Paper #3-4

TRANSMISSION NATURAL GAS DEMAND

Prepared for the Demand Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Task Group that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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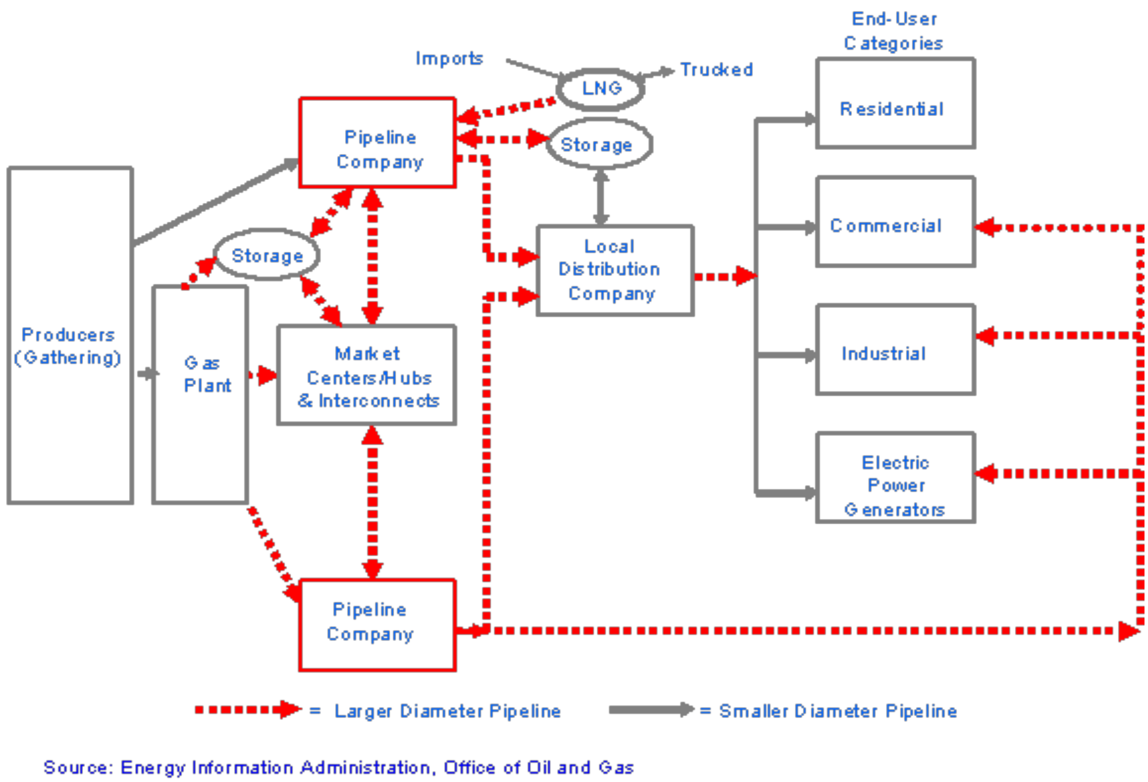
I. Summary of Findings

The North American natural gas lease, plant, pipeline, and distribution ("Natural Gas Transmission") system is an intricate network that reliably and efficiently delivers significant quantities of natural gas from the wellhead to end-users throughout the entire continent. This elaborate system is the culmination of decades of investment by countless participants and combines legacy components with state of the art improvements (Figure 1).

Figure 1.

Natural Gas Transmission Path



Expansion of natural gas lease, plant, pipeline, and distribution infrastructure generally requires growth in the natural gas market or development of new sources of supply. Still, even in a flat to declining market, additional infrastructure assets will likely be required to accommodate natural shifts in the supply and demand. Most of the natural gas infrastructure capacity added in the last 30 years has been to deliver new supply to existing load or to load that has shifted regionally.

It is important to note that each lease, plant, pipeline and distribution supply and delivery system is unique. Consequently a "one-size-fits-all" approach to seeking efficiency improvements will not work. This is because each system's age, geographic location, original design, modifications, and shifting supply and transmission patterns all are distinct. Therefore, an improvement may be cost effective in one facet but not be feasible or economic in another case. Due to this reality, the greatest opportunity for maximizing either economics or efficiency is in the initial design and construction phase of a major facility. For example, new gas processing plants tend to be more efficient than older legacy facilities.

Today, lease and plant fuel consumption for the US is about 3.5 Bcf/d or 6% of dry gas production while pipeline and distribution fuel consumption is about 1.7 Bcf/d or 3% of natural gas demand. Total Natural Gas Transmission fuel (lease and plant, pipeline and distribution) is about 5.2 Bcf/d or 8.5% of throughput (total natural gas demand) (see Figures 2 and 3). CO2 emissions from this segment of the industry are a function of natural gas throughput. As discussed below, these percentages have varied little over time and are not expected to do so in the future.

Figure 2
Total Transmission Percent of Demand

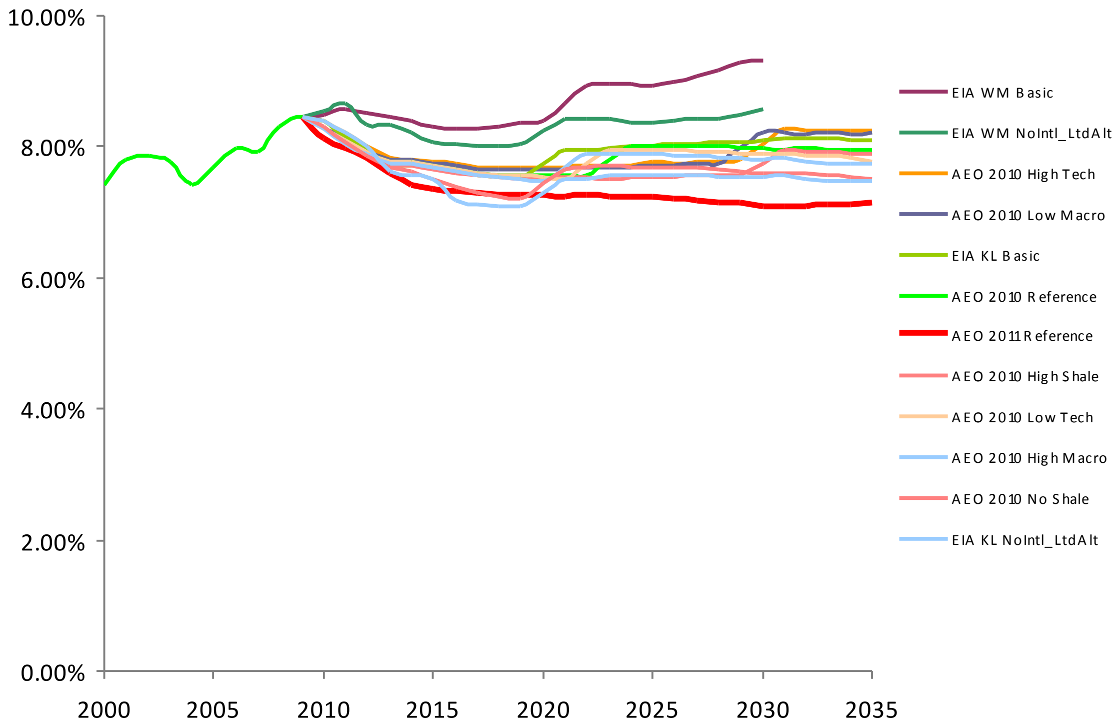
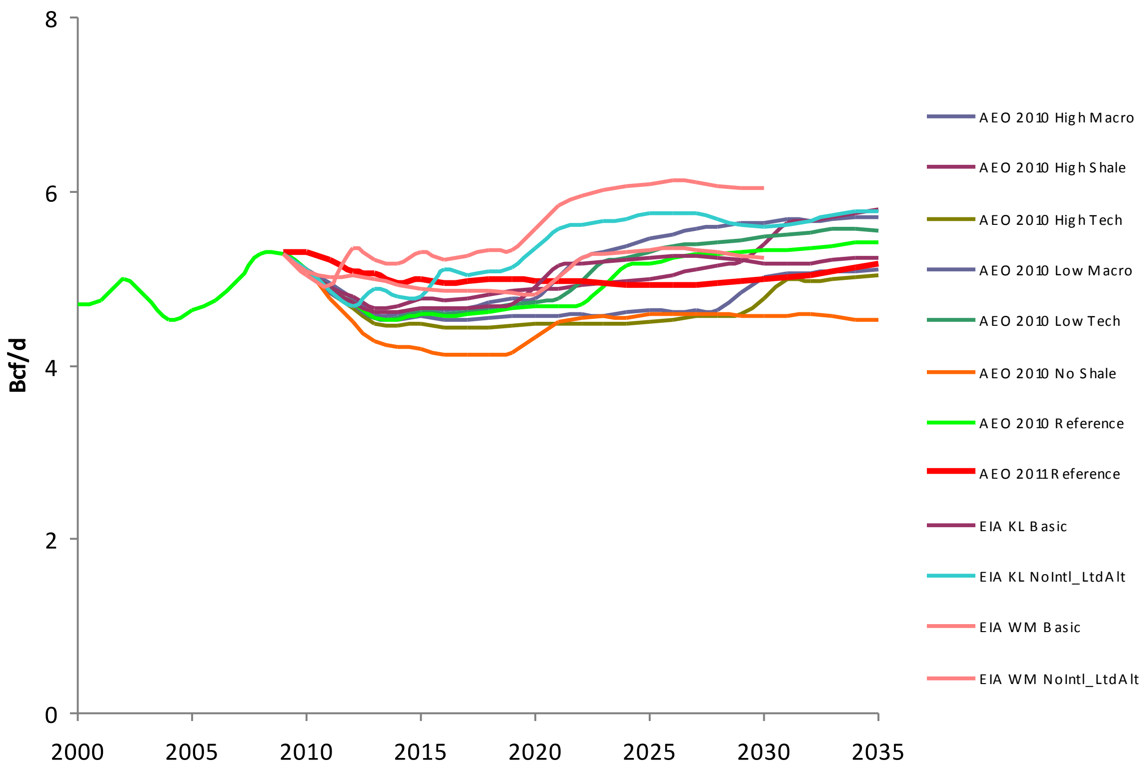


Figure 3
Total Transmission Fuel



Finding

It is reasonable to assume that natural gas consumption for Natural Gas Transmission fuel (lease and plant fuel, and pipeline and distribution fuel) for the US will stay within the historical range of about 7.1% to 9.5% of throughput for the foreseeable future with a demand range of 4.1 to 6.1 Bcf/d through 2035. It is important to note that discussion of Canadian Natural Gas Transmission fuel has been omitted due to different reporting standards. For example, commercial natural gas consumption in the oil sands is included in lease fuel. While refinery natural gas demand is in plant fuel. Therefore, in order to draw any reasonable conclusions in the report the Canadian data would need to be aggregated in a similar manner as the US data. That said, if the Canadian information was in a comparable format, we believe that you would likely draw conclusions analogous to the US from the Canadian statistics as well.

A. Definitions, Historical Trends and Projections

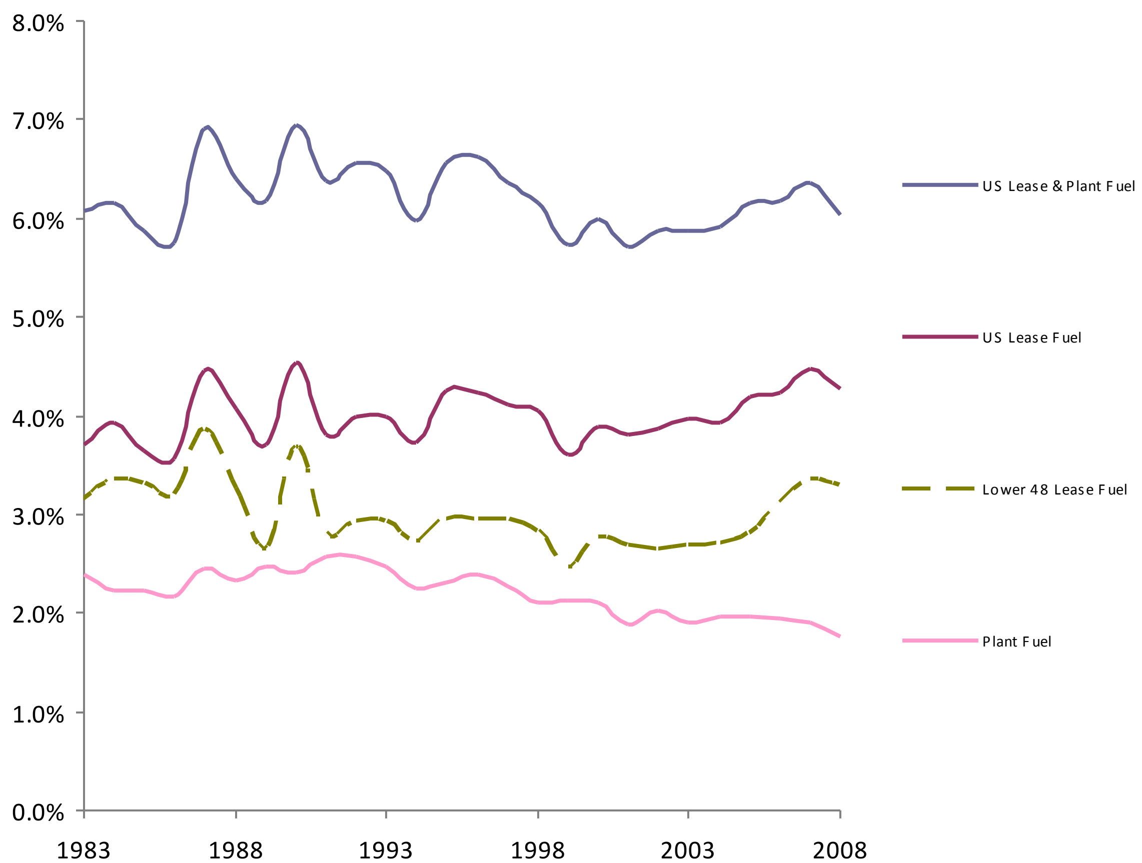
1. Lease and Plant Fuel Definitions

Lease fuel represents those quantities of natural gas used in well, field, and lease operations (such as gas used in producing operations, heaters, dehydrators, and field compressors); whereas, plant fuel is natural gas used as fuel in natural gas processing plants. These plants are distinguished as facilities designed to treat natural gas to meet pipeline specifications and recover natural gas liquids from produced natural gas.

Historical Trends

Lease and plant fuel has ranged between roughly 5.5% and 6.5% of US consumption since 1980, with the larger and generally increasing share consumed at the lease. Similarly, over the same time period, lease and plant fuel have maintained a very steady relationship with US natural gas production, averaging 6.1% over the last thirty years, as well as over the last ten years, with a deviation of 0.3% from the average over the last decade (Figure 4). Previous to 1980, lease and plant fuel use was significantly greater relative to production levels at the time. In 2008 US lease and plant fuel consumption were 2.4 and 1.0 Bcf/d, respectively.

Figure 4
US Lease & Plant Fuel Percent of Dry Gas Production



Since 1983 lease fuel alone, as a percent of US dry natural gas production has averaged 4.0%, while staying within a range of 3.5% to 4.5%. After removing data from Alaska (the state with the greatest lease fuel consumption and somewhat different driving factors at play due to its isolation and disconnect from Canada and US Lower 48 markets), lease fuel has increased 0.5% over the last few years. One factor may be the decline of shelf natural gas production in the Gulf of Mexico. GOM shelf production is generally associated with high pressure gas wells, which require less lease fuel. Plant fuel was relatively stable at 2.5% of US dry natural gas production from 1987 through 1992, then slowly declined through 2001 to a relatively stable level of 1.9% from 2001 to 2008.

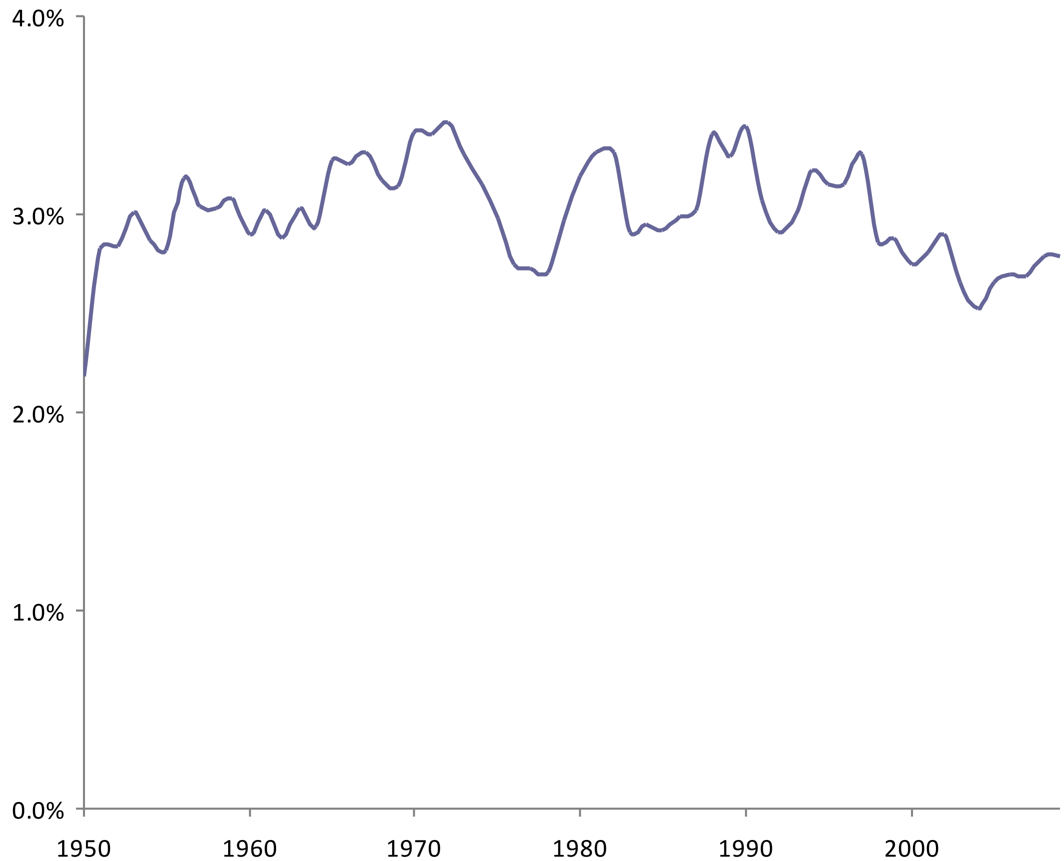
2. Pipeline and Distribution Fuel Definitions

Pipeline fuel is generally defined as gas consumed in the operations of natural gas pipelines, primarily in compressors; whereas distribution fuel is natural gas used as fuel in operations by various entities involved in the general distribution of natural gas.

a. Historical Trends

Pipeline and distribution fuel use has been running pretty steadily since 1950 at about 3% of total US consumption (see Figure 5). However, since 1998 this percentage has been consistently just under this long term historical average, at an average of 2.8%, having generally declined through 2004 to an historical low of 2.5% and increased somewhat thereafter to 2.8% in 2009. In 2009 pipeline and distribution fuel consumption were 1.7 and 0.08 Bcf/d, respectively. It is likely that recent figures are lower than the long-term historical average in part because of some increased use of electricity to power compressor stations. In recent years, when distribution fuel use data have been separately collected, it has represented about 5% of the total pipeline and distribution fuel consumption.

Figure 5
Pipeline and Distribution Fuel Use as a Percent of Total U.S. Natural Gas Consumption



B. Demand Outlooks for Natural Gas Transmission Fuel

Natural gas lease, plant, pipeline, and distribution fuel consumption projections are not of broad interest and are therefore not a significant focus of most general natural gas projections. Within the EIA's National Energy Modeling System (NEMS), which is used in producing the *Annual Energy Outlook*, natural gas lease and plant fuel consumption is set regionally using a historically based percentage of regional dry gas production. Pipeline and distribution fuel consumption is also set regionally, but based on regional natural gas throughput. These relationships are not assumed to change over the projection period. In the event that an Alaska pipeline is projected to be built in the model, additional lease, plant, and pipeline fuel volumes are added accordingly. As a result, on a national basis, the lease and plant fuel consumption as a percent of production and the pipeline and distribution fuel use as a percent of consumption do not vary appreciably over the projection period.

The *Annual Energy Outlook* includes a forecast comparison section that lists an "other" consumption category that is the sum of lease, plant, pipeline, and distribution fuel use, as well as natural gas used in vehicles. The 2010 version includes other consumption projections from EIA, as well as from IHS/Global Insight (IHSGI), Energy Ventures Analysis, Inc. (EVA), and Strategic Energy and Economic Research, Inc. (SEER). While the assumptions behind these other projections are not known, Table 1 provides the resulting projections of "other" consumption as a percent of total US dry gas production for 2015 and 2025.

Table 1

Projections of Lease, Plant, Pipeline, and Distribution Fuel Consumption as a Percent of US Dry Gas Production

	2015	2025
EIA	8.97%	9.39%
IHSGI	8.40%	9.45%
EVA	8.54%	9.67%
SEER	9.20%	8.92%

Source: Energy Information Administration, Annual Energy Outlook 2010, May 11, 2010.
[Note: Also includes natural gas used in vehicles, which for the EIA figures increased these percentages in 2015 and 2020 by 0.03 and 0.05, respectively.]

With the exception of SEER, each of the projections show an increase in lease, plant, pipeline, and distribution fuel consumption relative to domestic production projections. Unfortunately, it is not known in most cases how much of this increase is a result of growth in natural gas vehicle use.

II. Lease and Gas Plant Fuel Discussion and Outlook

A. General Discussion

The processing of wellhead natural gas into pipeline quality dry natural gas can be quite complex and usually involves several processes to remove: (1) oil and condensate; (2) water and water vapor; (3) elements such as oxygen, nitrogen, mercury, and helium, and compounds such as hydrogen sulfide and carbon dioxide; and (4) natural gas liquids (NGLs). In addition to these four processes, it is often necessary to add compression and/or install heaters at the lease near the wellhead. The gas-fired heaters stabilize oil production during cooler weather when NGLs condense from natural gas into crude oil. Compression may be required to boost pressure for delivery into gathering or transportation systems. The wells on a lease or in a field are connected to downstream facilities via a process called gathering, wherein small-diameter pipes connect the gas production to gas processing/treating facilities. Gathering systems can span large areas in square miles and connect hundreds or thousands of wells, each with their own production characteristics. There may be a need for intermediate compression, as well as treatment plants to remove water vapor, carbon dioxide, and sulfur compounds upstream of the processing plant.

Where pipeline quality natural gas is produced at the wellhead or field facility, the natural gas is moved directly to receipt points on the pipeline grid. Gas production not meeting pipeline quality is gathered to natural gas processing plants for NGL extraction, treating, and delivery of remaining natural gas at the plant tailgate. A natural gas processing plant typically receives gas from a gathering system and sends out processed gas via an output (tailgate) pipeline connected to one or more major intra- and inter-state pipeline networks. NGLs removed at the processing plant usually are transported to NGL fractionators. NGL Fractionation is a critical process in the production of natural gas, as Fractionators separate the NGLs into usable purity products (ethane, propane, butanes, and natural gasoline). These products are transported to petrochemical plants, refineries, and other customers. (1-p3)

Most large, modern natural gas processing plants use an efficient cryogenic turbo-expander process to extract the NGLs at extremely low temperatures. Older gas processing plants use a less efficient lean oil absorption process rather than the cryogenic turbo-expander process. There are other processes also in use today, such as external refrigeration units using propane as the refrigerant, and units achieving low temperatures by expansion from the pressure drop across a Joules-Thompson valve, all with the purpose of recovering NGLs. The recovery efficiencies and fuel consumption of each of the above processes are different, with the cryogenic turbo-expander process generally being the most efficient of all.

In general, all produced gas requires fuel to remove water content and to meet pipeline specifications. Lease and gas plant fuel is required to make the gas and crude oil production marketable. Gas plants remove NGLs, water vapor, carbon dioxide, hydrogen sulfide, nitrogen, and other constituents, and compress the processed gas to meet transmission pipeline specifications and enter into the Natural Gas Transmission network. Each step in the process requires fuel. To put it into context from a consumption perspective, historically, about 6% of total natural gas produced is consumed as lease and plant fuel to enable the natural gas to enter into the Natural Gas Transmission network. In addition to the above, there is a 0.5% fuel usage for NGL Fractionation into its purity products, which is not considered in this study.

It is important to note that the natural gas lease and processing assets are the culmination of decades of investment by hundreds of companies (over 180 gas plant operators in the US in 2009 alone) and combine legacy components with up-to-date retrofit improvements.

1. US Lease and Gas Plant Statistics
    a. More than 450,000 producing leases and offshore platforms (2)
    b. 579 gas plants and 33 NGL fractionators (3)

c. According to the EIA, 2008 lease fuel consumption was 2.4 Bcf/d and natural gas plant fuel consumption was 1.0 Bcf/d, for a total lease and plant fuel consumption of 3.4 Bcf/d.

B. Key Drivers for Lease and Gas Plant Fuel Demand

1. Lease and plant fuel is proportional to dry production with fuel rates determined to a large extent by the amount of engine driven compression horsepower required to boost the natural gas pressure to its various delivery points in the production chain from (1) separation at the lease, (2) treating, (3) gathering, (4) dehydration, and (5) plant processing for NGL recovery for delivery to a pipeline or distribution system. Overall lease and plant fuel consumes about 6.0% of dry production and has grown from 2003 to the present at a modest rate of 0.034% per year. Compression fuel is a substantial portion of the total lease and plant fuel.

2. Lease and plant fuel is dependent upon gas quality and type of production. Type of gas production ranges from high pressure well gas to low pressure gas associated with crude oil production and gas produced from enhanced oil recovery (CO_2 or steam floods). NGL content and acid gases (CO_2 and H_2S) in produced natural gas, and low wellhead pressure increase fuel demand. Lease fuel can range from 0.3% of gas production (high pressure gas well with gas meeting pipeline specifications) to 100+% in enhanced oil recovery operations.

3. Lease and plant fuel volumes are impacted by several drivers:

a. Conventional US gas production from producing wells declines at a rate of about 8% per year.

b. With continuing high oil and low gas market prices, there has been a shift in exploration to the development of oil reserves and/or high NGL content natural gas versus dry natural gas. Lower wellhead pressure is required to produce gas associated from oil production and high NGL content natural gas. Low wellhead pressure gas requires more lease fuel to compress the gas to plant and pipeline receipt pressures.

c. Declining bottom hole pressures in older reservoirs require more lease compression and hence more fuel.

d. Over the last 25 years, compressor unit technology (driver and compressor) have seen significant improvement in fuel consumption and emission reductions. As a result of these advances, the overall design efficiency of a gas turbine-driven centrifugal compressor unit now is close to 33%, which is a 50% improvement over the machines deployed 20 years ago. In addition, there have been advances in reciprocating engine technology. Since 1995 the efficiency of newer and more sophisticated gas-fired reciprocating engines has increased by 4 percent (from 42% to 46% peak thermal efficiency at 100% load) while at the same time the effectiveness of emissions control systems has improved to meet increasingly stringent NO_x requirements. Higher speed reciprocating engines (30% to 43% thermal efficiency) are used to power high horsepower, low speed, reciprocating compressors (80% to 92% compressor efficiency) to improve overall compressor unit efficiency. (5-p19-20) New production leases and gas processing plants will utilize the more fuel efficient compression; and the older technology compression with higher fuel rates will slowly be rationalized due to declining production. Eight gas processing plants (net) were added in the US from 2006 to 2009 with 3 Bcf/d of design capacity. (3)

e. Cryogenic processing technology is currently optimized. There are no major technology improvements on the horizon affecting fuel and extraction efficiencies.

f. Tightening of greenhouse gas emissions legislation and regulations, over time could reduce natural gas used for lease and gas plant fuel. However the long-lived nature of compression assets – typically depreciated over decades – would suggest no rapid pace of replacement to the existing fleet of compressors. Further it should be considered that lease and gas processing plant operators already are motivated to monitor and maintain equipment to reduce fuel used in operations, both as a matter of competitive advantage and, ultimately, profit optimization.

C. Other Considerations

Expansion of lease and natural gas gathering and plant infrastructure generally requires growth in the natural gas market. Still, even in a flat to declining market, additional natural gas pipeline and storage assets will likely be required to accommodate natural shifts in the supply and demand. (6-p9) “Most of the new pipeline capacity added in the last 30 years has been to deliver new supply to existing load or load that has shifted regionally. Both the Interstate Natural Gas

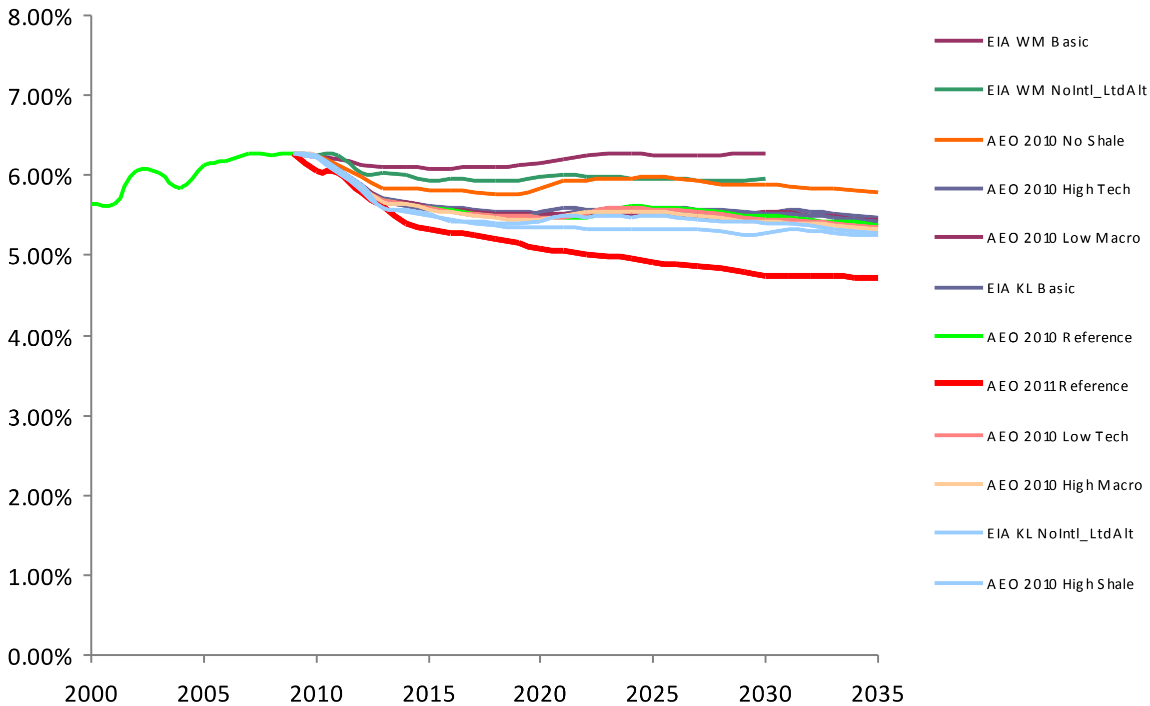
Association of America (INGAA) and the EIA expect that trend to continue as existing production is replaced with new supplies from new supply areas." (7-p43)

Federal, state, and local environmental and siting regulations often have an effect on an operating companies' ability to optimize equipment design efficiency. For instance, a lease or plant may be in an area with strict emissions limits. Consequently, the operating company needing to increase throughput capacity may not be able to install a compressor driven by either a gas-powered reciprocating engine or a gas turbine, even if the gas-powered compressor would have been the most efficient solution under the circumstances. Therefore, the company may need to install an electric motor to drive a compressor (which would have no emissions at the site) and/or install smaller gas driven compressors in multiple locations on separate leases to meet the emissions limits (which will require additional investments in land and equipment and will be much costlier). These choices actually may push the operating company to purchasing decisions that reduce both economic and gathering efficiency. (5-p23)

D. Demand Outlook for Lease and Plant Fuel

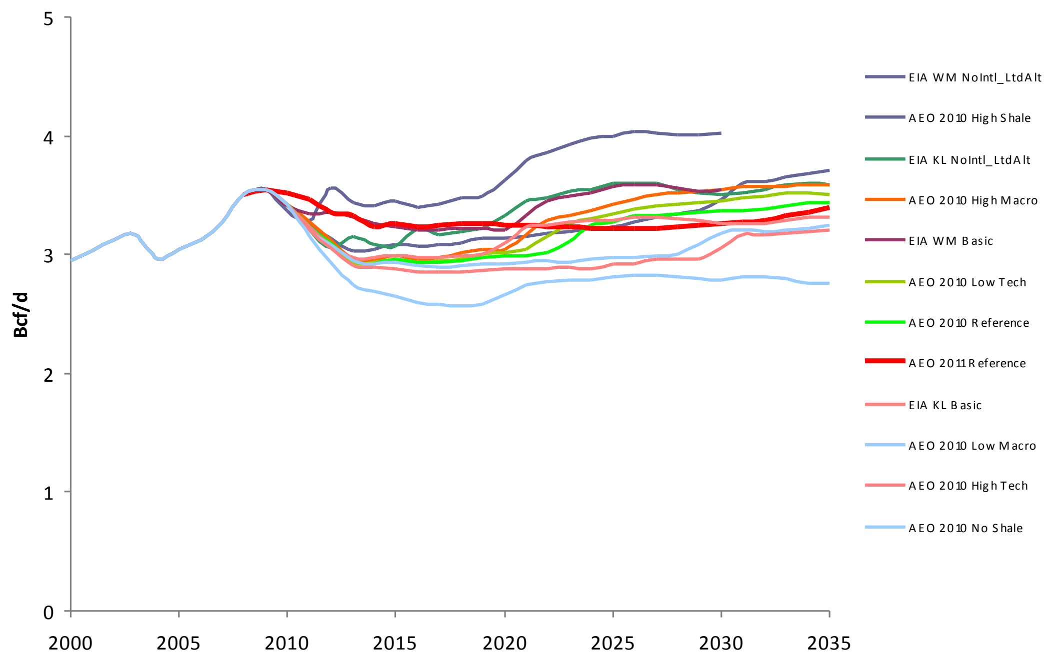
Lease and plant fuel as a percent of dry production is expected to generally range from 5.5% to 6.5% of dry gas production (see Figure 6).

Figure 6
US Lease and Plant Fuel Percent of Dry Proudction



Lease and plant fuel demand is expected to generally range from 2.5 to 4.0 Bcf/d depending primarily on US dry gas production (see Figure 7).

Figure 7
US Lease & Plant Fuel



Finding

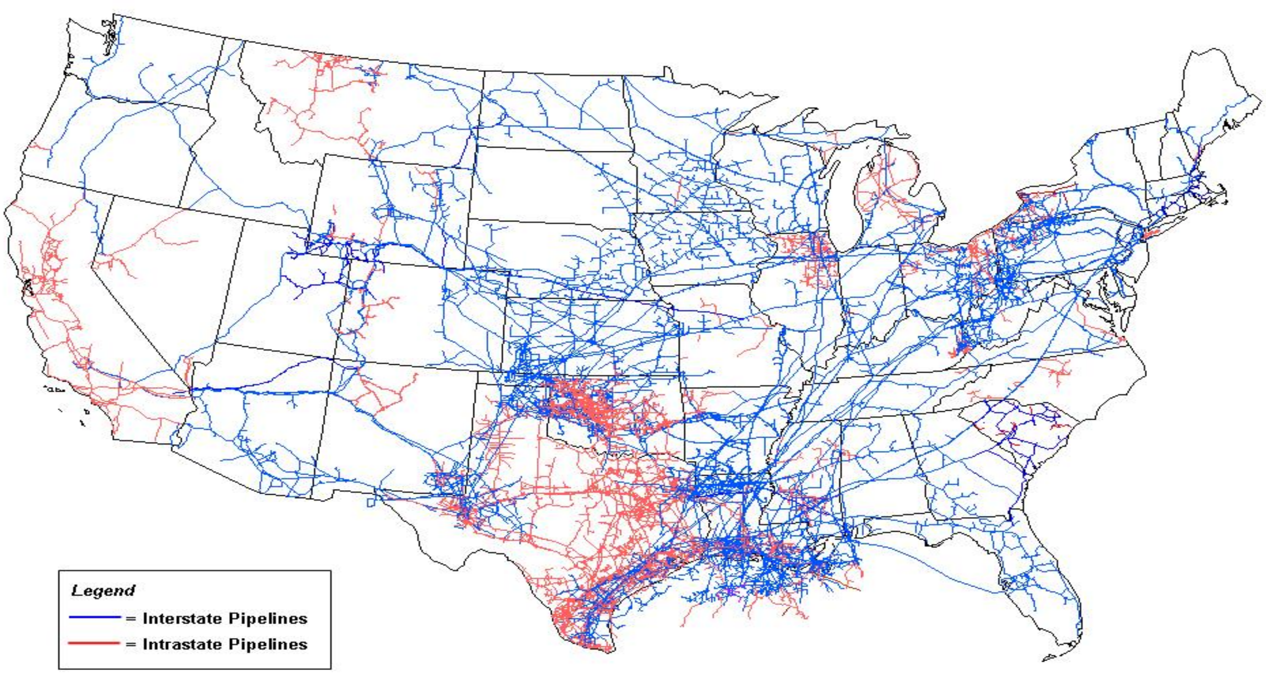
It is reasonable to assume that natural gas consumption linked to lease and gas plant fuel in the US will stay within the historical range of about 5.5% to 6.5% of dry gas production for the foreseeable future.

III. Natural Gas Pipeline and Distribution Fuel Discussion

It is broadly accepted that the US and Canadian natural gas delivery markets are mature, robust, and reasonably integrated. Today, the North American Natural Gas Transmission network is a complex web of interstate and intrastate pipelines supplying US end-users with 64 Bcf/d of natural gas (see Figure 8). Large-diameter, high-pressure pipelines use compression to push natural gas through trunk lines often hundreds, or even thousands, of miles to the city gates of local distribution companies and large, direct-connect consumers. (7-p40) To put it into context from a consumption perspective, historically, about 3% of total natural gas throughput is consumed as fuel to move natural gas from supply basins to end-users. (8)

Figure 8.

US Natural Gas Pipeline Network, 2009



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

The natural gas pipeline grid is comprised of:

1. More than 210 natural gas pipeline systems.
2. 305,000 miles of interstate and intrastate transmission pipelines.
3. More than 1,400 compressor stations that maintain pressure on the natural gas pipeline network and assure continuous forward movement of supplies.
4. More than 11,000 delivery points, 5,000 receipt points, and 1,400 interconnection points that provide for the transfer of natural gas throughout the United States.
5. 24 hubs or market centers that provide additional interconnections.
6. 400 underground natural gas storage facilities.
7. 49 locations where natural gas can be imported/exported via pipelines.
8. Liquefied natural gas (LNG) import facilities. (4-p23)

It's important to note that this complex pipeline network is the culmination of decades of investment by over 200 pipeline companies and combines legacy components with up-to-date retrofit improvements.

A. Key Drivers for Pipeline and Distribution Fuel Demand

Expansion of Natural Gas Transmission infrastructure generally requires growth in the natural gas market or development of new sources of supply. Still, even in a flat to declining market, additional natural gas pipelines and storage assets will likely be required to accommodate natural shifts in the supply and demand. (6-p9) "Most of the new pipeline capacity added in the last 30 years has been to deliver new supply to existing load or load that has shifted regionally. Both Interstate Natural Gas Association of America (INGAA) and EIA expect that trend to continue as existing production is replaced with new supplies from new supply areas." (7 - p43)

From an efficiency perspective, delivering natural gas via a pipeline is an effective means of transporting energy over long distances. In comparable energy terms and over equal transportation distances, natural gas compressor stations consume an average of 2% to 3% of throughput to overcome friction losses. (5-p1) For comparison, electric transmission lines lose 6.5% of the energy they carry due to electric resistance. (9)

Naturally, pipeline companies will attempt to be as efficient as possible while balancing efficiency with the need to provide dependable and flexible service to shippers. "For example, pipeline companies often guarantee a sufficiently high delivery pressure so that local distribution company customers do not need to install additional compression behind their city gates. While this may reduce the transportation efficiency of the interstate pipeline, it increases the overall efficiency of the wellhead-to-burner tip value chain." (5-p2) Notwithstanding, federal, state, and local environmental and siting regulations often have an effect on pipeline companies' ability to optimize design efficiency. If a pipeline is in an area with strict emissions limits, the pipeline company may not be able to install a compressor driven by either a gas-powered reciprocating engine or a gas turbine, even if the gas-powered compressor would have been the most efficient solution under the circumstances. The pipeline company may need to relocate compression to a less than optimal area outside of the non-attainment area, install an electric motor to drive a compressor (which would have no emissions at the site), and/or install larger diameter pipeline in lieu of additional compression (which may require additional right-of-ways and will be much costlier than compression). Or perhaps, even reroute the pipeline all together. These choices actually may push the pipeline company to purchasing decisions that reduce both economic and transportation efficiency. (5-p23)

Also, the increasing use of natural gas to generate electricity, both as a back-up to intermittent sources of renewable power and as a cleaner alternative to coal-generated power, means that pipelines do not operate as efficiently as they could if demand were constant and predictable. This reduced efficiency, however, is more than offset by the overall environmental and public health benefits gained by the increased use of natural gas to power generation. (5-p2)

It is important to note that each pipeline system is unique. Consequently a "one-size-fits-all" approach to seeking efficiency improvements will not work. This is because each pipeline system's age, geographic location, original design, modifications, and shifting transmission patterns all are distinct. Therefore, an improvement may be cost effective on one pipeline system but not be feasible or economic on another pipeline system. (5-p3) Due to this reality, the greatest opportunity for maximizing either economic or transportation efficiency is in the initial design and construction phase of a major facility. (5-p3)

B. Factoring in Carbon Reduction Efforts

If Congress were to enact legislation which adds a cost to emitting greenhouse gases (GHG), over time it is likely that natural gas used for pipeline and pipeline and distribution fuel could be reduced. Although GHG emissions are not the sole criteria in choosing to use electric or natural gas compression where compression is needed to maintain necessary operating pressures, any cost for emissions would be a factor. However the long-lived nature of compression assets – typically depreciated over 40 years – would suggest no rapid pace of replacement to the nation's existing fleet of compressors. Further it should be considered that pipeline operators already are motivated to monitor and maintain equipment to reduce fuel used in operations, both as a matter of competitive advantage and, ultimately profit optimization. Fuel used in operations is an independent and transparent variable for customers with pipeline flow through transportation alternatives.

Finally, the Natural Gas Act provides that interstate natural gas pipelines are entitled to recover prudently incurred costs, including a reasonable return on net investment in used and useful capital assets. As interstate gas pipelines invest in equipment that would reduce GHG emissions, they have the option of filing rate cases to recover and earn a return on that investment. As pipelines incur GHG emissions costs via fuel used in operations, fuel trackers or surcharges are established mechanisms for recovering those costs. Pipelines are motivated to minimize these operating costs to gain competitive advantage, even when actual costs may be recovered in rates or via fuel surcharges.

C. Compression Unit Selection Overview

"After a pipeline company determines the optimal balance between pipeline specifications and horsepower requirements, it selects the compressor units that best meet its load profile and operating needs. A number of considerations go into the selection including: (1) forecasted operating conditions, (2) the unit's air emissions to ensure compliance with air quality regulations, (3) the upfront, installed costs, (4) the projected operating costs, (5) the projected maintenance costs and availability of replacement parts, (6) compatibility of the unit with the existing compressor fleet, (7) the overall efficiency of the compressor unit (i.e., a combination of the thermal efficiency of the prime mover and the compression efficiency of the compressors themselves), (8) the reliability of compressor unit components, and (9) the expertise of pipeline personnel with particular equipment." (5-p30)

Typical drivers used in pipeline applications include: reciprocating gas engines, gas turbines, and electric motors.

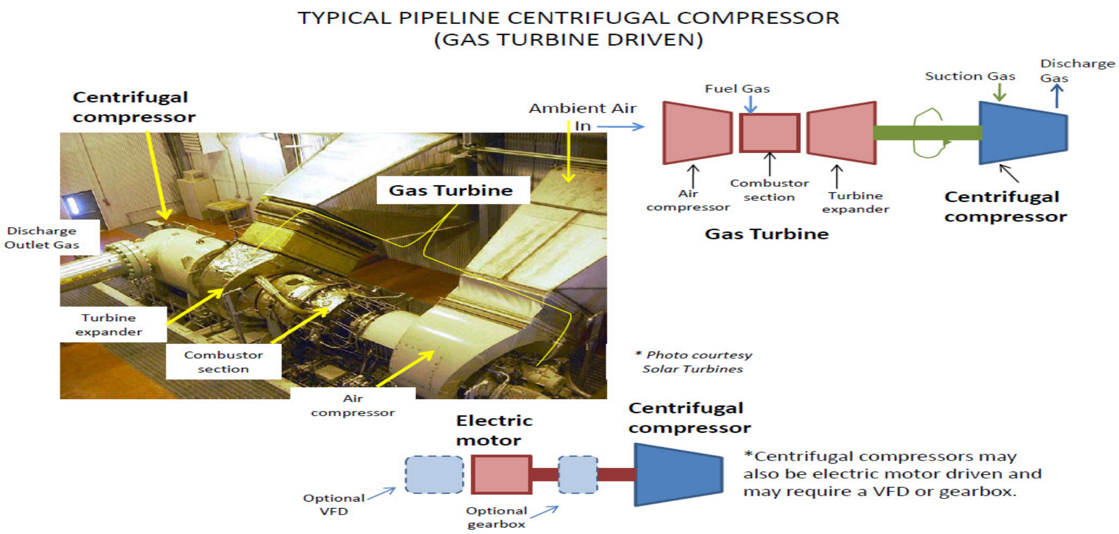
1. Reciprocating Gas Engines

Similar to an internal combustion (gas-fired reciprocating) engine used in a motor vehicle, the reciprocating gas engine uses a chamber, filled with natural gas, to drive a piston. The gas is ignited and combusted to cause the piston to move. Low speed and high speed engines are matched with compressors of corresponding speed. Legacy internal combustion, slow speed engines have significantly less sophisticated controls and lower fuel efficiencies than state-of-the-art engines. While today's reciprocating engines are quite efficient**,** they do have power limitations and can have high vibration issues that affect reliability. Certain components may be high maintenance, and the engine units require ample spare parts and service contracts as back up.

2. Gas Turbines

Gas turbines rely on the hot exhaust gas produced from the discharge of a gas generator to drive a power turbine (see Figure 9). The shaft output power from the power turbine is used to drive the pipeline gas compressor. Two types of turbines are used: (1) the aero derivative engine, which is based on gas turbines developed for the aviation industry (the hot exhaust gas is used to push the aircraft through the air rather than through a power turbine) and (2) the industrial turbine which is designed specifically for industrial use. Aviation industry developments have contributed to the continual improvement in performance (in terms of power and efficiency) of both aero derivative and industrial gas turbines.

Figure 9

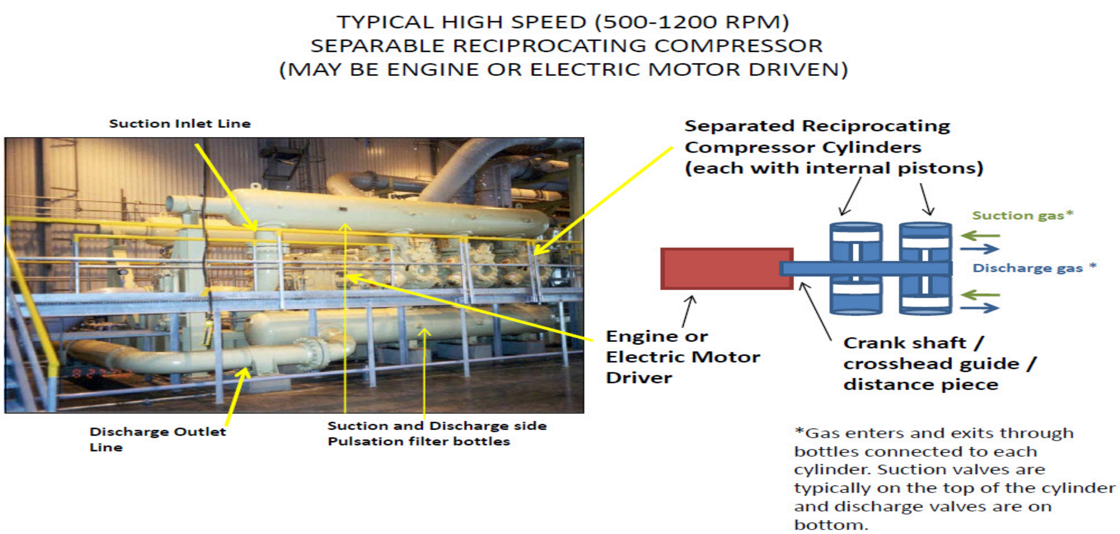


Source: Interstate Natural Gas Association of America, *Interstate Natural Gas Pipeline Efficiency*, October 2010.

3. Electric Motors

Electric motors are reliable and more efficient as stand-alone pieces of equipment than either reciprocating engines or gas turbines (see Figure 10). They are able to ramp up quicker than reciprocating engines or gas turbines. They also have an advantage where air quality regulations are an issue because they do not emit NO_x and CO_2 at the point of use. There are a number of competing factors, however, that affect the suitability of using an electric motor as the prime mover for a pipeline compressor. One is the relatively high cost of electric motors and the auxiliary equipment, training, and maintenance needed to support them. The availability and proximity of a suitable electric power supply or substation is also an issue, because it can be costly to install a new interconnecting electric power transmission line, and it may be difficult to obtain the necessary regulatory approvals. Reliability of the electric power transmission grid (overhead transmission lines are susceptible to damage in severe weather conditions), availability and cost of power from the local distribution company, and the obligation to pay electric demand charges even when the unit is not running are additional factors when considering installation of an electric motor. In addition, looking ahead to GHG regulations, the carbon footprint advantage that electric motors have over the reciprocating engines and gas turbines at the site is offset by high-energy losses in the transmission of electric power and the higher carbon footprint of the electric generation power source (e.g., electricity from coal).

Figure 10.



Source: Interstate Natural Gas Association of America, *Interstate Natural Gas Pipeline Efficiency*, October 2010.

The pipeline company's compressor selection (centrifugal or reciprocating) usually dictates the choice of the prime mover (gas turbine, reciprocating engine, or electric motor). Natural gas-powered reciprocating engines generally are limited to driving reciprocating compressors.

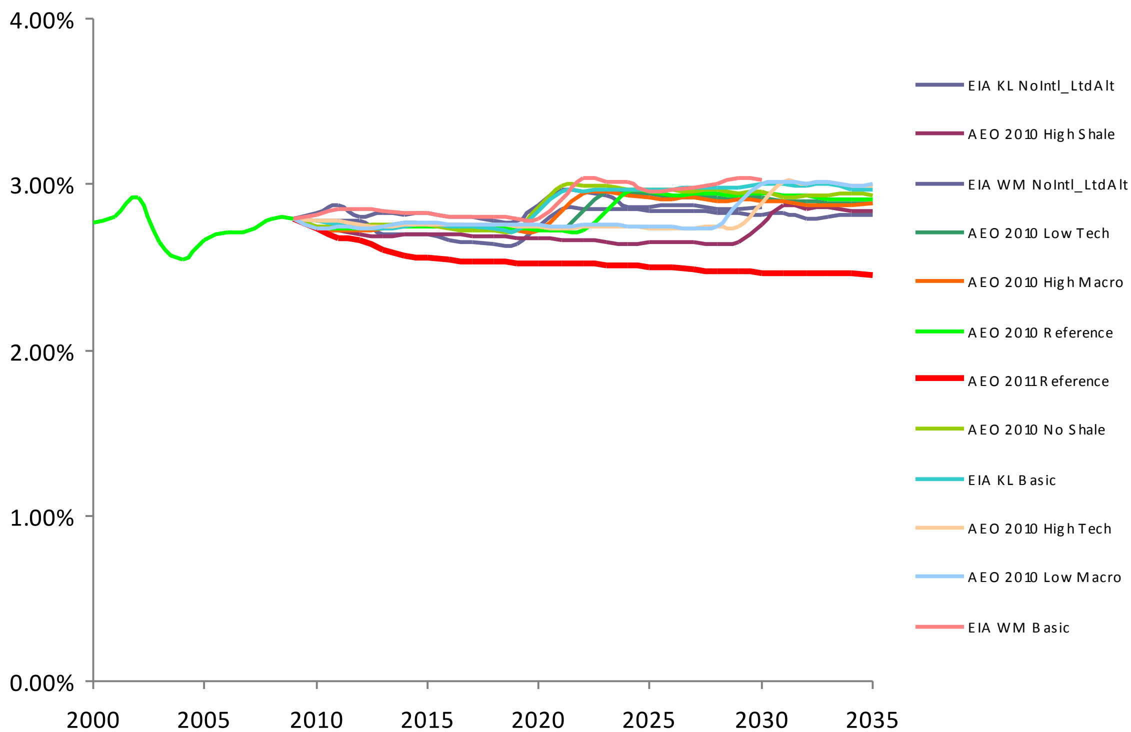
Natural gas-powered turbines generally are limited to driving centrifugal compressors. Electric motors may be used with either compressor technology, although pipeline companies have begun using electric motors to power centrifugal compressors on a more widespread basis than reciprocating compressors.

The upfront cost of component parts is an important consideration for pipelines when selecting compressors. Life cycle and avoided costs, where applicable, are also factors to be considered. Low speed compressor units powered by reciprocating engines are the most expensive option in terms of installation cost ($/hp). Gas-fired combustion turbines and electric motors have approximately the same installed cost. " (5-p34-35)

D. Demand Outlook for Pipeline and Distribution Fuel

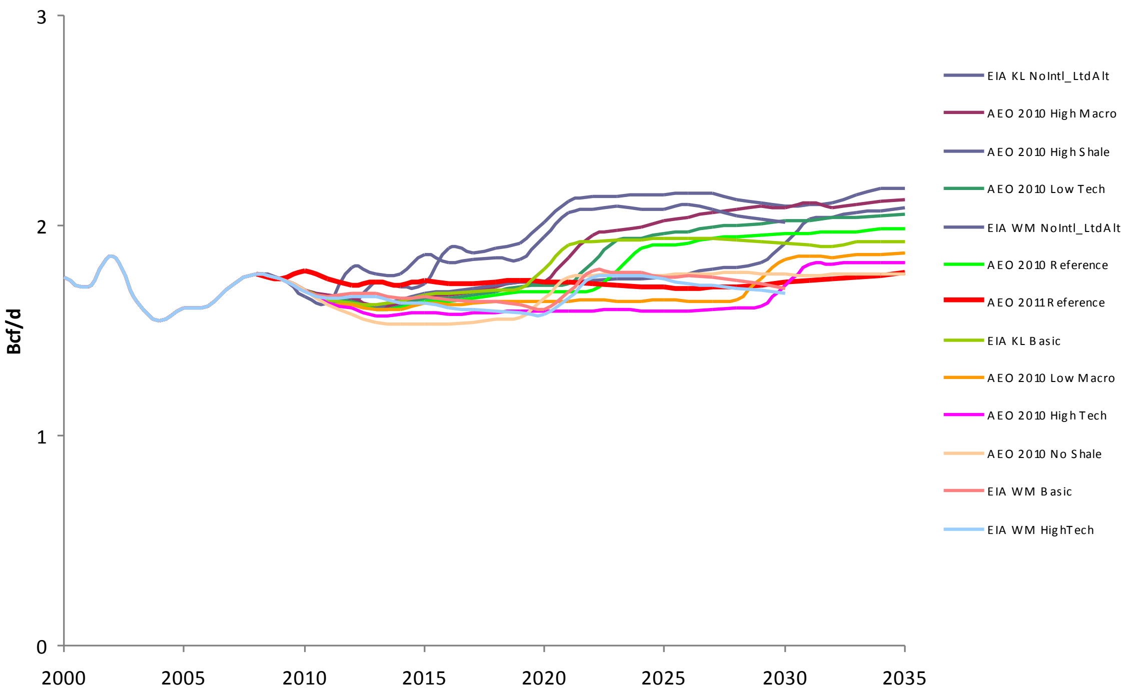
US pipeline and distribution fuel as percent of throughput (demand) is expected to generally range from 2.6% to 3.1% of throughput (see Figure 11).

Figure 11
Pipeline and Distribution Fuel Percent of Throughput



Pipeline and distribution fuel demand is expected to generally range from 1.5 to 2.2 Bcf/d depending primarily on US throughput (demand) (see Figure 12).

Figure 12
Pipeline & Distribution Fuel



Finding

It is reasonable to assume that natural gas consumption linked to pipeline and distribution fuel in the US will stay within a range of about 2.6% to 3.1% of throughput (demand).

Appendix - EIA Data Collection Overview for Lease, Plant, Pipeline, and Distribution Fuel

The methods used by the EIA for collecting and reporting such natural gas data have changed over the years as survey forms have been added and revised. For instance, lease and plant fuel have only been reported separately since 1983.

Since 1980, EIA has collected annual natural gas production data and related information, such as lease fuel consumption, from state agencies either on an informal basis, using Form EIA-627, or using the current Form EIA-895, "Monthly and Annual Quantity and Value of Natural Gas Production Report." As this is a voluntary survey, requested by state agencies that collect data on the volume of natural gas production in the State and the US Minerals Management Service for the Outer Continental Shelf, only 20 states reported volumes for lease fuel consumption in 2008, while all but one of the producing states provided data on natural gas production. To account for the missing data, EIA estimates lease fuel by assuming it to be a function of gross withdrawals of natural gas from gas, oil, and coal bed methane wells. The ratio used for missing states is either derived from company-owned on-system production and lease use reported on Form EIA-176 (a very limited representation of total production) or taken as an average of the state's historical ratio.

EIA collects data for plant fuel use from a question on Form EIA-64A, a required form to be filed annually by all natural gas processors who process gas produced in the United States. Processors are also asked to report on the volumes of gas received (including from which state/sub state it is produced), the shrinkage resulting from the extraction, and the amount of natural gas liquids produced on an annual basis. By only looking at domestically produced gas, the plant fuel used in processing gas from Canada, particularly from the Alliance Pipeline is presumably not included.

The volumes reported in EIA's *Natural Gas Annual* for pipeline and distribution fuel are collected on EIA's mandatory Form EIA-176 from the following respondents: interstate and intrastate natural gas pipeline companies; natural gas distribution companies; underground and liquefied natural gas storage operators; synthetic natural gas plant operators; field, well, or processing plant operators that either deliver natural gas directly to consumers (including their own industrial facilities), other than for lease or plant use or processing, or that transport gas to, across, or from a State border through field or gathering facilities.

The respondents are asked for "Natural gas consumed in your operations for pipeline or storage compression and pipeline distribution use" and are distinguished by pipeline/storage, distribution, new pipeline fill, and other. LNG facilities often include vaporization volumes as "other," while gatherers often include volumes of gathering condensate, vented gas and water. Any volumes reported as "other" or "new pipeline fill" are not currently used or included in a sector volume or other published value in EIA's reporting. Table 3 shows the 2008 volumes reported by respondent category and fuel use category. It is important to note that respondents can identify in more than one category, resulting in some volumes entered into more than one row in the table and some double counting if totals are taken. The "proper total" at the end of the table is without any double counting.

Table 3.

2008 Pipeline and Distribution Fuel Use by Respondent Category

(Million cubic feet)

	Pipeline compression	New pipeline fill	Distribution	Other
Distributor	16,412	39	17,080	10,093
Interstate pipeline	515,257	1,433	2,855	56,629
Intrastate pipeline	157,356	416	6,750	41,711
Storage operator	200,007	299	6,881	47,256
SNG plant operator	0	0	330	368
Producer	25,852	0	5,071	14,202
Gatherer	80,717	24	6,970	23,840
LNG operator	16,654	23	1,955	11,432
Other	14,248	344	2	8,283
Sum of above	1,026,503	2,578	47,894	213,813
Proper total	620,240	1,837	27,718	90,004

Source: Energy Information Administration, EIA-176 Query System

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