to be finished in December 2015 and will open for business in the beginning of 2016. However, construction time missed due to the negotiation deadlock could push back the start date by at least a number of months if not multiple years (AP 2014; IGU 2014).

beginning of January 2015, there have been 48 applications for permits to construct liquefaction facilities in order to export domestically produced natural gas as LNG. The total capacity proposed is approximately 42 billion cubic feet per day (bcf/d) (Ratner et al. 2015). A summary of US LNG export-oriented liquefaction facilities, features, stakeholders, and status is provided in Table 5.

Table 5 / LNG Export Liquefaction Facility Projects in the United States

LNG Export Liquefaction Facility	Features & Operator	Status
Sabine Pass LNG	◘ Located on Louisiana's Gulf Coast, converted from import facility to export liquefaction facility ◘ Six liquefaction trains capable of processing over 3.5 Bcf/d of natural gas ◘ Operated by Cheniere Energy ◘ Signed long-term LNG supply contracts for 20 years with four companies: BG, Gas Natural, Kogas, and GAIL ◘ Dual purpose import and export LNG facility	◘ The only project approved by both US DOE to export LNG to Free Trade Agreement (FTA) and non-FTA countries, and the Federal Energy Regulatory Commission (FERC) ◘ The first under-construction US project. Sabine Pass LNG T1 (first train) expected to come online in 2016.
Annova LNG	◘ Operated by Annova LNG LLC	Pre-final investment decision (FID); FTA exports; Expected online 2018
Barca LNG	◘ Operated by Barca LNG	Pre-FID; FTA exports
Cameron LNG	◘ 648 Bcf/y, 3-train facility ◘ Operated by Sempra Energy ◘ Tolling agreements with Mitsubishi (Japan, 16.6%), Mitsui (Japan, 16.6%), and GDF Suez ◘ Dual purpose import and export LNG facility	Pre-FID; FTA exports; FERC review in process; Expected online 2019
Cove Point	◘ Located in Cove Point, Maryland, on the Chesapeake Bay waterfront community ◘ Operated by Dominion Resources	Pre-FID; FTA and non-FTA exports; Expected online 2017

LNG Export Liquefaction Facility	Features & Operator	Status
	▫ Dual purpose import and export LNG facility ▫ To provide global gateway for PA shale gas	
Corpus Christi	▫ Operated by Cheniere Energy	Pre-FID; FTA and non-FTA exports; Expected online 2018
Delfin LNG	▫ Operated by Delfin FLNG	Pre-FID; FTA exports; Expected online 2017–21
Elba Island LNG	▫ Operated by Southern LNG ▫ Dual purpose import and export LNG facility	Pre-FID; FTA exports; Expected online 2016
Eos LNG	▫ Operated by Eos LNG	Pre-FID; FTA exports
Freeport LNG	▫ Three trains (6 bcm/y each) ▫ Operated by Freeport LNG Liquefaction ▫ Dual purpose import and export LNG facility	Pre-FID; FTA and non-FTA exports; Expected online 2018–19
Gasfin LNG	▫ Operated by Gasfin Development	Pre-FID; FTA exports; Expected online 2019
Golden Pass LNG	▫ Operated by Golden Pass Products ▫ Dual purpose import and export LNG facility	Pre-FID; FTA exports; Expected online 2018
Gulf Coast LNG	▫ Operated by Gulf Coast LNG Export	Pre-FID; FTA exports
Gulf LNG (Clean Energy)	▫ Operated by Gulf LNG ▫ Dual purpose import and export LNG facility	Pre-FID; FTA exports; Expected online 2019
Jordan Cove LNG	▫ Operated by Veresen	Pre-FID; FTA exports; Expected online 2018
Lake Charles LNG	▫ Operated by Trunkline LNG ▫ Dual purpose import and export LNG facility	Pre-FID; FTA and non-FTA exports; Expected online 2019–20
Lavaca Bay	▫ Operated by Excelerate Energy	Pre-FID; FTA exports; Expected online 2018
Louisiana LNG	▫ Operated by Louisiana LNG Energy	Pre-FID
Main Pass Energy Hub LNG	▫ Operated by Freeport-McMoran Energy	Pre-FID; FTA exports; Expected online 2017

LNG Export Liquefaction Facility	Features & Operator	Status
Magnolia LNG	▫ Operated by LNG Limited	Pre-FID; FTA exports; Expected online 2018–19
Oregon LNG	▫ Operated by Oregon LNG	Pre-FID; FTA exports; Expected online 2018
South Texas LNG	▫ Operated by Pangea LNG	Pre-FID; FTA exports; Expected online 2019–20
Venture Global LNG	▫ Operated by Venture Global Partners	Pre-FID; FTA exports
Waller Point LNG	▫ Operated by Waller Marine Inc.	Pre-FID; FTA exports; Expected online 2016

Source: Black & Veatch (2014), Cohen & Steers (2014), Eaton (2014), EIA (2014c), Global LNG (2015), Hanson and Simko (2015), IEA (2012a), IGU (2014), Maring and Mintz (2014), Philips (2013), Ratner et al. (2015)

NOTE: Most LNG export liquefaction facilities seeking approvals are limited to transporting LNG to the 20 countries holding free-trade agreements (FTA) with the United States. None of FTA countries are major importers of gas; and only Canada, Chile, Dominican Republic, Mexico, and South Korea have existing LNG import terminals (Cohen & Steers 2014; Ratner et al. 2015).

Floating liquefaction (FLNG) system

A relatively new technology, FLNG facilities are liquefaction systems aboard a ship designed as a solution for developing offshore gas fields and, in some instances, stranded onshore gas fields.[14] In recent years, FLNG technology quickly became the leading option in developing offshore, medium- or small-size gas fields (1 to 3 trillion cubic feet) that are numerous in Australasia and in Gulf of Guinea (Parker 2011; Sember 2011; Weeden 2014). Appendix 6 highlights FLNG projects under development, three of which are in the United States where FLNG facilities are used to accommodate onshore gas fields.

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[14] Discovered gas fields are deemed "stranded" or not commercially producible for either geographic limitations or economic reasons, resulting in the gas resource being left unused. The former stems from the gas fields being small in size and locating too remotely from a market for natural gas, making construction of a pipeline prohibitively expensive. The latter stems from situations where the local market for gas is too small, or the production would create oversupply in the market (PetroWiKi). Technologies being developed to exploit this untapped resource are liquefaction and gas-to-liquid technologies.

Two different FLNG models are currently employed, namely LNG production, storage, and offloading models (LNG FPSOs) and floating liquefaction, storage, and offloading (FLSO) facilities (without production capability) (Bresciani, Inia, and Lambert 2014; Cadei et al. 2013; IEA 2011). The process begins with an FLNG vessel being anchored over the subsea gas field. When an FLSO vessel is used, production fluid—consisting of gas, condensate and Produced Formation Water (PFW)—extracted by subsea production system is brought up using flexible risers to offshore central processing platform for treatment and processing similar to procedures discussed in the field treatment and plant processing sections. The processed gas now stripped of NGL and impurities is transferred to the FLSO ship where LNG trains liquefy the dry gas. LNG from the process trains is transferred directly to dedicated atmospheric pressure storage tanks in the hull of the FLNG facility, prior to being offloaded to LNG carriers for transportation to market destination (Cadei et al. 2013).

When an LNG FPSO is used, the process is similar to that of FLSO, except that the treatment and processing activities are conducted on the LNG FPSO instead of offshore central processing platform. The production fluids extracted from subsea well are brought up using flexible risers and transported directly to the turret of the floating structure. The production fluid is then delivered from the turret to the receiving area where the treatment starts, involving the separation of well fluids into wet gas, condensate, and PFW. Treated gas is then undergone further processing similar to plant processing processes to produce dry natural gas that is then liquefied to produce LNG. The LNG is transferred to storage tanks, and then offloaded to LNG carriers destined to markets (Cadei et al. 2013).

Two main options of offloading systems are currently available: *side-by-side transfer* or *tandem transfer*. The side-by-side transfer is carried out by a shuttle tanker temporarily moored alongside the FLNG facility. The transfer operation of the LNG is performed through a rigid connection between the arms located on the side of the FLNG and the carrier's midship manifold. The operation is normally supported by tugboats. This method is well proven and the shuttle tanker does not need to have special transfer equipment. However, calm weather and sea are required for this offloading system since the loading arms do not allow for a wide range of relative motion. These difficulties can be managed with the use of tandem transfer system that requires shuttle tankers equipped with tandem technologies capable of dynamic positioning. There are several different tandem technologies available like aerial hoses, submerged hoses, floating hoses, and motion compensating structures incorporating rigid arms (Cadei et al. 2013; Nilsson and Hjörne 2012).

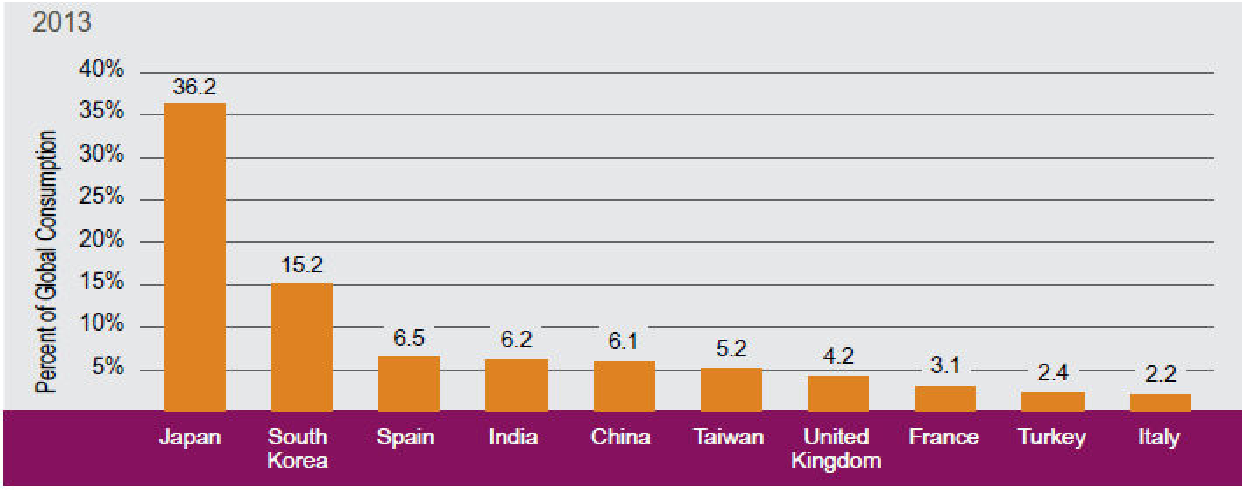
LNG Line-haul Transportation: Marine LNG Shipping

The stable, non-corrosive form of LNG makes it more easily and more economically transportable over a long distance. LNG can be moved in specially-designed insulated containers by ocean LNG carriers or trucks, albeit few truck shipments of LNG occur in the United States, mainly for the transportation to Canada and Mexico (ACSF 2012; C2ES 2011; EIA 2014a; Pipeline 101 2013). Transportation of LNG on rail is not yet available. The technology is still in infancy and so far no tank car is permitted to carry uncertified fuels like LNG on US rails. Nor are there enough plants that convert natural gas to LNG to support a robust gas-by-rail market (McAllister 2014).

Following liquefaction, whether at land-based or floating facilities, LNG is generally loaded onto specialized ocean-going tankers for shipment to a receiving terminal in the destination country. LNG carriers are double-hulled ships specially designed to handle the low temperature of LNG, and to prevent hull leaks and ruptures in the event of accident. The LNG is stored in insulated tanks[15] (generally 4 to 5 per tanker) at a temperature of -163°C and at atmospheric pressure to limit the amount of LNG that boils off or evaporates. This boils off gas is sometimes used to supplement fuel for the carriers (California Energy Commission 2015b; IEA 2015; Office of Fossil Energy n.d.; Origin Energy n.d.). Figure 23 shows top destinations of export LNG, with top five world's largest LNG importers including Japan, South Korea, Spain, India, and China, respectively.

Figure 23 / World's Top LNG Importing Countries

[15] There are currently three types of LNG carrier, each corresponding to a different tank design: membrane tanks, spherical tanks, and IHI Prismatic tanks (EKT Interactive 2015c).



At September 2013. Source: BP Statistical Review of World Energy, 2013.

Source: Cohen & Steers (2014)

As discussed previously, marine shipping is a primary means of line-haul, long-distance transportation of LNG. LNG carriers are not only among the most sophisticated types of cargo vessels, they are also among the most costly. Only about ten shipyards in the world are capable of building them (Total n.d.). Therefore, LNG marine shipping market consists predominantly of dedicated assets for specific routes booked under long-term (20–25 year) contracts. While LNG shipping spot market is used, it is still small and fragmented. The spot market currently exists mainly to cover imbalances as a result of, for instance, delays in terminal expansion or maintenance (Engelen and Dullaert 2010; Ruester 2010).

The need for longer-term contracts is rooted in the high capital costs of LNG carriers and the mutual need of LNG buyers and sellers to plan investments. The sellers of LNG need buyers to start up regasification terminals needed for their products, while buyers need to secure LNG supply and associated shipping capacity for transportation (Engelen and Dullaert 2010). More recently, there has been a very large increase in the sizes of vessels ordered to as much as 250,000 cubic meters. While larger vessels have the advantage of reducing transportation and overall LNG delivery costs, this size increase will affect the design of the LNG facilities and receiving terminals to accommodate larger ship and larger volume of LNG cargo. In other words, large-scale LNG facilities and receiving terminals are likely to be required (EKT Interactive 2015c).

Receiving and Storage

Once an LNG carrier arrives at the receiving terminals, it is moored at the unloading dock where the ship's unloading pumps unload the LNG into onshore pipes specially designed to withstand the extremely low temperatures (below -160°C). This process is completed in less than 12 hours. Boil-off gas is returned to the ship to maintain pressure in the cargo tanks (EKT Interactive 2015c; Elengy n.d.; Gas in Focus 2013; IEA 2015; Office of Fossil Energy n.d.; Origin Energy n.d.; Strande and Johns 2013).

The LNG then flows through the pipes to onshore, above-ground cryogenic LNG storage tanks that use auto-refrigeration to keep their contents cold at a temperature of -163°C. While in the storage tanks, despite the high-quality insulation, a small amount of heat still penetrates the LNG tanks, causing minor evaporation. The resulting boil-off gas is captured and fed back into the LNG storage tanks using compressor and recondensing systems (Adventures in Energy 2015a; EKT Interactive 2015c; Elengy n.d.; Gas in Focus 2013; IEA 2015; Office of Fossil Energy n.d.; Origin Energy n.d.; Strande and Johns 2013).

In some destination markets with limited or no onshore storage capacity, LNG Floating Storage Units (FSUs) are used for temporary storage of LNG before being transferred to the regasification facilities. In this model, LNG is loaded from LNG carriers to the FSU by ship-to-ship transfer systems described earlier (Gupta 2014). Nevertheless, today most receiving terminals are built with onshore storage tanks. Onshore storage can either be a flat-bottom tank with a capacity ranging from 4,000 m^3 to 200,000 m^3, or a horizontal or vertical, vacuum-jacketed, pressure tank for smaller amounts of LNG storage (less than 1,000 m^3/tank) (Gas in Focus 2013a).

The LNG is subsequently extracted from the storage tanks either for re-exportation or distribution to domestic markets.

LNG Re-exportation

For the purposes of federal regulation, LNG volumes that are re-exported from the United States after being imported from third countries are not treated the same way as exports of domestically produced natural gas. The US government does not ban the export of foreign-made LNG arriving to the US regasification terminals. At the time of this writing, seven companies have received permission to re-export LNG cargos that are imported from foreign countries with four applications pending. For terminal operators with active re-export permits, foreign LNG cargos are received, hold in storage, and then reloaded onto LNG carriers for shipment to foreign markets (Ratner et al. 2015).

US LNG re-export volumes are small, but have been growing substantially since 2009. The United States imported less than 1 percent of its natural gas in the form of LNG in the past couple of years (compared to a peak of 3% in 2007), primarily through the Everett terminal near Boston and the Elba Island terminal in Georgia (API 2014b). Declines in LNG imports have resulted in idle capacity at many US import terminals. The re-export business allows the LNG import terminals with re-export authorization to take advantage of the idle capacity and provides arbitrage opportunities by storing foreign-sourced LNG for period of world price increases. This trend almost doubled US LNG exports to other countries, including new recipients such as Brazil, India, Spain, and the United Kingdom (IEA 2012a, 2014b; Ratner et al. 2015).

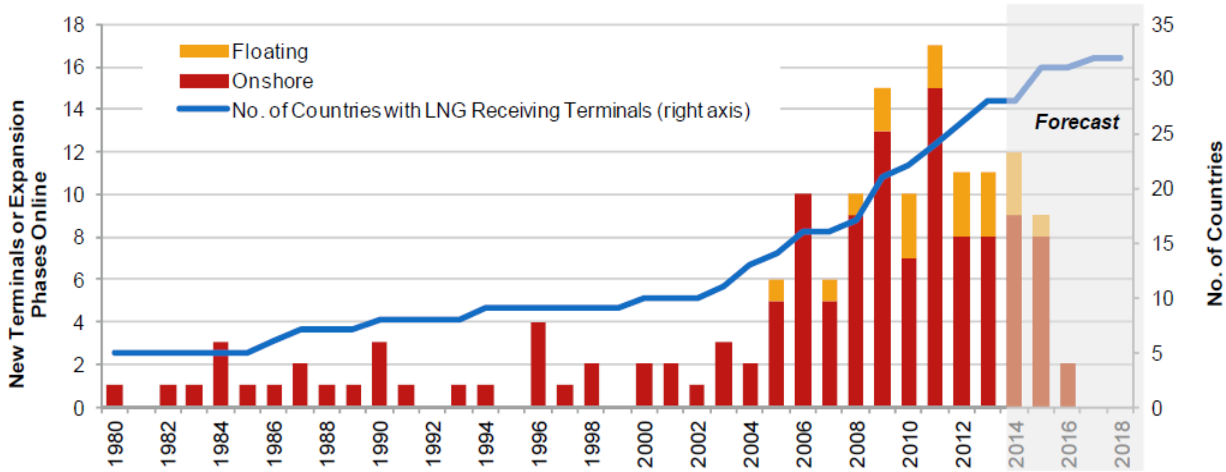
Domestic Market Distribution as LNG

For distribution to domestic markets, LNG extracted from the storage tanks can be loaded in liquefied form onto LNG tanker trucks for transportation. LNG transported by LNG trucks is vital as a means to supply natural gas to distribution sites for LNG fuel or industrial sites that are not connected to natural gas transmission grid (Elengy n.d.; ExxonMobil 2011; FERC 2015; Northeast Gas Association 2015b; Ratner et al. 2015).

Domestic Market Distribution as Dry Gas after Regasification

Alternatively, LNG can be regasified at the receiving terminals to turn the product back into gaseous form and then injected into a pipeline system for distribution throughout a gas system (Adventures in Energy 2015a; ExxonMobil 2011; FERC 2015; Northeast Gas Association 2015b; Ratner et al. 2015). Regasification of LNG can be performed using onshore and floating systems as further described below. Figure 24 depicts LNG receiving terminal development trends in the global markets.

Figure 24 / Global LNG Receiving Terminal Development



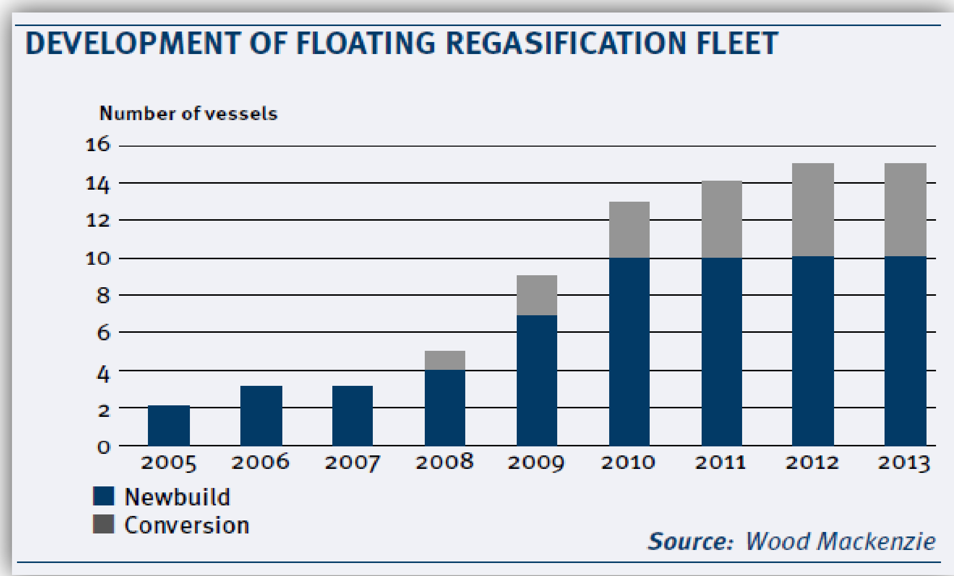
Source: IGU (2014)

Regasification: Onshore and Floating Systems

Regasification of liquefied gas consists of gradually warming the LNG back up to a temperature of over 0°C (Gas in Focus 2013a). The regasification facilities can be either an onshore terminal or a floating system, commonly known as a floating storage and regasification unit (FSRU) (Strande and Johns 2013; Wärtsilä 2014). An FSRU is essentially an LNG carrier using the cargo tanks as onboard storage and having the regasifacation units installed on the deck area from where the vapourized gas is transported ashore with the use of an associated subsea pipeline (Nilsson and Hjörne 2012; Strande and Johns 2013; Wärtsilä 2014).

FSRUs have begun to fill in the void in markets near populated areas where permitting issues have delayed or completely prevented the construction of receiving terminals (Parker 2011). FSRUs may be purpose-built or converted from an LNG carrier. The latter requires installation of vaporizers, loading arms, and extra pumps, along with the upgrades of power, electrical, and control systems. In general, time required for the conversion is 18 months for engineering and 6 months for the shipyard work (Gupta 2014). Figure 25 depicts trends in the development of FSRU fleet.

Figure 25 / Development of Floating Storage and Regasification Unit (FSRU) Fleet



Source: Parker (2011)

Once returned to its gaseous state, the natural gas undergoes odorizing and treatment processes needed to bring its characteristics in line with regulatory and end-user requirements. Its heating value, for example, may be tweaked by altering nitrogen, butane or propane content, or blending it with other gases. It is then compressed and metered before it is fed into pipeline laterals that connect to main natural gas pipeline transmission systems (Elengy n.d.; Gas in Focus 2013a; Ulama 2015). Afterwards, distribution processes are much like those of the compressed dry natural gas subsystem described previously. However, an emerging development of *small-scale LNG* downstream within the LNG subsystem of the natural gas supply chain is a noteworthy distinction, and is further explored below.

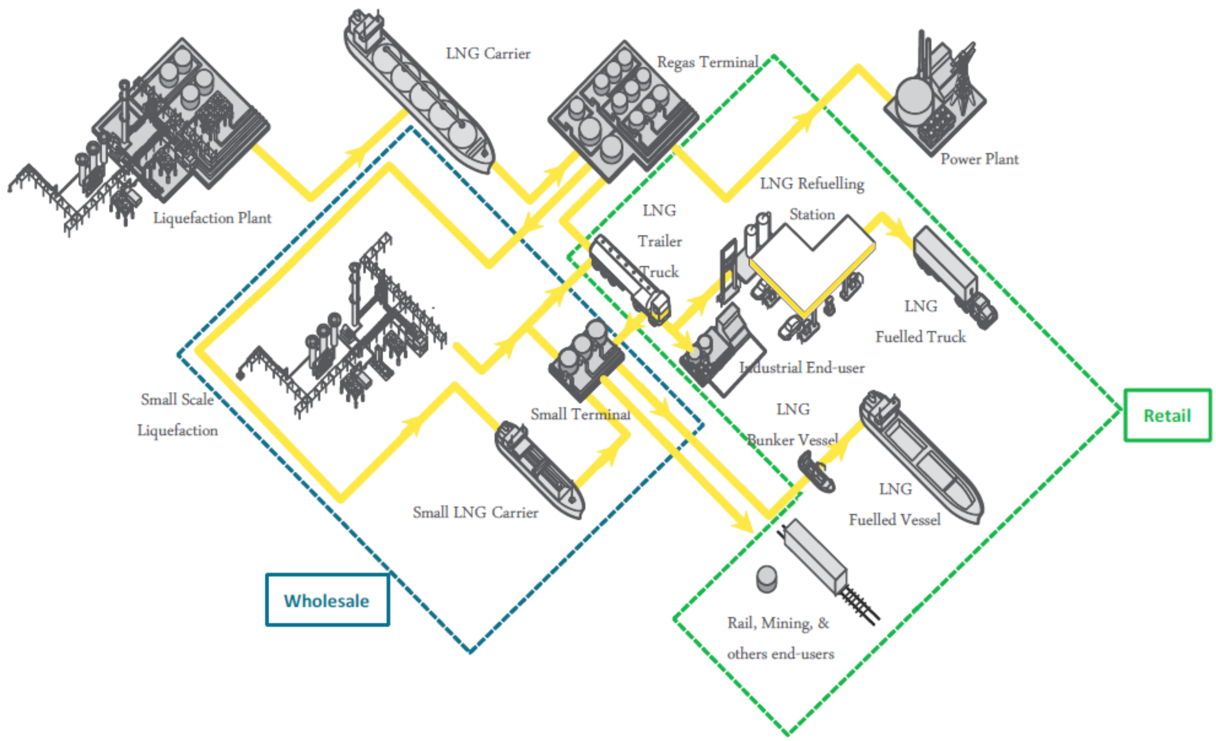
Small-scale LNG (SSLNG)

A next generation technology, mini- or small-scale LNG (e.g. GE's "LNG-in-a-Box") is well known, but has been commerciality unproven thus far. More recently, however, small-scale LNG (SSLNG) is growing to be one of the hottest new topics in technology circles because the majority of gas reserves worldwide are not big enough to make conventional large-scale LNG economic (Pettit, Darner, and Jelinek 2013). SSLNG are distinguished from conventional large-scale liquefaction facilities described earlier in terms of scale (capacity under 1 million tonnes per annum [MTPA] as defined by the International Gas Union), and position in the natural gas supply chain as depicted in Figure 26.

SSLNG, encompassing liquefaction units, satellite LNG storage tanks and/or regasification units, are developed in regions like New England and the coastal areas of the Middle Atlantic states where underground storage is lacking (geologic unsuitability).[16] Owned and operated by LDCs, these SSLNG systems are a critical part of the region's supply and deliverability network. The SSLNG systems make it possible to locally liquefy pipeline dry natural gas, turning dry gas into LNG for above-ground storage. From the storage, LNG can be regasified into dry gas for pipeline distribution to meet peak demand needs of local utilities, and to help maintain system pressures at different points of the regional natural gas system (NGA 2015A).

Figure 26 / Small-scale LNG (SSLNG)

[16] To provide a snapshot of this development, in 2014, according to Northeast Gas Association (NGA), liquefaction capability in New England among the LDCs was 44,000 million British Thermal Unit (MMBtu) per day, the LNG storage capacity was 16.3 billion cubic feet (Bcf), and vaporization (or regasification) capacity for daily sendout was approximately 1.4 Bcf/day. In New York, two LDCs have LNG facilities with storage capacity of approximately 3.2 Bcf, liquefaction capability of 16,800 thousand cubic feet (Mcf) per day, and a vaporization rate of approximately 26,100 Mcf/hr. LNG is also utilized by several LDCs in New Jersey, with total state storage capacity of about 4 Bcf (NGA 2015A).



Source: IGU (2014)

Moreover, SSLNG holds promise to bring natural gas to industrial and commercial markets not located near a pipeline system or within a distribution service area. SSLNG allows LNG to be distributed from the liquefaction sources directly to end-users via a trailer that can also serve to offload the LNG into the facility. This practice is currently adopted in the United States to serve paper mills, farms, industrial sites, and distribution sites that supply LNG for transport fuel applications, such as LNG as marine fuel (ship bunkering stations) and road transport fuel (transportation fleets, and LNG/LCNG[17] retail fueling stations). In fact, potential growth of end-user-oriented SSLNG is notable in the transport fuel

[17] A liquefied-compressed natural gas (LCNG) station combines LNG and compressed natural gas (CNG) in one station. A typical LCNG station is supplied with LNG and has dispensers for both LNG and CNG vehicles. The use of LNG supply for LCNG stations is in contrast to CNG stations that are typically tethered to the pipeline and are supplied with pipeline dry gas. At LCNG stations, LNG is pumped from the storage vessel through a dispenser into the vehicle. To produce CNG, the LNG is pumped into a vaporizer that converts it from liquid to gas in a controlled way so that it can be dispensed at the right pressure as CNG into the vehicle (Cullen 2014; Go With Natural Gas 2014).

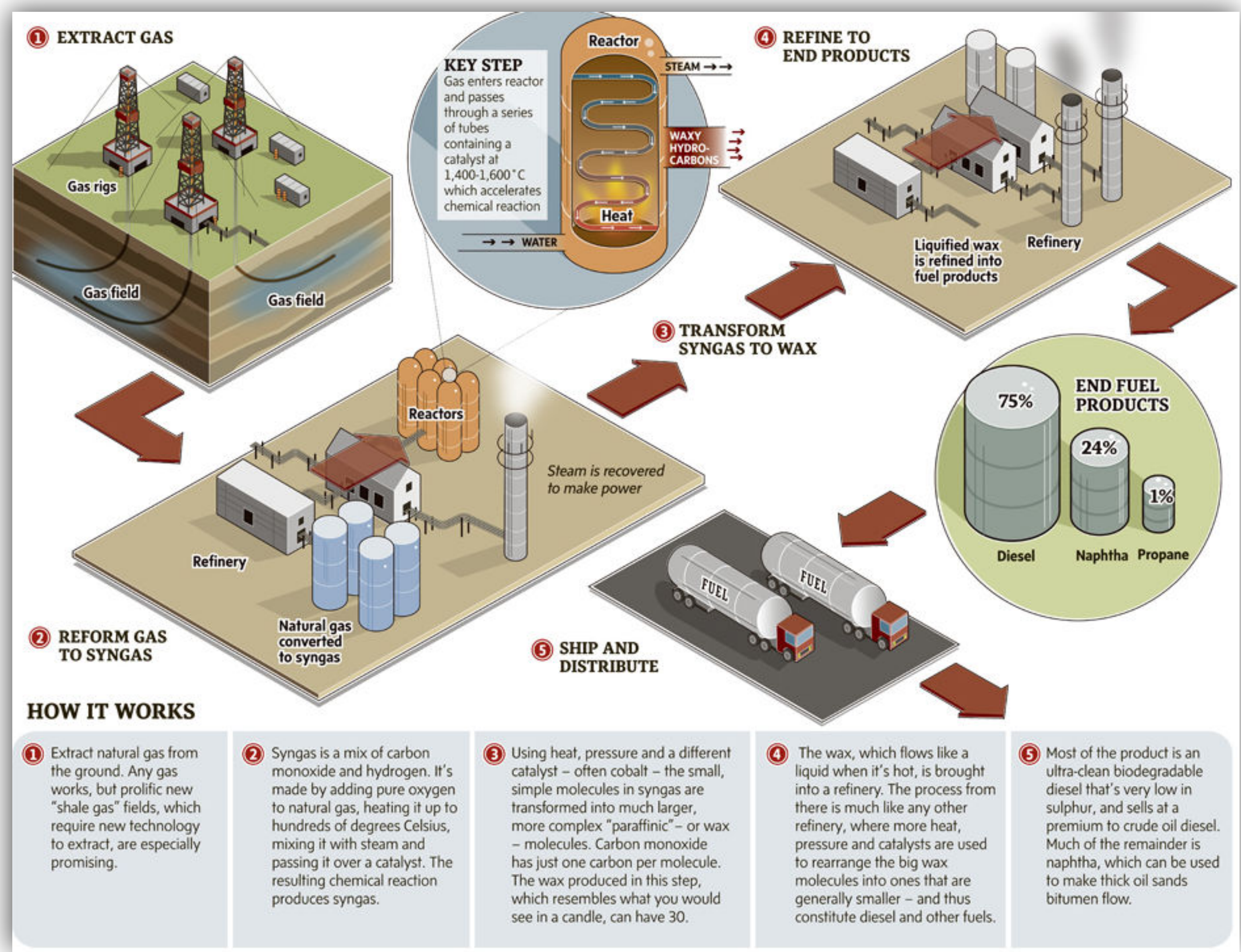
market. Shell, for instance, is commissioning a 0.25 MTPA liquefaction plant near Calgary in Canada. Other major oil companies are also planning to build LNG fueling corridors in North America to cater long-haul trucks (Adventures in Energy 2015a; IGU 2014; NGA 2015A).

GTL Subsystem

Compressed dry natural gas, transported via transmission pipelines, is delivered to a facilities equipped with gas-to-liquid (GTL) technologies. GTL technologies use chemical processes to convert gas to a wide range of products that would otherwise be produced from oil (EIA 2014e, IEA 2010, 2011; Shell Global 2015). The most common technique used at GTL facilities is Fischer-Tropsch (F-T) synthesis shown in Figure 27 and described further below (EIA 2014e; Shell Global 2015).

1. **Syngas Generation.** The first step in the F-T GTL process is converting the dry natural gas to a mixture of hydrogen, carbon dioxide, and carbon monoxide. This mixture is called *syngas*. The syngas is cleaned to remove sulfur, water, and carbon dioxide in order to prevent catalyst contamination, and then fed to an F-T reactor (EIA 2014e).
2. **Hydrocracking.** The reactor combines hydrogen with carbon monoxide to form different liquid hydrocarbons. This process is referred to as *hydrocracking*. The cost of building a reaction vessel to produce the required volume of fuel or products and to withstand high temperatures (500°–840°F) and pressures (40 atmospheres) can be considerable. Several companies are pursuing an alternative method that uses a different reactor design (called a micro-channel reactor) and proprietary catalysts that allow GTL production at much smaller scales (EIA 2014e; Van Eijk 2012).

Figure 27 / Gas-to-liquid Processes



Source: Vanderklippe (2012)

3. **Distillation.** The final step is distillation. Various boiling points are reached to separate out a wide range of products, including the followings (EIA 2014e; Shell Global 2015; Van Eijk 2012):
   - **GTL Naphtha** is used as a chemical feedstock for plastics manufacture.
   - **GTL Kerosene** is an alternative to conventional oil-based kerosene. Its primary use is to be blended with conventional Jet Fuel (up to 50%) for use in aviation (known as *GTL Jet Fuel*). GTL kerosene can be used as a blend with traditional jet fuel without any modifications to existing aircraft and engines.
   - **GTL Normal paraffins** are used for making more cost-effective detergents.

- **GTL Gasoil** is a diesel-type fuel that can diversify the global diesel fuel supply. Because it contains virtually no sulfur or aromatic compounds and has a high combustion quality, GTL gasoil burns more efficiently than conventional oil-based diesel. Thus, it produces fewer local emissions and less black smoke than conventional diesel. GTL gasoil can also be blended with conventional diesel and/or biodiesel and used in the same vehicles.
- **GTL Base oils** are used to make high-quality lubricants.
- **GTL Waxes** are virtually odorless, making them ideal for use in applications requiring the addition of color or fragrances, such as printing inks, packaging, fiberboard, plastic processing, candles, and coatings. To improve the long-term profitability of GTL plants, most GTL developers are looking to configure their plants to maximize wax production for the chemicals market instead of production of liquid fuels with minimum or no wax.

Once different GTL products are produced, they are fed to their own storage tanks ready for use and distribute to markets via the same infrastructure currently serve oil-based product counterparts (Van Eijk 2012).

GTL Facilities in the United States

Worldwide GTL production has remained small. There are currently five GTL plants operating globally, none of which is in the United States. These existing facilities have capacities ranging from 2,700 barrels per day (bbl/d) to 140,000 bbl/d, and include: two facilities operated by Shell in Malaysia, one by Shell in Qatar, one by Sasol in South Africa, and one by a joint venture between Sasol and Chevron in Qatar (Cernansky 2015; EIA 2014e; Kraussjan 2015; Pedersen 2014).

However, three GTL plants are proposed in the United States and to be located in Lake Charles, LA, Karns City, PA, and Ashtabula, OH. Of these, only the Lake Charles facility by South Africa-based Sasol is a large-scale GTL plant that would produce 96,000 barrels of diesel fuel and other liquids per day. The plant was originally planned to begin production in 2018. However, faced with more than 50 percent decrease in the price of oil since June 2015, Sasol announced in January

2015 that it is delaying a decision on whether to move forward with its Lake Charles facility (Cernansky 2015; EIA 2014e; Kraussjan 2015; Pedersen 2014).

Aside from Lake Charles facility, other cases in point demonstrate that GTL project feasibility has been and remains highly uncertain. Shell, which was reportedly considering the construction of a GTL plant in Louisiana of similar scale as Lake Charles facility, cancelled the plan in December 2013. Some of Shell's concerns included the lack of skilled labor, rising project cost estimates, increased uncertainty of future domestic natural gas prices, and a stagnating demand for gasoline (EIA 2014e; Liss 2012; Pedersen 2014). BP and ConocoPhillips built and briefly operated GTL demonstration plants in Alaska and Oklahoma, but stopped short of full development of the technology (Kraussjan 2015). On a related development, floating GTL units to make diesel fuel aboard a floating facility are still in the concept and design stage (EKT Interactive 2015b).

Looking forward, it is unlikely that GTL products will make significant inroad as potential markets for natural gas in the near future. This is because of a number of issues impacting GTL plant profitability, including: high capital cost, reliance on low-cost gas resources, reliance on relatively high oil prices, and low conversion efficiency (C2ES 2011; IEA 2011; Kraussjan 2015; Vanderklippe 2012). A 40,000-barrel-a-day facility could cost \$3–\$5 billion, and more than 40 per cent of the gas would be used up as fuel for the processing, with the conversion (or well-to-wheels) efficiencies reportedly hovering in the range of 60–65 percent. As a result of intensive capital cost and highly complex conversion process, the profit potential for a GTL plant depends on two dynamics in the energy markets: oil prices remaining high and natural gas prices staying low. Recent oil price drops has made expensive GTL project economically impractical. That is, while natural gas supplies and current domestic prices in the United States are deemed favorable, downward oil prices further erode cost advantage in relation to oil-based counterparts, and potential for plant profitability (Kraussjan 2015; Liss 2012; Vanderklippe 2012).

Concluding Remarks

The revolutionary leap made in exploration and production of shale gas in the United States has elevated an opportunity for natural gas to play a much greater role against coal in the electric power generation market, petroleum in the transportation fuel market, fuel oil in the commercial and residential markets, and oil-derived feedstock in the chemical and petrochemical manufacturing markets. However, a number of challenges and uncertainties remain that underpin the potentials of natural gas in garnering these market opportunities.

On the one hand, many large-scale market opportunities are all in a relatively early, and varying, stages of development. These markets span natural gas–fueled power plants, ethane cracking plants, export/liquefaction terminals, LNG import/receiving terminals, and natural gas transport vehicles and various types of fueling stations (e.g. LNG/CNG/LPG in motor transport, LNG in rail transport, LNG in marine shipping, and GTL products in air transport). Many uncertainties remain as to the speed and manner that these markets will evolve.

On the other hand, there is a pressing need for the development of gas product pipeline systems, and processing and storage facilities in order to bring the newfound gas supply to markets. Innovative technologies are also in varying stage of development to address logistical challenges associated with global transportation, as well as small, stranded gas fields that are not economically served by pipelines. These technologies—spanning LNG vessels, small-scale LNG, floating LNG and GTL units, among others—will shape the design and characteristics of future natural gas supply chain.

The natural gas supply chain framework presented in this paper provides a valuable frame of reference for business professionals and academic researchers working in specific systems of the natural gas supply chain to gain a global understanding of the entire system. It also serves as a structured starting point of due diligence for businesses operating in specific nodes and/or links of the supply chain in gauging the changing dynamics in the natural gas industry, technological development, and commercial marketplace.

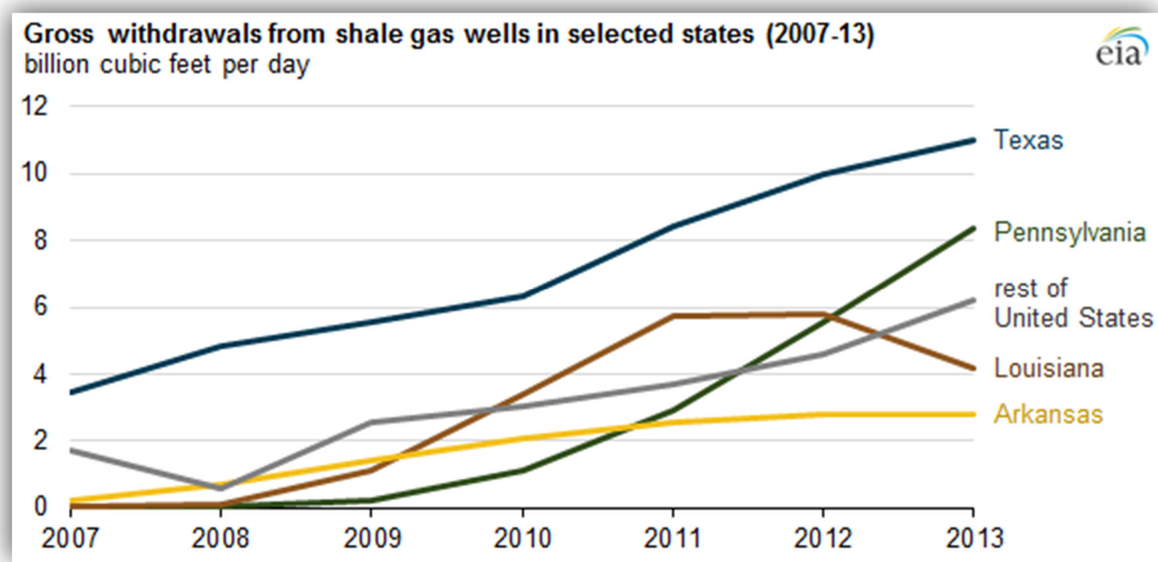
Appendix

Appendix 1 / Top US Shale Producing States, Plays, and Operators

Overall, states of Texas, Pennsylvania, Louisiana, and Arkansas produced 26 billion cubic feet per day (Bcf/d) or 79 percent of total US shale production in 2013. Shale gas production growth in Texas mainly came from the Barnett, Eagle Ford, and Haynesville-Bossier plays; in Pennsylvania from the Marcellus play; in Louisiana from the Haynesville play; and in Arkansas from the Fayetteville play (Tran 2014).

Historical production volume by selected states and shale plays are depicted in Figure A-1 and Figure A-2, respectively. Table A-1 provides descriptive summary of shale plays and corresponding operators.

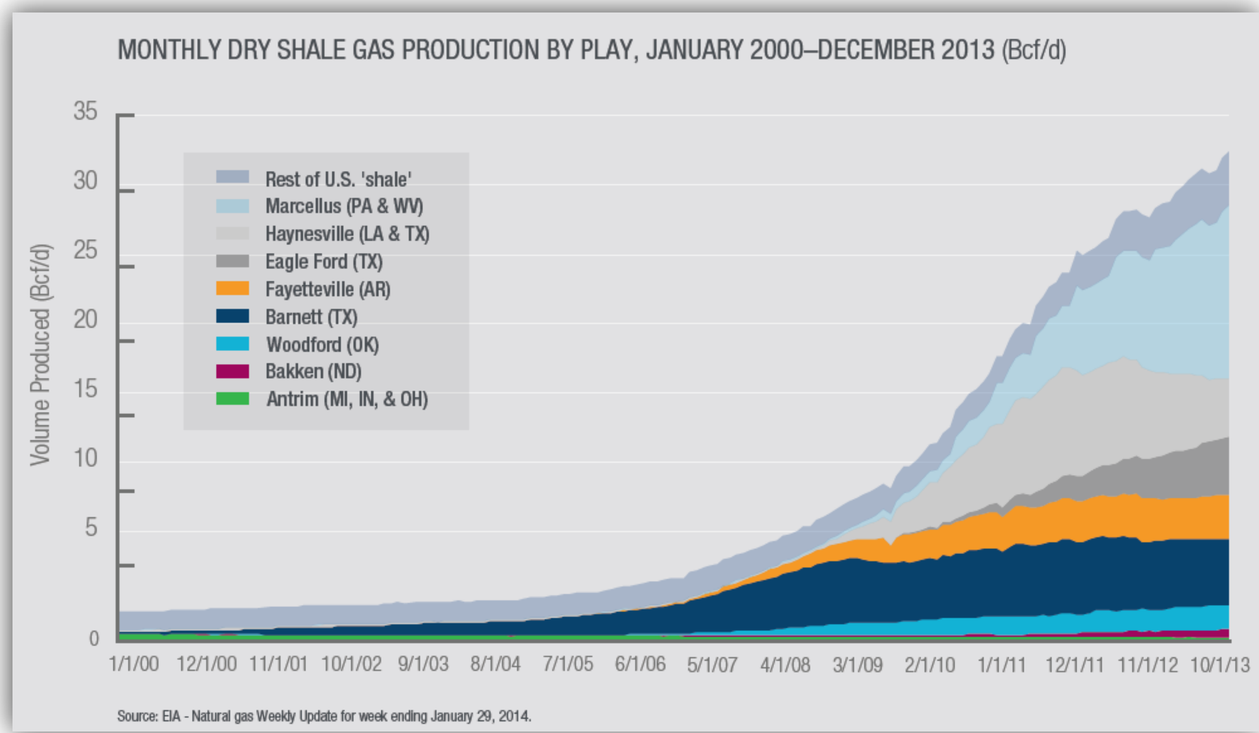
Figure A-1 / Gross Withdrawals from Shale Gas Wells in Selected States (2007–13)



Source: Tran (2014)

NOTE: Gross withdrawals refer to the full-volume of compounds extracted at the wellhead, including all natural gas plant liquids and all non-hydrocarbon gases, but excluding lease condensate. Also includes amounts delivered as royalty payments or consumed in field operations. Volumes used at the production site include: (1) the volume returned to reservoirs in cycling, repressuring of reservoirs, and conservation operations; and (2) gas vented and flared. Vented gas refers to gas released into the air on the production site or at processing plants (EIA 2014a, 2014c).

Figure A-2 / Dry Shale Gas Production by Play (2000–13)



Source: API (2014b)

Table A-1 / US Shale Plays, Characteristics, and Operators

Shale Plays	Location and Characteristics	Operators
Antrim Shale	◘ Located in the Michigan Basin, stretching through Michigan, extreme northern Ohio and also extreme northern Indiana ◘ Dry gas rich ◘ Exhibiting signs of maturation, with decreasing production activities	◘ Only two of Antrim Shale's top 10 producing companies increased their volumes of gas production from the shale during 2010–12, namely Linn Operating Inc. and Chevron Michigan. ◘ Other once major Antrim Shale gas producers such as Terra Energy Corporation, Ward Lake Energy, and Muskegon Development Company have steadily decreased their gas production from the play over the last few years.
Bakken	◘ Located in two US states Eastern Montana and Western North Dakota, and parts of two Canadian provinces Saskatchewan and Manitoba in the Williston Basin. ◘ The formation consists of three layers: an upper shale layer, middle dolomite, and a lower layer of shale. The shale layers are petroleum source rocks as well as seals for the layer known as the Three Forks (dolomite) or Sanish (sands) formations ◘ Primarily oil play (vs. gas)	Top Bakken producers include: ◘ Continental Resources – Holding 1.2 MM net acres in the Bakken in 2014 ◘ Whiting Petroleum Corporation – Holding 683,804 net acres in the Williston Basin in 2014, plus additional 170,000 net acres in the Williston basin after recently acquiring Kodiak Oil and Gas ◘ Hess Corporation – Holding 640,000 net acres in the Bakken Shale in 2014 ◘ Conoco Phillips – Holding 625,000 net acres in the Bakken Shale in 2014 ◘ EOG Resources – Holding about 600,000 net acres in the Bakken Shale core area in 2014
Barnett Shale	◘ Stretching from the Dallas–Fort Worth metroplex west and south, covering 5,000 square miles ◘ Oldest large shale play in terms of unconventional development; exhibiting signs of maturation ◘ Wet gas, rich in NGLs	◘ There were 135 producing companies in the Barnett Shale during the first half of 2014. ◘ Nearly 85% of total production (5,005 MMcfe/d) came from 6 operators in the first half of 2014: Devon Energy (26.3%), Chesapeake Energy (21.8%), ExxonMobil/XTO Energy (14.1%), EOG Resources (10.4%), Enervest (6.7%), and Quicksilver Resources (5.3%)

Shale Plays	Location and Characteristics	Operators
	◻ Activities dominated by natural gas (vs. oil)	
Eagle Ford, South Texas	◻ Stretching approximately 300 miles, from Mexico to south Texas northeastward into east Texas ◻ Formation at depths much lower than those found in Bakken, with an average thickness of 250 feet at depths ranging from 4,000 to 12,000 feet ◻ More liquids (NGL and oil) than dry gas ◻ The largest single oil and gas development in the world	Top five producers are: ◻ EOG Resources – Holding the largest leased acreage position, producing natural gas and NGLs total 220,000 barrels of oil equivalent (boe) a day, and about 170,000 barrels of oil a day from the Eagle Ford in 2014 (largest oil producer in the Eagle Ford) ◻ BHP Billiton PLC – Producing about 75,000 barrels of oil per day, and about 162,000 boe per day of natural gas and NGLs in the Eagle Ford in 2014 ◻ ConocoPhillips – third-largest oil producer in the Eagle Ford, eight-largest operator in terms of lease acres in 2014 ◻ Chesapeake Energy – second-largest net acreage position with nearly 450,000 net acres, producing about 80,000 barrels of liquids a day from the Eagle Ford in 2014 ◻ Marathon Oil – ninth-largest net acreage position, with about 200,000 net acres, reporting net sales volumes from the Eagle Ford in the third quarter of 2014 at total of 75,000 barrels a day of liquids, up by nearly 50% over the 52,000 barrels a day produced in the third quarter of 2013
Fayetteville Shale	◻ Located on the Arkansas side of the Arkoma Basin ◻ One of the first U.S. shale plays to be developed en masse ◻ Dry natural gas formation with geologic equivalent of the Caney Shale found on the Oklahoma side of the Arkoma Basin and the Barnett Shale found in north Texas	There were 11 operators in the Fayetteville in 2013, but almost 100% of the total 2013 production came from just three: Southwestern Energy (728 Bcf, or 71% of the total), BHP Billiton (162 Bcf, 16%), and ExxonMobil/XTO Energy (139 Bcf, 14%). Southwestern Energy held more than 905,000 net acres as of December 2014.

 101

Shale Plays	Location and Characteristics	Operators
Haynesville-Bossier plays	▫ Located in East Texas and Western Louisiana, generally recognized the shale interval in East Texas as Lower Bossier Formation and that in the southwest as Upper Bossier Formation ▫ The productive interval of the shale greater than 10,000 feet below the land surface The "sweet spot" or "core" generally considered to be on the Louisiana side of the play, and has been the focus of most horizontal drilling activity by operators thus far ▫ Dry gas rich (vs. wet gas and oil)	Operators and rig counts as of May 1, 2015 are: Chesapeake (6), Exco Resources (3), Anadarko (3), XTO Energy (2), Comstock Oil & Gas (1), EP Energy (1), BP America (1), Vine Oil & Gas (1), and J-W Operating (1)
Marcellus Shale	▫ Stretches from upstate New York south through Pennsylvania to West Virginia and west to parts of Ohio, covering an estimated 95,000 sq. miles in the Appalachian Basin ▫ Dry gas rich, particularly in the Northeast Pennsylvania portion of the play; with more liquids-rich gas found in a number of counties in Southwestern Pennsylvania and West Virginia ▫ Among the US fastest growing sources of natural gas production, rising from less than 1.7 Bcf/d in January 2010 to more than 16 Bcf/d in December 2014	Key operators in the Marcellus Shale in 2014 include: Range Resources, Chesapeake, XTO, Shell, Chevron, Talisman, and Cabot
Utica Shale	▫ Located a few thousand feet below the Marcellus Shale, underlying portions of Kentucky, Maryland, New York, Ohio,	Five companies operating in Eastern Ohio's Pt. Pleasant accounted for 88.2% of total oil and gas production (79,040 MMcfe/d, of which natural gas total 67,334 MMcf and 1,951 thousand barrels) in first half of 2014 are:

Shale Plays	Location and Characteristics	Operators
	Pennsylvania, Tennessee, West Virginia, and Virginia ▫ Thicker and more geographically extensive than the Marcellus ▫ Most of the oil & gas exploration and development activity in the Utica so far has been focused in Eastern Ohio's "Point Pleasant" which is more liquids rich and shallower, with gas production more prevalent (vs. oil)	Chesapeake (46.8%), Gulfport Energy (20.3%), Antero Resources (12.3%), Rice Energy (4.4%), Hess Corporation (4.4%)
Woodford Shale	▫ Encompassed 11,000 square miles in Oklahoma, Woodford shale consists of three sections based on the location of the shale in Oklahoma: the Cana formation (a liquids-rich play) located in the Anadarko Basin, the Woodford Central in the Ardmore Basin, and Woodford Western in the Arkoma Basin. ▫ Average thickness in the range of 75-380 feet, and a depth of 6,000–14,000 feet	Of the many companies operating in the Woodford Shale, Newfield Exploration and Devon Energy are the largest producers. Both of these companies have sold off many of their assets elsewhere in order to focus their attention on the Woodford Shale Play. Other key players in Woodford are Chesapeake, Cimarex, Continental Resources, and XTO Energy.

Source: Allegro (2013), Ausick (2015), Bandz (2014), The Haynesville Shale (2015), IEA (2010), INGAA Foundation (2014), Lipps (2013), Marcellus Connection (n.d.), NGI (n.d.), *Oil & Gas Journal* (2012), Railroad Commission of Texas (2015), Reed (2014), TCEQ (2015)

Appendix 2 / Top Five Gas Processing Company and Business Profile

Company	Business Profile
DCP Midstream	The company's assets are grouped into four main areas. ▫ The Rawhide processing plant and gathering systems are in the Permian basin of Texas, where DCP owns and operates 18 processing plants with a collective capacity of more than 1.3 Bcfd, and produces about 120 Mbpd of NGL. The Rawhide plant is part of DCP Midstream's expansion program for the liquids-rich Permian. ▫ National Helium is the largest gas processing plant in the Mid-Continent area, and it is one of 12 processing plants in DCP's Mid-Continent assets, which together have a processing capacity of more than 2 Bcfd. The National Helium facility has access to the Mont Belvieu, Texas, and Gulf Coast petrochemical markets via the Southern Hills pipeline. ▫ O'Connor plant is a deep-cut cryogenic plant in Colorado that was built to process gas production from the Niobrara shale play. The O'Connor plant is part of an eight-plant system with a total approximate capacity of 600 MMcfd. ▫ Eagle plant is part of its Eagle Ford play integrated system in South Texas, which has a processing capacity of 1.2 Bcfd and includes the Larose processing plant and the Paradis fractionation facility.
Enterprise Products Partners	▫ In 2012, Enterprise processed more than 6 Bcfd of gas and produced more than 343 Mbpd of NGL from its 24 processing plants in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Total processing capacity for all 24 plants is more than 12.4 Bcfd. Enterprise also owns interests in 15 NGL fractionation facilities in Texas, Louisiana and Ohio. ▫ In 2013, Enterprise began service from the third train of its Yoakum gas processing plant, which increased the facility's capacity to 900 MMcfd, allowing Enterprise to extract up to 111 Mbpd of NGL at the site. Each train has an operating capacity of 85 Mbpd. ▫ The company plans to construct a new liquefied petroleum gas (LPG) export terminal on the Gulf Coast. The initial loading rate for export-grade propane or butane service is expected to be 11 Mbbl per hour, which equates to approximately 6 MMbbl to 6.5 MMbbl per month (bpm). The new LPG marine terminal is expected to be in service in the fourth quarter of 2015.
Williams Companies Inc.	The company's large-scale midstream assets are concentrated in Colorado, New Mexico, Wyoming, the Gulf of Mexico and the Marcellus shale in the Northeast.

Company	Business Profile
	◻ In the Rocky Mountains, the company owns the Opal and Echo Springs processing plants in Wyoming, which have a combined daily inlet capacity of more than 2.2 Bcfd of gas and nearly 125 Mbpd of NGL production capacity. The Willow Creek processing plant in western Colorado has a gas processing capacity of 450 MMcfd and an NGL production capacity of 30 Mbpd. ◻ Parachute complex and three other treating facilities in western Colorado have a combined processing capacity of 1.2 Bcfd. The Four Corners system in New Mexico and Colorado has 5 processing or treating plants. Those plants have the combined capacity to process and treat 1.5 Bcfd of gas to produce 41 Mbpd of NGL. ◻ In the Gulf Coast region, the company has the Mobile Bay and Markham processing plants with a combined inlet capacity of 1.2 Bcfd and NGL production of 75 Mbpd. ◻ In the Marcellus shale region in the northeast, Williams' assets include a processing facility. There, construction is underway on a fractionation facility, and the company plans to build additional processing facilities.
Targa Resources	Targa has five main areas of operations. ◻ Sand Hills operations include its Sand Hills gathering and processing system and the West Seminole and Puckett gathering systems in West Texas. The Sand Hills refrigerated cryogenic processing plant has a gross processing capacity of 180 MMcfd. ◻ The Versado operations consist of the Saunders, Eunice, and Monument processing plants in southeastern New Mexico, which have an aggregate processing capacity of 280 MMcfd. ◻ In West Texas, Targa's SAOU processing facilities include the Mertzon, Sterling and Conger plants, with an aggregate processing capacity of 139 MMcfd. ◻ North Texas system includes the Chico and Shackelford gas processing facilities. The Chico plant has an aggregate processing capacity of 265 MMcfd and an integrated fractionation capacity of 15 Mbpd. The Shackelford plant has an aggregate processing capacity of 13 MMcfd. Also, construction is near completion on Targa's new 200-MMcfd cryogenic processing plant for the North Texas system. ◻ Badlands assets in the Williston basin of the Bakken shale play include a 20-MMcfd processing plant, with an expansion underway to increase the plant's capacity to 40 MMcfd.
MarkWest Energy Partners	The company divides its operations into five regions: the Northeast, the Marcellus shale, the Utica shale, Texas and Oklahoma.

Company	Business Profile
	▫ In the Northeast, MarkWest's assets are in Kentucky, southwestern West Virginia, and Michigan. The company has 652 MMcfd of processing capacity and 24 Mbpd of NGL fractionation capacity in those states, to serve producers in the Appalachian basin, the Huron-Berea shale, the Antrim shale, and the Niagaran Reef fields. ▫ In the Marcellus, MarkWest has 1.8 Bcfd of processing capacity and 98 Mbpd of fractionation to serve producers in southwestern and northwestern Pennsylvania, as well as in northern West Virginia. ▫ In the Utica, the company partnered with the Energy and Minerals Group (EMG) in a joint venture (MarkWest Utica EMG) to develop fully integrated gathering, processing, fractionation, and marketing operations in the liquids-rich areas of eastern Ohio. ▫ In Oklahoma, MarkWest has 235 MMcfd of processing capacity to serve producers in the Granite Wash and Woodford shales. ▫ In Texas, the company has 542 MMcfd of processing capacity to serve producers in the Cotton Valley, Haynesville shale, Eagle Ford shale, Travis Peak and Pettit formations.

Source: Stell (2014)

 106

Appendix 3 / Pipeline Infrastructure Development Trends Driven by Shale Gas Development

The growth in shale gas production has resulted in shifting flows on the US interstate pipeline network both in domestic and international markets. In the domestic markets, pipeline infrastructure developments in the US Northeast attest to the shifts in gas pipeline flows and associated capacity need for domestic markets. Pipeline capacity connecting Marcellus producing fields to either natural gas markets or interconnections to existing pipelines has been added (DOE 2015). For example, numerous projects to supply US Northeast markets with Marcellus and Utica shale gas are in various stages of development, including: Williams Companies' Constitution Pipeline (650 MMcfd), Algonquin's Atlantic Bridge (500 MMcfd) and Incremental Market (342 Bcfd) projects, National Fuel Supply's Northern Access project (350 MMcfd), and Tennessee Gas Pipeline's Northeast Energy Direct project (1.2 Bcfd) (Navigant 2014). A somewhat unique characteristic of these Marcellus Basin area pipelines is that while total capacity proposed will be large, the mileage will be seemingly small when compared to long-haul pipelines in the west. This is primarily due to the proximity of this supply to highly populated east coast markets (IHS 2013).

Infrastructure development for pipeline export also reflects changes in import/export pipeline gas flows. The increased supply from the Marcellus has not only reduced the need for Canadian exports to the US Northeast, but also led to increasing imports into Canada from the United States. At least three major pipeline expansions or extensions to move US gas pipeline export to eastern Canada have entered the execution phase of development, including: Spectra's Nexus Pipeline (2 Bcfd), Energy Trading Partners' Rover Pipeline (3.25 Bcfd, with 1.3 Bcfd to Dawn fully subscribed), and Tennessee Gas Pipeline's Niagara Expansion (158 MMcfd) (Navigant 2014).

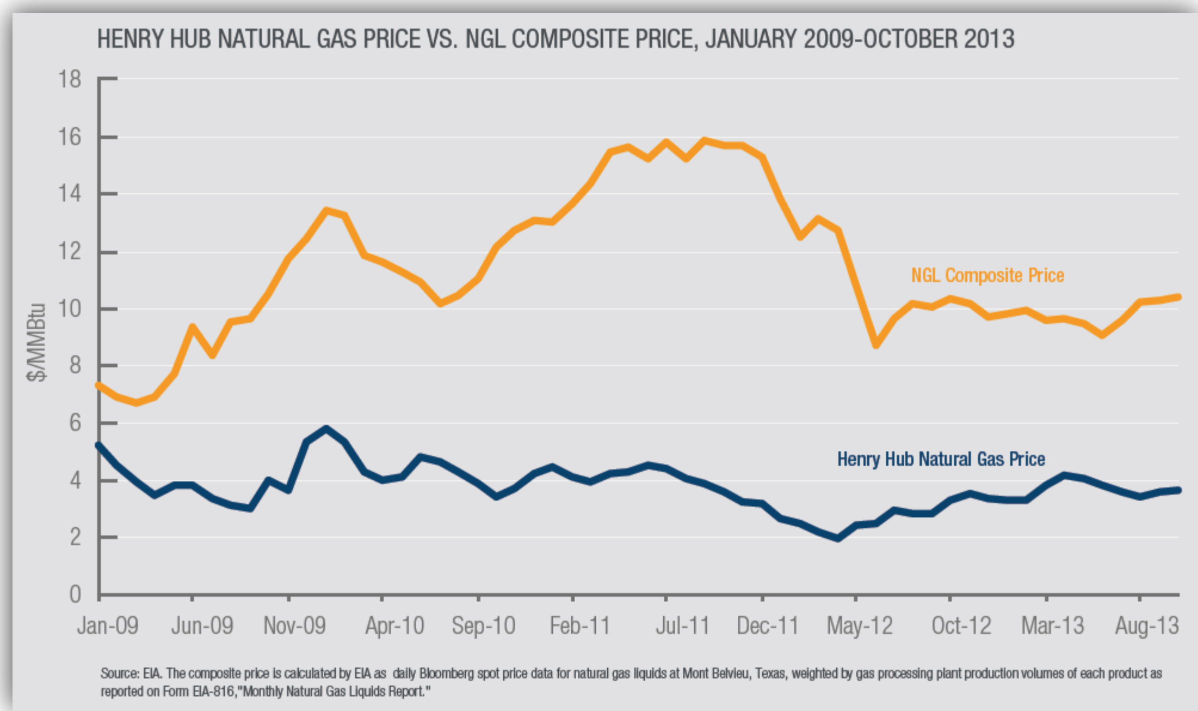
Continued pipeline infrastructure development is encouraged by natural gas producers and marketers, the principal shippers on the new "supply push" pipelines. These *anchor shippers* have been willing to commit to the long-term, firm contracts for natural gas transportation service. Effectively, such an agreement enables the operator to have confidence that a significant share of the project's development, construction, financing, and operating costs will be recoverable from shippers. Note that while firm contracts for transportation service effectively drive new pipeline expansion, these anchor shippers may make available transportation service to others in the secondary or resale markets once the pipeline is fully constructed and in operations (Black & Veatch 2014; DOE 2015; INGAA Foundation 2011, 2014).

Looking forward, it is projected that gas supply from Marcellus and Utica plays will continue to be delivered to the Eastern US seaboard, the US southeast region, mid-western markets across Ohio, the Gulf region through Ohio, and the Eastern Canadian, including Ontario markets. Concurrently, growing production in other areas such as in the Gulf Coast region will mostly stay in the region to meet increasing local demand growth, including LNG exports from Texas and Louisiana, and growing petrochemical gas use in the region. Growing Rocky Mountain production is projected to mostly flow to the West coast and West Texas (INGAA Foundation 2014; Navigant 2014).

Appendix 4 / Natural Gas Liquid (NGL) Production and Price Trends

Natural gas liquid (NGL) products are generally priced against that of oil, except for ethane that is priced against that of natural gas (API 2014b; Ratner and Tiemann 2014). The relatively low natural gas prices and high crude oil price since 2005 have resulted in NGL products priced significantly higher than natural gas on a Btu equivalent basis (see Figure A-3).

Figure A-3 / Relatively Prices of Natural Gas and NGLs



Source: API (2014b)

Such pricing conditions help to improve the producer's profitability at the wellhead and have provided a strong incentive for producers to shift their focus from dry gas plays to liquids-rich or wet shale plays, which include parts of the Marcellus Shale in southwestern Pennsylvania and northern West Virginia, and Utica Shale in eastern Ohio (see Appendix 1). Often, the NGL production are developed as a part of a large-scale gas development aimed at exports, but liquids from smaller-scale developments aimed at flaring reduction also added to the NGL production volume.

This trend results in increasing the yield of NGL relative to dry natural gas. NGL percentage of natural gas processing plant production has increased nearly 15 percent on a gaseous equivalent basis during 2008–14, growing from 6.1 percent to 7.1 percent (API 2014b; BP 2015b; EIA 2014f; Follette and He 2013; IEA 2010; Ratner et al. 2015; Ritenbaugh 2015; Tortoise Capital Advisors 2014).

The producers' gravitation toward wet gas plays has accelerated the surge in NGL production, which is exerting significant downward pressure on prices (Follette and He 2012). Ethane price has been on downward spiral along with natural gas price, selling at some one-third the price of naphtha, an oil-derived alternative to ethane in 2013. Similarly, propane prices have declined to much lower levels compared with natural gas over the past two years (Denning 2011; Follette and He 2013; Preel 2013; Ritenbaugh 2015). In contrast, prices for pentanes and butane have held up because of their use in the booming oil industry, for instance, as diluents for Canadian tar sands production or as gasoline blending components (Kemp 2012).

Appendix 5 / Ethane and Propane Market Trends

Ethane Market Trends

When prices of ethane drop too low as has recently been the case, one method for gas processors or producers to handle ethane is to blend a limited amount of it into natural gas pipelines, a method commonly called *ethane rejection*. This approach increases the heat value (Btu content) of the gas. Since dry natural gas is sold on a Btu basis, the increase in the heat value boosts the sale price of the gas. However, the oversupply of ethane market due to shale gas boom requires maximum ethane rejection. Ethane rejection in the Marcellus and Utica Shale plays reached 130,000 barrel per day (b/d) in 2014. That figure is expected to climb to 180,000 b/d in 2015. Maximum ethane rejection has resulted in many natural gas pipelines approaching the operational and safety limits imposed by pipeline operators. The ethane rejection limits are set to prevent corrosion or clogging up of the pipeline network, and limit the temperature at which gas sold to domestic and industrial customers burns, preventing damage to their equipment. Noncompliance to these limits can result in producer penalties and shipping restrictions (EIA 2014f; Kemp 2012; Ritenbaugh 2015).

Faced with such an impasse, natural gas processors or producers may either reduce ethane content of dry natural gas at a loss, or find other domestic markets or export markets for the surplus ethane. In domestic markets, with attractive NGL pricing relative to naphtha refinery streams, the feedstock percentage of NGLs used in the petrochemical industry has been increasing, with ethane taking a disproportionate share of the total. Ethane is almost exclusively used by the petrochemical industry to produce ethylene, which is a building block of a wide range of chemicals used to make solvents, textiles, inks, adhesives, shampoos, detergents, soaps, and commercial plastics such as packaging, pipe, housewares, and bottles. In fact, most US ethylene crackers are running at maximum ethane volumes. Today, the domestic ethylene industry can process 950,000 barrel/day (b/d) of ethane, with almost all of that feedstock volume coming from gas processing plants (BP 2015b; Braziel 2011; EIA 2014f; Huffman 2014; IEA 2012b; Ritenbaugh 2015; Tortoise Capital Advisors 2014).

In export markets, rapid growth in US ethane production has resulted in exports to Canada by pipeline and to Europe by liquefied ethane tankers. Pipeline exports began in December 2013 with the start of the Mariner West pipeline, which is anticipated to reach 0.09 million b/d in 2015. The first tanker exports are expected in 2015 with 0.02-million-b/d shipments from Sunoco Logistics's Marcus Hook terminal to Rafnes, Norway. Enterprise Products Partners has also announced a 0.24-million-b/d ethane export facility project on the US Gulf Coast (EIA 2014f).

Despite emerging domestic and export market development, ethane surplus is expected to continue in the foreseeable future as ethane production is project to continue to grow faster than the construction of new ethane recovery/fractionation facilities, ethane pipelines, export facilities, and ethylene crackers (EIA 2014f). In fact, while several large petrochemical steam crackers have been proposed and are currently under development, these projects are not likely to be completed until the end of the decade (IHS 2013).

Propane/LPG Market Trends

Propane (also called by a common term LPG[18]) is consumed in the United States primarily in residential and commercial buildings for water heating, cooking, and seasonally as a fuel for space heating in regions where natural gas supply is limited or unavailable. Moreover, propane is used as transportation fuel for forklifts, lawnmowers, outboard motors. Thus, demand for propane is highly seasonal. During the winter, propane is used to heat homes and livestock buildings. During the fall, it is used to supplement natural gas in drying crops (especially corn used for feeding livestock) and to produce ethanol that is blended in motor gasoline (BP 2015b; EIA 2014f; Tortoise Capital Advisors 2014).

The petrochemical industry is also a significant domestic consumer of propane as feedstock to produce ethylene and propylene. The latter is used in the production of products such as solvents, plastics, rigid foams, coatings, adhesives, textiles, fuel additive, and paints and cleaners (EIA 2014f; Huffman 2014).

Propane exports have grown considerably in the past two years. Since 2011, the United States has been a net exporter (exports exceeding imports) of propane.

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[18] LPG is a common term for propane (C_3H_8), butane (C_4H_{10}), or their mixtures (IEA 2010).

In 2013, the United States exported 0.3 million barrel/day (b/d) of propane, which grew to reach 0.45 million b/d in May 2014, or about 25 percent of total domestic production from gas processors and refiners. US exports of propane are destined to Canada, Japan, and Latin American countries (EIA 2014f). Overall, LPG produced from natural gas processing accounts for nearly 60 percent of total worldwide production during the last 10 years, with LPG from oil refineries accounting for almost all the remaining LPG (Engelen and Dullaert 2010).

To capitalize on the growing LPG export opportunities, companies all over North America are announcing plans to build, own, and operate LPG marine export terminals. An estimated increase of 20 million barrels per month of export capacity by 2016 is currently in planning and construction. This new capacity would triple the capacity of 2013 which stood at about 10 million barrels per day. Active players responding to the need for additional LPG export capacity in the US Gulf coast are Enterprise Products Partners and Targa Resources. Several other companies, including Energy Transfer Partners (ETP), Coastal Caverns, Occidental (Oxy), Phillips 66, and Trammo Gas have also announced plans to build, own, and operate LPG marine terminals in the US Gulf Coast. Similarly, the US east and west coasts, as well as Canada's west coast, have seen a surge in activity in marine export terminal projects. Companies are forging ahead with expansions at Ferndale, Washington, and Marcus Hook, Pennsylvania (a terminal supplied from Marcellus production) (Pettit, Darner, and Jelinek 2013).

Appendix 6 / FLNG Projects Underdevelopment

Projects	Descriptions
The Prelude and Concerto gas fields, Australia	◘ The world's first FLNG and the world largest ship ever constructed (see **Error! Reference source not found.**), **Shell Prelude** will be deployed off the northwest coast of Western Australia to extract and process gas from the Prelude and Concerto gas fields in the Browse Basin. The purpose of the project is to have a large movable facility that can be located directly on top of offshore fields. ◘ The construction of Prelude began in October 2012, with structure measuring at 1,601 feet (488 m) long and 243 feet (74 m) wide. When fully equipped with its storage tanks full, it will weigh around 600,000 metric tons. ◘ Drilling is expected to begin in 2017 and the fields to have a life expectancy of 25 years. The Prelude will remain onsite during all weather events, having been designed to withstand a Category 5 cyclone. It will stay permanently moored at the Prelude gas field for 20–25 years and produce at least 3.6 million tons per year of liquefied natural gas (LNG), 1.3 million tonnes per annum (mtpa) of condensate, and 0.4 mtpa of LPG. In later development phases, it should produce from other fields where Shell has an interest.
The Scarborough gas field, Australia	◘ The Scarborough gas field is about 220 km (132 miles) northwest of Exmouth in the Carnarvon basin. It is a mid-sized field with 226.5 billion cubic metres (Bcm) to 283.2 Bcm, or 8 trillion cubic feet (Tcf) to 10 Tcf, of essentially dry gas resources in 950 m (3,116 ft) of water. ◘ The field is being developed by a 50/50 joint venture of ExxonMobil and BHP Billiton. ExxonMobil has selected FLNG as the lead development concept for Scarborough, with a capacity from 6 mtpa to 7 mtpa. ◘ The construction of an FLNG facility for the field was estimated to be lower than that of the compression platform, pipeline, and onshore liquefaction plant.
The Caribbean FLNG project, Colombia.	◘ The project is under construction for Pacific Rubiales Energy, Colombia. It is a barge-mounted FLNG plant that will be docked in Colombia to liquefy gas from onshore fields. ◘ The project consists of a non-propelled barge that will be installed off the coast of Colombia. The FLNG barge will have a capacity of 500,000 mt per year.

Projects	Descriptions
	◻ Fabrication began in late 2012 and is on schedule for first deliveries in 2Q 2015.
Kanowit gas field and Rotan gas field, Malaysia.	◻ Malaysia's Petroliam Nasional Bhd (Petronas) began construction on its PFLNG 1 project in June 2013 and made its final investment decision on the PFLNG 2 project in February 2014. ◻ The PFLNG 1 vessel will be located on Malaysia's Kanowit gas field, which is 180 km (111 miles) offshore Sarawak, and is scheduled for completion by year-end 2015. The PFLNG 2 will be installed on the Rotan gas field in deepwater Block H offshore Sabah, Malaysia, and is expected to begin LNG production early in 2018. ◻ Both units are part of Petronas' strategies to tap gas reserves in Malaysia's remote and stranded fields that are currently considered to be uneconomical to develop and evacuate.
Niger Delta, Equatorial Guinea	◻ A number of companies have submitted proposals to Ophir Energy for FLNG facilities for offshore Equatorial Guinea. Currently, Ophir has an 80 percent interest in Block R, which covers 2,450 sq km (946 sq miles) in water depths from 600 m to 1,950 m (1,968 ft to 6,396 ft) in the southeastern Niger Delta. Three fields were discovered with total 2C of 74 Bcm (2.6 Tcf), which is enough to support a 2.5 MMmt/year FLNG development. ◻ First LNG production is expected in 2018.
The Abadi gas field, Indonesia.	◻ **The Abadi gas field is estimated to hold enough reserves for the production of 2.5 MMmt/year of LNG for more than 30 years.** ◻ **Inpex (65%) and Shell (35%) are two FEED (Front End Engineering Design) contracts for the FLNG project.**
The BC LNG Project	◻ **A floating liquefaction and storage unit (FLSU) will be docked on the west bank of the Douglas Channel near Kitimat, British Columbia.** ◻ **The FLSU with a capacity of 700,000 mt/year will be chartered in 1Q 2016 by Exmar to the BC LNG Project for a firm term-period of 20 years.**

Projects	Descriptions
The Port of Lavaca project, Texas, the United States	◻ Excelerate Energy completed its FEED work for its 4.4 MMmt/year dockside FLNG, which will be near Port Lavaca, Texas. ◻ The floating liquefaction, storage, and offloading (FLSO) vessel will have a storage capacity of 250,000 cm (8.8 MMcf). There will be a fully integrated onshore gas processing plant. The facility will interconnect to the region's existing pipeline system. The project will be designed and permitted to add a second FLSO facility for a total production capacity of up to 10 MMmt/year. ◻ The facility is expected to be in service by 4Q 2018 pending Federal Energy Regulatory Commission (FERC) approval.
The Port of Brownsville project, Texas, the United States	◻ The project is being developed by Eos LNG LLC with a date of delivery of January 1, 2018. ◻ The barge-mounted liquefaction facility will have a capacity of 2 MMmt/year. The site can be expanded to 4 MMmt/year. The FLNG barge is estimated to cost $750 million with another $250 million for onshore infrastructure.
The Venice project, Louisiana, the United States	◻ Cambridge Energy Group Ltd. is proposing the 8.2 MMmt/year FLNG export project near Venice, Louisiana. ◻ The project would consist of two self-propelled 4.1 MMmt/year FLNG vessels, one pipeline to six interconnections with intrastate pipelines, 12 LNG carriers, 6 tugs, and 6 LNG shuttle carriers. ◻ FERC approval for the project and the FID are expected in 3Q 2015.

Source: EBARA (2011), IEA (2011), Schilling 2014, Weeden (2014)

Figure A-4 / Shell Prelude FLNG Size

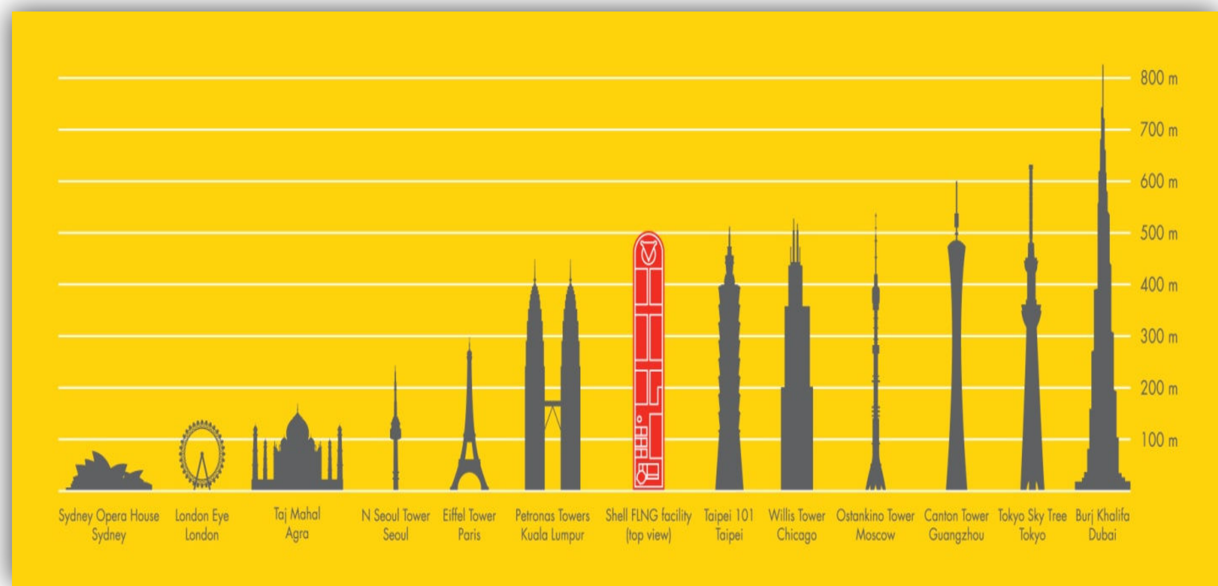

Image courtesy of Shell Global

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