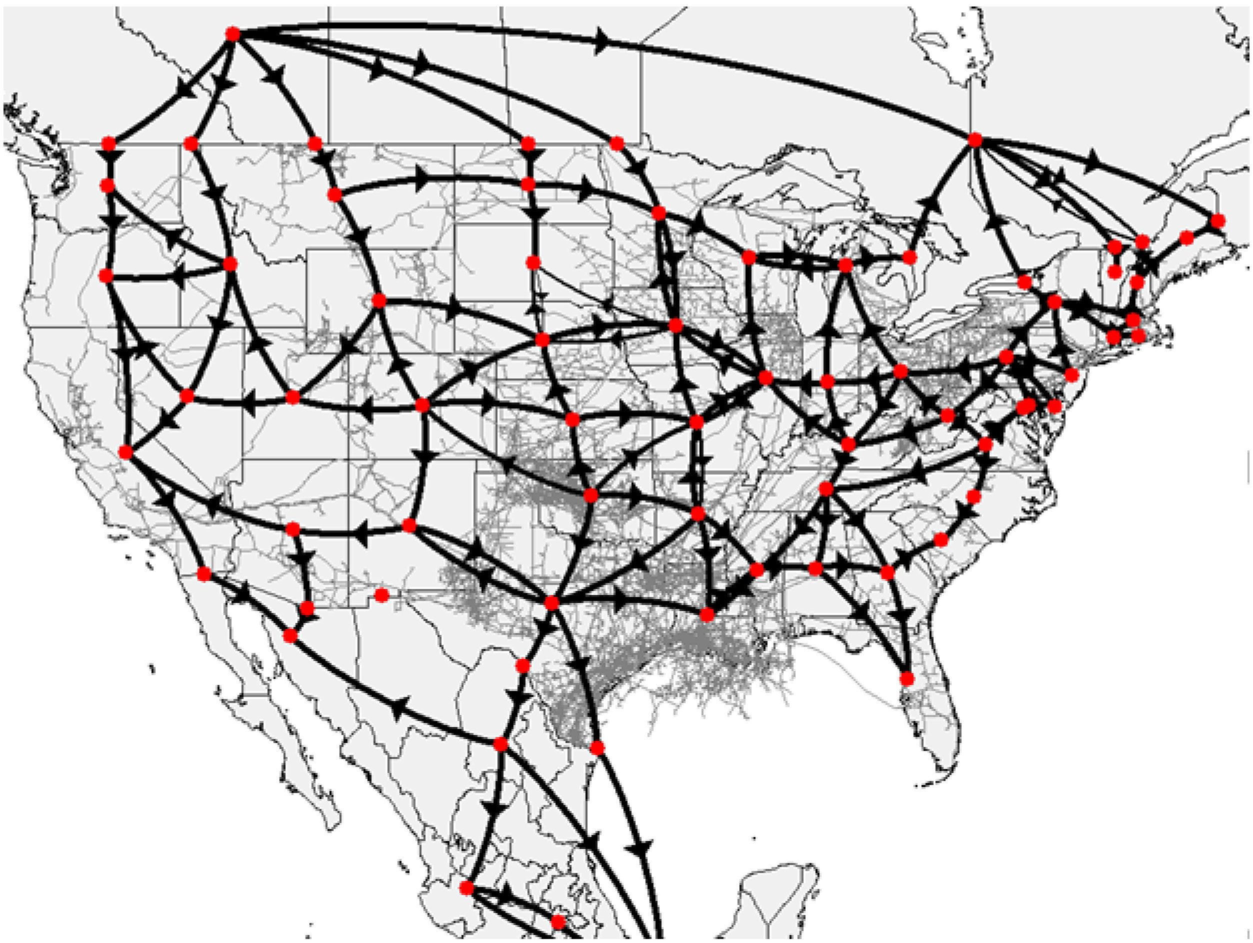
Natural Gas Market Module

The National Energy Modeling System (NEMS) Natural Gas Market Module (NGMM) projects wellhead, border, spot, citygate, and delivered prices that balance monthly natural gas supply and demand through a simplified North American pipeline network (Figure 1). These projections are generated using a quadratic program (QP) that maximizes consumer plus producer surplus minus variable transportation costs (with a nonlinear representation). The program is subject to linear constraints: mass balance requirements, pipeline capacity limits, and assumed storage withdrawals/injections. The NGMM model code solves for nonassociated dry natural gas production, state-to-state flows, imports and exports, pipeline fuel, and lease and plant fuel. Interstate pipeline capacity additions are projected using a similar but modified QP. The NGMM includes a representation of natural gas markets in Canada (two regions) and Mexico (five regions), as well as

Figure 1. Natural Gas Market Module network representation



Note: The figure represents the flows (black arrows) from hub to hub (red circles) as determined by the NGMM in a given year. Flows that are bidirectional indicate that in a given year, there is monthly (seasonal) variability in the direction of natural gas flow through the pipeline network. This level of granularity was used to approximate the existing infrastructure (gray lines).

Source: U.S. Energy Information Administration, Natural Gas Market Module domestic consumption and production at state and state/substate levels, respectively. A complete listing of NGMM assumptions and an in-depth description of the methodology is presented in the *Natural Gas Market Module of the National Energy Modeling System: Model Documentation 2018*.

Because other modules in NEMS provide natural gas consumption data to the NGMM at a more aggregate level (generally annually by Census Division), the NGMM disaggregates these volumes for the Lower 48 states at a monthly level based on historical average shares for the past five years, after subtracting econometrically estimated consumption levels for Alaska. The Oil and Gas Supply Module (OGSM) provides state/substate dry associated-dissolved natural gas production and expected dry nonassociated production as a basis for establishing annual, short-term natural gas supply curves at a state/substate level for the United States and for east and west Canada. The NGMM uses these curves in the QP to project realized production levels and their associated wellhead prices.

Liquefied natural gas (LNG) export capacities are projected separately in the module and are used to develop LNG export demand curves for the QP. Additional miscellaneous assumptions are made about supplemental natural gas supplies, LNG imports, consumption in Canada and Mexico, and supply in Mexico. The following NGMM outputs are benchmarked to align with EIA's *Short-Term Energy Outlook* (October 2018) for 2018 and 2019.

National

- Production
- Supplemental supplies
- Lease and plant fuel
- Pipeline fuel[1]
- Storage withdrawals
- Pipeline imports/exports
- LNG imports/exports
- Henry Hub price
- Delivered natural gas price to electric generators

Regional

- Delivered prices to residential and commercial customers

STEO benchmark factors calculated for this alignment in 2018 will be phased out during the next five years except in cases where no phase-out is applied—LNG exports, pipeline imports/exports, and the Henry Hub price.

Key assumptions

Supply curves for production of natural gas in North America

Projections of associated-dissolved natural gas production are assumed not to change in response to

[1] The STEO forecast for pipeline fuel includes fuel used for liquefaction at LNG export facilities. This total is calculated separately in the NGMM; therefore, the NGMM benchmarks to pipeline fuel after subtracting this volume from STEO. Fuel used for liquefaction is assumed to be 10% of the LNG export volume.

current year natural gas prices in the supply/demand balancing process in the NGMM's QP. Nonassociated natural gas is represented in each state/substate (or region for Canada and Mexico) using a short-term supply curve. Each curve is built off a price/quantity pair of the expected production level, with the assumed associated price from the previous projection year. For each state/substate a piece-wise linear supply curve with five segments is built off of this point using assumed slopes or elasticities. The segments are delineated at quantities ±3% and ±9% of the expected production level. The slopes (percentage change in production divided by percentage change in price) on the five segments, starting from the lowest volume to the highest volume, are 0.8, 0.7, 0.5, 0.3, and 0.2.

International representation

Consumption of natural gas in Canada and Mexico and imports/exports of liquefied natural gas to/from Canada and Mexico are set externally in the NGMM based on projections from the *International Energy Outlook 2017* (IEO2017)(Table 2). LNG imports into Mexico, however, are expected to decline through 2020, after which it is assumed they are entirely replaced by pipeline imports from the United States.

Production in East/West Canada is represented in the NGMM just as it is for states in the United States, using values computed by OGSM. Mexico is similarly represented but from production levels set from within the NGMM. Associated-dissolved production is set using a historically estimated equation as a function of the world oil price. In contrast, expected nonassociated production is set by estimating an equation with assumed projected values, based on the IEO2017 (Table 1), as a function of assumed associated Henry Hub prices. However, nonassociated natural gas production from Mexico's shale gas resources was not assumed to be developed. Actual projected values are allowed to vary off this baseline projection.

Table 1. Exogenously specified natural gas consumption, production, and LNG trade for Canada and Mexico

billion cubic feet per year

	Mexico nonassociated production	Mexico consumption	Mexico LNG Imports	Canada consumption	Canada LNG exports
2018	255	3,258	197	4,174	—
2020	237	3,559	110	4,415	—
2025	238	3,996	—	4,826	110
2030	273	4,068	—	5,170	96
2035	292	4,156	—	5,439	661
2040	308	4,289	—	5,926	1,214
2045	322	4,429	—	6,383	1,652
2050	372	4,579	—	6,776	1,652

Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis, based on U.S. Energy Information Administration, *International Energy Outlook 2017*. Canada consumption reflects higher growth in natural gas used in Canada oil sands production, which varies across high/low oil price cases.

United States LNG export capacity representation

The capacity to export LNG from the United States beyond existing infrastructure and new projects already under construction through 2021 is set endogenously in the NGMM outside of the QP. The actual level of exports out of each region is determined in the QP using a demand curve based on the projected available capacity, the estimated competing price in Asia or Europe in the given year, and a liquefaction and pipeline transport fee equal to just the variable cost component (i.e., excluding assumed capacity reservation or sunk charges for liquefaction). Exports fall lower than the operating capacity if the regional spot price plus liquefaction, shipping, and regasification costs exceed the price in Asia or Europe. The six projects that were under construction and/or were already online when AEO2019 was developed are assumed to come online/or to have come online within the following timeframes: [2]

- Sabine Pass LNG Terminal, LA (trains 1–5): 2018
- Cove Point, MD: 2018
- Cameron LNG (trains 1–3), LA: 2019–2020
- Elba Liquefaction Project, GA: 2018–2019
- Freeport LNG (trains 1–3), TX: 2019–2020
- Corpus Christi LNG (trains 1–3), TX: 2018–2019, 2022.

For all projects, trains are assumed to ramp up their utilization rate according to Table 2.

Table 2. Percentage of utilization by LNG train number and months after initial in-service date

Months after initial in-service month	Train 1	Train 2	Train 3
In-service month	10	10	50
1	25	25	85
2	50	50	—
3	50	85	—
4	85	—	—

In each projection year, the module assesses the relative economics of constructing and operating one to three generic trains, which produce 200 billion cubic feet per year, for the next 20 years in each of four representative Lower 48 states or a four-train Alaska LNG terminal. This assessment compares a model-generated estimate of the expected market price in Europe and Asia during the period with the expected price of domestic natural gas (assuming the increased exports) in each state, in addition to the assumed charges for liquefaction, shipping, and regasification (shown in Table 3). A present value of the differential is set with a discount rate of 10%. The first train will come on with a positive present value, while the next two trains require a progressively higher present value to reflect additional risk. Once the module determines that a train is economically viable, its LNG export capacity is added for three years in

[2] The dates and base capacities for LNG export facilities were consistent with EIA's reported U.S. liquefaction capacity as of October 2018.

the state showing the greatest positive economic potential. The decision to build a liquefaction facility is assumed to be made four years before the facility first comes online.

Table 3. Selected charges related to LNG exports

2017 dollars per million Btu

	Maryland	Georgia	Louisiana	Texas	Alaska
Liquefaction and pipe fee	3.77	3.77	3.43	3.43	6.99
Reservation charge	3.43	3.43	3.43	3.43	0.00
Shipping to Europe	0.80	0.80	0.98	0.98	2.29
Shipping to Asia	2.19	2.19	2.14	2.14	0.74
Regasification	0.11	0.11	0.11	0.11	0.11
Fuel charge (percent)*	15	15	15	15	15

*Percent increase in market price of natural gas charged by liquefaction facility to cover fuel-related expenses, largely fuel used in the liquefaction process.

Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis

Other constraining assumptions are considered, such as the earliest start year and maximum export capacity in each state. The projected market prices of LNG in Europe (National Balancing Point) and Asia (Japan) are based on the assumed volumes shown in Table 4, projected Brent oil prices, and North American LNG exports.

LNG import volumes are based on historical levels and are assumed to total 76 billion cubic feet per year in the projection period after being benchmarked to STEO values.

Table 4. International LNG volume drivers for world LNG Europe and Asia market price projections

billion cubic feet

	Flexible LNG[a]	LNG imports into OECD Europe and non-OECD Europe and Eurasia[b]	LNG imports into selected IEO regions: Asia[c]
2018	3,741	2,645	6,802
2020	4,218	3,692	8,978
2025	6,995	2,961	11,087
2030	8,889	3,485	11,806
2035	11,276	5,030	13,677
2040	14,174	6,066	16,058
2045	15,606	5,521	17,358
2050	17,041	4,924	19,808
2055	17,985	4,710	21,532
2060	18,728	4,703	22,449
2065	19,165	4,703	22,917
2070	19,492	4,703	23,152

[a]Flexible LNG is a baseline projection of the volumes of LNG sold in the spot market or effectively available for sale at flexible destinations.

[b]OECD Europe and non-OECD Europe and Eurasia includes all countries in Europe and all former Soviet Union countries except Kazakhstan, Russia, Turkey.

[c]The following IEO regions are included: China, India, South Korea, and other Asian countries. These regions are defined in the *International Energy Outlook 2017*.

Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis, based on U.S. Energy Information Administration, *International Energy Outlook 2017* DOE/EIA-0484(2017).

Other miscellaneous volumes

Although the NGMM receives primary production and consumption volumes from other NEMS modules, other miscellaneous volumes are set within the NGMM, including storage withdrawals and injections, supplemental supplies, and lease and plant fuel:

- Month/state storage withdrawals and injections are held constant during the projection period at the average historical level for the past five years, after being scaled to ensure that the net withdrawals during the year sum to zero for each state.
- The relatively small supplemental gas supply projections, which include synthetically produced natural gas and other gaseous substances mixed with the natural gas stream such as propane, are held constant at the average historical level for the past five years and assumed constant throughout the projection.
- Natural gas plant liquids production, as set in OGSM by state/substate on an annual basis, is moved to an assumed state for processing based on where each state's volumes were moved historically in recent years. The amount of natural gas used in processing facilities in each state is established using the ratio of natural gas plant liquids processed to the natural gas fuel needed to process it in the most recent historical year. Volumes are assumed constant throughout the projection.
- Similarly, lease fuel consumption is calculated by state/substate using historically based ratios, averaged for the past five years, of natural gas produced to the lease fuel consumed.
- Pipeline fuel use includes fuel used for distribution and storage services, as well as inter/intrastate pipelines. Fuel used for storage and distribution are set using exogenous, historically based ratios of the fuel used relative to assumed storage injections and withdrawals (0.4%) and delivered natural gas volumes (0.3–6.2%, respectively). The remaining volumes are assumed to reflect fuel used on interstate pipelines and are represented as a percentage of state-to-state flows that are lost.[3] In the historical years, these fuel volumes are allocated to state-to-state arcs proportionately to the historical flows in and out of the region to calculate a historically based loss factor for use in the projection period.
- Natural gas used at facilities that liquefy natural gas for export is assumed to equal 10% of the exported volumes.

Pipeline capacity expansion

Currently known pipeline capacity additions, such as projects under construction or those approved by the Federal Energy Regulatory Commission (FERC), are assumed to be built in the NGMM and come

[3] Although in AEO2019 all remaining pipeline fuel is assumed to be used by compressor stations on interstate pipelines, the NGMM does structurally allow for pipeline fuel use or losses on arcs coming from supply nodes (i.e., intrastate pipeline transport primarily serves to bring natural gas from processing plants to the interstate pipeline system).

online in November of the expected in-service year.[4] After 2019 and before the regular QP is solved in each NEMS iteration, unplanned pipeline capacity additions are determined by running a structurally identical QP but with two changes in primary model inputs: the weather assumption driving consumption levels and the limits on pipeline flows. For the regular QP, consumption levels are provided by the NEMS system that reflects normal weather, and flows between states/nodes are limited by projected capacity levels.

For the capacity expansion QP, consumption levels are multiplied by a sector/state specific factor to reflect a most extreme weather potential. For AEO2018, the factors applied to the residential and commercial sectors in winter months are based on historical differences between the most extreme January consumption level and average January consumption in recent years. The other months are based on similar differences in August. The factors for the industrial and electric generation sectors are assumed to be 10% higher than normal in all months. These sectors are not always the driving force behind pipeline additions because they can frequently employ other options in extreme weather. In addition, in the capacity expansion QP pipeline capacity additions are limited to 40% of the existing capacity. Accordingly, each variable tariff curve is extended from its price point at full utilization to a price generally twice as high, or 40% higher than existing capacity. This method is used to reflect the reality that pipeline capacity will only be added if enough users are willing to pay an additional reservation fee.

Pricing

Spot prices are effectively set within the quadratic program based on the marginal price (shadow price on each balancing constraint in the QP) at each node in the transportation network. Each state has a node where the monthly flows into and out of each state are balanced, including the internal state supply and consumption. The marginal prices at these nodes are used as a proxy for representative state-level spot prices. The price at each supply node (wellhead price) is set equal to the spot price minus the assumed transport or gathering charge ($2018 $0.29/thousand cubic feet). Most of the other arcs in the QP, usually representing state-to-state flows, are assigned a variable tariff in the QP via a curve, which allows the tariff to vary as a function of the pipeline utilization. These curves vary by arc and were informed by historical spot price differentials, historical state-to-state total pipeline capacities, and monthly historical state-to-state flows. All curves have the same general shape: a generally constant or flat tariff at low utilization rates and a sharply increasing rate as utilization approaches 100%. The difference in the price from one node to the next (or basis differential) will also reflect the pipeline fuel loss on the arc, and it can be even higher if pipeline flow constraints on the arc are binding in the QP.

State/month level citygate prices are set using econometrically estimated equations as a function of the spot price and the volume of natural gas consumed by residential and commercial customers in the month/state. Annual/Census division delivered prices to residential and commercial customers are set

[4] Historically, many projects are planned for the in-service date to coincide with the start of the peak demand (winter) season. See EIA's natural gas Pipeline Projects spreadsheet to view the in-service dates for recently completed and historical natural gas pipeline projects.

by adding a sector-specific econometrically estimated distributor tariff to the average annual citygate price in the Census division, calculated using residential plus commercial consumption in each state/month as a quantity weight. Distributor tariffs are a function of residential consumption per household and commercial consumption per unit of commercial floorspace for the residential and commercial sectors, respectively. Markups to annual/Census division delivered prices to industrial customers are set at the historical average from 2010–15 of the industrial price minus the average annual spot price in the region, calculated using industrial consumption in each state/month as a quantity weight. Historical industrial prices are estimated based on prices published in EIA's *Manufacturing Energy Consumption Survey*.

Prices for electric generators in the 16 regions in the Lower 48 states and 3 seasons that are used to exchange consumption volumes and prices between the NGMM and the Electricity Market Module (EMM) are set by adding a markup to the average spot price in the region/season, which was generated using electric consumption as a quantity-weight. These markups are initially set at the historical average from 2013–16, and they increase/decrease during the projection period as the ratio of electric consumption to other consumption in a given region or season increases or decreases. This method reflects the need for electric generators to purchase more firm pipeline service as their market shares increase. The price in Alaska is set by adding a historically based markup to an econometrically estimated citygate price.

The natural gas used in the transportation sector, excluding pipeline fuel use, is distinguished by fuel type—compressed natural gas (CNG) and LNG—and customer category—personal vehicle (purchased fuel at public station), fleet vehicle (purchased fuel at private station), train, and ship. All transport modes for a fuel type are assumed to see the same price with the following adjustments:

- Vehicles are assumed to pay the state and federal motor fuels taxes for either CNG or LNG
- Ships are assumed to pay the same price as vehicles minus the state motor fuels tax
- Trains are assumed to pay the same price as vehicles minus both the state and federal motor fuels tax
- Retail markups are higher for personal vehicles because of smaller volumes of fuel being sold
- Retail markups are lower for rail and ship use because of lower infrastructure costs.

The rail and ship prices are further disaggregated in the NEMS Transportation Demand Module, but no further distinction is made in the prices assigned in the NGMM.

For delivered prices to the transportation sector for vehicles using LNG, the price for delivered dry natural gas to a liquefaction plant is estimated by using the price for delivered natural gas to industrial customers. The retail price for LNG into a vehicle/train/ship is equal to the sum of the price to industrial customers, the assumed price to liquefy and transport the LNG to a station, the retail price markup at the station, and the excise taxes. Table 5 shows the national average state excise tax, and in the model these taxes vary by region.

For delivered prices to the transportation sector to vehicles using CNG, the markup from the regional citygate price is based on posted rates published in the U.S. Department of Energy's Office of Energy Efficiency & Renewable Energy publications of *Clean Cities Alternative Fuel Price Report*. These markups are adjusted for any change in the state and federal excise taxes seen historically versus what is assumed in the projection period. Prices at public and private stations are reported separately. The NGMM assumes that the public prices are for personal vehicles and private stations are for fleet vehicles. These reported prices are assumed to include the retail markup. Therefore, only CNG fleet assumptions are used to calculate a retail markup for rail and shipping transport using CNG's industrial price. The values used throughout the projection period for these components and the primary assumptions behind them are shown in Table 5.

The operating costs required for LNG for rail was assumed at 2018$ $0.24/diesel gallon equivalent (dge) (compared with $0.47/dge for LNG fleet vehicles, as shown above), with the assumption that liquefaction would occur at the refueling point and be less costly. All other assumptions for rail and marine retail price markups are assumed to equal those for fleet vehicles.

Table 5. Assumptions for setting CNG and LNG fuel prices

Year	CNG private	LNG private	LNG public
Retail markup after dry gas pipeline delivery, with no excise tax (2018$/dge)	0.90	0.73	0.93
Capacity (dge/day)	1,600	4,000	4,000
Usage (percent of capacity)	80	80	60
Capital cost (million 2018$)	0.91	1.14	1.14
Capital recovery (years)	5	5	10
Weighted average cost of capital (rate)	0.10	0.10	0.15
Operating cost (2018$/dge)	0.39	0.47	0.67
Federal excise tax (nominal$/dge)[1]	0.21	0.25	0.25
State excise tax (nominal$/dge)[2]	0.17	0.15	0.15
Fuel loss for liquefying and delivering LNG (percent of input volumes)	--	10	10
Fuel loss at station (percent of input volumes)	0.5	1.0	2.0

dge=diesel gallon equivalent.
Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis. U.S. Tax Code [1] and State Tax Codes [2].

Legislation and regulations

Current federal and state motor fuels taxes are applied to both compressed natural gas and liquefied natural gas used in vehicles.

Notes and sources

[1] Source: H.R. 3236 (Public Law number 114-41) and 26 U.S. Code 4041 and 4081 (Internal Revenue Service). Propane and compressed natural gas (CNG) are subject to a federal excise tax of $0.183 per gasoline gallon equivalent (GGE).

[2] Source: U.S. Department of Energy Office of Energy Efficiency and Renewable Energy's Alternative Fuels Data Center. When state motor vehicle fuel tax information was unavailable for alternative fuels, the following state government sources were used:

State of Connecticut Department of Revenue Services, PS 92 (10.1)
State of Delaware Division of Motor Vehicles, Transportation Services FAQ
Illinois Department of Revenue, Tax Rate Database, Motor Fuel Taxes
Massachusetts Department of Revenue, Motor Fuel Excise Overview
Comptroller of Maryland, Motor Fuel Tax Rates
Minnesota Department of Revenue, Fuel Excise Tax Rates and Fees
Montana Legislature, Montana Code Annotated 2015, 15-71-711
Nebraska Department of Revenue, Motor Fuels Division
New Hampshire Department of Safety, Road Toll Bureau
Ohio Department of Taxation, Motor Fuel Tax
State of Rhode Island, Division of Taxation, Taxation of Special Fuels
Texas Department of Motor Vehicles, Green Vehicle Laws and Regulations in Texas
State of Wisconsin, Department of Revenue, Alternate Fuel Tax
Wyoming Department of Transportation, Fuel Tax Administration, Tax Rates