8. Development of Natural Gas Supply Curves for EPA Platform v6

8.1 Introduction

Natural gas supply curves and regional basis are key inputs to IPM and are developed using ICF's Gas Market Model (GMM). ICF develops and maintains the GMM for use by both private and public sector clients. The model has been used to examine strategic issues relating to natural gas supply, pipeline infrastructure, pricing, and demand characteristics.

Like IPM, GMM is a large-scale linear programming model that incorporates a detailed representation of gas supply characteristics, demand characteristics, and an integrating pipeline transportation model to develop forecasts of gas supply, demand, prices, and flows. GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by each scenario. Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand at each node in the model.

On the supply side, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization. Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand side, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices. ICF updates GMM model inputs and performs calibration of the model on a monthly basis to ensure the model reliably reflects historical gas market behavior. Figure 8-1 shows the supply side of the calculation in GMM, and Figure 8-2 shows the interaction of IPM and GMM.
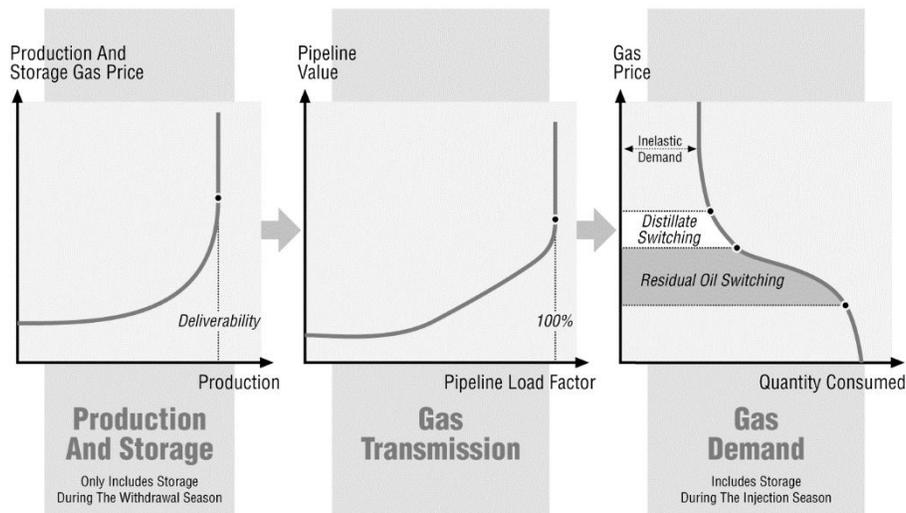
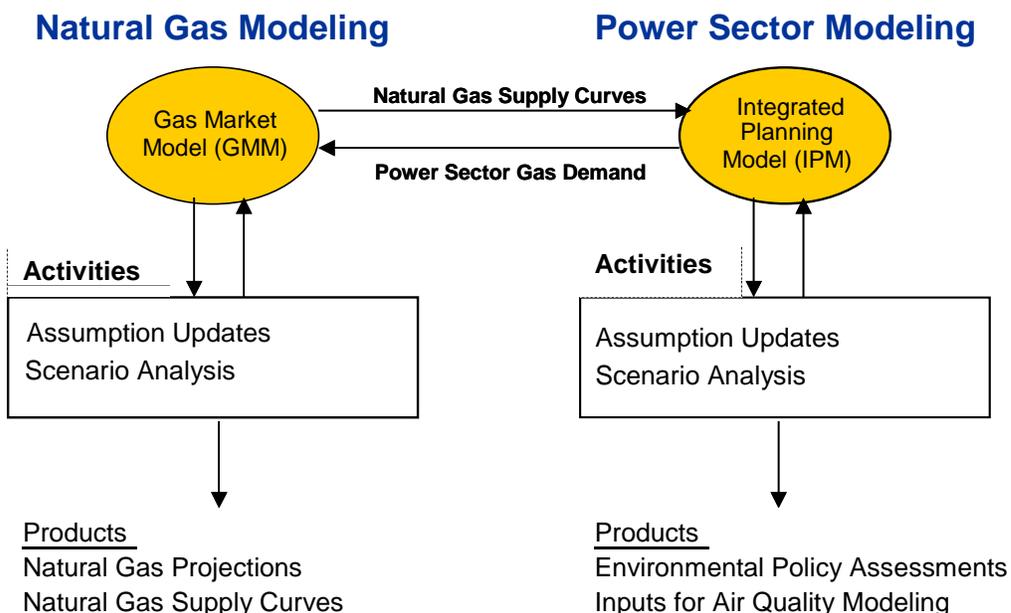### Figure 8-1 GMM Gas Quantity and Price Response

Figure 8-2 IPM/GMM Interaction

Natural Gas Modeling

Power Sector Modeling

Natural Gas Supply Curves

Gas Market Model (GMM)

Integrated Planning Model (IPM)

Power Sector Gas Demand

Activities

Assumption Updates

Scenario Analysis

Activities

Assumption Updates

Scenario Analysis

Products

Natural Gas Projections

Natural Gas Supply Curves

Products

Environmental Policy Assessments

Inputs for Air Quality Modeling

To establish gas supply curves in EPA's Platform v6, both GMM and IPM are operated in tandem and are iterated to develop a consistent Henry Hub gas price and total gas demand forecast that informs the derivation of those supply curves. In subsequent analyses using IPM, EPA's Platform v6 will continue to use these originally derived gas supply curves (without necessitating re-modeling in GMM), unless otherwise documented with a given scenario analysis. EPA's Platform v6 uses natural gas market assumptions in power market modeling as follows:

- IPM takes the natural gas supply curves, which are developed based on GMM outputs and specified as a function of Henry Hub prices.
- For each year, three sets of seasonal natural gas transportation differentials (summer, winter, and winter shoulder) are added to the supply curves to generate the final delivered curves by IPM region.
- IPM projects the power sector's demand for natural gas. The natural gas demand is compared to the supply curve to find the market-clearing price for natural gas.
- IPM's linear programming formulation takes into consideration the gas supply curves as well as coal supply curves and detailed power plant modeling in determining electric market equilibrium conditions. Oil usage is modeled as a function of price, which is exogenously supplied to IPM.

This chapter is divided in the following sections. The chapter starts with a brief synopsis of GMM, the primary tool used for generating the natural gas supply curves. This is followed by detailed discussions of modeling methodologies and data used in GMM. The methodologies and data description are grouped in the following five sections:

i) Resources data and reservoir description
ii) Treatment of frontier resources and exports
iii) Exploration and production technology characterization
iv) Oil prices
v) Demand assumptions

This is followed by discussion of natural gas assumptions and supply curves used for EPA Platform v6.

8.2   Brief Synopsis of GMM

ICF's integrated natural gas model, GMM, is designed to perform comprehensive assessments of the entire North American gas flow pattern. It is a large-scale, dynamic linear program that models economic decision-making to minimize the overall cost of meeting natural gas demand. GMM is reliable and efficient in analyzing the broad range of natural gas market issues.

Figure 8-3 Geographic Coverage of GMM
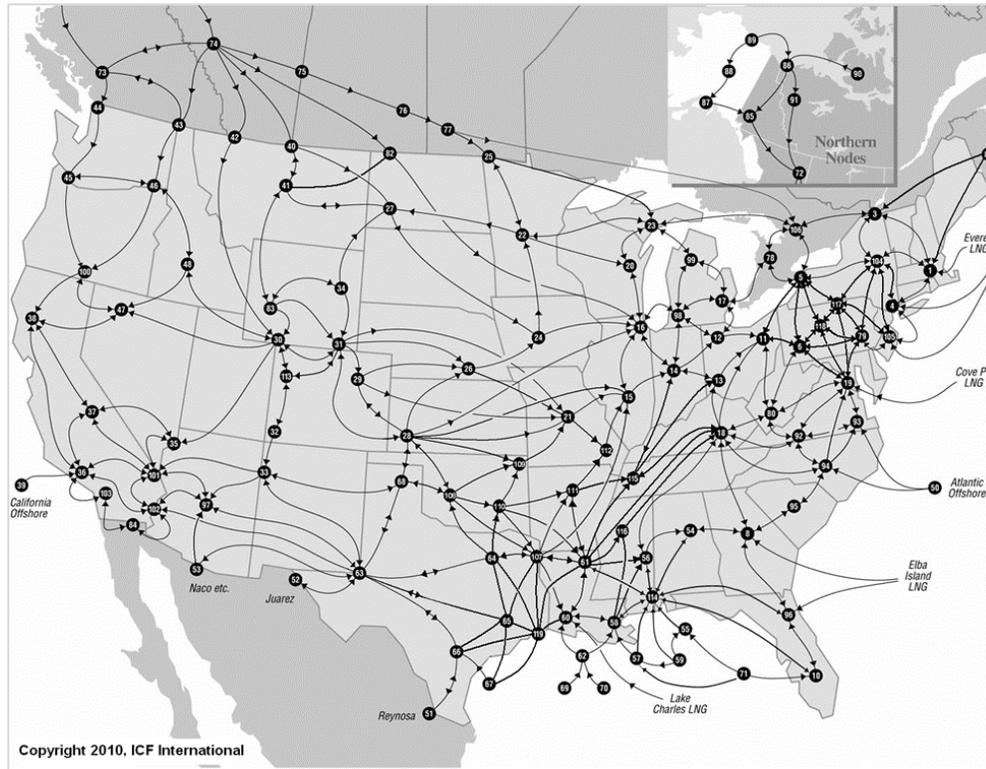
Important features of GMM are described below.

Natural Gas Market Prices in GMM are determined by the marginal (or incremental) value of natural gas at 121 regional market centers. Prices are "at the margin", not "average". Marginal prices do not translate directly into pipeline or utility revenues. Prices represent "market center" prices as opposed to delivered prices. Gas prices are determined by the balance of supply and demand in a regional marketplace. Supply is determined considering both availability of natural gas deliverability at the wellhead, the transportation capacity and cost to deliver gas to market centers.

Natural gas production prices are determined from spot gas price curves that yield price as a function of deliverability utilization: Curves reflect price for gas delivered into the transmission system (including gathering cost). Gas storage withdrawal price curves are added to the production price curves during the withdrawal season. Pipeline value curves are then added to yield a total supply curve for a node. The intersection of the supply curve and the demand curve (including net storage injections) yields the marginal price at a node. Price is set by the demand curve when all available supply is utilized.

Demand is modeled for residential, commercial, industrial, and power sectors for each of the 121 nodes. GMM solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. Econometric equations define demand by sector. The industrial

and power sectors incorporate fuel competition, dispatch decisions, new power plant builds, economic growth, and weather. GMM solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. GMM iterates with IPM to better capture electric sector demand for natural gas.

Electric generation is modeled regionally with plant dispatch based upon operating cost. Competing power generation technologies are evaluated on a full-cost basis to determine lowest cost capacity additions.

Transportation is modeled by over 423 transportation links between the nodes, balancing seasonal, sectoral, and regional demand and prices, including pipeline tariffs and capacity allocation. Node structure developed to reflect points of change or influence on the pipeline system. These points include: major demand and supply centers, pipeline hubs and market centers, and points of divergence in pipeline corridors. The pipeline network is largely represented as bundles of pipes, though in some regions individual pipes are represented. Gas moves over the network at variable cost. The variable cost as a function of pipeline throughput (i.e., pipeline discount curve) is used to determine the market value of capacity (i.e., the transportation basis) for each period in the forecast for each pipeline link.

Figure 8-4 Example Pipeline Discount Curve
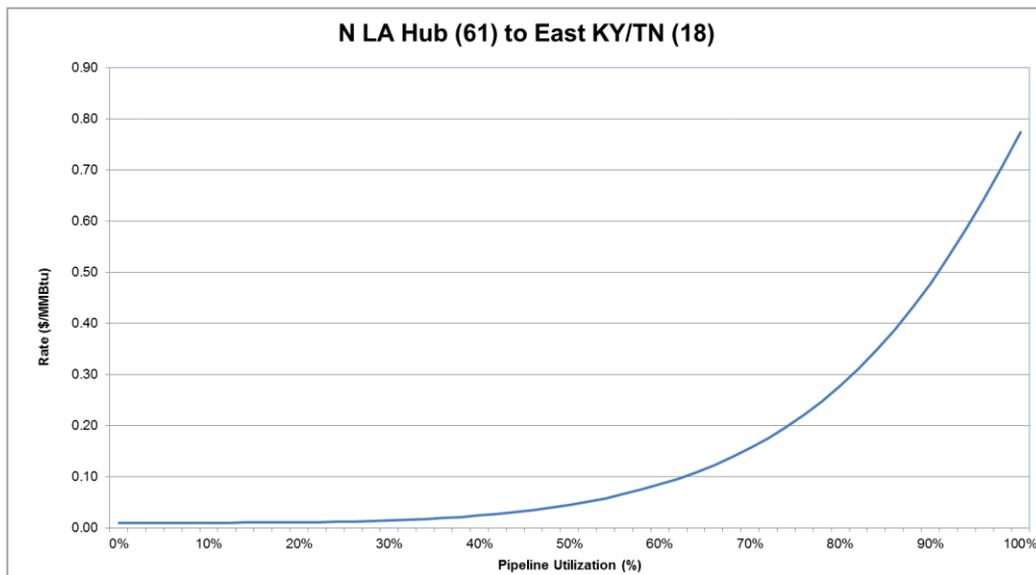
The upper end of discount curve may be shifted by additions of new pipeline capacity. The shift depends on expansion tariff relative to pre-expansion tariff and pricing of expansion (incremental or rolled-in). Curves have been fit to basis observed from actual gas prices and to annual load factors. Pipeline discount curve parameters can also be changed over time to reflect regulatory changes that affect pipeline values.

Pipeline capacity expansions address the physical constraints of transporting gas from supply regions to demand regions. They therefore contribute to determining the supply curves and seasonal basis. For the near–term, pipeline capacity expansions are input to GMM based on identifiable, near-term development plans and ICF's market assessment. For the longer term, new "generic" pipeline capacity is added in GMM when the market value of the added capacity exceeds its cost. Generic pipeline capacity in the model is added starting 2023 and it increases in 2025 and beyond as the natural gas markets grow.

ICF includes projects that satisfy certain criteria in its analysis. The criteria are listed below.

•   First Criteria: The project is already under construction;

OR
- Second Criteria: The project has the necessary approvals to proceed from FERC and other relevant regulatory proceedings;
OR
- Third Criteria: The project has been filed with FERC and has the necessary firm shipper commitments;
OR
- Fourth Criteria: The project has been filed with FERC and does not have the necessary shipper commitments, but does appear to have sufficient market support;
OR
- Fifth Criteria: The project has NOT yet been filed with FERC, but appears to have sufficient market support.

For the fourth and fifth criteria, ICF typically considers supply growth directly upstream of the project, market growth for markets that are relevant to the project's delivery point/s, and basis differentials that exceed the per unit cost of pipeline expansion as indicators of market support. If the indicators are all positive, ICF will add the project as a "generic" project and size it based on the level of market support. In the case in which there are multiple generic projects for a single GMM link, the generic projects will be sized in aggregate based on the total level of market support for expansion of the link. Generic projects are classified as such until one of the first three criteria are satisfied.

For certain markets like New York, New Jersey and New England, ICF looks closely at regulatory support for the project which could override the criteria above in determining the pipeline additions in GMM. For example, if a project like Constitution pipeline has been denied water permits even though it has broad market support, ICF does not include it in its base case.

Pipeline cost assumptions used in GMM have been derived by considering data from Oil and Gas Journal (OGJ) surveys of pipeline projects. Using regression analysis of the OGJ data across years, we determined an average U.S. pipeline cost of $183,000 per inch-mile for 2017 (in 2016 dollars) for large gas transmission pipelines. The pipeline cost for future years is kept flat in real terms post 2017. Regional cost multipliers have also been derived from OGJ data as the pipeline costs vary by region. Cost multipliers can be different across regions; for example, costs are relatively high in the Northeast where projects have been very difficult and time consuming to construct.

Supply is modeled by using node-level natural gas deliverability or supply capability, including import and export levels while accounting for gas storage injections and withdrawals at different gas prices. Total supply in the United States comes from three sources: production from natural gas fields located in the lower 48 states, Canadian imports, Alaska, and LNG imports. Natural gas production activity is represented in 82 of the 121 Model nodes where historical production has occurred, or where future production appears likely. The "base trend" for deliverability and gas price are developed from ICF's resource assessment using the Hydrocarbon Supply Model and a long-term "marker price". If the monthly solution price deviates from the "marker price", future exploration and production (E&P) activity is adjusted. Deliverability responds to prices, with a lag of 2 to 18 months.

The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

Natural Gas Storage activity is represented for 24 U.S. and two Canadian storage regions, with activity allocated to individual nodes based on historical field level storage capacity. Regional differences in the physical and market characteristics of storage are captured in the storage injection and withdrawal relationships separately estimated for each region:

- Differences between market area storage and supply area storage.

- Differences between regions with primarily depleted field storage and regions with primarily aquifer storage.

Net monthly withdrawals are calculated from a "storage supply curve" that reflects the level of withdrawals relative to gas prices. The curve has been fit to actual historical data. Net monthly injections are calculated from econometrically fit relationships that consider working gas levels, gas prices, and weather (i.e., cooling degree days). The level of gas storage withdrawals and injections are calculated within the supply and demand balance algorithm based on working gas levels, gas prices, and extraction/injection rates and costs.

Figure 8-5 GMM Natural Gas Storage Regions

Storage levels have an impact on GMM's seasonal basis differentials, which are an important component in constructing the gas supply curves and/or basis differentials that are then input into IPM. The arbitrage value of storage is driven by the seasonal difference in the supply-area gas prices plus the seasonal difference in pipeline transportation value. Storage expansions (or increased utilization of existing storage) decreases seasonal basis differentials in the region surrounding the storage facilities.

8.3   Resources Data and Reservoir Description

This section describes the approach used in GMM and documents the changes to the resource data and reservoir characterization work conducted for EPA Platform v6.

8.3.1   U.S. Resources and Reserves

This section describes the U.S. resource data sources and methodology used in GMM for EPA Platform v6.

Current U.S. and Canada gas production is from over 400 trillion cubic feet (Tcf) of proven gas reserves. ICF assumes that the U.S. and Canada natural gas resource base totals roughly 3,500 Tcf of unproved

plus discovered but undeveloped gas resource. This can supply the U.S. and Canada gas markets for over 100 years (at current consumption levels). Shale gas accounts for over 50 percent of remaining recoverable gas resources. No significant restrictions on well permitting and fracturing are assumed beyond restrictions that are currently in place.

Data sources: Conventional resource base assessment is based on data from the U.S. Geological Survey (USGS), Minerals Management Service (MMS), and Canadian Gas Potential Committee (CGPC) using ICF's Hydrocarbon Supply Model (HSM).

In the area of unconventional gas, ICF has worked for many years with the Gas Research Institute (GRI)/Gas Technology Institute (GTI) to develop a database of tight gas, coalbed methane, and Devonian Shale reservoirs in the U.S. and Canada. Along with USGS assessments of continuous plays, the database was used to help develop the HSM's "cells", which represent resources in a specific geographic area, characterizing the unconventional resource in each basin, historical unconventional reserves estimates and typical decline curves. ICF has recently revised the unconventional gas resource assessments based on new gas industry information on the geology, well production characteristics, and costs. The new assessments include major shale units such as the Fort Worth Barnett Shale, the Marcellus Shale, the Haynesville Shale, and Western Canada shale plays. ICF has built up a database on gas compositions in the United States and has merged that data with production data to allow the analysis of net versus raw gas production.

Resources are divided into three general categories: new fields/new pools, field appreciation, and unconventional gas. The methodology for resource characterization and economic evaluation differs for each.

New Fields

Conventional new discoveries are characterized by size class. For the United States, the number of fields within a size class is broken down into oil fields, high permeability gas fields, and low permeability gas fields based on the expected occurrence of each type of field within the region and interval being modeled. The fields are characterized further as having a hydrocarbon make-up containing a certain percent each of crude oil, dry natural gas, and natural gas liquids. In Canada, fields are oil, sweet nonassociated gas, or sour nonassociated gas.

The methodology uses a modified "Arps-Roberts" equation to estimate the rate at which new fields are discovered. The fundamental theory behind the find-rate methodology is that the probability of finding a field is proportional to the field's size as measured by its areal extent, which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be found earlier in the discovery process than smaller fields. The new equation developed by ICF accurately tracks discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas, the more accurate find-rate representation is an important component in analyzing the economics of exploration activity in these areas.

An economic evaluation is made in the model each year for potential new field exploration programs using a standard discounted after-tax discounted cash flow (DCF) analysis. This DCF analysis takes into account how many fields of each type are expected to be found and economics of developing each. The economic decision to develop a field is made using "sunk cost" economics where the discovery cost is ignored and only time-forward development costs and production revenues are considered. However, the model's decision to begin an exploration program includes all exploration and development costs.

Field Appreciation

Field appreciation refers to potential resources that can be proved from already discovered fields. These inventories are referred to as appreciation, growth-to-known or "probables." The inventories of probables are increased due to expected future appreciation due to many factors that include higher recovery percentages of the gas in-place resulting from infill drilling and application of improved technology and experience gained in the course of developing and operating the field.

<u>Unconventional Gas</u>

The ICF assessment method for shale gas is a "bottom-up" approach that first generates estimates of unrisked and risked gas-in-place (GIP) from maps of depth, thickness, organic content, and thermal maturity. Then, ICF uses a different model to estimate well recoveries and production profiles. Unrisked GIP is the amount of original gas-in-place determined to be present based upon geological factors—without risk reductions. "Risked GIP" includes a factor to reduce the total gas volume based on proximity to existing production and geologic factors such as net thickness (e.g., remote areas, thinner areas, and areas of high thermal maturity have higher risk). ICF calibrates expected well recoveries with specific geological settings to actual well recoveries by using a rigorous method of analysis of historical well data.

To estimate the contributions of changing technologies ICF employs the "learning curve" concept used in several industries. The "learning curve" describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period of time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures. Generally speaking, we find the learning curve effect is roughly 20 percent per doubling of cumulative wells.

Major Unconventional Natural Gas Categories

***Definition of Unconventional Gas:** Quantities of natural gas that occur in continuous, widespread accumulations in low quality reservoir rocks (including low permeability or tight gas, coalbed methane, and shale gas), that are produced through wellbores but require advanced technologies or procedures for economic production.*

Tight Gas is defined as natural gas from gas-bearing sandstones or carbonates with an *in situ* permeability (flow rate capability) to gas of less than 0.1 millidarcy. Many tight gas sands have *in situ* permeability as low as 0.001 millidarcy. Wells are typically vertical or directional and require artificial stimulation.

Coalbed Methane is defined as natural gas produced from coal seams. The coal acts as both the source and reservoir for the methane. Wells are typically vertical but can be horizontal. Some coals are wet and require water removal to produce the gas, while others are dry.

Shale Gas is defined as natural gas from shale formations. The shale acts as both the source and reservoir for the methane. Older shale gas wells were vertical while more recent wells are primarily horizontal with artificial stimulation. Only shale formations with certain characteristics will produce gas.

Shale Oil with Associated Gas is defined as associated gas from oil shale in horizontal drilling plays such as the Bakken in the Williston Basin. The gas is produced through boreholes along with the oil.


8.3.2   Upstream Cost and Technology Factors

In ICF's methodology, supply technology advancements effects are represented in three categories:

- Improved exploratory success rates
- Cost reductions of platform, drilling, and other components
- Improved recovery per well

These factors are included in the model by region and type of gas and represent several dozen actual model parameters. ICF's database contains base year cost for wells, platforms, operations and maintenance, and other relevant cost items.

Figure 8-6 GMM U.S. and Canada Projected Gas Production by Source
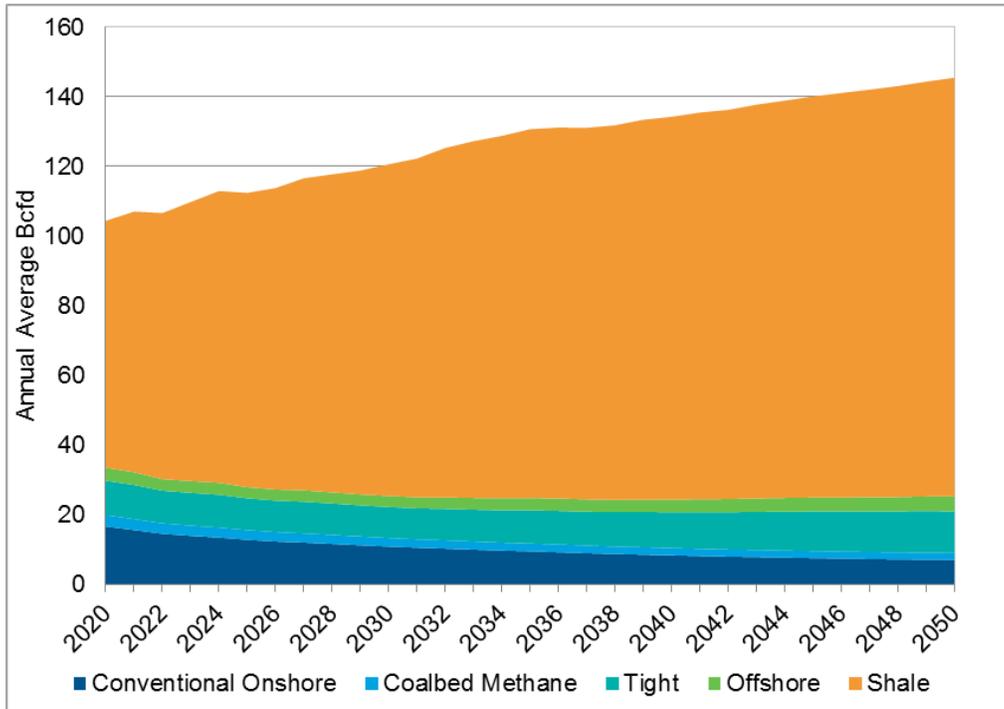
8.3.3   Historical Gas Production

ICF consistently updates the production and resource data that it used for EPA Platform v6. The historical production data for the model comes from PointLogic. An example comparison of production forecasts for the San Juan and Raton basins is shown in Figure 8-7.

Figure 8-7 Production Comparison for San Juan and Raton Basins
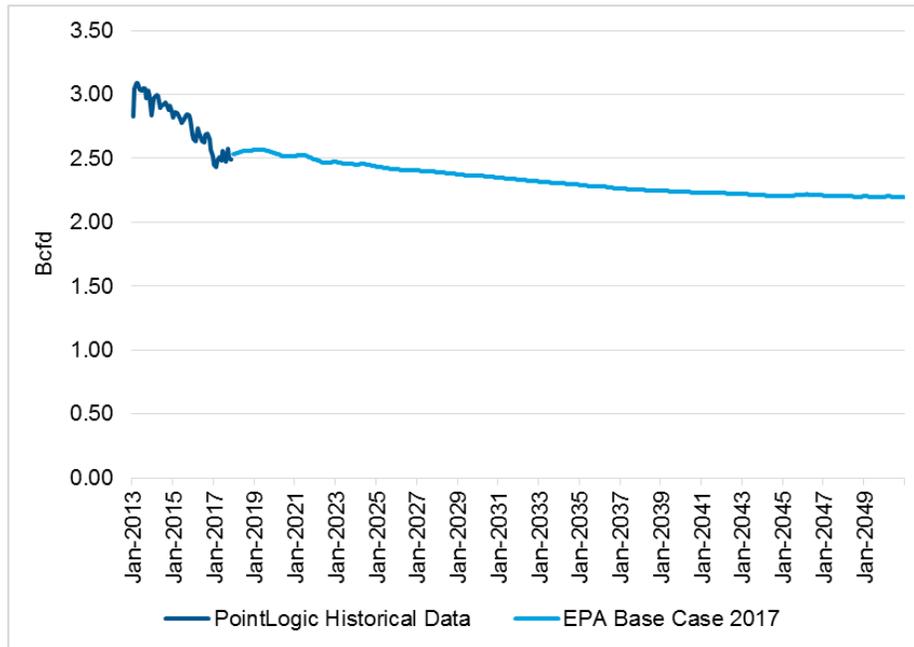
8.3.4 Treatment of Frontier Resources and Exports

Arctic Projects

GMM does not have resources located in frontier regions. Arctic projects (specifically Alaska and Mackenzie Valley gas pipelines) are not included in our projection.

Existing and Potential Liquefied Natural Gas (LNG) Terminals

LNG is natural gas that has been transformed to a liquid by super-cooling it to minus 260 degrees Fahrenheit, reducing its volume by a factor of 600. LNG is then shipped on board special carriers, and the process is reversed at a receiving facility with the re-gasified product delivered via pipeline. Based on current global LNG market conditions, ICF assumes that the six U.S. LNG terminals currently under construction are completed and expanded in future. Those terminals are Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, and Elba Island. By 2020, ICF projects U.S. LNG export capacity will be 10.3 billion cubic feet per day (Bcfd). Given the near-term low oil price expectations, we project that North American export terminal capacity utilization will average about 63% through 2020. U.S. export volumes are projected to approach six Bcfd by 2020. ICF projects that the capacity utilization will increase to over 80% by 2024. In addition to the U.S. trains currently under construction, ICF assumes an additional 5.8 Bcfd of export capacity will come online in North America between 2020 and 2035. ICF assumes that only one export facility will be built in British Columbia: Woodfibre (0.3 Bcfd).

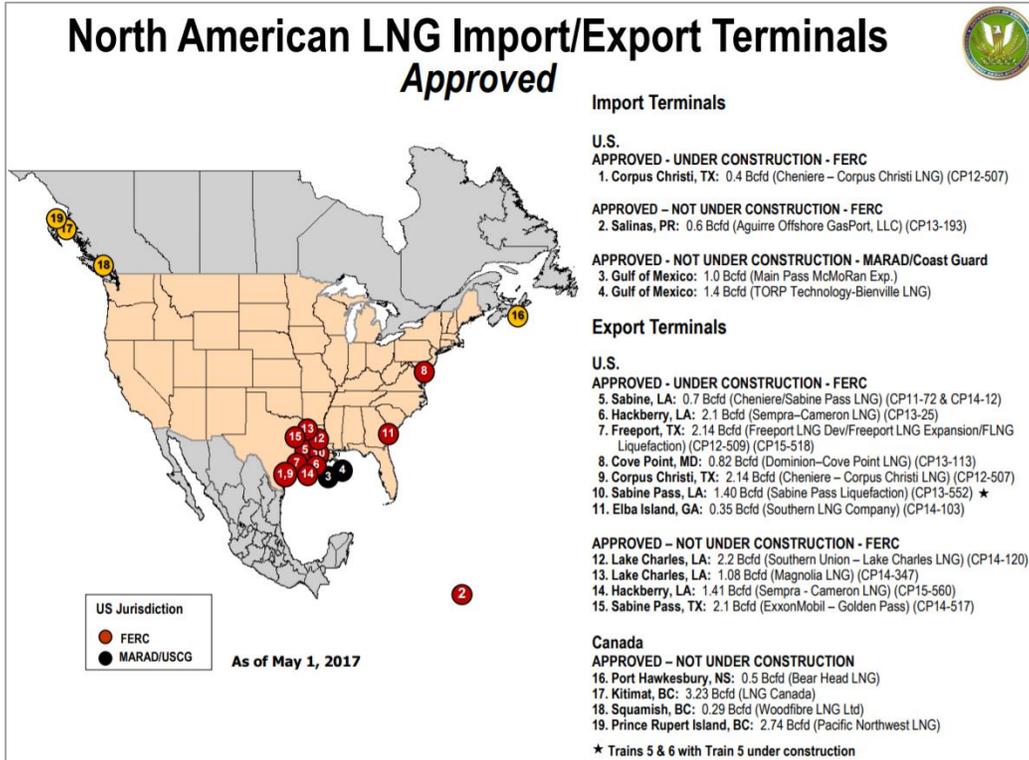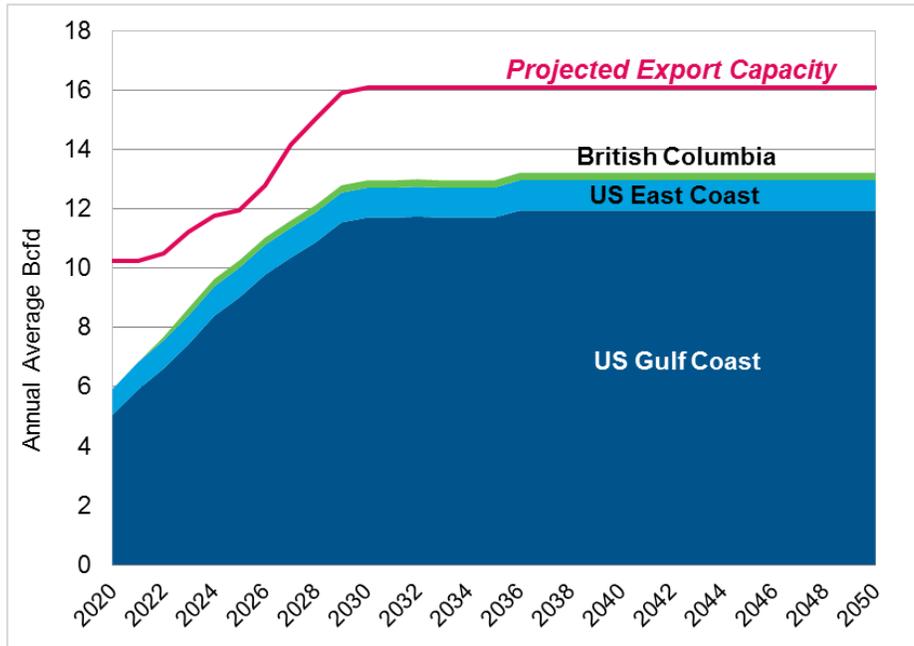**Figure 8-8 Existing and Proposed Marine LNG Terminals as of May 2017**

Figure 8-9 LNG Export Volumes versus Capacity

Mexico's demand for natural gas continues to rise, while its domestic production has been declining. Since 2010, Mexico's imports of U.S. gas have gone up over 300%, reaching 3.9 Bcfd in 2016. As Mexico continues to add gas-fired generation and sponsor new pipelines from the U.S., exports will continue to grow. ICF projects that exports will reach 8 Bcfd by 2035.

**Figure 8-10 U.S. Pipeline Exports to Mexico**
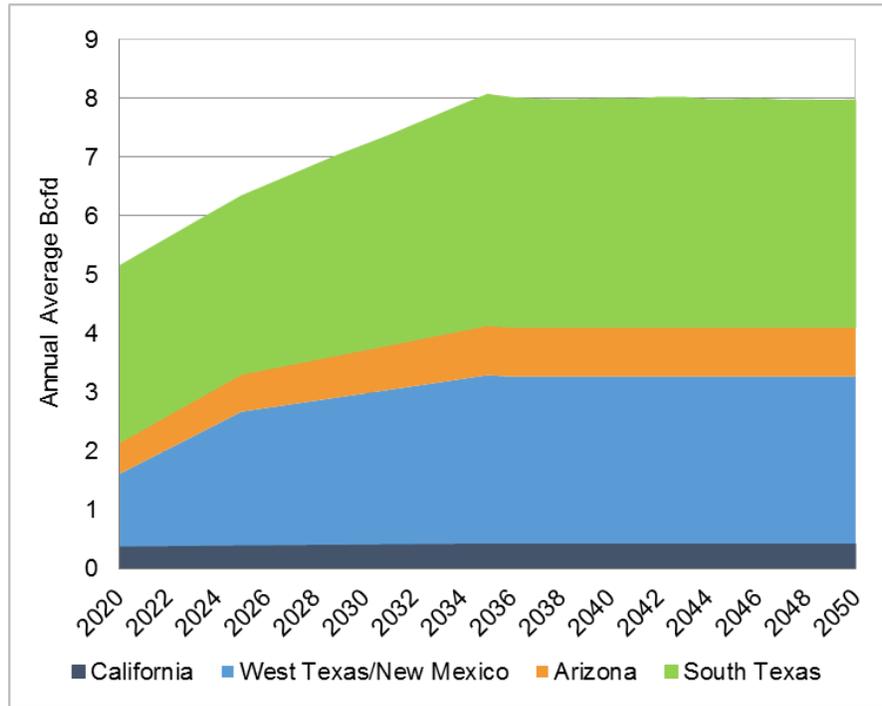
8.4 Oil Prices

Natural gas prices and LNG export levels are forecasted by taking into account oil prices. The following section contains discussions about the crude oil price assumptions used for EPA Platform v6.

ICF uses the Refiner Acquisition Cost of Crude Oil (RACC) price as an oil price input to GMM. The RACC price is a term commonly used in discussing crude oil. It is the cost of crude oil to the refiner, including transportation and fees. For the long-term, ICF projects a slow recovery in oil prices to an equilibrium marginal production cost of $75/bbl (in $2016). The residual oil price averages between 70 and 100 percent of the RACC price on a dollar per Btu basis. This is the price used to determine switching in the industrial sector. Figure 8-11 shows the ICF RACC price projection.

**Figure 8-11 Refiners' Acquisition Cost of Crude (RACC)**
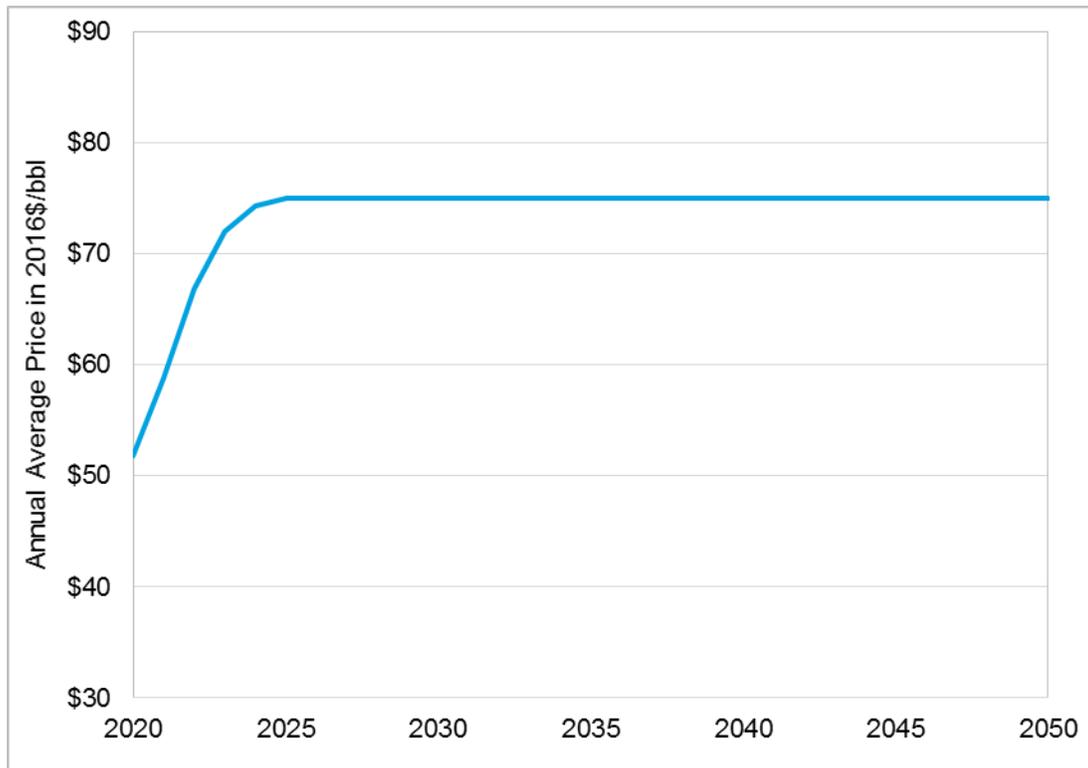
8.5 Demand Assumptions

Gas demand is calculated by sets of algorithms and equations for each sector and region. The model calculates monthly "real-time consumption", not "billed volumes." Demand reported by DOE/EIA represents billed volumes, which is time-lagged. Recent DOE/EIA and Statistics Canada data have been considered in the calibration of the model. However, the historical data represents ICF's backcast of the market. ICF performs market reconnaissance and data analysis each month to support the GMM calibration. GMM models natural gas demand in four end-use sectors: residential, commercial, industrial, and power generation.

Residential/Commercial gas demand calculated from regional equations fit econometrically to weather, economic growth, and price elasticity. The 41 regions for which residential/commercial demand are calculated are shown in Figure 8-12. Regression analysis was separately completed for each sector for 34 Lower-48 and 7 Canadian regions. The seventh Canadian region, Atlantic Provinces, has no historical gas use. An Alaska region is included in the Model, but all Alaska end use gas demand is input exogenously.

Figure 8-12 GMM Residential/Commercial Gas Demand Regions
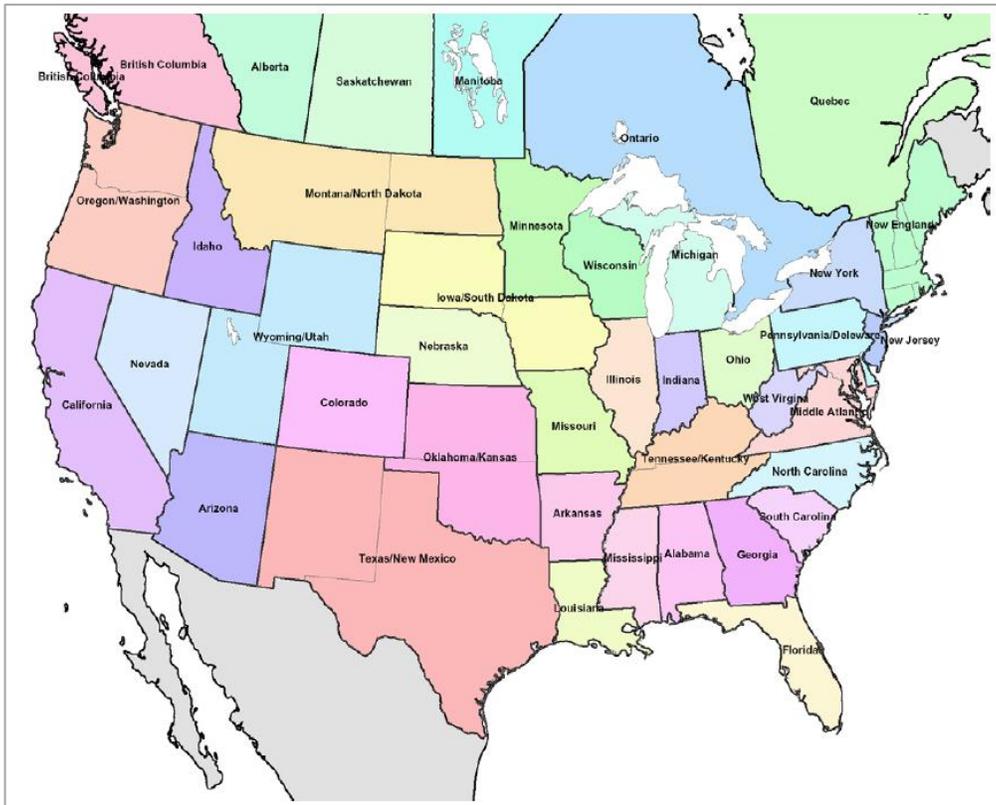
Industrial gas demand is based on a detailed breakout of industrial activity by census region. The U.S. is divided into 11 regions based on census region boundaries. The model includes ten industry sectors, focusing on gas-intensive industries. Those 10 industries are:

- Food
- Pulp and Paper
- Petroleum Refining
- Chemicals
- Stone, Clay, and Glass
- Iron and Steel
- Primary Aluminum
- Other Primary Metals
- Other Manufacturing
- Non-Manufacturing

Three end-use categories (Process Heat, Boilers, and Other End Uses) are modeled separately for each sector.

- Process heat: This includes all uses of gas for direct heating as opposed to indirect heating (e.g., steam production). The GMM econometric modeling indicated that forecasts for process heat for each industrial sector are a function of growth in output, the energy intensity trend, and the price elasticity. Growth in output over time for most industries is controlled by industrial production indices. Energy intensity is a measure of the amount of gas consumed per unit of output. Energy intensity tends to decrease over time as industries become more efficient.

- Boilers: This category includes natural gas-fired boilers whose purpose is to meet industrial steam demand. GMM econometric models indicated that gas demand for boilers is a function of the growth in industrial output and the amount of gas-to-oil switching. Industry steam requirements grow based on industrial production growth. A large percentage of the nominally "dual-fired" boilers cannot switch due to environmental and technical constraints.
- Other end uses: This category includes all other uses for gas, including non-boiler cogeneration, on-site electricity generation, and space heating. Like the forecasts for process heat, the GMM econometric modeling showed "other end uses" for each industrial sector to be a function of growth in output, the energy intensity trend, and the price elasticity.

The chemicals sector also includes feedstock demands for ammonia, methanol, and non-refinery hydrogen. Canada is divided into 6 regions based on provincial boundaries. The approach for Canada is a regression fit of historic data similar to that used in the residential/commercial sectors - sub-sectors of Canadian industrial demand are not modeled separately. The Canadian industrial sector also includes power generation gas demand. The Atlantic Provinces in Eastern Canada have no historical industrial gas demand.

Energy intensity and price elasticity inputs are based on Industrial Sector Technology Use Model (ISTUM-2). Boiler switching curves are defined from work for GRI (now GTI). The GMM captures both near-term price-induced switching and "demand destruction" effects of high gas prices.

Figure 8-13 GMM Industrial Gas Demand Regions
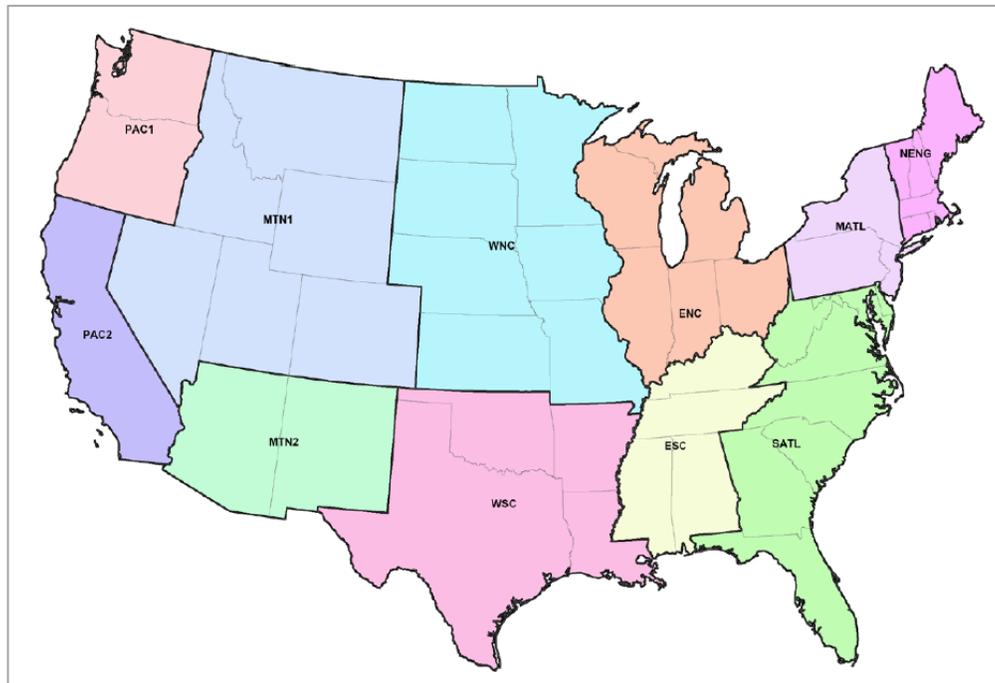
Power generation demand in the GMM is modeled for 13 dispatch regions for the contiguous U.S. All of the power sector inputs in GMM are changed to be consistent with IPM results over time. Most importantly, the total gas use regionally is bench-marked against IPM's gas use.

Figure 8-14 GMM Power Generation Gas Demand Regions
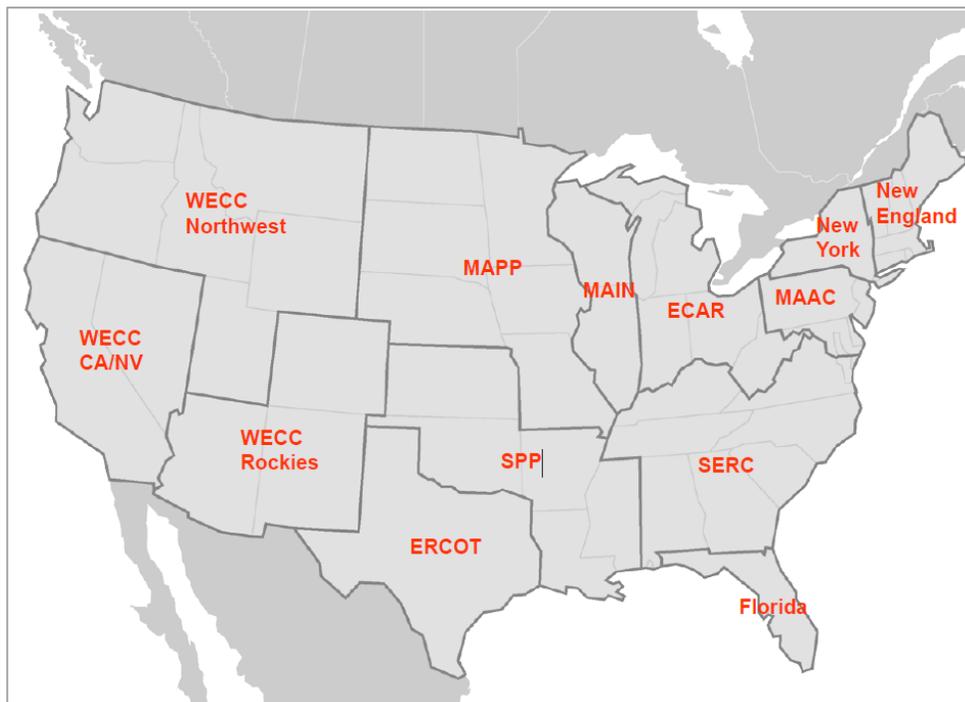
**Pipeline fuel** consumption is the gas consumed in the operation of pipelines, primarily in compressors, as well as pipeline losses. Pipeline gas-use is a function of the fuel rate and the volume of gas moved on each pipeline corridor. Pipeline gas-use is estimated as a percent of natural gas throughput for each link in the pipeline network. Pipeline gas-use is allocated evenly between the upstream and downstream nodes for each link. Historical pipeline gas-use is derived from EIA data on a state by state basis, and then mapped to each link in the pipeline network.

Lease & Plant gas use represents natural gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and used as fuel in natural gas processing plants. The lease and plant gas-use is forecast based on historical percentages of the dry gas produced at each node. Regional factors determine the share of lease & plant gas use for each supply region.

Figure 8-15 GMM U.S. and Canada Gas Demand Projection
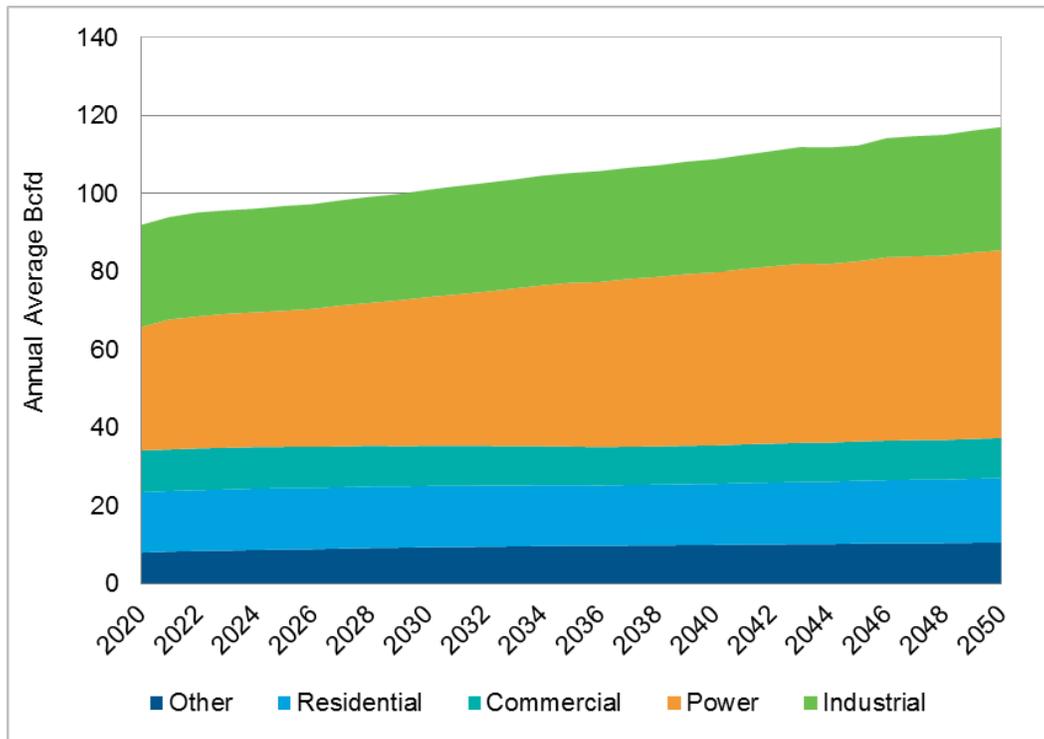
Note: "Other" includes pipeline fuel and lease & plant

There are four key drivers for natural gas demand in GMM. They are:

i) **Macroeconomic parameters:** From 2018 forward, ICF assumes U.S. GDP grows at 2.1% per year, and Canada GDP grows at 2.0% per year.[84]

ii) **Electric Demand Growth:** Electric demand growth rate is assumed to be 0.68% per year consistent with EPA Platform v6.

iii) **Demographics:** Projected demographic trends are consistent with trends over the past 20 years. U.S. population growth averages about 1% per year throughout our projection.

iv) **Weather:** Future weather is assumed consistent with regional and monthly average heating and cooling degree days (HDD/CDD) over the past 20 years (1997 through 2016).

8.6 Discussion of GMM Results Underlying the Natural Gas Supply Curves[85]

In this section, we describe GMM results underlying the natural gas supply curves for EPA Platform v6. A typical GMM run generates the following outputs:

- Natural gas prices
- Natural gas production by region
- Natural gas consumption by region and sector

---

[84] The U.S. Congressional Budget Office assumes an average annual GDP growth rate of 1.9% between 2018 and 2028, while the 2018 U.S. Energy Information Administration Annual Energy Outlook used an average annual GDP growth rate of 2.0% between 2018 and 2050.

[85] The GMM results presented in this section are illustrative and consistent with a draft version of the EPA Platform v6 November 2018 Reference Case. GMM was not rerun for a final calibration with EPA Platform v6 November 2018 Reference Case using IPM.

Table 8-1 summarizes the supply/demand balance and Henry Hub price for a GMM run underlying the natural gas supply curves. The regional breakout in the supply/demand data is by census region and the mapping to the state and GMM nodes is provided in Figure 8-16 and Figure 8-17. Table 8-3 provides additional results.

Table 8-1 Supply/Demand Balance and Henry Hub Price for a GMM Run Underlying the Natural Gas Supply Curves in EPA Platform v6

Demand (Bcf per year)	2017	2021	2023	2025	2030	2035	2040	2045	2050
New England	849	939	952	987	1,009	1,034	1,063	1,066	1,092
Mid-Atlantic	3,747	4,471	4,776	4,883	5,286	5,437	5,457	5,645	5,849
East North Central	3,852	4,413	4,442	4,498	4,747	5,160	5,385	5,508	5,723
West North Central	1,782	1,935	1,937	1,948	1,959	2,027	2,034	2,007	2,015
South Atlantic	3,694	4,522	4,536	4,528	4,917	5,294	5,630	5,905	6,192
East South Central	1,705	2,076	2,077	2,115	2,296	2,353	2,427	2,448	2,507
West South Central	6,322	6,974	7,053	7,047	7,334	7,502	7,604	7,641	7,774
Mountain	1,778	1,887	1,947	2,021	2,003	2,167	2,307	2,378	2,451
Pacific (contiguous)	2,888	2,815	2,794	2,758	2,534	2,512	2,559	2,645	2,679
Alaska	347	304	303	301	296	295	295	295	295
Total L-48	**26,619**	**30,033**	**30,514**	**30,785**	**32,084**	**33,486**	**34,465**	**35,242**	**36,281**
Total United States	**26,965**	**30,337**	**30,817**	**31,086**	**32,380**	**33,780**	**34,760**	**35,537**	**36,576**
Exports/Imports (Bcf per year)									
Net LNG Exports from US	593	2,698	3,343	3,990	5,065	5,064	5,164	5,160	5,159
Net Pipeline Exports to Mexico	1,589	1,967	2,142	2,316	2,632	2,945	2,928	2,858	2,911
Net Pipeline Imports from Canada	1,913	1,470	1,481	1,694	2,135	2,371	2,285	2,278	1,942
Supply (Bcf per year)									
New England	0	0	0	0	0	0	0	0	0
Mid-Atlantic	5,229	8,845	9,762	10,225	11,388	12,128	12,608	13,284	13,915
East North Central	1,595	2,780	3,108	3,341	3,812	4,133	4,328	4,520	4,683
West North Central	1,140	1,097	1,047	1,005	942	874	798	758	753
South Atlantic	1,559	2,288	2,534	2,751	3,173	3,433	3,591	3,755	3,890
East South Central	795	861	816	779	753	802	806	866	927
West South Central	11,869	12,406	12,189	12,178	12,536	13,067	13,168	13,732	14,423
Mountain	4,402	4,500	4,389	4,315	4,301	4,649	5,119	5,645	5,838
Pacific (contiguous)	196	174	175	178	181	183	178	170	163
Alaska	311	303	302	307	309	313	303	293	285
Total L-48	**26,788**	**32,951**	**34,020**	**34,772**	**37,087**	**39,269**	**40,596**	**42,731**	**44,593**
Total United States	**27,099**	**33,254**	**34,322**	**35,079**	**37,395**	**39,582**	**40,899**	**43,024**	**44,878**
	2017	2021	2023	2025	2030	2035	2040	2045	2050
Henry Hub, Nom$/MMBtu	2.82	3.14	3.61	3.77	4.38	4.60	5.76	7.33	8.18

Figure 8-16 Demand Region Definition

Copyright 2018, ICF

Figure 8-17 Supply Region Definition

Copyright 2018, ICF
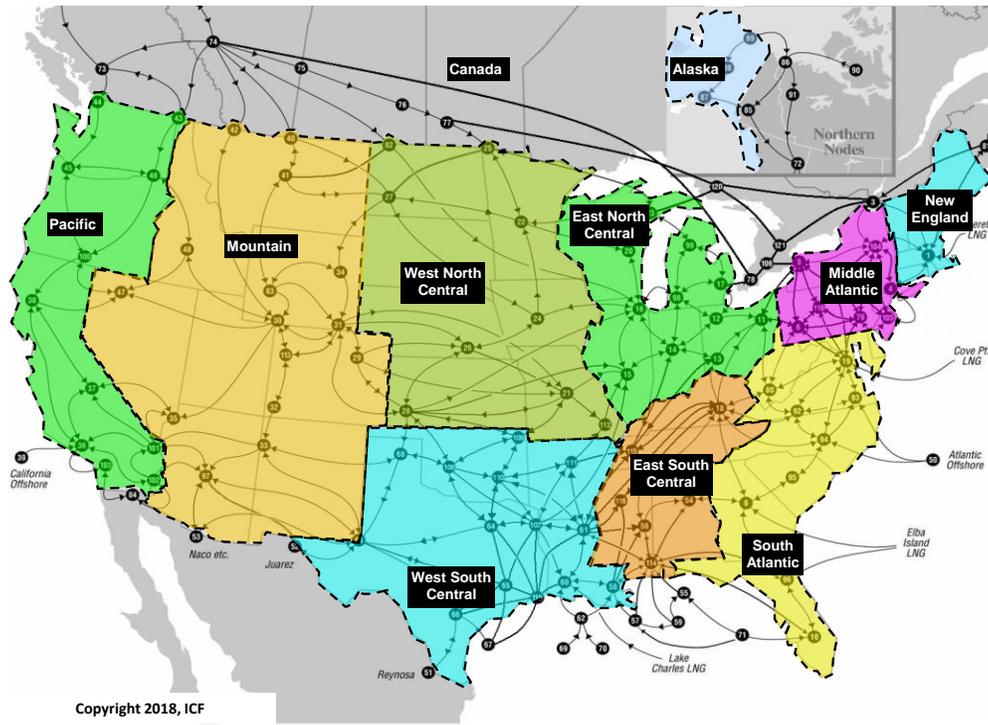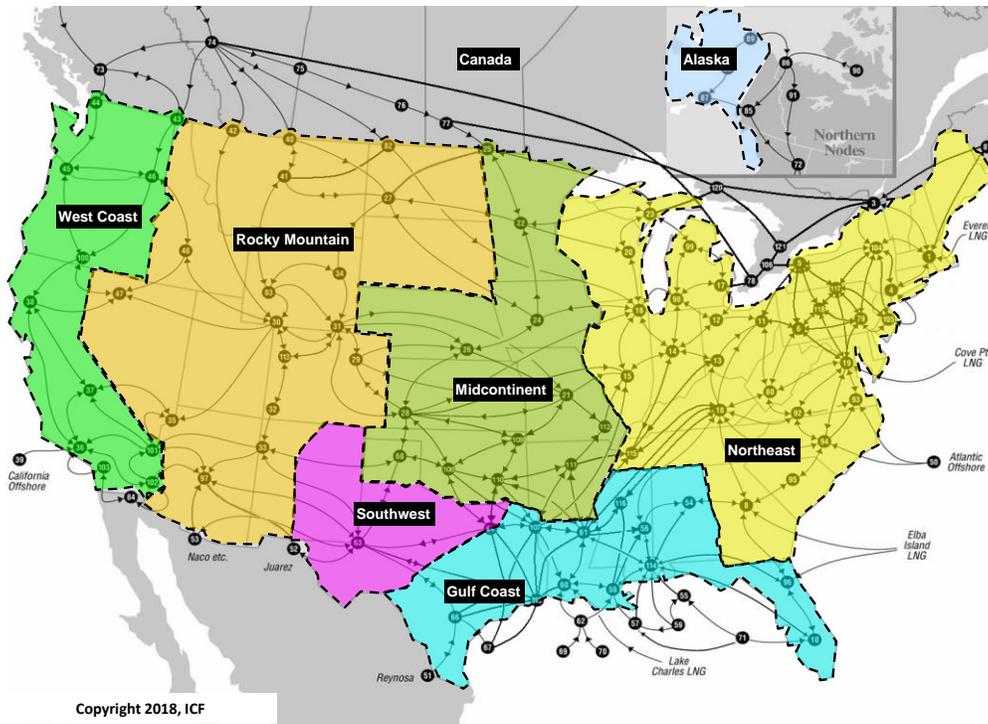
8.6.1   Supply Curves for EPA Platform v6

Henry Hub is a pipeline interchange hub in Louisiana Gulf Coast near Erath, LA, where eight interstate and three intrastate pipelines interconnect. Liquidity at this point is very high and it serves as the primary point of exchange for the New York Mercantile Exchange (NYMEX) active natural gas futures markets. Henry Hub prices are considered as a proxy for U.S. natural gas prices. Natural gas from the Gulf moves through the Henry Hub onto long-haul interstate pipelines serving demand centers. Due to the importance and significance of Henry Hub, GMM generated supply curves are specified at Henry Hub prices.

For IPM modeling, GMM generates a price forecast over a time horizon and a set of time dependent price/supply curves based on that price path for each year in the forecast. For each year, the mid-point price of the supply curve is set equal to the solved Henry Hub price from GMM and the mid-point volume is set equal to the solved gas consumption for the power sector from GMM. Each supply curve's elasticity is set equal to the effective price-elasticity for gas supply in that year. In this manner, even while GMM has itself projected particular levels of gas supply and consumption (and corresponding market-clearing prices) over time, the information included in those projections is input into IPM in the form of gas supply curves that enable IPM to solve for levels of power sector gas consumption and resulting gas prices that respect a least-cost power production future.

The final resulting supply curves developed for years 2021, 2023, 2025, 2030, 2035, 2040, 2045, and 2050 are shown in Figure 8-18 and Table 8-5. In the very short-term, gas supply is price inelastic because there are few years to respond to the market changes. Over time, gas supply becomes more price elastic because producers have more time to respond to the market changes. Thus, the supply curves are much more price elastic by 2025. In the longer term, resource depletion tends to offset elasticity making the curves slightly less elastic than they are between 2025 and 2030.

Figure 8-18 Supply Curves for 2021, 2023, 2025, 2030, 2035, 2040, 2045, and 2050
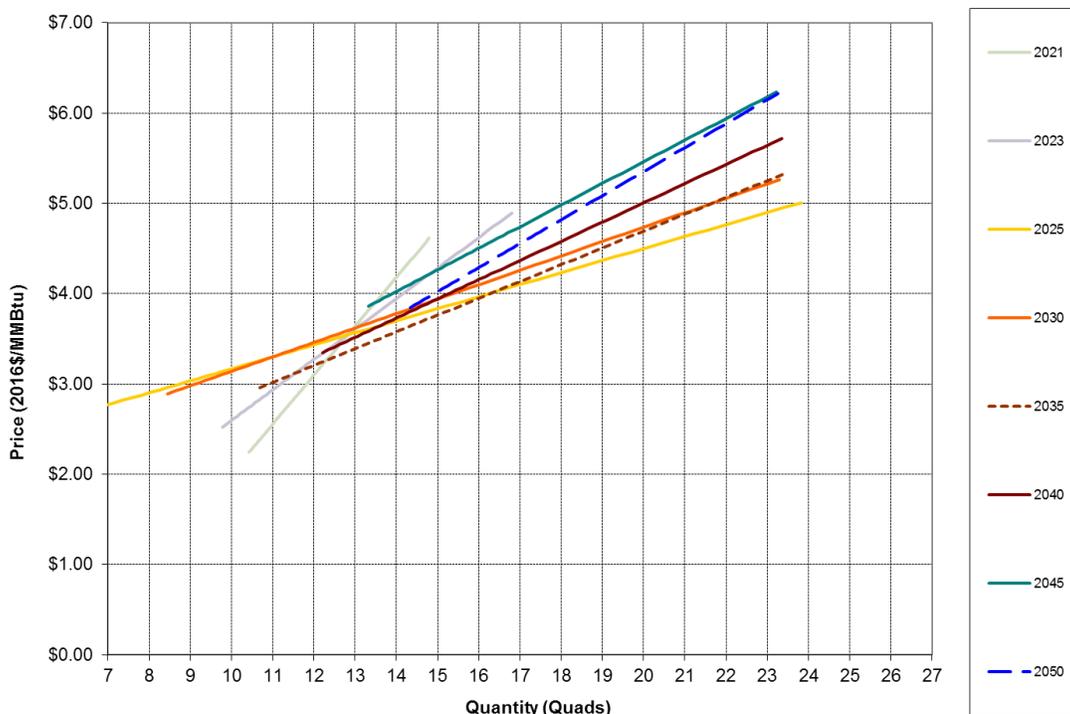
8.6.2   Basis

Basis is the difference in gas price in a given market from the widely used Henry Hub reference price. Basis reflects the price in a given market based on demand, available supply, and the cost of transporting gas to that location. A negative basis value represents that the gas price in that area is lower than the Henry Hub price. Basis between two nodes in GMM is the difference in prices between the two nodes. The GMM utilizes its network of 121 nodes that comprises 423 gas pipeline corridors to assess the basis between two desired nodes. The pipeline corridors between nodes are represented by pipeline links and can be characterized by their maximum capacity. Each of the links has an associated discount curve (derived from GMM natural gas transportation module), which represents the marginal value of gas transmission on that pipeline segment as a function of the pipeline's load factor. The basis value is calculated by using the supply/demand balance in two nodes along with the resulting prices in each node and the cost of transporting gas between the two nodes as determined by the discount curve on that link. The discount curve is a function of the pipeline tariffs and the load factor. The discount curves are continuously calibrated to accurately reflect historical basis values. Their parameters can be adjusted to account for regulatory changes that can affect pipeline values.

The GMM solves for basis monthly. Basis pressure (i.e., spiking basis) will generally occur when average monthly load factors rise to above 80%. Since many U.S. markets are winter peaking, the higher basis typically occurs in the winter months when gas use and load factors are highest. The IPM relies on seasonal basis that reflects averages of the monthly basis values solved for in the GMM.

GMM is not only used to estimate the gas supply curves, but also used to estimate the relationship of gas price at Henry Hub to gas prices elsewhere in the country. IPM uses these gas supply curves and regional price relationships (differentials) over time as inputs, based on GMM-projected future of gas supply/demand. While EPA's Platform v6 has the flexibility to re-determine the relationship of power sector gas demand to supply and to accordingly find different gas price futures, EPA's Platform v6 will maintain the future (basis differential) price relationship between Henry Hub and each regional location in a national supply picture as originally determined by these GMM projections. Table 8-4 provides the full set of seasonal basis differentials at the IPM region level.

8.6.3   Delivered Price Adders

As stated in section 8.2, GMM prices are market center prices and not delivered prices. In order to estimate delivered prices at a power plant, an adder is applied to the seasonal basis from GMM. ICF calculated this delivered price adder for each state by comparing its GMM historical prices with historical delivered gas prices to electric power plants based on EIA-176 data. The delivered price adders implemented in EPA Platform v6 are shown in Table 8-2.

Table 8-2 Delivered Price Adders

State	Adder (2016$/MMBtu)	State	Adder (2016$/MMBtu)
Alabama	0.01	Nebraska	0.46
Alaska	0.95	Nevada	0.21
Arizona	0.03	New Hampshire	0.01
Arkansas	0.13	New Jersey	0.26
California	0.16	New Mexico	0.02
Colorado	0.18	New York	0.17
Connecticut	0.05	North Carolina	0.24
Delaware	0.01	North Dakota	0.09
Florida	0.02	Ohio	0.03
Georgia	0.00	Oklahoma	0.03
Idaho	0.05	Oregon	0.01
Illinois	0.16	Pennsylvania	0.04
Indiana	0.14	Rhode Island	0.00
Iowa	0.26	South Carolina	0.17
Kansas	0.13	South Dakota	0.01
Kentucky	0.23	Tennessee	0.05
Louisiana	0.04	Texas	0.19
Maine	0.03	Utah	0.08
Maryland	0.13	Virginia	0.06
Massachusetts	0.03	Washington	0.10
Michigan	0.16	West Virginia	0.13
Minnesota	0.35	Wisconsin	0.09
Mississippi	0.03	Wyoming	0.06
Missouri	0.12	US	0.13
Montana	0.44	Canada	0.13

List of tables that are uploaded directly to the web:

Table 8-3 EIA Style Gas Report for EPA Platform v6

Table 8-4 Natural Gas Basis for EPA Platform v6

Table 8-5 Natural Gas Supply Curves for EPA Platform v6