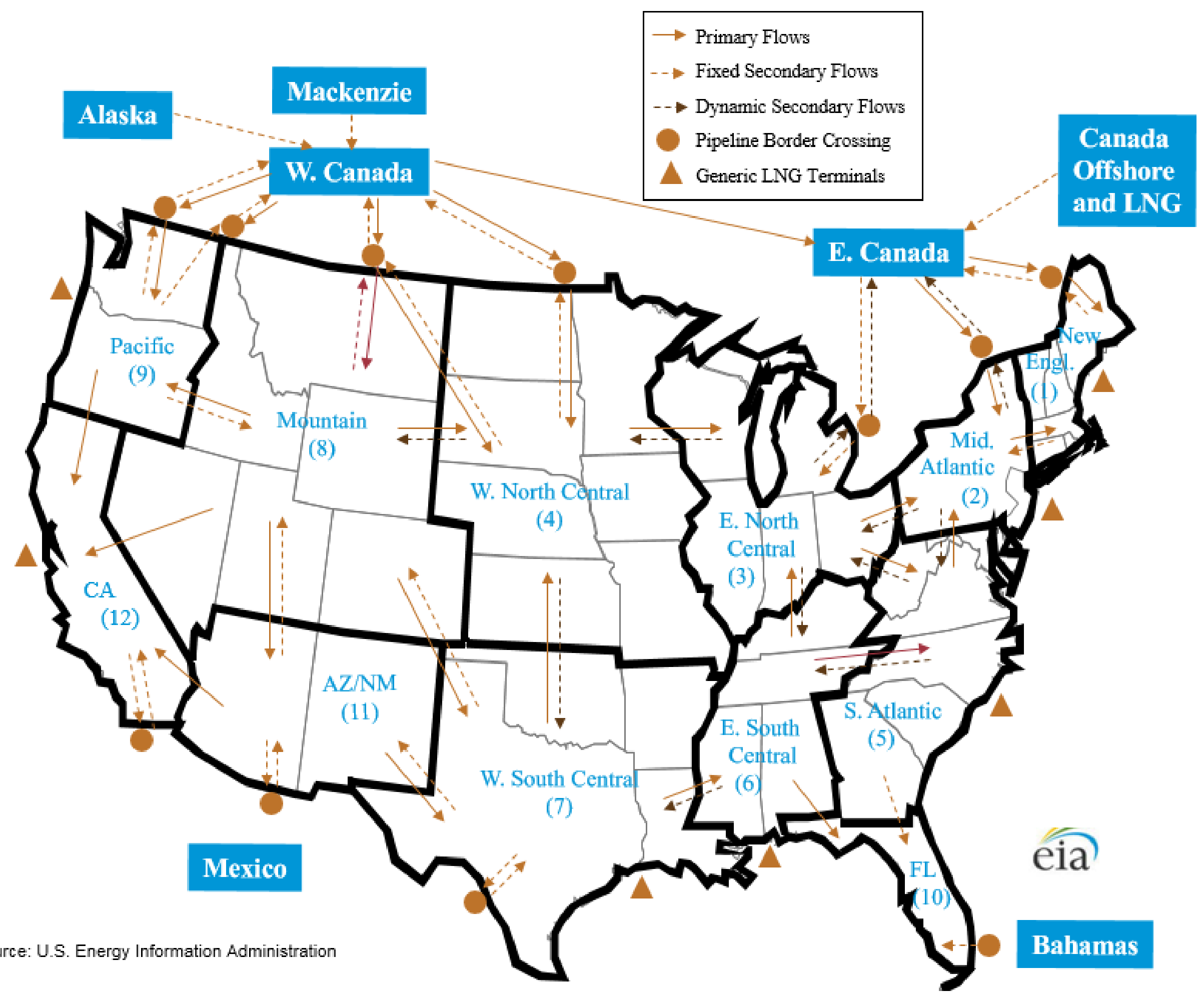
Chapter 10. Natural Gas Transmission and Distribution Module

The NEMS Natural Gas Transmission and Distribution Module (NGTDM) derives domestic natural gas production, wellhead and border prices, end-use prices, and flows of natural gas through a regional interstate representative pipeline network, for both a peak (December through March) and off-peak period during each projection year. These projections are derived by solving for the market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them. Natural gas flow patterns are a function of the pattern in the previous year, coupled with the relative prices of the supply options available to bring gas to market centers within each of the NGTDM regions (Figure 10.1). The major assumptions used within the NGTDM are grouped into five general categories: structural components of the model, capacity expansion, pricing of transmission and distribution services, supplemental natural gas, and imports and exports. A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in Model Documentation: Natural Gas Transmission and Distribution Module of the National Energy Modeling System, Model Documentation 2016, DOE/EIA-M062 (2017) (Washington, DC, 2017).

Figure 10.1. Natural Gas Transmission and Distribution regions



Source: U.S. Energy Information Administration

Key assumptions

Structural components

The primary and secondary region-to-region flows represented in the model are shown in Figure 10.1. Primary flows are determined, along with non-associated gas production levels, as the model equilibrates supply and demand. Associated-dissolved gas production is determined in the Oil and Gas Supply Module (OGSM). Secondary flows are established before the equilibration process and are largely set exogenously. However in the East, where secondary flows are expected to grow significantly, secondary flows are endogenously set based in part on price differentials between sending and receiving regions.

Liquefied natural gas (LNG) imports and domestically-produced natural gas exports are also not directly part of the equilibration process, but are set at the beginning of each NEMS iteration in response to the price from the previous iteration and projected future prices, respectively. LNG re-exports are set exogenously to the model. Flows and production levels are determined for each season, linked by seasonal storage.

When required, annual quantities (e.g., consumption levels) are split into peak and off-peak values based on historical averages. When multiple regions are contained in a Census Division, regional end-use consumption levels are approximated using historical average shares. Supply curves and electric generator gas consumption are provided by other NEMS modules for subregions of the NGTDM regions, reflective of how their internal regions overlap with the NGTDM regions. Pipeline and storage capacity are added as warranted by the relative volumes and prices. Regional pipeline fuel and lease and plant fuel consumption are established by applying a historically based factor to the flow of gas through a region and the production in a region, respectively.

Prices within the network, including at the borders and the wellhead, are largely determined during the equilibration process when supply and demand are balanced and prices are set. Delivered prices for each sector are set by adding an endogenously estimated markup (e.g., a distributor tariff) to either the regional representative city gate price or the regional market hub price.

Capacity expansion

For the first two years of the projection, announced pipeline and storage capacity expansions, which are deemed highly likely to occur, are used to establish limits on flows and seasonal storage in the model. Subsequently, pipeline and storage capacity is added when increases in consumption, coupled with an anticipated price increase, warrant such additions (i.e., flow is allowed to exceed current capacity if the demand still exists given an assumed increased tariff). Once the model determines that an expansion will occur, the associated capital costs are applied in the revenue requirement calculations in future years. Capital costs are assumed based on average costs of recent comparable expansions for compressors, looping, and new pipeline.

Pipeline and local distribution companies are assumed to build and subscribe to a portfolio of interstate pipeline and storage capacity to serve a region-specific colder-than-normal winter demand level, set at 30% above the daily average. Maximum pipeline capacity utilization in the peak period is set at 99%. In the off-peak period, the maximum is assumed to vary between 75% and 99% of the design capacity. The overall level and profile of consumption, as well as the availability and price of supplies, mostly cause realized pipeline utilization levels to be lower than the maximum.

Pricing of transmission and distribution services

Transport rates between regions are set for the purposes of determining natural gas flows through the representative pipeline network based on historical observed differentials between regional spot prices. Ultimately, regional city gate prices reflect the addition of reservation charges along each of the connecting routes and within a region. Per-unit pipeline reservation charges are initially based on a regulated cost-of-service calculation and an assumed flow rate and are dynamically adjusted based on the realized utilization rate. Reservation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base.

For the electric generator sector, delivered natural gas prices are based on regional prices which do not directly include any pipeline reservation fees (i.e., spot prices), with an added markup based on averaged historical values. For the residential and commercial customers, delivered natural gas prices are based on regional city gate prices with an added econometrically estimated distributor markup, set as a function of the sectoral consumption, as well as the number of gas burning households and commercial floorspace, respectively. For the industrial sector, distributor markups are estimated separately for energy-intensive and non-energy-intensive industrial customers as a function of consumption. Prices are originally set on a seasonal basis and are averaged with quantity-weights to derive annual prices.

The natural gas used in the transportation sector, excluding pipeline fuel use, is distinguished by fuel category (compressed natural gas and LNG), customer category (private refueling station (fleet) and public retail station), and transport mode (vehicle, train, and ship). All transport modes are assumed to see the same price with the exception that: 1) vehicles are assumed to pay the state and federal motor fuels taxes for either compressed natural gas (CNG) or LNG, 2) ships are assumed to pay the same price as vehicles minus the state motor fuels tax, and 3) trains are assumed to pay the same price as vehicles minus both the state and federal motor fuels tax, with the LNG price for trains further lowered to account for assumed lower infrastructure costs. The use by rail and ship is further disaggregated in the NEMS Transportation Sector Module, but no further distinction is made on the prices.

The price for delivered dry natural gas to a liquefaction plant is approximated by using the price for delivered dry natural gas to electric generators. The retail price for LNG into a vehicle/train/ship is therefore equal to the sum of the price to electric generators, the assumed price to liquefy and transport the LNG to a station, the retail price markup at the station, and the excise taxes. Table 10.1 shows the national average state excise tax, while in the model these taxes vary by region. The markup for the retail price of CNG at a station off of the regional city gate price is based on posted rates published in 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 tax seen historically versus what are assumed in the projection period. CNG for fleets is assumed to have a lower infrastructure and operating cost and is therefore assigned a lower price ($0.53 1987$ per thousand cubic feet or $0.14 2016$/diesel gallon equivalent (dge) less) than at a retail station. The values used throughout the projection period for these components and the primary assumptions behind them are shown in Table 10.1.

Table 10.1. Assumptions for setting CNG and LNG fuel prices

Year	CNG fleet	CNG retail	LNG fleet	LNG retail
Retail markup after dry gas pipeline delivery, with no excise tax (2016$/dge)	0.88	1.02	1.54	1.74
Capacity (dge/day)	1,600	1,100	4,000	4,000
Usage (percent of capacity)	80	60	80	60
Capital cost (million 2016$)	0.88	0.55	1.10	1.10
Capital recovery (years)	5	10	5	10
Weighted average cost of capital (rate)	0.10	0.15	0.10	0.15
Operating cost (2016$/dge)	0.37	0.56	0.45	0.65
Charge for liquefying and delivering LNG (2016$/dge)	--	--	0.83	0.83
Federal excise tax (nominal$/dge)	0.21	0.21	0.25	0.25
State excise tax (nominal$/dge)	0.17	0.17	0.18	0.18
Fuel loss for liquefying and delivering LNG (percent of input volumes)	--	--	10	10
Fuel loss at station (percent of input volumes)	0.5	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 and State Tax Codes.

The retail markup above the cost of dry gas for LNG for rail was assumed at $1.00 2016$/dge (compared to $1.54/dge for fleet vehicles as shown in Table 10.1), with the assumption that liquefaction would occur at the refueling point and cost $0.59/dge (compared to $0.83/dge for vehicles), operating costs would be $0.23/dge (compared to $0.45/dge for fleet vehicles), and capital cost recovery for additional equipment beyond the liquefiers would be $0.17/dge (compared to $0.26/dge for fleet vehicles, not shown in table).

Supplemental natural gas

The projection for supplemental gas supply is identified for three separate categories: pipeline quality synthetic natural gas (SNG) from coal or coal-to-gas (CTG), SNG from liquids, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for British Thermal Unit (Btu) stabilization, and manufactured gas commingled and distributed with natural gas). The third category, other supplemental supplies, are held at a constant level of 8.5 billion cubic feet per year throughout the projection because this level is consistent with historical data and it is not expected to change significantly in the context of a Reference case. SNG from liquid hydrocarbons in Hawaii is assumed to continue over the projection at the average historical level of 2.6 billion cubic feet per year. SNG production from coal at the currently operating Great Plains Coal Gasification Plant is also assumed to continue through the projection period at an average historical level of 51.0 billion cubic feet per year. Additional CTG facilities are assumed not to be economic to build over the projection period.

Natural gas imports and exports

U.S. natural gas trade with Mexico is determined endogenously based on various assumptions about the natural gas market in Mexico. Natural gas consumption levels in Mexico are set exogenously based on projections from the International Energy Outlook 2016 and are provided in Table 10.2, along with initially assumed Mexico natural gas production and LNG import levels, if any, targeted for markets in Mexico. Adjustments to production are made endogenously within the model to reflect a response to price fluctuations in the United States within the market in Mexico. In each year, the difference between production plus LNG imports, if any, and consumption in Mexico plus a very small assumed minimum level of pipeline exports is assumed to be imported from the United States.

Table 10.2. Exogenously specified Mexico natural gas consumption, production, and LNG imports

billion cubic feet per year

	Consumption	Initial Dry Production	Initial LNG Imports
2015	2,616	1,494	250
2020	3,115	1,225	0
2025	3,508	1,619	0
2030	3,913	2,094	0
2035	4,332	2,569	0
2040	4.765	3.044	0
2045	5,211	3,519	0
2050	5,670	3,994	0

Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis, based on U.S. Energy Information Administration, International Energy Outlook 2016 DOE/EIA-0484(2016).

Similarly to Mexico, Canada is modeled through a combination of exogenously and endogenously specified components. Western Canadian production, U.S. import flows from Canada, and U.S. export flows to Canada are determined endogenously within the model. Canadian natural gas production in Eastern Canada, consumption, and LNG exports are set exogenously in the model and are shown in Table 10.3. Production from conventional and tight formations in the Western Canadian Sedimentary Basin is set endogenously to the model using annual supply curves based on an expected production level equal to the beginning-of-year proved reserves multiplied by a historical production-to-reserve ratio, assumed to decline by 1% each year. A baseline projection of successful conventional/tight gas wells is set exogenously with an associated baseline price projection and is used to establish successful gas wells in the projection as the projected price varies from the base. Conventional/tight reserve additions are set equal to the product of successful natural gas wells and a finding rate (set at an historical level and assumed to decline 3% each year).

The remaining marketable (technically and economically recoverable) gas resource estimates for coalbed methane and shale gas are assumed in the model at 35 and 222 trillion cubic feet, respectively, as of the beginning of 2013 [10.1]. Production from coalbed and shale sources is established based on an assumed production path which varies in response to the level of remaining resources and the solution price in the previous projection year. LNG imports to Canada are set in conjunction with the LNG import volumes for the Lower 48 states.

Table 10.3. Exogenously specified Canada natural gas consumption, production, and LNG exports

billion cubic feet per year

Year	Consumption	Production Eastern Canada	LNG Exports
2015	3,646	80	0
2020	3,865	40	0
2025	4,235	17	0
2030	4,738	0	0
2035	5,210	0	1,003
2040	5,623	0	1,734
2045	6,028	0	1,734
2050	6,456	0	1,734

Source: Consumption and LNG exports – Based on U.S. Energy Information Administration, International Energy Outlook 2016, DOE/EIA-0484(2016); Production - Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis.

LNG imports to the United States and Canada are determined endogenously within the model using Atlantic/Pacific and peak/off-peak supply curves derived from model results generated by EIA's International Natural Gas Model (INGM). Prices from the previous model iteration are used to establish the total level of U.S./Canadian LNG imports in the peak and off-peak periods and in the Atlantic and Pacific regions. First, assumed LNG imports that are consumed in Mexico are subtracted (presuming the volumes are sufficient). Then, the remaining levels are allocated to the model regions based on the previous year's import levels, the available regasification capacity, and the relative prices. Regasification capacity is limited to facilities currently in existence and those already under construction, which is fully sufficient to accommodate import levels projected by the model. LNG import volumes into New England have an assumed minimum of 55 billion cubic feet per year.

LNG exports of domestically produced natural gas from the Lower 48 states and Alaska are set endogenously in the model. The five projects that were under construction and/or were already online when AEO2017 was developed were assumed to come online/or came online in the indicated year: Sabine Pass, LA, 2016; Cove Point, MD, 2018; Hackberry, LA, 2018; Freeport, TX, 2019; and Corpus Christi, TX, 2019. Beyond these, the model assesses the relative economics of a generic 200 billion cubic feet train in operation over the next 20 years in each viable coastal region by comparing a model-generated estimate of the expected market price in Europe and Asia over the next 20 years against the expected price of natural gas in each coastal region plus assumed charges for liquefaction, shipping, and regasification (shown in Table 10.4). A present value of the differential is set using a discount rate of 10%. The model limits the annual liquefaction capacity builds to three trains per year. Once the model determines that a train is economically viable, the train is added over three years in the region showing the greatest positive economic potential. Once a facility is built, the model operates it at its design capacity throughout the projection period unless the competing price in Asia or Europe falls below the delivered price of U.S. LNG in the region, excluding assumed reservation charges (i.e., "sunk" costs) for liquefaction.

Other constraining assumptions are considered, such as earliest start year and maximum export capacity in each region. The projected market prices of LNG in Europe (National Balancing Point) and Asia (Japan) are based on the assumed values shown in Table 10.5, projected Brent oil prices, and the level of North American LNG exports. Annual U.S. exports of LNG to Japan via Alaska's existing Kenai facility are assumed to have ended in 2016. LNG re-exports are assumed to end in 2016.

Table 10.4. Charges related to LNG exports

2016 dollars per million Btu

	South Atlantic	West South Central	Washington/Oregon	Alaska
Liquefaction & Pipe Fee	3.64	3.31	4.52	7.71
Shipping to Europe	1.08	1.41	4.25	4.02
Shipping to Asia	2.90	2.81	1.27	0.99
Regasification	0.11	0.11	0.11	0.11
Fuel charge (percent)*	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.

Table 10.5. International natural gas volume drivers for world LNG Europe and Asia market price projections

billion cubic feet

	Flexible LNG*	Consumption OECD Europe	Consumption Japan	Consumption S. Korea	Consumption China	Production China
2015	3,379	18,194	5,070	1,979	5,807	5,264
2020	3,893	19,319	5,188	2,107	9,109	7,200
2025	5,208	20,740	5,674	2,189	13,649	11,103
2030	6,370	22,519	5,760	2,350	17,665	14,195
2035	7,342	23,849	5,919	2,687	22,549	16,681
2040	8,706	25,487	5,982	2,981	27,236	18,667
2045	9,512	27,092	5,770	3,048	27,955	19,596
2050	10,392	28,796	5,565	3,116	28,695	20,571

*Flexible LNG is a baseline projection of the volumes of LNG sold in the spot market or effectively available for sale at flexible destinations, based on U.S. Energy Information Administration, International Energy Outlook 2016, DOE/EIA-0484(2016), and U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis.
Source: U.S. Energy Information Administration, International Energy Outlook 2016, DOE/EIA-0484(2016).

Legislation and regulations

The methodology for setting reservation fees for transportation services is initially based on a regulated rate calculation, but is ultimately consistent with the Federal Energy Regulatory Commission's alternative ratemaking and capacity release position in that it allows some flexibility in the rates pipelines ultimately charge. The methodology is market-based, meaning that rates for transportation services will respond positively to increased demand for services while rates will decline should the demand for services decline.

Section 312 of the Energy Policy Act of 2005 authorizes the Federal Energy Regulatory Commission to allow natural gas storage facilities to charge market-based rates if it was believed that they would not exert market power. Storage rates are allowed to vary in the model from regulation-based rates, depending on market conditions.

Notes and sources

[10.1] Coalbed and shale gas remaining marketable gas resources in the Western Canadian Resource Base from the Appendices of National Energy Board of Canada's "Canada's Energy Future 2013 – Energy Supply and Demand Projections to 2035 – An Energy Market Assessment," November 2013.